Project acronym and title:

SECURe – Subsurface Evaluation of Carbon capture and storage and Unconventional risks

REPORT ON REMEDIATION STRATEGIES FOR TUBINGS AND CASINGS

Authors and affiliation:

Laura Edvardsen, Kamila Gawel, Pierre Cerasi

SINTEF AS - SINTEF Industry, S. P. Andersens vei 15 B, 7031, Trondheim, Norway

Email of lead author:
pierre.cerasi@sintef.no

D5.3
Revision:1

Disclaimer

This report is part of a project that has received funding by the *European Union's Horizon 2020 research and innovation programme* under grant agreement number 764531.

Project funded by the European Commission within the Horizon 2020 Programme	
Dissemination Level	
PU	*Public*
~~**CO**~~	~~*Confidential, only for members of the consortium (incl. the Commission Services)*~~
~~**CL**~~	~~*Classified, as referred to in Commission decision 2001/844/EC*~~

Deliverable number:	**D5.3**
Deliverable name:	**REPORT ON REMEDIATION STRATEGIES FOR TUBINGS AND CASINGS**
Work package:	**5 Impact Mitigation and Remediation**
Lead WP/deliverable beneficiary:	

Status of deliverable		
	By	**Date**
Submitted (Author(s))	**Kamila Gawel & Laura Edvardsen**	**11.10.2019**
Verified (WP leader)	Pierre Cerasi	13.10.2019
Approved (EB member)	Jens Wollenweber (TNO)	21.10.2019
Approved (Coordinator)	E Hough (UKRI-BGS)	29.10.2019

Author(s)		
Name	**Organisation**	**E-mail**
Kamila Gawel	SINTEF Industry	kamila.gawel@sintef.no
Laura Edvardsen	SINTEF Industry	laura.edvardsen@sintef.no
Pierre Cerasi	SINTEF Industry	pierre.cerasi@sintef.no

Public introduction

Subsurface Evaluation of CCS and Unconventional Risks (SECURe) is gathering unbiased, impartial scientific evidence for risk mitigation and monitoring for environmental protection to underpin subsurface geoenergy development. The main outputs of SECURe comprise recommendations for best practice for unconventional hydrocarbon production and geological CO2 storage. The project is funded from June 2018–May 2021.

The project is developing monitoring and mitigation strategies for the full geoenergy project lifecycle; by assessing plausible hazards and monitoring associated environmental risks. This is achieved through a program of experimental research and advanced technology development that includes demonstration at commercial and research facilities to formulate best practice. We will meet stakeholder needs; from the design of monitoring and mitigation strategies relevant to operators and regulators, to developing communication strategies to provide a greater level of understanding of the potential impacts.

The SECURe partnership comprises major research and commercial organisations from countries that host shale gas and CCS industries at different stages of operation (from permitted to closed). We are forming a durable international partnership with non-European groups; providing international access to study sites, creating links between projects and increasing our collective capability through exchange of scientific staff.

Executive report summary

Well integrity is crucial to ensure a leak-free well, throughout its life cycle, and safe working conditions. The focus on well integrity is as equally important for (un)conventional oil and gas production as it is for CO_2 storage. Statistics on well integrity failures and past incidents indicate that there are knowledge and technology gaps. The most vulnerable well components are tubing, casing, cement and annulus safety valves.

Work Package 5 (WP5) in the SECURe project aims to establish best practices for remedial and mitigation technologies. This, to reduce the risk of loss of well integrity in unconventional hydrocarbon production and CO_2 storage operations.

This report will address several potential casing and tubing failure mechanisms in CO_2 and shale gas wells, and will describe remediation strategies to maintain well integrity. The objectives of this report are to:

- *Describe the most common well barrier envelopes used for CO_2 and shale gas wells based on the NORDSOK STANDARD D-010 concerning well integrity.*
- *Review different casing and tubing failure mechanisms. The different mechanisms considered in the report are: abrasion, corrosion and mechanical loads during hydraulic fracturing in unconventional oil and gas operations*
- *Review different remediation methods and technologies for failure of tubing and casing.*
- *Outline planned laboratory testing to investigate tubing mechanical strength after remediation by cement squeeze. This activity will complement similar tests investigating cement fracturing and remediation, outlined in WP5 Deliverable D5.1.*

Contents

FIGURES

1 Introduction

Well integrity is crucial throughout the life cycle of a well in order to mitigate well leaks and ensure safe working conditions. Regardless of the well's function, whether it is production of oil or shale gas, a monitoring well or an abandoned well, its integrity must be maintained. This applies of course also to CO_2 storage wells, with strict regulation as to duration of leak-free guarantee after abandonment. Since possible CO_2 storage sites include depleted oil reservoirs, the well integrity practice developed by the oil and gas industry becomes important for future CO_2 storage. Although the oil and gas industry has evolved over decades, there is still room for improvement of existing technology. The Petroleum Safety Authority in Norway led an investigation of well integrity issues using data from 406 offshore Norwegian wells [1]. The results indicated that 18% of the wells had some sort of integrity failure, issue or uncertainties and 7% of these wells were shut in due to the lack of well integrity. The investigation indicated that the most vulnerable well components were tubing, casing, cement and annulus safety valves. King et al. (2013) compared statistics of well failures in the North Sea UK, North Sea Norway and the Gulf of Mexico, they concluded that the major causes of well failure were leakage through cement and tubing [2]. In another study, 3533 Pennsylvanian wells monitored between 2008-2011 were investigated. Here, 85 cases of cement or casing failure were registered [3]. Loss of cement integrity can occur due to improper cement placement, cement shrinkage or development of channels [4]. Tubing and casing failure can be caused by corrosion, mechanical rupture [5] and abrasion [6].

Well integrity failure can have catastrophic consequences. In 2010, the Deepwater Horizon oil rig exploded and leakage from 1500 m below the surface of the Gulf of Mexico occurred. It was estimated that 4.9 million barrels of oil had been released into the Gulf of Mexico before the well was sealed [7]. This had a huge impact on the environment and the crew members as 11 workers lost their lives and 17 were injured [8]. Results of well integrity investigations and past incidents reveal that there are knowledge and technology gaps to fill. This report aims to reflect up on common tubing and casing failures in CO_2 storage and shale gas production in order to provide adequate mitigation measures.

1.1 THE AIM OF THIS REPORT

This report will address remediation strategies for tubing and casings in CO_2 and shale gas wells, providing proposals for best practice for CO_2 storage and unconventional hydrocarbon production. An earlier SECURe project deliverable D5.1 [9] focused mainly on remediation of cement sheath, but also mentioned remediation strategies for tubing and casing. In this report we discuss the major casing and tubing failure mechanisms and present a detailed description of casing and tubing remediation methods.

The objectives of this report are:

- Describe the most common well barrier envelopes used for CO_2 and shale gas wells based on the NORDSOK STANDARD D-010 concerning well integrity.

