Chair of Drilling and Completion Engineering

Master's Thesis

Challenges in the conversion of existing oil/gas producer wells to injector/monitoring wells in Carbon Capture and Storage (CCS) projects – a practical application

Ilia Filippov

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MONTANUNIVERSITÄT LEOBEN
www.unileoben.ac.at

AFFIDAVIT

I declare on oath that I wrote this thesis independently, did not use other than the specified sources and aids, and did not otherwise use any unauthorized aids.

I declare that I have read, understood, and complied with the guidelines of the senate of the Montanuniversität Leoben for "Good Scientific Practice".

Furthermore, I declare that the electronic and printed version of the submitted thesis are identical, both, formally and with regard to content.

Date 13.09.2021

Signature Author
Ilia Filippov

I want to dedicate this Thesis to my family, my girlfriend and all other important people we were on track together these tough times.

Affidavit

I declare in lieu of oath that I wrote this thesis and performed the associated research myself using only literature cited in this volume.

Eidesstattliche Erklärung

Ich erkläre an Eides statt, dass ich diese Arbeit selbständig verfasst, andere als die angegebenen Quellen und Hilfsmittel nicht benutzt und mich auch sonst keiner unerlaubten Hilfsmittel bedient habe.

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Abstract

Many E&P Operators are today assessing the viability of converting existing assets designed for production of hydrocarbons into assets designed for injection and permanent monitoring of CO2. This tendency is mainly driven by laws and regulations aiming at reducing CO2 emissions, and permanent storage in depleted reservoirs is seen as a great enabler to achieve just that. The number of CCS projects is growing because of the prospect to reduce the carbon footprint of oil and gas operations by converting existing production wells to CO2 storage wells.

The use of existing wells has certain advantages. On the one hand, there is no need to drill new wells, thereby reducing potential costs, which will be particularly significant when drilling offshore. On the other hand, there is a safety aspect: the fewer wells that penetrate the caprock, the better the integrity of the storage is.

The main objective of this work is to create a workflow of converting existing oil/gas production wells into injector/monitoring wells in CCS projects and adapt it to one or several company's existing wells in the Dutch sector of the North Sea.

Zusammenfassung

Viele E&P-Betreiber prüfen derzeit die Möglichkeit, bestehende Anlagen, die für die Förderung von Kohlenwasserstoffen ausgelegt sind, in Anlagen umzuwandeln, die für die Injektion und permanente Überwachung von CO2 ausgelegt sind. Diese Tendenz wird vor allem durch Gesetze und Vorschriften zur Verringerung der CO2-Emissionen vorangetrieben; die dauerhafte Speicherung in erschöpften Lagerstätten bietet dabei eine große Chance, dieses Ziel zu erreichen. Die Zahl der CCS-Projekte nimmt zu, da die Aussicht besteht, den CO2-Fußabdruck der Öl- und Gasaktivitäten durch die Umwandlung bestehender Förderbohrungen in CO2-Speicherbohrungen zu verringern.

Die Nutzung bestehender Bohrlöcher hat einige Vorteile. Zum einen müssen keine neuen Bohrungen durchgeführt werden, was die potenziellen Kosten senkt, was insbesondere bei Offshore-Bohrungen von Bedeutung ist. Zum anderen gibt es einen Sicherheitsaspekt: Je weniger Bohrungen in das Deckgestein eindringen, desto besser ist die Integrität des Speichers.

Das Hauptziel dieser Arbeit besteht darin, einen Arbeitsablauf für die Umwandlung bestehender Öl-/Gasförderbohrungen in Injektions-/Monitoringbohrungen im Rahmen von CCS-Projekten zu entwickeln, und diesen an eine oder mehrere bestehende Bohrungen des Unternehmens im niederländischen Teil der Nordsee anzupassen.

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Chapter 1 Introduction

1.1 Thesis Proposal

Emissions of carbon dioxide (CO2) worldwide are increasing every year. It is essential to reduce the CO_2 gas as it is a greenhouse gas that exacerbates climate change. CCS projects are one of the most promising areas for reducing carbon dioxide emissions in the industrial sector, which makes them of interest to oil and gas companies. Debates are going on about eliminating and preventing risks to enable such projects. A number of studies suggest a shift from no-leaks to a concept that relies on timely and thorough well monitoring and strives for no damage. This requires a focus on the issue of well integrity for early risk detection and prevention. In contrast, other studies have embraced a complete risk aversion position (driven by the ad-perpetuity nature of the storage) by stating that brand-new reservoir penetrations shall be drilled. Yet, the economic viability of many CCS projects is connected to low expenditure on wells, benefiting from full reuse or partial conversion of existing assets, and low cost on monitoring solutions.

Company Wintershall Dea is evaluating how possible it is to re-use available production or injection wells for Carbon Capture and Storage projects, thereby decreasing emissions footprint, avoiding drilling new wells, maintaining caprock integrity, and realizing CAPEX savings.

The main challenges within the realization of CCS projects are related to well integrity. The first difficulty is understanding the level of degradation of the barriers through the well lifetime, as production wells need to be used for CO2 storage. The second one is to know how well integrity will be affected during the injection phase, as CO2 solutions, whether dissolved in the brine, gaseous, or a critical state, can be hazardous to the well barriers. Last but not least is long-term monitoring in a permanent storage situation. A standardized workflow needs to be created to decrease the uncertainties connected with the well life.

The process of converting a former production well into a CCS well is a complex campaign that includes workover operations to prepare the well for injection and storage of CO2. Degraded and unsuitable well barriers need to be replaced or restored so the well barrier system can assure infinite integrity under constant monitoring.

A solution that addresses the issues mentioned above arising from converting existing oil/gas production wells into injector/monitoring wells for CCS would be a workflow that evaluates each point in greater detail, considering in a structured manner all the factors that influence well integrity.

The core objective of this Master Thesis is to elaborate such a workflow and adapt it to some company's wells in the Dutch sector of the North Sea.

To achieve this goal, the following tasks are defined:

- Research existing industry guidelines and standards in Europe, dedicated to qualification of well barrier envelopes for CO2, describe additional elements to conventional well integrity criteria that are associated with CO2 injection and storage;

- Research and list lessons learned from 50 years of CO_2 injection in EOR wells in terms of well integrity that apply to CCS;
- Research potential weak points in the primary and secondary well barrier envelope (in terms of degradation process through the life cycle of the well);
- Elaborate on degrading processes and the most commonly adopted mitigations against those;
- Describe the main measurements that need to be performed before, during, and after CO_2 injection;
- Practical implementation of the findings described above.

As a practical implementation, and using actual well data, the approach is to propose:

- Well schematics for the injection phase for the well candidate;
- Project parameters;
- Mitigations against degradation mechanisms for the well;
- Assessment of suitability to well conversion to CO_2 injector;
- Monitoring and measurements for each phase.

1.2 CO2 Physics and Associated Challenges

Before moving to CCS projects, it is important to understand CO_2 physical properties and phase behavior.

Carbon dioxide consists of two oxygen atoms that are covalently bonded to a single carbon atom. The molecular weight of the CO_2 is 44 g/mol, meaning that it is heavier than air with around 29 g/mol; That is why it can accumulate in the places near wellbore (lower lands) and be a hazard for people if the leakage is present.

Figure 1 represents the CO_2 phase behavior diagram. CO_2 can be in solid, liquid, gaseous or supercritical state depending on the temperature and pressure. The phase lines represent the transition phase when two phases are present at the same time. In the triple point, all three phases coexist in thermodynamic equilibrium.

CO_2 can be injected into any of these states. The CCS project aims to inject CO_2 in a liquid or supercritical state.

There are some challenges associated with CO_2 physical properties and phase behavior:

- CO_2, due to its weakly bi-polar nature, is highly soluble in water, which leads to carbonic acid formation, which in turn increases the probability of chemical degradation of the well barrier elements (section 1.2.1).
- During injections of liquid CO_2, phase behavior to gas can occur in the formation area because bottomhole injection pressure will be higher than reservoir pressure. This pressure drop will lead to the turning of liquid into a gas. If it is accompanied by a lower temperature than hydrate formation temperature, hydrates can be formed in a near wellbore zone area.

If it is the case and the hydrates will form, it will lead to a decrease in permeability of the reservoir (pores will be blocked with hydrates), and the efficiency of the injection will suffer (T. R. IEAGHG 2018).

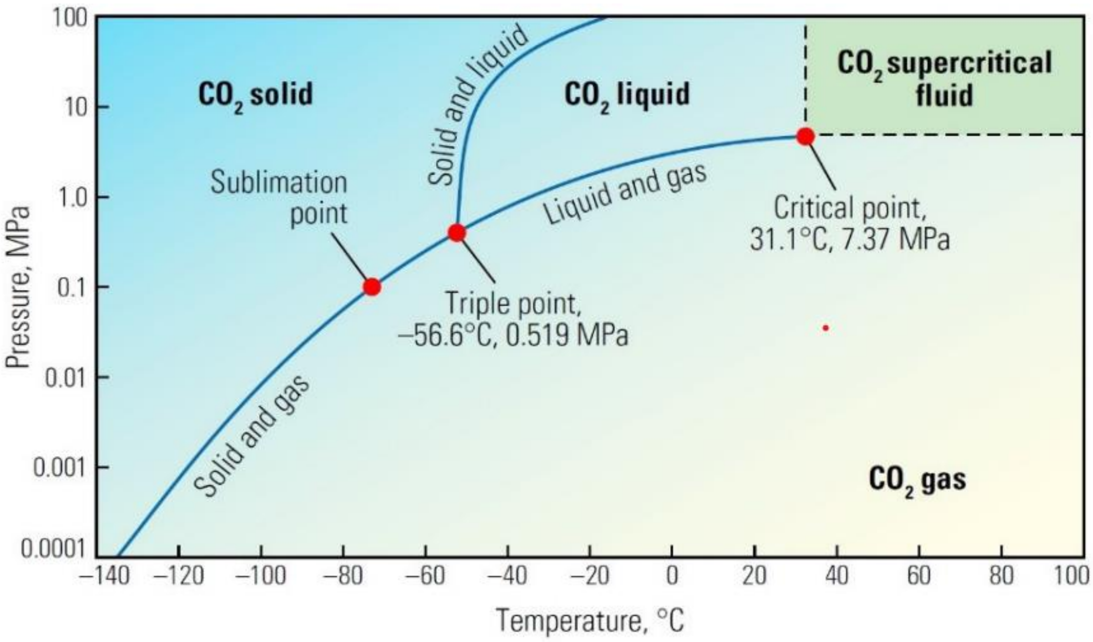


Figure 1: CO2 phase diagram (Oilfield review 2015)

– CO2 can transform into a supercritical state if such thermobaric conditions are met. Since supercritical CO2 increases the sweep efficiency of hydrocarbons (it is usually used in EOR methods to increase oil recovery) (Agarwal 2018), it can trigger the flowing of residual hydrocarbons in a reservoir and become a part of the mixture with CO2. If CO2 injection is performed in cycles while the well is shut-in between the shipping of CO2, the influx can go into the wellbore, causing a kick situation.

1.3 CCS Project Goals and Phases

As said before, CCS projects aim to capture and store CO2 to reduce its emissions. There are several methods of CO_2 storage: via EOR methods when it is injected into the reservoir to enhance oil recovery; in saline aquifers; in the depleted reservoirs; in coal beds; CO_2 reacting with carbonate rocks.

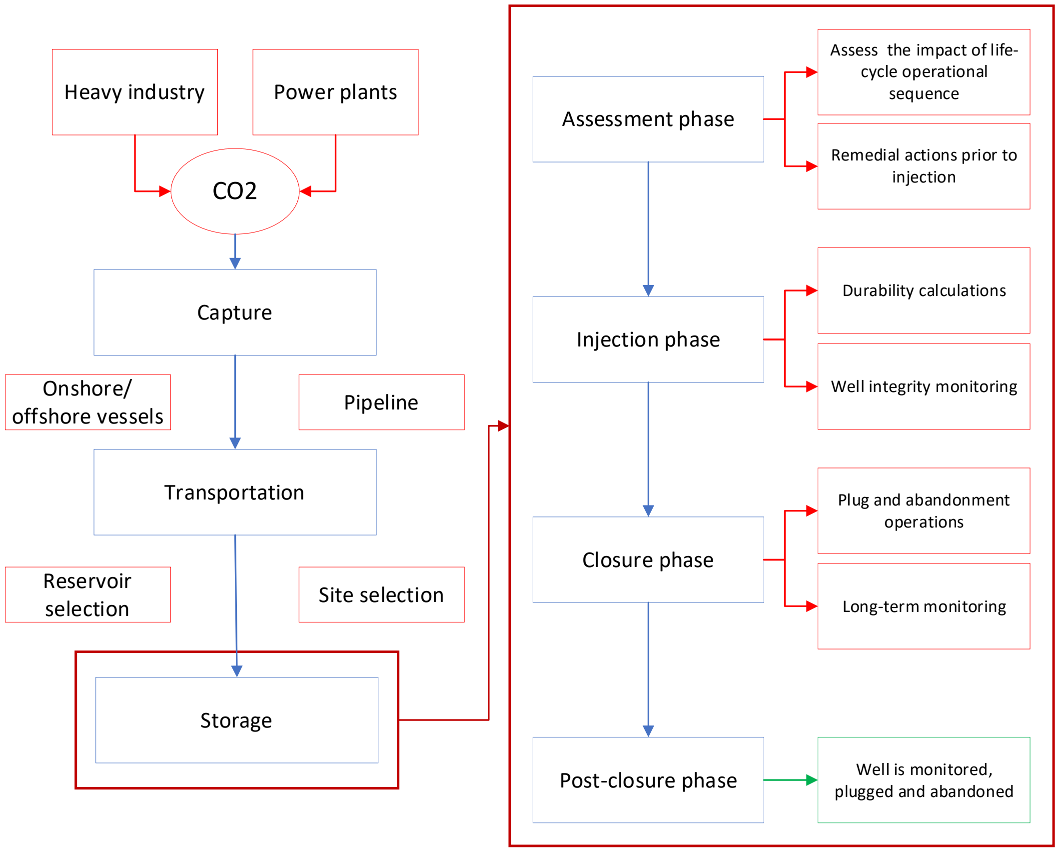


Figure 2: Simplified roadmap of a CCS project

Figure 2 represents a simplified overview of a CCS project's phases with a detailed explanation of storage. Primary phases of such a project include:

- Capture;

CO2 is captured from heavy industry, power plants, and other emitters; Many adopted techniques are observed in the literature to capture and purify CO2 for future injection (Volkart, Christian and Boulet 2013).

- Transportation;

After the CO2 is captured, it needs to be transported to the place of storage. There are different means of transportation of the captured CO2. Should a network of pipelines be available, it can be transported via pipelines. In offshore cases where no pipelines are available, or emitter locations are decentralized, special ships are used for transportation.

- Storage of the captured and transported CO2;

Storage in itself is an extensive campaign. Before even transporting, the site suitability needs to be assured.

A CO2 storage phase can be divided into the following stages:

- Assessment;

This stage starts with geomechanical and reservoir assessment to ensure reservoir integrity and capacity available for the CO2. After field and reservoir are assessed, particular wells need to be evaluated, and their suitability must be assured.

Any particular well used for injection needs to be evaluated regarding well integrity and its operational life. Should issues be detected that prohibit or impact the use of the well or even jeopardize reservoir integrity, the well needs to be remediated to suit the purpose.

- Injection phase;

During the injection phase, CO_2 is injected into the target reservoir according to the planned parameters. Durability calculations need to be done for the main components affected by the injected fluid.

The injection phase itself is hazardous due to the flowing conditions in the well. The dynamic state of the fluid in the wellbore increases the probability of chemical degradation. For example, in steel corrosion, the protective layer on the metal surface ($FeCO_3$) has fewer chances to form in dynamic conditions than in static, leading to a higher corrosion rate. Also, mechanical failures can be triggered as during flowing conditions, higher loads are applied.

Therefore, well integrity needs to be monitored precisely during the injection phase. Monitoring considerations are explained in section 1.4.2.

- Closure and post-abandonment phases;

After the injection is finished, the well is suspended and monitored for a period of time (usually 20 to 40 years) depending on the CO_2 plume behavior in the reservoir.

After the well is plug and abandonment (P&A), it needs to be checked, and means of long-term monitoring need to be applied (section 1.4.3), meaning that well integrity needs to be ensured as the next step is as handover to the government on which territory the company is operating

Closure and post-closure phases are outside the scope of this thesis; the main aspects are leak-proof P&A and long-term monitoring.

Chapter 2 Literature review

2.1. Industry guidelines and standards for CO2 injection

2.1.1. International and national well integrity standards

This section presents the analysis of primary standards that correspond to well integrity to analyze if there are any additional requirements for CO2 injector wells in CCS projects compared to ordinary injector wells and investigate if there are any special standards for the CCS projects.

The first step is to observe the main principles of the primary considerations described in common standards used in well integrity applications.

They are:

- NORSOK standard D -010:2021 – Well integrity in drilling and well operations;
- ISO standard 16530-1:2017 – Petroleum and natural gas industries – Well integrity, Part 1: Life cycle governance (ISO/TC 67/SC 4 Drilling and production equipment, 2017);
- NOGEPA industry standard no. 46:2018 – Well integrity management;
- Oil and Gas UK:2016 – Well Life Cycle Integrity Guidelines;
- Dutch State Supervision of Mines (SSM/SodM):2019 – The integrity of offshore wells;

These documents are commonly adopted well integrity standards in many legislations and areas globally. Special attention is paid to the Dutch State Supervision of Mines because of the area of interest.

Currently, there are no specific requirements pertaining to CO2 within the standards observed in the list above. CO2 injector wells are treated as ordinary injector wells, with the specification of the material properties.

Analysing the above standards, the most relevant sections are summarized in the following bullet points.

- General principles;

The overarching principle mentioned throughout all standards is the two well barrier concept of a primary and secondary barrier for wells penetrating hydrocarbon-bearing formations and/or formations with the potential flow to the surface.

The CO2 injector design must follow the two-barrier principle as the injected fluid can flow to the surface.

Two well barriers decrease the risk of uncontrolled flow because in case the primary barrier fails, the secondary barrier will contain the flow until the primary is reinstated.

- Material selection;

Materials of the well barrier elements that are a part of the well barrier system need to withstand all chemical and mechanical loads they are going to be exposed to.

While choosing the materials, modeling of loads expected during operations needs to be conducted. This task is usually done with the help of specialist software.

- Structural integrity;

The key components that provide structural integrity of the well during its service life need to be evaluated concerning chemical and mechanical loads, according to the failure and degradation mechanisms present during operations.

- Structural integrity monitoring;

Suitable systems for structural well integrity monitoring need to be established by the well operator. The main aim is to monitor failure and degradation damage mechanisms during the operations.

- CO2 injection considerations;

CO2 injection wells are categorized as gas wells from a well integrity perspective, assuming that well integrity envelope design will follow standard gas well design guidelines, emphasizing material selection, chemical, and mechanical loading scenarios.

2.1.2. Specific well integrity standards for CO2 injection

Besides the standards described above, the two following standards specify special requirements for well design in CO2 capture and storage and can therefore be used for well engineering in CCS projects:

- ISO standard 27914:2017 – Carbon dioxide capture, transportation, and geological storage – Geological storage
- Environmental Protection Agency US – Underground Injection Control (UIC): Class VI – Wells used for Geologic Sequestration of CO2.

a) ISO 27914:2017

This ISO standard was created aiming at CCS project standardization.

The well design principle of this ISO standard can be described as following: "Design of injection wells to deliver CO2 to the storage unit shall evaluate injectivity, permeability, and porosity of storage unit to avoid excessive subsurface pressure interference and to ensure acceptance of anticipated volume of CO2."

According to the citation above – the main aim is to design a well that will withstand the chemical and mechanical loading, assuming that already existing standard engineering considerations applicable for regular oil and gas wells are followed.

According to the standard, the main aspects of a well integrity envelope are:

– Conductor casing

The conductor should be secured and may be cemented to maintain integrity around the following casing strings;

- Surface casing

The surface casing needs to be cemented to the surface and ensure the isolation of protected groundwater sources from CO2. It shall be able to withstand maximum formation and operating pressures before the next casing interval;

- Intermediate and production casing/liner

Onshore and offshore wells shall be cased with the recommended grade, material, weight, and size of the casing to achieve the stated objectives of the well for safe injection. Liner and production casing are recommended to consist of a corrosion-resistant alloy (CRA) material in the wetting areas to decrease the corrosion in contact areas;

- Tubing

The tubing design needs to withstand expected loads, and the corrosion-resistant alloy is required as a material of choice. For the selection of tubing diameter, the injection rate should be evaluated at the planning phase. The maximum injection pressures will define the grade and weight of the tubing;

- Cement

The cement should be designed to support the casing structurally and resist all expected loads.

Another essential topic mentioned in the standard is corrosion, which needs to be monitored, evaluated, and mitigated, and appropriate material selection so the well will withstand the acidic environment and applied loads.

According to the ISO, to monitor steel corrosion state, it is necessary to:

– Perform chemical analysis of injected fluids for indicators of trace metals;
– Place corrosion coupons in the injection stream;
– Perform ultrasonic wall thickness testing;
– Make cathodic protection against galvanic corrosion.

b) Environmental Protection Agency US: UIC (Class VI well concept)

According to the broad experience of CO2 EOR injection and CCS projects in the USA, this particular class of wells was created. As well as the ISO standard observed above, it covers special requirements for CO2 injection wells.

The main criteria of Class VI wells can be described as:

- Casing and cement or other materials must be robust enough to endure all the chemical and mechanical loads. Material selection must be approved by international or national material selection standards (API, NORSOK, ISO);
- Surface casing need to be cemented to the surface;
- There must be at least one casing string till the injection zone depth. To add, it must be cemented with approved good bonding;
- Cement and its additives must be compatible with the CO2 stream;
- The packer needs to be set at a predetermined depth opposite to an appropriate cemented interval (the cement quality should be proven by cement bond log).

The monitoring requirements are:

- Ensure compliance with approved testing and monitoring plan;

- Use continuous recording devices to monitor pressure, rate, and volume of injected CO2;
- Corrosion monitoring;
- Use tracers or surveys to determine CO2 fluid movements.

2.1.3. Additional elements to conventional well integrity criteria associated with CO2 injection

Though US EPA and ISO standards proclaim special considerations for the well design and monitoring, the main standards used in the North Sea area, especially the Dutch sector (according to the Dutch State Supervisors of Mine), do not require any special design criteria for a CO2 injection well.

The main criterion is that the materials will withstand mechanical and chemical loads during the injection of CO2.

To sum up, the primary considerations for CO2 injection wells are:

- Material selection;
- Material corrosion and degradation control;
- Continuous monitoring for injection parameters and annulus pressure.

2.2 Key learnings/case studies

This section is devoted to analysing the international experience with CO2 injection as part of CCS or CO2 EOR campaigns. CO2 EOR aims to increase oil recovery by mixing oil with injected CO2: decreased mixture density leads to less complicated oil extraction.

2.2.1 Existing CO2 EOR and CCS projects

The historical base of CO2 injection projects for EOR purposes is broader than the CCS projects database, making it a viable source of information concerning injection wells design and common issues and failures of well barriers in a CO2-rich environment.

The main parameters of the projects are represented in Table 1 and Table 2 (NETL's CCS n.d.), EOR CO2, and CCS projects, respectively. These tables aim to illustrate the variety of projects from different countries with different capture methods observed during case studies analysis.

