Master's thesis

NTNU
Norwegian University of Science and Technology
Faculty of Engineering
Department of Geoscience and Petroleum

Andrea Johanne Skog

Cost Optimization Strategies and Methodologies for Drilling CCS Injection Wells

Master's thesis in MTPETR
Supervisor: Behzad Elahifar
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Sammendrag

Det nåværende globale kostnaden for karbonfangst- og lagringsteknologi (CCS) er på omtrent 600 dollar per tonn lagret CO2. Med et årlig utslipp på omtrent 431 millioner tonn, utgjør den samlede globale kostnaden for å lagre alt dette karbonet omtrent 28,5 milliarder dollar. Tilsvarende omtrent 313,5 milliarder NOK per år. Med tanke på dagens prislapp for CCS er det urealistisk å iverksette denne teknologien på stor skala. For å kunne oppnå en bredere spredning av denne teknologien må prisen reduseres kraftig. Å redusere prisen i mindre skala, over flere områder, kan utgjøre en vesentlig forskjell på den totale summen. Slik kan man over tid redusere den totale prislappen på CCS teknologi. Denne oppgaven handler om å redusere kostnadene for å drille CCS injeksjons brønner.

Forskjellige standardiserte rammeverk eksisterer i ulike land, dette kan påvirke kostnadene ved implementering av CCS. For eksempel er NORSOK standardene i Norge, ikke oppdatert for standarder innen CCS-teknologi. Det er viktig å kontinuerlig vurdere og oppdatere reglementet for å sikre kostnadseffektiv implementering av CCS.

Når det gjelder teknologiske framskritt, har alternativer som kontrollert slam nivå (CML) og slanke brønner vist seg lovende for kunne bidra til å redusere kostnadene. Det å bruke CML istedenfor underbalanser boring (UBD) kan potensielt redusere kostnadene på boreoperasjonen relatert til det å bore inn i reservoaret/lagrings formasjonen. Slanke brønner gjør det mulig å redusere kostandene og kompleksiteten på bore operasjonene.

CCS-boreteknologi har fortsatt et stort utviklingspotensial, videre forsking er nødvendig på flere områder. Dette inkluderer å oppdatere NORSOK-standarder, valg av kostnadseffektiv sement og tilsetningsstoffer, finne effektive kompletteringsteknikker, undersøke hvordan injeksjonsvæske påvirker temperaturen i reservoaret og finne gode metoder for å borre inn i en brønn hvor det allerede er lagret CO2.

En omfattende evaluering av flere faktorer er avgjørende for å oppnå kostnadsreduksjon innen CCS-teknologi, spesielt innen boreoperasjoner. Ved å utføre forskning, få tilgang til operasjonelle data og utforske ulike områder av boreoperasjonen, kan CCS bli mere økonomisk levedyktig, noe som muliggjør bredere implementering og er et betydelig bidrag til CCS.

Abstract

The current global cost of carbon capture and storage (CCS) technolgy stands at approximately $600 per ton stored CO2. With annual global emmisions reaching around 431 million ton, the total cost to sequenster all this carbon amounts to approximately $25.8 billion per year. Considering the current economics of CCS, large-scale implementation of this technology remains unrealistic. To achieve widespread adoption, it is cutical to focus on cost reduction stragies. By implementing improvments and targeting spesific areas the overall cost of CCS can be substantially reduced. This thesis focuses on reducing the cost of drilling CCS injection wells.

Different regulatory framwork excist in various countries, which can impact the cost of CCS implementation. For instance, in Norway, the NORSOK regulations, are not up to date with the latest advancements in CCS technology. It is imperative to continously asses and update regulations to ensure they are favorable to cost-effective CCS deployment.

In terms of technical advancements, alternatives like Controled mud level (CML) and slender wells have shown promise in cost reduction. Using CML instead of underbalanced drilling (UBD) might be an option which could help reduce the cost of the drilling operation when entering the reservoir/storage formation. Slender wells offer an option that reduces the drilling cost and the complexity of the operation.

It is it essential to acknowledge that CCS drilling technology still has significant progress to make. Further research is warrant in several areas. This includes updating the requirements outlined in NORSOK standards, determening the most cost—effective cement and additives, cost-effective completion techniques, invenstigating the impact of injection fluid on the thermal environment within the reservoir and how re-entery of the well should be approched following CO2 injection.

In summary, finding cost reduction strategied in CCS technology, particularly drillling operations, requires a comprehensive evaluation of multiple factors. Through research, operational data and exploration of additional areas, the economic feasibility of CCS can be improved, facilitating broader implementation and significant contirbution to CCS.

Acknowledgment

It is with great pleasure and pride I present my master thesis. I am immensely grateful for the opportunity to write about drilling CCS injection wells. It has been an interesting and exciting semester. Writing this thesis have been difficult at times, but also highly rewarding. This thesis represents the culmination of my studies at NTNU and is a source of great pride for me. I am proud of the accomplishments and personal growth I have achieved during my time here at NTNU. I would like to express my sincere gratitude to all those who have contributed to helping me in the process.

First, I would like to express my sincere gratitude to my advisor Behzad Elahifar of the Department of Geoscience and Petroleum at NTNU for his advice, motivation and immense knowledge. His guidance and feedback have been greatly appreciated. Our conversations and discussions have helped me in times of research and writing. I could not have imagined a better mentor for my thesis.

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I also thank the girls at Petroleum FK ladies, as well as my roommates, Andrine, Mari and Vilde. You will forever hold a special place in my heart.

To my family, I am deeply grateful for your unwavering support, understanding and belief in me. Thank you for always being there, for bringing me snacks during late nights, and for your unconditional love.

I love you all and appreciate your patience, motivation, and support.

Innhold ....