- Review different casing and tubing failure mechanisms. The different mechanisms considered in the report are abrasion, corrosion and mechanical loads during hydraulic fracturing.
- Review different remediation methods and technologies for failure of tubing and casing.
- Outline planned laboratory testing to investigate tubing mechanical strength after remediation by cement squeeze.

2 Well integrity

Well integrity is defined by the NORSOK STANDARD D-010 as "the application of technical, operational and organizational solutions to reduce the risk of uncontrolled release of formation fluids throughout the entire life cycle of the well and of course safety aspects". Describing well integrity is done by using the terms well barrier and well barrier element (WBE). A WBE alone cannot prevent unintentional flow from the formation, but in combination with other WBEs it acts as a well barrier. Hence, a well barrier is an envelope of one or several WBEs. To ensure well integrity, the NORSOK STANDARD D-010 states that two independent well barriers shall be available during all well activities. This also includes abandoned wells. The two well barriers are referred to as primary and secondary well barrier and reflect the first and second object that prevents flow from a source, respectively [10].

Leakage or other integrity faults are a result of failure of one or several WBE [11]. For an active CO_2 platform well, the most common WBEs using two well barriers are shown in Figure 1.

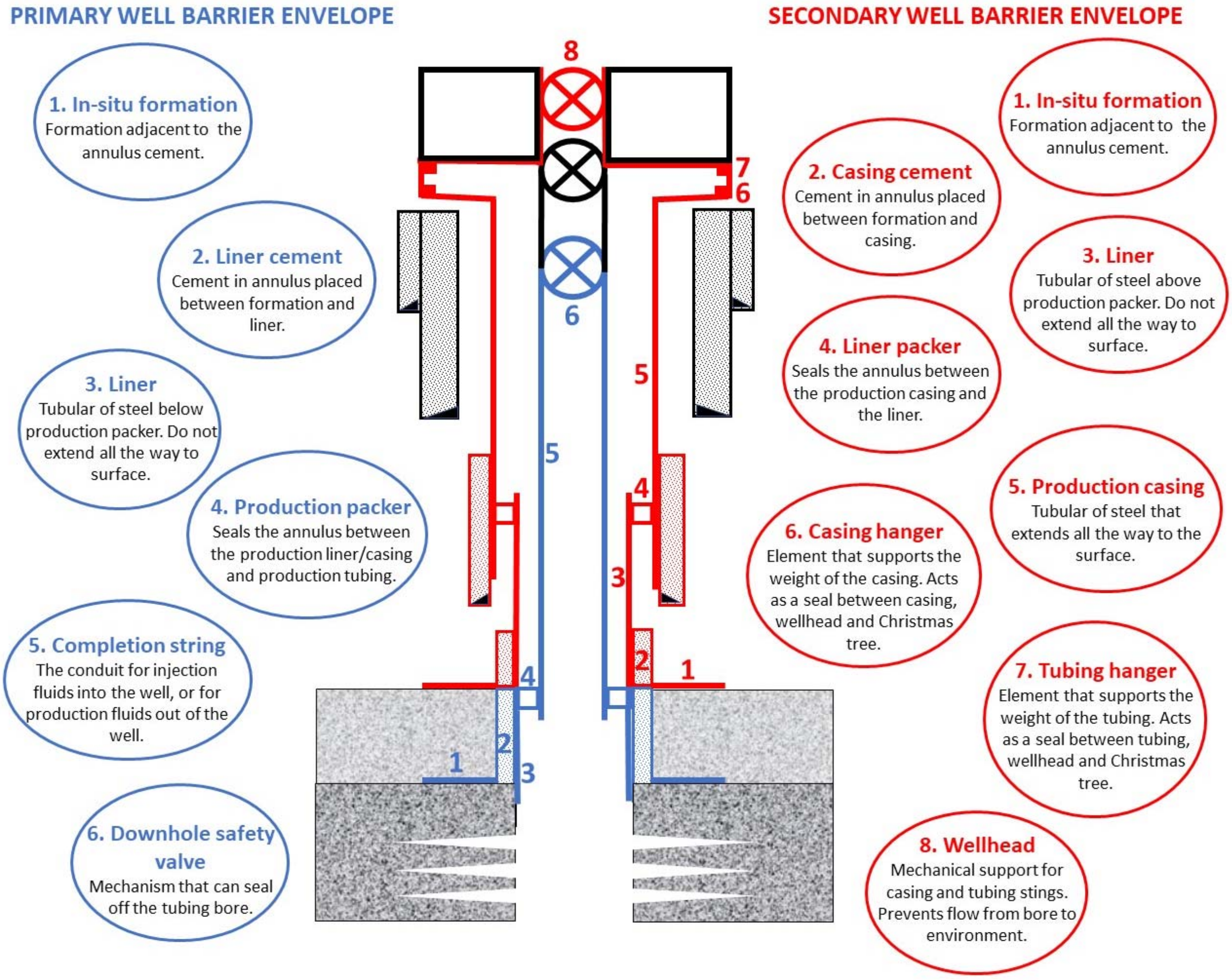

Figure 1 Simplified illustration of well barriers for a typical active CO_2 well. Primary well barrier envelope in blue and secondary well barrier envelope in red [11].

If the in-situ formation is to qualify as a WBE, the formation strength must exceed the maximum wellbore pressure. According to NORDSOK STANDARD D-010, failure of one of several WBEs in one of the well barriers means that the entire barrier has failed [10].

A typical shale gas well has a horizontal interval within the production zone [9]. For an active shale gas well, the most common WBEs using two well barriers are shown in Figure 2.

