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Establishing and Maintaining the Integrity of Wells used for Sequestration of CO2

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Abstract

There is a tendency for the CCS industry to believe that everything is already known about CO2 injection wells, based upon the experience of miscible fluid injection for the purposes of tertiary oil recovery, combined with the general experience of gas re-injection and gas production internationally. In fact, analysis of the technical issues identifies that CO2 injection wells for sequestration may be more challenging in a number of ways, both in the fluids and pressures they must handle and the long term duration for which full well integrity will be required.

Well integrity means the achievement of fluid containment and pressure containment within the well throughout its whole life cycle.

The technical challenges of CO_2 injection wells are highly dependent on the individual well design parameters, principally the formation being injected into (saline aquifer versus depleted gas formation) and the quality (impurity levels) found in the CO_2 source gas. These factors will impact the potential corrosion and other material degradation challenges which may threaten the well components including injection tubing, injection casing, cement and packer materials. The long term integrity of these components is critical to the injection phase of the life and the suspension and abandonment phases (depending upon the strategy selected for well abandonment).

A key part of the acceptance of CO_2 sequestration as a safe and reliable greenhouse gas control mechanism will be the proof that the well is truly leak-free. This integrity management element requires a comprehensive monitoring and pro-active warning system which highlights developing integrity issues before they become acute. Key well parameters requiring daily monitoring and intermittent testing will be identified in line with industry international standards and regulations. Acceptance criteria for well test results will be defined in the context of a CO_2 injection well. The oil and gas industry is only now commencing with comprehensive well integrity management systems and the CCS industry can make good use of the experience which is being established and software products such as the Intetech Well Integrity Toolkit (iWIT) which are proven to cover the comprehensive challenge that carbon dioxide injection wells represent.
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Keywords: Carbon Storage; Well Integrity; Corrosion; Materials; CO_2

1. Introduction

There is a tendency for the CCS industry to believe that everything is already known about CO2 injection wells, based upon the experience of miscible fluid injection for the purposes of tertiary oil recovery, combined with the general experience of gas re-injection and gas production internationally. In fact, analysis of the technical issues identifies that CO2 injection wells for sequestration may be more challenging in a number of ways, both in the fluids and pressures they must handle and the long term duration for which full well integrity will be required.

In designing any well due consideration has to be made of the different scenarios it will experience, through construction, operation, suspension and ultimate abandonment. Similarly a CO2 sequestration well has to be designed for the long term, and with operational design lives of typically 40+ years followed by the need for continued integrity for a planned abandonment for over 10,000 years it becomes clear that correct design, particularly in terms of the materials selected for well components is very critical.

Tens of thousands of wells internationally are known to be suffering from sustained annulus pressure (SAP), that is, pressure within the annuli of the well which cannot be reduced to zero by bleeding off. This phenomenon is indicative of a leak having developed and a source of pressure, typically the reservoir, which is driving the pressure rise continuously. Such problems are found in producing wells of all types, particularly high pressure gas producers because the gas fluid is of low viscosity. However, SAP is also prevalent in injector wells, both gas and water injectors and some of the more acute cases are even found in suspended and abandoned wells, the pressure source being either from the immediate wellbore or from an adjacent offset well. Incidences of well collapse and well blowout have been documented related to the existence of SAP and control and mitigation of SAP, is identified as one of the key well integrity challenges.

A key part of the acceptance of CO2 sequestration as a safe and reliable greenhouse gas control mechanism will be the proof that the well is truly leak-free. This integrity management element requires a comprehensive monitoring and pro-active warning system which highlights developing integrity issues before they become acute. Key well parameters requiring daily monitoring and intermittent testing have to be identified, developed from industry international standards and regulations. In the absence of international guidelines, acceptance criteria for well test results need to be defined in the context of a CO2 injection well. Well integrity data management systems have to be in place to track all the required data, identify developing problems and alert operators before major failure arises.

1.1. International Experience

There are various sources of CO2 and ways in which CO2 can be sequestered. Each is associated with different environmental conditions, particularly temperature, pressure, injected gas composition and water content. This means that care is needed when considering the well designs and materials choices which have been made in previous projects, as they may not be relevant to the specific conditions of new projects. As an example, the use of fibreglass and fibreglass-lined tubing has been frequently selected for water-alternating-gas (WAG) injection wells for shallow CO2 enhanced oil recovery (EOR) projects in the USA. However fibreglass is not suitable above 90 °C and 340 bar and so this experience could not be generalised to every scenario of injection where subsurface temperatures and pressures are often much higher for deep injection.