Figurer

Forkortelser/symboler

NTNU	Norges teknisk-naturvitenskapelige universitet
NORSOK	Norsk sokkels konkurranseposisjon
CFR	Code of federal regulations
CO2	Carbon dioxide
H2S	Hydrogen sulfide
SO2	Sulfur dioxide
CCS	Carbon, capture & storage
IEA	International Energy Agency
USD	United States Dollar
NOK	Norske kroner
EOR	Enhanced oil recovery
SPE	Society of petroleum engineers
CRA	Corrosion resistant alloy
MPD	Managed pressure drilling
CML	Controlled mud level
BHP	Bottom hole pressure
SBP	Surface back pressure
DGD	Dual gradient drilling
ECD	Equivalent circulating density
ROP	Rate of penetration
UBP	Underbalanced drilling
LRRS	Low riser return system
PD	Performance drilling
BHA	Bottom hole assembly
RCD	Rotating control device
RMR	Riserless mud recovery
Mt	Million tons
HI	Hydrogen index
TOC	Total organic carbon

1 Introduction

Carbon dioxide (CO_2) is a colorless and odorless gas and is a natural component in the atmosphere. CO_2 naturally is released into the air through decomposition of organic material, as a part of the carbon cycle.

Carbon is the foundation of all life on Earth, it regulates the Earth's temperature, provides energy and is a key ingredient in the food that sustains us. The carbon cycle is nature's way to reuse and recycle carbon atoms. The amount of carbon in the system is constant because the earth and its atmosphere are a closed system, but where the carbon is located is constantly changing. (NOAA, n.d.)

Most of the carbon is stored in rocks and sediments, the rest in the atmosphere, ocean and living organisms. The ocean is automatically and continuously exchanging carbon with the atmosphere and vice versa. The rest of the "reserves" will release carbon back to the asthenosphere through different processes; decomposition of organic material, fires, volcanic eruptions, burning of fossil fuel and other processes. (NOAA, n.d.)

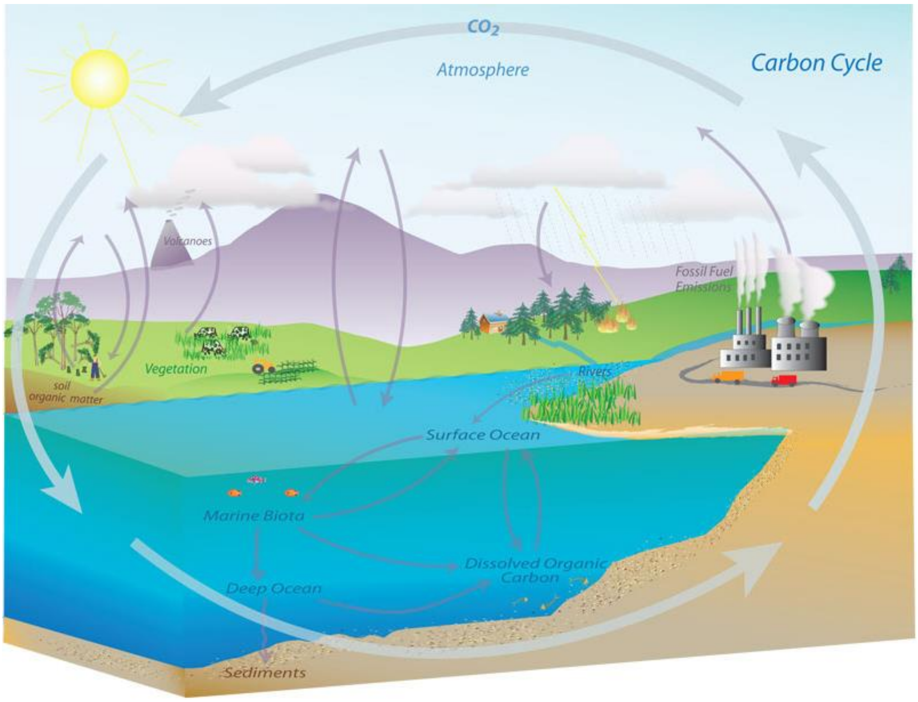

Figure 1. Illustration of the carbon cycle. (NOAA, n.d.)

The carbon cycle is a natural process, and the atmosphere is supposed to contain some amount of carbon, but human activities have over the last 60 years had a massive impact and interrupted the natural ways of this cycle. The annual rate of natural increase in CO_2 over the past 60 years is about 100 times faster than it previously was. Activities like burning fossil fuels, agricultural activities, using limestone to make cement and a lot of deforestation have led to CO_2 building up in the atmosphere faster than the system can soak it up. The amount of CO_2 in the atmosphere is rapidly rising and is already greater than it ever has been over the last 3.6 million years. (Lindsey, 2022)

CO_2 is the Earth's most important greenhouse gas. It absorbs and radiates heat. The effect of the increased level of CO_2 in the atmosphere can already be seen, the earth's temperature has risen by roughly 1 degree Celsius. The 10 warmest years in historical records have all occurred since 2010. (Lindsey, 2022)

