Understanding, Evaluating, and Remediating Leakage from Abandoned Oil and Gas Wells During Geological Storage of Carbon Dioxide

Dominic DiGiulio, Ph.D.

Independent Consultant for the Environmental Integrity Project's Center for Applied Environmental Science

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About the Author: Dr. DiGiulio is a retired geoscientist from the U.S. Environmental Protection Agency. He has conducted research on: emissions of volatile organic compounds from abandoned wells, leakage of produced water, condensate, and drilling fluids from impoundments to groundwater, contamination of groundwater from hydraulic fracturing, subsurface methane and carbon dioxide migration (stray gas), intrusion of subsurface vapors into indoor air (vapor intrusion), gas flow-based subsurface remediation (soil vacuum extraction, bioventing), groundwater sampling methodology, soil-gas sampling methodology, gas permeability testing, and solute transport of contaminants in soil. He assisted in the development of EPA's original guidance on vapor intrusion and the EPA's Class VI Rule on geologic sequestration of carbon dioxide. He has served as an expert witness in litigation relevant to oil and gas development, testified before State oil and gas commissions on proposed regulation, and testified before Congress on the impact of oil and gas development on water resources. His consulting services have included reports on: stray methane gas migration, geological carbon storage in Louisiana, storage of natural gas liquids in solution mined caverns, proposed oil and gas regulations in Colorado, impact to groundwater resources from Class II disposal wells in Ohio, Idaho, and Florida, produced water transport in barges along the Ohio River, proposed EPA regulation on discharge of produced water to surface water, and Bureau of Land Management leases in Wyoming, Montana, and Colorado.

Contact Information: dom.c.digiulio@gmail.com

Executive Summary

CO_2 leakage via abandoned wells is widely considered to be one of the most significant leakage pathways for geologic storage of CO_2. There are likely in excess of 4 million abandoned wells in the United States. Locating abandoned wells, especially in areas predating oil and gas well regulatory permitting requirements, can be problematic. Depleted oil and gas fields are especially of concern since they contain a large number of abandoned wells which may leak during repressurization.

The importance of properly evaluating wellbores prior to plugging to determine the need for corrective action and evaluating wellbores that have been plugged in the past cannot be stressed enough. Leakage of CO_2 into an Underground Source of Drinking Water would induce geochemical changes (e.g., mobilization of metals) affecting its usability as a water supply source. A major CO_2 release from a wellbore to the atmosphere would be a life-threatening scenario similar to that which occurred from a CO_2 pipeline rupture in Satartia, Mississippi in February 2020. Given this event, and documented CO_2 wellbore blowouts in the literature, it is apparent that there is a need for a setback distance from both injection wells and abandoned wells within the Area of Review containing supercritical CO_2. At present, there are no setback distances stipulated in federal or state regulations for geologic storage of CO_2.

Lower levels of leakage threaten the permanence of geological storage. A leakage rate of less than 1% per thousand years is necessary for geological storage of CO_2 to achieve the same climate benefits as renewable energy sources. There is no permanence criterion in federal Class VI permit requirements nor in Monitoring, Reporting, and Verification (MRV) plans that must be submitted per 40 CFR Part 98 Subpart RR requirements. State regulatory agencies should stipulate a permanence criterion as a prerequisite for Class VI permit application.

Class VI federal regulations require that owners or operators evaluate artificial penetrations that penetrate the confining layer of a storage reservoir within the Area of Review for the quality of casing and cementing, and in the case of abandoned wells, for the quality of plugging and abandonment. Corrective action then must be performed on artificial penetrations that could serve as a conduit for fluid movement. However, unlike injection wells which require internal and external mechanical integrity testing prior to injection, evaluation of artificial penetrations is non-prescriptive even though artificial penetrations in many instances will be indirect contact with pressurized supercritical CO_2 for thousands of years similar to injection wells. Unless the UIC Director requires additional information, regulatory requirements for providing information on oil and gas wells to be plugged or that have already been plugged amount to little more than providing a tabulation of wells. An operator may simply state that corrective action is unnecessary without providing publicly available supporting documentation (e.g., well schematics, cement evaluation logs, results of internal and external mechanical integrity testing, results of sustained casing pressure testing, etc.) or revealing that supporting information is absent. Also, legacy wells are plugged based on state regulations which do not mandate internal and external mechanical integrity testing prior to plugging and are not designed to contain supercritical CO_2.

Well barrier failure in oil and gas wells is very common. Hence, there must be a robust evaluation and regulatory review of both plugged and unplugged wellbores that penetrate the primary confining layer in the Area of Review prior to injection. Plugged wells can and do leak. Evaluation should commence with a review of available information including drilling logs, well completion and plugging reports, casing and cementing records, records on internal and external mechanical integrity tests, cement bond/variable density logs, information on well deviation, and wellbore diagrams. It is critical all information used by an

owner or operator in evaluating well penetrations be made publicly available during the Class VI permitting process to enable a third-party review.

In most instances when a wellbore is plugged, production casing will remain in place. Hence, cement between the borehole wall and production casing must be fully competent to prevent leakage. External mechanical integrity testing should be conducted at the interface of the storage reservoir and primary confining layer prior to plugging to verify the integrity of cement at this location and be supported with recently conducted cement evaluation logs. Sustained casing pressure testing or measurement of surface casing vent flow should be conducted prior to plugging as well. Sustained casing pressure and surface casing vent flow are direct indicators of annular well barrier failure. This testing could be supplemented by leak testing using flux chambers around well penetrations before and after plugging.

A robust evaluation of unplugged and plugged wells and corrective action prior to injection when necessary will increase the probability of protection of groundwater resources, protection of public health, and permanence of geological storage of carbon dioxide.

1. Understanding the Scale of the Problem

1.1. <u>Number of Abandoned Wells in the Unites States</u>

Geological storage of carbon dioxide (CO_2) requires identification of all potential leakage pathways at candidate storage sites (Bryant, 2007, Gasda et al., 2004, Mortezaei et al., 2021). CO_2 leakage via abandoned wells is widely considered to be one of the most significant leakage pathways for geologic storage of CO_2 (Jordan and Benson, 2009, Zhang and Bachu, 2011).

In 2020, the U.S. Environmental Protection Agency (EPA) estimated that there were over 3.2 million abandoned wells in the United States (EPA, 2020). This number includes oil and gas wells with no recent production (plugged, inactive, temporarily abandoned, shut-in, and idle), with or without a responsible owner (i.e., orphaned). A review of state records in 2020 by Kang et al. (2021) found that there were 4,653,000 oil and gas wells in the United States of which 1,954,000 were active and 1,519,000 were plugged (Kang et al., 2021) indicating the presence of 2.7 million inactive or abandoned wells.

However, this estimate of abandoned well numbers is likely low. There are a large number of undocumented abandoned wells in the United States especially in the Appalachian area where oil and gas developed started in the United States. The term "undocumented" refers to a well that is entirely unknown to a state regulatory agency or a well of which the agency has some evidence, but which requires further records research or field investigation for verification (IOGCC, 2021). For example, a recent (November 2022) review of a publicly accessible database hosted by the Pennsylvania Department of Environmental Protection (PADEP) catalogued 24,619 documented abandoned wells in Pennsylvania of which only 18,608 had associated geographical coordinates (DiGiulio et al., 2023). The PADEP estimates that there are approximately 200,000 abandoned oil and gas wells that remain undocumented. Hence, in Pennsylvania, the number of undocumented abandoned wells exceeds the number of documented abandoned wells by almost an order of magnitude. In another example, a New York state report in 1994 estimated that, of the 61,000 oil and gas wells drilled to that date, no records existed for 30,000 of them (Bishop, 2013).

Somewhere between 828,000 and 1,060,000 oil and gas wells were drilled prior to a formal regulatory system, most of which have no information available in state databases (IOGCC, 2021). Saint-Vincent et al. (2020b) state that when considering the presence of undocumented abandoned wells, there are likely in excess of 6 million abandoned oil and gas wells in the United States. Approximately two of three wells ever drilled in the United States are currently inactive and only about one in three of inactive wells are plugged (Kang et al., 2021).

Hence, using EPA's definition of abandoned wells, there are at least 4 million abandoned wells in the United States of which approximately 1.5 million are plugged.

1.2. Location of Abandoned Wells in Context to Geologic Storage of Carbon Dioxide

A large number of abandoned wells overlie areas of proposed geologic storage of CO_2. If active and depleted oil and gas fields are included among formations for subsurface storage potential, the locations of approximately 94% of documented orphaned wells overly potential underground storage formations (Kang et al., 2023). Most documented orphaned abandoned wells occur over saline aquifers of potential use for geologic storage of CO_2 (**Figure 1**). Depleted oil and gas reservoirs may be good candidates for injection of CO_2, primarily due to existing infrastructure facilities. However, the existence of a large number of well penetrations could increase the possibility of leakage from tens to hundreds of these wells (Celia et al., 2004; Raza and Gholami, 2019).

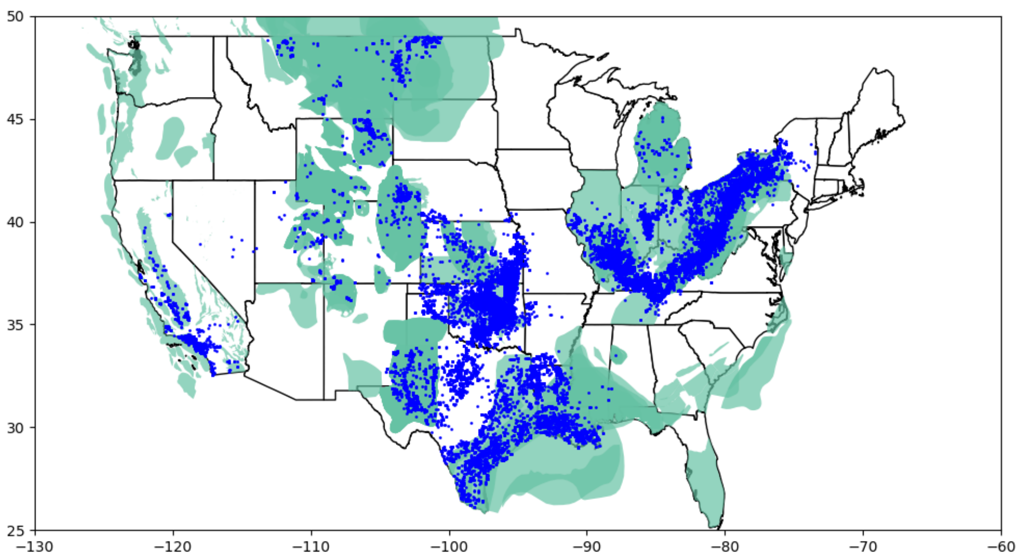

Figure 1. Locations of orphaned abandoned wells (blue dots) and saline aquifers of potential use for geologic storage of CO_2. Figure from Kang et al. (2023).

As an example, Rossi and DiGiulio (2023) conducted a review of the state of Louisiana's Strategic Online Natural Resources Information System (SONRIS) data portal to determine the number and location of abandoned wells in Louisiana in relation to locations of potential geologic storage of CO_2. Locations of potential storage reservoirs for CO_2 were provided in the National Carbon Sequestration Database and Geographic Information System (NATCARB) maintained by the National Energy Technology Laboratory (NETL) (NETL, 2015, 2022). Of 245,322 oil and gas wells listed in SONRIS, 58,704 wells were listed as active (23.9%), 182,051 wells were listed as abandoned (74.2%), and 4,567 wells were listed as abandoned and orphaned (1.9%). Hence, the majority of oil and gas wells (186,618 of 245,322 or 76.1%) in Louisiana are abandoned.

Most abandoned wells in Louisiana (158,457 or 87.0% of non-orphaned abandoned wells) are plugged. A total of 13,235 abandoned wells plugged prior to modern cementing standards in 1953 overlie saline aquifers designated for potential storage of CO_2 (**Figures 2 - 4**). Of these wells, only ~7.3% (1,720) have recorded perforation depths. Given the age of many of these plugs, and the relatively scant amount of data concerning perforation depths, appraising plug integrity may be difficult if not impossible in many parts of Louisiana. In this situation, EPA (2013) recommends replugging wells prior to injection of CO_2.

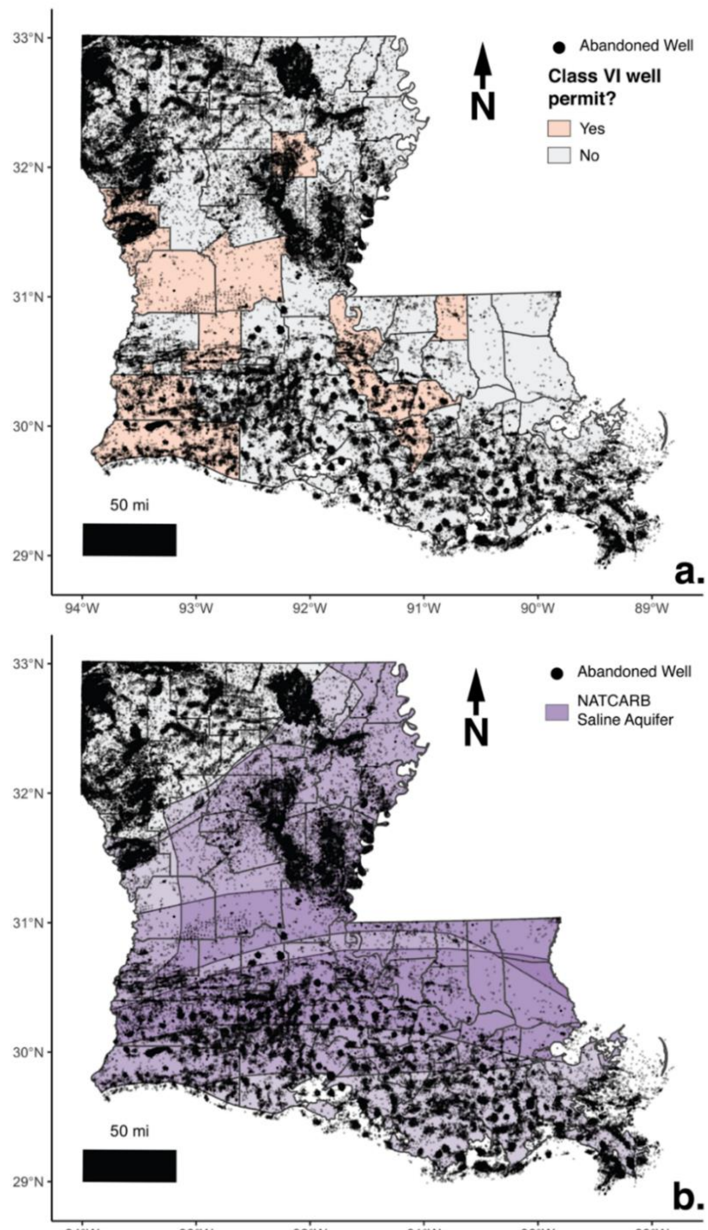

Figure 2. (a) Locations of abandoned wells in the SONRIS database in relation to parishes with pending or active Class VI well permits (US EPA, 2023), (b), and NATCARB saline aquifers (NETL, 2015). Figure from Rossi and DiGiulio (2023).

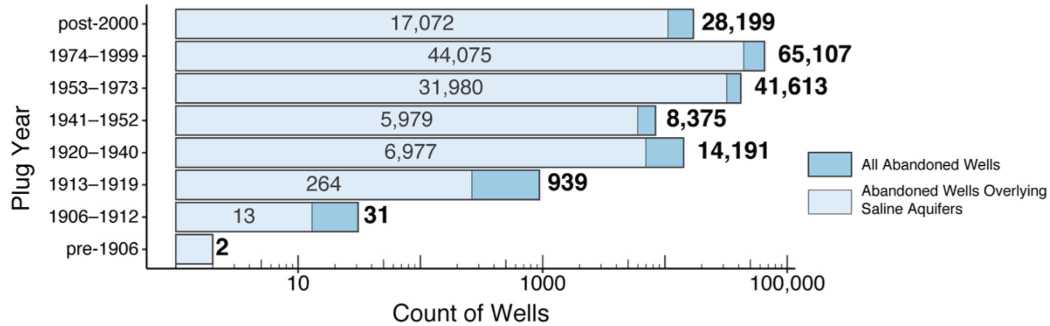

Figure 3. Count of plugged abandoned wells by plug age. Bold numbers are the total count of wells for each group, and numbers within bars indicate the count of wells overlying saline aquifers. Figure from Rossi and DiGiulio (2023).

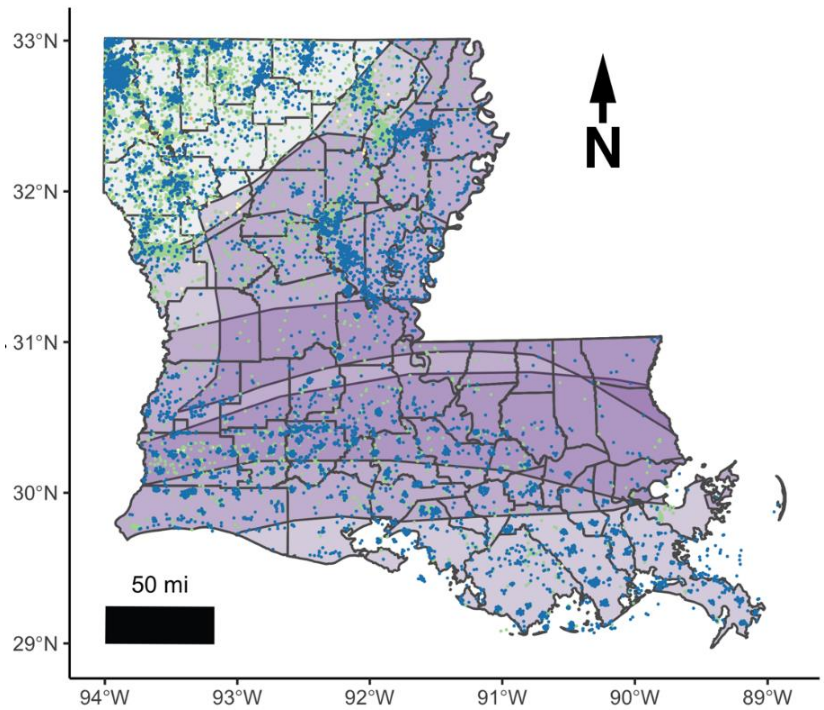

Figure 4. Locations of abandoned wells plugged prior to modern standards in 1953. Wells plugged prior to 1941 likely did not have cement plugs. Figure from Rossi and DiGiulio (2023).

1.3. Proximity of Abandoned Wells to Buildings and Homes

Abandoned wells are located in proximity to buildings and people. At least 4.6 million people live within 1 km of at least one documented orphaned well (Kang et al., 2023). DiGiulio et al. (2023) found that 2.7% (n=499), 23% (n=4,243), and 93% (n=17,299) of abandoned wells in western Pennsylvania were located within 10 m, 100, and 1 km of buildings (**Figure 5a**). In densely populated Allegheny County, DiGiulio et al. (2023) found that 9.8% (n=42), 41% (n=176), and 87% (n=373) of abandoned wells were within 10 m, 100, and 1 km of residences (**Figure 5b**).

Since the actual number of abandoned wells in Pennsylvania likely exceeds the number of documented abandoned wells having geographical coordinates by almost an order of magnitude (DiGiulio et al., 2023), the number of abandoned wells located in proximity to buildings is likely substantially higher. That is, the number of abandoned wells within 100 m of a building or residence in western Pennsylvania is likely far greater than 4,243. Kang et al. (2023) found that over 27,000 documented orphaned wells are located within 1 km of a domestic water well. Since domestic water wells are associated with residences, it is expected that abandoned wells will be located in proximity to residences through Appalachia (western New York, western Pennsylvania, eastern Ohio, West Virginia, and eastern Kentucky) in addition to parts of Oklahoma, Texas, Louisiana, and California.

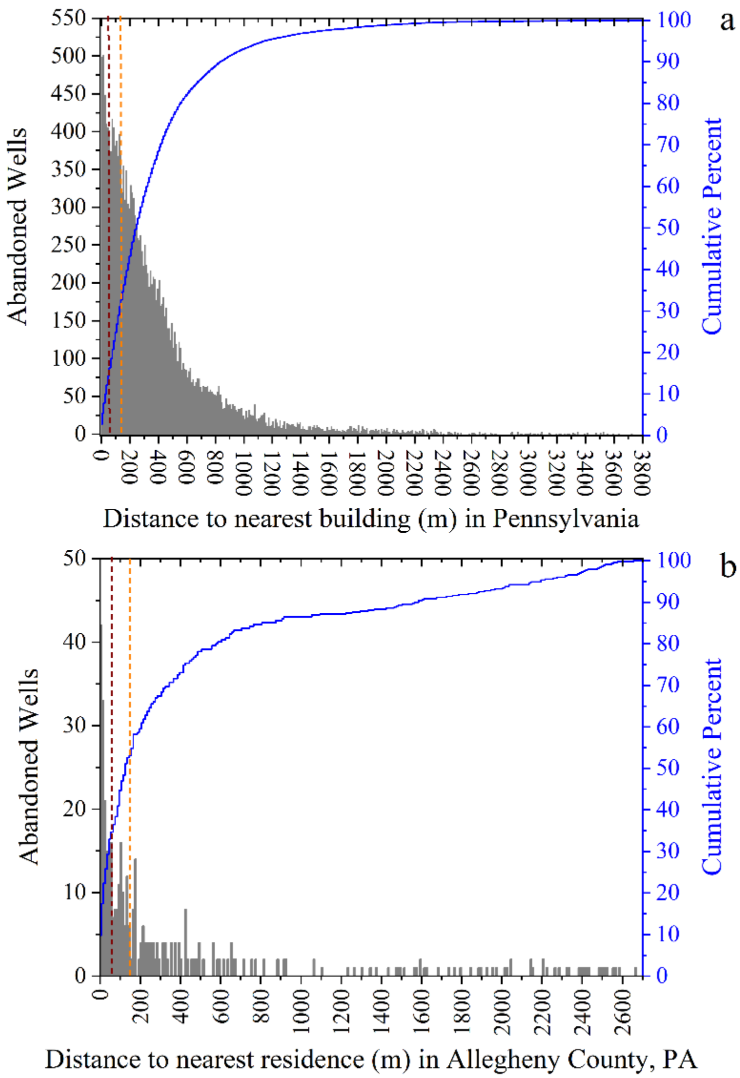

Figure 5. Histograms (bin size = 10 m) illustrating proximity of documented abandoned wells to (a) the nearest building in Pennsylvania and (b) to the nearest residence in Allegheny County in western Pennsylvania. Wine and orange-colored dashed lines represent setback distances from buildings in Pennsylvania for conventional (200 ft) and unconventional (500 ft) oil and gas wells (58 PA CS 3215). Figure from DiGiulio et al. (2023).

If leakage were to occur at the surface, asphyxiation and suffocation are the most common risks associated with large leakage concentrations of the gas. Continued exposure to concentrations above

20–30% is associated with suffocation to humans and most air-breathing animals (Damen et al., 2006). Since CO_2 is denser than air, topography could govern risk from a large-scale release with gas buildup being greater in valleys similar to that caused by a CO_2 pipeline rupture in Satartia, Mississippi in February 2020. This incident caused forty-five people in the town to seek medical attention at a hospital (PHMSA, 2022).

A clearly unacceptable release from a wellbore would be a CO_2 well blowout. A CO_2 well blowout is considered a "low probability high consequence incident" (Oldenburg and Budnitz, 2016) that could cause an immediate danger to public health in the vicinity of an abandoned well. The Sheep Mountain CO_2 blowout on March 17, 1982 is a well-documented case in the literature (Lynch et al., 1985). The leakage rate was estimated to be 13,000 tons of CO_2 per day (Lynch et al., 1985). One hundred percent CO_2 flow was observed in the well with chunks of dry ice occasionally ejected hundreds of feet into the air. Other examples of CO_2 well blowouts include the Travale geothermal field, Italy in 1972 having a CO_2 release rate of 113 kg/s and the Torre Alfina geothermal field, Italy in 1973 (Lewicki et al., 2007) having a CO_2 leakage release rate of 76 kg/s (Lewicki et al., 2007; Aines et al., 2009). For abandoned wells, there are several modes of well integrity failure that could potentially cause well blowouts. These include CO_2-induced cement degradation (Kutchko et al., 2007; Miao et al., 2020), and casing collapse (Solomon and Flach, 2010).

In developing criteria for geologic storage of CO_2 in depleted hydrocarbon reservoirs, Callas et al. (2022) recommend a population density > 75 people per km^2 as a disqualifying threshold for a storage well. It is apparent that there is a need for a setback distance from both injection wells and abandoned wells within the Area of Review containing supercritical CO_2. At present, there are no setback distances stipulated in federal or state regulations for geologic storage of CO_2.

1.4. What We Know from Leakage of Methane from Abandoned Wells

When considering potential leakage of CO_2 from abandoned wells it may be useful to examine leakage of natural gas from abandoned wells. Leakage of natural gas is common from both unplugged and plugged abandoned wells. Published rates of leakage of methane from abandoned wells are summarized in **Table 1**. Kang et al. (2016, 2017) and DiGiulio et al., (2023) found mean rates of leakage of methane from plugged abandoned wells in western Pennsylvania at 360 and 390 g/d, respectively. However, the computation of the mean rate of leakage from plugged wells in the dataset from DiGiulio et al. (2023) excluded an outlier, a plugged well leaking at a rate of 83 kg/d. When considering this outlier, the average leakage rate from plugged wells was 12.2 kg/d.

The important point here is that plugged wells can and do leak. Plugged wells penetrating the confining layer of a CO_2 storage reservoir would be expected to leak at a higher rate than plugged wells in depleted oil and gas reservoirs because of a much higher driving force for leakage (pressure). Leakage rates from both unplugged and plugged abandoned wells appear to follow a distribution whereby leakage from a relatively small number of wells accounts for the majority of total leakage (**Figure 6**). It is plausible that leakage of CO_2 from abandoned wells would follow a similar distribution.

For methane leakage from abandoned wells, Kang et al. (2019a) characterized a high emitter as having a methane flux in excess of 10 g/hr or 87.6 kg/yr. Bowman et al. (2023) characterized a super emitter as having a methane flux of 100 g/hr or 876 kg/yr. In Alberta, Bowman et al. (2023) found 14 wells (11% of sampled population) to be high emitters and 8 wells (6% of sampled population) to be super emitters.

Similarly, in Saskatchewan, Bowman et al. (2023) found 11 wells (11% of sampled population) to be high emitters and 3 wells (3% of sampled population) to be super emitters. The highest known methane emission rate measured is 45,000 kg/yr from an unplugged abandoned gas well in Alberta (Bowman et al., 2023).