Data has been gathered on the injecting well experience for various CO2 injection projects, mostly in the USA and from the Norwegian sector of the North Sea. The precise CO2 -stream composition is not always known, but these projects have generally utilised CO2 derived either from CO2 source wells, or extracted from produced natural gas. In either case, the composition would be expected to be of a reducing composition, possibly containing traces of sulphur compounds (H2S and some mercaptans) rather than any traces of oxidising contaminants. The materials choices used and the experience gained is of interest, but not necessarily of direct applicability to every CCS case.

1.2. USA Experience.

The summary of the most widely used materials in CO2-EOR well design and construction in the USA projects is given in Table 1 [derived from 1]. It must be borne in mind that the majority of the US experience is in shallow (lower pressure and temperature) conditions and most of the service is WAG, with water of possibly varying quality alternating with periods of dry CO2 injection. The purpose of the majority of USA CO2 injection projects is for miscible flood (i.e. tertiary oil production) rather than CO2 sequestration. Relatively short service lifetimes or frequent component replacement is tolerated in some of these applications.

Table 1 : The commonly used materials in CO_2 injection well design and construction - USA projects

Component	**Materials**
Xmas Tree (Trim)	316 SS, Electroless Nickel plate, Monel
Valve Packing and Seals	Teflon, Nylon
Wellhead (Trim)	316 SS, Electroless Nickel plate, Monel
Tubing	Glass Reinforced Epoxy (GRE) – lined carbon steel; internally plastic coated carbon steel, Corrosion Resistant Alloys (CRA)
Tubing Joint Seals	Seal ring (GRE), Coated threads and collars
ON/OFF Tool, Profile Nipple	Nickel plated wetted parts
Packers	Internally coated hardened rubber, etc. Nickel plated wetted parts; corrosion resistant alloys particularly in old wells to improve sealing to worn casings.
Cements and Cement Additives	API cements and/or acid resistant cements

The most complete record of materials of construction and experience for a CO2-EOR flood was provided by Chevron after 10 years operation at the SACROC (Scurry Area Canyon Reef Operators Committee) Unit [2,3]. The injection tubing was plastic coated but they had varying degrees of success with different coatings. Epoxy-modified phenolic coating was most successful except where applied too thick (>0.17mm thick) as that resulted in blistering; powder applied epoxy was the most resistant. The average service life for coated tubing was 50 months. They also tested 6 tubing strings with polyethylene liners, and they all failed. The mechanism was attributed to CO2 permeation of the liner, subsequent deterioration of the adhesive and collapse of the liner by pressure build-up.

Unocal used plastic coated injection tubing in their Dollarhide Unit (WAG) but damage during field installation led to tubing corrosion problems [4], They also reported problems of leaks at connections. They tried various 8-round thread coupling and thread lubricants including modified seal rings and premium nose-seal couplings, Teflon tapes and Teflon thread lubricant, but all developed tubing leaks. They finally established the use of a modified 8-round coupling with Ryton coating on the threads and a seal ring. They also applied low-speed make up of the connections and rigorous helium testing of each connection to solve the leak problem.

In one of the few continuous CO2 injection programs (no WAG used), Texaco ran bare carbon steel tubing in CO2 injection wells since the tubing would not be exposed to water and so no corrosion was expected [5].

It should also be considered that whilst many of these USA CO2-floods have been in service since the 1970’s, there is not yet long-term experience of the abandonment (storage) phase of the project life to indicate how the well integrity is maintained over time.

1.3. Experience Outside USA

StatoilHydro pioneered the longest-running CO2-storage project after Norway imposed a tax on CO2 emissions from its offshore gas and oil sector. Since 1996 it has been using amine solvents to remove the 9% CO2 from the natural gas extracted from the West Sliepner field. This is injected at about 1m tonnes/yr into a saline aquifer about 800m below the seabed at Sliepner. A slightly smaller scale operation, 0.7 m tonnes/yr, started up in 2006 at its Snohvit field in the Barents Sea, injecting at 2,500 m depth.

For Sliepner (illustrated in Figure 1), the tubing material selection was 25Cr duplex stainless steel. The injected gas is essentially sweet but may contain up to 150 ppm H2S and potentially 0.5-2% ppm of organics (mostly CH4) [6].

Estimating from the saline aquifer depth, the conditions are considered to be within the safe operating envelope of 25Cr duplex, bearing in mind that there are no oxidising acid species.