Country	Name	Type	Onshore /offshore	Duration of injection, [years]	Average rate of injection, [mil. tons/year]	Reservoir temperature, ^{0}C	Depth of injection, m	Cap Rock – Reservoir
USA	Air Products and Chemicals Inc.	CO2 – EOR	Onshore	1 - 9	0.1 – 1	70 – 100	1000 – 2000	Shale – Sandstone
USA	Jilin Oil Field EOR	CO2 – EOR	Onshore	>9	0.01 – 0.1	70 – 100	>2000	Shale – Siltstone
Canada	Judy Creek EOR	CO2 – EOR	Onshore	1 - 9	0.01 – 0.1	70 – 100	>2000	N/A – Carbonate
USA	MGSC – Loudon Field	CO2 – EOR	Onshore	<1	<0.01	<70	<600	N/A – Sandstone
USA	MGSC – Mumford Hills Field	CO2 – EOR	Onshore	1 – 9	<0.01	<70	<600	N/A – Sandstone
USA	MGSC – Sugar Creek Field	CO2 – EOR	Onshore	1 – 9	<0.01	<70	<600	N/A – Sandstone
Nederland	K12-B CO2 Injection Project	CO2 – EGR	Offshore	>9	N/A	>100	>2000	Evaporite – Sandstone
USA	PCOR – Bell Creek Project	CO2 – EOR	Onshore	1 – 9	>1	N/A	1000 – 2000	Shale – Sandstone
USA	PCOR – Northwest McGregor EOR Huff n' Puff	CO2 – EOR	Onshore	<1	0.1 – 1	>100	>2000	N/A – Carbonate
USA	PCOR Validation Phase – Zama Field Test – Pool F	CO2 – EOR	Onshore	1 – 9	0.01 – 0.1	70 – 100	N/A	Anhydrite – Carbonate

	Pembina Cardium CO2 EOR Pilot	CO2 – EOR	Onshore	1 – 9	0.01 – 0.1	70 – 100	1000 – 2000	Shale – Sandstone
Canada	Rangely-Webber EOR	CO2 – EOR	Onshore	>9	>1	70 – 100	1000 – 2000	Shale – Sandstone
USA	Salt Creek, Monell, Sussex Unit EOR	CO2 – EOR	Onshore	>9	>1	N/A	N/A	N/A – Sandstone
UK	SECARB – Cranfield Project	CO2 – EOR	Onshore	>9	>1	>100	>2000	Mudstone – Sandstone
USA	SWP – Farnsworth Unit Ochiltree Project	CO2 – EOR	Onshore	>9	0.1 – 1	N/A	>2000	Shale – Sandstone
USA	SWP – SACROC CO2 Injection Project	CO2 – EOR	Onshore	>9	>1	>100	1000 – 2000	Shale – Carbonate
Canada	Weyburn-Midale Project, Midale	CO2 – EOR	Onshore	>9	0.1 – 1	N/A	1000 – 2000	Evaporite – Carbonate
Canada	Weyburn-Midale Project, Weyburn	CO2 – EOR	Onshore	>9	>1	N/A	1000 – 2000	Evaporite - Carbonate
Brazil	Petrobras Lula Oil Field	CO2 - EOR	Offshore	1 – 9	N/A	<70	>2000 (+1500)	Salt – Carbonate

Table 1: CO2 EOR projects

Country	Name	Type	Onshore /offshore	Duration of injection, [years]	Average rate of injection, [mil. tons/year]	Reservoir temperature, ^{0}C	Depth of injection, m	Cap Rock – Reservoir
USA	Allison Unit CO2 – ECBM Pilot	CO2 – ECBM	Onshore	1 – 9	0.01 – 0.1	<70	600 – 1000	N/A – Coal
USA	American Electric Power – Mountaineer – 1	CCS in saline aquifer	Onshore	1 – 9	<0.01	N/A	>2000	N/A – Sandstone
USA	American Electric Power – Mountaineer – 2	CCS in saline aquifer	Onshore	1 – 9	0.01 – 0.1	N/A	>2000	N/A – Carbonate
Canada	Aquistore Project	CCS in saline aquifer	Onshore	1 – 9	0.01 – 0.1	>100	>2000	Shale – Sandstone
Africa	ARI Eastern Shale CO2 injection test	CCS in shale	Onshore	<1	0.01 – 0.1	N/A	<600	Shale – Shale
USA	Big Sky Validation Phase – Basalt Injection	CCS by reacting with rock	Onshore	<1	0.01 – 0.1	<70	600 – 1000	N/A – Basalt
Iceland	CarbFix	CCS by reacting with rock	Onshore	1 – 9	0.01 – 0.1	>100	600 – 1000	N/A – Basalt

Germany	CO2SINK Project (Ketzin)	CCS in saline aquifer	Onshore	1 – 9	0.01 – 0.1	<70	600 – 1000	Shale – Sandstone
USA	Frio Brine Pilot	CCS in saline aquifer	Onshore	<1	0.01 – 0.1	<70	1000 – 2000	Shale – Sandstone
USA	Illinois Industrial CCS Project	CCS in saline aquifer	Onshore	1 – 9	0.1 - 1	N/A	>2000	Shale – Sandstone
Algeria	In Salah Gas Storage Project	CCS in saline aquifer	Onshore	1 – 9	0.1 – 1	N/A	1000 – 2000	Siltstone – Sandstone
Japan	JCOP Yubari/Ishikari ECBM Project	CCS in saline aquifer	Onshore	1 – 9	<0.01	N/A	600 – 1000	N/A – Coal
USA	MGSC – Illinois Basin Decatur Project	CCS in saline aquifer	Onshore	1 – 9	0.1 – 1	N/A	>2000	Shale – Sandstone
USA	MGSC – Tanquary Site	CCS in coal seam	Onshore	<1	<0.01	<70	<600	N/A- Coal
USA	MRCSP – Appalachian Basin Test	CCS in saline aquifer	Onshore	<1	N/A	N/A	>2000	Shale – Sandstone
USA	MRCSP – Cincinnati Arch Geologic Test	CCS in saline aquifer	Onshore	<1	0.01 – 0.1	<70	1000 – 2000	Shale – Sandstone
Japan	Nagaoka Storage Project	CCS in saline aquifer	Onshore	1 – 9	<0.01	N/A	1000 – 2000	N/A – Sandstone

Australia	Otway Basin Project – CO2CRC	CCS in depleted field	Onshore	1 – 9	0.01 – 0.1	N/A	>2000	Mudstone – Sandstone
Australia	Otway Basin Project Stage 2 – CO2CRC	CCS in saline aquifer	Onshore	<1	0.01 – 0.1	N/A	1000 – 2000	Shale – Sandstone
USA	PCOR – Lignite Test	CCS in coal seam	Onshore	<1	<0.01	N/A	<600	N/A – Coal
Poland	RECOPOL Project	CO2 – ECBM	Onshore	<1	<0.01	N/A	1000 – 2000	Shale – Coal
USA	SECARB – Citronelle Project	CCS in saline aquifer	Onshore	1 – 9	0.01 – 0.1	N/A	>2000	Shale – Sandstone
USA	SECARB – Black Warrior Basin Project	CCS in coal seam	Onshore	<1	<0.01	N/A	<600	N/A – Coal
Canada	Shell Quest Integrated CCS	CCS in saline aquifer	Onshore	1 – 9	>1	<70	>2000	Shale, Salt – Sandstone
Norway	Sleipner Project	CCS in saline aquifer	Offshore	>9	0.1 – 1	<70	1000 – 2000 (<150)	Mudstone – Sandstone
Norway	Snohvit Field LNG and CO2 storage – Sto	CCS in depleted field	Offshore	1 – 9	0.1 – 1	70 – 100	>2000 (150 – 1500)	Shale – Sandstone
Norway	Snohvit Field LNG and CO2	CCS in saline aquifer	Offshore	1 – 9	0.1 – 1	70 – 100	>2000 (150 – 1500)	Shale – Sandstone

	storage – Tubean							
USA	SWP – Pump Canyon CO2 – ECBM Sequestration	CO2 - ECBM	Onshore	1 – 9	0.01 – 0.1	N/A	600 – 1000	Shale – Coal
France	Total Lacq Project	CCS in depleted field	Onshore	1 – 9	0.01 – 0.1	>100	>2000	Breccia – Carbonate
China	Yanchang Integrated CCS	CO2 – EOR	Onshore	1 – 9	0.01 – 0.1	<70	1000 – 2000	Mudstone - Sandstone

Table 2: CCS projects

2.2.2 Lessons learned from existing CO2 EOR and CCS projects

The main focus of this research is well integrity, and because of that, the main lessons learned from the CO2 – EOR and CCS experience are aimed at the well integrity during the injection phase.

2.2.2.1 Main issues during CO2 injection

A detailed explanation of each degradation and failure mechanism with commonly adopted mitigations is described in sections 1.2.1 and 1.2.2.

Factors that affect the well integrity during the initial well construction phase or production life cycle are not observed here.

The thesis describes converting an existing producing or suspended well into an injection well for CO2 storage. In any case, the well needs workover to be suitable for operations. Before the workover, well integrity is evaluated, and during workover, all weak points will be eliminated to ensure that the injection well can withstand the injection and storage phases. Therefore, factors that correspond to construction and production phases, like bad filter cake removal of wrong cement placement that could have affected well integrity, will be eliminated during workover.

According to the case studies, the list below represents the main issues during CO2 injection in both CCS and CO2 EOR projects.

- Exceeding the caprock fracturing pressure (caprock failure);
- Hydrate formation (near-wellbore zone plugging);
- Annulus pressure accumulation;
- Mechanical degradation of the components due to pressure and temperature cycling.

Below, each issue is observed in greater detail, along with possible mitigations.

- Exceeding the caprock fracturing pressure;

Both CCS and EOR operations are designed to inject the CO2 at downhole pressures not to exceed the caprock fracturing pressure. If it happens, it may cause the formation of new fractures and propagation of old ones, compromising the integrity of the caprock, making it a possible leakage path (Bourne, Crouch and Smith 2014), (Fu, et al. 2017). According to the US Environmental Protection Agency, the downhole pressure of the injected CO2 must not exceed the pressure that creates or propagates fractures in the caprock (40 CFR n.d.).

According to the studies, at least two operations were affected by the concern about exceeding the fracture propagation pressure of the caprock. In 2011, injection in the Tubaen formation in the Snohvit field was stopped as the pressure approached fracture pressure of the formation; later the injection into the Sto formation began (Kaufmann n.d.). In the same year, injection operations at InSalah filed were suspended because of possible vertical leakage due to caprock failure (Ringrose, et al. 2013).

A severe hazard is fracture propagation into the caprock as this can decrease the initial strength of the caprock and will lead to more fractures and to further fracture propagation, until eventually a new leakage path for CO2 is created to migrate to another reservoir, to another permeable, but unsuitable for CO2 storage layer, and as a worst-case scenario to the ground waters. This risk can be mitigated by diligent geomechanical assessment. Worst-case scenarios need to be assumed when modeling.

It is essential to understand the current state of the caprock, for example if there are any pre-existing fractures that can be reactivated or if new fractures can be formed. It must be considered that reactivation pressure is lower than propagation pressure, so bottom-hole pressure must be below fracture conditions during the injection.

Thermal control of the injection is also a significant factor to consider. The more the temperature difference between the reservoir and the injected fluid, the lower is the bottom hole pressure that the caprock can withstand (thermal fracturing effect).

- Hydrate formation;

Gas hydrates can be described as ice-like crystalline compounds formed by trapping gas molecules like CH4, CO2, and H2S in so-called cages created by hydrogen-bonded water molecules (Bavoh, et al. 2019). These structures are dangerous because they form over a short period of time (on the order of minutes) at high pressure and low temperature and can cause damage to the system where they are formed (Sloan 2003).

Hydrate formation due to CO2 injection in the depleted reservoirs mainly appears in the near-wellbore zone. This is a generic problem of liquid CO2 injection. The resulting pressure drop from the injection will initiate phase transition to a gaseous phase, leading to pressure drop to the values where hydrates are formed. These hydrates will clog the pores and, as a result, decrease permeability.

As a result, the injectivity is compromised, which leads to pressure increase in the well system, and it comes to an "out of plan" regime.

The problem of hydrate formation was observed in several fields, making it one of the main operational hazards. Cases in point are Sugar Creek field CO2-EOR test site (USA), Quest CCS (Canada) (IEAGHG 2019), ROAD (Rotterdam Opslag an Afvang Demostratieproject, the Netherlands) (Wildenborg, et al. 2018). Apart from real case studies, hydrate formation was demonstrated in simulations (Ding and Liu 2014), (Krogh, Nilsen and Henningsen 2012) and laboratory studies (Gauteplass, et al. 2018).

The main mitigation is to control the phase of the injected CO2. The injection process is modelled with special software that helps understand the injected fluid's phase behavior. With the help of such software, the process is modelled according to the reservoir parameters, and the wellhead pressure and temperature of the injected CO2 are adjusted to fit the model.

- Annulus pressure accumulation;

Annulus pressure accumulation can be observed when an annulus barrier is compromised, leading to a migration of CO2. This phenomenon can be caused by casing leak, cement seal faulting, or leakage into the well from the injected fluid (Lackey, Rajaram and Sherwood, et al. 2017). It can be hazardous as phase change can occur, depending on pressure and temperature conditions.

According to studies and survey reports about a variety of wells in different regions ((S. Bachu 2017), (Watson and Bachu 2009), (Lackey, Rajaram and Sherwood, et al. 2017), (Davies 2011), (Ingraffea, et al. 2014)), annulus pressure accumulation is a common indicator of well integrity problems. Observations from the Tarim basin (China) in high-pressure, high-temperature (HPHT) wells showed that these issues were mainly because of tubing failure during injection operations (Liu, et al. 2019).

Underestimating the risk of annulus pressure accumulation can cause serious well integrity problems, resulting in CO2 migration to the surface and into the environment, in injection and post-closure phases. Accumulated CO2 can affect casing or cement in the accumulation area, causing degradation or corrosion, leading to the failure of other well barrier elements.

Sustained casing pressure is a well-known generic problem with production wells, but the same can happen in CO2 injection wells. The injected gas can migrate in the annulus, compromising various barriers on its way.

The main mitigation is a diligent monitoring plan. A, B, C annuli need to be monitored to understand if any pressure is present in each of them. If so, it would mean that the primary barrier below is compromised, and remediation is needed.

If there is pressure accumulation in the A annulus, packer or tubing must have failed. The most common problems of pressure accumulation in B and C annuli are linked to casing and cement failure and need to be mitigated in time.

- Thermal and pressure cycling in the wellbore;

Thermal and pressure cycling during the injection can cause stresses and damage to the wellbore elements due to cyclic loading. Material exposed to changing cyclic loadings shows fatigue, leading to fatigue failures of the elements (Vrålstad, Skorpa and Werner 2019), (Anya, Emadi and Watson 2020).

According to (Roy, et al. 2018), the effects of thermal cycling in the wellbore were studies with a simulation model. Different temperatures were applied in the simulation during the injection, causing thermal expansion or contraction.

Expansion of each material is a response to a higher temperature. The kinetic energy of the atoms in the crystalline structure of the material increases; thus, more place is needed for one atom. Contraction responds to low temperature, and the mechanism is opposite to the expansion due to kinetic energy decrease. Not all materials shrink and expand at the same rate. It is subject to the thermal expansion coefficient.

The different coefficients of thermal expansion of casing, cement, and formation lead to the debonding and cracking of the cement. It can compromise the integrity of the cement and greatly influence well integrity due to the formation of micro annuli which could lead to potential leakage paths.

Also, a result of temperature cycling can be material fatigue. The fatigue resistance of a material and its strength decreases, and thus, the probability of fatigue failure increases with increased load cycling. Influencing parameters in this process are a total number of cycles, the difference in load values between minimum and maximum load, and the velocity or frequency of the load changes. The higher these parameters are, the earlier an onset of fatigue failure can be expected.

Pressure and temperature cycling, decreasing strength of the materials, and propagating mechanical failures need to be controlled, and their effect needs to be reduced to decrease the probability of damage.

To reduce thermal and pressure cycling in injection wells with the intermittent supply of the CO_2, the difference in temperature and pressure between the two cycles can be reduced by slower and more controlled loading scenario change. For example, by a slight decrease in the injection rate before the injection period to decrease pressure before shut-in of the well to wait for CO_2 supply, and by heating the injected fluid to reduce the difference between the reservoir and fluid temperature These options will help to decrease pressure and temperature cycling effect. (Roy, et al. 2018).

Proper material selection, covered in sections a) and b), can significantly reduce material fatigue.

2.2.2.2 Main degradation patterns of the well barrier materials

The main idea of the studies undertaken in this part is to understand the effect of a CO_2-rich environment on each material it is in contact with. The main materials observed are steel, cement, and polymers.

According to actual examples, the following degradation patterns can be present; a detailed analysis of each degradation pattern will be given in section 1.2.:

- Cement;

Cement degradation is widely described in the literature. Portland cement is not resistant to brine or water-saturated CO_2 due to the so-called carbonization effect. Degraded cement is permeable and porous because of carbonates and silica, which are a result of degradation. This process leads to the failure of the cement as a barrier, and CO_2 can leak through it ((Carroll, et al. 2016), (Ajayi and Gupta 2019), (Zhang and Bachu 2011)).

According to the studies performed in the SACROC Unit (USA), the cement samples showed degradation (Carey, et al. 2007). The main affected zone was on the interference of casing and cement and formation and cement. It was concluded that the cement matrix could withstand significant migration, but the degraded cement propagated micro-annuli. In terms of P&A for an eternity, the effect can be hazardous. The degradation decreases with the increasing distance from the reservoir. (Crow, et al. 2010).

- Steel;

An acidic environment created by CO_2 dissolved in water or brine can lead to corrosion of such components as casing or tubing (Choi, et al. 2013). The reaction between iron in the steel and carbonic acid consumes the material and can result in damage.

The corrosion rate of the various steels observed in the studies in an acidic CO_2 environment can be up to 20 mm/year. Still, it can be reduced up to 0.2 mm/year due to iron carbonate precipitation the steel surface (Choi, et al. 2013). This layer of iron carbonate is effective in static conditions while flowing conditions tend to remove the screen and maintain a relatively high corrosion rate. These conditions apply mainly to the tubing and casing during the injection phase.

Corrosion damaged multiple injection wells in the SACROC Unit (USA), where due to leakage, around 53% of the wells needed a new tubing resistant to CO_2 (Newton and McClay 1977). Materials retrieved from the Ketzin (Germany) CO_2 monitoring well were seen to be affected by corrosion (Gawel, et al. 2017). Casing corrosion was also investigated in the injector CO_2 well in the Weyburn CO_2-EOR field (Canada) (Laumb, et al. 2016). In the Sheep

Mountain CO_2 field (USA), around 60 % of tubing needed to be replaced due to CO_2 corrosion.

- Polymers (sealing elements);

Polymers can be affected by the acidic media which is present in a CO_2-rich environment. Case studies from China at Shengi CO_2-EOR field and Jilin CO_2-EOR field showed the necessity to change the packer elements, but the cause was not observed in detail (D. Zhu, Y. Lin and H. Zhang, et al. 2017). It could be both because of casing corrosion and polymer degradation.

According to the literature reviews, absorption of CO_2 by polymer materials can change mechanical properties of the polymer, such as stiffness and toughness. Increased brittleness will lead to lower resistance to the load cycling, decreased tensile strength will lead to reduced resistance to the loads (D. Zhu, Y. Lin и H. Zhang, и др. 2017)

Another generic problem of polymeric materials is volumetric swelling. While polymers such as nylon or rubber materials are significantly affected, a material such as Teflon is more susceptible to embrittlement than swelling.

In fact, there are a lot of various sealing materials and polymers; each kind of them has unique properties and purposes. Therefore, each material or specimen needs to be tested according to the operational parameters and approved to suit the purpose.

Key learnings/case studies

Chapter 3 Weak points analysis

3.1. Well barrier elements

According to the NORSOK D-010 standard, well integrity is defined as the "application of technical, operational, and organizational solutions to reduce the risk of uncontrolled release of formation fluids" (NORSOK 2021).

Well integrity is maintained by functioning well barrier envelope(s), consisting of well barrier elements. A well barrier envelope can be described as a system of different well barrier elements that maintain the integrity of the well during operations. For example, a barrier envelope can consist of well barrier elements such as casing, production packer, cement, etc.

Operators should confirm that the equipment used to preserve well integrity is appropriate for the operations. During the well operations planning phase, well integrity planning plays an important role. The main objectives that need to be considered while planning well barrier envelope are:

- Materials of the well barrier elements should withstand loads and the environment they are exposed to;
- Operational limits need to be evaluated during the lifecycle of the well. These limitations need to consider the effects of corrosion, erosion, wear, and fatigue;
- The status of the well barrier elements should be monitored, tested, verified, and maintained. The current well barrier element status needs to be known to estimate the risk of the barrier to fail;
- Sufficient independence between the barrier needs to be maintained. Independence is important; should a common barrier element fail, both barrier elements would be compromised at the same time;
- Risk analysis needs to be applied to the well barriers. For each element and the system of the elements, risk needs to be reduced to as low as reasonably possible (ALARP);
- An emergency plan needs to be prepared. It includes a list of actions to be followed in case of an emergency to regain well control as fast as possible.

Main considerations about the well barrier envelope can be described as follows:

- Prevent any major and minor leakage from the well to the external environment during normal well operations;
- Shut-in and seal the well on direct command during the emergency shutdown situation to prevent leakage during an emergency or abnormal operation;
- Well barrier envelope can endure the maximum anticipated pressure;
- Well, barrier elements are leak tested and function tested or verified by other methods;
- No single failure of well barrier element triggers uncontrolled flow from the well to the surroundings;
- It is possible to rebuilt a lost well barrier or to replace it with an alternative one;

- It can function competently;
- Physical location of the well barrier elements is known;
- Integrity status of the well barrier elements is monitored continuously when possible or checked periodically;

3.1.1 Well barrier schematics and diagram

Although it is vital to assume the conceptual considerations described above, a graphical representation is required to work with the real examples of the wells. Each well has a unique design and unique well barrier envelope.

The representation of the well barrier envelope with well barrier elements can be done in two different ways.

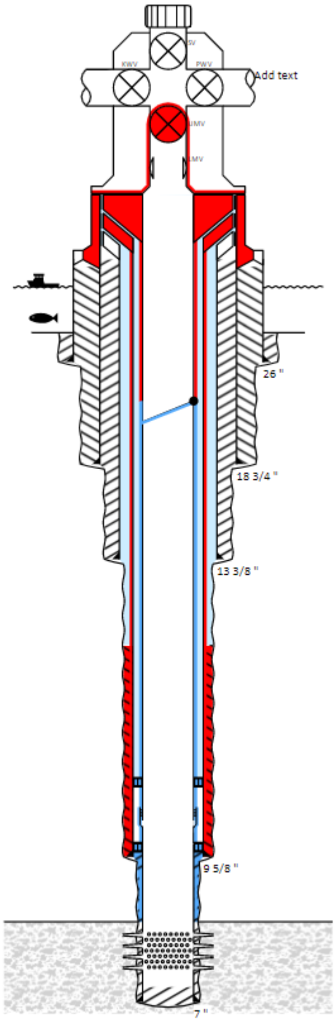


Figure 3: Well barrier schematics (Schlumberger WellBarrier n.d.)

The first way is well schematics. Well schematics for particular operational sequences can be observed in the industry standards like NORSOK or ISO (NORSOK 2021) (ISO 2017). An example of well barrier schematics (in this case created using WellBarrier software) is shown in Figure 3. Well schematics are representative and easy to comprehend. According to industry standards, primary barriers are shown in blue and secondary barriers are represented red. This makes it easy to see whether the "two- barrier" principle is followed.

Besides well barrier schematics, there is another means of well barrier envelope representation. This method is described as a network of well barrier elements where dependencies among well barrier elements are illustrated (Khalief 2020).

An example of a well barrier diagram is represented in Figure 4. The colour principle is the same as in the well barrier schematics, where primary well barrier elements are blue and secondary are red.

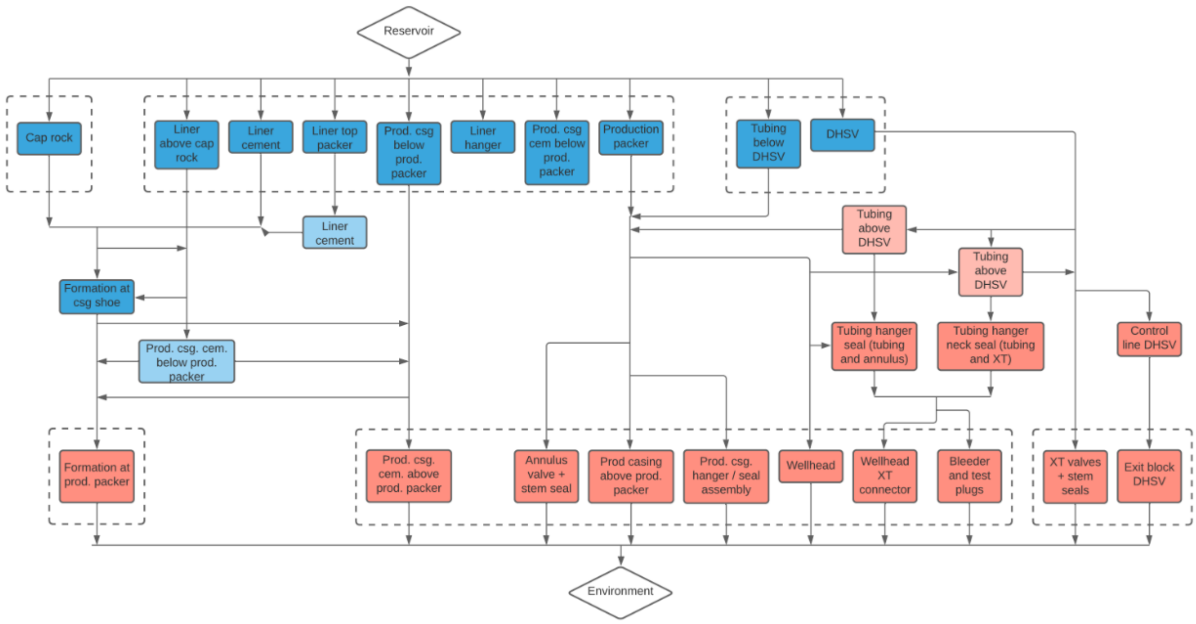


Figure 4: Network of well barrier elements

These means of graphical representation of the well barrier envelope are vital for the analysis of static well conditions (to represent the two-barrier principle), the illustration of different well barrier arrangements, and their functionality and reliability for the particular situation.

3.1.2 Description of each well barrier element

The previous section describes the main objectives for the well barrier envelope and means of representation, but as mentioned above, each well barrier envelope consists of multiple well barrier elements. Each of these elements represents a certain likelihood of failure that can lead to issues with well integrity, with consequences such as operation suspension for remediation or even blowout as a worst-case scenario. That is why each well barrier element needs to be fit on purpose for the particular operational sequence and environment.

Classification or grouping of barriers can be done in various ways. For analysing well design for the injection phase, well barrier elements were grouped into primary and secondary for better representation of well barrier envelope considerations.

However, the main purpose of this part is to analyze each well barrier element separately to understand the purpose and potential causes of failure during the injection of CO_2. Thus, it is more comprehensive to classify them as permanent or retrievable.

Well barrier elements

As an example, the well design from section 3.1.1 was taken. Below, all the elements will be represented in Table 3, following the idea of (Bakar, et al. 2021), to organize each element within the classification unit into the table of main metrics for the well barrier element.

The idea of such classification can be extracted from the CCS project cycle, observed in Figure 2. The idea is to convert the existing well into a CO2 injector. Only those elements which cannot be retrieved or changed will be considered. According to this, the assessment phase is required for the project to evaluate the current state of the components and if any workover and remediation are needed before future operations.

Permanent well barrier elements can be described like the components of the well barrier system that cannot be removed once installed. The best examples of such barriers are casing and cement. These elements cannot be retrieved and changed as a part of workover operations but can be resurrected to be fit-for-purpose for future operations.

Retrievable well barrier elements can be described as the components that can be retrieved and changed to fit-for-purpose for planned operations or use in the future downhole environment. Examples of such barriers are tubing with jewellery or packers.