Table 1. Mean values of methane emission rates and associated method for plugged and unplugged abandoned wells measured at the wellhead. Modified from DiGiulio et al. (2023).

Location	Mean Plugged Wells (g d^{-1})	n	Mean Unplugged Wells (g d^{-1})	n	Method	Source
Oil Creek State Park, Western PA	2.3	82	27	129	HiFlow Sampler	Saint-Vincent et al. (2020b)
Oil Creek State Park, Western PA	NM	NM	54	7	Mass Flowmeter + ASTM D-1945	DiGiulio et al. (2023)
Hillman State Park, Western PA	NM	NM	700	22	HiFlow Sampler + CRDS	Pekney et al. (2018)
Hillman State Park, Western PA	NM	NM	285	11	Mass Flowmeter + ASTM D-1945	DiGiulio et al. (2023)
North-Central PA	NM	5	270⁑	14	Static Flux Chamber + GC-FID	Kang et al. (2014)
Western PA	360	35	520	53	Static Flux Chamber + GC-FID	Kang et al. (2016,2017)
Western PA	390§	6	550	42	Mass Flowmeter + ASTM D-1945	DiGiulio et al. (2023)
Appalachian Basin, OH	0.0‡	6	672	6	HiFlow Sampler	Townsend-Small et al. (2016)
North-West WV	2.4	112	77	147	Dynamic Flux Chamber, GC-FID	Riddick et al. (2019)
Permian Basin, TX	NM	NM	149	37	High Flow Sampler + GC-FID	Townsend-Small and Hoschouer (2021)
Powder River Basin, WY and Denver-Julesburg Basin, CO, Uintah Basin, UT	0.048	113	41.0	13	HiFlow Sampler	Townsend-Small et al. (2016)
Cherokee Platform, Eastern OK	96	20	65	159	HiFlow Sampler, GC	Saint-Vincent et al. (2020a)
CA	6.86	97	850 (idle wells)	17	Static Flux Chamber + CRDS or GC, or mobile plume Integration + CRDS	Lebel et al. (2020)
Alberta	23	13	2130	111	Static Flux Chamber + portable gas analyzer	Bowman et al. (2023)
Saskatchewan	0.82	8	195	106	Static Flux Chamber + portable gas analyzer	Bowman et al. (2023)
United Kingdom	40	102	990	1		Boothroyd et al. (2016)

NM – no measurements NP – not provided CRDS – cavity ring down spectrometer GC – gas chromatograph
FID – flame ionization detector
† - mean value not calculated due to flow measurement below limit of detection
‡ - zero value due to authors assigning values of zero to measurements below detection.
§ - outlier of 83 kd d-1 excluded from calculation of mean. All measurements in vented wells in coal regions.
⁑ - estimate of mean includes plugged and unplugged wells.

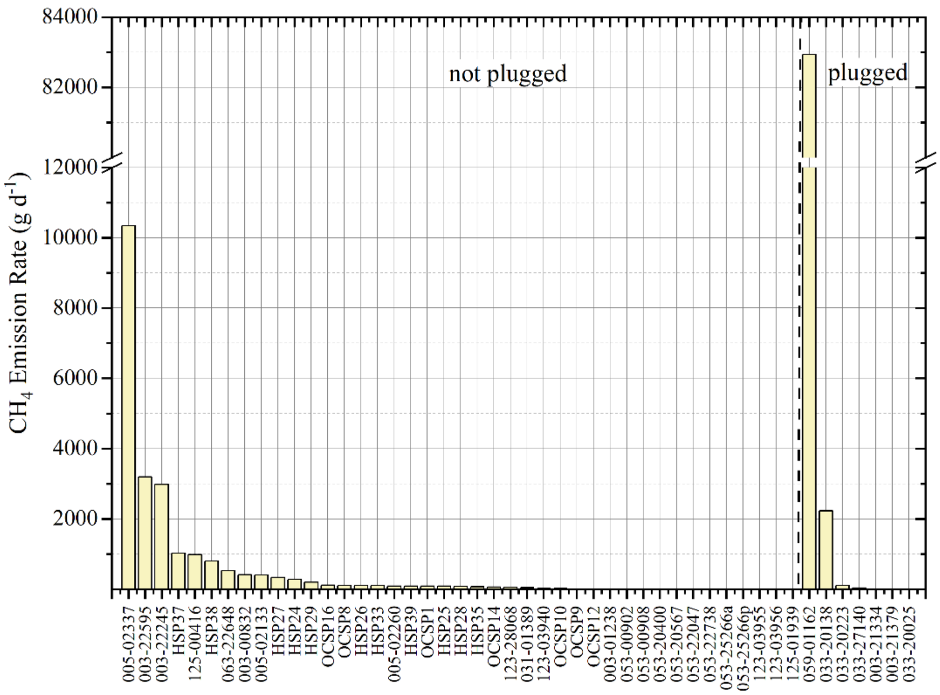

Figure 6. Methane emission rates from unplugged and plugged abandoned wells in western Pennsylvania. Figure from DiGiulio et al. (2023).

There are currently no federal or state regulations specifying a maximum leakage rate of CO_2 from abandoned wells after commencement of injection. Hypothetically, a maximum leakage could be calculated based on a permanence standard. For instance, the California Air Resources Control Board (CARB) requires 99% retention of CO_2 in a storage reservoir 100 years after injection ceases (CARB, 2018). In the hypothetical case of a depleted oil and gas field having 350 well penetrations and a storage volume of 40 million tons of CO_2, leakage of 1% over 100 years is equivalent to approximately 31 kg/d or 11,400 kg/yr (11.4 tons/yr) per well which in comparison to methane emissions is well beyond what would be considered a super emitter. For methane, an emission rate of this magnitude would likely require immediate plugging. The California Air Resources Control Board permanence criteria do not appear to be sufficiently stringent. In addition to consideration of more stringent permanence standards, there should be stipulated maximum emission rates for CO_2 at plugged abandoned wells.

2. Wellbore Barrier and Integrity Failure Frequency

To gain an understanding of the potential for leakage during geologic storage of CO_2, it is necessary to understand well barrier and integrity failure frequency and why wells leak. All modern oil and gas wells are constructed in a drilled hole (“wellbore”), which may be vertical, deviated, or horizontal. The wellbore typically traverses numerous geologic layers containing brines and hydrocarbons. Casing and surrounding sealants (typically Ordinary Portland cement) are placed in portions of the wellbore to maintain its stability, to protect against collapse and squeezing, and to prevent the movement of fluids between geologic layers. The resulting structure, including the wellbore, constitutes an oil and gas well (**Figure 7**). The inside of the well is hydraulically connected to the geologic layer targeted for fluid production or injection via holes through the casing (Wisen et al., 2020).

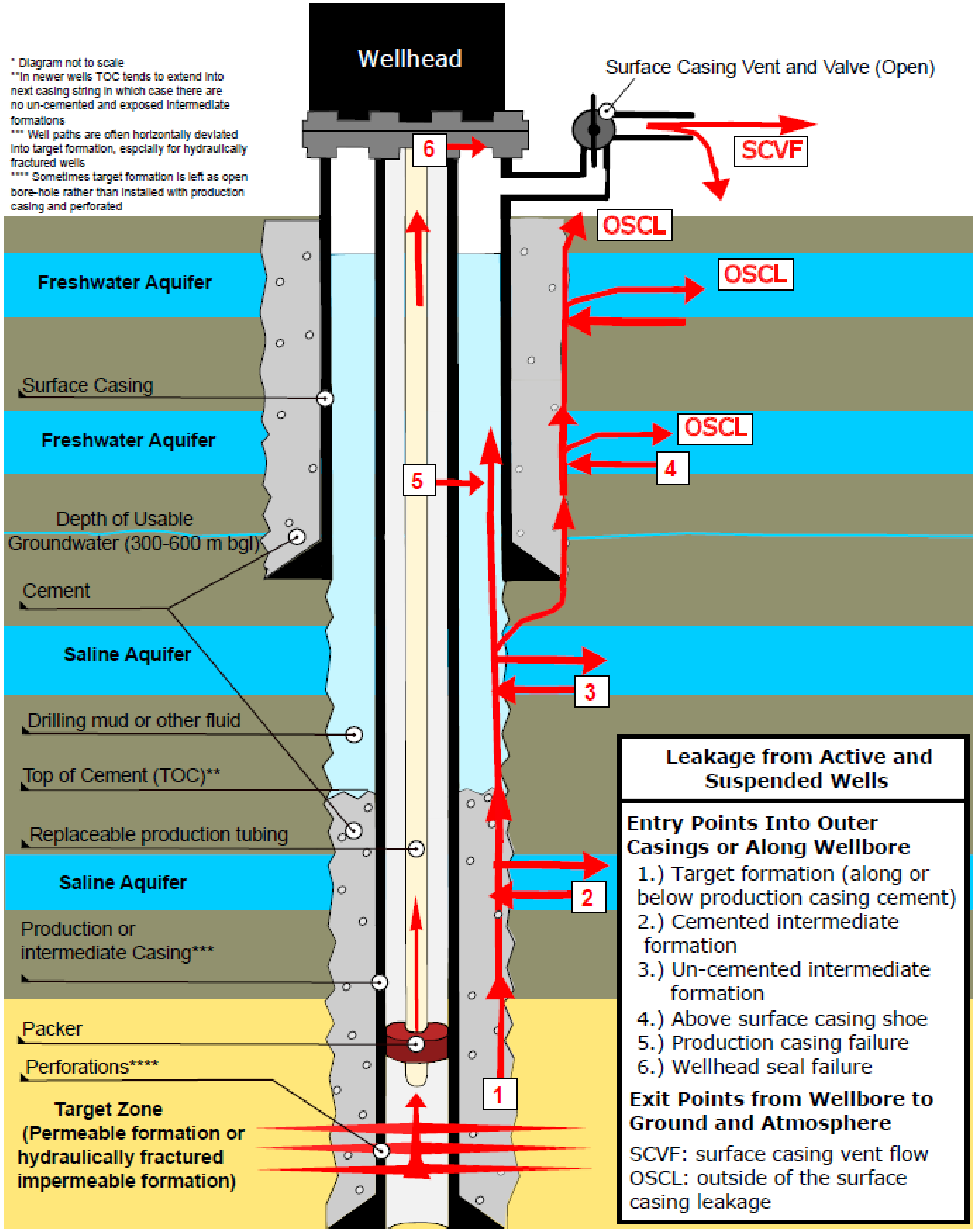

Figure 7. Schematic of an active well with leakage pathways classified according to entry and exit points along the wellbore. Figure is not to scale. Note that in the United States, with the exception of Pennsylvania, the surface casing vent is closed. Figure from Wisen et al. (2020).

Surface casing vent flow is defined as the flow of gas and/or liquid or any combination out of the surface casing annulus (Alberta Energy Regulator, 2003). In Canada, the annulus between surface casing and production casing remains open leading to surface casing vent flow in the presence of barrier failure. In the United States, with the exception of Pennsylvania, surface casing vents are closed, causing casing pressures to build up (sustained casing pressure) in the annular space between surface casing and production casing in the event of barrier failure (Lackey et al., 2021).

Surface casing vent flow and sustained casing pressure occur when there is no cement present or when a poorly cemented/damaged cement sheath fails to provide a continuous impermeable barrier to migrating gases (Dusseault et al., 2014). An uncemented or poorly cemented exterior annulus will not intercept or isolate formation fluids and increases the casing's susceptibility to corrosion. Leakage pathways through poorly cemented or damaged casing/hole annuli include circumferential microannuli (discontinuities with aperture dimensions on the order of microns) and channels with aperture dimensions on the order of millimeters to centimeters (Dusseault et al., 2014). A microannulus is a small gap between cement and casing or cement and a borehole wall. It can often be observed by comparing cement bond logs before and after casing pressurization where the latter closes the microannulus (Brufatto et al., 2003). Microannuli as small as 10-15 micrometers are sufficient to provide a pathway for gas migration to the surface, provided the conduit is continuous from the source to the surface casing shoe (Zhang and Bachu, 2011).

Subsurface leakage pathways at oil and gas wells include the production tubing and annular spaces between and outside casings, which can lead to gas in the surface casing and gas migration through soil (Soares et al., 2021; Wisen et al., 2020) (**Figure 7**). Natural gas emission sources at plugged abandoned oil and gas well sites include wellhead infrastructure, surface casing vents, and gas migration (**Figure 8**). Gas migration is the flow of gas that is detectable at the surface outside the outermost casing string (Alberta Energy Regulator, 2003; Soares et al., 2021). However, gas migration can also include leakage into groundwater ultimately leading to the presence of gas in domestic water wells (stray gas migration). It may develop if there are adjacent permeable formations, a drilling-damaged zone from the drilling process, or discontinuities between the outermost cement sheath and the borehole rock wall.

Several studies have been conducted to assess the impact of carbon dioxide on water quality (e.g. Wilkin and DiGiulio, 2010). Aquifers could be subjected to acidification due to high concentrations of carbon dioxide, and the acidification itself can result in a rise of contaminants such as arsenic, lead and mercury (Damen et al., 2006; Fogarty and McCally, 2010).

The terms 'well barrier failure' and 'well integrity failure' were differentiated by King and King (2013). The term 'well barrier failure' was used to refer to the failure of individual or multiple well barriers (e.g., production tubing, casing, cement) that has not resulted in a detectable leak into the surrounding environment. The main requirements of a cement barrier material consist: (1) impermeability to prevent flow of fluids through the barrier; (2) long-term integrity so that the barrier does not deteriorate over time; (3) non-shrinking to prevent flow between a plug and casing, casing and cement, and cement and the formation wall; (4) ductile to be able to withstand mechanical loads and changes in temperature and pressure; (5) resistance to downhole fluids and gases (corrosive gases as CO_2, H_2S, hydrocarbons etc.); and (6) ability to make a good bond to the formation or casing in which the barrier material is placed (Khalifeh and Saasen, 2020; NORSOK D-010, 2013). Surface casing vent flow and sustained casing pressure are unequivocal indicators of well barrier failure.

King and King (2013) used the term 'well integrity failure' for cases where all well barriers fail, establishing a pathway that enables leakage into the surrounding environment (e.g., groundwater, surface water, underground rock layers, soil, atmosphere). Hence, well integrity is generally understood as the ability of wellbore barriers to contain production fluids within the wellbore and prevent uncontrolled subsurface leakage, groundwater contamination, and/or emissions (Ingraffea et al., 2020; Lackey et al., 2021).

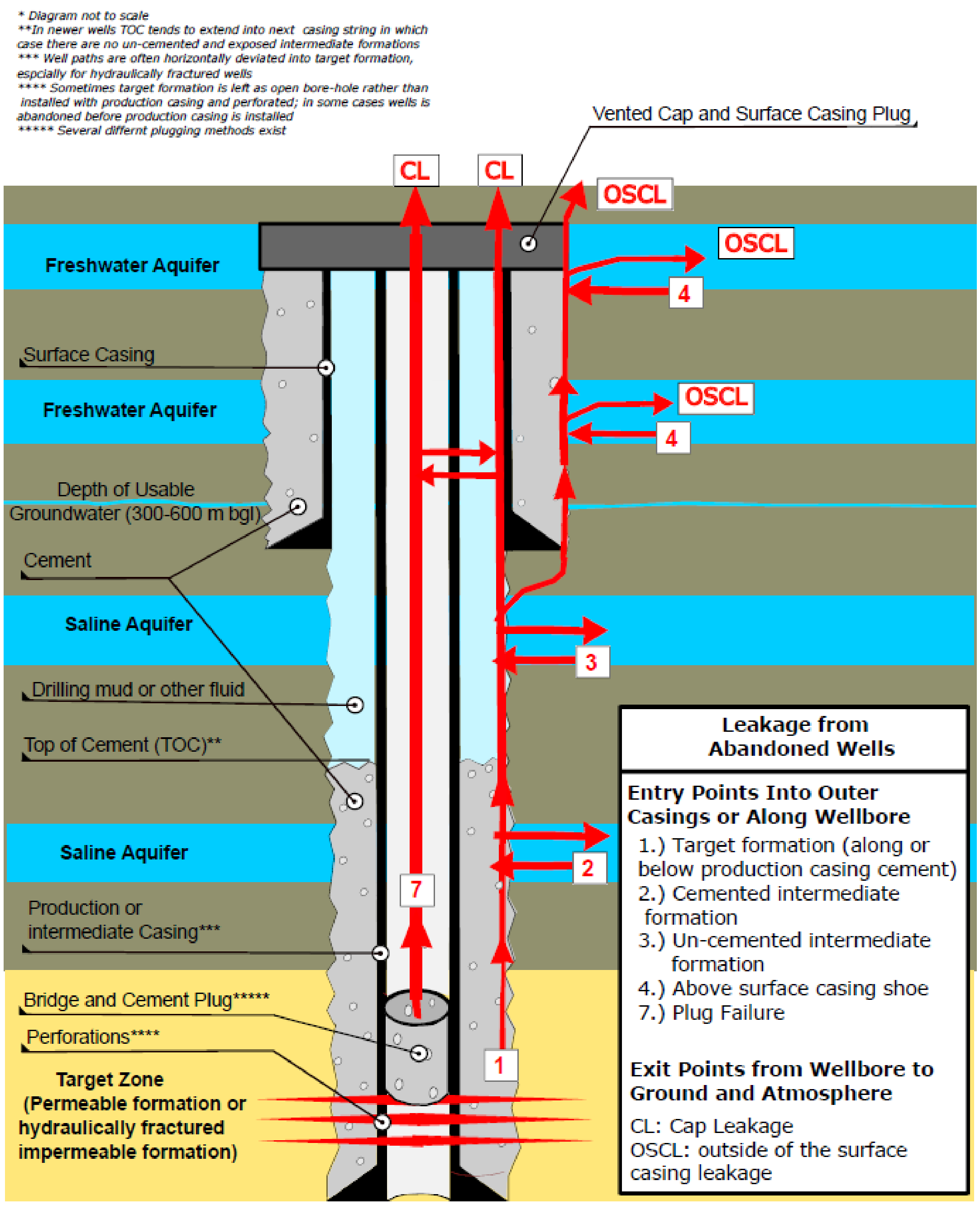

Figure 8. Schematic of an abandoned well and leakage pathways classified according to entry and exit points along the wellbore. Figure is not to scale. Figure from Wisen et al., (2020).

There are issues of concern associated with the use of these terms. For instance, sustained casing pressure due to gas flow by pathways 1, 2, 3, and 5 in **Figure 7** would be classified as a well barrier failure if the surface casing vent was closed and be classified as both well barrier and well integrity failure if the surface casing was subsequently opened to allow surface casing vent flow to the atmosphere. Also, groundwater is rarely monitored in the vicinity of oil and gas wells. So, detection of impact to groundwater is not possible unless one or more domestic wells have also been impacted. Even in that case, natural versus anthropogenic causes of impact will be debated. Hence, documented cases of well integrity failure are likely substantially underreported.

Overall, the presence of sustained casing pressure, surface casing vent flows, and gas migration are indicators of well barrier and integrity failures, which increase the potential for gas emissions and groundwater contamination (Ingraffea et al., 2014, 2020; Lackey and Rajaram, 2019; Soares et al., 2021). Gas migration and surface casing vent flows require wellbore treatments such as cement squeezes and casing repair (Hachem et al., 2023; Ingraffea et al., 2014; Yousuf et al., 2021). In contrast, gas emissions from the aboveground wellhead infrastructure often are relatively easy fixes, such as tightening of joints and replacement of parts, and are more likely to originate from the producing formation, indicating that plugging can reduce the emissions.

Well barrier and well integrity failures are not necessarily addressed through well plugging and can persist after the well is "properly" plugged (Bowman et al., 2023; Kang et al., 2021; Wisen et al., 2020). Surface casing vent flow or sustained casing pressure may be due to annular gas flow which may not have been investigated or remediated prior during plugging. While Class VI regulations require internal and external mechanical integrity testing of injection wells prior to plugging, no internal or external mechanical integrity testing is required in federal regulations for non-injection wells prior to plugging wells for the purpose of geological storage. This is a deficiency in Class VI regulations, since in many cases, especially at depleted oil and gas fields, abandoned wells will be directly exposed to highly pressurized supercritical CO_2 for thousands of years similar to injection wells. Non-injection wells are plugged based on state regulations which also do not mandate internal and external mechanical integrity testing prior to plugging. The process of investigating and remediating well barrier or well integrity failure is more complex and expensive than the average plugging procedure which is why it is typically not done. Once plugged, subsurface leakage via the annulus may go unchecked leading to persistent groundwater impacts or emissions to the atmosphere.

Recent analysis of state and provincial databases show that wellbore barrier and integrity failure are widespread in the abandoned oil and gas well populations in Canada and the U.S. and are likely under-reported or not reported at all depending on the jurisdiction (Wisen et al., 2020; Lackey et al., 2021; Ingraffea et al., 2014, 2020). Overall, the widespread occurrence of subsurface leakage in the abandoned oil and gas well population may mean that plugging alone cannot remediate all impacts of abandoned oil and gas wells, and investigations of subsurface leakage are important for understanding and mitigating gas emissions from abandoned oil and gas wells and broader environmental impacts (Bowman et al., 2023). Investigations of leakage from abandoned wells are not required during Class VI permitting.

Davies et al. (2014) summarized the percentage of wells with barrier or well integrity failure (**Figure 9**). Rates of barrier and well integrity failure ranged from 2 to 75% depending on the study. For offshore wells on the United Kingdom Continental Shelf, 10% of 6,137 wells (operated by 18 companies) had been shut-in (valves at the well head closed) during a five-year period as a result of structural integrity issues (Davies et al., 2014).

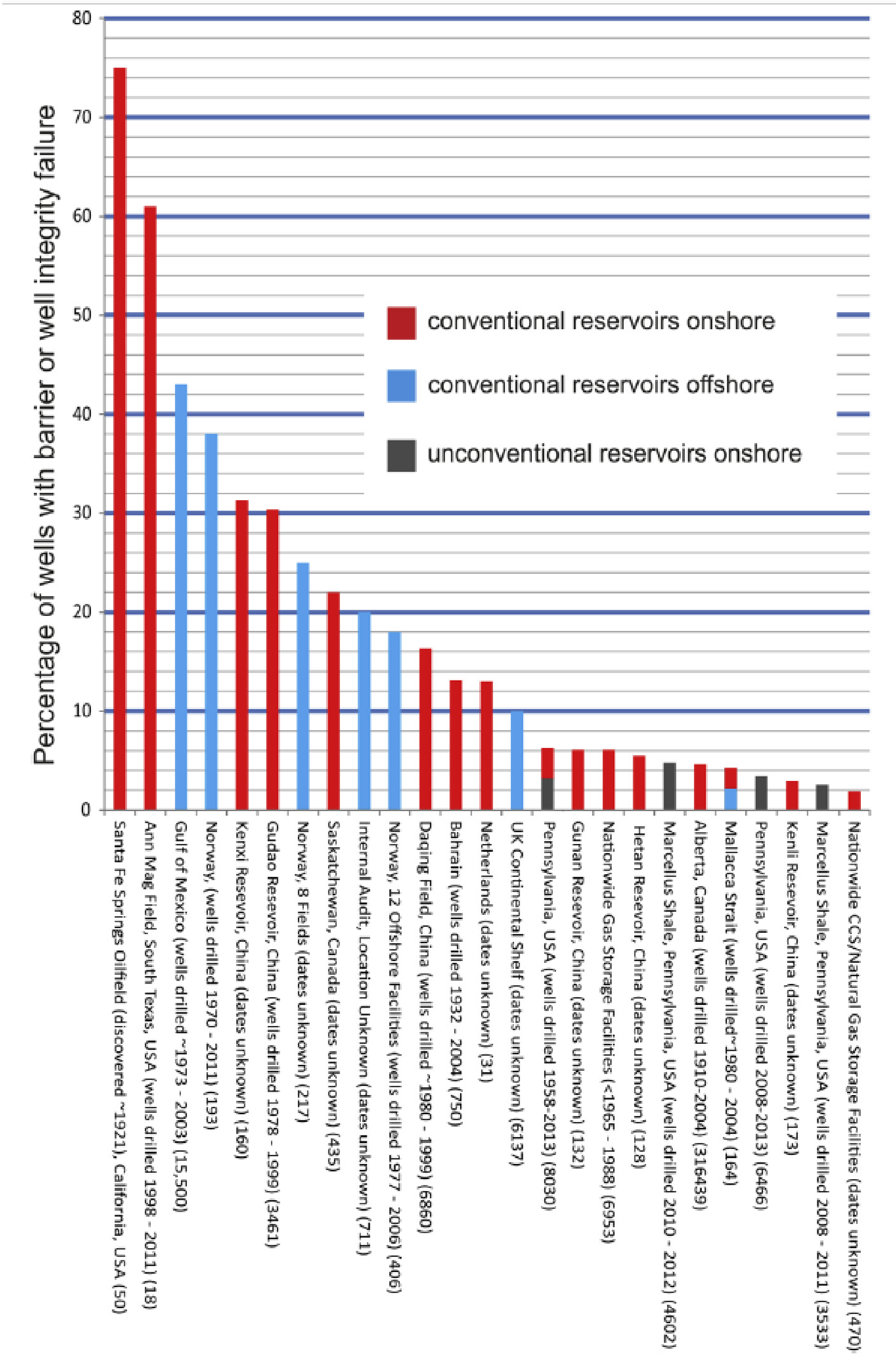

Figure 9. Graph of percentage of well barrier and integrity failures reported in 25 different studies around the world, with drilling dates and number of wells in each study. Figure from Davies et al. (2014).

Vignes and Aadnøy (2010) examined 406 wells at 12 Norwegian offshore facilities operated by 7 companies. Of wells examined, 18% had well barrier issues. The Petroleum Safety Authority in Norway also performed analyses of barrier failures and well integrity on the Norwegian continental shelf. Its analysis showed that: in 2008, 24% of 1677 wells were reported as having well barrier failures; in 2009, 24% of 1712 wells had well barrier failures; and in 2010, 26% of 1741 wells had well barrier failures (Vignes, 2011). It is unclear whether the same wells were tested in successive years or whether surveys targeted different wells (Vignes, 2011). A study of 217 wells in 8 offshore fields was also carried out by the Norwegian Foundation for Scientific and Industrial Research. Between 11% and 73% of wells had some form of barrier failure, with injectors 2 to 3 times more likely to fail than producers (Vignes, 2011). At the 20th Drilling Conference in Kristiansand, Norway, in 2007, Statoil presented an internal company survey of offshore well integrity (Vignes, 2011). This analysis showed that 20% of 711 wells had barrier failures, issues, or uncertainties (Vignes, 2011). When subdivided into production and injection wells, the survey concluded that 17% of 526 production wells and 29% of 185 injection wells had well barrier failures.