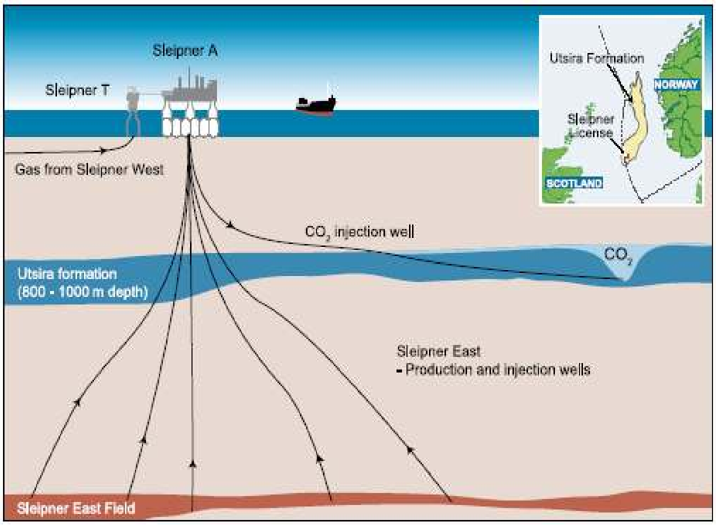

Figure 1 : Simplified diagram of the Sleipner CO_2 Storage Project. Inset: location and extent of the Utsira formation.

For Snohvit the tubing was AISI 4140 with all completion components in 25Cr duplex stainless steel. The choice of 4140 is unusual and possibly driven by low temperature fracture considerations, but this is not certain. Like Sleipner, there would be no oxidising acid components from this offshore source.

1.4. Summary

The key conclusions to be drawn from the above CO2 injection well experience are:

- There is mixed performance of various polymeric linings at high pressure conditions. For deeper wells with >350 bar at bottom hole conditions, linings would not be recommended because of concerns of blistering.
- Whilst the WAG service typical of many USA wells results in particularly aggressive intermittent wet and dry service at the bottom of the well, the experience in several cases of corroded liners and casings is an indication that the conditions would be aggressive in CCS service if the aquifer flowed back to the well-bore over time (e.g. during prolonged well shut-in, or at abandonment). Thus, selection of Corrosion Resistant Alloys for the bottom of the well would be advised, following the approach taken by StatoilHydro.
- High performance tubing connections are necessary to minimise the risk of CO2 leaks to the annulus.
- Materials selection used in existing CO2 injection projects has often been 25Cr duplex stainless steel, but that may not be applicable where the components in the injected fluid stream are more acidic or oxidising. 25Cr duplex stainless steel will depassivate at around pH2.

2. Defining the Well Corrosivity

The injected supercritical CO_2 fluid is dry and non-corrosive, so during the injection phase the well is not subject to corrosion and standard low alloy carbon steels could be used for all the well components, considering only the injection phase of the well life. Injection of fluids is assumed, ideally, to push back the aquifer waters during the well life creating a dry, non-corrosive zone around the immediate well bore. However, such an ideal scenario may not exist at all stages of the well life.

It has to be assumed that at the interface of the brine and the injected fluid within the formation, there will be a rapid dissolution of CO_2 and other injected components into the water phase. The reservoir brine (formation water) will change in composition as a consequence, depending upon its initial composition, but undoubtedly becoming more corrosive as its pH drops.

Scenarios that have to be considered are the possibility of corrosive water contact with the bottom of the tubing during any periods of well shut-in or long term suspension when the lack of injection may allow the reservoir brine to move back towards the well bore. At bottomhole temperature conditions the estimated corrosion rate of carbon steel in contact with an aqueous phase completely saturated with CO_2 would be around 5-8 mm/y assuming slow (0.1 m/s) flow conditions. Given the effectively infinite supply of corroding species (dissolved CO_2) it is expected that this corrosion rate would be sustained (i.e. it would not stifle as it does in a confined volume of fluid), resulting in rapid loss of the exposed section of any carbon steel injection tubing below the packer.

On completion of the injection period when the well is abandoned to long term storage the tubing may be removed and the well capped, and therefore continued resistance to well fluids over the long storage term would not be a necessity in this scenario. If it is intended that the tubing is kept in place during the abandonment phase then it may be necessary to consider CRA material for the whole tubing if it is envisaged to be totally exposed to the aggressive water over the long term. This decision needs a more complete understanding of the long-term well–life scenario on a per project basis and the interest or need for continuing annulus pressure monitoring in abandoned wells.