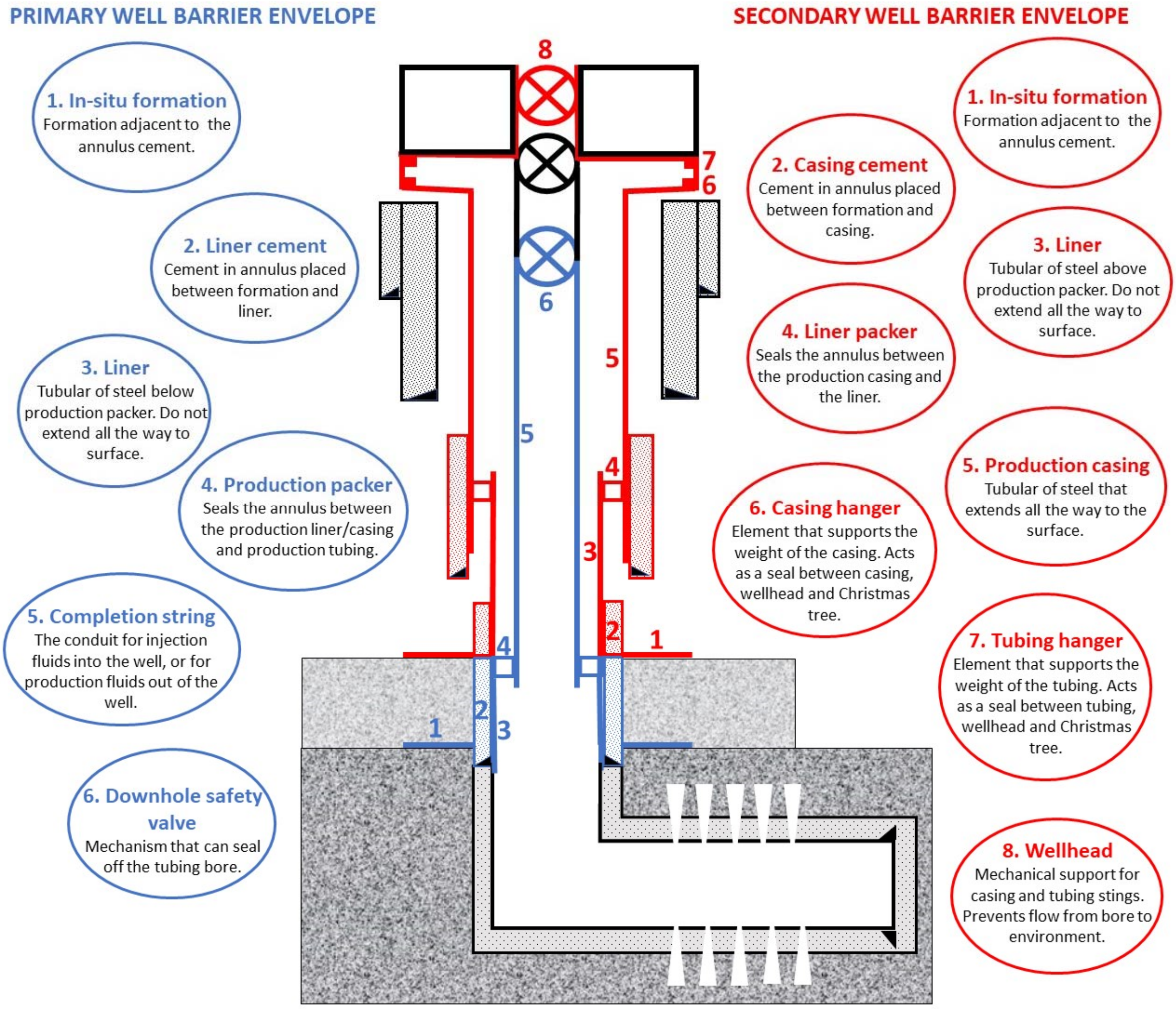

Figure 2 Simplified illustration of well barriers for a typical active shale gas well. Primary well barrier envelope in blue and secondary well barrier envelope in red [9, 11].

In Figure 2, hydraulic fracturing within a chosen interval of the production casing was not included in the primary well barrier envelope. Comparing the illustrations of the CO_2 and shale gas wells, the difference is the horizontal part of the wellbore. Even though the final part of the wellbore is dissimilar for these two cases, there is no essential difference within the perspective of well barriers and WBEs [9]. Whereas most pilot CO_2 injection wells onshore were until now vertical wells, new projects and offshore wells such as the one in Sleipner will likely include deviated and horizontal injection wells [12].

For abandoned wells, the principle of using two independent well barriers is still valid. If other potential flow zones at shallower depths exist, additional well barriers may be necessary to establish integrity of the well after permanent abandonment. This applies to both CO_2 and shale gas wells [9]. An illustration of the most common WBEs using a primary and secondary well barrier with an additional openhole-to-surface well barrier is shown in Figure 3.

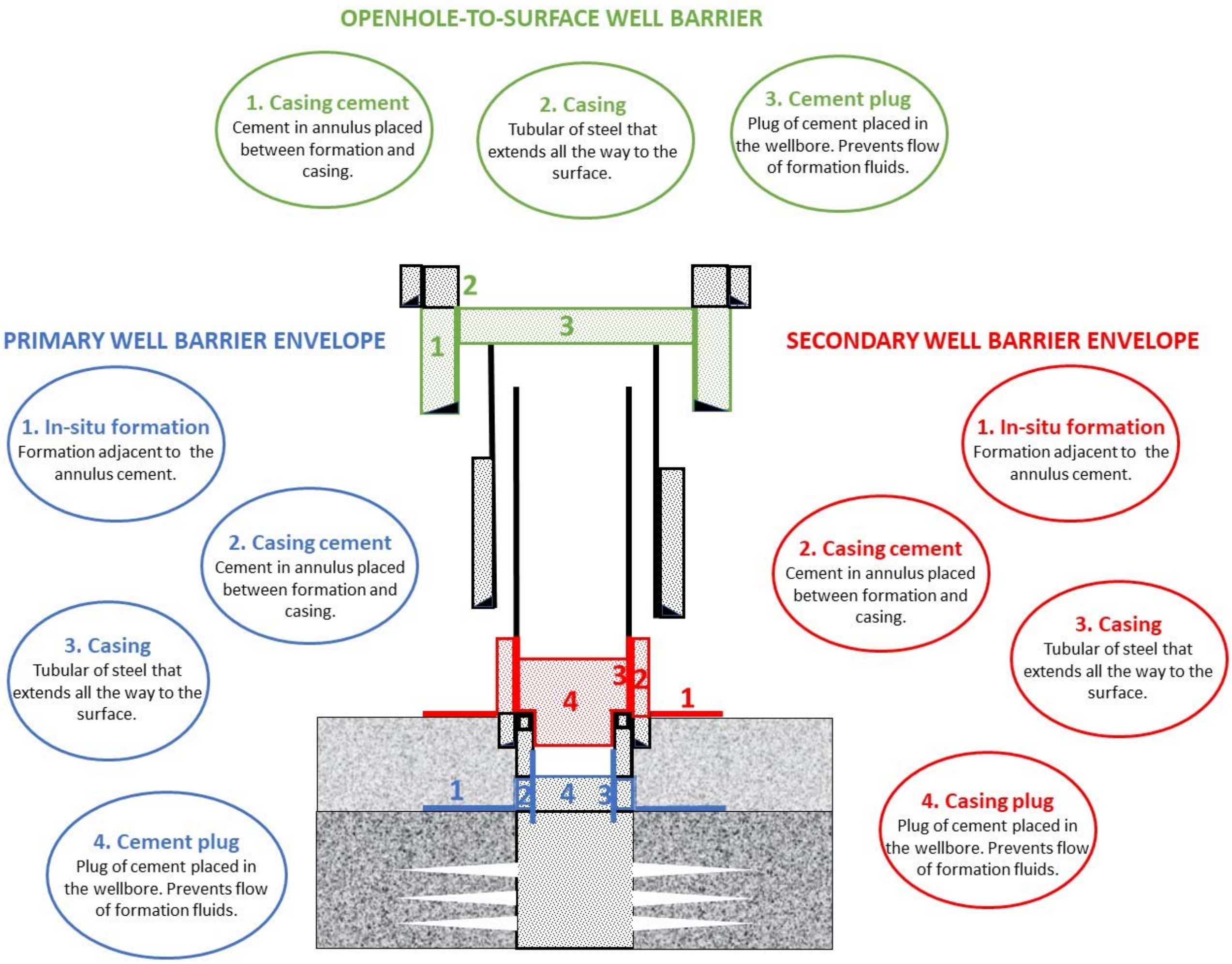

Figure 3 Simplified illustration of well barriers for a typical abandoned shale gas well. Primary well barrier envelope in blue, secondary well barrier envelope in red and openhole-to-surface well barrier in green [9, 11].