There are approximately 15,500 producing, shut-in, and temporarily abandoned wells in the outer continental shelf area of the Gulf of Mexico of which 6,692 (43%) have reported sustained casing pressure (Brufatto et al., 2003). In the Gulf of Mexico, sustained casing pressure appears to be related to well age. By the time a well is 15 years old, there is a 50% probability of sustained casing pressure or well barrier failure (Brufatto et al., 2003).

For onshore wells, the results of an inspection project carried out by the State Supervision of Mines Netherlands were also reported by Vignes (2011). Their inspections, carried out in 2008, included only 31 wells from a total of 1349 development wells from 10 operating companies. Of those wells, 13% (4 of 31) had well barrier failure. Problems were identified in 4% of the production wells (1 of 26) and 60% of the injection wells (3 of 5).

Since 1995, well operators in British Columbia have been required to test for gas leakage at the surface prior to well abandonment (BC, 1995). Additionally, since 2010, the Oil and Production Regulation of the province's Oil and Gas Activities Act has required operators to test for leakage after drilling, after recompletion, and during routine maintenance. Excluding wells abandoned prior to 1995, by the end of 2017 in British Columbia, 21,525 wells had been drilled of which leakage was reported in 2,322 cases (10.8%) having a mean reported surface casing vent flow of 5.9 m3/d (~3.9 kg/d at 1 atm and 293 K) (Wisen et al., 2020). However, a field-based leakage study indicated that only one-half of wells with detected leakage appeared in the British Columbia database (Werring, 2018) suggesting that the true percentage of leaky wellbores in British Columbia could be much higher than the 10.8% calculated from the regulatory database.

Abboud et al. (2020) found that 6.2% of abandoned wells in Alberta were experiencing surface casing vent flow. In a later field-based study, Bowman et al. (2023) found that 31.8% of abandoned wells in Alberta were experiencing surface casing vent flow while 3.5% of abandoned wells were experiencing surface casing vent flow in Saskatchewan. In the Lloydminster area of Alberta, Husky Oil reported that 45% of surveyed wells suffer from gas migration problems (Schmitz et al., 1996). The measured surface casing vent flow rate in Alberta is comparable to sustained casing pressure rate of 26.5% measured in Colorado and New Mexico (Lackey et al., 2021). Hence, in these locations, nearly one-third of abandoned wells had wellbore barrier or integrity failure via pressure build-up or annular gas flow, respectively.

In Pennsylvania during unconventional gas In the Marcellus Shale Formation, Vidic et al. (2013) derived a figure of 3.4% well barrier leakage for shale gas production between 2008 and 2013. Using the same database, Ingraffea (2012) argued 6.2% of 3391 shale gas wells drilled in Pennsylvania in 2011 and 2012 had failed. Considine et al. (2013) identified 2.58% of unconventional wells as having some form of barrier or integrity failure.

Chilingar and Endres (2005) describe incidences of gas migration via unplugged abandoned wells in the Los Angeles Basin, California where many homes and commercial structures have been constructed directly over poorly plugged oil and gas wells. In March 1985, a commercial department store exploded in the Fairfax area of Los Angeles injuring over 23 people. Escaping oilfield gases burned for days through cracks in the sidewalks and within the parking lot surrounding the store. Eventually, well records were obtained that revealed that the well casing of an abandoned well had developed leaks as a result of corrosion holes located at a depth beginning at approximately 366 m, and extending deeper (Endres et al., 1991). In February 1989, gas was observed bubbling in the street across from where the March 1985 explosion occurred due to clogging of a vent well. In January 2003, gas leakage occurred through abandoned wells in a residential area in the Fairfax area during injection of natural gas to enhance oil recovery in South Salt Lake Oilfield.

As described by Chilingar and Endres (2005), between the 1970s and 1990s, gas leakage occurred through plugged abandoned wells during pressurization of the partially depleted Montebello Oilfield for gas storage. Natural gas had been injected at a pressure of 10.3 MPa (1500 psig) at a depth of 2,386 m in 1930 era wellbores. While information was not provided on dates and methods of plugging, it is obvious that well plugging was not effective. Thirteen homes had to be abandoned and demolished to provide access to drilling rigs in an attempt to replug old wells. This case is particularly relevant for geological storage of CO_2 since it demonstrates what could happen when pressurized CO_2 or brine reaches previously competent plugged abandoned wells.

Chilingar and Endres (2005) also discuss gas leakage through abandoned wells during natural gas storage that occurred at the Playa del Rey Oilfield located in the Marina del Rey area. There are over 200 old and abandoned wells throughout this area, including wells that had to be abandoned in order to accommodate the construction of the Marina del Rey Boat Harbor. Gas from abandoned wells leaks into a massive gravel bed occurring at a depth of 15 m below sediment in the harbor. Probes placed into the gravel zone have measured gas flow rates as high as 20 - 30 l/min (19.2 – 28.8 kd/d at 1 atm pressure and 298 K). Also, drilling rigs have experienced blowouts as a result of encountering the high-pressure gas zone when penetrating the gravel. Gas inventory studies have shown that leakage is directly proportional to the reservoir pressure maintained for gas storage. Chilingar and Endres (2005) observed that 38 of 50 (~75%) of operating oil wells in the Santa Fe Springs oilfield were leaking gas during waterflooding. Waterflooding pressurizes a formation which would have provided an increased driving force for leakage.

Osborn et al. (2011) and Jackson et al. (2013) noted that methane concentrations in water wells increased with increasing proximity to gas wells in northeastern Pennsylvania, and that the sampled gas was similar in composition to gas from nearby production wells in some cases. More recently, other studies (Darrah et al., 2014; Molofsky et al., 2013) found gas compositions in wells with higher methane, ethane, and propane concentrations sometimes match Marcellus gas, likely through leaks in well casings. However, in other instances, they do not match the gas compositions in the Marcellus Shale, suggesting that intermediate formations are providing the source for the additional methane, probably due to insufficient cementing in poorly constructed wells. The Darrah et al. (2014) study in particular identifies eight locations in the Marcellus (and also for one additional case in the Barnett Shale in Texas) where annular migration through/around poorly constructed wells was the most plausible mechanism for measured methane contamination of groundwater. This finding is important because gas migration in abandoned wells may not be from the producing formation. During geologic storage of CO_2, it is possible that abandoned wells may have a competent cement seal between a storage reservoir and the overlying confining unit with gas leakage originating from overlying formations.

Gas leakage can induce geochemical changes in groundwater. Kelly et al. (1985) described conditions in groundwaters near a well blowout in Ohio in which the natural oxidants (e.g., oxygen, nitrate, sulfate) in the aquifer were replaced by iron and manganese, which had dissolved from the reduction of the oxides within the aquifer. Furthermore, the total dissolved solids increased in concentration and sulfate reduction of the methane produced hydrogen sulfide. The study by Chafin (1994) in the San Juan basin in New Mexico and Colorado also indicated a strong association between methane and hydrogen sulfide. This association was substantiated by van Stempvoort et al. (2005) in the Lloydminster heavy oil belt, who showed by isotopic characterization that in-situ microbially-catalyzed methane oxidation was associated with sulphate reduction in groundwaters adjacent to the leaky oil well.

Abandoned wells are also known to leak brine. A 1989 U.S. Government Accountability Office (GAO) report (GAO, 1989) found that EPA was aware of 23 cases nationwide in which both groundwater and drinking water wells were contaminated by Class II disposal wells. In addition to these 23 cases, there were two reported cases where residents saw water flowing out of abandoned oil and gas production wells located near enhanced recovery wells. As GAO acknowledged, because of possible underreporting by individuals whose drinking water was contaminated and the difficulty and expense of groundwater investigations, this number is an underestimate to some unknown degree. Most cases resulted from cracks in the injection wells or from injection directly into drinking water. However, in more than a third of the cases, drinking water became contaminated when injected brines traveled up and through plugged abandoned wells in the vicinity of the injection wells. Contamination was not discovered until water supplies became too salty to drink or crops were ruined. Again, this illustrates that plugged wells can and do leak.

In all but three cases, contamination of groundwater was judged too costly or infeasible to remediate. In one case, the state authorized expenditure of 300 million dollars to plug abandoned wells and commence groundwater remediation. In 1976, before beginning the Underground Injection Control Class II program, EPA proposed requiring all operators to search for and plug any improperly plugged abandoned wells within a ¼-mile radius of their injection wells. However, after industry objected to this rule, EPA waived this requirement for disposal wells operating prior to 1976. In 1989, GAO estimated that only 23 (± 7) %, or about 20,300 out of an estimated 88,000 Class II disposal wells at the end of 1987 were subject to the ¼-mile area of review for finding abandoned wells. Even under current standards, the search for abandoned wells is limited to wells of public record which constitute a fraction of actual abandoned wells. According to GAO, 53 wells were plugged in Oklahoma in 1987 because brine could be seen flowing at the surface. Neither the EPA nor the states require groundwater monitoring for Class II wells. Although monitoring wells can be used to measure the extent of contamination, they are of limited value for detecting contamination away from the well since they can only be used in a small area and are therefore not useful for assessing large aquifers.

Wellbore communication between abandoned wells and wells used for hydraulic fracturing (frack hits) has been observed. In February, 2021, fluid flowed for four days from an unplugged oil and gas well in southeastern Ohio (Noble County) that had been idle since 2012. The fluid is thought to have migrated from nearby fracking waste injection wells (Burger, 2021). Frack hits are unpredictable, uncontrolled, and can be violent, damaging tubing, casings, and well integrity. In some cases, frack hits involve blowouts of fracking fluid (Jacobs, 2017a, b).

In the Permian Basin, oilfield operators are currently reinjecting 10 million barrels of produced water per day, volumetrically equivalent to ~2.4Mt CO_2 per day at reservoir conditions (Bump and Hovorka, 2023). Over the past 5 years, risk of induced seismicity has resulted in an increasing trend toward shallow injection targets rather than the deep reservoirs historically used (Scanlon et al., 2020). There is little publicly available monitoring data but there are an increasing number of reports of old, even unknown wells suddenly erupting salt water at the surface, along with anecdotal evidence of increasingly contaminated aquifers and anomalous subsurface pressures (Gold, 2022a, 2022b). Similar events have occurred in Ohio (Harvilla, 2021a, 2021b). Leakage of brine due to aquifer over-pressurization from injection of produced water into Class II disposal wells can cause leakage of brine into surface waters or Underground Sources of Drinking Water and may introduce contaminants (e.g., heavy metals, organic compounds, radionuclides) and/or induce geochemical changes that may limit the usefulness of waters for human consumption. It is plausible to imagine something similar with large-scale CO_2 injection in a heavily drilled basin (Bump and Hovorka, 2023).

Given that wells have been drilled, and abandoned, for more than a century, and available records are highly variable in their information content, characterization of existing wells will necessarily involve significant uncertainties. Coupled with uncertainties associated with geological and hydraulic properties of the natural formation materials, leakage of CO_2 from a storage formation is likely to at least some extent (Celia and Bachu, 2003). Hence, the important question is not whether there will be leakage, but whether the extent of leakage is acceptable (Celia and Bachu, 2003) and how leakage will be monitored and quantitated.

The primary purpose of geological storage of CO_2 is mitigation of climate change. A leakage rate of less than 1% per thousand years is necessary for geological storage of CO_2 to achieve the same climate benefits as renewable energy sources (Shaffer, 2010). In a Special Report on Carbon Dioxide Capture and Storage, the Intergovernmental Panel on Climate Change (IPCC, 2005) stated that for a well-selected, designed, operated and appropriately monitored system, the balance of available evidence suggests that it is very likely the fraction of stored CO_2 retained is more than 99% over the first 100 years and it is likely the fraction of stored CO_2 retained is more than 99% over the first 1000 years. Leak rates of 0.01% per year, equivalent to 99% retention of the stored CO_2 after 100 years, may be adequate to ensure the effectiveness of CO_2 storage (Hepple and Benson, 2005). As part of an application for Sequestration Site Certification, the California Air Resources Board (CARB) requires a greater than 90% probability of occurrence that 99% of CO_2 will be retained in the storage complex over 100 years post-injection to be eligible to receive Permanence Certification required for operation in California (CARB, 2018). There are no storage effectiveness criteria in the Class VI federal regulations. This is a major regulatory deficiency that now must be resolved on a state-by-state level.

To assess the risk of abandoned wells, Callas et al. (2022) used a storage security calculator developed by Alcalde et al. (2018) to estimate the percent of CO_2 leaked for different densities of wells per square kilometer in a well-regulated environment using the IPCC (2005) guidance that 99% of CO_2 stored should be retained in 1,000 years to be an effective mitigation tool. Based on the cumulative leakage estimates and the IPCC guidance, Callas et al. (2022) determined that a well density greater than 8 wells/km^2 would result in more than 1% cumulative CO_2 leaked in 1,000 years in a well-regulated environment. Therefore, well densities of 8 wells/km^2 are of concern. They categorize the density of existing or abandoned well as >8 wells/km^2, 6–7 wells/km^2, 4–5 wells/km^2, 2–3 wells/km^2, and <1 well/km^2 as worst to best for wellbore leakage concerns. The greater the number of wells penetrating the primary confining layer, the greater the probability of loss of containment of CO_2.

3. Why Oil and Gas Have Barrier and Integrity Failure

Understanding why oil and gas wells have barrier and integrity failure is essential to understanding how to evaluate legacy or abandoned wells prior to plugging, how to properly plug abandoned wells, and how to evaluate wells that have already been plugged prior to injection of CO_2. Multiple factors over the operating life of a well may lead to failure (Bonett and Pafitis, 1996; Brufatto et al., 2003; Carey et al., 2013; Chilingar and Endres, 2005; Dusseault et al., 2000; Watson and Bachu, 2009, Barclay et al., 2022) (**Figure 10**). However, the most important mechanism leading to gas and fluid migration is poor well construction or exposed (or uncemented) casing (Watson and Bachu, 2009). Brufatto et al. (2003) state that sustained casing pressure may be due to tubing and casing leaks, poor mud displacement during cementing, improper cement slurry design, and damage to primary cement after setting. They state that tubing and casing leaks can result from poor thread connection, corrosion, thermal-stress cracking, and mechanical rupture of the inner string or from a packer leak. Inadequate mud removal prior to cementing is a major contributing factor to gas migration. Improper cement slurry design results in gas flowing though cement prior to setting (Barclay et al., 2022). The following is a more detailed discussion of factors leading to wellbore barrier and integrity failure.

3.1. Uncemented or Poorly Cemented Casing in Portions of the Wellbore and Corrosion

Of the several well integrity failure modes, failures resulting in open gaps and annuli, e.g., between cement and casing or between cement and formation, are considered to be the most likely cause of large leakage flow (Kutchko et al., 2007; Bachu and Bennion, 2009). The large number of documented cases of sustained casing pressure in oil and gas wells (Bourgoyne et al., 1999; Choi et al., 2013; Lackey et al., 2017) suggests that gaps and annuli are commonly present in wells (Huerta et al., 2013). Poor bonding of cement to steel casing and to a borehole wall can lead to gaps and annular spaces that compromise well integrity (e.g., Oldenburg et al., 2011).

Watson and Bachu (2009) found that exposed casing was the most important indicator for surface casing vent flow and gas migration. In a study by the authors, approximately 150 well casings and cement bond logs were analyzed, which led to three important conclusions: 1) the majority of significant corrosion cases occurred on the external wall not the internal wall of the casing; 2) a large proportion of the wellbore lengths were uncemented; 3) external corrosion was most likely to occur in areas where there is no or poor cement.

Although all wellbore casings have some potential to degrade over time, the potential for corrosion is significantly elevated if the cement sheath quality is poor or inexistent. There are a number of particularly corrosive agents found in natural gas, CO_2 and H_2S. Dissolved in water, CO_2 forms weak carbonic acid and H_2S forms sulfurous acid, both yielding a low aqueous pH, and hence corrosive to iron. Other corrosive agents contained in drilling fluids include dissolved oxygen and treatment acids that are not fully reacted and subsequently can accelerate casing corrosion (Dusseault et al., 2014). Degradation of the cement sheath over time may exacerbate pre-existing pathways that have arisen from corrosion or rock damage during drilling. Filler additives e.g., bentonite and gypsum, are often used in cements to reduce cementing costs across non-completed intervals in shallower areas. However, these filler additives are often susceptible to acid attack from CO_2 and H_2S (Dusseault et al., 2014).

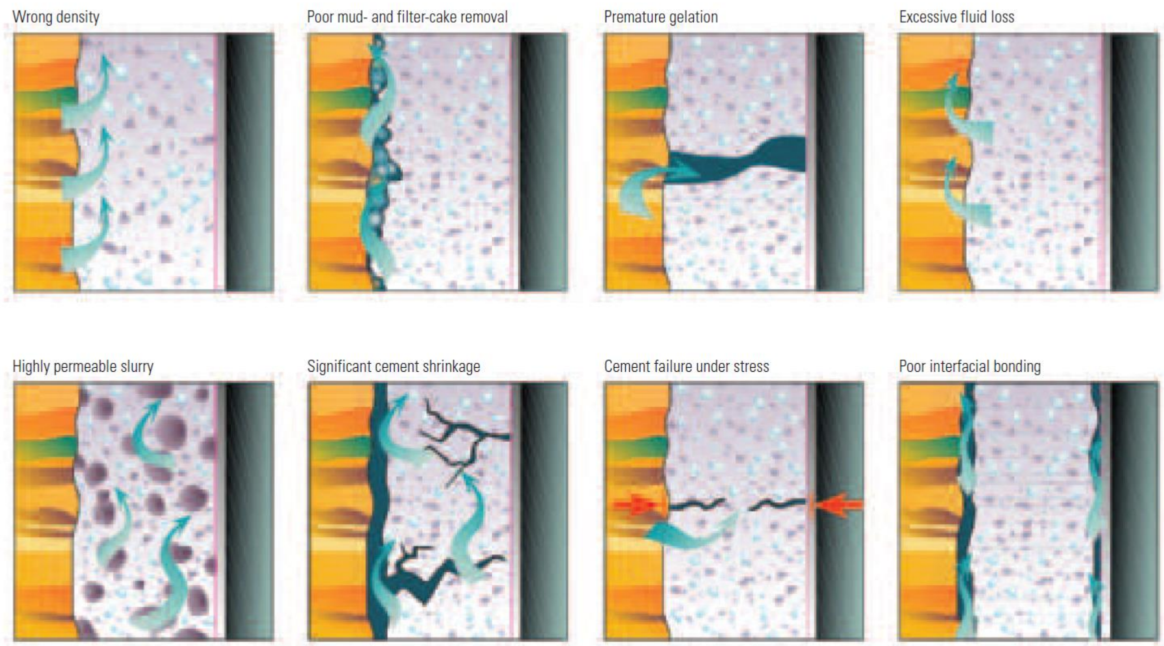

Figure 10. Primary cementing parameters that affect sealing. Incorrect cement density can result in hydrostatic imbalance. Poor mud- and filter-cake removal allows gas to flow up the annulus. Premature gelation leads to loss of hydrostatic pressure control. Excessive fluid loss allows gas to enter the slurry column. Highly permeable slurries provide poor zonal isolation and resistance to gas flow. Significant cement shrinkage and cement failure under stress create fractures and microannuli that transmit fluids. Poor bonding at cement-casing or cement-formation interfaces also can cause failure. Figure from Barclay et al., (2022).

For long-term integrity of new wells, the full cementation of each annulus is most desirable. Thus, production casing should be cemented into the intermediate casing, which should be cemented into surface casing. In this manner, there will be no exposed casing that might corrode over time or promote the accumulation of gas. This would appear to be the best solution to the prevention of corrosion over the life of the well. It is also the preferred solution to minimize surface casing vent flow and gas migration that are predominantly associated with non-commercial intermediate zones that should be sealed off (Watson and Bachu, 2009).

The slow deterioration and corrosion of a wellbore, both the cement and the steel, presents an issue for long-term wellbore integrity (>100 years) for geologic storage of CO_2. Although improved primary cement jobs may reduce the occurrence of poorly cemented intervals, cement remains vulnerable to deterioration over long times, especially if exposed to acidic fluids, potentially leading to the development or exacerbation of slow leakage problems.

For geologic storage of CO_2, a poor cement job is perhaps the most important concern for leakage in wellbores (IEA, 2009). Upon chemical degradation of the cement, corrosion of the casing will be induced and the chance of leakage from the storage site increases (IEA, 2009). For injection wells, corrosion can be reduced by a proper material selection, applying corrosion inhibitors, cathodic protection, or coating of the cement (Choi et al., 2013; Talabani et al., 2000, Gaurina-Međimurec, 2010; Rutqvist, 2012; Zhu et al., 2013). However, these factors are not relevant to abandoned wells.

When CO_2 is dissolved in water, it is partly hydrated and carbonic acid is formed

$$CO_2(aq) + H_2O(l) \rightarrow H_2CO_3$$

Carbonic acid then dissociates to

$$H_2CO_3 \leftrightarrow H^+ + HCO_3^-$$

and

$$HCO_3^- \leftrightarrow H^+ + CO_3^{2-}.$$

In the presence of CO_2 dissolved in water, metal is unstable and as a result of the chemical reactions between carbonic acid and steel, Fe^{2+} is released:

$$Fe + H_2CO_3(aq) \rightarrow Fe^{2+} + 2HCO_3^- + H_2$$

When concentrations of Fe^{2+} and CO_2^{-3} ions exceed the solubility limit, $FeCO_3$ precipitates:

$$Fe^{2+} + CO_3^{2-} \rightarrow FeCO_3$$

The precipitated compound occupies a different volume compared to the initial compounds and it causes the casing to decompose.

Investigators in a number of studies have documented corrosion of casing caused by CO_2 (Cui et al., 2021; Elgaddafi et al., 2021a, b; Hoa et al., 2021; Lin et al., 2016). The rate of corrosion is largely controlled by temperature, pressure, salt concentration, pH, flow rate, and CO_2 partial pressure (Cui et al 2021). Elgaddafi et al. (2021a) conducted an experiment with 2 types of the API carbon steels, Q125 and T95, and concluded that the CO_2 corrosion rate of the API steels is sensitive to the fluid rate regardless of the temperature. In addition, they found that the corrosion rate of the Q125 steel is more affected by the fluid flow than that of T95. Hoa et al. (2021) used the carbon steel X70/1.8977, and suggested that care should be taken in choosing the cement type combined with high alloyed steel to avoid crevice corrosion and pitting in wellbore. Cul et al. (2021) demonstrated that high NaCl concentrations increase the CO_2-NaCl corrosion at high temperature. In addition, scanning electron microscope (SEM) results showed that the area of CO_2 corrosion became denser and uniform at high temperature.

3.2. Poor Mud Displacement Prior to and During Cementing

Another major reason for sustained casing pressure, surface casing vent flow, and gas migration is poor mud displacement prior to cementing. During oil and gas well construction, a cement slurry is pumped down production casing, and circulated up the annulus outside of production casing. The main objective is to uniformly place the cement slurry while effectively displacing the drilling mud from the annulus. This requires a properly mixed slurry and a suitable fluid displacement technique that achieves turbulent flow in the annulus (Smith, 1990; Ravi et al., 2002; Bellabarba et al., 2008; Nelson, 2012). Sufficient isolation between the cement slurry and the drilling mud must be maintained to ensure drilling mud does not become embedded within the cement. Mixing of mud and cement may occur if the density contrast between the drilling mud and the cement slurry is low and wash fluids and spacers are not used (Bellabarba et al., 2008). Typically, a water-based Portland Class G cement slurry with a density of approximately 2000 Kg/m^3 or slightly higher is used in primary cementing operations (Dusseault et al., 2000). When utilized, modern process-controlled cement mixing systems minimize density variation issues during cementing (Bonnett and Pafitis, 1996). Poor cement mixing can result in a nonuniform column of cement in the annulus that may lead to solids settling, free-water development, and premature bridging of cement to the borehole wall (Bonnett and Pafitis, 1996). Embedded mud can reduce the compressive strength of the set cement or even prevent slurry gelation from occurring.

The term 'bond' Is a measure of the intergranular contact between cement and casing or between cement and a borehole wall maintained by the radial effective stress (Dusseault et al., 2000). Cement requires a water-wet clean surface to achieve a cohesive bond. Cement will not bond to salt, oil-rich beds, oil sands, high porosity shale, and drilling mud filter cake (Dusseault et al., 2000; Watson et al., 2002). If residual mud remains on the casing or borehole wall, a stable long-lasting cement bond will not form (Brufatto et al., 2003; Zhang and Bachu, 2011; Bonnett and Pafitis, 1996). When effective bonding does occur, bond strength is less than 1-2 MPa relative to fluid pressures in the 10's of MPa (Dusseault et al., 2000). Washed-out areas of the wellbore wall present a particular problem because drilling mud accumulates within voids and is difficult to remove because scraping is ineffective. It is also difficult to generate good turbulent flow displacement in spacer fluids and cement in deep washouts (i.e., low velocity because of a large area) (Bellabarba et al., 2008; Macedo et al., 2012).

If channels of mud remain in the annulus, the lower yield stress of drilling fluids may offer a preferential route for gas migration. Also, during cement hydration, water may be drawn from mud channels leading to shrinkage-induced cracking of the mud providing a route for gas migration. If the mud filter cake dehydrates after the cement sets, an annulus may form at the formation-cement interface providing yet another route for gas migration. For example, a 2 mm thick mud filter cake contracting by just 5% will leave a void of 0.1 mm resulting in an effective permeability on the order of several darcies (Bonnett and Pafitis, 1996).

If the drilling mud is water-based and dominated by sodium ions, contact with the calcium-rich cement fluids causes massive flocculation and virtual solidification of the mud, making it nearly impossible to dislodge embedded drilling mud. The mud cake and any embedded drilling mud dehydrates over time because of the ionic exchange reactions that cause collapse of the hydrated cement sheath around the clay minerals, leaving behind a void space to act as a pathway for fluid and gas migration (Zhang and Bachu, 2011).

3.3. <u>Invasion of Fluids During Cement Setting</u>

During setting, elevated hydrostatic pressure in the cement slurry results in water loss from the slurry to the surrounding formation. Cement subsequently losses its ability to maintain hydrostatic pressure because of shear stress transfer of cement to the rock mass or increased vertical strain at the borehole wall which begins to support the weight of the column of cement and impedes continued downward settlement of cement (Dusseault et al., 2000; Brufatto et al., 2003; Bonnett and Pafitis, 1996). In areas where the cement slurry does not maintain sufficient hydrostatic pressure during setting, pressure in the cement can drop below the pore pressure in the surrounding rocks leading to invasion of fluids (gas and brine) and the development of channels and gas pockets (Brufatto et al., 2003; Macedo et al., 2012). Cement slurry density must be sufficiently high to resist gas intrusion but not too high to induce fractures in a formation (Bonnett and Pafitis, 1996). This is of particular concern in deviated boreholes. As cement particles settle to the low side, a continuous water channel may form on the upper side creating a pathway for gas migration (Bonnett and Pafitis, 1996; Brufatto et al., 2003). Hence, deviated wells would be expected to be more prone to leakage.