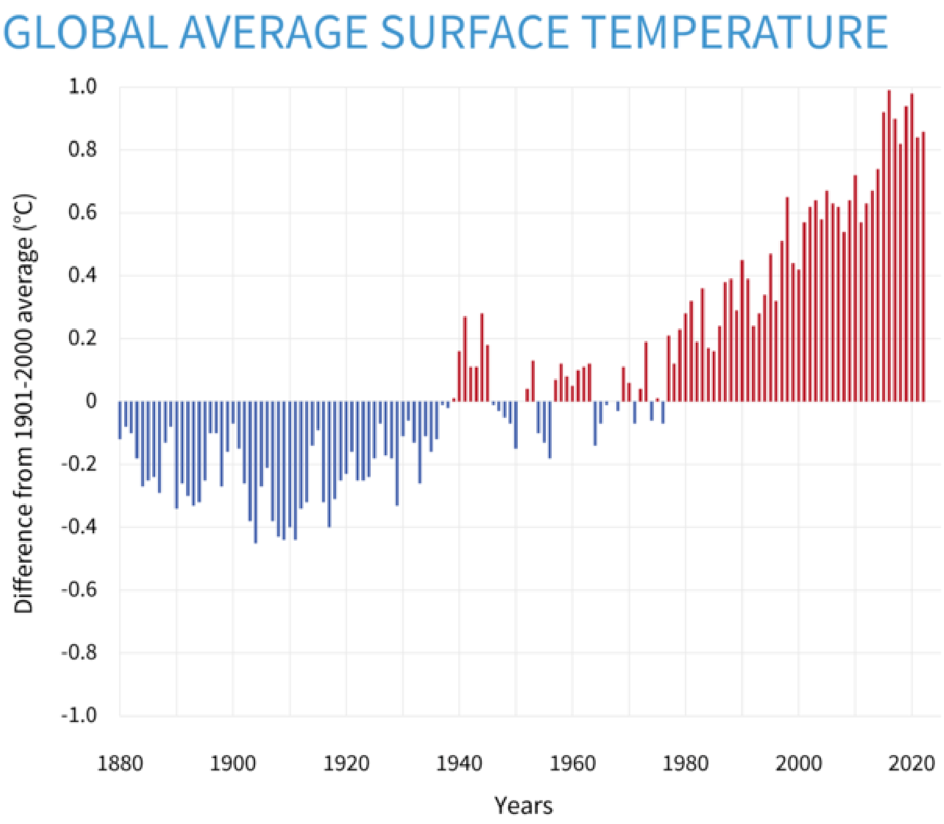

Figure 2. Yearly surface temperature compared to the 20th century average from 1880-2022. Blue indicates cooler than average, and red indicates warmer than average. (Lindsey, 2022)

If the levels of carbon dioxide in the atmosphere and the global temperature keep rising it is going to cause a dramatic transformation of our planet. Higher temperatures will worsen any type of natural disaster, the storms, heat waves, floods and droughts will be even more fatal and critical than they ever have been. The weather will become more frequent and severe. Wet areas will become even wetter and dry areas even dryer. Many people will most likely lose access to clean drinking water, and crops worldwide will be at risk of being destroyed. The world population is rapidly increasing, and we are in danger of ending up in a situation where we are more people having to share fewer resources. (Guy, 2023)

The list of consequences from global warming goes on, but there is no doubt that the world cannot continue in the direction we have been moving in for the past 60 years. CCS is a technology that has the potential to help reduce the amount of CO_2 in the atmosphere, and hopefully stop the relentless progression towards irreversible climate change.

2 Carbon capture & storage (CCS)

Carbon capture and storage, known as CCS, is a process intended to capture produced CO2 at its source and store it to avoid releasing it to the atmosphere. The CCS system includes three steps. 1) capturing the CO2. 2) transporting the CO2 from where it was captured to a storage site. 3) injecting the CO2 into a long-term storage space, typically a subsurface reservoir. Long-term in this context is from hundreds to thousands of years. CCS is sometimes referred to as CCUS, carbon capture, *utilization* and storage. Utilization refers to using the captured CO2, instead of just storing it, and using it in a way that further helps reduce the amount of CO2 in the atmosphere. This could mean using it for injection in drilling, or converting it to chemicals, cements, plastics and other products.

2.1 Why CCS?

CO2 emissions have increased to a record level of 422 ppm in the atmosphere. (Scripps university of oceanography, USSanDiego, 2023) Even though the growth of emissions has slowed down over the last years, the world is still on track to raise the global temperature way beyond the recommended window of 1.5 - 2 deg C. Global temperature is often measured in reference to pre-industrial levels (1850-1900). Figures from 2022 show that the average temperature in the atmosphere has already passed 1.1degC above pre-industrial levels. (Mulhern, 2020)

Data from the special report shows that emissions trends are still not aligned with a track consistent with limiting the temperature rise to below 2 deg C. Without an increased and urgent ambition to act to reduce the amount of CO2 in the atmosphere, the world will surpass 1.5 deg C by the end of 2030. (IPCC, 2005)

The picture below illustrates how global energy was divided between various sources in 2019. 84.3% of global energy comes from fossil fuels. (Hanna Richie, 2022)

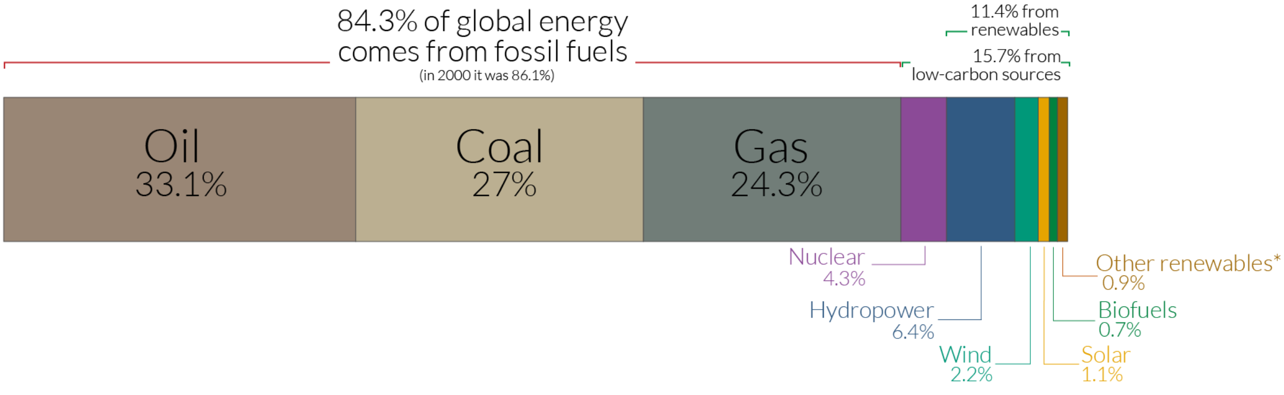

Figure 3. Global energy consumption by source, based on data from 2020. (Hanna Richie, 2022)

The energy mix today is not vastly different from what it was in 2020. Fossil fuels are still the primary resource to global energy, and it is likely to stay that way for a long time. Therefore, it is necessary to find a method that both reduces carbon emissions and allows for further use of fossil fuels.