The general description in Figure 3 applies to abandoned oil and gas, CO_2 and shale gas wells. In plug and abandonment (P&A) operations, the wellhead and valves are removed. The casing and tubings may remain in the borehole or be removed. In Figure 3 the tubing is removed but the casing remains. This is a typical procedure when both casing and cement are validated as intact WBEs [9].

3 Casing and tubing failure mechanisms

There are different casing and tubing failure mechanisms that can be encountered in unconventional oil and gas and CO_2 wells. If leakage occurs, the first cause of action is to detect the source of the leak and understand which well barrier element(s) has failed [11]. When the leak is located and its nature known, useful countermeasures can be initiated. This section reviews common casing and tubing failure mechanisms in injection and production wells. Injection wells are however more prone to failure [1]. The Petroleum Safety Authority in Norway investigated well integrity issues offshore Norway and collected data from 406 wells. The study reveals significant differences between injection and production wells: failures have been reported in 33% of all injection wells and 15% of all production wells.

3.1 ABRASION AND ITS MITIGATION

Abrasive wear of well barrier elements has been observed in both CO_2 as well as shale gas wells [6, 13] but it is a problem mainly in unconventional oil and gas production. During shale gas production the main culprit for abrasive wear are fracturing fluids containing proppants [14]. Proppants are particulate (granular) materials used to keep the incipient fracture open during and after a hydraulic fracturing process. Conventional proppants include sand, ceramic, glass beads and nutshells [15]. The abrasive forces act both upon pumping the fluids with proppants downhole as well as during their backflow to the well. The abrasive wear of well barrier elements can be prevented by either limiting the proppant backflow or by improving the design of well barrier elements. It is both dependent on better design of geometry of well elements as well as on better choice of materials used (e.g. high strength alloys and ceramic couplings) that can limit abrasive wear and prolong the lifetime of the elements. In CO_2 wells, abrasion will probably be caused by particles in drilling fluids, either during circulation or after shut-in, where settling may have occurred.

One of the most critical processes for abrasive wear in a well is discharge of fluid from a tubular string in the wellbore where casing and other structures in wells can be eroded. In order to reduce this erosion a system that mitigates abrasive action of discharged fluids can be used [16]. The system is comprised of a tubular string with a fluid discharge apparatus. The fluid discharge apparatus includes a curved flow path that directs the fluid away from the tubular wall and thus reduces impingement of the fluid on the well element.

Proppant backflow can be avoided by setting screens that permit reservoir fluids but block proppant transport. The screens used can be conventional metal sand screens although often these standard screens suffer from insufficient erosion resistance. Thus, alternative materials that have higher hardness and consequently better erosion resistance have been proposed for screen design. Among them are advanced ceramics that show excellent resistance to wear and corrosion [17].

3.2 CORROSION AND ITS MITIGATION

Corrosion of casings and tubings in acidic environments is common and has long been a challenge in oil, shale gas and CO_2 wells [18]. Corrosion can occur on the external and internal surfaces of casing and tubing systems. External corrosion is dictated by the environmental conditions in which the casing or tubular are installed. For example, the presence of cement sheet at the outer surface of casing will prevent casing from external corrosion by providing high pH environment. On the other hand the presence of water based drilling fluids outside the casing may enhance external corrosion. [19]. Internal corrosion is dictated by the environmental conditions within the casing or tubular and occurs when the internal surface interacts with injection or production fluids [20].

Casing and tubings are typically made of carbon steels. But corrosion resistant chromium steels (13Cr and 10Cr) can also be used. For more information about steel types typically used in oil and gas production see the following references [21, 22].

There are different types of processes that may contribute to corrosive failure of steel well barrier elements [23, 24]: (1) **Sweet corrosion**, by far the most prevalent form of internal attack encountered in oil and gas production, is caused by CO_2. Dry CO_2 is not corrosive at the temperatures encountered within oil and gas production systems but when it dissolves in aqueous solution it forms carbonic acid that can promote corrosion of steel, see equations below [24]:

$$\mathrm{CO_2 + H_2O \rightarrow H_2CO_3}$$

$$\mathrm{H_2CO_3 + Fe \rightarrow FeCO_3 + H_2}$$

CO_2 corrosion is influenced by temperature, pH, composition of the aqueous solution (e.g. salinity), presence of non-aqueous phases, flow condition, and metal types [23]. Supercritical (Sc) CO_2 is also a source of corrosion. Aqueous Sc CO_2 environments is highly corrosive and even stainless steels (13Cr and high-alloy CrNi steels) have been subject to some degree of corrosion [25]. The sweet corrosion is not only characteristic for CO_2 wells but is a likely scenario in unconventional oil and gas wells where the production fluids contain CO_2. (2) **Sour corrosion** is caused by H_2S [23]. Like CO_2, H_2S alone is not corrosive but it becomes severely corrosive in the presence of water. Hydrogen sulfide in water forms a weak hydrosulfuric acid that is corrosive. The iron corrosion products are iron sulfides and hydrogen, see equation below [24]:

$$Fe + H_2S \rightarrow FeS + H_2$$

Iron sulfides can form a scale that at low temperature can act as a barrier and slow down corrosion. Different forms of sour corrosion can be encountered: uniform, pitting, and stepwise cracking. It can eventually lead to steel pipe embrittlement and/or perforations. This type of corrosion can be encountered in producing wells where the production fluids contain H_2S gas. (3) **Oxygen corrosion** occurs due to strong oxidation properties of O_2. Oxygen can enter the well through leaky pump seals, casing, vents and hatches. Oxygen accelerates the anodic destruction of metal. The forms of corrosion associated with oxygen are mainly uniform corrosion and pitting. (4) **Galvanic corrosion** occurs when two metals with different electrochemical potential are in contact in an electrolytic environment. The metal with lowest potential becomes the anode and starts corroding. When the ratio of the cathode to anode area is large, corrosion can be severe. (5) **Microbiological corrosion** is caused by bacteria or rather their metabolism products such as CO_2, H_2S, and organic acids.

