CO_2 leakage through existing wells: current technology and regulations

S. Taku Ide[1], S. Julio Friedmann[2], and Howard J. Herzog[3]

[1]Dept. of Petroleum Engineering, Stanford Univ.
[2]Lawrence Livermore National Laboratory, 7000 East Ave, Livermore, CA 94550
[3]Labratory for Energy and the Environment, MIT Cambridge MA 02139

Abstract

Preexisting wells and well bores are high-permeability pathways through the crust, and as such present zones of elevated risk to CO2 storage projects. Although current well closure and abandonment technology appears sufficient to contain CO2 at most sites, individual wells may suffer from a variety of factors that limit their integrity, including improper cementation, improper plugging, overpressure, corrosion, and other failure conditions. As a whole, wells in the US can be subdivided into three categories: wells that are not plugged, wells plugged before 1952, and those plugged after 1952 (when the American Petroleum Institute standardized plugging procedure and cement composition).

After use, wells may be plugged and abandoned, with the liability of leakage remaining with the parent company. However, in some cases wells are orphaned and have no current parent company, leaving liability with the state. Current regulatory frameworks for well completion, plugging, and abandonment may not suffice in accounting for the most likely features, events and processes that affect well integrity after initial CO2 injection.

Keywords: Leakage, Wells, Regulatory Issues, Policy, Safe Water Drinking Act

Introduction

Recognition of the increasing risks of global warming has increased interest in greenhouse gas (GHG) emission reduction approaches. Carbon capture and storage (CCS) has emerged as a key technology pathway to reduce GHG emissions. Of potential storage options, geological storage currently offers the highest chance of success with low relative costs. This involves CO_2 injection into deep reservoirs, such as saline aquifers, depleted oil and gas fields, and deep unmineable coal seams.

It is likely that CO_2 injected into any of these targets will encounter man-made well bores. These penetrated the cap-rocks and reservoirs, creating potential conduits for buoyant CO_2 to migrate towards the surface. The overwhelming majority of these wells were plugged and abandoned in a fashion that makes CO_2 escape highly unlikely; however, there are potential risks associated with orphaned, abandoned, and even old wells that were properly closed. As such, well bores are permeable fast paths that could, in the worst cases, lead to leakage of CO_2 out of storage sites. Although it is widely discussed that well bores represent the greatest potential risk for leakage, there is relatively little known about the current distribution of potentially leaky wells, their occurrence relative to potential storage sites, and the probability of leakage at a given well. Similarly, there remain uncertainties about the regulatory and legal framework associated with old and abandoned wells should CO_2 escape through the well bore. This paper focuses on the current state of knowledge regarding the physics and chemistry of well-bore failure in CO_2 systems, the technical aspects of orphaned and abandoned wells, and key aspects of the current regulatory framework.

Outline of Physics and Chemistry in CCS Process

For most sites of interest, the pressures and temperatures of injection will make CO_2 a supercritical fluid. Since many potential target reservoirs are brine bearing, CO_2 will be buoyant and migrate towards the formation top. Provided that the rock above the formation is impermeable, it will physically trap the buoyant CO_2, which will spread laterally in a plume. As CO_2 migrates, some of the CO_2 will become trapped through residual trapping, chemical dissolution, and mineralization.[1] Injected gases that are not trapped will remain a mobile phase. As long as the integrity of the cap rock is not compromised by permeable conduits like wells or faults, the cap rock will prevent the escape of mobile CO_2 phase. However, as a result of active hydrocarbon exploration and production during the last century, many of the sites under consideration for CCS projects may have wells that penetrate the cap rock.

Wells that do penetrate the cap rock are potential sites through which mobile CO_2 phase might escape. Under typical circumstances, such wells would be properly cemented and plugged at depth, preventing upward migration of CO_2. However, these wells may not have a proper plug in place to prevent the flow of CO_2 to the surface, and cement might fail either mechanically or due to corrosion.[2] If well integrity is compromised, it may act as a high-permeability conduit through which CO_2 could escape.

Recent research has shown that CO_2 could leak even from wells that are properly plugged.[2] This occurs when carbonic acid forms due to dissolution of CO_2 into brines, forming carbonic acid as shown in Eqn. 1.[2]

$$H_2O_{(l)} + CO_2 \rightarrow H_2CO_{3(aq)} \tag{1}$$

When this acid comes in contact with hydrated cements, corrosion can occur.[2] The rate at which this degradation occurs depends primarily on temperature, but also on cement, brine, and rock composition.[2] Currently, there is little chemical kinetic data or equations of state to use in modeling this problem.