CCS is the only method today that meets both requirements. CCS technology can play a huge role in reducing the amount of CO_2 in the atmosphere and the effects of global warming. In fact, according to the latest report by the Intergovernmental Panel on Climate Change, lowering emissions will not be sufficient given the volume that is already in the atmosphere. Carbon removal is essential and unavoidable to help achieve global emission targets and reduce the concentration of CO_2 in the atmosphere. (Mulhern, 2020). CCS will not solve the climate crisis on its own but will be a bridging technology during the transition from today's energy mix to a future consisting of new, renewable resources.

Global Status of CCS

As of September 2022, there are 196 projects in the CCS facilities pipeline. This includes storage sites in operations, under construction and in development phases. Together these projects have a capture capacity of 243 Mt per year. Of the 196 projects, 30 are in full operation; these 30 can store together 42.6 Mt CO_2 per year. (Global CCS Institute, 2022)

As of 2021, the total amount of CO_2 stored through large-scale CCS projects globally is estimated at around 300 million tons. This includes both the amount CO_2 stored permanently and CO_2 used for enhanced oil recovery (EOR), which involves injecting CO_2 into oil reservoirs to increase production. While 300 million tons is a significant achievement, it is still a small fraction of the total amount of CO_2 emissions globally. The International Energy Agency (IEA) estimates that the world needs to capture and store around 7000 million tons of CO_2 per year by 2030 to stay under the 2deg C goal. It is still a long way to go to achieve the necessary scale of CO_2 storage to address climate change. (Global CCS Institute, 2022)

CCS future

Currently, the cost of carbon capture and storage technology worldwide is estimated to be around 600 USD per ton of CO_2 stored. Given the global annual carbon emissions amount to approximately 431 million tons, the cost to sequester all this carbon would roughly be 25.8 billion USD each year. (Mulhern, 2020). Given the economics of carbon capture, it is not currently realistic to implement CCS on a wide scale. But with increased research in the area and improvement in technology, production will hopefully plummet over the next years.

Carbon capture has been successfully demonstrated in pilot-scale and many industrial processes on a large scale for many years. Nowadays, applying capture technologies to large-scale power projects is a practical solution. Although the technology has already proven its effectiveness, further research is necessary to minimize cost and energy penalties for the next generation of capture technologies. To bring many commercial-scale demonstration projects online, significant global financial investments are needed. This portfolio of projects will offer significant benefit through "learning by doing", and coupled with ongoing research, will significantly contribute to reducing costs for carbon capture.

2.2 CCS technology: Capture

A CCS project begins with capturing CO_2 emissions from sources before it is released into the atmosphere. Carbon capture and separation technologies have been in use on a large scale in industries such as natural gas and fertilizer for many years and have more recently been implemented in the power sector.

When fossil fuels, including coal, oil and natural gas, are burned or converted into energy, they release CO_2 as a by-product. In coal-based power plants across North America, Europe, and China, where coal is pulverized to a powder, the CO_2 must be separated from the combustion flue gases at diluted concentrations. However, in other systems like coal gasification, where coal is converted into chemicals, natural gas or liquids, the CO_2 can be more easily separated. According to the global institute of CCS, CO_2 capture can be carried out through three basic methods: pre-combustion, post-combustion, and oxyfuel with post-combustion. (Global CCS Insitute, 2022)

Pre–Combustion

Pre-combustion processes involve converting fuel into a gaseous mix of hydrogen and CO_2. The hydrogen is separated and can be burned without any CO_2 emissions, while the CO_2 is compressed and transported for storage.
However, the fuel conversion steps needed for pre-combustion are more intricate than those involved in post-combustion, making it more challenging to apply this technology to existing power plants.

Post-Combustion

In the post-combustion process, the CO_2 is separated from exhaust gases. Various methods, including liquid solvent, can be used to capture CO_2. In an absorption-based technique, the CO_2 is absorbed by the solvent and later released through heating to form a high purity CO_2 stream. This method is commonly employed to capture CO_2 for use in the food and beverage sector.

Oxyfuel Combustion

In oxyfuel combustion, oxygen is used instead of air for fuel. The oxyfuel processes generate exhaust gas consisting primarily of water vapor and CO_2. This results in an easy separation of CO_2, leading to the production of high purity CO_2 stream.

2.3 CCS technology: Transport

Safe and reliable transport of CO_2 is a crucial step between CO_2 capture and storage in a CCS operation. Transport of CO_2 occurs daily in many parts of the world. However, significant investment in transportation infrastructure is needed to enable large-scale deployment.

Pipelines are currently and expected to remain the most prevalent method of transporting large quantities of CO_2 involved in CCS. There are already millions of kilometers of pipelines around the world that currently transport CO_2. Although it is possible to use trucks and rails for small amounts of CO_2 transportation, they are mainly used at project sites to move the captured CO_2 to a nearby storage facility. Given the enormous amount of CO_2 that CCS will capture in the future, it is unlikely that trucks and rails will play a significant role in transportation. An alternative for many regions of the world is to transport CO_2 by ship. CO_2 shipments already occur on a small scale in Europe. (Global CCS Insitute, 2022)

The development and operation of CO_2 pipelines on both land and underwater has yielded significant expertise. Extensive network of pipelines already exists around the world, both on land and under the sea. According to the global ccs institute, the US currently runs around 50 CO_2 pipelines that can transport roughly 68 million tons of CO_2 per year.