Feature	Observation
Casing/liner	
Function	1. Isolate the formations near the wellbore and prevent the flow out of them 2. Permanent
Design and construction Standards: - ISO 11960 - ISO 13679 - ISO 10405	1. Casing string must be designed in the way that it is able to withstand all expected loads during the operations; 2. Minimum's acceptance design factors shall be calculated for each load type. Estimated effects of temperature, the pressure shall be included in the design factors; 3. Worst-case scenarios should be used to evaluate the loads.
Main causes of failure	Chemical: corrosion; Mechanical: Unexpected loads (deformation, shear failure), fatigue
Casing/liner cement	
Function	1. Provide a permanent and impermeable hydraulic seal between the wellbore and the casing to prevent flow of the formation fluids, keep pressures from below and above. To add, it will support casing strings structurally; 2. Permanent
Design and construction Standards: - API RP 10B - ISO 10426-1	1. Process of cementation (squeeze cementing) need to be done according to best practices; 2. Properties of the cement must ensure zonal isolation and support of the casing with being durable to thermobaric conditions; 3. Cement within the zones, where contact with fluids is conceivable, ought to be planned to anticipate corruption of the cement.
Main causes of failure	Chemical: degradation; Mechanical: Unexpected loads (Cement cracking, de-bonding), fatigue.
Wellhead/casing hanger	
Function	1. Support corresponding casings and a tubing mechanically; 2. Prevent flow from the wellbore to the environment or the adjacent formations; 3. Retrievable.

Feature	Observation
Design and construction Standards: - ISO 10423	1. The WP for each section of the wellhead shall exceed the maximum well shut-in pressure the section can become exposed to plus a defined safety factor; 2. For dry wellheads, there shall be access ports to all annuli to facilitate monitoring of annuli pressures and injection/bleed-off of fluids; 3. For subsea wellheads, there shall be access to the casing by tubing annulus to facilitate monitoring of annulus pressure and injection /bleed-off of fluids; 4. Wellheads that will be used as a flow conduit for continuous or intermittent production from or injection into annulus/annuli, shall be designed and qualified for such functions without impairing the well integrity function of the wellhead; 5. The casing hanger shall be locked down to ensure seal integrity during normal working loads as well as well control situations;
Main causes of failure	Chemical: degradation, corrosion; Mechanical: unexpected loads, fatigue, WH growth (temperature regimes);
Surface tree	
Function	1. Provide a flow conduit for hydrocarbons from the tubing into the surface lines. Stop the flow by means of flow valve and/or the master valve; 2. Deliver vertical access through the swab valve; 3. Retrievable
Design and construction Standards: - ISO 10423 (API Spec 6A) - API Spec 6FA - API Spec 6FB - API Spec 6FC	1. The surface tree shall be equipped with the following: 1.1. one fail-safe closed automatic master valve and one fail-safe closed automatic wing valve in the main flow direction of the well; 1.2. if the tree has flowing side outlets, these shall be equipped with automatic fail-safe valves; 1.3. one manual swab valve and tree cap for each bore at a level above any side outlets; 1.4. isolation valves on downhole control lines which penetrates the tree block; 2. All primary seals (inclusive production annulus) shall be of metal-to-metal type; 3. All connections, exit blocks etc. that lie within a predefined envelope shall be fire-resistant;

Feature	Observation
	4. The tree shall be designed to withstand dynamic and static loads it may be subjected to including normal, extreme and accidental load conditions;
Main causes of failure	Chemical: degradation; Mechanical: unexpected loads, fatigue;
Tubing hanger	
Function	1. Support the weight of the tubing; 2. Prevent flow from the bore and to the annulus; 3. Provide a hydraulic seal between the tubing, wellhead and tree; 4. Provide a stab-in connection point for bore communication with the tree; 5. Retrievable
Design and construction Standards: - ISO 13533 - ISO 13628-4 - ISO 10423	1. The tubing hanger shall be designed, qualified, tested, and manufactured in accordance with recognized standards; 2. When used in conjunction with annulus injection (gas lift, cutting injection, etc.) any low temperature cycling effects need to be taken into consideration;
Main causes of failure	Chemical: corrosion; Mechanical: unexpected loads, fatigue;
Completion string	
Function	1. Provide a conduit for formation fluid from the reservoir to surface or vice versa, and prevent communication between the completion string bore and the A-annulus. 2. Retrievable
Design and construction Standards: - ISO 11960/API - Spec 5CT - ISO 13679	1. All components in the completion string (pipe/housings and threads) shall have ISO13679 CAL III connections or CAL IV connections when exposed to free gas during its lifetime. 2. Dimensioning load cases shall be defined and documented; 3. The weakest point(s) in the string shall be identified;

Feature	Observation
	4. Minimum acceptable design factors shall be defined. Estimated effects of temperature, corrosion, wear, fatigue and buckling shall be included in the design factors; 5. The tubing should be selected with respect to: 5.1. tensile and compression load exposure; 5.2. burst and collapse criteria; 5.3. tool joint clearance and fishing restrictions; 5.4. tubing and annular flow rates; 5.5. abrasive composition of fluids; 5.6. buckling resistance; 5.7. metallurgical composition in relation to exposure to formation or injection fluid; 5.8. Strength reduction due to temperatures effects;
Main causes of failure	Chemical: corrosion; Mechanical: unexpected loads, fatigue, buckling, shear failure, erosion, deformation, collapse/burst;
Production packer	
Function	1. Provide a seal between the completion string and the casing/liner, to prevent communication from the formation into the A-annulus above the production packer; 2. Prevent flow from the inside of the body element located above the packer element into the A-annulus as part of the completion string; 3. Retrievable
Design and construction Standards: - ISO 14310	1. The production packer shall be qualified and tested in accordance to principals given in recognized standards, i.e., ISO14310 V1 as minimum and V0 if the well contains free gas at the setting depth; 2. The setting depth shall be such that any leak through the casing below the packer, will be contained by the well barrier system outside the casing. The formation integrity and any annulus seal (e.g., cement) shall be able to withstand the pressures or temperatures expected throughout the lifetime of the well; 3. It shall be permanently set (meaning that it shall not release by upward or downward forces), with ability to sustain all known loads; 4. Mechanically retrievable production packers shall be designed to protect against unintentional activation.

Feature	Observation
	5. The packer (body and seal element) shall withstand maximum differential pressure, which should be based on the highest of: 5.1. pressure testing of tubing hanger seals; 5.2. reservoir-, formation integrity- or injection pressures less hydrostatic pressure of fluid in annulus above the packer; 5.3. shut-in tubing pressure plus hydrostatic pressure of fluid in annulus above the packer less reservoir pressure; 5.4. collapse pressure as a function of minimum tubing pressure (plugged perforations or low-test separator pressure) at the same time as a high operating annulus (maximum allowable) pressure is present;
Main causes of failure	Chemical: corrosion; Mechanical: unexpected loads, fatigue, deformation, swelling;
Liner top packer	
Function	1. Seal the annulus between the casing and liner, and resist pressures from below and/or above. 2. Retrievable
Design and construction Standards: - ISO 14310 - ISO/FDIS 14998	1. The packer, including a tie-back packer, shall be qualified and tested in accordance to principles given in recognized standards, i.e., ISO14310 V1 as minimum, and V0 if the well contains free gas at the setting depth; 2. The packer shall be designed for the maximum differential pressure (burst and collapse) and maximum downhole temperature expected during installation and throughout its service life. Other downhole conditions, such as formation fluids, H_2S, CO_2, etc. shall also be considered in estimating the lifetime of the packer; 3. The packer element is not accepted as a WBE in permanently abandoned wells or wellbores. 4. The risk of sealing failure due to variable downhole temperatures/cyclic loading shall be evaluated.
Main causes of failure	Chemical: corrosion; Mechanical: unexpected loads, fatigue, deformation, swelling;

Table 3: Main well barrier elements representation (Schlumberger WellBarrier n.d.)

3.2. Damage mechanisms and most commonly adopted mitigations

Damage mechanisms can be divided into two groups:

- Chemical damage;
- Mechanical damage.

Chemical damage corresponds to such mechanisms as corrosion and degradation, which are dependent on the chemical compound of the injected fluid.

Mechanical failures correspond to such mechanisms as fatigue and unexpected loads, dependent on the operational regime parameters.

The key degradation and failure mechanisms were already considered in the literature review in section 2.2.2.2, and will be assessed in greater detail in the following chapters.

3.2.1 Chemical degradation mechanisms

Main chemical degradation mechanisms can be divided by the material they are affecting:

- Steel corrosion;
- Cement degradation;
- Sealing elements degradation.

The first and the most hazardous mechanism is corrosion. Corrosion itself is a broad topic of research. Here, only corrosion mechanisms are represented that are caused by CO2 presence.

Cement degradation is also an important and widely observed issue, detrimental to the long-term storage of CO2. Nowadays there are many modifications of cement depending on the conditions and tasks to be solved. However, there is still much research and development (R&D) work to improve well integrity.

Although several studies about sealing elements degradation have been conducted, with experiments and solutions, there are still gaps as the sealing material can be made of a great variety of polymeric materials with different properties, making each unique.

a) Steel corrosion

With the injection of CO2 comes the risk of internal corrosion. Dry CO2 gas itself is not corrosive, but it becomes so when dissolved in an aqueous phase. Water presence is dependent on the project requirements of the injected solution.

As the injected fluid in CCS projects is pure CO2 and does not contain water, the water from two other sources should be considered.

The first source is water condensate, as still there is a small percentage of the water in the fluid as it cannot be completely pure. According to (Bakar, et al. 2021) (Cailly 2005), even 0.0086 mol% H2O influences corrosion. Because of the temperature difference (wellbore temperature is always higher than the temperature of CO2), the condensate accumulates on the metal surfaces and evolves into carbonic acid in contact with CO2. This is applicable for all CO2 phases.

The second source is residual water in the depleted reservoir. According to (Bakar, et al. 2021) injected fluid that was in mixture with the formation water can flow back into the wellbore, initiating corrosion of the steel components in the well.

CO2 is highly soluble in water and brine and has an even greater solubility in hydrocarbons. CO2 dissolves in oil during production and transport phases, and can also dissolve in water and react with iron in carbon steel pipes. Under ideal conditions, iron carbonate (FeCO3) can create a protective layer and prevent further conversion of iron. This protective layer can prevent cathodic and anodic reactions, although it depends on such parameters as flow rate, temperature, and pressure.

Two primary forms of corrosion during CO2 injection are general and localized corrosion (Cailly 2005).

General corrosion can be described as uniform dissolution and thinning. Carbon steels are affected by the carbonic acid that is present when CO2 is dissolved in water. It affects the majority of the metal surfaces and can be predicted.

Damage from the *localized corrosion* is localized rather than being spread over the exposed metal surface. This form of corrosion is not that easy to predict. The two main occurrences are pitting corrosion and crevice corrosion. Crevice corrosion is mainly dependent on H2S content, while pitting corrosion is present because of CO2. Pitting corrosion is hazardous as the pits are small, which does not lead to significant weight loss, but it can cause failure by perforation through the metal surface.

The following equations can represent the CO2 corrosion process (Nygaard 2010):

$$\textbf{Equation 1}: CO_2 + H_2O \rightarrow H^+ + HCO_3^-$$

$$\textbf{Equation 2}: 2H^+ + 2HCO_3^- + Fe\ (s) \rightarrow Fe^{2+} + 2HCO_3^- + H_2$$

$$\textbf{Equation 3}: Fe\ (s) + 2H^+(aq) \rightarrow Fe^{2+}(aq) + H_2(g)$$

At the steel/liquid interface, an anodic reaction occurs, and iron atoms are oxidized as cations; and in the meantime, a cathodic reaction occurs, and protons are reduced. Bicarbonate and carbonate anions themselves can react with ferrous ions to form an iron carbonate film. Solid iron dissolves into iron ions in solution, corroding the surface of the steel. This corroded steel is not structurally stable, which is why the tube's well thickness is decreasing.

Another classification can be made based on the H2S presence and partial pressure: sweet and sour corrosion.

Sour corrosion has such effects as stress corrosion cracking and sulphide stress cracking. These two effects need to be considered diligently during material selection. The main factor of sour corrosion is the presence of H2S.

Sweet corrosion attacks metals due to the acidic nature of carbonic acid. The pH of the solution is also dependent on the partial pressure of the CO2. According to the (T. R. IEAGHG 2018) for the same pH, weak carbonic acid will be more hazardous than a strong acid. As carbonic acid can rapidly dissociate on the metal surface, it provides the hydrogen ions needed at the cathode.

According to (Oil and Gas Facilities 2018) a CO2/H2S ratio of 500 is taken as a threshold for sweet corrosion. Above this value, it will be regarded as fully sweet corrosion. If the value is below 20, the process is governed as sour corrosion. At values between 20 and 500, the corrosion mechanism is both sweet and sour; thus, individual testing for each unique value has to be done to estimate the corrosion effect.

Only sweet corrosion is observed in this research as the injected fluid is assumed to be free of H_2S. According to (Goto, et al. 2013), 95% purity for the injected CO_2 is economically viable and safe for sour corrosion, and mainly captured CO_2 is this pure. The CO_2/H_2S ratio is assumed to be more than 500 at this purity, therefore following the sweet corrosion mechanism.

The rate of sweet corrosion is dependent on the following factors:

- Water Content;

For CO_2 corrosion to occur, water must be present, and it must wet the steel structure. Wettability is dependent on the fluid content (if there are impurities and what they are). The greater the water content in the solution, the more likely corrosion is to occur. Even if the dry and waterless solution is injected, there still can be sources of water that will boost the corrosion rate.

- CO_2 Partial Pressure;

The higher the partial pressure of CO_2 is, the higher corrosion rate becomes. CO_2 corrosion results from a reaction of steel surface with carbonic acid. An increment within the fractional weight of CO_2 would cruel that more carbonic corrosive may well be shaped with a more prominent concentration of cathodic particles to perform the decrease response. The corrosion rate would rise. As mentioned above, here, sweet corrosion is observed. Thus, the partial pressures of other impurities are not accounted for.

However, in favourable conditions in which protective film can form, the corrosion rate is reduced, and pressure increases the precipitation and formation of $FeCO_3$ scales. This effect increases long-term as the iron carbonate will accumulate and protect the iron in the steel from carbonic acid attacks. This effect also depends on the injection rate of the CO_2 solution, as under dynamic conditions the rate of formation of the iron carbonate screen will decrease.

- Temperature;

It is anticipated that the rate of a chemical reaction rises with temperature. Because more energy is available at higher temperatures, the activation energy barrier is easier to overcome. For CO_2 corrosion, where water is a dependent factor, there is an exclusion. At higher temperatures, where water is above the dew point, it does not condense. Without the presence of condensed water, there is a decrease in the rate of corrosion. Also, with the formation of the protective $FeCO_3$ film, higher temperatures decrease the solubility of this film which in turn increases the likeliness of film formation.

- pH;

The pH has a strong influence on the corrosion rate due to its effect on the formation of the protective $FeCO_3$ film. The higher the pH - the lower the amount of H^+ ions in solution, resulting in lower solubility of $FeCO_3$. In contrast, if pH drops, the solubility of $FeCO_3$ increases because there is more H^+ in the solution.

When the pH is increased from 4 to 5, the solubility of the released corrosion products is reduced by only a factor of five. When the pH is increased from 5 to 6, the solubility of the corrosion products increases a hundredfold (Oil and Gas Facilities 2018).

According to (Maarten, et al. 2010), the expected pH is around 3 to 4, which is low and can be characterized as an acidic environment and the effect need to be assumed.

- Flow regime and velocity;

The velocity of the fluid flow affects corrosion in two ways: breaking down protective films and reducing the concentration of ions near the pipe wall.

When the flow is laminar, films can form without destruction. However, when the flow regime becomes transient or turbulent, the protective film is removed and further formation of the protective layer is prevented or reduced.

It should be mentioned that films formed in pits are not as effective at preventing corrosion at high flow rates, as they are more porous and friable.

As observed in case studies in section 2.2, and described in more detail in this part, corrosion affects well integrity a lot. As the corrosion problem is well-known, commonly adopted mitigation against this effect is covered in section 0.

b) Cement degradation

According to the case studies observed in section 2.2, another challenge in CCS projects is cement degradation in contact with carbonic acid. As was observed in section a), the presence of water during the injection operations will lead to carbonic acid formation.

Carbonic acid deteriorates the cement used in wells that were not initially designed for CO2 injection. This impairment can take place in the cement adjoining the well, either in the annulus between the casing and the formation, or at the interface between the casing and the cement. Even though the degradation process is not fast, it still can compromise cement as a barrier and influence the long-term integrity of the well (Oilfield review 2015).

Cement quality is critical to the well mechanical properties and integrity. The degradation leads to a decrease in permeability and strength. Being the primary barrier in most well architectures, it can lead to fluid leakage into shallower formations or pressure build-up in the annulus if compromised.

The cement in the wells initially designed for production is typically cemented with Portland cement. This type of cement is commonly made of portlandite (Ca(OH)2) and calcium silicate hydrates (CSH) (Hossain and Amro 2010). The tendency of Portland cement to degrade in the presence of carbonic acid was observed through a wide variety of laboratory and field tests. The process of cement carbonization can be explained with the following equations (Hossain and Amro 2010):

Equation 1 describes the process of carbonic acid formation and dissociation

$$\boldsymbol{Equation\ 1}: CO_2 + H_2O \leftrightarrow H_2CO_3 \leftrightarrow H^+ + HCO_3^- \leftrightarrow 2H^+ + CO_3^{2-}$$

The products from Equation 1 interact with the cement and lead to degradation.

The term H2CO3 for carbonic acid will be used in the following equations for the more obvious interpretation.

$$\boldsymbol{Equation\ 2}: H_2CO_3 + C - S - H \rightarrow CaCO_3(s) + \boldsymbol{SiO_xOH_x(s)}$$

In Equation 2, calcium carbonate is formed and also amorphous silica gel (in bold). Other equations represent the behavior of CaCO3 with the future contact with Ca(OH)2.

$$\boldsymbol{Equation\ 3}: H_2CO_3 + Ca(OH)_2 \rightarrow CaCO_3 + 2H_2O$$

$$\boldsymbol{Equation\ 4}: H_2CO_3 + CaCO_3 \rightarrow Ca(HCO_3)_2$$

$$\boldsymbol{Equation\ 5}: Ca(HCO_3)_2 + Ca(OH)_2 \rightarrow 2CaCO_3 + H_2O$$

Initially, the formation of the carbonic acid is taking place (eq. 1). Then formed carbonic acid reacts with calcium-silicate-hydrates and calcium hydroxide, and as a product, calcium carbonate is formed (eq. 2 and eq. 3).

Then, the carbonic acid reacts with the calcium carbonate and forms water-soluble calcium bicarbonate (eq. 4).

The last reaction is the reaction between calcium bicarbonate and calcium hydroxide to form water and solid calcium carbonate (eq. 5). It induces more dissolution of CO2 and continues the reaction to promote degradation.

As mentioned above, the main problem of cement degradation is increased bulk porosity and permeability and a change in the front thickness of cement. According to the studies, once CO2 reaches the cement and the degradation process has started, the degraded front will move at the rate of around 1 mm/year (Duguid, Carey and Butsch. R. 2014).

Table 4 represents the findings from testing cement samples in a CO2-rich environment in different experimental setups.

Cement sample	Experimental setup	Main Findings
Class H cement + DI water (W/C ratio = 0.38) Class H cement + 6% Bent. + DI water (W/C ration = 0.7)	CO2 saturated brine (pH 3.7-2.4) Exposure time (1.3 – 7.2 days) Temperature (23 – 50 °C) Dynamic conditions	Cement degradation in Cement with bentonite was higher, averaging around 0.75-1.2 mm in 7.2 days (0.1-0.16 mm/day)
Class H cement (W/C ratio = 0.38)	CO2 saturated brine (pH 3.7-2.4) Exposure time (1.3 – 7.2 days) Temperature (23 – 50 °C) Dynamic conditions	The highest rate of reaction was observed at the highest experiment temperature = 50 °C and lowest pH = 2.4, averaging around 0.07 – 0.24 mm/day
Class H cement (W/C ratio = 0.38)	Wet scCO2 Exposure time (9 days – 12 months) Tests (22 °C at 0.1 MPa; 22 °C at 30.3 MPa; 50 °C at 0.1 MPa; 50 °C at 30.3 MPa) Static conditions	After 9 days the exposure was less than 1mm. meaning that the degradation rate was around 0.1 mm/day
Portland cement	Wet scCO2 Exposure Time (84 days) Temperature (50 °C) Pressure (10 MPa) Static conditions	The degradation rate was around 0.2 mm/day

Table 4: Degradation rate of different cements (Abid, et al. n.d.)

A slow degradation rate of only 1mm/year does not account for the presence and influence of micro annuli. Without channelling or micro annuli, the degradation process is slower as the CO2 has to migrate through the whole cement matrix. In the presence of micro-annuli, CO2 can migrate upwards to the next bonded interval, destroying small cement bridges along the way, and the degradation rate can increase significantly, up to 1000 times (1 m/year).

Even though the process is not that fast, assuming the average degradation rate in the short-term, it can be hazardous from a long-term perspective leading to poor zonal isolation of the permeable layers and affect the debonding, leading to leakage paths propagation. Degraded cement itself is permeable enough to be a leakage path for CO2.

Over the last 20 years, many new slurries and components were tested, so there is mitigation against this problem, which will be studied in section 0.

c) Sealing elements degradation

Three materials can be observed in the wellbore: cement, steel, and sealing elements, mostly rubber. It should be considered here that the well needs to be converted into a CO2 injection well with the intention of long-term storage, much longer than what was planned for the production well, constructed 20 or 30 years ago. This implies that the sealing elements must be replaced and the new ones must be able to withstand the conditions in which they will be used.

The main focus element here is the production packer, which is part of the primary well barrier envelope. If it is compromised, remediation is required to reinstate the two-barrier principle.

The main parameters that affect the integrity of rubber materials are volume, quality, tensile strength, and hardness.

This area is not well researched, and there are still a lot of gaps. The idea here is to understand the main consequences of the degradation of the sealing elements, particularly rubber elements, and propose material selection from best industry practices.

According to (D. Zhu, Y. Lin and H. Zhang, et al. 2017), an experiment was conducted, how CO2 affects the rubber packer in reservoir conditions. Three types of rubbers were tested: NBR (Nitrile Butadiene Rubber), HNBR (Hydrogynated Nitrile Butadiene Rubber), FKM (Fluorine rubber).

NBRs are manufactured by emulsion copolymerization of butadiene with acrylonitrile. They can be used in the temperature range from 40 to 108 degrees. It is mainly used in gaskets, O-rings, and oil seals. This kind of rubber is resistant to a wide chemical impurity like CO2.

HNBRs are more vulnerable to chemical degradation as olefinic groups are removed during hadronization of the NBR with Wilkinson's catalyst. Compared to NBR, HNBRs have a wider range of allowed temperatures from 40 to 165 and decreased degradation over long periods of time.

FKM are aggressive fluid-resistant, and comparing to NBRs this material has a higher upper-temperature threshold, up to 260 degrees.

The idea here is not to observe the exact result of the experiments but to understand the common trend of sealing materials degradation.

- Tensile mechanical properties;

Tensile mechanical properties such as elongation at rupture and tensile strength after degradation in CO2 environment were reduced compared to the initial condition. According to the statistics, these properties were reduced almost two times. It can be concluded that with time, due to corrosion, tensile mechanical properties can weaken significantly.

- Hardness;

Hardness, measured after the effect of CO2 was decreased. It needs to be mentioned that in liquid CO2, the decrease of hardness was more significant than in gaseous CO2.

To understand the consequences, morphology analysis needs to be applied. According to the (D. Zhu, Y. Lin and H. Zhang, et al. 2017) , the main issue was bubbling. Deformation and dissolution were present. These consequences can lead to leakage paths formation due to unsealing.

Above, only rubber packers were examined, although there are other sealing elements besides packer, such as:

- X-mas tree sealing;
- Valve packing and seals;
- Wellhead sealing;
- Tubing hanger;
- Tubing joint seal rings;
- Profile Nipples and ON/OFF tool (if there is one in a completion design);

Material selection of these elements needs to be conducted correctly to mitigate degradation and further consequences.

3.2.2 Mechanical failures

a) Steel components mechanical failure

– Shear failure

Shear failure is a generic problem for well tubulars e.g., casing.

(Dusseault 2004) described casing shear as a consequence of formation shear that happens due to changes in stress and pressure caused by the exploiting conditions - depletion, injection, and heating. (Wang 2011) described a shear fracture mechanism resulting from the displacement of rock strata along the bedding plane or steeply inclined fault planes.

When a fluid is injected into the porous formation, it increases pore pressure within this permeable formation. According to the Coulomb criterion, higher pore pressure triggers a decrease in effective normal stress, making shear easier. As a result, permeable formation expands volumetrically what may cause shearing near the bonding surfaces where there is stress concentration. Shear displacement leads to loss of pressure integrity or to pipe jamming in the casing.

(Plaxton 2018) established that the lack of stress uniformity between the formation, cement, and the casing plays a significant role in the shearing process. High contrast in stiffness means high shear stress contrast, triggering the formation of a shear band at a lithological interface with weak shale. That is why it can be expected that shear distortion will occur not along the whole perforation interval but on such a single interface, an observation confirmed in fields in Alberta, California, and the North Sea.

- Collapse/burst failure

Collapse and burst failure are a generic problem for the tubing string in an injection well, but also can occur in the parts of de-bonded cement in the casing. These failures are attributed to radial stresses.

Tensile failure due to axial tension and connection stands out as the result of compression or tension.

(Kiran 2017) suggested that the presence of voids and cement channels at the casing-cement interface could induce up to 60% reduction in casing collapse resistance.

Meanwhile, the stress is constantly changing during injection as the flow rate and dynamic load vary. It has been found that such stress changes can cause casing or tubing failure.

The mechanism is mainly attributed to the unequal external load exceeding casing or tubing yield strength which changes the circular orientation to oval. Collapse of the casing or tubing is primarily classified into yield, transitional, elastic, and plastic.

Yield strength collapse is based on yield at the inner wall using the Lamè thick wall elastic solution. For thick walls ($D/t < 15$), the tangential stress exceeds the yield strength of the material before failure due to collapse instability occurs.

Elastic collapse is based on theoretical elastic instability failure. This criterion is dependent on yield strength and applicable to thin wall pipes ($D/t > 25$). As well as yield collapse, elastic collapse phenomenon is based on the pipe's wall thickness and yield strength.

According to API, plastic collapse is based on empirical data obtained from tests of K-55, N-80, and P-110 grade steels. No analytic expression has been derived that accurately models behavior at this regime. Still, according to regression analysis, all tubes manufactured following API standardization will fail when exceeding the plastic collapse pressure in 95% of the occasions.