Corrosion can have the following forms [24]: (1) metal wastage, (2) pitting, (3) crevice corrosion, (4) intergranular corrosion, (5) stress corrosion cracking, (6) blistering, (7) embrittlement, (8) sulfide stress cracking, (9) corrosion fatigue. The sweet corrosion and oxygen corrosion result primarily in the first five forms, while sour corrosion takes the last four forms.

Metal wastage relies on a uniform loss of metal. **Metal wastage** can occur during pumping of poorly inhibited stimulation fluids that can be the case in unconventional oil and gas production. However, this could also occur in CO_2 injection wells, if reduced injectivity is experienced. **Pitting** is a type of corrosion that starts on weak spots of passivating film that will preferentially dissolve and form pits. This type of corrosion progresses fast and finally may result in perforations. **Crevice corrosion** occurs in confined spaces to which the access of the injection or production fluid is possible but very limited. **Intergranular corrosion** arises at the boundaries of material crystallites and takes place when the boundaries are more susceptible to corrosion than their interiors. **Stress corrosion cracking** is a corrosion which leads to the formation of cracks in metals due to the presence of corrosive fluids when the metal is under tensile stress. **Blistering** relies on the formation of a raised area, often dome shaped. It is initiated either by loss of adhesion between a coating or deposit and the metal or by delamination of the coating upon expansion of gas trapped within. The most common reason for metal **embrittlement** is a diffusion of hydrogen to the metal bulk. Hydrogen embrittlement results in a decrease of the toughness or ductility of a metal. **Sulfide stress cracking** is a form of hydrogen embrittlement. When metal reacts with H_2S, atomic hydrogen is produced as a corrosion byproduct. The atomic hydrogen either combines to form molecular hydrogen (H_2) at the metal surface or diffuses into the metal matrix. The presence of sulphur from H_2S inhibits hydrogen recombination and thus increases the amount of atomic hydrogen in the metal matrix leading to embrittlement. The sulfide stress cracking requires only low concentrations of H_2S to occur and the consequences of this type corrosion are often severe. **Corrosion fatigue** is a mechanical degradation of a material under the joint action of corrosion and repetitive mechanical loads. The most common **corrosion prevention** method is application of corrosion inhibitors although some other methods like anticorrosive coatings [26] or cathodic protection has also been applied [24].

Corrosion inhibitors are used to minimize harmful consequences of both injection and production fluids. During acid stimulation, corrosion rates of carbon or chrome steels are higher than under typical production conditions. Corrosion inhibitors used to protect steel casing or tubing during acidizing are mostly different from those used to treat production fluids and they are usually added in larger amounts [27]. Corrosion inhibitors utilize different corrosion protection mechanisms [24]. One of them is restriction of the rate of the anodic process or the cathodic process by simply blocking active sites on the metal surface. Secondly, the inhibitor may increase the potential of the metal surface so that the metal enters the passivation region where a natural oxide film forms. The third corrosion protection mechanism relies on strong adsorption of the corrosion inhibitor and formation of an organic, protective film on the metal surface. A detailed review of corrosion inhibition mechanisms has been published elsewhere [24, 28].

A **protective coating** constitutes a barrier between the material and a corrosive environment. Fusion-bonded epoxy and a three-layer polyolefin (polyethylene or polypropylene) are currently the most widely used external anti-corrosion coating systems although single and double-layered coatings are also in use [24]. Sometimes a single layered coating is not sufficient to prevent corrosion [29]. Especially when wireline tools are used the risk for mechanical damage of the coating is large [30]. This was the case, at the Ekofisk field (North Sea) where due to the presence of corrosive H_2S and CO_2 wells were completed with tubing internally coated with heat treated phenolic resin. Wireline tool damages in addition to coating blistering were observed [29]. According to Groves et al. (2001), current commercial coatings lack the mechanical robustness required to prevent wear by wireline tools. Therefore, successful application of polymer coatings cannot be applied alone and needs to be supported by chemical inhibition [30].

Cathodic protection is a corrosion protection method that relies on minimizing the difference in potential between anode and cathode. This is done by applying a current to the structure to be protected [24]. When enough current is applied, the whole structure will be at one potential, thus, there will be no electron flow. There are two types of cathodic protection [31]: (1) Sacrificial (galvanic) anode cathodic protection that uses the naturally occurring electrochemical potential difference between different metallic structures to provide protection; (2) Impressed current cathodic protection that uses an external power source with inert anodes. According to Curry (1970), the main problem in well casing protection is determining the current requirements for protection [32].

3.3 MECHANICAL LOADS DURING HYDRAULIC FRACTURING

Hydraulic fracturing (HF) is a process in which high pressure is applied in order to create cracks in the shale formations through which natural gas, oil, and brine will flow more freely. The high pressure is imparted by pumping fracking fluid downhole. The high pressures associated with hydraulic fracturing operations can sometimes be detrimental for the production casing. Casing failures during hydraulic fracturing operation or shortly following the operation have been reported [33, 34]. In order to prevent casing failures on pressure loads during HF, the casing material needs to be strong enough to withstand the stresses imparted by HF.

4 Remediation strategies of damaged tubing and casing

Replacement of well components is a relatively complex and costly operation as it requires well workover, thus it is almost the last strategy after a simpler and less expensive solution failed or cannot be applied to remediate the leak. The description of replacement strategies is beyond of the scope of this report and in this chapter, we focus on tubing and casing remediation methods.

Several methods exist that are typically used to repair casing or liner damage caused by the factors described in Section 3 of this report. Among them are [35-38]: (1) installation of straddle packer, (2) installation of expandable casing/liner (i.e. casing patch), (3) squeeze cementing, (4) swaging.

4.1 STRADDLE PACKER

Straddle packer application to isolate the zone with damaged casing is schematically shown in Figure 4. A straddle packer is an assembly of two (or more) packers and some tubing. The tubing allows for flow of fluids between the intervals below and above the packer while the zone with damaged casing is separated and thus any leakage behind the casing is prevented. Straddle packers can be retrieved but can also be applied permanently over the leaky intervals. This method can also be applied to damaged tubing. The disadvantage of the straddle packer method is that the diameter through which the fluids flow is reduced.

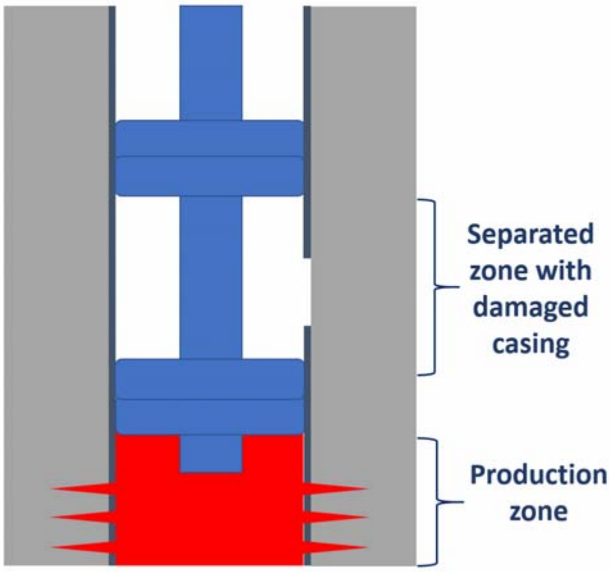

Figure 4 Schematic illustration of the assembly of straddle packers used to isolate damaged casing.