Producing formations are often not the source of a leak because these regions are often sealed with the highest quality cement in a wellbore (Watson and Bachu, 2009; Dusseault and Jackson, 2014). Significant amounts of water lost to adjacent permeable strata prior to loss of hydrostatic pressure generally results in dense cement (Dusseault and Jackson, 2014). Once setting is complete, cement is essentially impermeable. Gas can only flow through interfacial channels, where there has been mechanical failure of the cement, and through microannuli between casing and cement or between cement and the borehole wall. Intermediate and shallow depth sources are typically thin, non-commercial hydrocarbon bearing formations found in low permeability sandstones and silts, high permeability sand seams, or even in coals. These formations often have pressures at or slightly above regional pore pressure because gases slowly generated by biogenic processes or travelling from a deeper source become trapped in these regions. These formations present a significant risk for leakage because if the adjacent cement quality is poor, gas can seep into the exterior wellbore annulus (rock-casing annulus) and accumulate through the displacement of water (Saponja, 1999).

3.4. <u>Cement Shrinkage During Setting</u>

Portland cements are finely ground anhydrous calcium silicate and calcium aluminate compounds that hydrate when added to water, generating a product that provides strength and low permeability (Nelson, 2012). Portland cements continue to shrink after setting and during hardening because hydration reaction products occupy less volume than the original paste (Dusseault et al., 2000; Brufatto et al., 2003). Autogenous shrinkage of cement can result in a volume loss of 4-6% (Ravi et al., 2002; Parcevaux and Sault, 1981), far greater than is needed for a massive loss of radial stress. High salt content formation brines and salt beds can also lead to substantial cement shrinkage due to osmotic dewatering of cement slurries during setting and hardening (Dusseault et al., 2000). Leakage pathways may form either during the initial drilling and completion of the wellbore or later during the active life of the wellbore (i.e., after completion and before abandonment), or even in the decades following plugging and abandonment of the wellbore (Dusseault et al., 2014).

Dusseault et al. (2000) discuss the development of a microannulus as a result of cement shrinkage. Even minor shrinkage (~0.1-0.2%) will reduce the radial stress between cement and rock to less than pore pressure (Dusseault et al., 2000). This consequently leads to the development of circumferential fractures that grow vertically because of differences between lateral stress gradients and fluid pressure gradients. The vertical growth is much greater if the fluid is gas rather than a liquid, because the difference in the gradients is significantly higher.

Pathway development as a result of cement shrinkage is a slow process. Diffusion rates of gas into the fractures and the size of the apertures limit the ability to transmit gas. As a result, the effects of cement shrinkage may not be detectable until abandonment or even decades following the plugging and abandonment of the wellbore because of increasing pressure arising as the result of development of a free gas column taking place (Dusseault et al., 2000, 2014).

3.5. Wellbore Deviation

Watson and Bachu (2009) found that a deviated wellbore (i.e., any wellbore where the total length is greater than the true vertical depth) is a major factor in the development of a leakage. Poor casing centralization is likely the main contributing factor to this finding. An eccentric casing results in issues with adequate displacement of drilling mud and uniform placement of the cement slurry, therefore increasing the probability of leakage issues. Eccentric casing placement is a critical factor contributing to inadequate mud removal in deviated wellbores. A difference in annular space thickness on the two sides of the casing makes displacing the drilling mud and placing the cement slurry more difficult, especially when the interior casing is in direct contact with the exterior casing or the rock wall over a considerable distance. Residual mud may be left behind in the thinner annulus (contact zone) because turbulent displacement will be inhibited and the cement slurry will preferentially flow up the wider side of the annulus (Bellabarba et al., 2008; Roth et al., 2008).

In a review of the regulatory record, Vidic et al. (2013) noted a 3.4% rate of cement and casing problems in Pennsylvania shale-gas wells (that all had some degree of deviation) based on filed notices of violation. Pennsylvania inspection records, however, show a large number of wells with indications of cement/casing impairments for which violations were never noted, suggesting that the actual rate of occurrence could be higher than reported (Ingraffea et al., 2014; Vidic et al., 2013).

3.6. Mechanical Stress

Geomechanical processes during drilling, injection and completion can affect wellbore integrity (Orlic, 2009; Rutqvist, 2012). Elevated temperature and/or pressure during fluid injection causes casing expansion and subsequent compression of the cement sheath (increase in the radial stress). When the pressure or temperature increase ends, the reverse occurs, the radial stress drops. However, the process is seldom fully reversible, and the radial stress may even drop below the pore pressure in the strata outside the casing (Dusseault et al., 2014).

Casing expansion induces radial stress cracks in the cement sheath (Goodwin and Crook, 1992; Ravi et al., 2002). In addition to resistance to downhole chemical attack, the long-term integrity of a cement sheath depends on Young's modulus (ratio of compressive stress to strain) and tensile strength (Ravi et al., 2002). Experiments conducted by Goodwin et al. (1990) demonstrated that stiff cements or cements having a high Young's modulus are more susceptible to damage caused by temperature and pressure changes. Pressure cycling of a well can easily debond the rock and cement (there is strain incompatibility because of the different stiffnesses). Wells that have experienced several pressure or thermal cycles will almost always show loss of bond, sometimes for vertical distances in excess of 100 m (Dusseault et al., 2000). Continuous cyclic casing expansion activity results in the development of a microannulus when the radial stress drops below the pore pressure (Dusseault et al., 2000; Zhang and Bachu, 2011; Dusseault and Jackson, 2014). Microannuli and stress cracks ultimately lead to gas flow or gas pressure buildup in annuli.

The use of enhanced recovery methods (steam injection, hydraulic fracturing, etc.) elevates the mechanical and thermal loading on wellbores, and significantly increases the probability of leakage problem development during the operational lifetime of the wellbore, before final abandonment (Dusseault et al., 2014). Steam injection wells are subjected to significant temperatures, i.e., 'thermal shock' (Bour, 2005). Likewise, hydraulically fractured wells where the exterior casing is exposed to the fracturing fluids are subjected to high pressures. Due to the magnitude of stresses imposed on the wellbores using such stimulation techniques, the likelihood of developing microannuli and stress fractures is significantly increased (Watson and Bachu, 2008). The use of a suspended production tubing string through which hydraulic fracturing fluids are introduced to the stimulation zone has the effect of eliminating the cyclic high pressures acting on the exterior casing. An abandoned well in which production tubing was utilized during oil and gas production is less likely to have microannuli. Other processes such as cement squeezes can also expand casing and cause radial cement cracks.

In addition to chemical degradation, the cement sheath of abandoned wells may be impacted by stress changes and deformation during CO_2 injection (Bachu and Bennion, 2009; Wigand et al., 2009). As pore pressure increases, there is a possibility of stress distribution alteration around the well leading to casing deformation or crack generation in the cementing (Patil et al. 2022). Beside the increase of pore pressure, the cooling effect caused by the injected CO_2 can decrease the radial, axial and tangential stresses of the composite system, and these compressive stresses may turn to tensile stresses (Bai et al, 2015, 2016). Because of these reasons, considering chemical–mechanical combined effects is necessary for well integrity assessment. Chemical–mechanical effects have the potential to hinder the well integrity when a leakage path is already present due to cement shrinkage or fracturing, gaps along interfaces, or casing failures (Carroll et al., 2016).

Changes in the reservoir stress and deformation during carbon dioxide injection may impact wellbore integrity by increasing the hydraulic aperture of rock–cement or casing–cement interfaces, leading to increased potential leakage paths (Bachu and Bennion, 2009; Rutqvist, 2012; Tao et al., 2011). Wellbore permeability can also be raised during drilling and completion of the well through layers, which may cause rock failure (Orlic, 2009; Rutqvist, 2012).

3.7. Casing Failure in Poor Consolidated or Unconsolidated Media

A large number of current oil and gas reservoirs in the world, including some major fields in the Gulf of Mexico, the Bohai Bay of China, and the Campos basin offshore of Brazil, are located in formations involving geologically young and poorly consolidated or unconsolidated sands (Peng et al., 2007). The main problems associated with these weak formations are wellbore stability while drilling, casing failure, and sand production during oil extraction (Peng et al., 2007). In unconsolidated oil sand pay zones in western Canadian, sand production and casing damage are common occurrences (Wagg et al., 1999).

Serious wellbore casing damage and casing failure have occurred in oilfields in China. Peng et al. (2007) state that in 1983, casing was reported as damaged at 3,688 wells in 10 Chinese oilfields. In 1985, casing was reported as damaged at 6,711 wells in 14 oilfields. By 1994, casing was reported as damaged at 13,500 wells. Lan et al. (2000) state that in Daqing Oilfield, the biggest oil producer in China, over a 40-year period, casing was reported as damaged at 6,860 wells accounting for 16.3% of all wells in the field. Peng et al (200& states that in the Shengli Oilfield, casing damage was reported at 1,052 wells between 1978 and 1999 accounting for 30.4% of all wells drilled. Fu (2002) examined 1,122 damaged wells in the Gudao reservoir and noted that the location of the casing damage was concentrated on an unconsolidated sandstone, the oil-bearing layer, and that most casing failures occurred in the perforation areas. The major cause of the casing damage was that cavities were produced around the casing in the unconsolidated sandstone due to sand production inducing non-uniform pressures around the casing and causing casing buckling and shear failure.

3.8. Casing Failure from Subsidence

Casing damage commonly occurs during reservoir depletion. Casing failures induced by formation compaction have occurred in reservoirs in the North Sea, the U.S. Gulf of Mexico, California, South America and Asia (Peng et al., 2007). In the North Sea Chalk Basin, more than 90 casing failures occurred from increased axial and radial loads on the wellbore caused by the compaction of the high-porosity chalk during the reservoir depletion (de Silva et al., 1990). In the 1980s, in the Belridge Field in Kern County California, nearly 1,000 wells experienced severe casing damage (at a peak rate of 160 wells per year) due to depletion-induced compaction of diatomite (Fredrich et al., 1996, 2000). The diatomite formations in Kern County in southern California are highly porous and compressible, and hence are particularly susceptible to depletion-induced compaction (Dusseault et al., 2001). Waterflood programs were then initiated to counter the subsidence, which led to much lower rates of well failure in the late 1990s of around 2–5% of active wells per year or approximately 20 wells per year (de Rouffignac et al., 1995; Fredrich et al., 1996; Dusseault et al., 2001). The current situation with groundwater overdraft in the southern San Joaquin Valley may pose an added risk to oil and gas wells and geologic storage of CO_2 in the region due to continued subsidence.

3.9. Seismicity

After a well is permanently plugged and abandoned, natural or induced seismicity can damage wellbores. For example, hundreds of oil well casings were sheared in the Wilmington oil field in Los Angeles during five or six earthquakes of relatively low seismic moment magnitude (**M** 2 to **M** 4) during a period of maximum subsidence in the 1950s (Dusseault et al., 2001). The seismic moment magnitude is the product of the area of rupture, the average displacement on the fault (a fracture or zone of fracture between two blocks of rock), and the shear modulus, a parameter related to the rigidity of rocks in the fault zone measured on a logarithmic scale (GWPC & IOGCC, 2021). Recently, Pozzobon et al. (2023) documented increased leakage of gas from plugged oil and gas wells resulting from seismic activity due to injection of produced water into disposal wells and hydraulic fracturing.

Impacts of earthquakes on buildings and pipelines, including those that are buried, have long been an active area of civil engineering research. There are empirical estimates of pipeline damage that relate the number of repairs to peak ground acceleration, peak ground velocity, maximum ground strain, and other factors. There is potential to extend this existing body of research to subsurface wellbore leakage caused by earthquakes (Kang et al., 2019b). Hence, seismic monitoring and hazard assessment should be based not only on the magnitude of seismic event but on ground motion.

USEPA’s Class VI regulations require permit applicants to provide a determination that seismic activity will not compromise subsurface containment of injected carbon dioxide (40 CFR 146.82(a)(3)(v)). The Class VI rule provisions do not address potential damage to buildings and infrastructure (including wellbore cement sheaths of active and abandoned wells) associated with geologic storage of CO_2.

However, as part of its permanence requirements for geologic sequestration, the California Air Resources Board (CARB) has developed requirements which include consideration of natural and induced seismicity (CARB, 2018). In the California Carbon Capture and Sequestration Protocol under the Low Carbon Fuel Standard (CARB, 2018), if an earthquake of **M** ≥ 2.7 is detected within a radius of one mile of CO_2 injection operations, a determination must be made whether the mechanical integrity of any well, facility, or pipeline within this radius has been compromised. This protocol however does not consider a naturally occurring major seismic event at distance from an injection well which could induce ground movement damaging wellbores.

A site area that has experienced a nearby earthquake should be ruled out in addition to sites that are near recently active faults (Callas et al., 2022). In developing criteria for geologic storage of CO_2 in depleted hydrocarbon reservoirs, Callas et al. (2022) recommend the historic occurrence of a seismic event of **M** ≥ 3 with an epicenter within 10 km of a storage well and **M** < 3 with an epicenter within 5 km of the pressure front of a storage well as disqualifying thresholds. Callas et al. (2022) also state that lack of a lower confining seal (permeability > 100 nD) is a disqualifying threshold because of potential pressure propagation to basement rock capable of producing seismic activity.

3.10. Well Type

Watson and Bachu (2009) noted that the occurrences of leakage varied between wells that were drilled, plugged, and abandoned, versus wells that were drilled, cased and abandoned. The authors found that within the study area, wells that were cased and abandoned accounted for 98% of all leakage cases reported. It may simply be that the presence of a steel casing with exterior cement subjected to a long operating life span is likely to develop a behind-the-casing pathway, whereas a well that is immediately abandoned, and plugged with a number of long cement plugs, does not have such a potential for pathway development (Dusseault et al., 2014).

Measurements show lower average rates of methane emissions from plugged wells than unplugged wells (DiGiulio et al., 2023; Bowman et al., 2023; Kang et al., 2016; Townsend-Small et al., 2016; Saint-Vincent et al., 2020a; Williams et al., 2020). Bowman et al. (2023) found that abandoned gas wells emitted more methane compared to the well type categories of crude oil, injection disposal, storage, and other.

Kang et al, (2016) found that unplugged gas wells in noncoal areas and plugged and vented gas wells in coal areas in western Pennsylvania were high methane emitters with average methane emissions of 660 kg/yr and 410 kg/yr, respectively. In comparison, DiGiulio et al. (2023) found average methane emission rates of 140 kg/yr in plugged abandoned wells in coal areas and 200 kg/yr in unplugged abandoned wells in western Pennsylvania. However, a very highly emitting (30,000 kg/yr) plugged well in coal area was excluded as an outlier in calculations. Including this well would have raised the average methane emission rates of plugged wells to 4,450 kg/yr. Wells in Pennsylvania that are plugged in coal areas are required to have gas vents, which are designed to release methane and other gases to the atmosphere in order to prevent explosions. Large orders-of-magnitude variation in the emission rates implies that plugging status (based solely on whether or not a well is plugged) is not sufficient for identifying high emitters (Kang et al., 2019). Leakage to groundwater and/or to the atmosphere can occur at poorly plugged wells (Kell, 2011; McMahon et al., 2018).

3.11. Location

The occurrence of leakage problems, although not limited to a particular area, is often found to be more likely in some geographic areas (Watson and Bachu, 2009; Hachem et al., 2023). Geographically-identified problem areas may reflect problematic geological conditions or particular activities occurring in the area. Bowman et al. (2023) found large variations in emissions from abandoned oil and gas wells at the provincial and sub-provincial level of Alberta and Saskatchewan. Saponja (1999) discussed how typical formations found in the Lloydminster area of Alberta, the presence of shallow gravel beds, swelling clays and thin non-commercial hydrocarbon-bearing formations, make both obtaining and maintaining an adequate seal much more difficult.

3.12. Drilling Activity

Watson and Bachu (2009) observed a strong correlation between historical oil prices and surface casing vent flow and gas migration occurrences. When oil prices were high, there was an increase in drilling activity. During these times, the authors noted that there were elevated occurrences of vent flows and gas migration. They suggested that with larger financial incentives to drill many wells rapidly, combined with limits on equipment availability, wellbore construction practices were negatively impacted, which may explain the elevated occurrences of leakage problems.

3.13. Age

Wells constructed prior to federal or state regulation (i.e., in the late 1800s or early 1900s) during early oil exploration pose the greatest risk because these wells are not documented in state records, may be relatively deep, often consisted of an open (i.e., non-cased) well bore over much of their length, and generally have inferior construction as compared to modern standards. Open holes are susceptible to cross-migration between aquifers, especially if no plug is present, leading to a migration of injected fluids into nearby underground sources of drinking water. The steel casings sometimes present in early abandoned wells were often removed to address material shortages during World War II (de Smet et al., 2021). Steel casings are the primary detectable portion of the well through magnetic surveys. Thus, their absence requires field campaigns to locate suspected wells. In ranking criteria for suitability of geologic storage of CO_2 in depleted hydrocarbon reservoirs, Callas et al. (2022) categorize the age of existing or abandoned wells as pre-1930s, 1930–1952, 1952–1974, and 1974 to present as worst to best for wellbore integrity concerns.

3.14. Cement Carbonation

For oil and gas wells, cement carbonation is not normally considered an important factor for barrier or integrity failure. However, for geologic storage of CO_2, cement carbonation may be an important factor. Ordinary Portland Cement (OPC) is currently and historically the prime material used for creating permanent well barriers. OPC is well suited for use in wells, as the hydration process can take place submerged in water and the development of strength is predictable, uniform and relatively rapid. Set cement has low permeability and is nearly insoluble in water. By using different additives, systems for well cementing can be designed for a wide range of temperatures and pressures (Tveit et al., 2021). OPC is also an inexpensive material, and it is therefore used in almost all well cementing operations (Nelson and Guillot, 2006). However, OPC cannot withstand high temperatures and corrosive environments, which may lead to gas influx unless certain chemicals or additives are added (Vignes, 2011). Cement is also known for becoming brittle after setting, and can experience bulk shrinkage during setting, typically in the range of 0.5–5.0% (Salehi et al., 2016; Nelson and Guillot, 2006). These challenges can be mitigated by adding different additives and optimizing the cement slurry for each individual operation (Lende, 2012).

The reaction of CO_2 and water forms carbonic acid.

$$CO_2(aq) + H_2O(l) \rightarrow H_2CO_3(aq)$$

There are then two main reactions that take place, one involving ‘‘carbonation’’ of the cement, where some of the cement components such as portlandite are converted to (mostly) calcium carbonate (calcite), and a second reaction, if calcite is undersaturated in brine, calcite dissolves over time (Abid et al., 2015; Carey et al., 2007; Carey, 2013; Huerta et al., 2013; Zhang and Bachu, 2011; Zhang et al., 2015).

$$Ca(OH)_2(s) + H_2CO_3 \rightarrow CaCO_3(s) + 2H_2O(l)$$

$$Ca(CO)_3(s) + 2H_2O(l) \rightarrow Ca(OH)_2(s) + H_2CO_3(aq)$$

The first of these reactions is almost always observed and can result in increased strength and decreased permeability. If the second reaction occurs, there can be a significant time lag for the dissolution front to proceed along the length of the well.

Zhang and Bachu (2011) provided a review on the well integrity in CO_2 storage sites and highlighted certain approaches that can determine the rate of cement carbonation. Laboratory experiments showed that the rate of carbonation is directly related to pressure, temperature, and flow rate, and indirectly related to salinity. Moreover, cement-water systems without carbonate minerals revealed a larger carbonation rate than a system with carbonate water. The results obtained from the field scale analysis indicated that the interaction with CO_2 will take place over a long period of time and carbonation, or changes in porosity and permeability can be induced (Zhang and Bachu, 2011).

Laboratory and field studies have found that chemical reactions between cement and carbonic acid (CO_2 dissolved in water) can degrade cement integrity (net dissolution) and in other cases lead to precipitation and self-sealing of gaps and spaces (Carey et al., 2010; Crow et al., 2010). There are numerous experimental studies that indicate that cement carbonation may not lead to significant leakage when cement remains intact (Duguid et al., , 2005; Duguid and Scherer, 2010; Barlet-Gouedard et al., 2006, 2007, 2009; Kutchko et al., 2007, 2008, 2009; Rimmele et al., 2008; Bachu and Bennion, 2009; Wigand et al., 2009; Pratt et al., 2009; Carey et al., 2007, 2010; Matteo and Scherer, 2012; Rochelle and Milodowski, 2013; Jung and Um, 2013; Jung et al., 2013; Mason et al., 2013). Kutchko et al. (2007) demonstrated that higher degree of hydration decreased permeability, leading to increase of the cement’s resistance to attack. Condor et al. (2009) observed a decrease of permeability and an increase of compressive strength during the initial exposure of CO_2 in their experiment. Adeoye et al. (2019) found that carbonation of an engineered cementitious composite could lead to an increase in its compressive strength, and the damage was limited to microcracks in weeks of CO_2 disposure. Modeling studies have provided similar results (Carey et al., 2007; Huet et al., 2007, 2010; Scherer and Huet, 2009; Corvisier et al., 2010; McNab and Carroll, 2011; Deremble et al., 2011; Wilson et al., 2011; Gherardi et al., 2012; Fabbri et al., 2012; Raoof et al., 2012; Jacquemet et al., 2012; Brunet et al., 2013, Wertz et al., 2013).

Matteo and Scherer (2012), using reaction rates derived from experiments, calculated that degradation of a 10 m long segment of intact cement would take on the order of two million years. Therefore, only when there are preexisting local leakage pathways associated with annular spaces or fractures in the cement can any leakage occur. Matteo and Scherer (2012) also performed analytical calculations and determined that it was unlikely for small annular openings to be converted into large openings from progressive dissolution. However, when two-phase flow (combined gas and liquid flow) is occurring along the leakage pathway, the buffering from the cement can be counteracted by the acidification from dissolution of the separate-phase CO_2.

To enhance the cement integrity against the interaction with dry (supercritical) or wet (dissolved in brine) CO_2, several approaches have been proposed which include employing pozzolanic materials, decreasing the water to cement ratio, adding latex and dispersing nanomaterials (Abid et al., 2015; Tiong et al., 2020). However, many of these methods suffer from significant shortcomings. For instance, a large quantity of pozzolanic materials can significantly reduce the thickening time of the cement. Reducing the water to cement ratio, on the other hand, can increase the chance of inducing cracks in the cement.

Non-Portland cement cannot resist against the interaction with supercritical CO_2 for a long time and special additives may lose their integrity over time. Nanomaterials can improve the cement performance in CO_2 storage sites, but they are expensive and require operational cost justification (Tiong et al., 2020). According to Ringrose (2020), wellbore integrity in a CO_2 storage site can be maintained by a good cement placement and a standard Portland cement can provide a long-term hydraulic isolation. Ringrose (2020) argued that the cement interface with casing or formations is the likely path of fluid migration that must be carefully monitored. For example, for a well after 30 years of CO_2 injection, prominent leak paths at both the cement-casing and cement-formation interfaces were found after coring (Carey et al., 2007). In general, it appears unlikely that cement carbonation will significantly affect wellbore integrity. Similar to leakage of natural gas, debonding of cement from casing or the borehole wall are the most likely pathways for CO_2 migration.

4. Evaluating Unplugged Wells in the Area of Review

The U.S. Environmental Protection Agency defines the area of review (AoR) as the region surrounding the storage project where underground sources of drinking water (USDWs) may be endangered by the injection activity if leakage were to occur (40 C.F.R. § 146.84). The AoR is the areal extent of the maximum extent of the CO_2 plume or the pressure front in the storage reservoir needed to push reservoir fluids upward into the deepest USDW through a hypothetical open wellbore (EPA, 2013). Depending on the cumulative injection volume and geologic setting, an AoR for a CO_2 storage project could be more than two orders of magnitude greater than that for a Class II disposal well (typically ¼ mile). Locating all abandoned wells within a large AoR, especially in areas having historic (i.e., early 1900s) oil and gas development will be challenging in some cases and likely infeasible in others.

Indirectly, the AoR is a primary control on project cost, as it will determine the number of abandoned wells needing review and possible remediation and the monitoring footprint of the project (Bump and Hovorka, 2023). As geological storage of CO_2 transitions from limited, government-supported pilot projects to large-scale commercial enterprises, dealing with competing subsurface uses which also pressurize subsurface formations will likely become ever more important (Bump and Hovorka, 2023). These might include active hydrocarbon production, natural gas storage, produced water disposal in Class II wells, hazardous waste disposal in Class I wells, and geothermal projects.

Pressure buildup induced in a formation during initial projects will limit injectivity by other operators attempting to use the same formation for storage. Depleted gas fields are one particularly attractive example for CO_2 storage, as abandonment pressures are below initial reservoir pressures giving them large leeway for pressure buildup (Arts et al., 2012; Van der Meer, 2013; Total, 2015). However, depleted oil and gas fields contain a large number of abandoned wells which may leak as the oil and gas fields re-pressurize. It may be possible to manage pressure buildup in saline aquifers by producing water while injecting CO_2 (Birkholzer et al., 2015; Gonzalez-Nicolas et al., 2019). However, this may be unattractive since it adds cost to the project and generally requires reinjecting the produced water, which simply displaces the problem to another reservoir.

Bump and Hovoraka (2023) state that when determining an AoR, the scenario of an open borehole is conservative since other fluids such as drilling mud may be in boreholes. They propose an approach used by the Texas Commission on Environmental Quality (TCEQ) for hazardous disposal wells (Class I wells). For Class I wells, the TCEQ allows the assumption that the wellbore is filled with drilling mud having a density of 9 pounds per gallon (ppg). They base this on the work of Johnston and Knape (1986), who reviewed historical drilling practices, consulted with experienced drillers and concluded that 9 ppg was a conservative minimum assumption, even in old wells drilled with cable rigs and native muds. For reference, 9 ppg mud is roughly equivalent in density to 120,000 ppm brine (Bump and Hovorka, 2023). Drilling mud is also a thixotropic fluid. Left undisturbed, it develops a gel strength that increases with time (Johnston and Knape, 1986). Using this approach, allowable pressure increase in a formation would need to displace a column of dense mud instead of brine thereby allowing much higher pressure buildup during storage. The long-term safety of this approach for geological storage of CO_2 requires considerable scrutiny if implemented by a state achieving primacy for Class VI wells, especially since aqueous flow to the surface has been observed in abandoned wells during aquifer pressurization from Class II disposal wells. High pressure buildup in aquifers is undesirable from the standpoint of potential leakage and induced seismicity.