Technical Perspective of Well Plugging and Leakage

The evolution of plugging techniques has been well documented in numerous oil and gas publications. For instance, common cementing methodologies in the 60's are described in detail in <u>Rotary Drilling Handbook</u> (1961) by J.E. Brantley, methodologies in the late 70's in <u>Cementing</u> (SPE monograph, 1976) by D. Smith, and cementing methodologies and materials in the 80's through the present are available in <u>Oil Well Engineering</u>(1985) by H. Rabia and <u>Petroleum Well Construction</u> (1998) by M. Economides, et. al. These sources document advancements in well plugging practices over the past four decades, and suggest that the evolution of plugging techniques is modest. Most of the changes have occurred in plug lengths and additives that alter the properties of basic cement.

While the modern objectives of plugging—protection of potable water source and the isolation of hydrocarbon zones—are the same in all states, minor details such as plugging material and plug length vary from state to state. Further details can be obtained from Oil and Gas Divisions or its equivalent in each of the states.

Cementing background

Cement was introduced to the petroleum industry as early as 1903, when Frank Hill of Union Oil Co., poured 50 sacks of portland cement down a well in order to isolate a water zone.[3] Different techniques of cementing were soon patented in California but did not spread quickly to other states.[3] As a result, many hydrocarbon states independently developed unique cementing techniques.[3] Commonly, cement was used to bolster the production of hydrocarbons (i.e. cement lining, prevention of water flow into well), but was seldom used for plugging purposes. For example, in California, plugging with cement was not practiced until it became mandatory under the regulations of California Oil and Gas Division, established in 1915.[4] By then, some 30,000 wells had been drilled in the state.[4] Other states lagged behind California in establishing a regulatory body that oversaw plugging practices, resulting in thousands of wells that were abandoned without appropriate plugs. In Indiana, about 55,000 wells had been drilled between 1876 and 1949, the year Indiana Oil and Gas Division was established.[5] In Texas, thousands of wells were drilled and left unplugged between its first hydrocarbon discovery in 1866 and the year the Texas Railroad Commission gained authority to monitor hydrocarbon activities in 1919.[6] Evidence suggests that operators tried to plug wells in "good faith" before regulatory bodies were formed. However, these plugs are likely to be inadequate to prevent CO_2 leakage during CCS projects – plugs discovered from the early days of hydrocarbon production include tree stumps, logs, animal carcasses, and mud.[7]

Even after many state regulatory bodies were established in the 30's and 40's, effective cement plugs were often not installed.[3] This lack of efficacy can be attributed to the fact that cement was poorly understood. Although the basic composition of cement used in the early days is essentially the same as the one used today, early cements lacked crucial additives.[3] Additives are, chemical compounds that are added to basic cement components in order to tailor the cement to specific down-hole temperature and pressure conditions.[3] Without these additives, basic cement often failed to harden and form an effective plug.[3] There were instances when operators dumped ice into the well after a cementing procedure in hopes that the ice would lower the well-bore temperature such that cement could harden.[3] If the cement poured into the well-bore did not readily set and harden, the cement would become contaminated with the surrounding drilling mud. Contamination by mud has been observed in high frequencies in cement plugs placed in the Gulf Coast before 1928.[3]

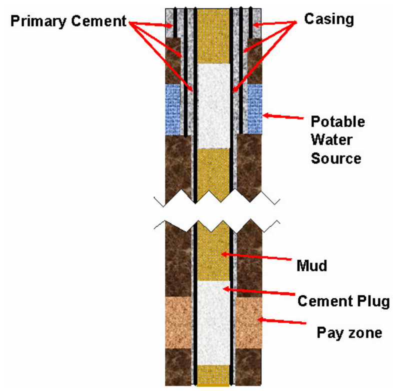

Figure 1: A diagram of a plugged and abandoned well. Cement plugs must bridge across potable water sources and hydrocarbon producing zones, and often extends more than 50 ft above and below these formations.