4.2 EXPANDABLE CASING/LINER

Another method used to prevent damaged casing or tubing from leaking is installation of an expandable casing/liner (patching) [39-42]. Figure 5 shows schematically how the patching works. First the corrugated liner/patch is positioned across the leak area within the casing or tubing. Then the expander assembly is run upward. The forces it imparts expands the liner, so it makes contact with the casing wall. The friction caused by the compressive hoop stress anchors the section of the patch on the casing wall. The expansion process creates hydraulic and gas-tight contacts between the existing casing/liner and the patch. Sometimes the external surface of the liner is coated with epoxy resin to improve bonding between patch and casing. The epoxy resin extrudes into holes and cavities in the casing wall and acts as an additional sealing agent. Finally, when the expander assembly tool is removed from the hole the patch is pressure tested to verify whether patching was successful. The patching does not have any significant effect on the diameter of the casing in the patched area but the standard 1/8-inch thick liner may reduce the casing diameter by just 7.62 mm [43]. Patches for normal patching and high-pressure operations are available on the market. Special liner materials that suit highly corrosive conditions or high temperature wells (316°C) can also be applied [43]. Expandable casing/liners can be easily joined together to achieve the necessary length. Patches may also be used to provide strengthening of partially corroded or otherwise weakened casing or completion equipment. An expandable patch can also be used to completely replace a damaged interval by using tie-back system. The tie-back system is a connection that creates a hydraulic and gas-tight linkage between the old and the new casing. In this case the internal diameter of the well is preserved.

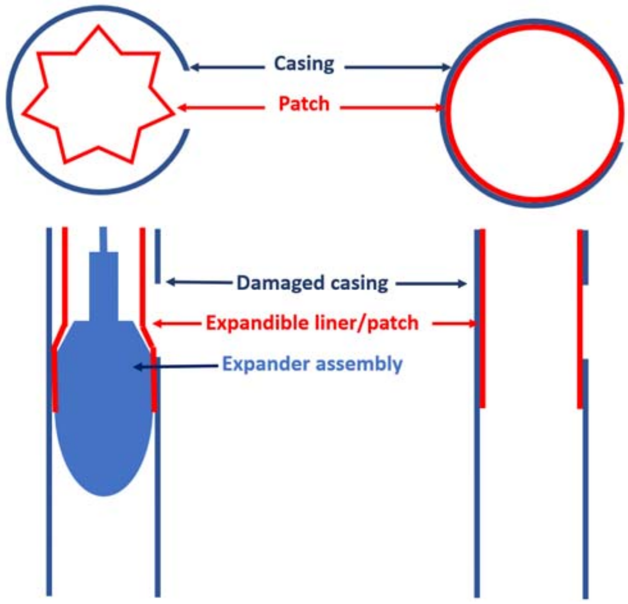

Figure 5 Schematic illustration of patching process.

4.3 SWAGING

Sometimes stress from the surrounding formation may lead to bending or even collapse of the well casing. Collapsed or deformed casing can be repaired so that the original geometry of the casing is restored by running a swaging tool through the well [36, 38]. The swaging tool is run on a single-strand wireline (slickline) and acts as a circular wedge that forces the casing walls out while it is run through the deformed or collapsed section of the well, see schematic illustration of the process in Figure 6. A jar is included in the tool string to provide the force necessary to push the swaging tool through the tubing restriction. A jar is a mechanical or hydraulic device used downhole to deliver an impact load to another downhole component, especially when the component gets stuck. The pressure exerted by the swaging tool can exceed 7 tonnes per square centimeter [38]. Swaging tools can also be applied to repair tubing.

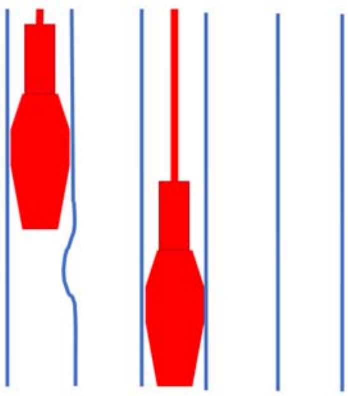

Figure 6 Schematic illustration of a swaging tool run through a collapsed casing/tubing.

4.4 SQUEEZE CEMENTING

Squeeze cementing can be applied to repair a damaged casing [38]. The procedure of squeeze cementing is as follows: the section of damaged casing is isolated by setting packers above and below the damage. Cement slurry is pumped between the two packers. The slurry fills up open spaces in and behind the casing before it hydrates and hardens. Any hardened cement remaining in the well, has to be removed by milling. The milling is a harsh process and can be deteriorative for the newly remediated casing. It is why for severely damaged casings, there may be a need for additional protection of the casing. Cirer et al. (2012) [44] have suggested that an epoxy reinforced fiberglass pipe inside the well behind which the cement will be pumped can be used to guide the milling tool after hardening and in this way it will protect the casing during the milling operation. Squeeze cementing is a rather expensive method and it bears the risk of further fracturing the casing [36].

An alternative to squeeze-cementing is pumping cement between a scab-liner/casing and a damaged casing to seal off the damaged section [38]. This option can be used in case of open-hole completion. The disadvantage of the scab cementing method is the reduced diameter of the hole.

5 Conclusion

In this report, we have described that damage to tubing is not infrequent in subsurface wells; fortunately, operators are equipped with a range of options to deal with loss of barrier elements in a well, from chemical methods to mechanical ones.

The most common failure mechanisms characteristic for unconventional oil and gas wells is corrosion, abrasion and mechanical failure during fracturing operations while CO_2 wells are mainly susceptible to corrosion. All the remediation strategies including straddle packer, expandable casing/liner (patching), swaging and squeeze cementing are applicable to failures in both CO_2 as well as unconventional oil and gas wells.

If the available remediation options described fail, there is still the option of a workover, meaning that a section of the well must be dismantled and recompleted. Alternatively, if a workover is not possible, a costlier scenario would be to side-track the well, that is, mill out the casing from above the problem zone, and drill a new borehole from there on. The old well is then 'killed' by plugging it below the new bifurcation point. The options described above to remediate perforated tubulars almost always involve remediation that leaves the well with a restricted diameter at the point of intervention. This is most extreme for methods where a new pipe section is introduced to bridge or replace the existing, damaged casing or liner. Expandable liners and carefully performed squeeze cementing mitigate this size restriction, which is important during the operational life of the well, but less of a concern after well abandonment. If damage to tubing is not causing a leak, but rather constriction due to some sort of scale build-up, the application of chemical remediation such as scale inhibitors will restore original pipe cross-section in the treated interval.