Transition collapse is obtained by a numerical curve fit between plastic and elastic regimes.

According to API, most tubular are affected by plastic and transitional collapse during the operations.

On the other hand, casing or tubing failure occurs when the internal pressure exceeds the yield strength of the casing material. However, this failure type depends also on the external load resisting the internal pressure.

- Fatigue failure

Fatigue is the irreversible, cumulative, progressive, and localized structural damage when a material is subjected to cyclic loading. The cyclic loading or stresses can be distinguished as fully reversed, repeated or fluctuating loads.

Moreover, classification into low cycle or high cycle loading can be made. Low cycle fatigue can be characterized by repeated plastic deformation, while high cycle fatigue is elastic. A lower number of cycles is needed before failure during plastic deformation cycles and a higher amount for the elastic deformation.

Casing fatigue failure could occur when the well exhibits alternating temperatures during the injection. Also, fatigue loading is induced during injection due to the temperature difference between injected fluids and the reservoir temperature.

Casing is exposed to low temperatures during CO2 injection, whereas during injection stop, temperature increases again. Such cyclic temperature can lead to debonding between cement and casing. This and other cement issues will be observed in the next paragraph.

b) Cement mechanical failures

According to (Ravi 2002) , there are three main mechanical failure modes of the cement:

- Mode 1: Rock-cement debonding

Debonding due to stiffness contrast or pressure and temperature inside the casing can compromise the rock-cement interface. Debonding can also be caused by shrinkage of the cement slurry or incomplete removal of mud at the rock-cement interface. In the future, it can be a leakage path for CO2, which will lead to even greater debonding.

- Mode 2: Cement-casing debonding;

This type of debonding also happens mainly due to a contrast in stiffness. Insufficient mud removal also increases the probability of debonding. As the temperature and pressure in the casing changes, the casing diameter decreases or expands, forming a micro-annulus.

Mode 1 and 2 can be propagated because of the following drivers.

1. Effects of thermal cycling during injection of the CO2, mainly if CO2 is transported with ships, which means the injection will be periodic. This will lead to thermal and pressure fluctuations in the wellbore, which will lead to the expansion or shrinkage of the casing and cement.
2. Steel and cement have different rates of expansion, which will lead to de-bonding. For example, when the cold CO2 is injected, the casing will shrink more than the casing, leading to de-bonding at the casing-cement interface. This comes from the fact that cement is more ductile than steel, which means that during the same expansion or shrinkage, cement will go into plastic deformation mode earlier, leading to failure.
3. Another driver for debonding is depletion and future re-pressurization of the reservoir. During the lifetime of the well, the drop in reservoir pressure leads to shrinkage of the reservoir. After CO injection, the pressure will return to near initial values and a renewed reservoir expansion. This effect can lead to de-bonding according to both modes 1 and 2.

Besides debonding modes 1 and 2, there are modes 3 and 4:

- Mode 3: Cement failure;

The main driver of this mode is cement shrinkage. The entire sheath of the cement could crack due to the shrinkage of the cement, and tensile failure is the most dominant failure mode.

Another driver is casing expansion, which can occur during pressure and temperature increase as a part of temperature and pressure cycling. This can lead to cracking of part of the cement sheath, especially for the cement with high Young's modulus.

Cement is described as a ductile material, meaning that crack is accompanied by plastic deformation, which will lead to migration path creation.

- Mode 4: Mix of mode 1-3;

In fact, not only is one failure mode present in the well at a time, but two can be present simultaneously. For example, the cement can be cracked with the expansion part of mode three, and then the bond in interface cement-casing can be compromised while shrinkage.

(Ferla 2009) simulated the effect of injection (CO2 steam) to understand the stresses in the near wellbore region. According to the results, the casing went in compression due to thermal stresses, which led to debonding at casing-cement contact. It was also observed that the shear stresses in systems cement-casing and cement-formation increased. The maximum point of stress was around the centre of the cement. This occurs because of the different abilities of the materials to shrink and expand.

3.2.3 Simultaneous effect of chemical degradation and mechanical failure

As mentioned before, corrosion is the main hazard for steel in the wellbore. The consequence of the corrosion is that the metal surface is thinning and eventually losses strength, which means that due to corrosion, the steel element (ex. casing) will be able to withstand lower loads compared to its new condition.

The strength reduction of the metal element will lead to an increase in the probability of mechanical failure.

A good example of how chemical degradation accelerates mechanical failure is tubing corrosion. The material loss will lead to wall thinning, and as a result, collapse and burst resistance will decrease. If the loads are not adjusted according to estimated corrosion severity and decreased load resistance, mechanical failure and compromised tubing integrity can appear.

Cement degradation is one of the considerable hazards in a CO2-rich environment, along with steel corrosion. It leads to reduced strength of cement, resulting in accelerated propagation of one of the cement failure modes described in the previous section.

According to (W. Y. Liu 2017), casing cement failure can be accelerated by the chemical degradation of the cement and corrosion of the casing.

3.3. Mitigation and remedial actions

3.3.1 Mitigation actions

The degradation and failure mechanisms above can compromise the integrity of the well. Well integrity in CCS projects is an important topic that needs to be considered in detail, so the main idea of this chapter is to represent the most commonly adopted mitigations and preventive measures against failure and degradation.

Mitigation and remedial actions

a) Steel damage mitigation

The main parameters that influence the corrosion rate are observed in section a). The list below represents them and proclaims the main considerations to be taken to decrease their effect:

- Water content;

This parameter can be controlled by the purity of the injected CO2, which is highly dependent on the source of the CO2.

- pH;

This parameter cannot be accurately maintained because the environment is acidic itself. Chemical inhibitors are used to decrease pH.

- Temperature, flow regime, and velocity

These parameters are operational parameters of the injection and are calculated with the help of specialized software, taking into assumption characteristics and geomechanical assessment of the reservoir.

According to (Sorem 2008), corrosion can be mitigated or controlled by either material selection that can withstand the corrosive environment or by using chemical inhibitors to decrease the harshness of the environment and make it milder and less corrosive.

- Chemical inhibition

Chemical inhibition is carried out with corrosion inhibitors that can be selected and qualified for continuous or intermittent injection.

The continuous injection is conducted by installing a port at the bottom of the tubing. The inhibitor is injected from a surface tank down the annulus through the tubing injection port and into the injection stream inside the tubing.

An alternative method is a batch injection, where the tubing volume is filled with inhibitor or squeezed into the formation for a while before it is flushed out.

The disadvantage of this method is that the well must be shut in periodically, resulting in downtime in injection operations.

However, this also depends on the supply method of CO2. For example, there will be downtime if the injection is permanent and sustainable. Still, when the supply is periodical, e.g., vessel transport, batch chemical inhibitors injection can be done during the shut-in periods between supplies.

The mode of action of the chemical inhibitors is adsorbing on the metal surface (Usman 2017) Adsorption is described as an adhesive process where a substance like ions, atoms, or molecules of gas, that are called adsorbate, adheres to a surface (adsorbent).

The chemical inhibitor's efficiency depends on the adsorption property on the metal surface, which is dependent on its physical and chemical properties, functional groups, aromaticity, steric effect, and the density of the electrons at the donor atoms (Usman 2017).

According to this, the inhibition frequency is chosen according to the supply, and the chemical inhibition agent itself is chosen due to the analysis of the steel materials and regime parameters.

– Corrosion-resistant materials

The more common approach for steel corrosion mitigation is material selection. Materials that will be able to withstand the corrosive environment need to be specified and chosen accurately.

According to the classification above, it is important to analyze the duration of the operations and make a material choice for permanent elements according to the required duration of the operation, to be cost-effective (T. R. IEAGHG 2018).

According to (CATO-2 2013) the list below represents some of the commonly adopted steel types that can withstand corrosion:

Martensitic stainless steel or corrosion-resistant steel. These steels contain at least 11.5% of chromium, such as 13Cr and 17Cr. The main aim of adding chromium to the steel is to promote strong adherence of the corrosion product to the steel surface.

As a result of the API specification, 13Cr became a common choice for low or moderate-temperature environments. The limitation is H2S and chlorides content; 13Cr steel can only withstand media that contains CO2 and a low portion of H2S and chlorides.

In higher temperatures and higher concentrations of H2S, 15Cr can be used. It is a modified 13Cr alloy (2Mo-5Ni) that increases the resistance of the material.

Martensitic steels are becoming inefficient in higher concentrations of H2S as they are susceptible to sulphide stress cracking (SSC). But on the other hand, they are extremely resistant to chloride stress cracking (CSC).

Super martensitic stainless steel. As observed above, these can be described as martensitic steel but with higher nickel and molybdenum and lower carbon content. According to (Bakar, et al. 2021) super 13Cr steels show better corrosion resistance than ordinary 13Cr steel.

Ferritic-austenitic alloy (duplex steel). This type of steel contains chromium, manganese, nickel, vanadium, and molybdenum. It is a mixture of ferritic and austenitic steel which tends to be stronger and more resistive to corrosion pitting and stress cracking than regular austenitic steel.

This type of steel tends to have high chromium content (at least 20%) and low carbon content. 22Cr is one of the duplex steels being used in the oil and gas industry. The 25Cr- type (super duplex steel) contains significantly more nickel and molybdenum.

Comparing to steels observed previously, duplex steel is superior in terms of corrosion. It is more resistant to both H2S and CO2, mitigating sweet and sour corrosion to a greater extent. Effects such as SSC or CSC are also mitigated due to the high chromium content in duplex steels. The only downside of such steels is their price. Compared to martensitic and super martensitic steels, duplex steels are much more expensive and are typically used in harsh environments (H2S, CO2, chlorides, etc.) when no other steels can be used.

The steels observed above are the best choice in the industry to deal with corrosion. The harsher the environment, the more corrosion resistance is required. For example, martensitic steels are good to be used in CO2 media with shallow H2S content, but with increasing H2S content, the probability of SSC is increasing. To decrease it, super martensitic steels can be used.

As well as corrosive media content, other parameters like temperature and pressure need to be considered. The higher they are, the more reactive the environment, the higher the corrosion effect.

The project assumes that CO_2 is pure and does not contain any impurities like H_2S or chlorides that can increase the corrosion effect.

Summing up, the selection of the suitable material for injection operations is essential. According to (Syed 2010) , the use of corrosion resistance casing or liners in both construction and workover operations provides enhanced corrosion protection for severe CO_2 service. Still, it comes with the implication of increased cost. That is why such parameters purity of injected CO_2 and injection parameters need to be carefully determined while choosing the suitable alloy.

Besides material selection and chemical inhibition for corrosion avoidance or mitigation, corrosion also needs to be measured and quantified during operations. The list below represents the main monitoring methods that can be used for corrosion monitoring:

- Corrosion coupons;

According to (Jaske 1995) a coupon is a small piece of metal (for example, a strip or a ring), made of the same material as the casing or tubing and placed in the appropriate place to measure the corrosion.

It is weighted at the beginning, and after a while, it is weighed again to benchmark the loss of weight and measure the corrosion. The coupon is placed and recovered by wireline.

- Corrosion loop;

A corrosion loop is a section of tubing valved so that some of the injection fluid passes through. The composition needs to be the same to evaluate how the coupon has corroded, and this will help to understand the effect on the tubing. According to (USEPA 2013) , the problem with this method is that the data cannot be accurate due to differences in such parameters as depth, temperature, and pressure. The problem is that the corrosion loop can be described as a small diameter bypass, through which the fluid flows as well. The temperature difference comes from the fact that corrosion loops are placed at a shallower depth but not at the end of the tubing for easier retrieve, thus doing readings in different parameters. Pressure difference comes from a different diameter of the bypass and real tubing. However, according to (CATO-2 2013) the data is still valid.

- Casing and tubing inspection logs;

Such logs are run to measure thickness and integrity, cross-sectional wall loss, radius, pitting, etc. Currently, there are several solutions on the market, but the principle is the same. It can be said that Schlumberger heritage “USIT” tool became more of a generic name of the solution for corrosion casing or tubing integrity assessment. The tool was used in many evaluations and used its efficiency in industry practices.

The USI* UltraSonic Imager tool (USIT) uses a single transducer mounted on an Ultrasonic Rotating Sub (USRS) on the bottom of the tool. The transmitter emits ultrasonic pulses between 200 and 700 kHz and measures the received ultrasonic waveforms reflected from the internal and external casing interfaces. The attenuation rate of the resulting waveforms indicates the quality of the cement bond at the cement/casing interface, and the resonance frequency of the casing allows the determination of the casing wall thickness required for the pipe inspection. Because the transducer is mounted on a rotating substrate, the entire circumference of the casing is scanned. This 360° data coverage makes it possible to assess the quality of the cement joint and determine the internal and external condition of the casing. The very high angular and vertical resolution makes it possible to detect channels up to 1.2 inches wide. [3.05 cm]. Maps of the cement joint, thickness, internal and external radii as well as annotation maps are created in real time at the well site.

As mentioned earlier, impurities in mixtures with CO_2 is a vast topic that needs to be dealt with in more detail. The assumption for the practical application in this document is that the purity of CO_2 is higher than 95%, meaning that impurities do not affect the fluid, and the corrosion will be sweet (Goto, et al. 2013).

According to ((Bakar, et al. 2021), (T. R. IEAGHG 2018), (CATO-2 2013)) and the information provided in this section, the following guidelines may be concluded:

- High-pressure dry CO_2 does not corrode carbon steels even in the presence of small amounts of methane, nitrogen or other impurities (chlorides, sulphates and others). The main driver of corrosion is the presence of water which needs to be reduced to its minimum.
- 13Cr and Super 13Cr show good performance in the CO_2 environment. Still, they are limited by temperature, which needs to be below 150 degrees Celsius together with a combination of low amounts of H_2S (partial pressure < 1bar) and no presence of oxygen.
- The reservoir water containment needs to be evaluated because one of the ways CO_2 can contact water is through the influx of residual water from the reservoir into the wellbore when the well is shut-in between injection cycles. This water can contain a significant amount of H_2S, O_2, that can propagate corrosion of such material. A simulation was done by (Bakar, et al. 2021), proving the possibility of such a scenario that necessitates the use of CRA such as duplex steel to assure sufficient corrosion resistance in the presence of impurities.
- A distinction between casing and tubing needs to be made. Tubing is in constant contact with the CO_2 and has to be made of CRA, while casing robustness criteria does not always require CRA. This is applicable for the part of the casing above the production packer where the annulus between casing and tubing can and will be monitored for CO_2 that can start corrosion, even though chemical inhibition is present and protects the casing. It is recommended to use CRA if and where the accessibility of intervention is not good.
- The casing section below the packer is in contact with CO_2 and needs to be made of corrosion-resistant material.
- A high-performance tubing connection needs to be used. It is well known that, even with the proper selection of the tubing materials, connections can be damaged and become a leakage path during operations. Connections must therefore be gas-tight and corrosion-resistant, as well as able to withstand expansion and contraction during thermal and pressure cycles, and last but not least, they must be able to withstand the expected loads.

Mitigation of mechanical failures in the steel is controlled with the right choice of the injection parameters. The process needs to be modelled in specialist engineering software, and the suitability of the tubing needs to be assured for the variety of mechanical loads expected during the operation of the well.

Mechanical integrity depends on the steel grade and geometrical parameters of the tube. The idea is to observe loading scenarios for tubing because it is the weakest point in the system. Worst-case scenarios need to be observed while modeling the process. They are:

Tubing:

- Tubing injection
- Shut-in
- Tubing leak (collapse)
- Full/partial evacuation

Each of the scenarios observed above can be present during CO2 injection through the tubing. While tubing injection is a normal and expected operation, other scenarios can result from failure or damage and need to be calculated to assure that the system will withstand loads in case of these scenarios.

This is important to estimate, as it also shows if the suitable tubing diameter was chosen.

b) Cement damage mitigation

Once the cement is set, it is no longer possible to influence such parameters as displacement, slurry content, or cementing practices. That is why other cement degradation mitigation techniques should be considered. The scope of this thesis is to assess existing wells built 30 to 40 years ago, and at that time the cement was placed, it is evident that degradation of the cement took place to a certain degree. In most cases, de-bonding or even cracking of the cement sheath can be expected. Therefore, any repair, remediation, or integrity improvement of the existing well barriers made from cement will have to utilize special and fit-for-purpose materials, designs, and operational practices as a part of workover operations to fulfil the requirements of restoring well integrity for the intended CO2 storage.

Cement slurry design plays a great role in cement degradation. Modification to the Portland based cement systems is necessary to increase the suitability of the cement for this particular operation.

Ways of modification can be divided into three directions:

- Reduce the permeability of the cement matrix;
- Reduce the amount of the reactive particles by using special materials;
- Protect reactive particles with coating;

Starting with permeability reduction, some methods are commonly used (T. R. IEAGHG 2018):

- Reduce water/cement ratio;

Reducing the amount of water used for the same amount of cement will reduce permeability, which is favourable from a degradation point of view.

Reducing the W/C ratio, however, will also increase the density of the slurry, which is a great disadvantage for such wellbores that cannot withstand higher hydrostatic pressures. Also, the viscosity of the slurry will increase; thus, dispersants need to be added to control this parameter. These parameters are vital for the squeeze cementing operations, and it is important to control them not to compromise the operations.

- Reduce cement permeability and density by adding diluents;

One of the most common materials to use in this case is pozzolans and fly ash. These additives were used successfully for a long time (Khizar 2019). They reduce the volume of reactive material and reduce cement permeability better than systems with materials like bentonite or silicates. In addition to the main effect, they also reduce the density of the slurry, which is beneficial because high densities can be detrimental for squeeze cementing operations, which need to be prioritized as a part of the workover.

- Use three-particle approach;

The concept is adding specific particle-sized materials that fill pore spaces and, as a result, reduce permeability. In addition, the concentration of reactive components is also decreased. On the other hand, mechanical performance will improve, and higher strength will be achieved compared with the pozzolan systems.

A solution here is a “tri modal” or three-particle approach, which led to the development of several high-performance cement systems. It can cover a wide range of slurry densities, making them available for various wellbore conditions.

- Use materials to protect reactive particles;

The idea here is to add special components that will protect reactive particles. The most common additives are extenders.

Any material with a specific gravity lower than that of cement will act as an extender. Such additives reduce the density of cement slurry in one of three ways. Pozzolanic and inert organic materials have a lower density than cement and can partially replace cement by reducing the density of the solid material in the slurry. Physical and chemical expansions have a lower density and absorb water, allowing more water to be added to the cement slurry without free liquid or particle segregation. The gases behave differently in that they produce foamed cement with exceptionally low density and acceptable compressive strengths.

- Operational accuracy;

The quality of the cementing process itself, e.g., good mixing of the slurry or best practices on displacement, is of great importance to install a durable and defect-free cement sheath.

Good mixing of the slurry is an important consideration at this stage, and the slurry needs to be homogeneous and ideally have the same properties at every point of the slurry. Poor mixing and maintenance will result in an inhomogeneous mortar, which may also damage the future cement sheath.

Another consideration that needs to be taken into account is cement displacement, and it does not matter if it is a primary or remedial cementing. During such operations, all the properties need to be assumed. One of the best practices is to pump the lead cement, followed by the higher density tail, so the higher density tail will cover the zone, where the potential CO2 contact is possible. This will decrease the effect of hydrostatic and increase the displacement efficiency.

- Non-Portland systems;

Another solution is to use non-Portland systems that do not have limestone as a component, opposite Portland cement clinker. The downside of the non-Portland systems is that base materials are more difficult to obtain. The non-Portland systems include calcium sulfoaluminate-based systems and other specialty cement.

According to (T. R. IEAGHG 2018) calcium sulfoaluminate-based cement is the best choice for CO2 storage as it is not reactive with CO2. The wide amount of CO2 injection case studies in the USA approved that this cement system was able to maintain integrity even in high-rate acid injection wells.

The downside of using special cement like this is that they are complex systems and require additional steps in planning.

Also, these materials are not compatible with Portland cement systems. Incompatibility of cement slurry while primary and remedial cement operations can be an issue.

Other specialty cements are geopolymeric, magnesium oxide cement, hydrocarbon-based cement systems, and even ceramic-based cement. They are types of cement that were evaluated to be not reactive to CO2. However, the main downside is the low frequency of their usage and low experience gained from using these cements.

As these types of cement are not widely used, additional testing of the common cement additives needs to be done to evaluate cement system properties in greater detail which can be not economically beneficial to carried out frequently. Lack of special testing could lead to not inappropriate cement slurry design; hence, problems with cement described earlier.

Usually, specialty cement has a narrow range of densities and specifications. For example, ceramic-based cement was initially designed for nuclear waste disposal at shallow depths and therefore is not resistant to high pressure and temperature conditions.

For remedial cementing, special requirements for the cement slurry need to be considered (Nelson E.B. and D. Guillot 2006):

- Rheology and sedimentation;

Low viscosity allows pumping through coiled tubing and penetration into small cracks and voids. But, if the viscosity is below a certain value, it can lead to free water formation and sedimentation. On the other hand, thick slurries are useful for cementing large voids.

- Low gel-strength during placement;

It is essential since gelation restricts slurry flow and increases surface pressure.

- The choice of cement particle size depends on the type of leak and the formation;

Engineering micro cement can be used to repair small leaks in cased formations or in low-permeability formations. To repair leaks in unconsolidated formations, gravel/grain size, permeability and pore size of the formation are used to determine the suitable cement particle size.

- The absence of free water is desirable;

- Proper fluid-loss control confirms optimal filter-cake build-up within cracks and perforations.

The fluid loss rate can be adjusted from low (<50-100 ml/30 min) for small fractures or to match formation permeability to high (300-500 ml/30 min) for large fractures or voids behind the casing.

- The thickening time for squeeze jobs is designed so that squeezing, placement, and subsequent well cleanout are possible.

Thickening time is usually a function of thermobaric conditions in the wellbore. The temperature in squeeze cementing is usually higher than in primary cementing, which should be taken into account in the design of the cement slurry.

- A higher cement slurry density results in a better quality of setting cement, but causes higher hydrostatic pressure during placement.

By adjusting the particle size in the suspension, a low-density suspension with good mechanical properties or a high-density suspension with relatively low viscosity can be obtained.

Chemical resistance;

This project implies that it will be pure CO2 without impurities injected for storage; that is why it is not needed to consider the resistance of cement to other additives except CO2.

- Economic cement slurry design;

The cement costs less than 10% of the total squeeze operation costs. Choosing the cement system that increases the chance of squeeze job success is thus recommended.

According to cement slurry requirements and available cement solutions, the best choice is to use "tri-modal" cement solutions or pozzolan (fly ash) solutions. The three-particle solution might be the superior of the two due to higher strength. As an example of such a cement solution, the "CRETE" cement family can be mentioned.

The primary mitigations for mechanical failure of the cement are slurry design and quality of operations, as they will ensure the required mechanical strength.

c) Sealing elements damage mitigation

The main damage mechanisms of elastomer elements and their consequences observed in section c), need to be mitigated in future operations.

According to the (T. R. IEAGHG 2018), the main strategy of damage mitigation of the sealing elements in CCS operations is the right choice of material. The USA has a lot of experience in CO2 EOR, which is even harsher in terms of the injected media (WAG technique). WAG or water alternating gas is an enhanced oil recovery process. Water and gas are injected alternately to improve sweep efficiency and reduce gas channelling from an injection to a production well. The idea is to use the same materials in CCS used in CO2 EOR, as the damage mechanism is the same.

According to the (Solutions/API 2008) the following materials, represented in Table 5, are recommended for each sealing element.

Component	Material of selection
Christmas Tree (trim)	316 SS, Nickel, Monel
Valve packing and seals	Teflon, Nylon
Wellhead (trim)	316 SS, Nickel, Monel
Tubing hanger	316 SS, Incoloy
Tubing joint seals	Coated threads and collars (IPC), seal rings (GRE)
ON/OFF tool, profile nipple (if exists)	Nickel plating of the wetted parts, 316 SS
Packers	Internally coated hardened rubber of 80-90 durometer strength (Buna-N), nickel-plated wetted parts

Table 5: Sealing elements and their material of selection

The key points that are covered in the table above can be represented as follows:

- 316 SS is the metal of choice for the valve trim or wellhead trim in any wetted region. The corrosion-resistant properties of stainless steel (316 SS) were observed in the previous sections;
- Buna-N and Nitrile rubbers with an 80-90 durometer reading are used for packers effectively; the same is valid for Teflon and Nylon for the valve packing and seals applications;
- Tubing thread leaks are one of the most common source of tubing integrity loss problems. For better sealing, sealing rings are used. As a solution for the unsealing of the tubing can also be an appropriate make-up torque that does not exceed allowable limits
- For packers, nickel plating is used on all wetted parts, and internally coated hardened rubber elastomers of 80-90 durometer strength are used to prevent permeation.

3.3.2 Commonly adopted remediation techniques

The scope of this Master Thesis is to provide recommendations and observe risks that can appear while converting existing production wells to CO2 injectors. When risks are known, it is needed to describe the operational solutions to overcome these risks and decrease their probability. These solutions can be adopted as a part of workover operations.

In general, well components can be divided into permanent and retrievable ones.

The permanent components are such structural components as casing or cement. Generally, casing and cement sheath cannot be retrieved. There is an option to mill a section and place a new casing and cement, but it is not economically feasible in many cases; that is why it will not be considered, and we observe structural components as permanent ones.

The retrievable components include a part of the completion assembly which can be taken out to the surface during well intervention operations. An example of the retrievable components could be tubing or Xmas tree, which can be retrieved and changed to fit-on-purpose.

In the case of the permanent components, where no retrieval and replacement are possible, special techniques are needed to remediate the risks mentioned in the previous sections.

1) Casing repair techniques

CO_2 injection wells face the same risks with casing/tubing leaks as production wells, especially if a well was initially designed as a production well and has been in operation for many years.

Casing leaks can also be repaired by squeeze cementing. The squeeze cementing operation can cause further damage to the casing due to the pressure exerted. Another option is to place a cement plug in the damaged casing, which is more successful than the squeezing (Nelson E.B. and D. Guillot 2006), but this solution can only be applied during the plugging & abandonment phase.

This section focuses on alternative methods involving casing integrity restoration, which allow continued operation of the wellbore. A number of these methods are also used to repair cement leaks behind the casing.