The material selection of the critical well components in the bottom of the well is driven by the environment composition which is achieved when the injected gas dissolves in the initial fluid present. The corrosivity is driven by the temperature, the chloride content and the pH of the resulting solution.

2.1. Injection Fluid Composition

The gas composition is dependent upon the source and method of CO_2 extraction process. Whilst oilfield-derived CO_2 may be fairly reliably reducing, CO_2 produced from coal fired power plants (for example) may contain a variety of oxidising species including oxygen and traces of sulphur dioxide and nitrogen dioxide [8] .

The aggressive chemical components in the injected gas are:

- CO_2; controls the basic material selection
- H_2S; shifts the choice of materials significantly because of risk of pitting and/or hydrogen loading
- O_2; introduces a pitting risk
- SO_2 and NO_2; make the environment more acidic

2.2. Brine Composition

Injection may be into either a depleted gas reservoir or a saline aquifer. The depleted reservoir rock will be filled with formation water, the composition of which may vary significantly, but is typically 20 – 120 g/l chloride ion content. Typically formation waters in carbonate rocks are close to saturated in bicarbonate ions, usually 1500 - 2500 ppm although some waters (from sandstones) may be very low in bicarbonate ion concentration.

A saline aquifer could be considerably more concentrated in composition. Example compositions have 150 – 200 g/l chloride ions with varying bicarbonate ion content depending upon the rock type from 0 – 2500 ppm.

2.3. Wellhead and Bottomhole Conditions

The temperature and pressure conditions at the bottomhole conditions will depend primarily on well depth. Table 2 suggests possible ranges.

Table 2 : Estimated Wellhead and Bottomhole conditions.

WHT, °C	Ambient
WHP, bar	120–150
BHT, °C	70–120 °C
BHP, bar	400–500

3. Matrix of Conditions and Corresponding Material Selection

The materials choices are indicated in Table 3 for example CO2 stream compositions from different capture processes, and for two different chloride levels representing reservoirs with high and low salinity brines. For materials for downhole well components, relatively high strength materials are needed. The alloys proposed below are all available in high strength forms, either through heat treatment (13Cr, S13Cr) or by cold working, to yield strength typically 80ksi–120ksi.

Table 3 : Downhole Materials Selection Matrix for Different Injection Compositions

	Mol%	**Post Combustion**	**Oxy-Fuel (nil oxygen)**	**Oxy-Fuel (trace oxygen)**	**IGCC (high H_2S)**	**IGCC (low H_2S)**
	Carbon Dioxide	> 99.9	> 99.9	c. 96.	c. 97	> 98.5
Contaminants present	Oxygen	Trace	0	0.5- 1.0	0	0
	Sulphur Dioxide	Trace	0	0	-	-
	Hydrogen	-	-	-	c.1.0	c. 0.5
	Nitrogen Dioxide	-	0	Trace	-	-
	Hydrogen sulphide	-	-	-	c. 1	< 0.002
Chloride <50,000 ppm		Alloy 625	13Cr	Alloy 625	Alloy 28/ Alloy 825	22Cr
Chloride > 50,000 ppm		Alloy C276	S13Cr/ 22Cr	Alloy C276	Alloy 28/ Alloy 825	22Cr

The CO2 stream with the least contamination, the high-purity oxy-fuel case, can be handled using the standard API 13Cr grade in most formation waters (chloride content <50,000 ppm). This selection assumes that the oxygen content is actually zero as indicated in Table 3. In the higher concentration saline aquifers the higher alloyed proprietary Super-13Cr material is needed, or 22Cr duplex stainless steel.

If there is also some trace hydrogen sulphide present (e.g. IGCC), then this strongly encourages pitting and the 13Cr/S13Cr options are no longer suitable; 22Cr duplex stainless steel is needed. At higher levels of H2S the pitting risk is further increased and the high alloy stainless steel, Alloy 28 or the nickel Alloy 825 are needed.

In the most severe conditions with oxygen present or oxidising acid gases (SO2, NO2) it is necessary to change to the highly pitting resistant, high molybdenum content nickel alloys such as

Alloy 625 and, at high chloride content, Alloy C276. These would also be needed in the oxy-fuel combustion case if the oxygen content was not actually zero.