In many cases, a leakage pathway may develop between one of the casing strings and the next one, or the rock formation, without apparent damage to casing (or tubing) being detected. This can be due to debonding of the cement behind the casing, usually from the casing itself, due to the low bond strength between certain cements and steel. Even if a log is run and no damage is observed in the casing itself, it is very difficult to assess integrity of the cement outside of the casing with sonic methods, let alone detecting debonding across to steel barriers. It is possible that such occurrences in the future might be detected by active and passive seismic monitoring, from surface and/or neighboring wells (this is the theme of ongoing work at the NCCS research centre – www.nccs.no). However, early detection may not be possible, which means that pressure may have built up behind casing rendering squeeze cement operations more hazardous and delicate. The SECURe project aims at providing advances in such areas at the frontier between well integrity, geomechanics of the near well area, microseismics and surface geophysics. It is recognized that an integrated, multidisciplinary approach is needed to improve monitoring of leakage developing from well barrier breach events. This will be developed in work packages 2, 4 and 5 in SECURe.

5.1 PLANNED TESTS IN WP5

Investigating steel corrosion due to exposure to CO_2-brine is challenging in the laboratory, short of coming into possession of tubing extracted from the field. The alternative planned in WP5 is to concentrate on evaluating remediation techniques, given a breached tubing. The tests to be performed will thus investigate the mechanical integrity of squeeze cement "patches" of artificial holes drilled into a metal tube. Several sizes of holes will be drilled in a tube, then placing the tube into a hollow cylinder sandstone or shale outcrop plug. The assembly will in turn be placed into SINTEF's new, CT-transparent Well Integrity pressure cell (Figure 7), with cement being pressurized from the borehole (an additional tube will be placed in the borehole, preferably made of plastic or polyether ether ketone (PEEK) for easy removal after cement hardening). Cyclic pressure testing will then be performed, pressurizing and depressurizing oil or a flexible tube in the borehole. This may be performed under CT inspection or imaged post-mortem. The pressure conditions at which the new cement is breached will be recorded and the aspect of the obtained fractures measured.

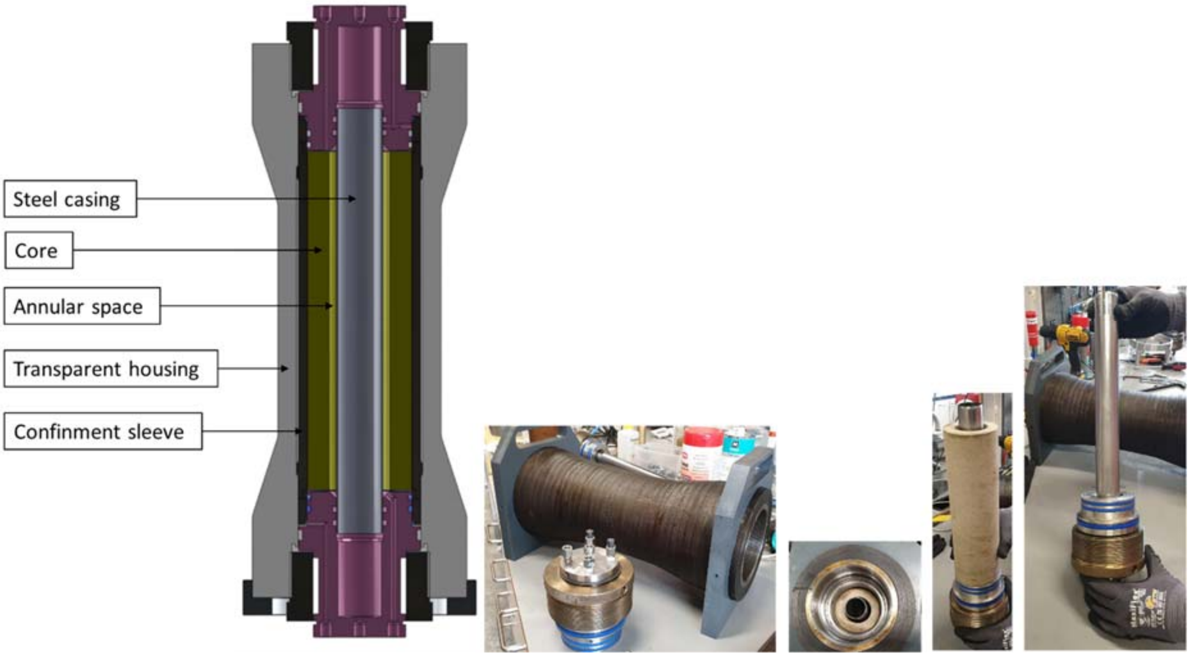

Figure 7 Schematic illustration and photographs of the new CT-transparent, 4" diameter Well Integrity pressure cell at SINTEF. This cell will be used to investigate cement squeeze remediation of perforated metal tubes simulating corroded tubing. The metal tube can be cemented to an outcrop, hollow cylinder rock core plug.

6 References

1. Vignes, B. and B.S. Aadnoy. *Well-integrity issues offshore Norway*. in *SPE/IADC Drilling Conference, Proceedings*. 2008.
2. King, G.E. and D.E. King, *Environmental Risk Arising From Well-Construction Failure--Differences Between Barrier and Well Failure, and Estimates of Failure Frequency Across Common Well Types, Locations, and Well Age.* SPE Production & Operations, 2013. **28**(04): p. 323-344.
3. Davies, R.J., et al., *Oil and gas wells and their integrity: Implications for shale and unconventional resource exploitation.* Marine and Petroleum Geology, 2014. **56**: p. 239-254.
4. Bellabarba, M., et al., *Ensuring zonal isolation beyond the life of the well.* Oilfield Review. **20**(1): p. 18-31.
5. Brufatto, C., et al., *From mud to cement—building gas wells.* Oilfield Review, 2003. **15**(3): p. 62-76.
6. Gawel, K., et al., *Study of Materials Retrieved from a Ketzin CO2 Monitoring Well.* Energy Procedia, 2017. **114**: p. 5799-5815.
7. Azwell, T., et al., *The Macondo blowout environmental report.* Deepwater Horizon Study Group Environmental Report, 2011.
8. Group, D.H.S., *Final report on the investigation of the Macondo well blowout.* Center for Catastrophic Risk Management, University of California at Berkeley, 2011.
9. Jelena Todorovic, C., P., *Report on remediation strategies for tubings and cement sheaths*, in *SECURe report, D5.1*. 2019.
10. D-010, N., *Well integrity in drilling and well operations*. 2013, Standards Norway: www.standard.no.
11. Torbjørn Vrålstad, T., J., Wollenweber, J., Abdollahi, J., Karas, D., & Buddensiek, M. , *Description of leakage scenarios for consideration in the work in SP3*, in *MiReCOL report, D8.1*. 2015.
12. Boait, F., et al., *Spatial and temporal evolution of injected CO2 at the Sleipner Field, North Sea.* Journal of Geophysical Research: Solid Earth, 2012. **117**(B3).
13. Venkatesh, E.S., *Erosion Damage in Oil and Gas Wells*, in *SPE Rocky Mountain Regional Meeting*. 1986, Society of Petroleum Engineers: Billings, Montana. p. 12.
14. Gawel, K., A. Lavrov, and M. Torsæter, *Shale gas well drilling, completion, production and abandonment operations (Report 5.1)*, m. H2020 project: M4ShaleGas - Measuring, mitigating, managing the environmental impact of shale gas (http://www.m4shalegas.eu/downloads/M4ShaleGas%20-%20D5.1%20-