- Patching casing;

This method is an alternative to squeeze cementing to repair casing/liner leaks when squeeze cementing has failed or is not applicable. A casing patch can be placed over or completely replace a damaged part of the troublesome casing (Manceau J.-C. 2014). In the latter case, the inner well diameter is retained.

Casing patch can be coated with epoxy resin on the outer surface before placement across the desired interval. An expander assembly functions as expanding a patch against the casing. A simplified example of its installation can be found in Figure 5.

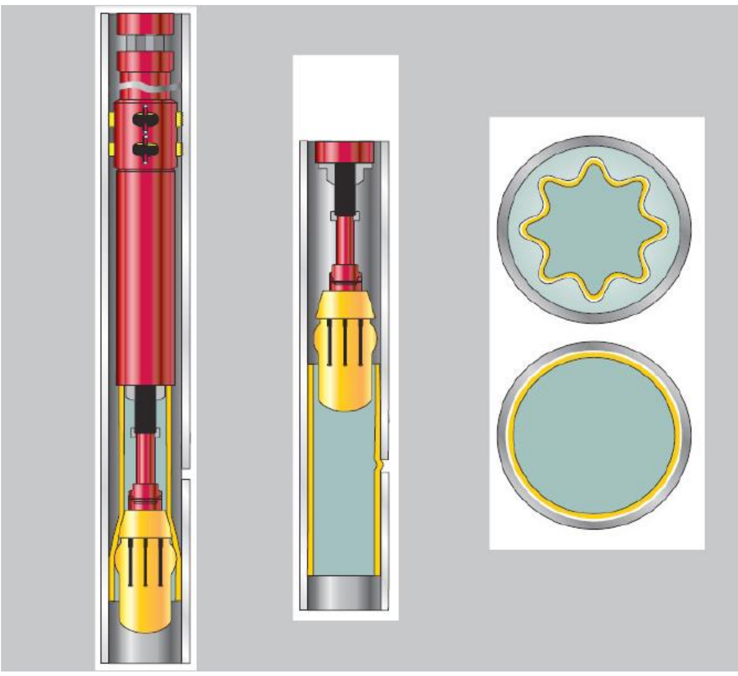


Figure 5: Steel liner casing patch installation procedure: 1) After placing over the desired interval, the patch is expanded; 2) fully expanded patch covering the leak site; 3) top view of the casing patch before and after expanding

The expanded patch is attached to the casing wall by friction caused by compressive ring tension. During expansion, the epoxy fills voids in the casing and becomes an additional sealant. This technique creates a hydraulic and gas-tight connection between old and new casing. Patching casing operations can typically be conducted in a matter of days. This technique proved its efficiency in several case studies.

- Expandable Casing/Liner;

The expandable casing has become a standard technology in the oil & gas industry over the past 10-15 years. It is commonly used in extended reach drilling but can also remove leakage in existing wells. It is primarily used for damaged casing sections. After expandable casing is in place, perforation can be repeated.

A desirable option is to use this technology in the existing well at the long interval of the damaged tube. The expandable liner is run downhole together with the expander assembly, which contains a solid cone. When the liner has reached the desired depth, the expansion process is initiated by driving the cone through the liner from the bottom upwards using mechanical force or hydraulic pressure. During the expansion process, the liner diameter increases, therefore, reduces overall liner length. On the other hand, wall thickness decreases not significantly. The expansion is complete when the anchor hanger seals the expandable liner against the casing. An expandable liner can comprise many joints to create the necessary length.

Expandable liner technology can be used to expand the existing casing/liner that is cemented in place. When the casing expands, the hydrated cement in the annulus behind the casing shrinks. In laboratory experiments (Kupresan 2014), it has been observed that after expansion the cement becomes softer and changes its consistency. But after a certain period of rehydration (in contact with water) the cement regains its compressive strength and solid structure.

Correct material selection is important in any of these operations, whether a patch or expandable casing/liner, according to the best practices observed in section 3.2.4.3.

- Swaging;

When casing is deformed or collapses in the well, a swaging technique is used to restore it to its correct shape (Manceau J.-C. 2014). A swaging tool forces the tubing or casing walls out while driven through a deformed/collapsed section.

2) Cement repair techniques

This section aims to examine commonly adopted techniques and tools with which repair operations are performed.

Various techniques are used either for remedial cementing during primary cementing operations or well remediation as a part of workover operations. General applications are represented in the list below:

- Repairing an unsuccessful primary cement job (insufficient bonding, mud channelling, cement degradation)
- Repairing casing or liner leaks (corrosion or split pipe)
- Well zonal isolation

- Plugging one or more zones (in case of injection well).

Squeeze cementing is performed through perforations, holes, or fractures in the casing or the annular space into a target interval, which can be behind the casing, or into the formation ((Nelson E.B. and D. Guillot 2006), (Manceau J.-C. 2014)).

Squeeze cementing operations start with wellbore preparation. If the slurry needs to be injected bottom-off, a plug must be installed below the squeeze interval to prevent the slurry from flowing further downhole. The slurry is pumped through drill pipe or coiled tubing as a part of workover operations until the wellbore pressure reaches the predetermined value. In most cases, the tubing is pulled out of the cement slurry during the setting period. The next step is removing excess cement, which is usually performed by reverse circulation as a part of workover operations.

The term squeeze cementing is wide itself, and there are different classes of this operation. Each of them is designed to be fit on purpose for each particular issue. The classification is represented below:

- Low-pressure squeeze;

Low-pressure squeezing is the best option for remedial work in the producing zone. The reason for this is that in this operation it is possible to precisely control the pump pressure and slurry hydrostatic pressure, thus avoiding formation fracturing (Nelson E.B. and D. Guillot 2006).

Circulating squeeze is a typical low-pressure method. This procedure involves circulating cement slurry between two perforations, isolated by a packer or cement retainer. If there is only one set of perforations, or the zone to be cured is not close to the perforations, the casing can be perforated from both the upper border of the casing and the lower one to reach the de-bonded interval of the cement in the annulus. This will create a possibility to cure the annuli and assure bonding in the preferable interval.

This method is efficient only if the flow can be achieved in micro annuli with low pressure. A cement retainer can be easily removed after the operation.

- High-pressure squeeze;

If there are micro annuli, channels or fractures in the annular cement, or if fluids and debris cannot be removed at low pumping pressures, low pressure squeeze is not a suitable remedial option (Nelson E.B. and D. Guillot 2006). In such cases, it is necessary to induce fractures in the formation at or near the perforated interval to allow cement slurry placement. Further pressure initiates dehydration of cement and the filter cake accumulates on the formation walls and in all channels and fractures.

One of the methods of squeeze cementing that is especially good for preventing leakage either above or below an injection zone that has poor zonal isolation is block squeeze.

The sections above and below the target formation should be perforated for this operation, which requires isolating a permeable zone with a packer or retainer. The permeable interval below the future injection zone is perforated and squeezed first, then the permeable interval above. The two residual cement plugs are drilled out after squeezing. Then the injection zone is ready for the perforation as a part of the preparation for the injection operations.

- Bradenhead squeeze;

The Bradenhead squeeze technique is a low-pressure squeeze applied after making sure that the casing can withstand the applied pressure (Nelson E.B. and D. Guillot 2006). The good thing about this technique is that no additional tools are required and the success rate is high.

It is often applied with lost circulation problems or after a primary cementing job to fix a soft casing shoe. A hesitation squeeze pumping method, where pressure is applied intermittently, separated by pressure falloff intervals, often forces the cement slurry more effectively into the voids. Most coil-tubing squeeze applications use this technique.

Still, there are some drawbacks to the Bradenhead squeeze. The list below observes them:

- The whole casing is exposed to pressure during waiting-on-cement time. Casing integrity must be certain.
- -During squeezing, the casing expands and restricts the flow of cement slurry through the micro-annuli or microchannels in the annulus. These channels may not be filled with the slurry and will reopen after pressurizing is stopped.

Following, the main sealing tools that are required for the cement squeezing operations are introduced. The main application of squeeze tools is to isolate the wellhead and casing from high pressures applied during operations. The list below describes two commonly adopted tools used in squeeze cementing operations.

- Retrievable Squeeze Packer;

Compression or tension set packers are used for squeezing. The packers can be installed above or below the target interval or between two intervals. The packer ensures circulation in the wellbore before the slurry is injected and seals the annulus during the squeeze.

Disadvantages of using this packer are:

- Backflow cannot be prevented;
- Reversing excess slurry may damage the squeezed cement;
- Mechanical problems during running/placement;
- Contamination of the cement is probable during the operation;
- Build-up of cement on the packer/string;
- Valve opening during squeeze job;

The retrievable packers have a by-pass valve that allows fluid flow when the packer is lowered into the wellbore and after the packer is installed. The valve is closed while the cement is being squeezed through. After cementing, the valve provides reverse circulation to clear excess mud. The main advantage over a drillable retainer is that the packer can be removed and reused.

- Drillable Cement Retainer;

Cement retainers are drillable packers with a controllable valve. Cement retainers or bridge plugs create a false bottom and isolate the wellbore below the squeeze target. Cement retainers are used to prevent backflow or a high negative differential pressure that disturbs filter-cake build-up. A cement retainer has the advantage that it can be placed more precisely than a packer, close to the formation or between perforations.

Disadvantages are an additional trip for its setting, and the fact that it cannot be reused.

Table 6 represents the summary of the squeeze cementing operations and their application according to the description above.

Squeeze technique	Application
Low-pressure squeeze	Loss of well integrity in producing/injection zone
Circulating squeeze at low pressure with cement retainer/packer	Annular cement failure; casing/liner leak
High-pressure squeeze	Channels, cracks, micro-annuli in cement; casing shoe or liner top remediation cementing
Block squeeze at high pressure with cement/retainer	Zonal isolation of a permeable zone – leakage prevention
Bradenhead squeeze with coiled-tubing and retainer/packer	Annular cement failure; casing/liner leak

Table 6: Summary of squeeze cementing operations

Depending on the failure mode, the most appropriate technique can be used.

3) Sealant repair techniques

Another solution for the mitigation of both casing and cement leaks is the use of sealants. Sealants were initially used for hydraulic control lines and surface-controlled subsurface safety valves (SCSSV) ((Rusch 1999), (Julian 2013)). As sealant technologies improved over time, they became a successful remedial technique for the leakage of the casing/liner.

The purpose of this chapter is to demonstrate the main sealant technologies that are available so far and elaborate on particular cases that can be used in a wide variety of applications.

Although there are different sealant technologies for different applications, the focus will be on preparing old production well for injection operations. The two main classes are pressure and temperature-activated sealants.

- Pressure activated sealants

The main applications where these types of sealants can be used for:

- Surface leaks - valves, pinholes, weld defects, etc.
- Wellhead leaks – pack-offs, bradenheads, casing/tubing hangers
- Casing/tubing leaks
- Cement leaks - micro annuli, plugs, cavern casing shoe
- Downhole leaks – SCSSVs, umbilical lines, subsea good control systems, packers, pressure and temperature gauge mandrels, etc.

An example of this technology that is presently in use is Seal-Tite®. The pressure-activated sealant formula consists of a supersaturated mixture of short-chain polymers, monomers, and other components (Rusch 1999). High differential pressure at the leak site causes polymerization of the sealant into a flexible solid, as illustrated in Figure 6.

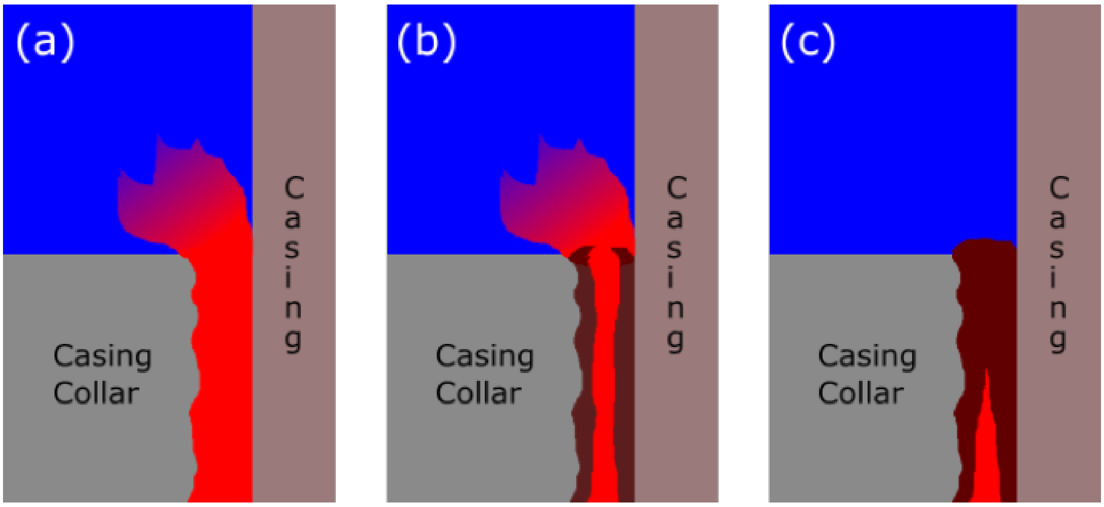


Figure 6: Illustration of the mechanism of a pressure-activated sealant: a) The sealant is pressed through the leak under pressure; b) The differential pressure causes polymerisation on the sides of the leak; c) The leak is plugged and the remaining sealant remains liquid as the differential pressure is no longer present.

The sealant polymerises first on the edges of the leak, gradually passes over the leak and closes it. The reaction stops when the pressure is reduced. The resulting plug is elastic and fills the holes/cracks in the leakage area. At first the plug is brittle, but over time it gains strength while remaining flexible. The cork can withstand 9×10^{11} pressure up to the pressure that activated its polymerisation. The remaining injected sealant remains liquid - it does not clog or block the hydraulic system. The effectiveness of the sealing mechanism does not depend on the pressure, temperature and time required to reach the leakage point, as the formula of each sealant is developed individually for the specific problem.

The advantage of pressure sealant remediation is that no well workover is necessary, which greatly reduces costs. This is why this technology has become popular in subsea, offshore and Arctic/remote areas. It is used worldwide and a high success rate of 80% has been recorded between 2005 and 2012((Rusch 1999), (Julian 2013)).

The majority of repairs concern wellhead pack-offs. However, the development of an ultrasonic leak detection system made it possible to use this sealing technology to repair small leaks in the casing/pipes without pulling out the pipes.

- Temperature-activated sealants

Temperature-activated sealants are polymer resin systems designed to cure at a specific temperature. This allows the sealant to be placed, injected or squeezed in a liquid state into the desired interval in the well and then cured when the resin reaches the appropriate temperature.

The curing temperature, density, viscosity and curing time can be precisely calculated for a specific application. In general, polymer resins tolerate some degree of contamination and are compatible with most wellbore fluids and cement. Processing of polymer resin systems can be reversible by means of milling or acid treatment. A couple of examples of commercially available thermally activated sealants are described below.

ThermaSet® (WellCem) is a polymer resin system elaborated for lost circulation issues (Knudsen 2014), channels in the annulus, casing leaks, and plugging in general (Beharie 2015). However, it can be used for other well integrity issues.

It penetrates permeable formation and narrow channels, cures into a flexible and robust plug that withstands thermal expansion, provides good bonding to steel and rock.

Temperature-activated sealants can, in principle, be used for squeeze-cementing and remediation of the casing and annular cement integrity loss.

d) Retrievable elements management

- Tubing replacement/repair;

Tubing replacement requires a workover operation, so the costs are comparable to packer replacement. This operation is applied when other more straightforward solutions cannot be used to remediate the leakage. When the tubing is pulled out of hole, the leaking parts are replaced, and the tubing is inspected if any other repairs are needed.

- Wellhead and X-mas tree repair;

Wellhead equipment can be quickly inspected and repaired for onshore or platform wells. For subsea wells, well head and X-mas tree repair implies a well service vessel and remotely operated vehicle (Manceau J.-C. 2014). Depending on the type of the problem, the repair can take place at the sea bottom or X-mas tree can be removed to be repaired onshore on site. The latter operation requires well killing.

- Packer Replacement;

A leaking packer is recognised by a drop in annular pressure if the casing and tubing are known to be intact (Manceau J.-C. 2014). Removal and replacement of the production or injection packer is a complex operation involving killing the well, removing the X-tree, pulling out the tubing and removing the packer.

The permanent packer is removed with a packer mill. After milling, the remaining packer pieces are retrieved and the well is flushed to remove debris. The retrievable packer is removed along with the tubing and then replaced.

Summarizing the range of technologies and methods used in the industry that can be used to repair and mitigate leaks that must be repaired before the well can be used for injection operations, a list of key observations can be given:

- Squeeze cementing;
- Casing/liner repair;
- Sealant technologies for zonal isolation include pressure- or temperature-activated sealants, polymer-based gels, and different cement systems.

3.3.3 Summary of remedial actions

Below Table 7 represents the applicability of each of the remedial techniques for the particular well barrier element.

WBE/Method	Squeeze cementing/ sealants	Casing/liner repair	Replacement
Formation	Yes	No	No
Annulus cement	Yes	Yes	No
Tubing	No	Yes	Yes
Casing/liner	Yes	Yes	No
Valves and wellhead	No	No	Yes

Table 7: Applicability of remediation methods for each well barrier element

3.4 Monitoring

Monitoring in CCS projects plays a significant role. With the help of direct and inferred measurements, the current state of each element in the well barrier element can be evaluated, tested, and approved to be able to work efficiently during the operations.

It needs to be conducted on every phase of a CCS project: assessment, injection and closure, and post-abandonment phase.

The more precise workflow of the monitoring setup can be represented with the diagram in Figure 7.

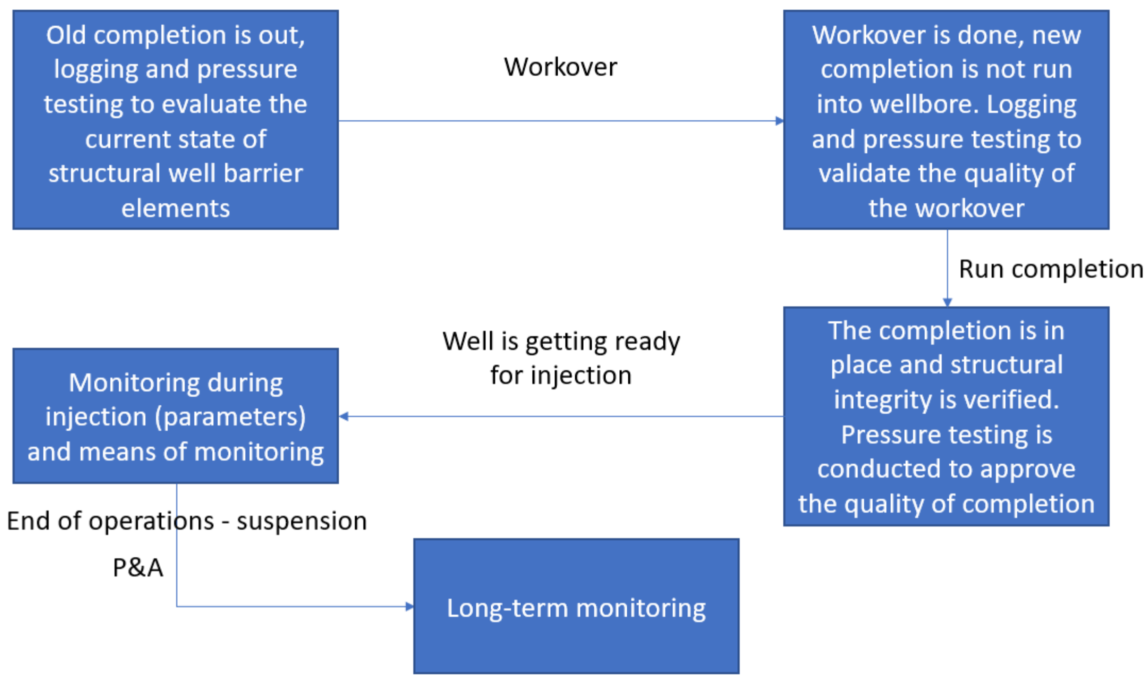


Figure 7: Roadmap for the monitoring phases

3.4.1 Pre-injection

To better understand the measurements, the whole life cycle of the well needs to be observed.

In the beginning, the well was drilled for production purposes. It needs to be assumed that the average age of the wells is 30 to 40 years. So, after the well was drilled, measurements were done to assure by pressure testing and logging that the cement was set properly and the casing string is intact. After the completion is run, it is also pressure tested with all the elements, before production operations commence. There can be well interventions during this time and measurements conducted after operations and periodically to assure well integrity. All those logs and data are called baseline.

After a production life of the well, the field where this well is situated is evaluated to be converted into a CO2 storage field. Therefore, the well needs to be assessed for the possibility to be converted.

A first assessment can be made according to the baseline measurements, but this can be problematic due to the age of the baseline data. If the well was built in 1980 and the last CBL was conducted in 1985, by 2021 the baseline data will no longer be representative and will not show the current state of well integrity. Moreover, if there were compromised well barriers 30-40 years ago, they are even worse now than in the past.

According to all the above, baseline data will help to understand potential problems that could exist and that could have gone even worse during operations.

After the well is selected, current measurements need to be conducted. The procedure must be the following (Wright 2011):

- The current completion needs to be extracted;

This is done to have access to the structural elements of the well to conduct testing and measurements. According to industry practices, the completion also needs to be removed for future workover operations.

- Pressure testing of the structural elements is conducted to examine if the integrity is maintained;

The only direct measurement at this state is a pressure test to a maximum differential pressure of the casing to assure integrity.

- Logging of the elements is conducted to evaluate the current state of the elements;

Logging is done to evaluate the current state of the structural components and the precise place of the damage to establish a detailed plan for the subsequent workover operations.

Table 8 below represents the methods that can be used for the purpose explained above.

Method	*Purpose*
Cement	
CBL/VDL	Estimation of cement quality, TOC; VDL is a preferable option
Casing	
Caliper log	Diameter of the casing (if any deformation is present)
Electromagnetic Induction tool (Electric potential tool)	Corrosion rate and wall thickness (cathodic corrosion)
Acoustic	If any casing leaks are present

Table 8: Measurements before and after the workover (no completion)

All the demands listed in Table 8 can be covered by utilizing an Ultrasonic Imaging Tool which nowadays is industry common practice.

According to the diagram in Figure 7, the next step is workover. The main goal of the workover is to repair structural components that were compromised during the production life (Дмитриев 2007) or introduce new barrier elements, to create well barrier envelopes that are suitable for future operations. Procedure and operational details of such workover are not a part of this thesis.

The requirements for the structural elements are listed in section 0 and need to be followed to make the well fit-for-purpose in the future.

Once the workover of the structural elements is done, pressure testing and logging need to be conducted to ensure full integrity, after which the new completion can be installed. The measurements are the same as for the pre-workover monitoring setup represented in Table 8.

As mentioned in section 0, it is vital to run and test a completion that will withstand the injection cycles of the well. Elements need to be corrosion-resistant and appropriate for the expected loads and stresses.

Table 9 below represents the commonly adopted tests for each element of the completion and other retrievable parts that were replaced during the workover (DHSV, X-mas tree, and components, etc.).

Part of equipment	**Testing**
DHSV	- Pressure test at low and high differential pressure - Inflow test
Tubing and components	Pressure leak testing
Packer elements	- Inflow test - Annulus pressure test
Surface tree	- Pressure test valves at low and high differential pressure - Pressure test connections between tree and wellhead at high differential pressure
Tubing hanger	Pressure leak testing
Wellhead and component	Pressure leak testing

Table 9: Completion testing methods

At this stage, all the equipment is proved to function within the envisaged operational regime. and the injection phase can commence.

3.4.2 Injection

For the CO2 injection phase, a monitoring plan needs to be established that is consistent with regulations and laws of the region of operations.

For the Dutch part of the North Sea, regulations are controlled by the EU directive ((EU directive annex II 2017), (V. G. Vandeweijer 2011)). As a reference for the already adopted monitoring techniques, the P18 field operations were observed (V. G. Vandeweijer 2011)

Table 10 below describes to the main parameters to be monitored, monitoring frequencies, and main technical solutions for monitoring each parameter.

Monitoring parameter	**Frequency**	**Solution**	**Comments**
Injection rate	Continuous	Flowmeter	At wellhead
Injected gas composition	Continuous	Gas analyser	A compressor station
Well integrity logging	Every 2-5 years	Wireline logging + pressure testing	Wireline logging from surface+ pressure testing equipment
Wellhead pressure	Continuous	Surface pressure sensor	At wellhead
Wellhead temperature	Continuous	Surface thermometer	At wellhead
Annulus pressure	Continuous	Surface pressure sensor	At wellhead
Tubing head pressure	Continuous	Surface pressure sensor	At X-mas tree
Tubing head temperature	Continuous	Surface thermometer	At X-mas tree
Bottomhole pressure	Continuous (and monthly readings with memory gauges)	Pressure gauge	A part of downhole permanent sensors or memory gauges at the end of the tubing
Bottomhole temperature	Continuous (and monthly readings with memory gauges)	Fibre-brag grating sensor	
Pressure gradient	Every 6 month	Memory gauge combined with shut-in	A part of downhole permanent sensor
Temperature gradient	Every 6 month	DTS or memory gauge combined with shut-in	DTS is more preferable in terms of preciseness

Table 10: Monitoring requirements for the injection phase

Regarding frequency of well integrity logging, NORSOK – D 010 suggests to decrease the frequency of measurements with time, e.g., at two- year intervals initially, and after the third logging run an expansion to a 3.5- year interval.

In addition, according to (V. G. Vandeweijer 2011) each parameter, depending on its value, can represent normal, alert, and contingency situations. Suitable measures need to be applied to reduce the risk and hazards connected with each observed parameter.