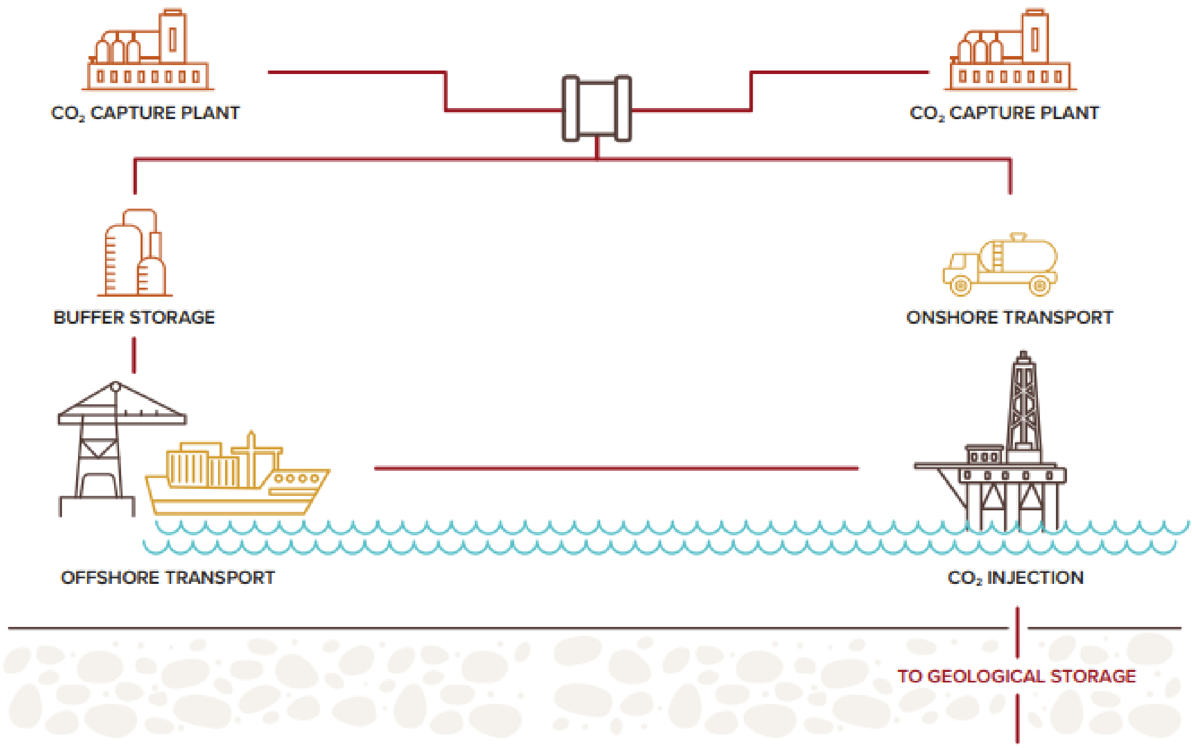

Figure 4. Transport overview of CCS technologies. (Global CCS Insitute, 2022)

Despite the potential benefits of Carbon Capture and Storage (CCS), it is important to recognize the substantial scale of pipeline infrastructure needed to support its long-term deployment on a global scale. To put things in perspective, the CO_2 transportation infrastructure needed over the next 30-40 years, according to IEA's recommended strategy for halving energy-related CO_2 emissions by 2050, will be approximately 100 times greater than the current infrastructure. This highlights the magnitude of the challenges ahead and the need for significant investments and planning to achieve widespread implementation of CCS. It is important to note that CO_2 pipelines and ships do not pose any greater risk than the transportation of hydrocarbons like natural gas and oil, which already are being managed safely.

2.4 CCS technology: Storage

The final stage of the CCS process involves injecting and storing CO_2, which has been done safely and effectively for over 50 years. In fact, storage is the simplest and most logical CO_2 mitigation solution, given the abundant underground storage resources available. Geological systems around the world can retain centuries' worth of CO_2 captured from industrial processes or directly from the air.

Geological storage has been a natural process in the Earth's upper crust for hundreds of millions of years and is one of the most widely used methods for CCS, involving the injection of captured CO_2 into rock formations, where it is permanently sequestrated from the atmosphere. (IPCC, 2005)

Several decades of successful CO_2 storage worldwide have proven that there are no technical barriers to its implementation. In Norway alone, the Sleipner and Snøhvit facilities have stored close to 26 million tons of CO_2 since 1996. The safety of CO_2 storage in geological formations is also supported by leading scientists and experts, confirmed in the 2005 Special Report on CCS by the Intergovernmental Panel on Climate Change. (Global CCS Institute, 2022)

Once captured and compressed into a fluid, the CO_2 is pumped down a well into the porous storage formation. A part of the CO_2 will migrate to the top of the formation and become structurally trapped beneath the impermeable cap rock, while another part will dissolve into the saline water naturally present in the storage formation and become trapped indefinitely. The remaining CO_2 is trapped in the pore spaces of the storage formation, and over time, it may react with the reservoir rock and fluids to form a new mineral, effectively locking it into a solid mineral permanently.

For a geological structure to be used as a storage site, it must have a porous basin and an impermeable rock working as a migration barrier. Such formations are often found near existing oil and gas fields, both onshore and offshore, and are often close to CO_2 sources (Cooper, 2009). Several structures may work as storage sites for CO_2 injection and the discussed options in this thesis are presented in Figure 5.