Owners or operators seeking a Class VI injection well permit are required to report the following information regarding abandoned wells within the AoR that may penetrate the primary confining zone: the well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information required by the UIC Program Director (40 CFR 146.82(a)(4)). Unless the UIC Director requires additional information, regulatory requirements for providing information on oil and gas wells to be plugged or that have already been plugged amount to little more than providing a tabulation of wells. Although not mandated in the Class VI regulations, information provided on oil and gas wells to be plugged should be similar to that required for injection wells since in many cases, abandoned wells will be in direct contact with highly pressurized supercritical CO_2 similar to injection wells.

Owners or operators of Class VI injection wells must perform corrective action on all artificial penetrations in the AoR that may penetrate the confining zone and are determined to have been plugged and abandoned in a manner such that they could serve as a conduit for fluid movement and endanger USDWs (40 CFR 146.84(d)). A determination of need for corrective action is non-prescriptive. That is, when an operator provides a tabulation of wellbores penetrating the primary confining layer in the Area of Review, the operator may simply state that corrective action is unnecessary without providing supporting documentation (e.g., well schematics, cement evaluation logs, results of internal and external mechanical integrity testing, results of sustained casing pressure testing, etc.) or revealing that supporting information is absent.

If fluids are migrating from a well that must be plugged, then the first challenge is to locate the fluid-migration path. Typically, subsurface fluids migrate through completion components, leaky plugs, deficient cement squeezes, or flaws in the primary cement sheath or the caprock (Barclay et al., 2022). The caprock might be compromised by natural fracturing or by fracture-stimulation treatments. When multiple reservoirs exist, identifying which one is leaking enables targeted remediation. Knowing the condition of primary and secondary cement is vitally important (Barclay et al., 2022).

The first step to evaluate the integrity of abandoned wells once used for production is to review historical well records, well logs, and schematics from available information. However, well records are not publicly available in all states. Drilling records can yield clues as to areas that might be susceptible to failure. Events such as well bore collapse during drilling or conditions that placed unusual loads on the casing may also indicate a higher chance of wellbore integrity failure. EPA (2013) recommends that the design casing load also be checked to ensure adequacy for the actual loads faced by the well. Mud logs and open-hole caliper logs can show areas of weak formations. Weak formations are susceptible to well bore instability and subsequent cement failure. Events such as a loss of circulation, well bore stability problems, lack of the use of centralizers, and/or improper removal of drilling mud before cementing can all lead to premature cement or casing failure. Reviewing load calculations, if available, and comparing them to actual events recorded in the drilling log may give the owners or operators an indication of an under-designed casing that may be susceptible to failure. For example, if the casing had a low axial loading stress and stuck pipe was experienced during casing placement, it is possible that the casing may have experienced damage.

Well casing (if not pulled) and annular cement (or lack of) should be examined prior to plugging. Tests that could be potentially utilized to evaluate the integrity of unplugged wells prior to plugging are summarized in **Table 2.** The materials used for the well casing and cement must be compatible with carbon dioxide (40 CFR 146.84(c)(3)). The integrity of any existing casing and cement must be determined in order to assess the quality of well construction as required in 40 CFR 146.84(c)(3). Casing failure is most common at joints and in weak formations where instability around the well bore can lead to failed cement and to casing buckling. Pressure testing is commonly used to evaluate casing. Weak formations are also common areas for cement failure, as are high pressure formations, due to fluid intrusion. Multi-finger caliper logs measure the radius of the casing in a non-destructive way. They can give a 360-degree picture of the inside of the casing and identify any defects caused by corrosion, erosion, or other events (e.g., dropped tools). Results of any internal mechanical integrity tests should be reviewed. If leaks were encountered and were not sealed, corrective action would be required (40 CFR 146.84(d)).

Cement bond/variable density logs (CBL/VDL) are run to determine the presence of cement, cement to casing bonding and cement to formation bonding. Acoustic signals emitted by a transmitter installed in a wireline logging tool are used to produce waves that travel through a section of the casing to evaluate the condition of the cement (e.g., good, moderate or poor). A receiver, installed in the same tool below the transmitter, measures the arrival time and attenuation of the transmitted and reflected acoustic waves. Depending on the degree of the attenuation, the acoustic impedance of the reflected wave signals can provide semi-quantitative insight whether or not there is adequate bond development, good contact, or faults in the cement sheath that may require remedial attention (Dusseault et al., 2014). However, CBL/VDLs average the results for the entire radius and therefore cannot provide three-dimensional pictures of the cement bond or determine the reasons for a poor-quality cement bond.

Table 2. Tools for Assessment of the Integrity of Abandoned Wells. From EPA (2013)**.**

Tool	**Target**	**Advantages**	**Disadvantages**
Multifinger calipers	Casing	Non-destructive, relatively simple	Only examines interior, only detects casing damage
Sonic Logs	Cement	Non-destructive, yields information on cement bond	Results averaged over well circumference, can't indicate reasons for poor quality bond
Ultrasonic Logs	Casing, Cement	Non-destructive, can detect flaws in casing and cement, provides three-dimensional images	Sensitive to well fluids
Cement evaluation log	Cement	Non-destructive, yields information on quality of cement bond	Results averaged over well circumference
Tracers	Leak detection	Can pinpoint routes of leaks, channeling	Radioactive tracers require special handling and may have negative public perception
Dynamic Cased Hole Tester	Cement	Can determine porosity of cement	Semi-destructive, untested in low porosity conditions
Sidewall coring	Cement	Can give detailed analysis of cement condition	Destructive

When evaluating oil and gas wells for plugging and abandonment, it is important to run new CBL/VDLs because significant changes in the condition of the wellbore may have occurred since the last log, and because CBL/VDL technology has improved (Dusseault et al., 2014). CBLs should never be relied upon if they were run at excess borehole pressure because this expands the casing against the cement sheath and may close any microannuli at the cement-rock interface (Dusseault et al., 2014). However, the presence of microannuli can be evaluated by performing the cement evaluation log both with and without pressure (Randhol et al., 2007).

More recently, ultrasonic imaging tools have been developed that apply ultrasonic waves on the casing wall. The resulting resonance of the casing can provide insight on the material behind the casing (solid, liquid or gas) based on the acoustic impedance. Ultrasonic imaging tools typically complement acoustic logs (see Bellabarba et al., 2008; Chatellier et al., 2012; Nelson, 2012). The ultrasonic imaging tool can be used to return 360-degree information on casing thickness, cement thickness, and cement bond.

Logging tools are incapable of detecting defects in cement beyond one casing string in the radial direction, so that the presence of an intermediate casing string outside the cemented-in production casing string shields the CBL/VDLs from detection of microannular spaces and other problems in the rock-cement system outside the outermost casing. Hence, CBL/VDLs are of little use in examining cement outside intermediate or surface casing. Cement logging tools are not successful at detecting problem areas behind the outermost casing (Saponja, 1999; Bellabarba et al., 2008).

Radioactive tracers can be used to detect leaks behind casing and fluid leaking along channels in the well bore. Radioactive tracers are injected down the well, and gamma detectors are used to detect any fluid flow. Noise and temperature logs can provide additional information about the possible source depth of a leak. Noise logs are often conducted to attempt to detect gas leakage behind the casing. As outlined by Slater (2010), sound measurements are made by a highly sensitive microphone at particular intervals in the wellbore. Gas in the annular region may produce noise at a diagnostic frequency identified by that can indicate the nature of gas flow (McKinley et al. (1973). In conjunction with noise logs, temperature logs are often conducted to measure downhole temperatures and compare these measurements to the downhole temperature gradient to detect unexpected variations possibly attributable to gas flow (Slater, 2010).

The quality of composition of cement behind casing can also be evaluated using modular sidewall coring tools and dynamic cased hole testers (EPA, 2013). Modular sidewall coring tools take small cores of the casing and cement for analysis in the laboratory. Laboratory analyses can include scanning electron microscopy, X-ray diffraction, and measurements of permeability and density. This leaves approximately 1-inch diameter holes in the side of the well, which is then patched with a remedial cement squeeze after testing is completed (EPA, 2013). The dynamic cased hole tester can determine the porosity of cement (EPA, 2013).

5. Evaluating Plugged Abandoned Wells in the Area of Review

Much of the discussion in the previous section applies to evaluating wells that have already been plugged. Again, the first step in evaluating abandoned wells is to review whatever records are available for information relevant to plugging. Dry and abandoned wells have only surface casing cemented to the surface and the plugs are shallow in depth at the bottom of the surface casing and a few meters below the depth of the surface casing shoe (depending upon the regulatory requirements at the time of plugging). If these wells are within the AoR and penetrating the storage reservoir and/or confining zone, these wells will need to be re-entered and properly plugged (EPA, 2013).

Plug locations must be reviewed as required in the Class VI Rule (40 CFR 146.84(c)(3)). Abandoned wells should include a cement plug through the primary confining zone, and/or across the injection zone/confining zone contact, with sufficient integrity to contain supercritical CO_2 and elevated pressures (EPA, 2013). In the absence of an adequate plug across the confining zone, cross-migration may occur wherein fluids enter a permeable zone below the lowermost USDW and then migrate upward from that zone (**Figure 11**). Cement plugs should also be located across the bottom of any casings and at the base of the lowermost USDW (EPA, 2013). A surface plug would also typically be required by local well abandonment regulations to ensure that there is no risk of anyone physically falling into the well bore. Cement plugs are considered superior to mechanical plugs for preventing the movement of fluids into or between USDWs. Mechanical plugs are not sufficient for the long-term isolation of CO_2, as eventually the metal is likely to corrode and the plug will fail (EPA, 2013). Materials that are compatible with CO_2 must be used where appropriate (40 CFR 146.84(d)).

If there are cracks, channels, or annuli in a plug that would allow fluid migration (**Figure 12**), the plug should be drilled out and replaced (EPA, 2013). In addition, if the plug material may corrode in a CO_2 rich environment, it should be replaced (EPA, 2013). However, without reentering a well, determination of plug integrity is infeasible. Loss of plug integrity could be implied though if there was substantial leakage of gas to the surface.

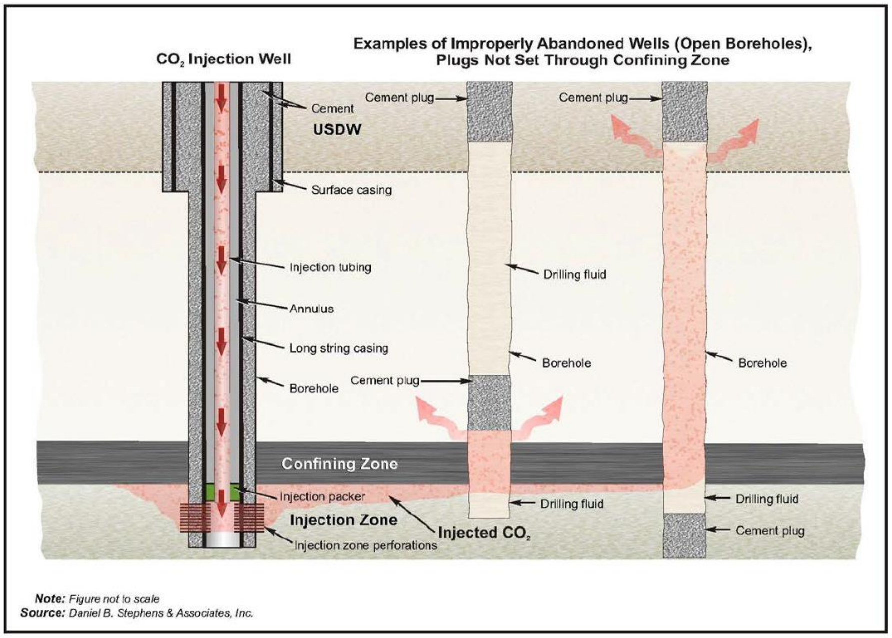

Figure 11. Examples of Carbon Dioxide Leakage Through Improperly Abandoned Wells. Figure from EPA (2013).

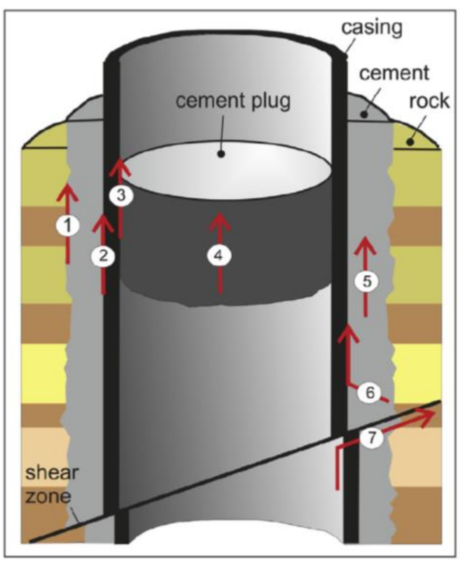

Figure 12. Routes for fluid leak in a cemented wellbore. 1 - between cement and surrounding rock formations, 2 - between casing and surrounding cement, 3 – between cement plug and casing or production tubing, 4 - through cement plug, 5 - through the cement between casing and rock formation, 6 - across the cement outside the casing and then between this cement and the casing, 7 - along a sheared wellbore. From Davies et al., 2014 after Celia et al. (2005).

If the annular space outside a plug in casing can serve as a conduit for fluid movement, especially at the interface of the injection zone and confining layer, remedial cementing should be performed or the casing should be removed and replaced with a cement plug (EPA, 2013). The characteristics of the plugging fluid (i.e., composition, specific gravity) should also be considered, as drilling fluid of sufficient weight may resist displacement by the injectate or mobilized fluids.

The presence of a plug in an abandoned well may not eliminate the possibility of fluid migration especially for wells plugged decades ago. Regulations on plugging and abandonment have changed considerably over the years. Until relatively recently, little emphasis was put on ensuring that wells were properly plugged and regulations covering plugging and abandonment operations were often vague and inadequate. Hence, older plugging requirements may no longer be considered adequate. The most problematic abandoned wells are the ones drilled and completed prior to the establishment of the regulatory agencies. These wells are undocumented, and their integrity is highly questionable due to a lack of regulations and policies.

The first oilfield cement classification was developed by the American Petroleum Institute (API) in 1953. Many abandoned prior to the early 1950s either were not plugged or were plugged with very little cement in them. Hence, the integrity of the wells plugged before the early 1950s is highly questionable (Aminu et al., 2017; Calvert and Smith, 1990). Prior to that, cement often lacked sufficient additives for proper cement setting in conditions experienced in oil and gas wells. As a result, the plugs in many of these older wells failed to set properly and may have experienced channeling and/or cement failure because of fluid intrusion.

More recently plugged wells though may also have not been adequately plugged as bankrupt owners may have used substandard materials. Even "properly" plugged wells may contain annular spaces that could facilitate fluid movement, have well plugs that have degraded over time due to a poor cement job and/or corrosive conditions, and degrade when in contact with a CO_2 plume.

If no records are available or adequacy of plugging, especially behind casing, cannot be confirmed, the existing plugs, if present, should be drilled out (**Figure 13**) and downhole tests performed to evaluate casing and cement behind casing. However, evaluation of plugged wells necessitates speculative judgement as evident in **Figure 13**.

The Corrective Action Plan, submitted prior to injection, must indicate what corrective action will be performed (40 CFR 146.84(b)(2)(iv)). The Corrective Action Plan is a condition of the Class VI permit and is subject to UIC Program Director approval (40 CFR 146.84(b)). However, the Class VI regulations do not specify that the Corrective Action Plan be submitted with the Class VI permit application. Hence, there is no solicitation for public comment for this plan. Additionally, the owner or operator must demonstrate guaranteed site access to wells potentially needing corrective action in the future (40 CFR 146.84(b)(iv)). In performing corrective action, owners or operators must use methods designed to prevent the movement of fluid into or between USDWs, including use of materials compatible with the carbon dioxide stream, where appropriate (40 CFR 146.84(d)).

Evaluation and corrective action for wells which the plume is not expected to reach in the near future may be phased if approved by the UIC Program Director. If a phased approach is approved for performing corrective action for a project, EPA (2013) recommends that all required corrective action on wells identified as deficient during the permit application process (or AoR reevaluations) receive corrective action prior to the end of the injection phase.

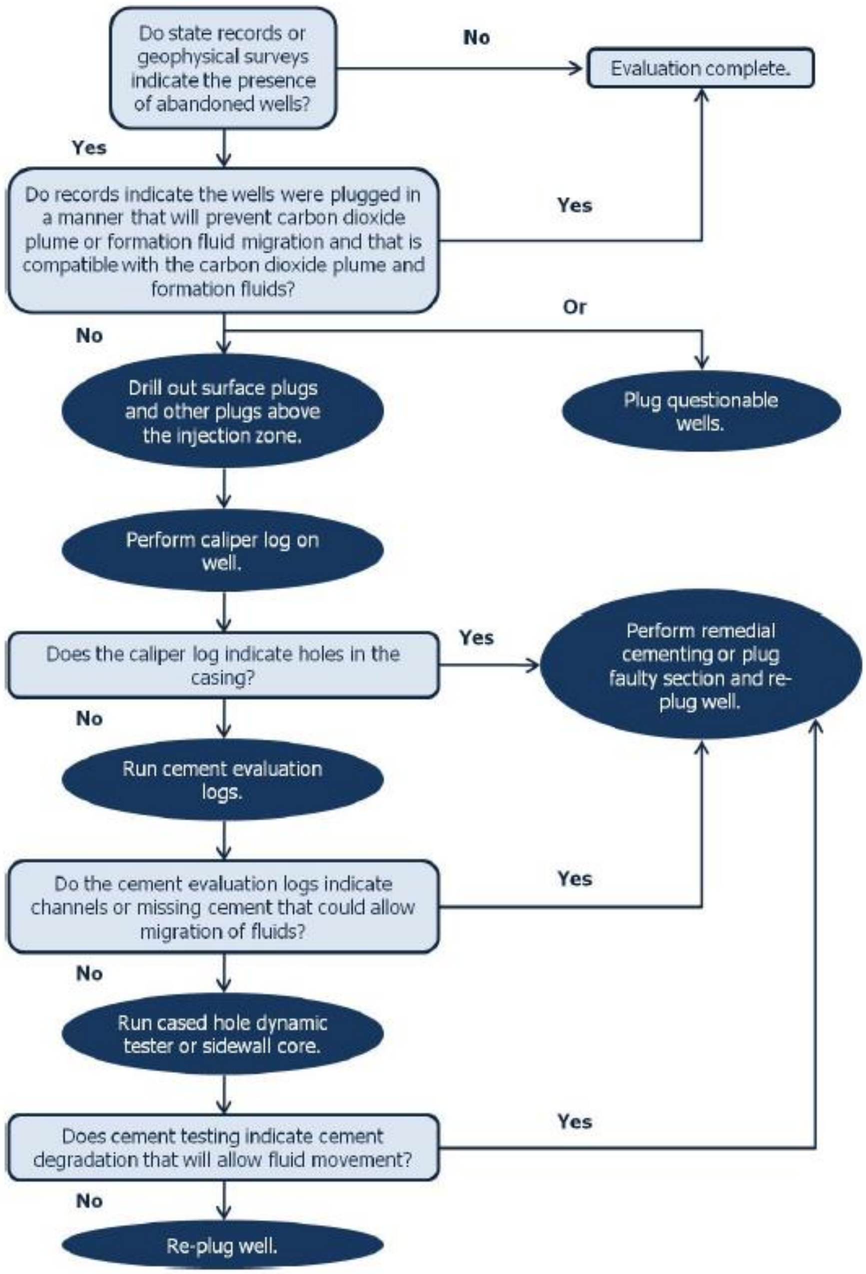

Figure 13. Well Evaluation Decision Tree. Figure from EPA (2013).

Performing corrective action on improperly abandoned wells is intended to prevent the movement of CO_2 or other mobilized fluids into or between USDWs. Acceptable forms of corrective action include well plugging and/or remedial cementing of the improperly abandoned well. In addition to corrective action, EPA (2013) recommends performing enhanced monitoring in the vicinity of improperly abandoned wells, including groundwater monitoring and using indirect geophysical techniques for obtaining monitoring results.

If an abandoned well is plugged using funds from the Bipartisan Infrastructure Law, additional requirements are applicable. To apply for funding to plug orphaned wells under Section 40601 of the

Bipartisan Infrastructure Law (BIL; Public Law 117-58, November 15, 2021) states must inform the United States Department of the Interior of its well plugging regulations, including the witnessing requirements (qualifications of witnesses, documentation) and require their contractors to meet those requirements (DOI, 2023). For states not having well plugging regulations, at a minimum, plugging standards established in the Bureau of Land Management's Onshore Oil and Gas Order No. 2 Section III.G (BLM, 1988) must be used. For States with established surface reclamation standards, all well closures must meet those requirements. For states not having surface reclamation standards, a well site must reflect, at minimum, the Bureau of Land Management's Reclamation and Abandonment Standards (BLM, 2007). States must track and report all plugging activities through existing systems such as the Groundwater Protection Council's Risk Based Data Management System (RBDMS).

Also, states must conduct an inspection of each orphaned well site being considered under the grant application "to screen for leaks of methane and other gases - and if identified to measure the rate of such leaks - and to identify potential surface water or groundwater contamination." Also, state agencies must "conduct or supervise post-plugging inspections within 12 months of the plugging activity to verify the lack of gaseous emissions and water contamination from plugged wells and the achievement of vegetation performance standards appropriate to the site's future land uses, if applicable" (DOI, 2023).

States must follow, as the minimum standard, the Department of Interior methane emission guidelines (DOI, 2022) (and subsequent revisions). Emission guidelines require the use of ground-based techniques, such as hand-held natural gas detectors, high-flow samplers, and flux chambers capable of detecting methane emissions at leak rates of 1 gram per hour or lower (DOI, 2022). The measurement equipment employed must have a documented precision throughout the quantification range of 30% or better. If gas is leaking into and through the soil and quantification of soil leaks is attempted, the measurement equipment employed must have a documented precision of 50% or better (DOI, 2022). The measurement equipment employed must have a documented accuracy throughout the quantification range of 30% or better (DOI, 2022). Duplicate measurements must be made at ~5% of wells (randomly selected) to assess precision. If there is a well head or other infrastructure present at the orphaned well, EPA Method 21 - Determination of Volatile Organic Compound Leaks (EPA, 2017) is preferred. In the case where there are multiple leaks from a single well (e.g., a well head is leaking from more than one valve), the rate at each leak must be recorded before summing emissions (DOI, 2022). The recommended method for estimating "other gasses" is to use geographically specific oil and gas profiles (emission factors) that provide an average fractional percentage of different gases in the gas stream for each specific basin (DOI, 2022). Hence, other gases such as hydrogen sulfide and carbon monoxide and vapors such as benzene are not directly measured.

6. Well Plugging Methods

6.1. Hydrostatic Control

For unplugged oil and gas wells, corrective action will consist of plugging these wells. Corrective action for compromised plugged wells will consist of drilling out plugs and replugging wells. Prior to plugging operations, the well should not be flowing or losing fluid. Drilling fluid should be used to ensure hydrostatic balance or slight overbalance. The drilling fluid should be homogenous throughout the wellbore meaning the density and properties of the wellbore fluid should be the same from top to bottom. Gel strength development of the drilling fluid will also assist the hydrostatic pressure in resisting the flow upward.

There are many different types and versions of drilling fluid, but most can be put into two categories, either water- or oil-based. In addition, synthetic oil-based fluids are commonly referred to as nonaqueous fluids. The nonaqueous fluids are generally stable and maintain designed fluid characteristics better than the early period oil-based fluids. However, nonaqueous fluids are compressible. The deeper the borehole, the greater the hydrostatic pressure is exerted on this compressible fluid. The fluid compressibility must be taken into consideration for the volume of mud to fill the hole and displace the fluid from the work string to the desired depth. On a balanced plug pumping scenario, the displacement could be different by several barrels from the calculated volume to the actual volume.

6.2. Junk in Hole Removal

Plugging typically commences with attempted removal of debris or junk in the hole. Junk in the hole is common especially in wells abandoned in the early 1900s. In California, if junk cannot be removed from the wellbore, cement must be down squeezed through or past the junk and a 100-foot cement plug must be placed on top of the junk (CA Code of Reg, Title 14, sec 1723).

6.3. Casing Removal

The ultimate goal of plugging is to achieve a rock-to-rock barrier. This is best achieved in the absence of casing. Based on state regulatory requirements, there is sometimes an attempt to pull uncemented or poorly cemented production casing from the wellbore using a cut-and-pull operation. The casing cut can be done using explosives, chemicals, mechanical cutters, or using abrasive cutters. Regardless of which type of cutting technique is used, usually the cut is performed when the casing is under tension. Some of the challenges associated with explosive cutters are health and safety considerations associated with the transportation, handling and storage of explosives. There are also uncertainties related to dispersion of force from the explosive device and shape of the resulting cut. In California, a hole must be full of fluid prior to the detonation of any explosives and explosives can only be used by a licensed handler with required permits (CA Code of Reg, Title 14, sec 1723).

Electrical or hydraulic mechanical pipe cutters can also be used to cut casing. One of the advantages of mechanical cutters is the use of a centralizer which holds the cutter in the center of the pipe. Hence, the risk of damaging the outer casing due to eccentricity is reduced. Abrasive cutting techniques can be used whereby abrasive cutting particles are injected into a water jet to wear away the production tubing, casing, drill pipe or drill collar. Radial cutting torches can also be used which use thermite derivatives to melt casing radially (Khalifeh and Saasen, 2020). Also, chemical cutters can be used which utilize chemicals to react with steel to cut casing. The efficiency of chemical cutters can be affected by the presence of scale, poor spray pattern, or eccentricity of casing (Khalifeh and Saasen, 2020).

The presence of scale deposition in casing and casing-cement bond strength may necessitate pulling capacity of cement beyond the working unit or work string capacity. Therefore, the casing may need to be cut into short lengths with retrieval accomplished over multiple trips. During casing pulling, debris may fall down around the casing causing it to get stuck in the wellbore perhaps rendering casing irretrievable. Also, casing retrieval may induce wellbore collapse, substantially complicating plugging operations (Khalifeh and Saasen, 2020). Removal of casing offers the best opportunity for a wall-to-wall seal during plugging at a given depth. However, there are risks and difficulties in casing removal.

In lieu of pipe removal, casing milling can be used to grind away a section of casing and cement. When casing is milled away, the generated debris known as *swarf* needs to be transported to surface or left behind in the bottom of the well. Milling fluids are usually water-based fluids containing bentonite/bicarbonate mud, bentonite/mixed metal hydroxide mud, xanthan gum/sea-water mud, and potassium formate fluid (Ford et al., 1994; Messler et al., 2004; Offenbacher et al., 2018). Considering the geometry of the circulation system and non-Newtonian behavior of milling fluids, the hydrodynamics of swarf transportation and hole cleaning are identical to cutting transportation and hole cleaning during drilling (Khalifeh and Saasen, 2020). However, swarf debris are much larger, have irregular shapes, and have a higher density than rock particles (Ford et al., 1994) necessitating consideration of settling velocity in static and dynamic fluids for effective removal (Khalifeh and Saasen, 2020).