Monitoring parameter	Normal situation	Alert situation	Contingency situation
Injection rate	Flow rate is within the pre-determined range No pressure fluctuations are present	Fluctuations at constant pressure or pressure exceeding the value above the maximum rate but still within the range of the safety margins. Cause of the pressure increase /fluctuations needs to be found (Compressor, or other sources).	Fluctuations at constant pressure or pressure exceeding the value above the safety margins. Injection needs to be stopped until the situation goes at least to alert value, and the cause of the pressure increase has been determined.
Injected gas composition	A defined % of the gas composition is maintained.	Allowed fluctuations are reached. Gas composition needs to be adapted and injection rate needs to be reduced temporarily	The gas contamination is above the allowed fluctuations. The injectivity is stopped temporarily until the gas composition is adapted.
Well integrity logging	All measurements are within the expected range.	Measurements are above the expected values. Additional measurements need to be done or repeat the ones that have already been done.	Measurements are significantly above the expectation values Injection must be stopped. Additional measurements must be taken to identify shallow gas accumulations, investigate options and be ready to abandon the well in an extreme situation.
Wellhead pressure	No fluctuations are expected at constant flow rates.	Loss of pressure is present Injection flow is reduced until normal	No recovery of injection pressure after lowering injection flow

Monitoring parameter	Normal situation	Alert situation	Contingency situation
		injection pressure is recovered and root cause determined.	Injection needs to be stopped, the cause needs to be investigated and evaluated whether conditions are safe to continue.
Wellhead temperature	The temperature is within the determined operational limits for the temperature range.	The temperature reaches the determined operational limits within 5 to 10 degrees. Additional measurements are needed to determine the cause.	The temperature reaches the determined operational limit within 5 degrees. Injection must be stopped until the cause of the temperature change is clarified and the operations are marked to be safe.
Annulus pressure	Constant pressure without any fluctuations.	Increase or decrease in pressure within safety margins. Perform additional measurements like logging or sampling and analysis of fluids to detect the presence of the leaked CO_2.	Increase or decrease in pressure above safety margins. Investigate the causes of the situation with additional measurements and consider options to remediate; as worst case the well needs to be abandoned.
Tubing head pressure	No fluctuations are expected at constant flow rates.	Pressure fluctuations above or below expected values. Lower the injection flow until normal injection pressure is recovered and investigate why.	Pressure fluctuations above or below safety margins. Injection needs to be stopped, the cause investigated, and evaluated whether the conditions are safe to continue.
Tubing head temperature	The temperature is within the determined operational limits for the temperature range.	Temperature reaches the determined operational limits within 5 to 10 degrees. Investigation is needed to understand the cause.	The temperature reaches the determined operational limit within 5 degrees. Injection must be stopped until the cause of the temperature change is

Monitoring parameter	**Normal situation**	**Alert situation**	**Contingency situation**
			clarified and the operations are marked to be safe.
Bottomhole pressure	Flowing downhole pressure in agreement with simulations	Deviations from expected values are observed. Recalibrate the reservoir simulation model until a history match is achieved.	Significant deviation from expected values is observed. Re-evaluation of the reservoir model needs to be done; injection might have to be stopped during this period.
Bottomhole temperature	Flowing bottomhole temperature agrees with the well model.	Deviation from the expected values. Recalibration of the initial model needs to be done until history match is achieved.	Significant deviation from expected values is observed Initial model needs to be re-evaluated. If no explanation of the pressure deviation can be given, the injection needs to be stopped until the problem is solved.
Pressure gradient	Pressure needs to fit the expected simulation model.	Deviation from the expected values is present. Recalibration of the reservoir simulation model needs to be done until history match is achieved.	Significant deviation from the expected values is observed. Re-evaluation of the model is required, and if the cause of the deviation is not found, the injection needs to be stopped for the period.
Temperature gradient	Temperature data is in agreement with the expected well mode	Deviation from the expected values is present. Recalibration of the reservoir simulation model needs to be done until history match is achieved.	If a significant deviation from the expected values is observed. Re-evaluation of the model is required, and if the cause of the deviation is not found, the injection needs to be stopped for the period.

Monitoring parameter	Normal situation	Alert situation	Contingency situation

Table 11: Normal, Alert, and Contingency situations for each measured parameter

It should be mentioned that tubing head pressure and temperature anomalies can appear because of supply problems or other issues at the surface. The sensors are situated at the X-mas tree.

3.4.3 Post-injection

The injection phase is finished when the planned amount of CO_2 is injected into the reservoir.

The post-injection phase can be itself divided into the following phases:

- Suspension phase;

During this phase, the well is suspended and monitored. The purpose of this phase is to monitor plume migration within the reservoir to confirm there is no leakage at reservoir scale, and to observe the dissolution of the overpressure zone near the injection well, as it spreads into the reservoir and makes the pressure profile homogeneous.

During this phase, attention must be given to legacy wells that interact with the same reservoir and are exposed to CO_2. The main issue is that materials used in now abandoned wells were not specially designed to resist CO_2. Cement plugs can be degraded by CO_2, and steel can be corroded. Apart from chemical damage of the existing wells, the pressurization of the reservoir can lead to mechanical failure, creating micro annuli in formation-cement and cement-casing systems and cracks within the cement. This can lead to the creation of new leakage paths of stored CO_2 into the environment.

- Abandonment phase;

Once the pressure profile within the reservoir is homogeneous, indicating the CO_2 has been distributed evenly and no overpressure near the injection wells is apparent any more, the suspension phase can be ended and the injection well(s)can be plugged and abandoned.

Before permanent P&A it must be assured that the integrity was not compromised during the suspension phase.

P&A operations and monitoring options during this phase are also out of scope for this thesis. This by itself is broad topic of research, as there are many possibilities for P&A, like using shale as a barrier to seal the annulus or specially designed slurries or polymers as a barrier inside the well.

P&A operations need to be done with great accuracy. The integrity needs to be assured because after the well is permanently plugged and abandoned, it is handed over to the region's government, where operations were conducted. The company will not be responsible for the well; therefore, it is vital to leave a safe legacy in terms of reputation and public safety.

The public does not widely accept CCS projects, so an excellent safety record will help increasing public acceptance as well as belief in such projects to be a solution for the environmental problems.

- Post-abandonment phase;

The long term-monitoring is mainly accomplished using seismic monitoring, where the CO_2 plume is monitored within the reservoir. It helps to predict and estimate if there is any leakage on reservoir or field scale. It can be possible that plumes will migrate to other reservoirs in the same field that was not deemed suitable for CO_2 injection because of chemical and mechanical unsuitability. This particular topic is not a part of the thesis but a part of geochemical and reservoir assessment.

Currently, there are few solutions for monitoring the well integrity of this phase, but some new solutions can be used to monitor the integrity of the plugged and abandoned phase.

One technology that can be mentioned here is EXPRO's so- called CaTS (Cableless Telemetry System).

The system was designed to measure pressure and temperature in different well applications, but it can also be used in the post abandonment phase, as represented in Figure 8.

Pressure and temperature are measured and transmitted to the receiver at the wellhead. A ship passing by can receive the information from the receiver at the wellhead. The tool has a power battery supply so that it can work autonomously and provides a good option to monitor the well integrity of the abandoned well and detect leakage at the early stages.

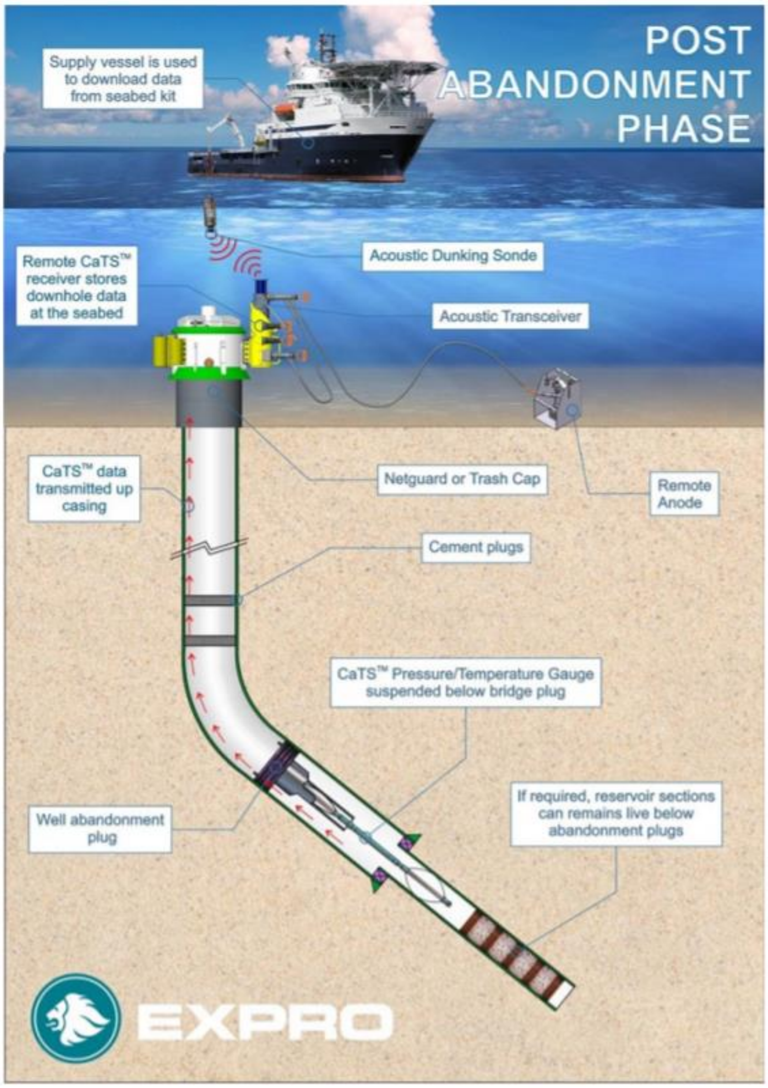


Figure 8: CaTS solution from company EXPRO (Horsfall 2018)

Chapter 4 Practical implementation

The main purpose of this part is to assess the well in terms of suitability to conversion to a CO2 injector. In Chapter 2 and Chapter 3, the main challenges and weak points were reviewed. Considering the provided knowledge and literature, it is now possible to assess real wells in terms of conversion into CO2 injectors and mitigate risks and hazards with the help of mitigation techniques observed in sections 0 and -.

4.1 Well conversion workflow

The workflow can be separated into phases:

- Initial assessment of suitability to well conversion to CO2 injector;

In this step, the decision must be made if the well is a suitable candidate by accessibility to the required reservoir and initial well design according to the project requirements. The baseline information of the well is analyzed to come up with the decision. In other words, at this stage, the most suitable well candidates in the field are chosen for further analysis.

- Assessment of well integrity;

At this stage, permanent and retrievable barriers of the well are analyzed.

During this evaluation, it must be stated that workover solutions must meet reliability criteria for all elements that make up the barrier well casing.

- The proposition of the fit on purpose design for the injection operations;

Here, the new design of the assessed well needs to be proclaimed. Project parameters are assumed at this stage, and it needs to be checked if the design can withstand the loads. Moreover, the monitoring plan also needs to be proclaimed for each well.

4.2 Initial assessment of suitability to well conversion to CO2 injector

To start with the individual well assessment, following work has been or is assumed to be conducted already:

- Geomechanical and reservoir assessment
- Reservoir for the injection is chosen and modelled to prove integrity
- Selected storage reservoir is “Buntsandstein” (Bunter Sandstone).

Initially, eight possible wells were ready to be assessed for the next step: four from group A and four from group B.

The main criteria here were:

- Reservoir availability and current design – if target reservoir is accessible;
- High seal potential of caprock which can serve as a primary barrier;
- Current operational state – if a well is suspended, there are no cement plugs which should be drilled. If the well is P&A, it is out of the scope of this assessment.

- All the information was extracted from various reports on the particular wells that were made available from the company's responsible business unit.

4.2.1 Assessment of group A wells

Group A wells include wells A1-A4. Their well design is shown in Figures 9-12, respectively.

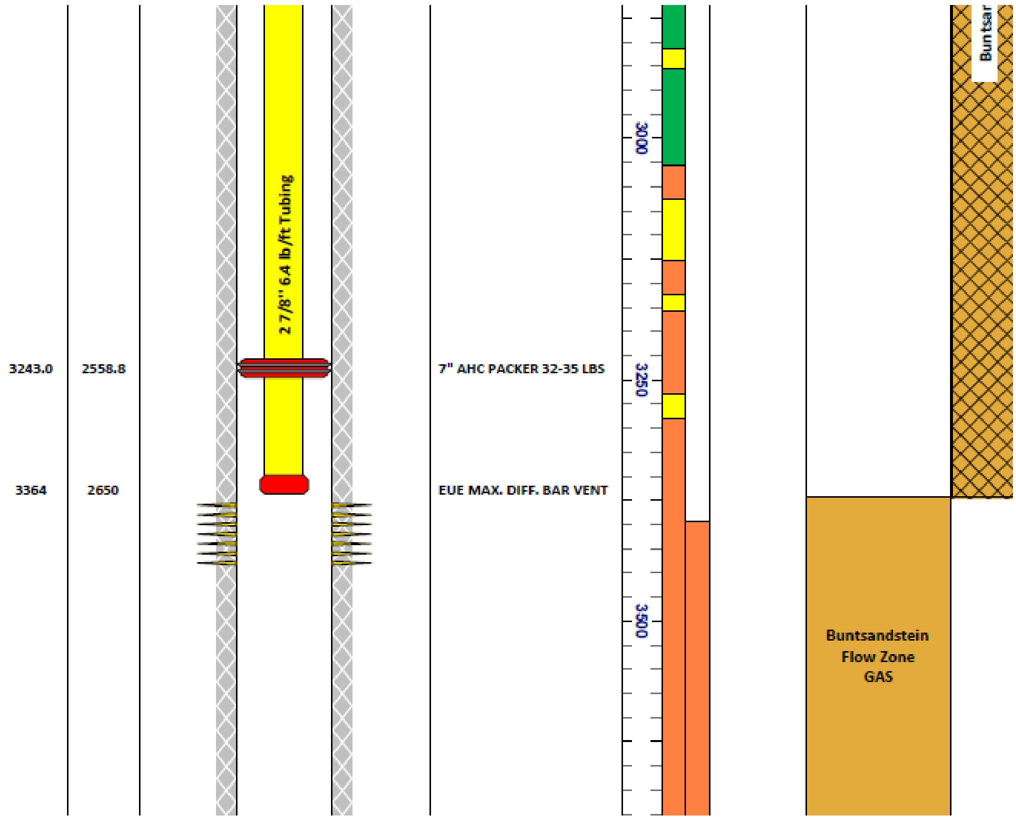


Figure 9: Well A1

As can be seen from the schematics, the perforations cover the desired reservoir that is going to be used for the CO2 storage. Initial design of the well is appropriate for the future operations. The production casing is long enough to be perforated if more perforations are required.

There is a caprock above the reservoir that can be regarded as a primary barrier in scope of formation.

This well is suitable for further assessment.

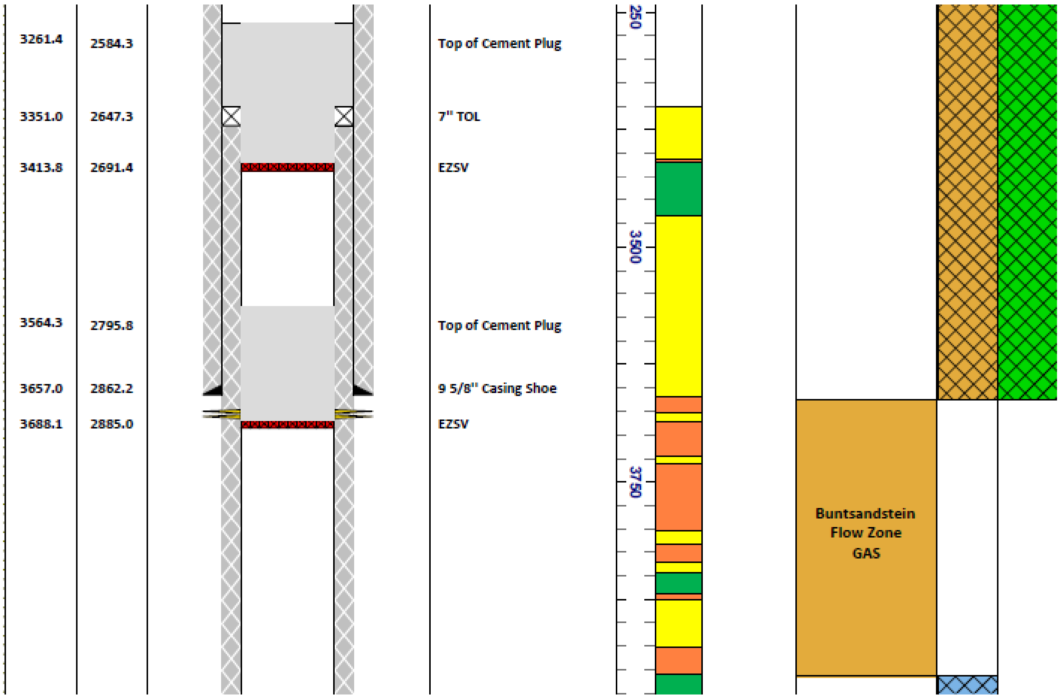


Figure 10: Well A2

The current design of well A2 can potentially provide a good access to the target reservoir, but the well is plugged and abandoned.

Therefore, this well is out of scope for further assessment.

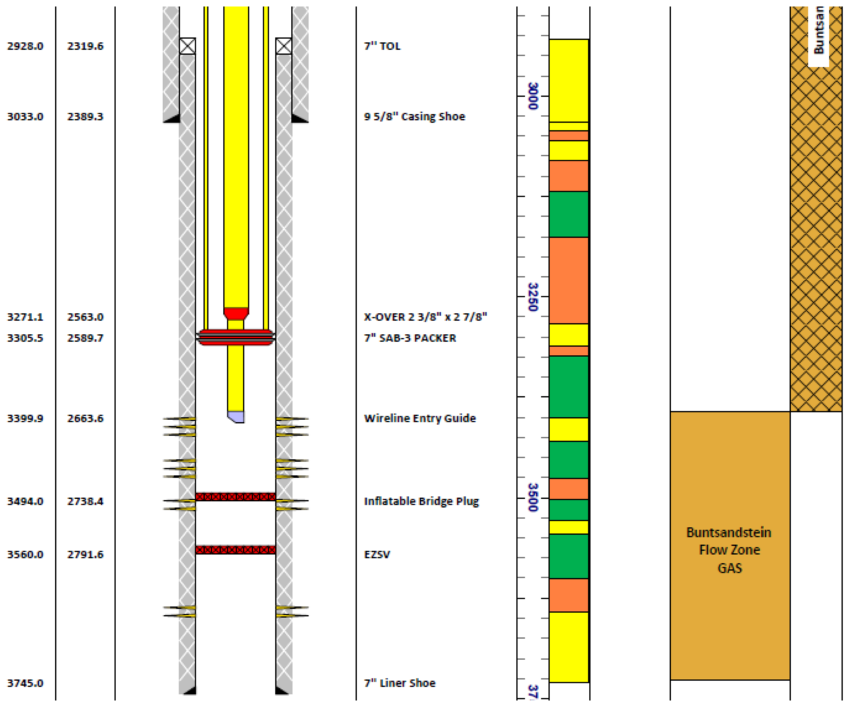


Figure 11: Well A3

Perforations cover the desired reservoir that is going to be used for the CO2 storage. Initial design of the well is appropriate for future operations.

There is a caprock above the reservoir, that can be regarded as a primary barrier in scope of formation.

The well is currently suspended and no cement plugs need to be drilled out before start of operations.

This well is suitable for further assessment.

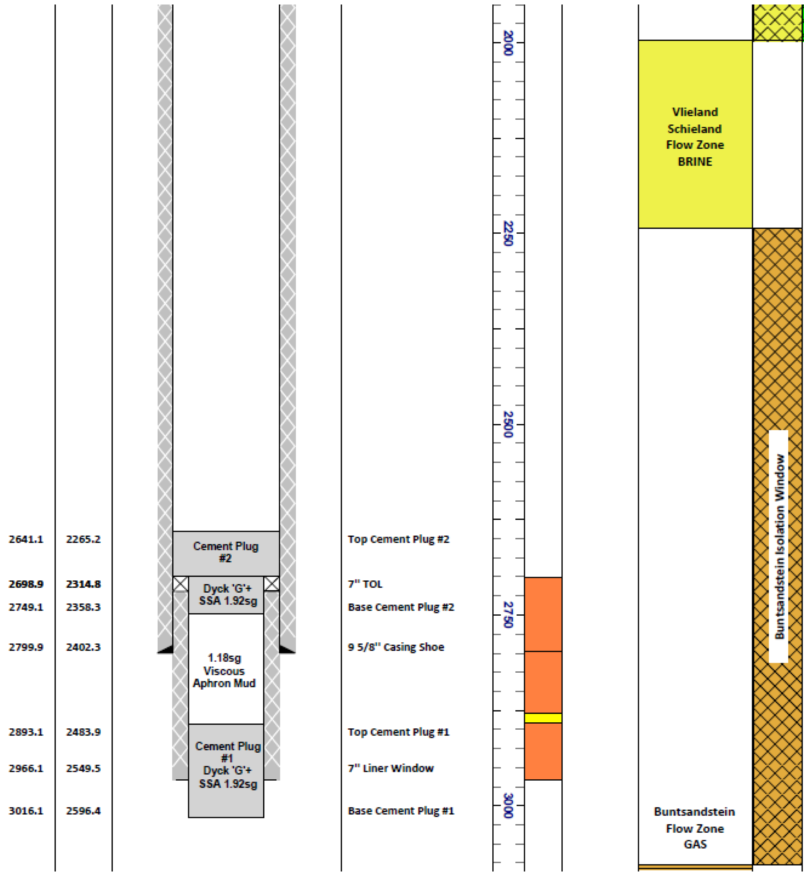


Figure 12: Well A4

The current design does not provide a decent access to the target reservoir. The "Buntsandstein" reservoir zone is thin and lays below the target measured depth of the well. It is also plugged and abandoned. Therefore, this well is out of scope for further assessment

Based on the assessment criteria, two wells out of four can be chosen to work on further. The summary is represented in Table 12.

Criteria/Well	Well A1	Well A2	Well A3	Well A4
Reservoir availability	yes	yes	yes	no
Sufficient caprock	yes	yes	yes	yes
Current state	suspended	permanent P&A	suspended	permanent P&A

Criteria/Well	Well A1	Well A2	Well A3	Well A4
Chosen for the further assessment	Yes	No	Yes	No

Table 12: Summary of group A initial wells assessment.

4.2.2 Assessment of group B wells

Well design for B1-B4 wells is represented in Figures 13 – 16.

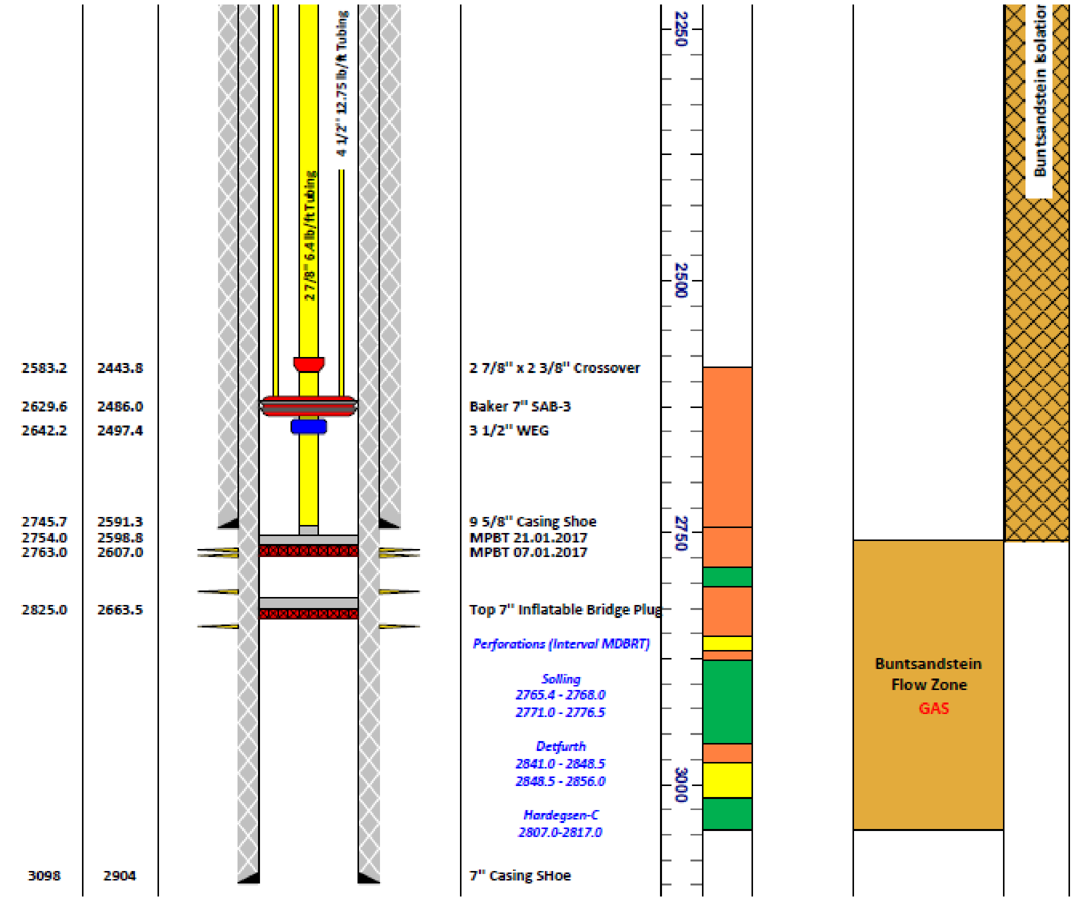


Figure 13: Well B1

The current design of well B1 can potentially provide good access to the target reservoir but the required zone of the well is plugged and would require additional work to drill out the cement plugs.

Due to this fact this well will not be considered further, however, after a more detailed examination of technical feasibility and cost impact of regaining access to the reservoir, the well could be assessed as again as a potential candidate.