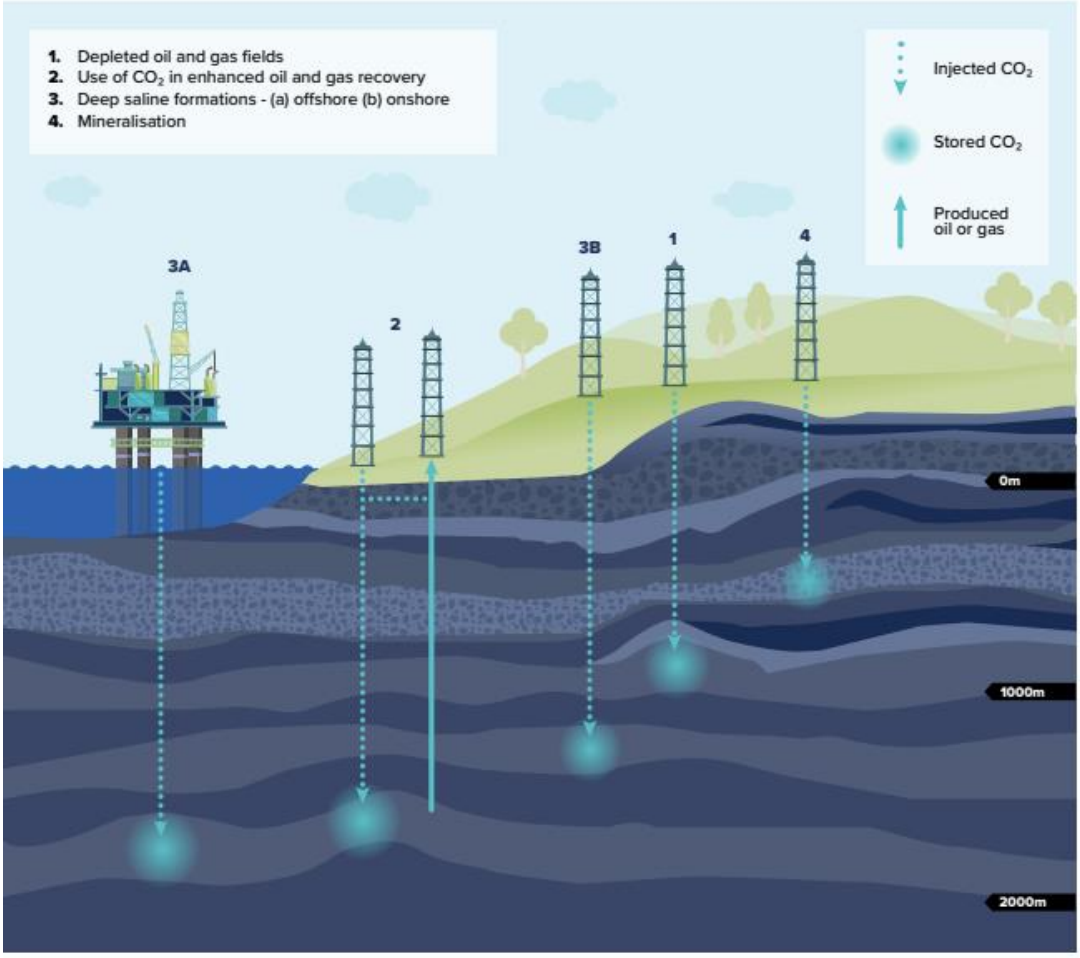

Figure 5. Options for storing CO2 in deep underground geological formations (Global CCS Institute, 2022)

Storing in depleted oil and gas fields is one of the most promising options for CCS. These fields have already been explored and developed, so there is existing infrastructure and knowledge available for drilling and injecting CO2. Additionally, these fields have already proven to be effective in retaining hydrocarbons for millions of years, so they are also likely to be effective for CO2 storage.

Injecting CO2 into already produced fields can also have an added benefit of enhancing oil and gas recovery, by pushing residual hydrocarbons towards production wells. This process is called enhanced oil recovery (EOR). However, not all depleted fields are suitable for CO2 storage, and geological assessments and monitoring are necessary to ensure the safety and effectiveness of the storage operation. (Hannis, et al., 2017)

Deep saline formations refer to porous rock formations saturated with saltwater and found deep underground, typically below freshwater aquifers. These formations can also be used to store large amounts of CO2. The process involves injecting CO2 into the saline formation, which then dissolves in the saltwater and becomes trapped within the rock pores. Like other storage methods, the saline formation must have a cap rock to prevent the CO2 from escaping to the surface. Deep saline formations have the potential to store vast amounts of CO2 with estimates suggesting they could store over 100 years of global CO2 emissions. While there are some concerns around potential impacts on local freshwater resources and induced seismicity, extensive research and monitoring can help mitigate these risks. Overall, CO_2 storage in deep saline formations is a promising choice for archiving large-scale emissions reductions. (K. Michael, 2010) (European commission, n.d.)

Mineralization also known as mineral carbonation, is a process in which CO_2 reacts with naturally occurring minerals in the storage formation to form solid carbonates, effectively locking away the CO_2 for geological timescales. Mineralization can occur naturally over extended periods of time but can also be accelerated through the injection of CO_2 into storage formations. CO_2 reacts with minerals such as magnesium and calcium silicates, forming solid carbonates that are stable over geological timescales. The process of mineralization is attractive for CCS storage because it supplies an added level of permanence, as the CO_2 is locked away in solid form rather than just being stored as a gas or liquid. However, mineralization is still in the initial stages of development and further research is needed to determine the feasibility and scalability of the technology for large-scale CCS deployment. (Ramkumar, 2016)

Monitoring technologies have been successfully developed to measure, monitor, and verify injected CO_2 in the subsurface throughout the lifecycle of a CCS site. Emergency shutdown procedures, well re-completion, and recementing techniques, adopted from the oil and gas industry, are used to detect and remediate any unlikely CO_2 leaks.

There are more underground storage resources available than needed to meet climate targets. Storage resources are found in almost every nation. (IEA, 2021)

2.5 Physical properties of CO2

Carbon dioxide is composed of one carbon and two oxygen atoms bounded together. It has a melting point of -55.6 deg C and a boiling point of -78.5 deg C. Its molar mass is 44gmol^{-1}. At atmospheric pressures and temperatures CO_2 appears colorless and odorless. The gas is soluble in water, acetone and ethanol. The gas has a high density, 1.977gmL^{-1}, because of its high density it can displace oxygen. CO_2 forms carbonic acid when it reacts with water, it is used to freeze food, control chemical reactions and as a fire extinguishing agent. (National Center for Biotechnology Information , n.d.)