%20Review%20of%20shale%20gas%20drilling,%20completion%20and%20production%20-%20Nov.%202015.pdf), Editor. 2015.
15. Kamila Gawel, A.L., Malin Torsæter, *Review of shale gas well drilling, completion, production and abandonment operations. .* M4ShaleGas Report, 2015.
16. Frosell, T.J., et al., *Erosion reduction in subterranean wells*. 2013, Google Patents.
17. Muessig, S., et al., *Ceramic Screens, an Innovative Milestone in Sand Control*. 2011, Society of Petroleum Engineers.
18. Kermani, M.B. and D. Harrop, *The Impact of Corrosion on Oil and Gas Industry.* SPE Production & Facilities, 1996. **11**(03): p. 186-190.
19. Eckert, R.B., *32 - Residual life predictions—extending service life*, in *Trends in Oil and Gas Corrosion Research and Technologies*, A.M. El-Sherik, Editor. 2017, Woodhead Publishing: Boston. p. 765-786.
20. Ilman, M.N. and Kusmono, *Analysis of internal corrosion in subsea oil pipeline.* Case Studies in Engineering Failure Analysis, 2014. **2**(1): p. 1-8.
21. Specification, A., *5CT (ISO 11960), 2011.* Specification for Casing and Tubing, Petroleum and natural gas industries—Steel pipes for use as casing or tubing for wells", 9th Edition, American Petroleum Institute.
22. Xiaolong Zhang, E.K., *Specifications and design criteria for innovative corrosion monitoring and (downhole) sensor systems, including sensitivity analysis*, in *CATO-2 Deliverable WP3.4-D16*. 2013.
23. K, N., *Corrosion and its mitigation in the oil and gas industry.* PM-Pipeliner Report, 2010.
24. Popoola, L.T., et al., *Corrosion problems during oil and gas production and its mitigation.* International Journal of Industrial Chemistry, 2013. **4**(1): p. 35.
25. Wei, L., et al., *Corrosion behaviors of steels under supercritical CO2 conditions.* Corrosion Reviews, 2015. **33**: p. 151-174.
26. Hossein Ashrafizadeh, A.M., Pierre Mertiny, *Erosive and Abrasive Wear Resistance of Polyurethane Liners.* Aspects of Polyurethanes, 2016.
27. Kelland, M.A., *Production Chemicals for the Oil and Gas Industry*. 2009: CRC Press.
28. Dariva, C.G. and A.F. Galio, *Developments in Corrosion Protection: Chapter 16. Corrosion Inhibitors - Principles, Mechanisms and Applications,*. Developments in Corrosion Protection. 2014: InTech.
29. Houghton, C.J. and R.V. Westermark, *North Sea Downhole Corrosion: Identifying the Problem; Implementing the Solutions.* Journal of Petroleum Technology, 1983. **35**(01): p. 239-246.
30. Groves, S., et al., *Impact Testing of Downhole Tubing Internal Coatings*, in *CORROSION 2001*. 2001, NACE International: Houston, Texas. p. 8.
31. WV, B., *Handbook of cathodic corrosion protection. 3rd edition. New York: McGraw Hill.* 1997.
32. Curry, E.L., *Well Casing Corrosion and Cathodic Protection*, in *SPE Rocky Mountain Regional Meeting*. 1970, Society of Petroleum Engineers: Casper, Wyoming. p. 8.
33. Patel S, W.S., Jonasson K. , *Review of well integrity in Western Australia.* Petroleum in Western Australia, 2015: p. 24–31.
34. Adams, N.J., et al., *A Causation Investigation for Observed Casing Failures Occurring During Fracturing Operations*, in *SPE Hydraulic Fracturing Technology Conference and Exhibition*. 2017, Society of Petroleum Engineers: The Woodlands, Texas, USA. p. 24.
35. Erik B. Nelson, D.G., *Well Cementing.* 2006.
36. Todorovic J, V.T., Buddensiek M, Wollenweber J *Overview of available well leakage remediation technologies and methods in oil and gas industry. MiReCOL report, D8.2.* 2016.
37. Abdollahi J, C.I., Wollenweber *Assessment of Oil & Gas Remediation Technologies for CO2 Wells. MiReCOL report, D8.3.* 2016.
38. Macenau JC, H.D., De Lary L, Jensen NB, Reveillere *Mitigation and remediation technologies and practices in case of undesired migration of CO2 from a geological storage unit - Current status.* Internationa Journal of Greenhouse Gas Control, 2014. **22**: p. 272-290.
39. Chustz, M., Mason, D., Schober, J., De Lucia, F., Butterfield, C., Didyk, V., , *Expandable liner installation avoids sidetracking following production casing failure in the Gulf of Mexico.* In: Paper SPE/IADC 91923 Presented at the SPE/IADC Drilling Conference, Amsterdam, Netherlands, 23-25 February, 2005.
40. Daigle, C., Campo, D.B., Naquin, C.J., Cardenas, R., Ring, L.M., York, P.L., *Expandable Tubulars: field examples of application in well construction and remediation.* In: Paper SPE 62958 Annual Technical Conference and Exhibition, Dallas, TA, USA, 1-4 October., 2000.
41. A. Storaune, W.J.W., *Versatile expandables technology for casing repair.* Paper SPE/IADC 92330 Presented at the SPE/IADC Drilling Conference, Amsterdam, Netherlands, 23-25 February 2005.
42. D.G. Durst, N.R., *Expandable tubulars facilitate improved well stimulation and well production.* SPE 121147 Western Regional Meeting, Society of Petroleum Engineers, San Jose, CA 2009.
43. *https://www.weatherford.com/en/documents/brochure/products-and-services/intervention-and-abandonment/homco-casing-patch/*.
44. Cirer, D., Arze, E., Moggia, J.M., Soto, H.R., *Practical cementing technique to repair severe casing damage.* Paper SPE/ICoTA 154241 Presented at the Coiled Tubing and Well Intervention Conference and Exhibition, The Woodlands, TX, USA, 27-28 March., 2012.