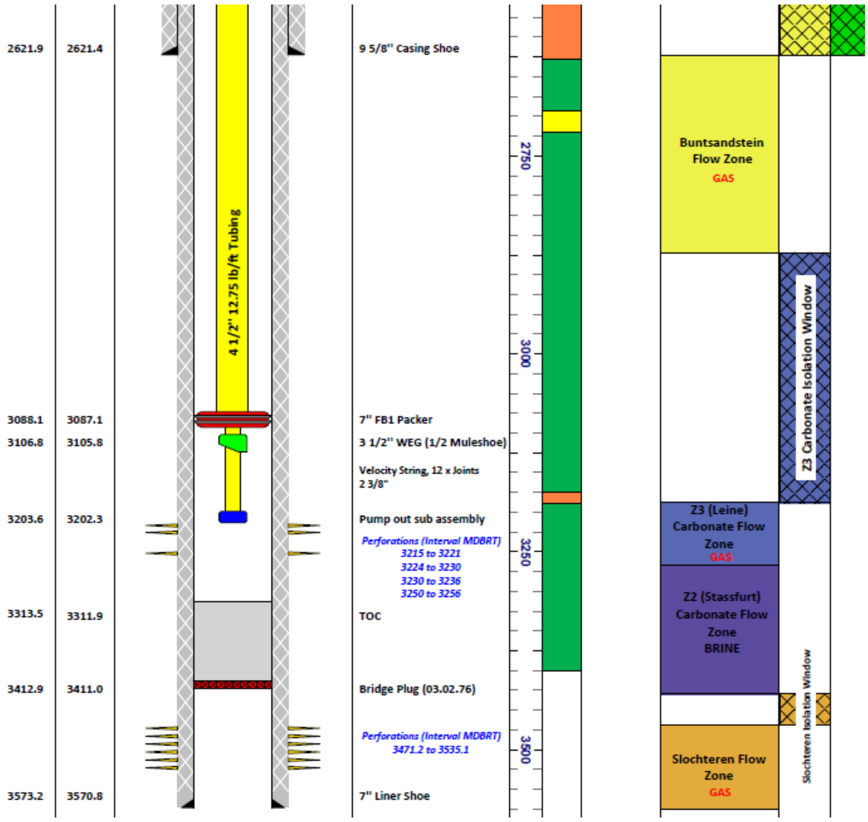


Figure 14: Well B2

Perforations in well B2 do not cover the desired reservoir that is going to be used for the CO_2 storage, but the initial design of the well is appropriate for future storage operations as the liner zone is available for more perforations to access the Bunter sandstone target reservoir.

There is a caprock above the reservoir that acts as a primary barrier.

The well is currently suspended state and no cement plugs need to be drilled before the start of operations. The cement plug at 3313.5 m measured depth isolates the lower flowing zones.

This well is suitable for further assessment.

An assessment of the suitability of the Buntsandstein flow zone with regards to injectivity, departmentalisation etc is out of scope for this thesis.

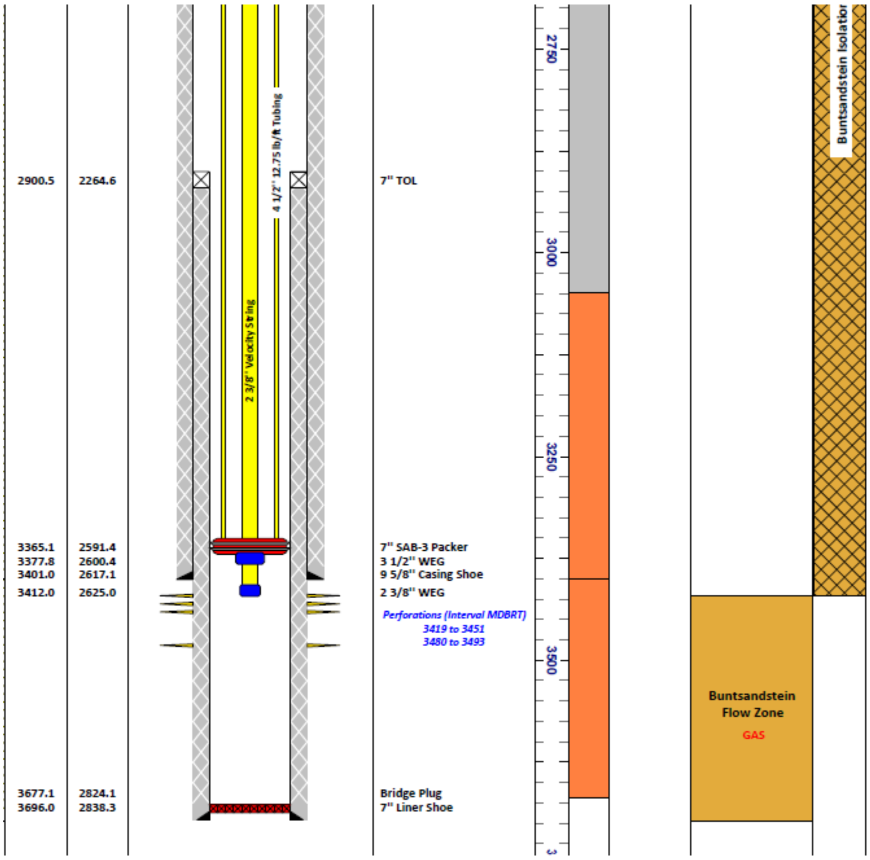


Figure 15: Well B3

As can be seen from the schematics, the perforations in well B3 cover the desired reservoir that is going to be used for the CO2 storage. The initial design of the well is appropriate for future CO2 storage operations.

There is a caprock above the reservoir that acts as a primary barrier.

The well is currently suspended and no cement plugs need to be drilled before the start of operations.

This well is suitable for further assessment.

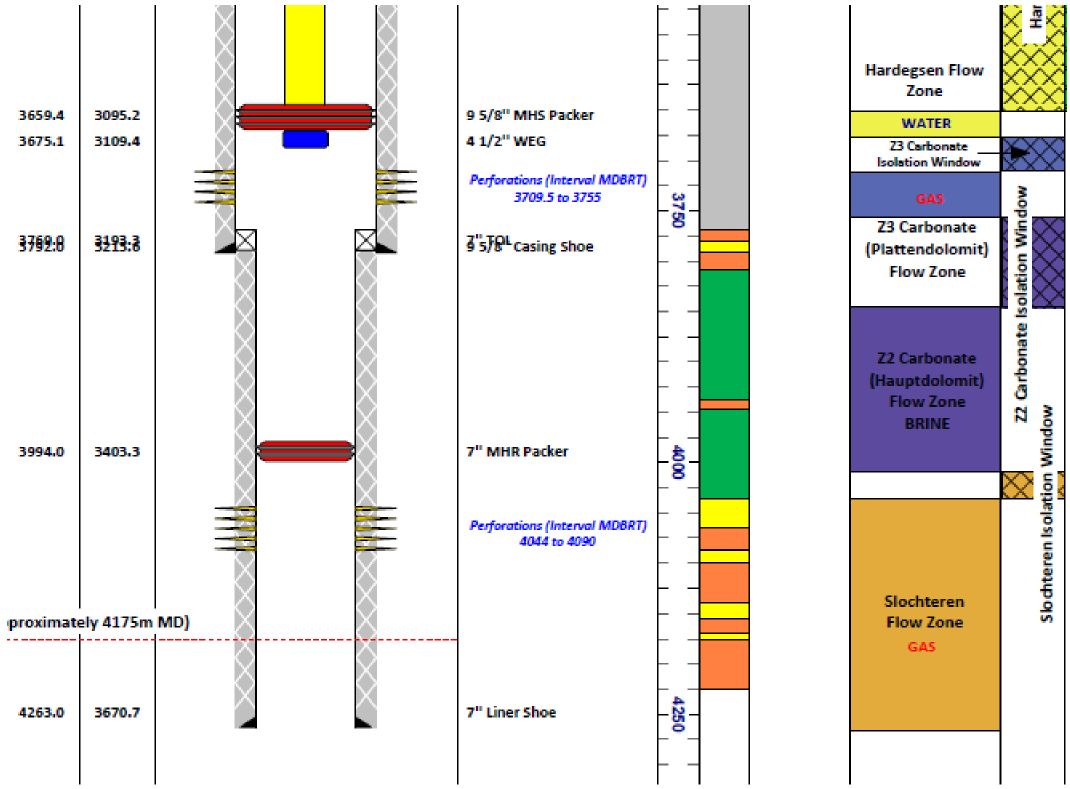


Figure 16: B4 Well Design

As one can see from the figure, the current design of well B4 does not provide access to the target formation. Therefore, the this well is out of scope for further assessment.

The summary of the assessment is represented in Table 13.

Criteria/Well	Well B1	Well B2	Well B3	Well B4
Reservoir availability	yes	yes	yes	no
Sufficient caprock	yes	yes	yes	yes
Current state	Plugs at target zone	suspended	suspended	suspended
Chosen for the further assessment	No	Yes	Yes	No

Table 13: Summary of group B wells initial assessment

4.3 Well Integrity Assessment

4.3.1 General workflow

The following steps are needed to be taken:

- Identify the barrier;

This step aims to identify all the barriers that keep the well fluid inside the wellbore and prevent uncontrolled discharge into the atmosphere or overburden. The main barriers to be observed in this part are those used during the well's production life.

The main focus of this assessment are permanent elements because retrievable elements can be easily replaced during the workover to serve the purpose, while most difficulties come up with permanent well barrier envelope components

Barriers with their function and design considerations are represented in section 3.1.2.

- Evidence of damage;

At this step, the possible well barrier damage needs to be understood. The information can be extracted from the baseline monitoring data. Even if it is old, the well integrity status for that time will be available.

Further information can be received from the measurements required to be made prior to and after the workover operations as a part of the monitoring plan, which is mentioned in section 3.4.1.

According to section 3.4.1, the old completion needs to be extracted to measure structural barrier elements' permanents. The possible solutions are observed in section 3.4.1

- Definition of the acceptance criteria;

The main aim of the acceptance criteria here is to cover both design requirements, covered in section 3.1.2 for each barrier, and special requirements that correspond to CO_2 injection, observed in section 0.

This criterion is important to make the well fit on purpose for the CO_2 injection operations

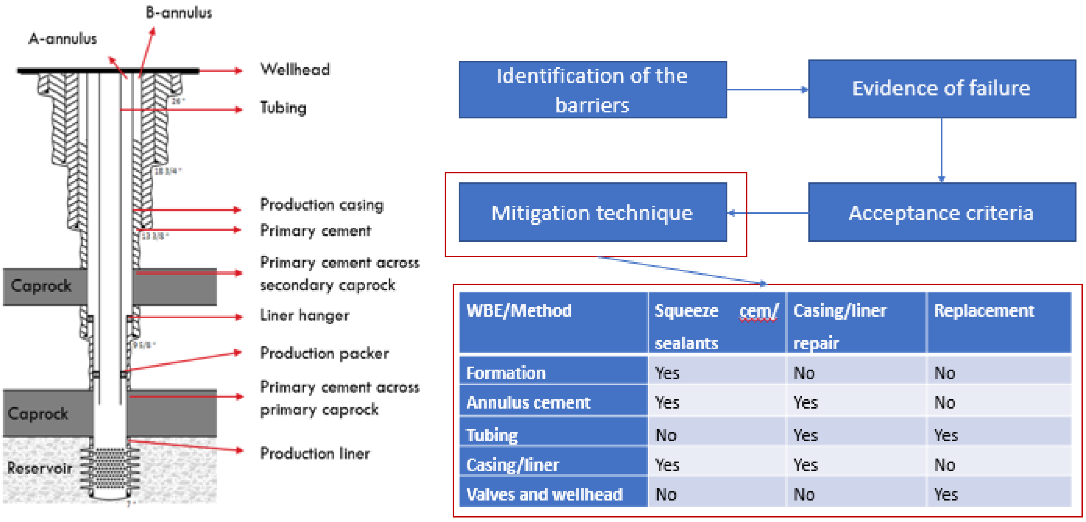
- Mitigation/remedial operations;

Once the damages are identified and the acceptance criteria for the elements are proclaimed, the damage needs to be remediated with the techniques observed in section 0.

As a part of the workover, according to section 3.4.1, the well integrity of the permanent structural elements needs to be assured with logging and pressure testing before running a new completion.

After running a new completion, which also has to fulfil the acceptance criteria, it must be pressure tested to ensure integrity.

The methodology with the example of the well is represented in Figure 17.



WBE/Method	Squeeze cem/ sealants	Casing/liner repair	Replacement
Formation	Yes	No	No
Annulus cement	Yes	Yes	No
Tubing	No	Yes	Yes
Casing/liner	Yes	Yes	No
Valves and wellhead	No	No	Yes

Figure 17: Methodology of assessment example

4.3.2 Well A1 Assessment

After running a new completion, which also has to satisfy acceptance criteria, it must be pressure tested to ensure integrity.

To start with the assessment, it is crucial to represent the well design, emphasizing the well barriers that need to be assessed.

Figure 18 represents the design of the well during the production phase. Retrievable elements were removed on purpose to assess only permanent structural elements

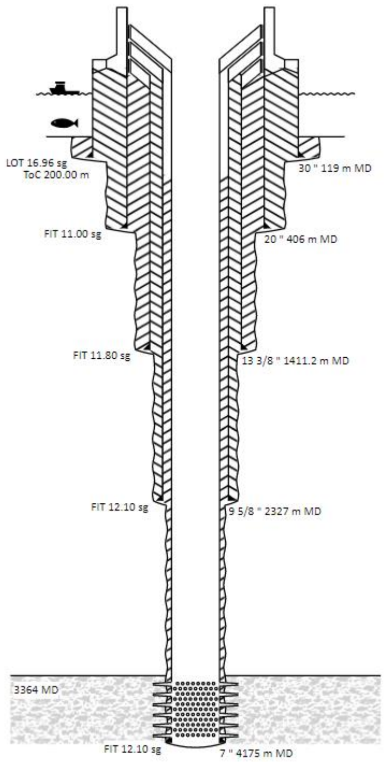


Figure 18: Design of the production well A1 in the assessment phase

As mentioned before, the assumption is that only core elements are observed, meaning that completion string with components will be excluded from the analysis. The main focus will be on the permanent well barrier elements:

- Cement quality;

This part includes observing the cement quality of the production casing, especially at the caprock and intermediate casing and the casing shoe across the caprock.

To evaluate the cement bonding, the cement bond logging (CBL) and variable density log (VDL) were run for the 7-inch casing and the zone near the shoe of the 9.625-inch casing. This assessment is based on the baseline, while further assessment and measurements are required to approve the current state, but if the bonding was poor in 1985, it would not get better in 2021. The required measurements for the assessment are represented in section 3.4.1.

The assessment of the CBL was done according to the internal isolation criteria in the company, described in Table 14 below.

Score	Description	Isolation
1	High CBL, strong casing arrivals, no formation arrivals. No bond between cement and pipe	No
2	Med to high CBL, strong casing arrivals, weak to no formation arrivals. Bond between cement and casing is poor, can be patchy/partial	No
3	Low to med CBL, Strong formation arrivals but still some attenuated casing arrivals visible. There is in general bond between the casing and the cement but there are possibly channels or micro-annulus	Unlikely to provide isolation
4	Very low CBL. No casing arrivals and strong formation arrivals. There is good bond between the casing-cement-formation	Likely to provide isolation

Table 14: CBL isolation score description

There is a rule of thumb in the industrial practice that a good bonding defined by the CBL is about 1-2 mV and a minimum of 3 m length of well-bonded cement. These are the benchmarked numbers from the industrial practice (V. G. Vandeweijer 2011).

Table 15 and Table 16 below represent the CBL/VDL logs interpretation of the area near the intermediate casing shoe and 7-inch casing, respectively.

Top, m (MD)	Base, m (MD)	Score	Remarks
2225	2279	2	High/medium CBL. Strong casing arrivals from VDL. Presence of double casing.
2279	2326	3	Low/medium CBL. Weak casing.

Top, m (MD)	Base, m (MD)	Score	Remarks
2294	2326	2	High/medium CBL. Strong casing arrivals from VDL. Presence of double casing.

Table 15: Isolation score of intermediate casing shoe area in Well A1

This section summarizes that remedial action before converting the well into the CO2 injector is necessary. The interpretation shows that the bonding of the cement is poor at the section being close to the casing shoe, and hence it is a potential hazard of the uncontrolled flow into the aquifer just above the shoe.

The most appropriate solution is high-pressure squeeze cementing to ensure a good bonding zone at the casing shoe.

Top, m (MD)	Base, m (MD)	Score	Remarks
2326	3028	3-4	From low to medium CBL. From weak to no casing arrivals. Good bond quality and mainly hydraulically isolated
3028	4153	2-3	Medium/high CBL. Medium to strong casing and weak formation arrivals from VDL.

Table 16: Isolation score of 7-inch casing in Well A1

The upper part from the casing shoe to 3028 is good quality, and no remediation is needed. The lower part that also includes the perforation zone is compromised by mainly bad bonding and hydraulic communication in the annulus. This compromised the cement across the primary caprock, and remediation actions are required.

Assuming that the evaluation is dated around 1986, it needs to be measured again.

It is crucial to have a good bonding across the primary caprock, for which the best solution is through squeeze cementing. This will help to recreate the bonding around the caprock.

As the bonding is recreated during remedial operations, the acceptance criteria are partly covered. The bonding is sufficient enough. Another criterion for the cement is to withstand the acidic environment with which it can be attacked.

As the squeeze cementing operations are required, the cement to be pumped needs to be resistant to the CO2 environment. The solution here can be pozzolan cement or tri particle cement solution from "CRETE" cement.

If all the discussed points are covered, the acceptance criteria are approved, making this barrier appropriate for the CO2 injection well.

- Production casing and intermediate casing

Both the 7-inch and 9.625-inch casings were pressure tested prior to production and did not fail, but pressure testing needs to be applied again to understand the current status. Production casing (7-inch) mainly consists of N-80 grade steel of different weights and P-110 grade steel. Intermediate 9.625" casing consists only of N-80 grade steel.

Table 17 below represents the grading and weights of these two casing strings.

Size, inch	Weight, lbs/ft	Grade	Top MD, m	Bottom MD, m
9.625	43.5	N-80	Surface	1695
	47	N-80	1695	2327
7	23	N-80	Surface	1723
	26	N-80	1723	2589
	29	N-80	2589	2761
	32	P-110	2761	2915
	35	P-110	2915	3412
	35	N-80	3412	4175

Table 17: Casing design of well A1

According to the reports, neither of the two casing strings was made of Cr13 steel, making them not resistant to the CO_2 attacks.

There was no information about the sustained casing pressure, proving the possible communication between the completion and the casing as well as in B and C annuli. That needs to be checked prior to workover.

The cement evaluation tool (CET) log was run in the interval 3397 – 3967m MD, mainly to check the casing conditions, and the result is that casing is in bad condition, having lower compressive strength. This means that it can be compromised during injection operations and need to be cured before the operations. Here it needs to be assumed that these logs were run long ago, and the condition needs to be checked

The idea here is to use an expandable liner that can solve two problems. The first is the poor casing quality, and the second is the capability to withstand an acidic environment by using the expandable liner manufactured with CRA. The main area of focus is under the production packer as it will be exposed to CO_2 through the operations.

The analysis above elaborates on the main structural elements that cannot be removed and changed. All the retrievable elements retrieved with the completion prior workover will be changed to fulfil the requirements.

Table 18 summarizes the analysis according to the defined workflow.

Well barrier	Evidence of failure	Special acceptance criteria	Remediation solution
Cement at production and intermediate casing	Poor bonding (CBL)	Resistant to CO_2 degradation	Squeeze cementing with degradation resistance slurry (e.g., pozzolan, CRETE) (section b) and 2))

Well barrier	Evidence of failure	Special acceptance criteria	Remediation solution
Production casing	Poor condition – decreased compressive strength (CET)	Corrosion resistance	Expandable casing patch from 13Cr or Super 13Cr material to withstand CO_2 corrosion (section a) and 1))
Tubing	Old tubing replacement due to aging effect	Corrosion resistance	A new tubing from CRA like 13Cr or 15Cr, depending on injected fluid (section a) and d))
X-mas tree and valves	Old tree replacement due to aging effect	Corrosion resistant components	Special material selection for the valves and sealing elements (section c) and d))
Packer and downhole sealing elements	Old elements replacement due to aging effect	Corrosion resistant components	Special material selection for the packers and sealing elements (section c) and d))

Table 18: Assessment results and solutions for the well A1

The assessment was conducted according to the reports and baseline data gained before 1990, which means that the situation could have worsened. Moreover, the wells were not initially constructed for future operations.

According to the assessment and monitoring plan, the logging and pressure testing need to be applied prior to workover and after the workover without completion. The new completion needs to be tested.

4.3.3 Well A3 Assessment

Figure 19 represents the design of the well during the production phase.

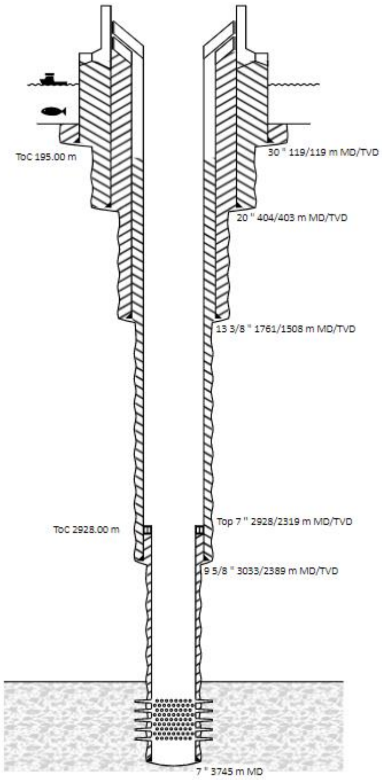


Figure 19: Design of the production well A3 in the assessment phase

- Casing/liner cement;

Table 19 and Table 20a below represent the CBL/VDL logs interpretation of the desired interval of liner overlap and 7-inch liner. The evaluation score is based on Table 14.

Top, m (MD)	Base, m (MD)	Score	Remarks
2929	3033	3	Low/medium CBL. Weak casing arrivals from VDL. Presence of double casing.

Table 19: Integrity score of liner overlap in Well A3

The summary of this section is that remedial action is necessary before converting the well into the CO2 injector. The interpretation shows that the bonding of the cement is intermediate at the area being close to the casing shoe. It is a potential hazard of the uncontrolled flow into the aquifer just above the shoe.

In this case, the most appropriate solution is high-pressure squeeze cementing.

Top, m (MD)	Base, m (MD)	Score	Remarks
3033	3044	3	Low/medium CBL. Weak casing arrivals from VDL. Presence of double casing
3044	3056	3	Low/medium CBL. Weak casing. Low print quality for the VDL
3056	3080	2	Medium/high CBL. Strong casing and weak/strong formation arrivals from VDL
3080	3119.5	3	Low CBL. Weak casing and strong formation arrivals from VDL
3119.5	3176	2	Medium/high CBL. Strong casing and weak formation arrivals from VDL
3176	3283	4	Low CBL. No casing and strong formation arrivals from VDL. Halite interval
3283	3311	2	Medium/high CBL. Strong casing and weak formation arrivals from VDL
3311	3323	3	Low CBL. Weak casing and strong formation arrivals from VDL
3323	3400	2	Medium/high CBL. Strong casing and weak formation arrivals from VDL
3400	3430	4	Low CBL. No casing and strong formation arrivals from VDL. Salt intervals
3430	3476.5	3	Low/medium CBL. Weak casing and strong formation arrivals from VDL
3476.5	3502	4	Low CBL. No casing and strong formation arrivals from VDL. Salt intervals
3502	3528	2	Medium/high CBL. Strong casing and weak formation arrivals from VDL. Presence of clay
3528	3546	4	Low CBL. No casing and strong formation arrivals from VDL.
3546	3601	3	Low/medium CBL. Weak casing and strong formation arrivals from VDL
3601	3643	4	Low CBL. No casing and strong formation arrivals from VDL.
3643	3730	2	Medium/high CBL. Strong casing and weak formation arrivals from VDL. Presence of clay

Table 20: Integrity score of 7-inch casing in Well A3

As can be seen from the interpretation, the bond quality in the upper part of the 7" liner can be described as poor to intermediate, meaning that remediation is needed. The following intervals (3119.5 – 3176 m, 3323 – 3400 m, 3546 – 3601 m) have good bonding. The measurements from 1985 depth show it this way; re-evaluation is needed to understand the current state of the well.

- Liner and intermediate casing

Table 21 below represents the grading and weights of last 2 casing strings

Size, inch	Weight, lbs/ft	Grade	Top MD, m	Bottom MD, m
9 5/8	47/53.5	N-80	surface	3033
7	35	N-80/P-110	2928	3745

Table 21: Casing design of well A3

According to the reports, neither of the two casing strings was made of Cr13 steel, making them not resistant to the CO2 attacks.

Table 22 below summarizes the analysis according to the defined workflow.

Well barrier	Evidence of failure	Special acceptance criteria	Remediation solution
Cement at production and liner cross-section	Poor bonding (CBL)	Resistant to CO2 degradation	Squeeze cementing with degradation resistance slurry (e.g., pozzolan, CRETE) (section b) and 2))
Liner	Need to be evaluated and if positive	Corrosion resistance	Expandable casing patch from 13Cr or Super 13Cr material to withstand CO2 corrosion (section a) and 1))
Tubing	Old tubing replacement due to aging effect	Corrosion resistance	A new tubing from CRA like 13Cr or 15Cr, depending on injected fluid (section a) and d))
X-mas tree and valves	Old tree replacement due to aging effect	Corrosion resistant components	Special material selection for the valves and sealing elements (section c) and d))
Packer and downhole sealing elements	Old elements replacement due to aging effect	Corrosion resistant components	Special material selection for the packers and sealing elements (section c) and d))

Table 22: Assessment results and solutions for the well A3

4.3.4 Well B2 Assessment

Figure 20 represents the design of the well during the production phase.

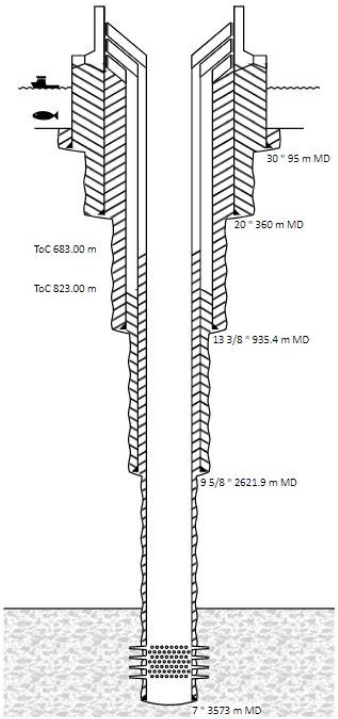


Figure 20: Design of the production well B2 in the assessment phase

- Cement quality;

Table 23 and Table 24 below represent the CBL/VDL logs interpretation.