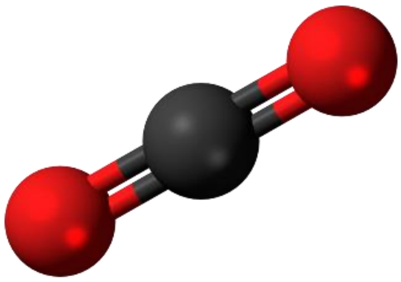

Figure 6. Illustration of the CO_2 molecule. One carbon atom (black) connected to oxygen atoms (red). (Yirka, 2014)

2.5.1 Phase diagram

Fig. 2. Illustrates the CO_2 phase diagram. Two important points are highlighted in the diagram, the critical point and the triple point. At the critical point liquid and gaseous phase coexist in equilibrium. The critical point for CO_2 is at T = 31 deg C & P = 5.16 bar. The triple point is the temperature and pressure which solid, liquid and gaseous phase coexist in equilibrium. The triple point for CO_2 is at T = 56.6 deg C & P = 5.18 bar. (Linde Gas, n.d.)

The physical properties of CO_2 will change under different pressure and temperature conditions. CO_2 naturally exists in gaseous form. However, at higher pressures and temperatures beyond the critical point, CO_2 may exist as a liquid-like supercritical fluid or gaseous phase. What characterizes a supercritical phase is that it is difficult to distinguish whether the CO_2 is in a gaseous or liquid phase.

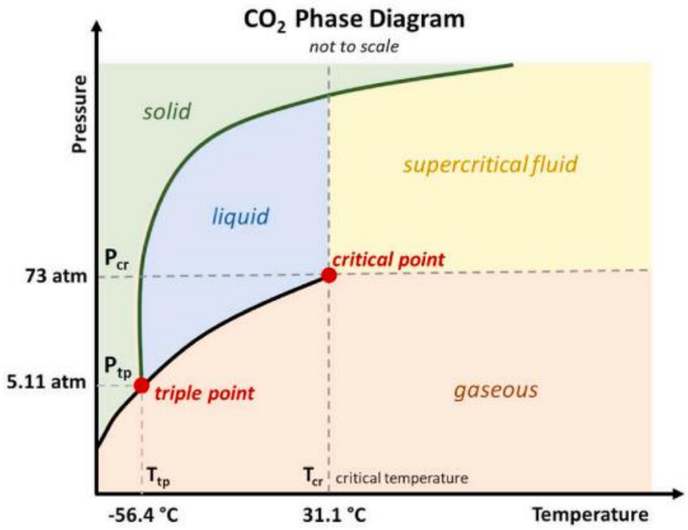

Figure 7. P-T-Diagram of Carbon Dioxide. (McLaughlin, et al., 2023)

The pressure and temperature regimes will vary with the different CCS operations, and the CO_2 will most likely change phase from when being captured to being stored. CO2 is with today's technology normally captured and separated in a vapor phase. (Brobakken, 2018)

There are different options for transportation of CO2. The different options have varying pressure and temperature requirements, which is going to influence the phase the CO2 is going to be transported in. The optimal way for transporting CO2 is in a liquid phase, this makes it possible to transport in relative low pressure and temperature conditions. The optimal way of storing CO2 is in supercritical phase, this is the best and safest choice for long-term storage of CO2 (Brobakken, 2018). To achieve a supercritical phase, the geological formations that are going to be used for storage need to be in environments with pressure and temperatures above the critical point. This will be further discussed in later chapters.

2.5.2 Density

Density of carbon dioxide varies with different pressures and temperatures. Increased pressure will result in increased density. While increased temperature will result in decreased density. (Brobakken, 2018)

The figure below illustrates how the density of CO2 will increase with depth. This is important to keep in mind when planning for CO2 storage, considering the optimal phase of stored CO2 is as a supercritical fluid.

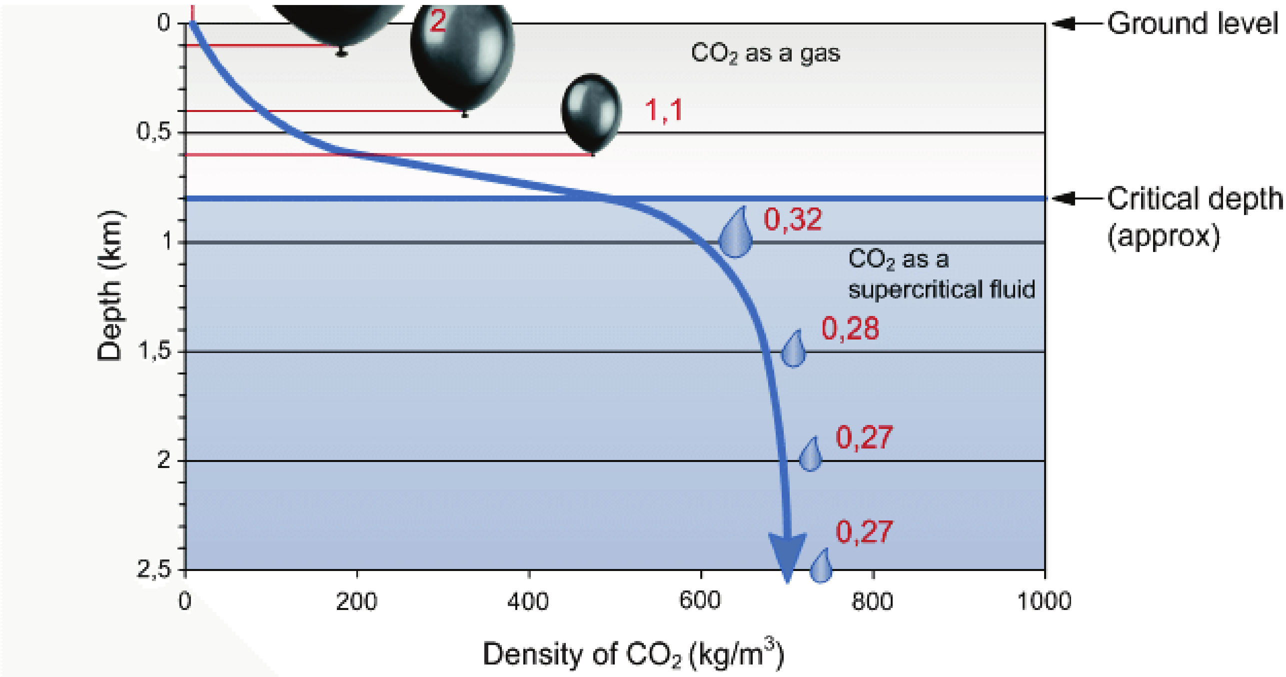

Figure 8. Illustration of how the density of CO2 changes with depth. (IEA, 2008)