Section milling is difficult to execute safely and efficiently. The fluids designed for section milling must have sufficient weight and viscosity to suspend and transport swarf to surface while keeping the opened hole stable. There is a risk of splitting and buckling the casing. As the cutting tool is worn out after only a few feet of milling, frequent trip out is often required, which is time consuming (Khalifeh and Saasen, 2020). Upward milling is a new form of section milling technique where the milling operation is performed while moving upward, cutting the swarf into small bits, where the swarf falls down into the wellbore (Joppe et al., 2017; Nelson et al., 2018).

6.4. Mud Conditioning in an Open Borehole

If casing removal has been accomplished, the next step prior to plugging is mud conditioning. Mud contamination of cement is the primary cause of plugging failures in open boreholes (Arbad and Teodoriu, 2020; Beach and Goins, 1957; Schumacher et al., 1996). To ensure adequate bonding between cement and the formation prior to plug placement, a hole must be free of swarf, cuttings, gels, and mud must be in a fully displaceable or circulatable condition. This allows the spacer fluid to effectively displace the mud at the desired hole interval prior to cementing (Beirute et al., 1991). Cement contamination by drilling fluid is more likely to occur when the drilling fluid removal is inefficient (Hault and Crook, 1979).

Mud displacement can be carried out hydraulically or mechanically. In the hydraulic process, spacer fluids are used to displace drilling or milling fluid. There are several types of spacer systems available including: flushes, gels, water based, oil based, and emulsions (water in oil emulsion and oil in water emulsion). Flushes are mainly used to achieve turbulent flow for improved mud removal (Beirute, 1976). Spacers are designed to improve cement bonds by water-wetting the cement-pipe or cement-formation interfaces while not destabilizing any sensitive zones and not adversely affecting the mud or cement properties (Farachani et al., 2014). In order to obtain an improved mud removal, studies show that density of displacing fluid should be at least 10% greater than the displaced fluid, and that frictional pressure of the displacing fluid should be greater by at least 20% than the displaced fluid (Shadravan et al., 2015). The maximum mud removal occurs when the viscosity profile of spacer systems is higher than the viscosity profile of the drilling fluid and lower than the cement slurry.

Additives can be added to spacer fluid to enhance mud cake removal and permit turbulent flow at low pumping rates (Carney, 1974; Labarca and Guabloche, 1992; Moran and Lindstrom, 1990; Shadravan et al., 2015; Shadravan et al., 2017). Surfactants can be added to the spacer fluid to help to leave the formation water wet for a better bond and in the cement. However, spacer fluids are unlikely to completely remove the mud cake without using mechanical aids (Khalifeh and Saasen, 2020).

Mechanical devices such as scratchers can be utilized to make it easier to displace mud from borehole walls. The rotational-type scratcher cleans the formation when work string is rotated. The reciprocation type-scratcher cleans the formation by moving upwards and downwards. During the mechanical cleaning operation, a wash fluid can be pumped to displace and wash the mud and filter cakes (Khalifeh and Saasen, 2020).

In areas where washouts or lost circulation have occurred, effective mud removal is challenging. Annular flow velocity is lower in boreholes having an irregular geometry compared to boreholes having a round cross-section. If the annular velocity is too low, the mud will largely be left in the washout area in a gelled state. Another challenge introduced by washouts is that if there is a large uncertainty in hole size. The cement volume could be underestimated and the plug length will be less than required. Therefore, the borehole must be calipered prior to cementing and plug placement (Khalifeh and Saasen, 2020).

Even in boreholes having a round cross-section, laminar flow is less effective compared to turbulent flow for mud displacement because the axial velocity of mud near the pipe or formation wall boundary is lower for laminar fluid flow (Hault and Crook, 1979). In order to achieve a turbulent flow regime for spacer and cement, a high flow rate is required. However, in practice, turbulent flow may be unachievable due to the high viscosity of spacers and cement. Also, while effective mud displacement requires the use of high pumping rates during cementing, a high pumping rate may hydraulically fracture the formation. Hence, the fracture gradient of the formation must be known and pumping rates must be carefully controlled (Regan et al., 2003).

6.5. Balanced-Plug Method

There are three primary methods for plugging a borehole. The balance plug, dump bailer, and two-plug methods of plug placement have been used since the 1970s (Herndona and Smith, 1976). The balanced plug method is widely used to place abandonment plugs throughout the world (Poole, 2021). The balanced plug method is often used in conjunction with mechanical bridge plugs and packers. These prevent the cement from falling below a desired point and allow the wellbore to be circulated without worrying about cement fallback during placement (Poole et al., 2021).

In the balanced-plug method, spacer fluid is pumped ahead of cement to displace mud and attempt wetting of the formation or casing surface. Wiper balls/darts can be used to provide mechanical separation between the mud, spacer, and cement slurry to minimize intermixing and contamination of the spacer and cement slurry in the work string during displacement (Poole, 2021).

Volumes of spacer ahead and behind the slurry are calculated so that the spacer height inside and outside the work string end up at the same level (**Figure 14a**) Khalifeh and Saasen (2020). The fundamental assumption of balanced plug calculation is that fluids are going to stay in place while the work string is pulled upward (Roye and Pickett, 2014). A stinger can be employed to minimize agitation (**Figure 14b**). In addition to agitation while pulling out the work string, cement can be contaminated by poor mud removal by spacer fluid and displacement during setting caused by density differences (Khalifeh and Saasen (2020).

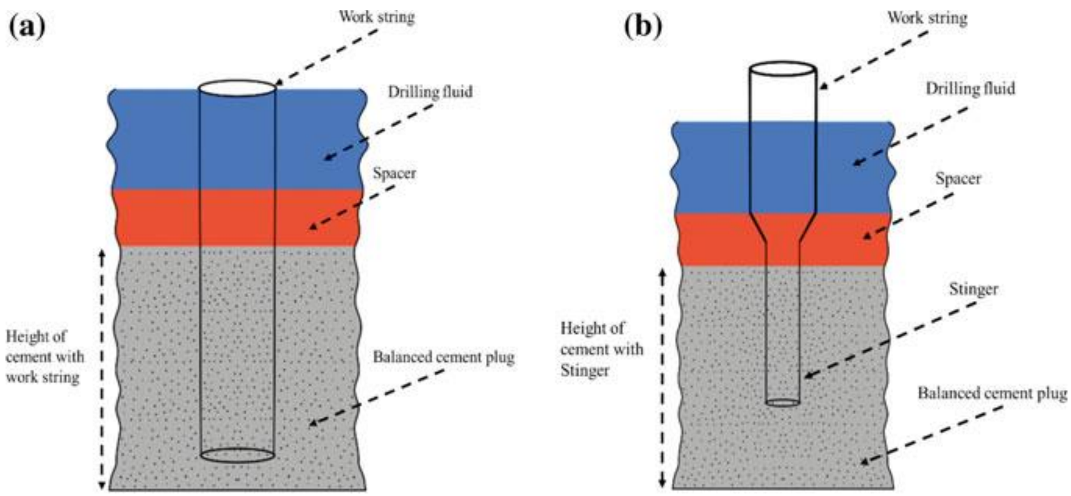

Figure 14. Balanced-plug placement technique. (a) common work string, (b) deploying a stinger to minimize the agitation of slurry during pulling out of slurry. Figure from Khalifeh and Saasen (2020).

A properly designed plug can be contaminated during pulling the tailpipe of the work string out of the cement plug, especially in deviated sections (Isgenderou et al., 2015). In deviated holes, unstable fluid interfaces with regards to gravitational forces, and fluid contamination introduce complications to balance the fluids during plug placement. In addition, deviated boreholes intensify challenges related to free fluid and particle segregation.

6.6. Dump Bailer Method

In the dump bailer method, a bailer filled with cement is run into the wellbore and opened electronically or mechanically via touching a mechanical foundation (**Figure 15**) (Khalifeh and Saasen, 2020). The in-situ drilling fluid in the well is subsequently replaced by the cement slurry, ideally with minimum mixing. In this method, the cement slurry has a higher density and a higher viscosity than the drilling fluid. Advantages of this method include lower cost and improved operational time compared to other methods. Disadvantages include the need for multiple runs due to low capacity of bailers, cement setting inside bailers due to static conditions, and uncertainties associated with mud or spacer removal (Khalifeh and Saasen, 2020). The dump bailing method fails when the cement slurry is significantly contaminated by and mixed with the in-situ fluid. In California, placement of a cement plug by bailer is not permitted beyond a depth of 3,000 feet and water is the only permissible hole fluid in which a cement plug can be placed by bailer (CA Code of Reg, Title 14, sec 1723).

Experience has shown that the dump-bailer approach is often unsatisfactory in providing an adequate seal (Dusseault et al., 2014). Watson and Bachu (2009) state that because bridge plugs are composed of cast iron and nitrile elastomers, they are susceptible to corrosion by formation and injected fluids, in particular in the presence of dissolved CO_2. Watson and Bachu (2009) describe a small subset of wellbores that were re-entered to evaluate the efficiency of plugging using a mechanical plug and the dump bailer method of cement placement. Bridge plugs underwent significant degradation over a 5-30 year period. Cement plugs placed on top of the bridge plug were near nonexistent in some cases. Due to corrosion of bridge plugs, and the inefficiency of placement observed for dump-bail cement caps, Watson and Bachu (2009) suggested that over a long period of time (hundreds of years), approximately 10% of these abandonment methods would fail and allow formation gases to enter the wellbore.

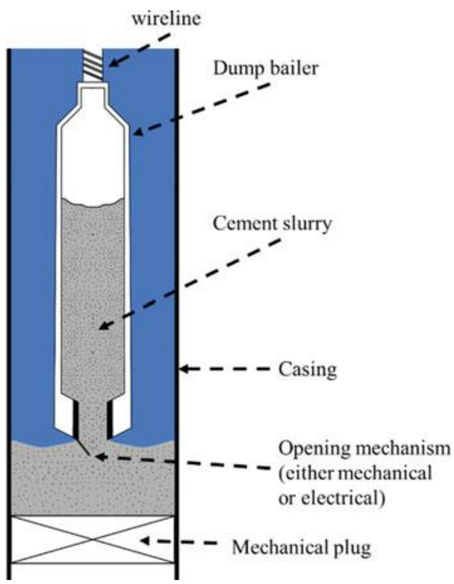

Figure 15. Dump bailer method for plug placement in casing. Figure from Khalifeh and Saasen (2020)

6.7. Two-Plug Method

To minimize the contamination of the cement plug with the fluid ahead and behind, the two-plug method can be used (**Figure 16**). In this technique, a wiper dart is used to push lead cement behind a spacer fluid to a locator sub. When the first wiper dart seats on the locator sub, pressure increases during injection until the diaphragm of the wiper dart ruptures. Cement then passes through the first wiper dart. Injection continues with additional spacer fluid behind a second wiper dart behind tail cement until the second wiper dart ruptures releasing additional spacer fluid behind tail cement. Thus, from surface down to a depth close to the tailpipe or stinger, the slurry is fully separated from the spacer and consequently, the risk of contamination is decreased (Khalifeh and Saasen, 2020).

There are several possible mechanisms that may cause leakage paths to form, both during and after the plugging operation. During setting, loss of fluid from the cement slurry to the formation may cause gas intrusion to the cement slurry, allowing gas channels to form (Tveit et al., 2021). Bulk shrinkage during setting may also create small cracks and gaps or microannuli that may become leak paths for leaking hydrocarbons (Barclay et al., 2001). The hydraulic bonding strength, the ability to prevent flow between the cement and the casing or formation, may be drastically reduced by inadequate hole cleaning pre-cementing (Khalifeh et al., 2018; Evans and Carter, 1962). Even when successful in creating a strong hydraulic bond, this may fail over time. Debonding can occur as a result of various processes and factors, many of which are outside the operator's control, such as changes in the tectonic stresses in the formation, subsidence, pressure decrease during production, pressure build-up post plug and abandonment, stimulation practices and temperature fluctuations or cement shrinkage with time (Thiercelin et al., 1998; Nelson and Guillot, 2006).

6.8. Plug Placement in Cased Wellbore

The balanced plug, dump bailer, and two-plug methods can be used in cased boreholes. When considering plug placement for a cased hole, if there is no annular flow outside casing, a mechanical bridge plug is typically installed inside casing to create a foundation for a cement plug above which the well is filled with fluids such as brine, drilling mud, or corrosion-inhibiting fluid. The purpose of a mechanical bridge plug is to prevent gas invasion and repositioning of cement during setting. Gel plugs or viscous pills can also be used as foundation for cement plugs but may not be sufficient to hinder downward flow of cement (Harestad et al., 1997). The purpose of the fluid above the bridge plug is to maintain pressure and prevent rapid corrosion of the steel casing. The requirement on length of cement plug is variable. The longer the cement plug is, the lower the chance to be subject to through-going gaps and the greater the resistance is to leakage flow if a gap were to develop.

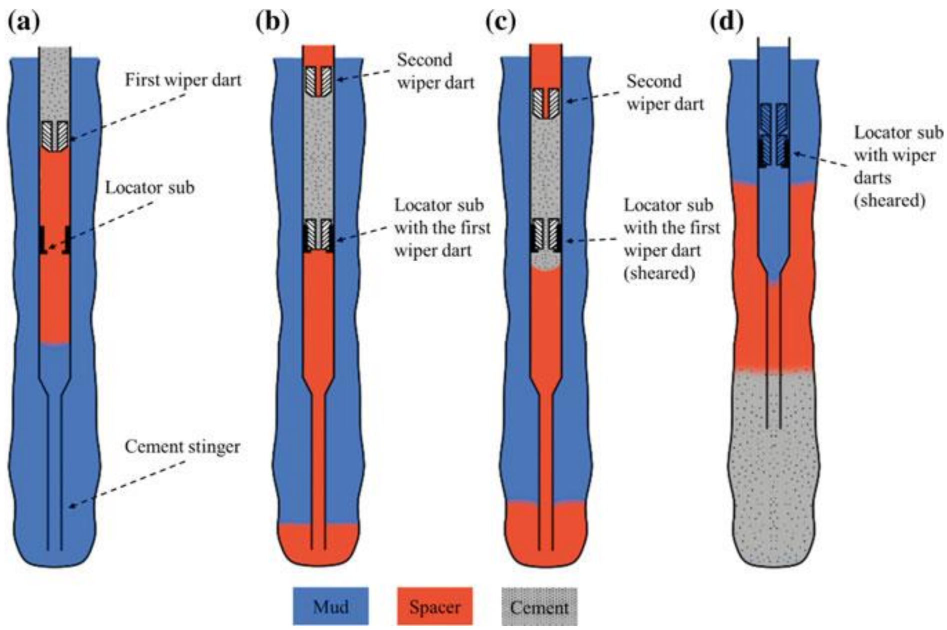

Figure 16. Two-plug method: (a) first wiper dart separates cement from spacer until it lands on the locator sub, (b) second wiper dart separates cement from spacer behind cement, (c) the diaphragm of the first wiper dart is sheared due to the increased pressure and cement slurry passes through it, (d) second wiper dart seats on the first wiper dart and its diaphragm is sheared due to the increased pressure and the spacer passes through it (Nelson and Guillat, 2006). Figure from Khalifeh and Saasen (2020).

The mechanical plug is not considered part of the barrier. If the mechanical plug passes a pressure test prior to cement placement, a cement plug is placed on top of the mechanical plug and left undisturbed until it develops high enough strength. If the mechanical plug did not successfully pass a pressure test, the cement plug is pressure tested. Pressure test failure of cement plug means that another cement plug needs to be established. Different regulatory authorities require different plug lengths.

6.9. Tagging and Pressure Testing Cement Plugs

After a plug is installed, the depth of the plug is tagged and the top of cement is drilled to reach hard cement. This operation is known as cement dress-off. After a plug is installed, it is necessary that the plug keeps its position and does not move. Weight testing is used to measure the bond strength to casing or a borehole wall. Weight testing can be conducted using drillpipe or a weight attached to coiled tubing or a wireline (**Figure 17**). One of the main limitations of coiled tubing to be used in weight testing is the maximum weight that can be created. In addition, coiled tubing may be susceptible to helical ramp or tortuosity and difficult to apply more weight. Compared to drillpipe and coiled tubing, the use of wireline for weight testing is not accepted by many regulators due to the limitations of exerted weight (Khalifeh and Saasen, 2020).

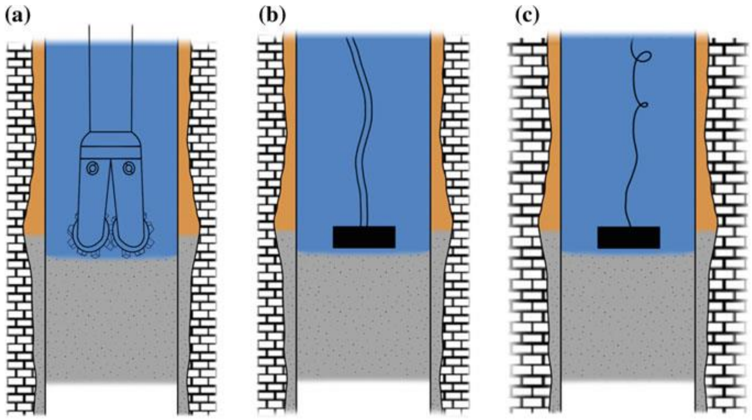

Figure 17. Weight testing of cement plug placed inside casing; a drillpipe, b a heavy weight may be used with coiled tubing but coiled tubing may experience helical shape due to its design factors, c limited weight can be used for wireline. Figure from Khalifeh and Saasen (2020).

Weight testing does not provide any information about the integrity of the plug. Weight testing measures the shear bond strength of plug to adjacent material. So, the required shear bond strength measured by drillpipe during weight testing is defined as drillpipe tag weight. If the position of cement does not change, the cement plug is regarded as “qualified”. Otherwise, a new cement plug needs to be established (Khalifeh and Saasen, 2020).

Pressure testing is applied to plugs installed inside casing, open hole plugs which are extended to casing or plugs installed entirely in openhole. Pressure testing gives an insight about integrity of the cement plug and sealing capability at the interface of cement plug and adjacent element. It does not necessarily provide information about the hydraulic bond strength of entire plug length. In positive pressure testing, fluid is injected by surface pump whereas pressure above the plug is higher than the pressure below, P1 is higher than P2 (**Figure 18**). When the pressure difference across the plug fulfills regulatory requirements, the pressure is monitored for a period of time and if a stable pressure is attained, the plug is considered qualified (Khalifeh and Saasen, 2020). Different regulatory authorities have different minimum and maximum pressure testing requirements in addition to length of time to hold pressure, and maximum pressure loss during testing. During pressure testing, casing should not be damaged nor impact cement behind casing. To avoid this issue, the test pressure is selected to not exceed the casing strength minus wear allowance (Khalifeh and Saasen, 2020).

There are some concerns associated with the positive pressure testing technique including, but not limited to uncertainty associated with sealing capability of casing connections, casing corrosion, and ballooning effect of casing. When hydraulic pressure is applied, the injected fluid can leak through casing connections and a stable pressure reading may not be reached. In this case, it is difficult to identify the source of the leak whether it is casing connections or a failed plug. Where casing experiences small holes caused by corrosion, the applied hydraulic pressure leaks through the casing and pressure monitoring does not show a stable reading. A ballooning effect can occur when there is liquid in the annular space behind casing and casing thickness has been affected over years. In this scenario, the casing can expand if the applied pressure exceeds the casing design criteria such as its elasticity (Khalifeh and Saasen, 2020). If the plug is set in a previously pressure tested casing, the pressure limit should be below the previous casing test pressure (Poole et al., 2021).

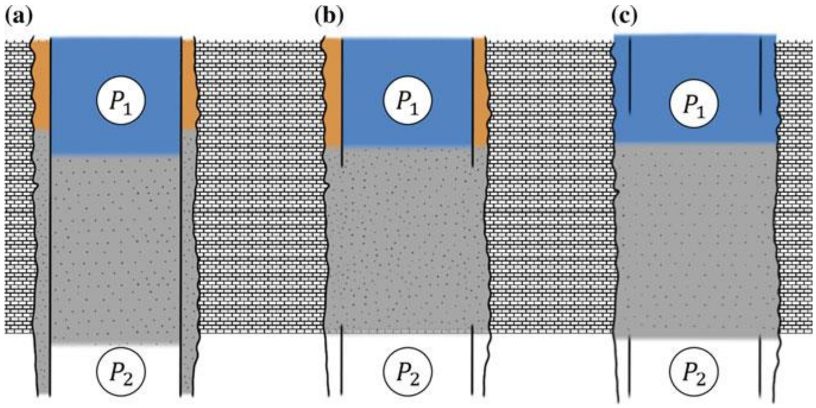

Figure 18. Cement plug installed in wellbore; a cement plug is installed inside casing across a qualified annular barrier, b cement plug installed in an openhole but extended to casing, c cement plug entirely installed in an openhole. Figure from Khalifeh and Saasen (2020).

In negative pressure testing (also known as inflow testing), the hydrostatic pressure above the plug is decreased so that pressure below the plug (P2) will be higher than pressure above the plug (P1) (**Figure 18**). Then, the changes in pressure are recorded. A stable pressure means a sealed plug. Negative pressure testing is used where integrity of connections or casing string above the plug is questioned and positive pressure testing cannot be performed (Khalifeh and Saasen, 2020).

6.10. Use of Coiled Tubing for Plugging

Coiled tubing is a long continuous pipe wound on a spool. The pipe is straightened prior to being pushed into the wellbore and rewound to recoil the pipe back onto the transport and storage spool. Depending on the pipe diameter and the spool size, coiled tubing can range from 2,000 to 15,000 ft or greater lengths. This technique has proved to be very economical to place small volumes of cement slurries required in curing channeling behind tubulars, blocking off perforations, squeezing cement into perforations, curing lost circulation zones during drilling, and placing cement whipstocks (Portman, 2004). However, there are some concerns limiting the use of coiled tubing for cement plug placement including fatigue problems, hole cleaning, special cement slurry design, unit space and capacity, and crane capacity (Khalifeh and Saasen, 2020).

Coiled tubing fatigue life is a major area of concern as the coiled tubing diameter increases for cementing applications. This concern is greater in coiled tubing with larger diameters (Newman and Brown, 1993). There is no practical non-destructive means of measuring the amount of damage accumulation. Limited flow capacity due to the size of the coiled tubing and lack of mechanical agitation reduces hole cleaning efficiency in large hole sizes (Elsborg et al., 1996). A typical cement slurry designed for placement with coiled tubing has a longer thickening time, and lower viscosity and yield stress (Bybee, 2011).

6.11. Cement Squeezes

Placing a cement plug in a cased wellbore is not sufficient to prevent leakage if fluid flow is occurring in the annulus between casing and the borehole wall. The annulus cement may be damaged in the form of cracks and microannuli (i.e. debonding) due to forces occurring in normal well operations such as pressure testing, injection, stimulation and production, especially for older wells. Thermal, mechanical, tectonic and chemical stresses can also raise the leakage risks by the corrosion of casing and tubular, fracturing the cement, cement dissolution and cement permeability enhancement (Carroll et al., 2016). Cement-casing interfaces are subject to debonding and other processes over time that lead to failure to seal that creates a leakage flow path for formation fluids and CO_2 upward past the plug into the fluid-filled well. When casing remains in a borehole or cannot be removed at a required depth of plugging, and cement is either not present or damaged, potentially allowing fluid flow behind casing, cement must be installed behind casing (Garcia et al., 1976).

If gas or brine flow is occurring outside casing due to lack of primary cement, a "squeeze" operation is performed to fill the void space with a sealing material, typically cement. The problem (defective) interval is first detected by wireline tools (cement bond logs and noise and temperature logs).

The casing is perforated using a perforation gun, which effectively blasts a hole through the casing, the cement, and into the adjacent formation rock. Cement squeezes can be performed using either a packer or a bradenhead squeeze. The methods differ in how the treated section is isolated from the rest of the well. In the packer squeeze, a bridge plug isolates the area below the area to be treated while a modified packer with a bypass valve isolates the area above the treated area. Cement retainers are used if significant back pressure is expected. A bradenhead squeeze only isolates the area below the area to be cemented. It is typically used only if the casing above the treated area is strong enough to withstand the squeeze pressure (EPA, 2013). In cement squeezes, either drillable packers or retrievable packers can be used. Drillable packers allow less freedom in placement but better control of the cement. They are preferred if high pressures are maintained on the cement after the squeeze (EPA, 2013).

A cement slurry is pumped down a tube filling the perforated area with cement. The casing is then sealed off with a valve or a packer to induce elevated pressures by continuing to pump cement down the tube in the isolated region. The induced pressures squeeze the cement through the perforations into the annular region (Dusseault et al., 2014). Increased pressure on the cement forces water out of the cement slurry leaving behind the partially dehydrated cement. Cement squeezes can either be low pressure or high pressure. Low pressure squeezes are used to set a small amount of cement in a given area and operate at a pressure lower than the fracture pressure of the formation. Higher pressure squeezes are used when channels or disconnected microannuli are to be cemented. The higher pressure squeezes may fracture the formation and then allow the cement to flow into disconnected channels (EPA, 2013).

Cements used in squeeze cementing can vary depending on the nature of the defect. All materials used for cementing of abandoned wells must compatible with the carbon dioxide stream, where appropriate (40 CFR 146.84(d)). Traditional cements may be supplemented with or replaced by materials such as polymer gels and acrylic grouts. Acrylic grouts can be used for small casing leaks or cases where pressure leak off is detected. High concentration low molecular weight polymers can be used for small to moderate leaks. High molecular weight polymers are typically used for channeling and lost circulation applications. Cement or cement/polymer blends are typically used for severe leaks (Randhol et al., 2007).

Under suitable conditions, cement squeeze operations are said to be ". . . a routine and highly predictable procedure" (Chmilowski and Kondratoff, 1992). However, in many circumstances, formation conditions and fracture aperture limit control of the remedial operation. Extremely permeable formations or formations containing large vugs and natural fractures may not be able to support a cement column, as cement slurries may flow unconstrained into the formation. On the other hand, particular geological materials, such as swelling clays and media with low permeability, limit feed rates that can lead to hydration immediately at perforations, consequently blocking passage for cement to enter the void space (Chmilowski and Kondratoff, 1992; Saponja, 1999; Watson et al., 2002). The cement may also undergo shrinkage and deterioration, which may compromise a seal over time.