3.1. Wellhead and Xmas Tree

The injection fluid is completely dry at wellhead conditions and so standard low alloy carbon steel (AISI 4130) Xmas tree and wellhead equipment would be completely safe for a CO2 injection well. The selection of AISI 4130 is made because of the need to specify good toughness to minimise the risk of brittle fracture in the event of a major CO2 leak or blowout. The more usual AISI 4140 material has higher carbon content and it is harder to achieve the required fracture toughness requirement. AISI 316 stainless steel trim is recommended to provide long term sealing capability on sealing faces.

***3.2.** Injection Completion String*

Recommendations for corrosion mitigation and monitoring for the completion string (downhole tubing) can be summarised as followed:

No corrosion risk in upper section of tubing. Possible risk of attack of tailpipe below packer because of possible intermittent wetting of the lower pipe (on internal and external surfaces) during well shut-in for various time periods.

Upper section of tubing above packer, L80 grade carbon steel; completion components 13Cr stainless steel.

Tailpipe below packer and flapper valve, CRA material depending upon environment, table 3.

High performance premium tubing connections to minimise risk of CO2 leakage to the annulus

Production annulus fluid to be treated with oxygen scavenger and corrosion inhibitor to prevent any risk of galvanic corrosion between different metals in electrical contact.

Annulus fluid to be biocide treated to mitigate against any risk of microbial influenced corrosion in the annulus.

Corrosion monitoring by caliper survey of tubing approximately every five years, or by visual examination of tubing whenever removed during workovers for whatever purpose as opportunity arises.

3.3. Cement

Acid resistant cements are required in the section of the well which will be exposed to the CO2-saturated water phase. Cement integrity will have to be proven after placement by carrying out cement bond integrity test of the shoe bond area for each casing.

4. Well Operations

A key part of the acceptance of CO2 sequestration as a safe and reliable greenhouse gas control mechanism will be the proof that the well is truly leak-free. This integrity management element requires a comprehensive monitoring and pro-active warning system which highlights developing integrity issues before they become acute. Key well parameters requiring daily or continuous monitoring are:

- THP (tubing head pressure)
- BHP (bottom hole pressure)
- THT (tubing head temperature)
- BHT (bottom hole temperature)
- Annuli pressures for each well annulus
- Hours of injection per day (since shut-in periods represent higher risk of water diffusing back to the well bore)

All data should be recorded, stored, trended and checked against a defined well safe operating envelope.

Results of leak testing of seals and integrity tests (pressure testing) of the well at intermittent periods as well as chemical analysis of any fluids sampled from well annuli also need to be stored and checked. Given the criticality of preventing CO2 emissions, the acceptance criteria recommended would be the same as API 6A. That is, the wellhead and Xmas tree should perform as well throughout its operational life as it did during manufacturing tests.

In the context of a well designed and constructed for the sequestration of CO2, the overwhelming driving force should be to prevent sustained annulus pressure, SAP. To achieve this, detailed consideration has to be given to every aspect of the well design, construction, operation, monitoring, condition evaluation, workover, suspension and abandonment. A dedicated well integrity software is recommended to be able to check that annuli pressures and all other test parameters (such as valve and seal leak tests) are collected according to defined schedule and that data meets safe limits. The software should immediately highlight the existence of any potential problems and send email warnings if testing is behind schedule or results are indicative of developing problems.

The Intetech Well Integrity Toolkit software has been relied upon by operators for many years for well integrity management. It has recently been installed by a gas storage operator in Europe and is equipped with the functionality needed to assure the management of wells for CO2 injection. The software integrates all well monitoring data, carries out real-time analysis to identify possible problems before they become critical and sends email alerts identifying wells with high risk status.

5. Conclusions

CO2 sequestration wells require detailed consideration of the well integrity in every aspect of the well design, construction, operation, monitoring, condition evaluation, workover, suspension and abandonment. Whilst useful information may be derived from international experience with miscible flood and WAG injection with CO2, wells for CO2 sequestration may have more demanding requirements. Specifically in CO2 sequestration compared to CO2 miscible flood:

- the composition of the supercritical CO2 may be different depending upon its source, and may have very aggressive trace constituents.
- temperatures and pressure may be higher at the bottomhole conditions
- routine maintenance and repair or replacement of the well equipment may be less acceptable and so higher integrity designs may have to be selected
- well service lives may be longer
- acceptable leak tolerance during service will be at minimum levels possible (i.e. as good as manufacturers testing can achieve).
- integrity will need to be maintained for long duration into the future in the abandoned wells

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