Most improvements in well cements developed between 1937 and 1950. In 1937, the American Petroleum Institute (API) established a committee to study cements.[3] By 1952, API had agreed on a standard cement composition and additives and published these findings in the API *Code 32*, which divided cements into 8 classes depending on the depth and additives.[3] Since this original publication, the basic classes of cements have not changed. Notable differences in plugging procedures since 1953 are in plug lengths and the increase in the number of plugs in a single well.[7] These changes are mainly the result of the Safe Drinking Water Act of 1974, under which operators were required to isolate all fresh water drinking zones in addition to the hydrocarbon producing formations.[1] The technique of cementing was also researched and improved during this time. The new standard technique, which is still the most common method of plugging used today, minimizes the mud contamination of cement.[8] This method is often referred to as the displacement method (Figure 1).

Regulatory Framework

In the United States, a body of federal and state law governs underground injection to protect underground sources of drinking water. Under the Safe Drinking Water Act of 1974, EPA created the Underground Injection Control Program (UIC), requiring all underground injections to be authorized by permit and prohibiting certain types of injection that may present an imminent and substantial danger to public health.[2]

---

[1] Safe Drinking Water Act provisions on underground injection are available at 42 U.S.C. § 300h *et seq.* (2005) and UIC provisions are available at 40 C.F.R. § 144 e*t seq.* (2005).

[2] Safe Drinking Water Act provisions on underground injection are available at 42 U.S.C. § 300h *et seq.* (2005) and UIC provisions are available at 40 C.F.R. § 144 e*t seq.* (2005). For an analysis of the Safe Drinking Water Act and UIC as applied to carbon sequestration, see Mark de Figueiredo, *The Underground Injection Control of Carbon Dioxide*, A Special Report to the MIT Carbon Sequestration Initiative (2005); and Elizabeth Wilson, Timothy Johnson, and David Keith, "Regulating the Ultimate Sink: Managing the Risks of Geologic CO_2 Storage", *Envtl. Sci. Tech.* 37: 3476-3483 (2003).

The primary objective of UIC is to prevent the movement of contaminants into potential sources of drinking water due to injection activities. To achieve this goal, contaminant concentration in underground sources of drinking water is monitored. If traces of contaminants are detected, the injection operation must be altered to prevent further pollution. There are no federal requirements under UIC to track the migration of injected fluids within the injection zone or to the surface.[9] Under UIC, a state is permitted to assume primary responsibility for the implementation and enforcement of its underground injection control program upon the timely showing that the state program meets the requirements of EPA's UIC regulations. For injection wells associated with oil and gas recovery, a state may assume primary responsibility by demonstrating that its underground injection program is "effective" to prevent underground injection which endangers drinking water sources. Injection wells for any other purpose must meet minimum requirements promulgated by EPA.[3]

A key regulation in the UIC program aimed to prevent leakages of injected fluids through wells is the Area of Review (AOR) requirement. Under this requirement, injection operators must survey the area around the proposed injection wells before any injection projects can commence. This area is determined through either an analytical method or a fixed radius method, the latter being the preferred approach in the industry.[10] The fixed radius method requires that the injection operator review an area with a radius no less than a ¼ mile.[10] The radius used can vary among hydrocarbon producing states, as each state has a different approach for determining the appropriate area to be reviewed.[10] Once the area has been determined, each operator must review the available well records that penetrate the injection zone within the AOR.[10] Operators are required to plug all inadequately plugged wells that are found.

Unowned and inactive wells subject to replugging are often termed ***orphan wells***. Many orphan wells lie outside of the AOR for a given site, and these may become leakage pathways, as injected fluid can migrate outside of the anticipated area. Although states are generally not legally responsible for these orphan wells, they nevertheless frequently monitor them.[4] If significant leakage that endangers the environment or public health is detected from these wells, the state will use available funds to plug the well. Funds to plug these wells are often collected through production tax, fees, and other payments related to the oil and gas industry. In Texas, a major source of revenue is a fee on the oil and gas production. The fees are $5/16^{th}$ of a cent per barrel of oil and $1/30^{th}$ of a cent per thousand cubic feet of gas. Other states similarly rely on production taxes, although tax rates vary.