A concern about casing perforation and cement squeeze operations in stiff naturally fractured rock is that as the grout is forced into the formation at fracturing pressures, the grout fails to penetrate fully into the crack that has been forced open by the high pressures. Thus, even though one pathway may be sealed, cracks as large as 20-50 microns can be opened up from the squeezing operation (Dusseault et al., 2014).

6.12. Perforate, Wash, Cement (PWC)

In this method, a perforation gun is run to the barrier depth where there no cement or poor cement behind casing. The casing is then perforated. In the next step, a washing tool is run in hole and washes the annular space behind the perforated casing to remove the debris, settled mud and mud film (Ansari et al., 2016; Ferg et al., 2011). The washing process can be carried out several times to clean the formation surface. A spacer fluid is then pumped below the bottom perforations and extended to above the top perforations. Cement is then pumped below the bottom perforations until cement reaches the top perforations (**Figure 19)**.

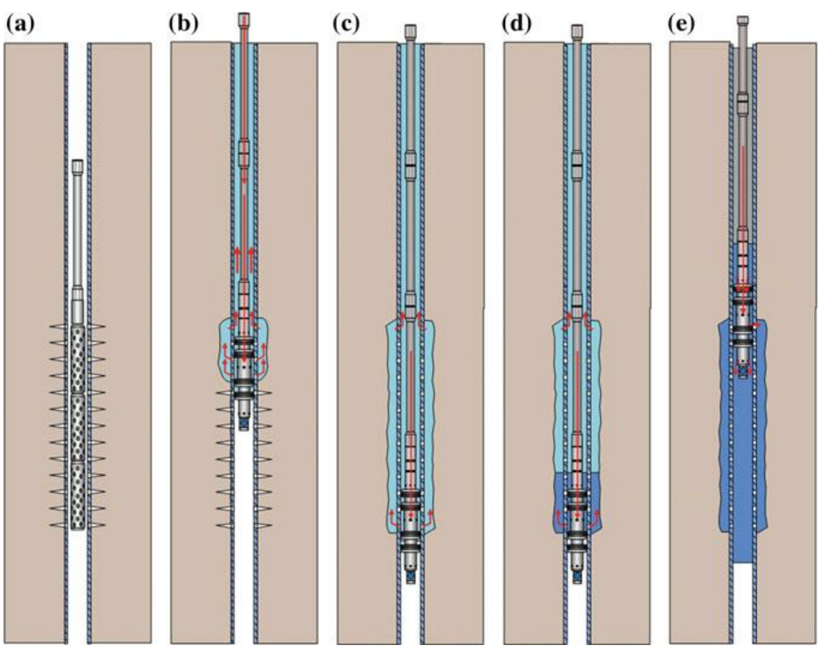

Figure 19. Perforate and wash part of PWC technique: (a) casing is perforated, (b) a washing tool is used to wash the annular space behind the perforated interval, (c) the bottom hole assembly is run downward to bottom perforations, (d) spacer is pumped and work string is pulled, upward, (e) spacer is extended above the top perforations. Figure from Khalifeh and Saasen (2020).

One of the most challenging parts of the PWC technique is effective washing. Wash fluid is a modified water-based fluid is pushed through the created perforations and transported out from the annular space. The displacement efficiency of spacer and placement of cement is a strong function of exit velocity and inclination of the casing. To check the quality of a PWC job, cement remaining inside the casing must be drilled out with subsequent logging of annular cement using cement evaluation tools. However, holes created during perforating introduce error during logging in addition to uncertainties already present using cement evaluation tools (Khalifeh and Saasen, 2020).

After cementing, the quality of the annular barrier is commonly tested using cement bond logs (CBL) and variable density logs (VDL), which provide qualitative measurements (Khalifeh et al., 2017). These logs are not capable of providing quantitative measurements on cement quality. Hence, PWC operations do not guarantee well integrity.

During a plugging and abandonment campaign, a Norwegian operator placed cement plugs in casing in eight oil and gas wells in 70 m of water off the Norwegian Continental Shelf assuming that existing annular cement was competent. Leakage in annular cement was subsequently observed in all plugged wells necessitating well reentry, milling of casing, and replacement of cement plugs (Tveit et al., 2021).

7. Mathematical Modeling of CO_2 Migration in Abandoned Wells

Mathematical modeling of brine and CO_2 leakage in abandoned wells has provided considerable insight into subsurface and wellbore flow processes and the potential effectiveness of monitoring techniques. Efficient geologic storage of captured CO_2 necessitates injection into formations as a supercritical fluid where temperature and pressure exceeds the critical point of CO_2 (T=31.1°C, P=57.38 MPa) (**Figure 20a**). Supercritical CO_2 has density in the subsurface between about 250 and 1000 kg/m3 (**Figure 20b**). While these high densities allow for significant mass to be stored per volume of pore space, the density is still significantly lower than the density of formation water or brine. Hence, supercritical CO_2 is buoyant.

Mathematical modeling of leakage in wellbores requires a consideration of: (1) single (brine or CO_2) or two-phase (brine and CO_2) flow; (2) fluid movement from the injection formation to a wellbore; (3) effect of leakage on the pressure field within in the injection formation; (4) upconing of the CO_2-brine interface around the leaky wells; and (5) intrusion of brine and CO_2 into other formations above and below the injection formation and associated pressure changes in those formations (Celia et al., 2015).

Ideally, simulation would incorporate two-phase flow in three dimensions in all formations affected by leakage over a large domain (e.g., 50 km by 50 km) with fine-scale resolution near numerous wellbores. Three-dimensional numerical multiphase simulations are necessary to capture the complexity of leakage processes. However, this approach is computationally prohibitive especially if stochastic or probabilistic modeling (e.g., Monte Carlo analysis) is desirable (Celia et al., 2015). Probabilistic modeling is desirable because information on wellbores (well cements used, properties of rock formations along the borehole, data from well tests performed, abandonment procedures, and other relevant information) are generally lacking (Celia and Bachu, 2003) and input parameters to models are highly variable.

As a result, simplified models have been developed to address and quantify the leakage potential along wellbores in field scale systems. For instance, Qiao et al. (2021) used a single-phase radial diffusivity model to simulate bottom hole pressure over time with subsequent vertical migration and release into an overlying aquifer. Viswanathan et al., (2008) developed a system-level model (CO_2-Pens) integrating information from process level laboratory experiments, field experiments/observations and process-level numerical modelling to assess CO_2 leakage from wellbores and resulting impacts of carbon dioxide on a shallow aquifer as well as the atmosphere.

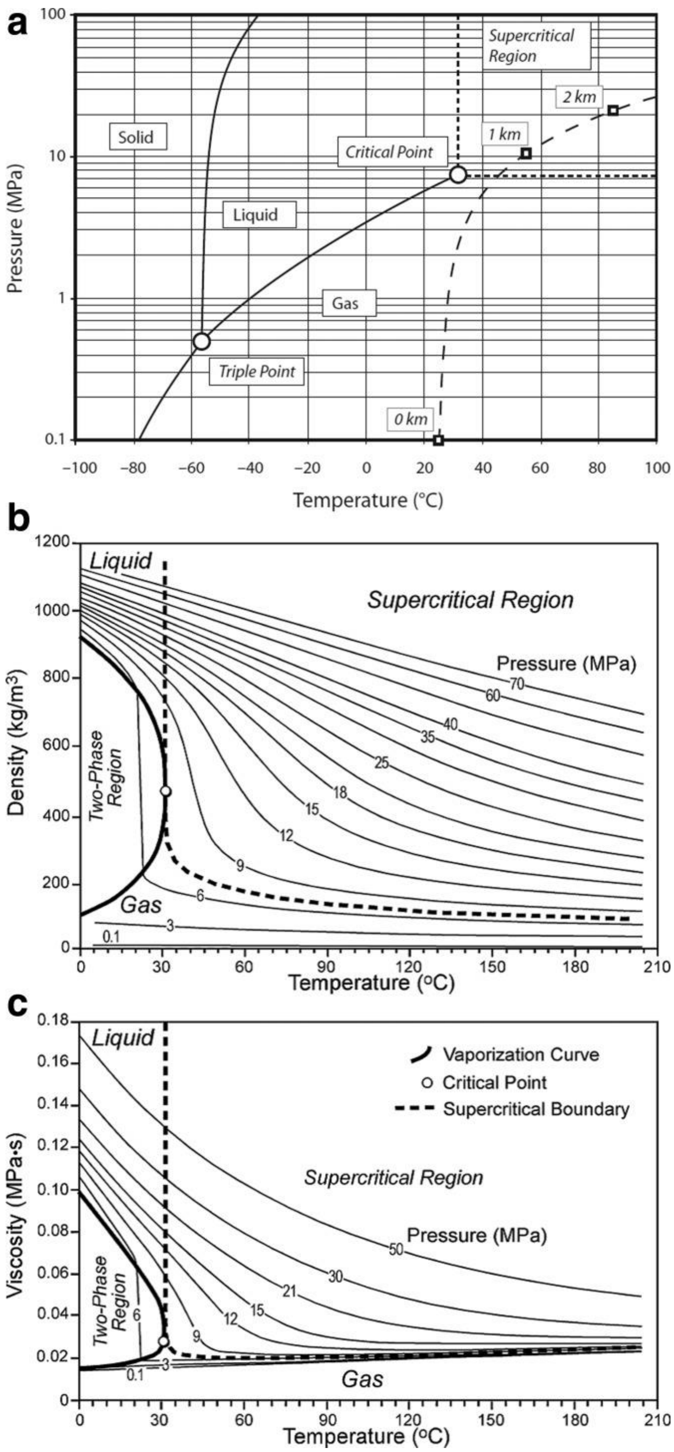

Figure 20. (a) Phase diagram for pure CO_2, (b) density of CO_2 as a function of temperature and pressure, and (c) viscosity of CO_2 as a function of temperature and pressure. Note that the dashed line in Figure 2a indicates typical temperatures and pressures as a function of depth below land surface. Figure 2a taken from Nordbotten and Celia (2012), Figures 2b and 2c taken from Nordbotten et al. (2005a).

Another group of investigators have focused on the development of analytical solutions to address wellbore leakage potential (Doherty et al., 2017; Nordbotten and Celia, 2012; Nordbotten et al., 2004, 2005a,b, 2006a,b, c, 2009, 2012; Nordbotten and Dahle, 2011; Tao et al., 2010, 2011), while others studied the hybrid analytical/numerical approaches (Gasda et al., 2009; Pan et al., 2011a,b,c). Nordbotten et al. (2005) developed a semianalytical solution to predict leakage from a leaky well. The solution provides CO_2 plume extent and leakage rate from an abandoned well located at an arbitrary distance. Gasda et al. (2009) developed a hybrid numerical–analytical model to capture both a large-scale carbon dioxide plume associated with injection and a small-scale leakage problem associated with localized flow along wells. They showed that this hybrid numerical–analytical method is a powerful tool for evaluating leakage risk in geological CO_2 storage because it combines the advantages of both numerical and analytical methods. Cihan et al. (2011) presented analytical solutions to describe coupled diffuse and focused leakage of groundwater in a multilayered system which can include any number of aquifers, alternating aquitards, pumping/injection wells and leaky wells. They used a one-dimensional radial flow equation in aquifer and one-dimensional vertical flow through aquitard in terms of hydraulic head build-up.

Modeling wellbore as an equivalent Darcy medium can assist in overcoming the uncertainties associated with wellbore architecture and in estimating wellbore flow rates (e.g. Gasda et al., 2008). Pawar et al. (2009) used this approach to model the potential for CO_2 leakage in deeper formations for a storage site in Alberta, Canada. The model explicitly accounted for wellbore details, including abandonment plugs, casing and annulus cement. Such detailed simulation can prove valuable for developing effective abandonment practices as well as mitigation strategies for carbon dioxide sequestration sites.

Another approach to modelling the carbon dioxide leakage along the well is using the drift-flux modelling technique. The drift-flux model is employed in wellbore flow models since it is continuous, differentiable and relatively fast to compute (Shi et al., 2005). Pan et al. (2011b) developed a coupled wellbore and reservoir model for simulating leakage through wellbores. They used the drift-flux model for describing transient two-phase non-isothermal wellbore flow of CO_2–water mixtures.

The U.S. Department of Energy's National Risk Assessment Partnership has developed an Open-Source Integrated Assessment Model (NRAP-Open-IAM) which incorporates wellbore leakage during geologic carbon storage (Vasylkivska et al., 2021). The leakage pathway component models included with NRAP-Open-IAM are Open Wellbore (Pan et al., 2011b; Pan and Oldenburg, 2014,2017,2018,2020), Cemented Wellbore (Harp et al., 2016), and Multisegmented Wellbore (Celia et al., 2011; Nogues et al., 2012; Nordbotten et al, 2005, 2009; Nordbotten and Celia, 2006).

The Open Wellbore component model calculates CO_2 and brine leakage along a completely uncemented legacy well. Cemented Wellbore and Multisegmented Wellbore component models calculate CO_2 and brine leakage along fully-cemented wells. Both the Cemented Wellbore and Multisegmented Wellbore component models consider the extent to which intermediate formations (i.e., porous and permeable formations overlying the primary sealing caprock but underlying the lowermost drinking water aquifer) attenuate unwanted fluid migration that might otherwise reach receptors of concern (Vasylkivska et al., 2021). Both aquifer and atmosphere receptor component models are included with NRAP-Open-IAM. Currently, there are four aquifer component models: Carbonate Aquifer, Deep Alluvium Aquifer, FutureGen 2.0 Shallow Aquifer, and Above Zone Monitoring Interval (AZMI). Each aquifer component model simulates the flow of leaked CO_2 and/or brine within the aquifer and accounts for the geochemical reactions that take place when CO_2 and/or brine is introduced. Aquifer component models calculate the volume of groundwater impacted in the aquifer and allow users to evaluate impact (pH, TDS, heavy metals, organics) (Vasylkivska et al., 2021). One atmospheric receptor component model is included with NRAP-Open-IAM. This model uses the wind speed, leak location(s), and leak magnitude to calculate CO_2 dispersion in the near-surface atmosphere (Zhang et al., 2016).

Mathematical modeling has provided valuable insight into expected processes and potential hazards of wellbore leakage during geological storage of CO_2. When supercritical CO_2 is injected into a storage formation, a two-phase CO_2 and brine fluid system is created. Because CO_2 is only slightly soluble in brine (up to a few percent by mass), the injected CO_2 will remain as a separate fluid phase for a significant period of time, with a strong buoyant drive upward. When CO_2 dissolves into the brine, the pH of the aqueous phase is lowered, and this lower pH can drive a sequence of geochemical reactions in aquifer and aquitard rocks and in well cements. While dissolution will take place from the beginning of the injection period, typically the time scale for significant amounts of CO_2 mass to dissolve in brine are long, and dissolution only becomes significant in the post injection period (Celia et al., 2015). Over longer time scales, dissolution of the CO_2 into the brine can become important in reducing pressure (Celia et al., 2015).

During brine drainage (CO_2 displacement of water), water will evaporate into the CO_2-rich phase if CO_2 is injected with little to no water vapor ("dry" CO_2). A fraction of H_2O (less than 1% by volume) can evaporate into the "dry" CO_2 phase creating ''wet'' CO_2 which is much more corrosive to metal piping compared to ''dry'' CO_2 (Celia et al., 2015). However, continued "dry" CO_2 injection will eventually lead to a zone around the injection well where all water has been evaporated, leaving dry CO_2 and precipitated salt from brine in the pore space (Pruess and Garcia, 2002).

When injection ceases, the pressure drive dissipates and the longer-term migration is controlled by a combination of buoyant migration along upsloping directions in the formation, capillary trapping of the CO_2, and CO_2 dissolution into the brine (Celia et al., 2015). While injection represents a brine drainage process, post injection migration will involve both brine drainage along the leading edge of the migrating CO_2 plume and brine imbibition along the trailing edge. As such, brine displacement of CO_2 along the trailing edge results in some CO_2 being trapped behind the mobile plume of CO_2, at saturations at or above the residual saturation for CO_2.

Forces that control CO_2 migration include hydrodynamic drive and buoyancy, with the former (pressure gradients coupled with elevation) acting to drive the fluid away from the injection location and the latter driving the CO_2 updip and upward. Because pressure propagates faster and farther away from the injection well than the injected CO_2, an area of elevated pressure is created that can be significantly larger than the areal footprint of the CO_2 plume.

During injection, pressures at abandoned wells gradually increase to a maximum value until the injection is stopped, followed by a steady decline during the post-injection period (Pawar et al., 2022). For a given injection well configuration, the maximum pressure reached as well as the time at which the maximum is reached varies between abandoned wells. Also, the maximum value is reached after the injection is stopped demonstrating that it takes time for the pressure front to travel through the reservoir. This is also manifested in the differences in the pressure decay behavior during the post-injection period (Pawar et al., 2022).

In a saline aquifer, the pressure field associated with injection could extend over hundreds to thousands of square kilometers (Celia et al., 2005). A CO_2 plume could move laterally under the influence of both pressure drive and buoyancy, until an abandoned well is encountered. The pressure increase in the injection formation can then drive fluid leakage (both brine and CO_2) along defective wells if the materials in these wells have imperfections that allow for fluid flow (Celia et al., 2004, 2005; Nordbotten et al., 2005, 2008).

If leakage of fluid(s) occurs, the flow rate will be determined by the pressure field and the pressure field around the leaky well will subsequently be modified by leakage due to drawdown around the leaky well (Celia et al., 2005). The leakage-induced drawdown could lead to an upconing (upward flow) of the more dense brine underlying the less-dense carbon dioxide. As the interface retreats upward, this could result in simultaneous flow of brine and CO_2 along the leaky well, at least for some time period. Even dissolved CO_2 may exsolve (come out of solution) along an updip/upward migration path as a result of pressure and temperature decrease (Celia and Bachu, 2003). CO_2 that migrates through and/or along these wells will leak into overlying formations, eventually reaching shallow depths where, as a gas, it can migrate quickly to the surface (**Figure 21**). This lateral spreading acts as an enhanced storage reservoir and thereby mitigates the transport fluxes along the borehole. The effect of this is to spread the CO_2 across larger regions and/or more strata of the subsurface, with some of it stored in permeable formations closer to the land surface.

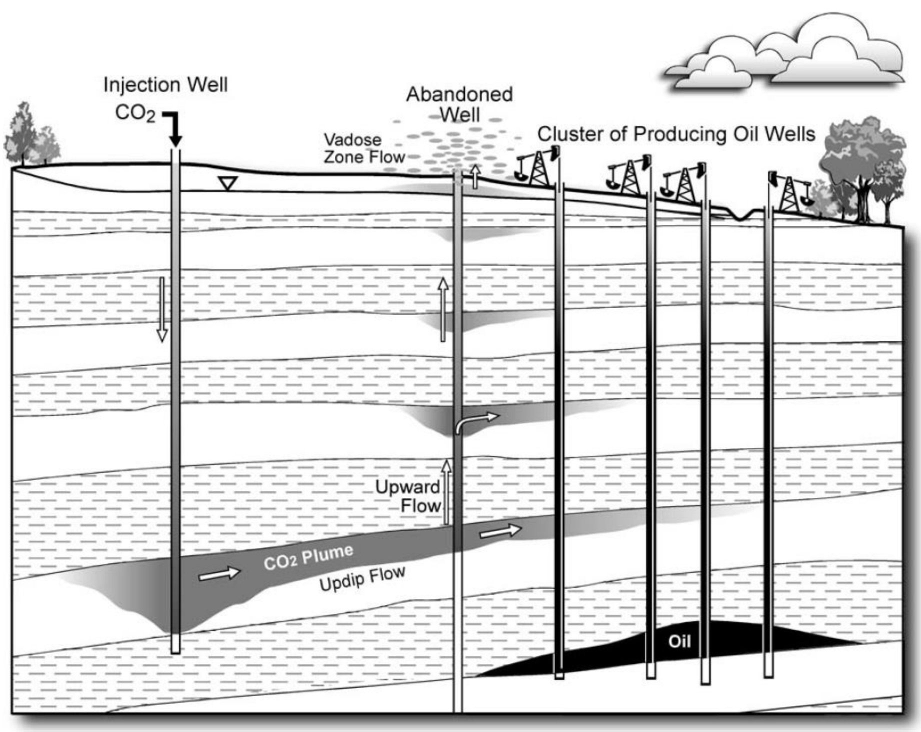

Figure 21. Leakage pathway through an abandoned well. Figure from Nordbotten and Celia (2012).

When a CO_2 plume encounters an abandoned well, leakage will occur through or along the cement zones if present. This might involve flow through the well plugs within the casing, or it might involve flow outside the casing through the cement used for sealing the casing to the formation. The potential leakage pathways through abandoned wells include: between the outside of the casing and the cement, through the cement in the annulus, from the annular region between the cement and the formations, through the cement plug, and from the area between the cement and inside of the casing (Benson et al., 2003; Celia and Bachu, 2003; Celia et al., 2004; Damen et al., 2006; Gaurina-Međimurec and Mavar, 2017; Gaurina-Međimurec and Pašić, 2011; IPCC, 2005).

For leakage within the casing, CO_2 transport would be essentially one-dimensional, and would be controlled entirely by casing and cement properties (Celia and Bachu, 2003). However, leakage along the outside of the well casing is more likely because a greater number of leak pathways and secure cement emplacement outside casing can be challenging (Celia and Bachu, 2003). When leakage occurs outside casing, there is a potential for intrusion of CO_2 into the surrounding rock matrix. This can occur by diffusion, or advection in the case of significant pressure and/or buoyancy drive.

Leakage rates and timeframe will depend on the migration path and medium properties, and will require a good understanding of cement degradation over time scales of tens to hundreds of years, longer than the existing historical record. Because well construction and abandonment procedures have changed over the past 100 years, the analysis of leakage through existing wells must include an historical dimension (Celia and Bachu, 2003).

As previously discussed, when a well is abandoned, cement plugs may be placed within the casing at several depths, or perhaps at only one depth. In any case, cement is used to prevent unintended fluid migration along and within the borehole. The cement used in the completion and abandonment of wells has historically been of variable quality, may have degraded with age and under the effect of formation brines or H_2S if present (Celia and Bachu, 2003). Ordinary Portland Cement systems are used conventionally for zonal isolation in wells. However, Portland cement is thermodynamically unstable in CO_2-rich environments and could degrade to some extent upon exposure to CO_2 in the presence of water.

Under normal conditions, a well-formed cement will have permeability on the order of 10^{-6} to 10^{1} milliDarcy. However, in situ cement may have a much higher effective permeability, because of incomplete sealing along the boundaries, generation of cracks within the cement, generation of a microannulus along the outside of the well casing, and degradation of the cement with time (Celia and Bachu, 2003). A thin (1 millimeter) degraded zone of cement, with very large permeability in the degraded zone, or an annulus associated with poor bonding of the cement to the rock, can lead to large effective permeability if the annular opening is continuous along the well.

Recent studies have begun to provide data on well permeabilities. For example, Crow et al. (2010), Duguid et al. (2013), and Gasda et al. (2013) have reported results from so-called vertical interference tests, where old wells have been re-entered and measurements have been made to provide information from which direct estimates of permeability of material outside of casing (i.e., well cements in the annular space between the casing and rock) can be estimated. Most of these tests have been performed over a vertical distance of a few meters. Results range from very low values (below 0.1 milli-Darcy) to several hundred milli-Darcy, with one measurement in the range of a few Darcy. As a complement to this work, Tao and Bryant (2014) have used sustained casing pressure data in addition to well flow data to estimate effective permeability along the entire length of a well. Kang et al. (2015) performed a similar analysis based on measured methane leakage rates at a set of old wells in Pennsylvania.

8. Conclusions

8.1. Abandoned wells as a risk of leakage during geologic storage of CO_2

There are likely in excess of 4 million abandoned wells in the United States of which approximately 1.5 million are plugged. The locations of approximately 94% of documented orphaned (without a responsible owner) abandoned wells overlie potential underground storage formations for carbon dioxide (CO_2). These wells create potential pathways for CO_2 leakage.

Leakage through abandoned wells creates a risk of greenhouse gas emissions, and also a direct threat to human health and safety, because abandoned wells are frequently located in proximity to buildings and people. For instance, in western Pennsylvania, over 23% of documented abandoned wells (> 4,200 wells) are located with 100 m of a building or residence. Since the actual number of abandoned wells in Pennsylvania likely exceeds the number of documented abandoned wells by almost an order of magnitude, the number of abandoned wells located in proximity to buildings is likely substantially higher.

A major CO_2 release from a wellbore would be a life-threatening scenario similar to that which occurred from a CO_2 pipeline rupture in Satartia, Mississippi in February 2020. Leakage of natural gas is common from both unplugged and plugged abandoned wells. Leakage rates from both unplugged and plugged abandoned wells appear to follow a distribution whereby leakage from a relatively small number of wells accounts for the majority of total leakage. It is plausible that leakage of CO_2 from abandoned wells would follow a similar distribution. Published rates of wellbore failure range from unplugged wells range from 2 to 75% depending on the study. Published rates of gas migration outside casing have been reported as high as 45% in surveyed wells.

In addition to contaminating groundwater and domestic water wells, gas migration from abandoned wells has caused explosions and fatalities. Gas leakage through plugged abandoned wells during re-pressurization of partially depleted oil field for gas storage has been documented. These cases are particularly relevant for geological storage of CO_2 since it demonstrates what could happen when pressurized CO_2 or brine or formation water reaches previously competent plugged abandoned wells. Pressurization of saline aquifers due to oil and gas wastewater disposal is also causing flow of brine to the surface in abandoned wells especially in the Permian Basin and Ohio. Similar scenarios during large-scale CO_2 injection in heavily drilled basins are plausible.

Given that wells have been drilled, and abandoned, for more than a century, and available records are highly variable in their information content, characterization of existing wells will necessarily involve significant uncertainties. Coupled with uncertainties associated with geological and hydraulic properties of the natural formation materials, leakage of CO_2 from a storage formation is likely to at least some extent. Hence, the important question is not whether there will be leakage, but to what extent is leakage acceptable and detectable. A leakage rate of less than 1% per thousand years is necessary for geological storage of CO_2 to achieve the same climate benefits as renewable energy sources.

The documentation needed to evaluate the integrity of each abandoned well is often lacking. In one state examined, Louisiana, the majority of oil and gas wells overlying potential storage areas are plugged and abandoned – many of which were plugged prior to modern cementing standards in 1953. Only a small fraction of these plugged wells (~7%) have recorded perforation depths. Given the age of many of these plugs, and the relatively scant amount of data concerning perforation depths, appraising plug integrity may be difficult if not impossible, necessitating reentry of these wells.