Top, m (MD)	Base, m (MD)	Score	Remarks
2391	2628	2	Medium/high CBL. Wiggly VDL with clear casing arrivals. Presence of double casing. Interval 2391-2528m cemented on 20/11/1985. Interval 2528-2628m and downward to 7" casing shoe, cemented on 15/02/1976.

Table 23: Integrity score for Well B2

Summary of this section is that it needs remedial action before converting the well into the CO2 injector. The interpretation shows that the bonding of the cement is poor at the section being close to the casing shoe; it is a potential hazard of the uncontrolled flow into the aquifer just above the shoe. Need to be freshly revaluated to prove.

Top, m (MD)	Base, m (MD)	Score	Remarks
2628	2692.5	4	Low/medium CBL. No/very weak casing and strong formation arrivals from VDL.

Top, m (MD)	Base, m (MD)	Score	Remarks
2692.5	2720.5	3	Medium CBL. Very weak casing and strong formation arrivals from VDL.
2720.5	3175	4	Low/medium CBL. No/very weak casing and strong formation arrivals from VDL.
3175	3189	2	High/medium CBL. Strong/weak casing and wiggly VDL. Anhydrite presence. Cycle skipping? Fast formation
3189	3400	4	Low CBL. No/very weak casing and strong formation arrivals from VDL. In the interval 3213-3272.5m, spiky CBL (cycle skipping) and higher TT2 due the presence of fast formation.

Table 24: Integrity score for 7-inch casing in Well B2

- Production casing and intermediate casing

Table 25 below represents the grading and weights of 2 last casing strings of Well B2.

Size, inch	Weight, lbs/ft	Grade	Top MD, m	Bottom MD, m
9 5/8	53.5	P-110	surface	2621.9
7	35	P-110	surface	2528.7
	29	N-80	2528.7	3570.8

Table 25: Casing design of well B2

Table 26 below summarizes the analysis.

Well barrier	Evidence of failure	Special acceptance criteria	Remediation solution
Cement at production and intermediate casing	Poor bonding (CBL)	Resistant to CO2 degradation	Squeeze cementing with degradation resistance slurry (e.g., pozzolan, CRETE) (section b) and 2))
Production casing	Need to be evaluated and if positive	Corrosion resistance	Expandable casing patch from 13Cr or Super 13Cr material to withstand CO2 corrosion (section a) and 1))
Tubing	Old tubing replacement due to aging effect	Corrosion resistance	A new tubing from CRA like 13Cr or 15Cr, depending on injected fluid (section a) and d))

X-mas tree and valves	Old tree replacement due to aging effect	Corrosion resistant components	Special material selection for the valves and sealing elements (section c) and d))
Packer and downhole sealing elements	Old elements replacement due to aging effect	Corrosion resistant components	Special material selection for the packers and sealing elements (section c) and d))

Table 26: Assessment results and solutions for the well B2

4.3.5 Well B3 Assessment

The Figure 21 represents the design of the well during the production phase.

- Casing/liner cement;

This part includes observing the cement quality of the production casing, especially at the caprock and intermediate casing and the casing shoe and across the caprock.

To evaluate the cement bonding, the CBL and VDL were held for the 7-inch casing and the zone near the shoe of the 9.625-inch casing. The logging was conducted in the 1990s, meaning that the evaluation needs to be done as part of a workover after removing old tubing.

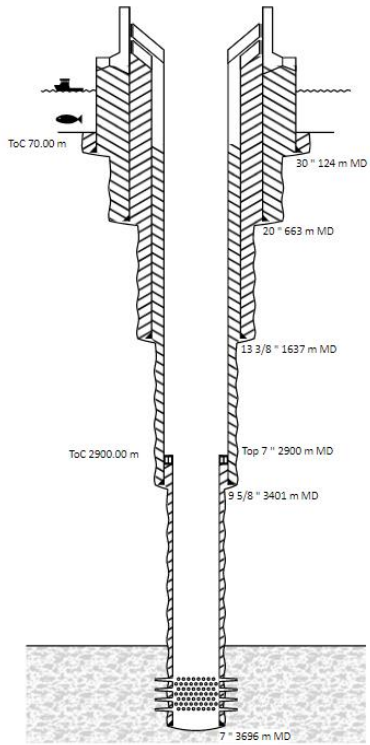


Figure 21: Design of the production well B3 in the assessment phase

Table 27 and Table 28 below represent the CBL/VDL logs interpretation of the desired interval of the liner overlap and 7-inch liner.

Top, m (MD)	Base, m (MD)	Score	Remarks
3049	3401	2	High CBL. Strong casing and wiggly VDL. Interval 3105-3166m shows low CBL and weak casing arrivals. From 3049 to 3340m erratic TT2 indicates log quality issue. Double casing
3401	3669	2	Medium/high CBL. Strong casing and wiggly to strong formation arrivals from VDL.

Table 27: Integrity score of a liner overlap in Well B3

Top, m (MD)	Base, m (MD)	Score	Remarks
3401	3680	2	Poor radial coverage. Run after displacing to sea water. This caused a reduction in hydrostatic pressure of 650-770psi. Log was run under 1000psi pressure.

Table 28: Integrity score of 7-inch casing in Well B3

- Liner and intermediate casing

The Table 29 below represents the grading and weights of the 9 5/8 casing string.

Size, inch	Weight, lbs/ft	Grade	Top MD, m	Bottom MD, m
9 5/8	43.5	L-80	surface	2037
	47	L-80	2037	3037.9
	53.5	P-110	3037.9	3159.6
	47	L-80	3159.6	3347.6
	53.5	L-80	3347.6	3401
7	29	L-80	2900.5	3696

Table 29: Casing design of well B3

The Table 30 below summarizes the analysis according to the defined workflow.

Well barrier	Evidence of failure	Special acceptance criteria	Remediation solution
Cement at liner and intermediate casing	Poor bonding (CBL)	Resistant to CO2 degradation	Squeeze cementing with degradation resistance slurry (e.g., pozzolan, CRETE) (section b) and 2))

Liner	Need to be evaluated and if positive	Corrosion resistance	Expandable casing patch from 13Cr or Super 13Cr material to withstand CO2 corrosion (section a) and 1))
Tubing	Old tubing replacement due to aging effect	Corrosion resistance	A new tubing from CRA like 13Cr or 15Cr, depending on injected fluid (section a) and d))
X-mas tree and valves	Old tree replacement due to aging effect	Corrosion resistant components	Special material selection for the valves and sealing elements (section c) and d))
Packer and downhole sealing elements	Old elements replacement due to aging effect	Corrosion resistant components	Special material selection for the packers and sealing elements (section c) and d))

Table 30: Assessment results and solutions for the well B3

4.4 Injection Phase Design Proposition

The objective of this phase is to propose the design for each well previously assessed so that they follow the two-barrier principle. Material selection and measures to reduce the risk of future leakage were discussed in Section 4.2, so the main purpose of this part is to show that the two-barrier principle is followed for each well, to describe the project parameters with respect to CO2 conditions, and to verify that the well will withstand the expected loads using strength calculations in the Landmark program.

The proposed design of each well is demonstrated in the shut-in phase to show that the two-barrier principle is followed.

4.4.1 Well A1

Well A1 design is represented in Figure 22.

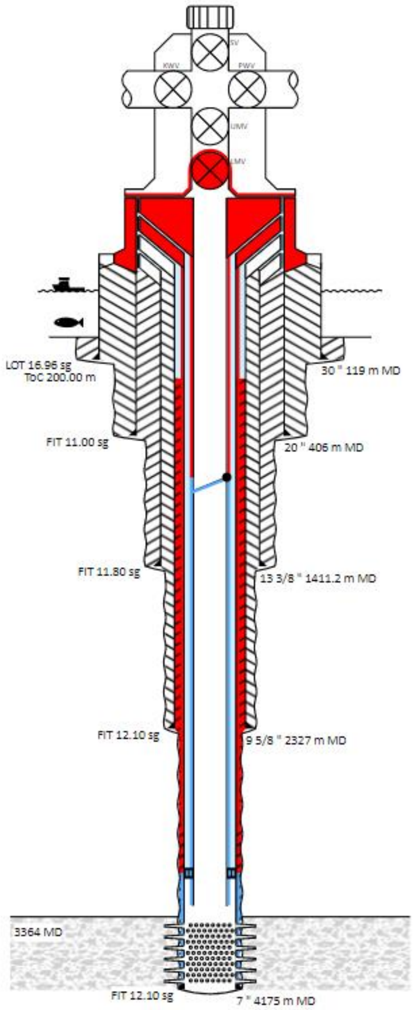


Figure 22: Well A1 proposed design for injection

Table 31 represents the well barrier envelope elements. A more precise explanation of common design consideration was presented in section 3.1.2.

Primary well barriers	Secondary well barriers
Caprock	Production casing (above packer)
Tubing (below DHSV)	Production casing cement (above packer)
Production packer	Intermediate casing
Production casing (below packer)	Intermediate casing cement
Production casing cement (below packer)	Tubing (above DHSV)
	Casing and tubing hanger
	Wellhead and X-mas tree

Table 31: Primary and secondary well barrier elements in Well A1

4.4.2 Well A3

Well A3 design is represented in Figure 23.

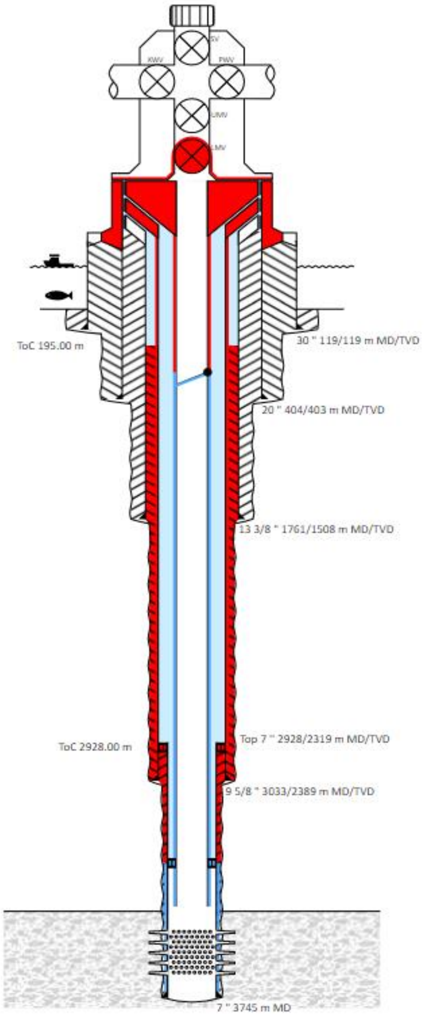


Figure 23: Well A3 proposed design for injection

Primary well barriers	**Secondary well barriers**
Caprock	Production liner (above packer)
Tubing (below DHSV)	Production liner cement (above packer)
Production packer	Liner top packer
Production liner (below packer)	Production casing
Production liner cement (below packer)	Production casing cement
	Tubing (above DHSV)
	Casing and tubing hanger
	Wellhead and X-mas tree

Table 32: Primary and secondary well barrier elements in Well A3

4.4.3 Well B2

Well B2 design is represented in Figure 24.

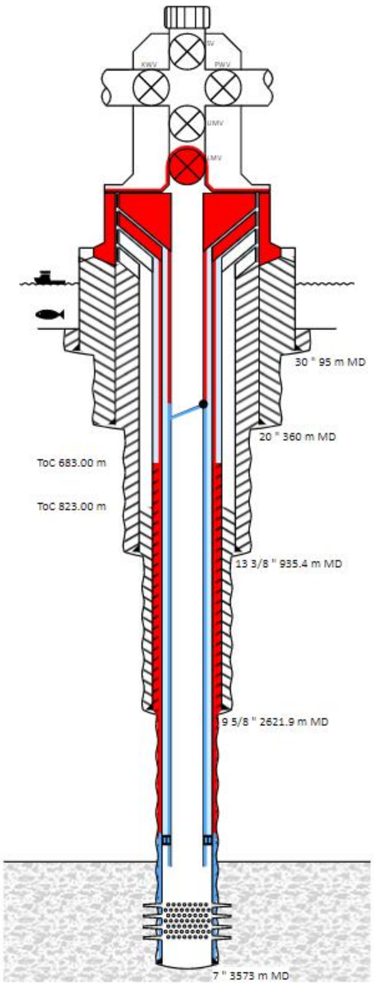


Figure 24: Well B2 proposed design for injection

Primary well barriers	**Secondary well barriers**
Caprock	Production casing (above packer)
Tubing (below DHSV)	Production casing cement (above packer)
Production packer	Intermediate casing
Production casing (below packer)	Intermediate casing cement
Production casing cement (below packer)	Tubing (above DHSV)
	Casing and tubing hanger
	Wellhead and X-mas tree

Table 33: Primary and secondary well barrier elements in Well B2

4.4.4 Well B3

Well B3 design is represented in Figure 25.

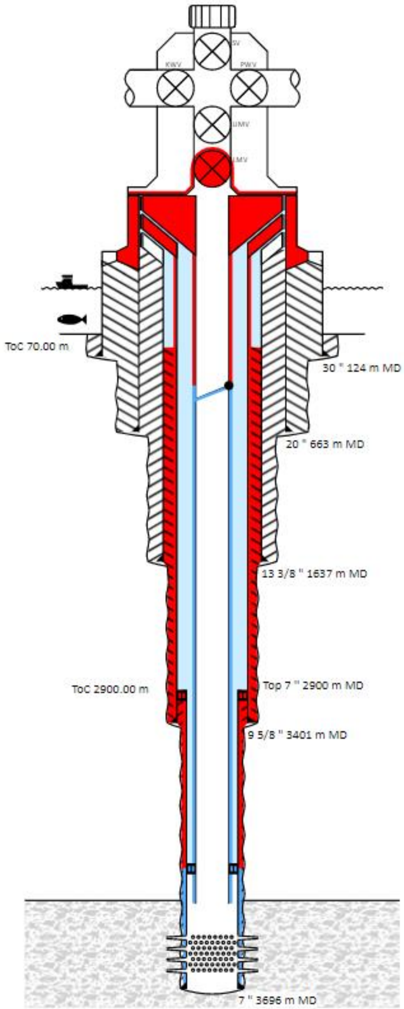


Figure 25: Well B3 proposed design for injection

Primary well barriers	**Secondary well barriers**
Caprock	Production liner (above packer)
Tubing (below DHSV)	Production liner cement (above packer)
Production packer	Liner top packer
Production liner (below packer)	Production casing
Production liner cement (below packer)	Production casing cement
	Tubing (above DHSV)
	Casing and tubing hanger
	Wellhead and X-mas tree

Table 34: Primary and secondary well barrier elements in Well B3

4.5 Project Parameters

The project parameters were initially taken from (Maarten, et al. 2010).

Table 35 - Table 38 describe each scenario that was observed and approved in the study.

Parameter	Value	Unit
CO_2 phase	Liquid	-
Density	902.7	kg/m^3
WH Fluid temperature	10	°C
WH fluid pressure	80	Bar
Reservoir temperature	105	°C
Initial reservoir pressure	35	bar
Max. injection rate	1.77	Mt/year

Table 35: Scenario 1

In this scenario hydrate formation in a near-wellbore zone can be expected, as the temperature is low enough for the hydrates to form (Maarten, et al. 2010)

Also, during injection into the reservoir, due to low reservoir pressure, a phase transition from liquid to gaseous phase can occur. This can lead to pressure drop due to fluid expansion and hydrate formation. The effect can be modelled with specialized software prior to operations.

High-temperature differences can lead to the thermal cracking of the caprock. This needs to be evaluated during the geomechanical assessment phase.

As the injected fluid volume depends on the difference between injection bottomhole and reservoir pressure, the higher density, which leads to higher bottomhole pressure, will increase efficiency of the injection process.

Parameter	Value	Unit
CO_2 phase	Liquid	-
Density	865.4	kg/m^3
WH Fluid temperature	15	°C
WH fluid pressure	80	Bar
Reservoir temperature	105	°C
Initial reservoir pressure	35	bar
Max. injection rate	<1.77	Mt/year

Table 36: Scenario 2

In this scenario, according to (Maarten, et al. 2010), the temperature is increased up to 15 degrees, while maintaining the same pressure as in the first scenario. This measure was applied to decrease the probability of near wellbore hydrate formation due to the low fluid temperature.

The risk of near-wellbore hydrate formation due to phase transition is still present. The temperature difference of fluid and reservoir is decreased, however, which decreases the probability of caprock thermal fracturing.

Decreased density, compared to scenario 1, will lead to a decrease in bottomhole pressure, which will lead to maximum injection pressure decrease.

Parameter	**Value**	**Unit**
CO2 phase	Supercritical	-
Density	617	kg/m^3
WH Fluid temperature	32	°C
WH fluid pressure	80	Bar
Reservoir temperature	105	°C
Initial reservoir pressure	35	bar
Max. injection rate	1.59	Mt/year

Table 37: Scenario 3

In this scenario, a supercritical phase is present. While maintaining constant pressure within scenarios 1 to 3, here the temperature was increased. This measure will decrease the probability of the caprock's thermal fracturing and mitigate hydrate formation in the near-wellbore zone.

As bottomhole injection pressure is a sum of wellhead pressure and hydrostatic pressure, decreased density of the supercritical CO2 will reduce bottomhole injection pressure. It results in a lower difference between reservoir pressure and bottomhole pressure. Therefore, the maximum injection rate will decrease.

To summarize, this scenario combines several advantages:

1) Decreased hydrate risk due to increased CO2 temperature;
2) Decreased formation fracture risk because of lower bottomhole injection pressure.

However, heating CO2 to create the required supercritical phase will require additional investment.

Parameter	**Value**	**Unit**
CO2 phase	Liquid	-
Density	927.3	kg/m^3
WH Fluid temperature	10	°C
WH fluid pressure	110	Bar
Reservoir temperature	105	°C
Initial reservoir pressure	35	bar
Max. injection rate	1.86	Mt/year

Table 38: Scenario 4

In this scenario, the temperature is the same as in scenario 1, but the wellhead pressure is increased up to 110 bar. This adjustment increases the maximum injection rate due to an increase in bottomhole pressure.

Although this scenario carries a considerable risk of fracturing caprock and hydrate formation, other hazards are similar to scenario 1.

4.6 Durability Calculations

For each well and for each of the scenarios described above, tubing analysis was performed with specialized software (Landmark).

Von Misses ellipse is used as a reference for calculations, meaning that all the loads need to be inside the ellipse to be sure that the operations will go as planned.

The tubing's size, material, and grade are the same in all four designs, as specified in Table 39 below.

Size	114.3 mm
Grade	L-80
Material	13Cr

Table 39: Tubing specifications

Durability calculations were performed for all four wells.

Here the example for Well A1 is shown. The design of the well has been accurately recreated in the Landmark software and is represented in Figure 26.

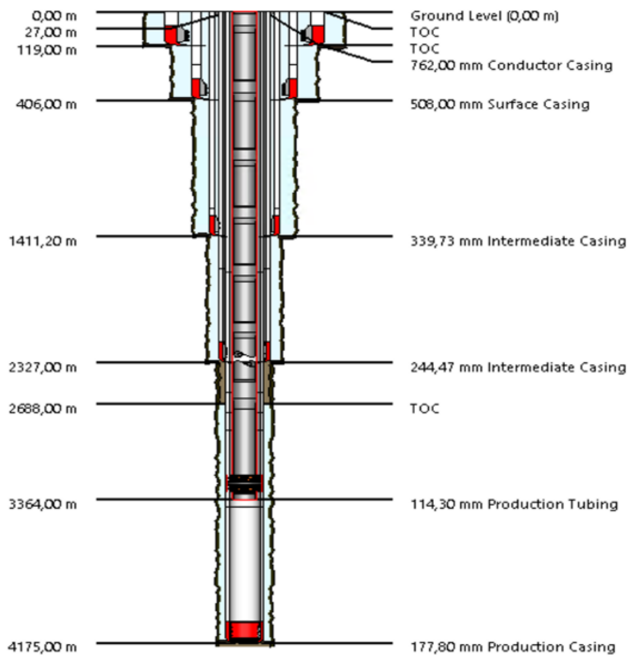
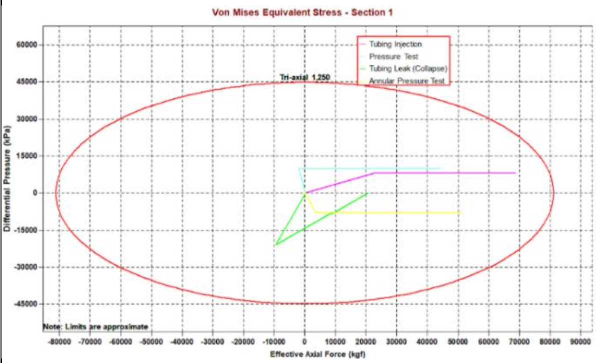


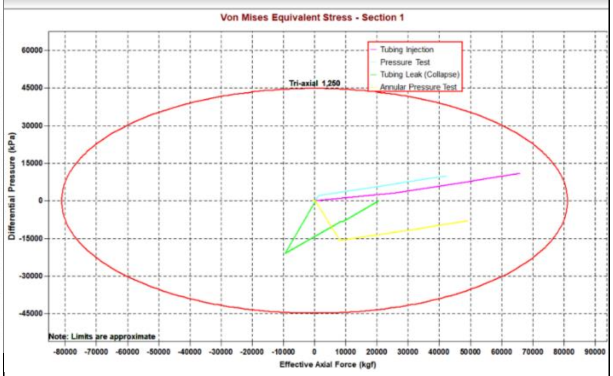
Figure 26: Design of well A1 in Landmark software

Figure 27 represents the calculated loads on tubing in each of the scenarios described in the previous section, as the most impacted element during the injection. Lines are the loads that are present during the injection operations.

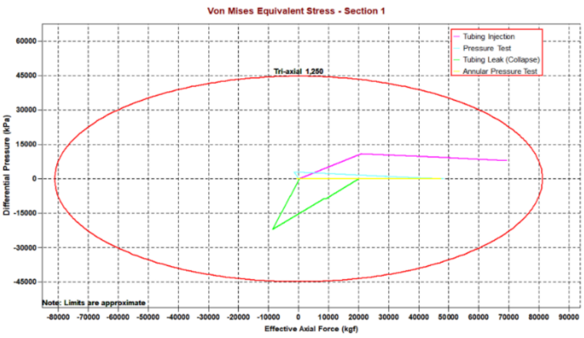
Scenario i



Scenario ii



Scenario iii



Scenario iv

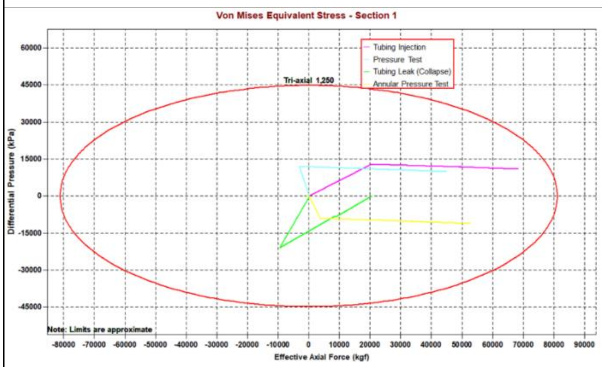


Figure 27: Well A1 Injection Scenarios

As can be seen from the calculation, the tubing will withstand the applied loads.

This applies to the remaining wells A3, B2 and B3, too – tubings will withstand the loads.

Chapter 5 Conclusion

The goal of this thesis was to research and evaluate the feasibility of converting existing oil and gas wells into CO2 injection wells. The following issues were addressed and resolved:

- Main standards and guidelines for well integrity in CO2 injection wells were researched, and it was shown that there are no extra criteria to such wells besides more precise monitoring (especially corrosion monitoring) and material selection so that all integrity-relevant well components will be able to withstand both chemical and mechanical loads;
- Case studies for CO2 injection wells were examined and the most common issues were benchmarked among these wells. Based on the findings, a list of common issues was created for deeper analysis in the corresponding chapters;
- With the help of lessons learned from case studies, main weak points in the architecture of a CO2 injection well were found and analyzed in terms of degradation and failure mechanisms;
- After understanding the main causes of damage through chemical degradation and mechanical failure, a list of mitigation against each degradation and failure was developed to decrease the probability of damage;
- The next step was to describe a monitoring setup for each phase. For this purpose, a monitoring and measurement roadmap from conversion to abandonment was created, following every step in between;
- After analyzing the theoretical part, all the findings were applied to real wells. Among eight wells, four were chosen according to a pre-selection matrix
- Project parameters options were analyzed, and the most appropriate parameter combination was chosen;
- For each well, the injection design was selected and approved with WellBarrier software;
- For each of the four wells, the current state was analyzed, and a remediation plan was developed after which the wells were checked to meet the operational criteria with the help of load calculations in the Landmark software package;
- Finally, a generic monitoring plan was built for each well.

It could be demonstrated that under certain circumstances the re-purposing and conversion of existing wells into CO2 injection wells as part of CCS projects is feasible if all potential issues have been addressed that may lead to compromised integrity of the storage system.

Findings and work steps or processes described in this thesis may provide assistance to the industry when future conversion plans need to be developed or evaluated.

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Acronyms

ALARP	As low as reasonably possible
CBL	Cement bond logging
CCS	Carbon capture and storage
CET	Cement evaluation tool
CO2	Carbon dioxide
CRA	Corrosion resistant alloy
EOR	Enhanced oil recovery
FKM	Fluorine rubber
HNBR	Hydrogynated Nitrile Butadiene Rubber
NBR	Nitrile Butadiene Rubber
P&A	Plug and abandonment
R&D	Research and development
SCP	Sustained casing pressure
VDL	Variable density log

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