The main reason why states do not plug all of their orphan wells is due to the lack of available funds.[6] For example, there are currently 135,000 orphan wells in Texas. If all these wells were plugged at an average cost of $4,500 each, the total project would cost hundreds of millions.[6] In 2001, Texas allocated only $12.2 million to plugging orphan wells.[6] Such funding shortages force the states to become selective when plugging existing orphan wells, ranking the hazard level of each well. Only those deemed highly hazardous are plugged immediately.[6] State regulators have tried to alleviate the occurrence of these orphan wells by requiring well operators to demonstrate financial ability to plug wells before and during well operation.[11]

Unlike orphan wells, wells that were properly abandoned under the existing regulations at the time of plugging are not monitored by the state. These wells are termed ***abandoned wells***. States are not mandated to monitor for leakage or other failures at these properly abandoned sites. The lack of monitoring is based on the assumption that once a well plug is set, the it will not fail.[3]

Discussion

Although plugging practices have dramatically improved over the last century, the risk of CO_2 leakage from wells remains a substantial risk in CCS projects. One can group current inactive

---

[3] The 1980 reauthorization of the Safe Drinking Water Act exempts the underground injection of fluids which are used in connection with natural gas storage operations. The rationale was that natural gas storage does not pose a threat to drinking water quality and storage operators have an economic incentive to prevent natural gas leakage. *H.R. Rep No. 96-1348*, *reprinted in* 1980 U.S.C.C.A.N. 6080, 6085.

wells into three groups: wells without cement plugs (*could be plugged with other materials*), wells plugged before 1952, and wells plugged after 1952.

Wells lacking a cement plug are most likely to be shallow wells that were drilled prior to 1930's. By 1930, many major hydrocarbon producing states had begun to monitor plugging operations. Thus wells abandoned after the 30's is likely to have some form of a cement plug, although they may be of poor quality. Some deeper wells drilled in the last three decades may be lacking a plug as well if operators were unable to plug the well due to bankruptcy. Many wells were left unplugged after the 1986 oil bust as many companies became insolvent. These deeper wells are of primary concern, because many of the target formations for CCS sites are penetrated by these deep wells.

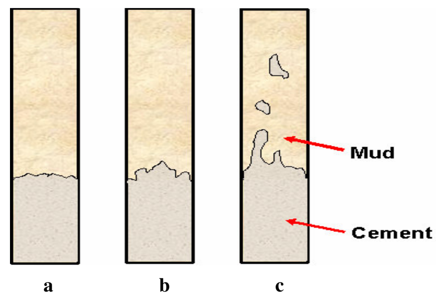

Figure 2: Schematic diagrams of cement plugs. Contamination of cement by mud can lead to unpredictable or poor cement setting. As time elapsed during setting (a to c), the cement begins to diffuse into the drilling mud, resulting in an irregular interface. Pieces of cement can break off before the cement hardens into a seal.

The second type of wells—wells that were plugged with cement prior to 1952—may prevent CO_2 leakages better than wells that were left unplugged or plugged with ad-hoc materials. However, their integrity cannot be assured and thus still remain to be major leakage sources. As discussed, cement plugs prior to 1952 were often contaminated with mud and failed to harden into effective seals (Figure 2).

The cement plug deformation shows poor setting of the cement plug, which was corrected with the introduction of appropriate additives after 1952. Additives greatly shortened the time required for the cement to harden, thereby reducing the diffusion of cement into the drilling mud. The deformation of plugs such as in the figure above usually leads to loss in strength, and thus plugs from this era may fail when exposed to high pressures that can arise during a CCS project. The integrity of these plugs must be better assessed and understood.

Wells plugged after 1952 are the least likely to leak, due to modern methods and the due diligence required by regulation. However, we must consider the possibility of cement degradation by CO_2-brine mixture shown by Scherer et. Al.[2] Their findings indicate that cement exposed to carbonic acid for a prolonged period of time could corrode the cement. If so, CO_2 could migrate along the well bore toward the surface. It is important to note, however, that cement degradation has not been a serious issue in enhanced oil recovery activities with CO_2 flooding over the past 30 years.[12] There is little kinetic data on cement corrosion rates under a range of common conditions of pressure, temperature, and brine-rock composition. As such, it could take tens to thousands of years for CO_2 to corrode enough cement to reach the surface. In addition, it is not clear that even substantial degradation of the cement or casing would result in large volume escape of CO_2. The rates of leakage would be a function of the injection pressure, the local geology, and the size of the aperture through which buoyant CO_2 might flow. Thus, it may prove that the real effects of cement corrosion are minor and the associated risks negligible. More laboratory and field research is needed to understand and quantify these effects for both scientific and regulatory purposes.