8.2. Causes of leaks

Gas emission sources at plugged abandoned oil and gas well sites include pipe fittings, casing corrosion, surface casing vents, and gas migration. Gas migration is the flow of gas that is detectable at the surface outside the outermost casing string. However, gas migration can also include leakage into groundwater ultimately leading to the presence of gas in domestic water wells (stray gas migration). It may develop if there are adjacent permeable formations, a drilling-damaged zone from the drilling process, or discontinuities between the outermost cement sheath and the borehole rock wall. Aquifers could be subjected to acidification due to high concentrations of carbon dioxide, and the acidification itself can result in a rise of contaminants such as arsenic, lead and mercury.

Overall, the presence of sustained casing pressure, surface casing vent flows, and gas migration are indicators of well barrier and integrity failures, which increase the potential for gas emissions and groundwater contamination. Gas migration and surface casing vent flows require wellbore treatments such as cement squeezes and casing repair which may not have been addressed during plugging. Once plugged, subsurface leakage via the annulus may go unchecked leading to persistent groundwater impacts, emissions to the atmosphere, or other environmental risks such as explosive hazards. Hence, findings of investigations of subsurface leakage are important for understanding and mitigating gas emissions from abandoned oil and gas wells and broader environmental impacts.

Understanding why oil and gas wells have barrier and integrity failure is essential to understanding how to evaluate abandoned wells prior to plugging, how to properly plug abandoned wells, and how to evaluate wells that have already been plugged. Of the several well integrity failure modes, failures resulting in open gaps and annuli (e.g., between cement and casing or between cement and formation) are considered to be most likely to result in large leakage flow. The potential for corrosion of casing is significantly elevated if the cement sheath quality is poor or nonexistent. Thus, production casing should be cemented into the intermediate casing, which should be cemented into surface casing. For geologic storage of CO_2, a poor cement job is perhaps the most important concern for leakage in wellbores. Upon chemical degradation of the cement, corrosion of the casing will be induced by water containing carbonic acid increasing the chance of leakage presenting a long-term issue (>100 years) for wellbore integrity.

Another major reason for barrier and integrity failure is poor mud displacement prior to cementing. The main objective during primary cementing is to uniformly place the cement slurry while effectively displacing the drilling mud from the annulus. An eccentric casing due to poor centralization results in inadequate displacement of drilling mud and nonuniform placement of the cement slurry. Mixing of mud and cement may occur if the density contrast between the drilling mud and the cement slurry is low and wash fluids and spacers are not used. Embedded mud can reduce the compressive strength of the set cement or even prevent slurry gelation from occurring. Cement requires a water-wet clean surface to achieve a cohesive bond. Cement will not bond to salt, oil-rich beds, oil sands, high porosity shale, and drilling mud filter cake. If residual mud remains on the casing or borehole wall, a stable long-lasting cement bond will not form. Washed-out areas of the wellbore wall present a particular problem because drilling mud accumulates within voids and is difficult to remove because scraping is ineffective and turbulent flow of a spacer fluid or cement necessary for mud displacement cannot be achieved. Also, during cement hydration, water may be drawn from mud channels leading to shrinkage-induced cracking of the mud providing a route for gas migration. If the mud filter cake dehydrates after the cement sets, an annulus may form at the formation-cement interface providing yet another route for gas migration.

Cement loses its ability to maintain hydrostatic pressure during setting because of shear stress transfer of cement to surrounding rock which begins to support the weight of the cement column. This impedes downward settlement of cement during water loss to a surrounding formation which is the result of high initial hydrostatic pressure in the cement column. In areas where the cement slurry does not maintain sufficient hydrostatic pressure during setting, pressure in the cement can drop below the pore pressure in the surrounding formation leading to invasion of fluids and the development of channels and gas pockets.

Cement shrinkage during setting is another cause of barrier and integrity failure. Autogenous shrinkage of cement (uniform reduction of internal moisture due to cement hydration) can result in a volume loss of 4-6%, far in excess of that required to maintain radial stress of cement against a borehole wall. High salt content formation brines and salt beds can also lead to substantial cement shrinkage due to osmotic dewatering of cement slurries during setting and hardening. Leakage pathways could continue to form decades following plugging and abandonment of the wellbore.

Geomechanical processes during drilling, injection and completion can also affect wellbore integrity. Elevated temperature and/or pressure during fluid injection causes casing expansion and subsequent compression of the cement sheath (increase in the radial stress). When the pressure or temperature increase ends, the reverse occurs, the radial stress drops. However, the process is seldom fully reversible, and the radial stress of casing against a borehole wall may drop below the pore pressure in the strata outside the casing. Casing expansion also induces radial stress cracks in the cement sheath. Stiff or brittle cements are especially susceptible to damage caused by temperature and pressure changes. Pressure cycling of a well can easily debond the rock and cement. Wells that have experienced several pressure or thermal cycles will almost always show loss of bond and development of microannuli, sometimes for vertical distances in excess of 100 m. The use of enhanced recovery methods (steam injection, hydraulic fracturing, etc.) elevates the mechanical and thermal loading on wellbores, and significantly increases the probability of leakage during the operational lifetime of the wellbore, before final abandonment. In addition to chemical degradation, the cement sheath of abandoned wells may be impacted by stress changes and deformation during CO_2 injection. As pore pressure increases, there is a possibility of stress distribution alteration around the well leading to casing deformation or crack generation in the cementing.

Another concern is casing damage in areas that have experienced subsidence due to oil and gas reservoir depletion or overpumping of groundwater. Casing damage or failure commonly occurs during reservoir depletion, especially in areas with highly porous compressible media. This issue is particularly relevant when partially depleted oil and gas fields are to be used for geologic storage of CO_2. The current situation with groundwater overdraft in the San Joaquin Valley in California and other areas of the country may pose an added risk abandoned oil and gas wells due to continued subsidence.

After a well is permanently plugged and abandoned, natural or induced tectonic stresses may damage wellbores. For example, hundreds of oil well casings were sheared in the Wilmington oil field in Los Angeles during five or six earthquakes of relatively low magnitude (**M** 2 to **M** 4) during a period of maximum subsidence in the 1950s. A site area that has experienced a nearby earthquake should be ruled out in addition to sites that are near recently active faults. In the California Carbon Capture and Sequestration Protocol under the Low Carbon Fuel Standard, if an earthquake of **M** ≥ 2.7 is detected within a radius of one-mile of CO_2 injection operations, a determination must be made whether the mechanical integrity of any well, facility, or pipeline within this radius has been compromised.

Wells constructed prior to federal or state regulation (i.e., in the late 1800s or early 1900s) during early oil exploration pose the greatest risk of leakage because these wells are not documented in state records, may be relatively deep, often consisted of an open (i.e., non-cased) well bore over much of their length, and generally have inferior construction as compared to modern standards. Open holes are susceptible to cross-migration between aquifers, especially if no plug is present, leading to a migration of injected fluids into nearby underground sources of drinking water. The steel casings sometimes present in early abandoned wells were often removed to address material shortages during World War II.

For oil and gas wells, cement carbonation is not normally considered an important factor for barrier or integrity failure. However, for geologic storage of CO_2, cement carbonation may be an important factor. Ordinary Portland Cement is currently and historically the prime material used for creating permanent well barriers. Investigators conducting laboratory and field studies have found that chemical reactions between cement and carbonic acid (CO_2 dissolved in water) can degrade cement integrity (net dissolution) and in other cases lead to precipitation and self-sealing of gaps and spaces. There are numerous experimental studies that indicate that cement carbonation may not lead to significant leakage when cement remains intact. Therefore, only when there are preexisting local leakage pathways associated with annular spaces or fractures in the cement can leakage likely occur.

8.3. Evaluating Unplugged Wells in the Area of Review

The U.S. Environmental Protection Agency defines the area of review (AoR) as the region surrounding the storage project where Underground Sources of Drinking Water (USDWs) may be endangered by the injection activity if leakage were to occur. The AoR is the areal extent of the maximum extent of the CO_2 plume or the pressure front in the storage reservoir needed to push reservoir fluids upward into the deepest USDW through a hypothetical open wellbore. Depending on the cumulative injection volume, an AoR for a CO_2 storage project could be more than two orders of magnitude greater than that for a Class II disposal well (typically ¼ mile). Locating all abandoned wells within a large AoR, especially in areas having historic (i.e., early 1900s) oil and gas development will be challenging in some cases and likely infeasible in others, potentially resulting in leakage of CO_2.

As geological storage of CO_2 transitions from limited, government-supported pilot projects to large-scale commercial enterprises, dealing with competing subsurface uses which also pressurize subsurface formations will likely become ever more important. These might include active hydrocarbon production, natural gas storage, produced water disposal in Class II wells, hazardous waste disposal in Class I wells, and geothermal projects in which permitting does not require consideration of geologic storage of CO_2. Depleted oil and gas fields are attractive for CO_2 storage, as abandonment pressure is below initial reservoir pressures, giving them large leeway for pressure buildup. However, depleted oil and gas fields contain a large number of abandoned wells which may leak as the oil and gas fields re-pressurize. It may be possible to manage pressure buildup in saline aquifers by producing water while injecting CO_2. However, this may be unattractive since it adds cost to the project and generally requires reinjecting the produced water, which simply displaces the problem to another reservoir.

Owners or operators seeking a Class VI injection well permit are required to report the following information regarding abandoned wells within the AoR that may penetrate the primary confining zone: the well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information required by the UIC Program Director. Owners or operators of Class VI injection wells must perform corrective action on all artificial penetrations in the AoR that may penetrate the confining zone and are determined to have been plugged and abandoned in a manner such that they could serve as a conduit for fluid movement and endanger USDWs.

If fluids are migrating from a well that must be plugged, the first challenge is to locate the fluid-migration path. The first step to evaluate the integrity of abandoned wells once used for production is to review historical well records, well logs, and schematics from available information. However, well records are not publicly available in all states. Drilling records can yield clues as to areas that might be susceptible to failure. Events such as well bore collapse during drilling or conditions that placed unusual loads on the casing may also indicate a higher chance of wellbore integrity failure. Well casing (if not pulled) and annular cement (or lack of) should be examined prior to plugging. As recommended by the EPA, tests that could be utilized to evaluate the integrity of unplugged wells prior to plugging include internal mechanical integrity tests (pressure testing), multi-finger caliper logs measure the radius and internal corrosion of casing, cement bond/variable density logs supplemented with ultrasonic logs, and radioactive tracer, noise, and temperature logs which can provide information on source depth of a leak. The quality of composition of cement behind casing can also be evaluated using modular sidewall coring tools and dynamic cased hole testers.

8.4. Evaluating Plugged Wells in the Area of Review

The evaluation of abandoned plugged wells requires a two-step approach. The first step is to review whatever records are available for information relevant to proper plugging. Dry and abandoned wells have only surface casing cemented to the surface and the plugs are shallow in depth a few meters below the depth of the surface casing shoe (depending upon the regulatory requirements at the time of plugging). If these wells are within the AoR and penetrating the storage reservoir and/or confining zone, these wells will need to be re-entered and properly plugged.

Plug locations must be reviewed as required in the Class VI Rule. Abandoned wells should include a cement plug through the primary confining zone, and/or across the injection zone/confining zone contact, with sufficient integrity to contain separate-phase carbon dioxide and elevated pressures. In the absence of an adequate plug across the confining zone, cross-migration may occur wherein fluids enter a permeable zone below the lowermost USDW and then migrate upward from that zone. Cement plugs should also be located across the bottom of any casings and at the base of the lowermost USDW. A surface plug would also typically be required by local well abandonment regulations to ensure that there is no risk of anyone physically falling into the well bore. Materials that are compatible with CO_2 must be used where appropriate, though compatible material are not specified in EPA regulations.

If there are cracks, channels, or annuli in a plug that would allow fluid migration, the plug should be drilled out and replaced. In addition, if the plug material may corrode in a CO_2 rich environment, it should be replaced. If the annular space outside a plug in casing can serve as a conduit for fluid movement, especially at the interface of the injection zone and confining layer, remedial cementing should be performed or the casing should be removed and replaced with a cement plug. The characteristics of the plugging fluid (i.e., composition, specific gravity) should also be considered, as drilling fluid of sufficient weight may resist displacement by the injectate or mobilized fluids.

Regulations on plugging and abandonment have changed considerably over the years. Until relatively recently, little emphasis was put on ensuring that wells were properly plugged and regulations covering plugging and abandonment operations were often vague and inadequate. Hence, older plugging requirements may no longer be considered adequate. The most problematic abandoned wells are the ones drilled and completed prior to the establishment of the regulatory agencies. These wells are undocumented, and their integrity is highly questionable due to a lack of regulations and policies.

The first oilfield cement classification was developed by the American Petroleum Institute in 1953. Many abandoned prior to the early 1950s either were not plugged or were plugged with very little cement in them. Hence, the integrity of the wells plugged before the early 1950s is highly questionable. Prior to that, cement often lacked sufficient additives for proper cement setting in conditions experienced in oil and gas wells. As a result, the plugs in many of these older wells failed to set properly and may have experienced channeling and/or cement failure because of fluid intrusion.

More recently constructed wells might also may not have been plugged properly either, as bankrupt owners may have used substandard materials. Even “properly” plugged wells may contain annular spaces that could facilitate fluid movement, have well plugs that have degraded over time due to a poor cement job and/or corrosive conditions, and degrade when in contact with a CO_2 plume.

If no records are available or adequacy of plugging, especially behind casing, cannot be confirmed, EPA (2013) recommends that the existing plugs, if present, should be drilled out and downhole tests performed to evaluate casing and cement behind casing. Evaluation of plugged wells necessitates speculative judgement. In addition to corrective action, EPA recommends performing enhanced monitoring in the vicinity of improperly abandoned wells, including groundwater monitoring and using indirect geophysical techniques for obtaining monitoring results.

8.5. Plugging Oil and Gas Wells

The ultimate goal of plugging is to achieve a rock-to-rock barrier. This is best achieved in the absence of casing. After removal of junk in the hole, depending on state regulations, there is sometimes an attempt to pull uncemented or poorly cemented production casing from the wellbore using a cut-and-pull operation. The casing cut can be done using explosives, chemicals, mechanical cutters, or using abrasive cutters. The presence of scale deposition in casing and casing-cement bond strength may necessitate pulling capacity of cement beyond the working unit or work string capacity. Therefore, the casing may need to be cut into short lengths with retrieval accomplished over multiple trips. In lieu of pipe removal, casing milling can be used to grind away a section of casing and compromised annular cement. However, section milling is difficult to execute safely and efficiently. There is a risk of splitting and buckling the casing. As the cutting tool is worn out after only a few feet of milling, frequent trip out is often required, which is time consuming and expensive.

If casing removal has been accomplished, the next step prior to plugging is mud conditioning. Mud contamination of cement is the primary cause of plugging failures in open boreholes. Mud displacement can be carried out hydraulically or mechanically. In the hydraulic process, spacer fluids are used to displace drilling or milling fluid. Spacers are designed to improve cement bonds by water-wetting the cement-formation interfaces while not destabilizing any sensitive zones and not adversely affecting the mud or cement properties. Additives can be added to spacer fluid to enhance mud cake removal and permit turbulent flow at low pumping rates. Surfactants can be added to the spacer fluid to help to leave the formation water wet for a better bond to cement. However, spacer fluids are unlikely to completely remove the mud cake without using mechanical aids. In areas where washouts or lost circulation have occurred, effective mud removal is challenging. Annular flow velocity is lower in boreholes having an irregular geometry compared to boreholes having a round cross-section. If the annular velocity is too low, the mud will largely be left in the washout area in a gelled state. Another challenge introduced by washouts is that if there is a large uncertainty in hole size. The cement volume could be underestimated and the plug length will be less than required. Therefore, the borehole must be calipered prior to cementing and plug placement.

Even in boreholes having a round cross-section, laminar flow is less effective compared to turbulent flow for mud displacement because the axial velocity of mud near the pipe or formation wall boundary is lower for laminar fluid flow. In order to achieve a turbulent flow regime for spacer and cement, a high flow rate is required. However, in practice, turbulent flow may be unachievable due to the high viscosity of spacers and cement. Also, while effective mud displacement requires the use of high pumping rates during cementing, a high pumping rate may hydraulically fracture the formation. Hence, the fracture gradient of the formation must be known and pumping rates must be carefully controlled.

There are three primary methods for plugging a borehole. The balance plug, dump bailer, and two-plug methods of plug placement have been used since the 1970s. These methods are often used in conjunction with mechanical bridge plugs and packers. These prevent the cement from falling below a desired point and allow the wellbore to be circulated without worrying about cement fallback during placement. Because bridge plugs are composed of cast iron and nitrile elastomers, they are susceptible to corrosion by formation and injected fluids, in particular in the presence of dissolved CO_2. The mechanical plug is not considered part of the barrier. If the mechanical plug passes a pressure test prior to cement placement, a cement plug is placed on top of the mechanical plug and left undisturbed until it develops high enough strength. If the mechanical plug did not successfully pass a pressure test, the cement plug is pressure tested. Pressure test failure of cement plug means that another cement plug needs to be established. Different regulatory authorities require different plug lengths.

In the balanced-plug method, spacer fluid is pumped ahead of cement to displace mud and attempt wetting of the formation or casing surface. Wiper balls/darts can be used to provide mechanical separation between the mud, spacer, and cement slurry to minimize intermixing and contamination of the spacer and cement slurry in the work string during displacement. Volumes of spacer ahead and behind the slurry are calculated so that the spacer height inside and outside the work string end up at the same level. The fundamental assumption of balanced plug method is that fluids are going to stay in place while the work string is pulled upward.

In the dump bailer method, a bailer filled with cement is run into the wellbore and opened electronically or mechanically via touching a mechanical foundation. The in-situ drilling fluid in the well is subsequently replaced by the cement slurry, ideally with minimum mixing. In this method, the cement slurry has a higher density and a higher viscosity than the drilling fluid. Advantages of this method include lower cost and improved operational time compared to other methods. Disadvantages include the need for multiple runs due to low capacity of bailers, cement setting inside bailers due to static conditions, and uncertainties associated with mud or spacer removal. The dump-bailer approach is often unsatisfactory in providing an adequate seal.

To minimize the contamination of the cement plug with the fluid ahead and behind, the two-plug method can be used. In this technique, a wiper dart is used to push lead cement behind a spacer fluid to a locator sub. When the first wiper dart seats on the locator sub, pressure increases during injection until the diaphragm of the wiper dart ruptures. Cement then passes through the first wiper dart. Injection continues with additional spacer fluid behind a second wiper dart behind tail cement until the second wiper dart ruptures releasing additional spacer fluid behind tail cement. Thus, from surface down to a depth close to the tailpipe or stinger, the slurry is fully separated from the spacer and consequently, the risk of mud contamination is decreased.

The balanced plug, dump bailer, and two-plug methods can be used in cased boreholes as well. When considering plug placement for a cased hole, if there is no annular flow outside casing, a mechanical bridge plug is typically installed inside casing to create a foundation for a cement plug above which the well is filled with fluids such as brine, drilling mud, or corrosion-inhibiting fluid.

After a plug is installed, the depth of the plug is tagged, and the top of cement is drilled to reach hard cement. This operation is known as cement dress-off. After a plug is installed, it is necessary that the plug keeps its position and does not move. Weight testing is used to measure the bond strength to casing or a borehole wall. Weight testing can be conducted using drillpipe or a weight attached to coiled tubing or a wireline.

Pressure testing is applied to plugs installed inside casing, open hole plugs which are extended to casing or plugs installed entirely in open hole. Pressure testing gives an insight into the integrity of the cement plug and sealing capability at the interface of cement plug and adjacent element. When the pressure difference across fulfills the requirement asked by local authority, the pressure is monitored for some minutes and if a stable pressure is reading, the plug is considered a qualified plug. Different regulatory authorities have different minimum and maximum pressure testing requirements in addition to length of time to hold pressure, and maximum pressure loss during testing. During pressure testing, casing should not be damaged nor impact cement behind casing. To avoid this issue, the test pressure is selected to not exceed the casing strength minus wear allowance.

Placing a cement plug in a cased wellbore is not sufficient to prevent leakage if fluid flow is occurring in the annulus between casing and the borehole wall. When casing remains in a borehole or cannot be removed at a required depth of plugging, and cement is either not present or damaged, potentially allowing fluid flow behind casing, cement must be installed behind casing. If gas or brine flow is occurring outside casing due to lack of primary cement, a “squeeze” operation is performed to fill the void space with a sealing material, typically cement. A cement slurry is pumped down a tube filling the perforated area with cement. The casing is then sealed off with a valve or a packer to induce elevated pressures by continuing to pump cement down the tube in the isolated region. The induced pressures squeeze the cement through the perforations into the annular region. Increased pressure on the cement forces water out of the cement slurry leaving behind the partially dehydrated cement. Cement squeezes can either be low pressure or high pressure. Low pressure squeezes are used to set a small amount of cement in a given area and operate at a pressure lower than the fracture pressure of the formation. Higher pressure squeezes are used when channels or disconnected microannuli are to be cemented. The higher-pressure squeezes may fracture the formation and then allow the cement to flow into disconnected channels.

Under suitable conditions, cement squeeze operations are said to be routine and predictable. However, in many circumstances, formation conditions and fracture aperture limit control of the remedial operation. Extremely permeable formations or formations containing large vugs and natural fractures may not be able to support a cement column, as cement slurries may flow unconstrained into the formation. On the other hand, particular geological materials, such as swelling clays and media with low permeability, limit feed rates that can lead to hydration immediately at perforations, consequently blocking passage for cement to enter the void space. The cement may also undergo shrinkage and deterioration, which may compromise a seal over time. Another concern is that in stiff naturally fractured rock is that as the grout is forced into the formation at fracturing pressures, the grout fails to penetrate fully into the crack that has been forced open by the high pressures. Thus, even though one pathway may be sealed, cracks as large as 20-50 microns can be opened up from the squeezing operation.

In the Perforate, Wash, Cement (PWC) method, a perforation gun is run to the barrier depth where there no cement or poor cement behind casing. The casing is then perforated. In the next step, a washing tool is run in hole and washes the annular space behind the perforated casing to remove the debris, settled mud and mud film. The washing process can be carried out several times to clean the formation surface. A spacer fluid is then pumped below the bottom perforations and extended to above the top perforations. Cement is then pumped below the bottom perforations until cement reaches the top perforations. One of the most challenging parts of the PWC technique is effective washing.

To check the quality of cement squeezes and PWC jobs, cement remaining inside the casing must be drilled out with subsequent logging of annular cement using cement evaluation tools. However, holes created during perforating introduce error during logging in addition to uncertainties already present using cement evaluation tools. These logs are not capable of providing quantitative measurements on cement quality. Hence, cement squeezes and PWC operations do not guarantee well integrity.

8.6. Mathematical modeling of wellbore leakage

Finally, mathematical modeling of brine and CO_2 leakage in abandoned wells has provided considerable insight into subsurface and wellbore flow processes and the potential effectiveness of monitoring techniques. When supercritical CO_2 is injected into a storage formation, a two-phase CO_2 and brine fluid system is created. Because CO_2 is only slightly soluble in brine (up to a few percent by mass), the injected CO_2 will remain as a separate fluid phase for a significant period of time, with a strong buoyant drive upward. When CO_2 dissolves into the brine, the pH of the aqueous phase is lowered, and this lower pH can drive a sequence of geochemical reactions in aquifer and aquitard rocks and in well cement. While dissolution will take place from the beginning of the injection period, typically the time scale for significant amounts of CO_2 mass to dissolve in brine are long, and dissolution only becomes significant in the post injection period. Over longer time scales, dissolution of the CO_2 into the brine can become important in reducing pressure.

During brine drainage (CO_2 displacement of water), water will evaporate into the CO_2-rich phase if CO_2 is injected with little to no water vapor (“dry” CO_2). A fraction of H_2O (less than 1% by volume) can evaporate into the dry CO_2 phase creating ‘‘wet’’ CO_2 which is much more corrosive to metal piping compared to dry CO_2. However, continued dry CO_2 injection will eventually lead to a zone around the injection well where all water has been evaporated, leaving dry CO_2 and precipitated salt from brine in the pore space.

When injection ceases, the pressure drive dissipates, and the longer-term migration is controlled by a combination of buoyant migration along upsloping directions in the formation, capillary trapping of the CO_2, and CO_2 dissolution into the brine. While injection represents a brine drainage process, post injection migration will involve both brine drainage along the leading edge of the migrating CO_2 plume and brine imbibition (refilling of brine into pore structure) along the trailing edge. As such, brine displacement of CO_2 along the trailing edge results in some CO_2 being trapped behind the mobile plume of CO_2, at saturations at or above the residual saturation for CO_2.

During injection, pressures at abandoned wells gradually increase to a maximum value until the injection is stopped, followed by a steady decline during the post-injection period. For a given injection well configuration, the maximum pressure as well as the time at which the maximum is reached varies between abandoned wells. Also, the maximum value is reached after the injection is stopped demonstrating that it takes time for the pressure front to travel through the reservoir. This is also manifested in the differences in the pressure decay behavior during the post-injection period.

Forces that control CO_2 migration include hydrodynamic drive and buoyancy, with the former (pressure gradients coupled with elevation) acting to drive the fluid away from the injection location and the latter driving the CO_2 updip and upward. Because pressure propagates faster and farther away from the injection well than the injected CO_2, an area of elevated pressure is created that can be significantly larger than the areal footprint of the CO_2 plume. In a saline aquifer, the pressure field associated with injection could extend over hundreds to thousands of square kilometers. A CO_2 plume could move laterally under the influence of both pressure drive and buoyancy, until an abandoned well is encountered. The pressure increase in the injection formation can then drive fluid leakage (both brine and CO_2) along defective wells if the materials in these wells have imperfections that allow for fluid flow.

If leakage of fluid(s) occurs, the flow rate will be determined by the pressure field and the pressure field around the leaky well will subsequently be modified by leakage due to drawdown around the leaky well. CO_2 that migrates through and/or along these wells will leak into overlying formations, eventually reaching shallow depths where, as a gas, it can migrate quickly to the surface. This lateral spreading acts as an enhanced storage reservoir and thereby mitigates the transport fluxes along the borehole. The effect of this is to spread the CO_2 across larger regions and/or more strata of the subsurface, with some of it stored in permeable formations closer to the land surface.

When a CO_2 plume encounters an abandoned well, leakage will occur through or along the cement zones if present. This might involve flow through the well plugs within the casing, or it might involve flow outside the casing through the cement used for sealing the casing to the formation. The potential leakage pathways through abandoned wells include: between the outside of the casing and the cement, through the cement in the annulus, from the annular region between the cement and the formations, through the cement plug, and from the area between the cement and inside of the casing. Leakage rates and timeframe will depend on the migration path and medium properties, and will require a good understanding of cement degradation over time scales of tens to hundreds of years, longer than the existing historical record.

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