Above discussion illustrates that a potential for leakage exists in a wide variety of inactive wells, even from those that are properly sealed with cement. Hydrocarbon producing states actively monitor inactive wells that are not plugged. They do not, however, provide the same type of monitoring to wells that are deemed to have been abandoned properly. Furthermore, many states are unable to monitor wells that are yet to be discovered. These undiscovered wells are typically wells drilled in the early twentieth century, and they are often buried under subsequent constructions that have taken place. This lack or inability of fluid migration monitoring may become problematic. To reduce these risks, a revision of existing regulations may be needed to address liability issues that could arise due to surface leakage. Revisions should address issues such as how abandoned wells should be assessed before and after CO_2 injection, how CO_2 concentrations might be monitored at the surface, the process of designating a responsible party for a long-term monitoring of abandoned injection sites, and how to allocate funds to replug high-risk wells.

Lastly, CO_2 sequestered underground could surpass the ¼ to ½ mile radius that is typically used to assess the wells in the area around and injection well. As the AOR increases for sequestration projects, the number of wells that fall within this area may increase significantly. In order to ensure proper injection-site integrity, it may be necessary to alter regulations to cover the likely footprint for injection. Regulators may need to concern themselves with the determination of the CO_2 injection footprint, the requirements for operators to treat abandoned and orphan wells, and the liability associated with leakage within and without the predetermined footprint.

Conclusions

1) Properly abandoned wells are currently not monitored. Only orphan wells are monitored by state. We have established that properly sealed wells are subject to leakage as well, so this lack of monitoring must be addressed.

2) Most states do not have sufficient resources to properly plug all orphan wells and abandoned wells with unacceptable leakage risk. State and federal bodies should investigate methods for securing funds to treat and mitigate those wells.

3) It is currently unclear what the real physical and chemical risks of leakage are for the three classes of wells described. Targeted research on well integrity and isolation containment would provide insight that could help regulators and decision-makers plan large-scale injection projects.

4) Regulators must establish appropriate AOR for each sequestration project. Methodologies to determine this area must be standardized on a federal level and should not be left up to the state to choose an AOR, as liabilities arising from well leakage could be large.

References

[1] Global Climate and Energy Project – Stanford University, http://gcep.stanford.edu/pdfs /ib0KJnIw5S-8G1RS8EqnPg/orr_tech05web.pdf

[2] Scherer, G.W., M.A. Celia, J.H. Prevost, S.Bachu, R. Bruant, A. Duguid, R. Fuller, S.E. Gasda, M. Radonjic, and W. Vichit-Vadakan, "Leakage of CO_2 through Abandoned Wells: Role of Corrosion of Cement," in *The CO_2 Capture and Storage Project* (CCP, Volume II, D.C. Thomas and S.M. Benson (Eds.), 823-844, 2005.

[3] Dwight Smith, *Cementing* (Dallas: Millet the Printer Inc.), 1976

[4] Jim Campion (California Oil and Gas Division), letter to author, 17 August 2005.

[5] Beth Hernly (Indiana Oil and Gas), personal communication, 6 July 2005.

[6] Michael L. Williams, Charles R. Matthews and Tony Garza, *Texas Plugging Primer* (Texas: Rail Road Commission of Texas, Oil and Gas Division), 2000.

[7] Ramon Fernandez (Texas Central Records), personal communication, 12 July 2005.

[8] Hussain Rabia, *Oil Well Drilling Engineering, Principles and Practice* (Maryland: Graham & Trotman Inc., 1986), 270.

[9] Elizabeth Wilson, Timothy Johnson, and David Keith, "Regulating the Ultimate Sink: Managing the Risks of Geologic CO_2 Storage", *Envtl. Sci. Tech.* 37: 3476-3483 (2003).

[10] United States Environmental Protection Agency, *Guidance Document for the Area of Review Requirement*, 1985 (Norman: USEPA. 1985)

[11] United States Environmental Protection Agency, *Federal Financial Responsibility Demonstration for Owners and Operators of Class II Oil and Gas Related Injection Wells*, 1990 (Washington, DC: USEPA. 1990)

[12] Stephen Guillot (Kinder Morgan), letter to author, 8 August 2005.