2.5.3 Solubility in water

CO2 is stored in subsurface geological formations in liquid form. CO2 will most likely react with water when it is injected into the subsurface. Either with brine in the formation or with water being injected into the field. Some of the CO2 will dissolve into the water and form a liquid phase. This can help to keep the CO2 confined in the underground formation, reducing the risk of a leak.

The amount of CO_2 that will dissolve into the water is dependent on the solubility of the CO_2. Solubility is defined as the maximum amount of a substance that will dissolve in a given amount of solvent at a specific temperature. (Hannis, et al., 2017). The water's salinity level will also affect the CO_2 solubility.

The solubility of CO_2 in water is a crucial factor considering subsurface storage. The more soluble CO_2 is in the water, the more CO_2 can be stored in a given volume of water. However, this also means that it takes longer for the CO_2 to dissolve in the water, which can affect the overall efficiency of the storage process. The reaction between carbon dioxide and brine will be an essential trapping mechanism ensuring long-term storage. In some cases, it may be beneficial to enhance the solubility of the CO_2 in water by adding chemicals known as surfactants. These can help increase the amount of CO_2 that can be dissolved in the water and can improve the overall efficiency of the storage process. However, the use of surfactants can also have potential environmental and economic impacts that need to be carefully considered. (Brobakken, 2018)

2.5.4 Acidity

The acidity of water can increase due to dissolved carbon dioxide (CO_2). When CO_2 dissolves in water, it forms carbonic acid (H_2CO_3) through the following reaction:

$$H_2O + CO_2 \rightleftharpoons H_2CO_3$$

Carbonic acid is a weak acid, which means that it only partially dissociates into hydrogen ions (H^+) and bicarbonate ions (HCO_3^-). The hydrogen ions increase the concentration of H^+ in the water, making it more acidic. (Tiong, et al., 2019)

Acidity is a crucial factor to consider when planning for carbon capture and storage (CCS) operations for several reasons. The presence of acidic compounds in CO_2 streams can lead to corrosion in pipelines and storage equipment. The storage of acid gases underground can also have environmental impacts. If the gas leaks into the surrounding soil and water, it can lower the pH and create acidic conditions that can harm plants and aquatic life. The solubility of CO_2 in water increases with increasing acidity. This means that the CO_2 streams with higher acidity can dissolve more CO_2, which can improve the efficiency of the process. However, it also means that if the acidity is too high, it can lead to corrosion and other issues. And the stability of the stored co_2 can be affected by the pH of the storage site. In general, lower pH values can lead to faster dissolution of the CO_2 in the surrounding water, which can reduce the stability of the storage site over time. (Jacobson, 2020), (Brobakken, 2018).

Monitoring and controlling the acidity of the gas stream and the storage site can help reduce the risk of corrosion, health and safety issues and environmental impacts. This can also affect the efficiency and stability of the CCS process. It is therefore important to consider the acidity of CO_2 streams and the potential impact on pipelines, equipment and storage sites. This may involve adjusting the pH of the CO_2 stream to ensure it is within acceptable ranges, or designing infrastructure and storage sites that are resistant to corrosion and other issues related to acidity.

To summarize CO_2 can behave differently depending on the geological conditions of the location where it is found, it can exist as a gas, a liquid or a solid. The optimal way is to store the CO_2 as a supercritical fluid, with properties of both a gas and a liquid. CO_2 can dissolve in groundwater and form carbonic acid, which can cause chemical reactions and alter the properties of subsurface minerals. This can lead to changes in permeability and porosity, affecting the movement of the fluids. Furthermore, CO_2 can interact with different rock types and minerals. These reactions can result in mineral dissolution, mineral precipitation, and mineral alteration.

3 Drilling for CCS Injection: Comparing Techniques and Regulations with Conventional Oil and Gas Wells

CCS is a promising technology that can mitigate greenhouse gas emissions from various industrial processes. One of the key components of CCS is the injection of captured CO2 into deep geological formations. This is done through injection wells. However, the drilling and construction of wells for CO2 injections pose unique challenges that differ from conventional oil and gas wells. This chapter provides an overview of the drilling techniques and equipment used in CCS injection wells, types of wells used for CCS injection and international regulations and standards.

3.1 Comparison of drilling injection wells for CCS and conventional oil and gas wells

When considering injection wells for CCS, it is important to understand the difference between these wells and conventional oil and gas wells. According to the Society of Petroleum Engineers (SPE), while the drilling process for both types of well is similar, the main difference lies in their purpose. Injection wells for CCS are designed specifically to inject CO2 into geological formations for long-term storage, while oil and gas wells are designed to extract hydrocarbons for commercial use. While there are significant differences between injection wells for CCS and conventional oil and gas wells, there are also many similarities. Both types of wells are typically drilled using similar equipment and techniques and require careful consideration of geological and reservoir properties to ensure that they are effectively and safely designed, constructed and operated.

The differences and similarities are gathered from a paper called: Design of Carbon Capture and Sequestration CCS Wells. (Ceyhan, et al., 2022)

3.1.1 Pressure

The difference in purpose has significant implications for the design and operation of the wells. CCS injection wells are typically drilled to greater depths than oil and gas wells and must withstand higher pressures to ensure the safe and effective injection of CO2. This requires specialized drilling equipment and well design to ensure that the wellbore can withstand the high pressures and temperatures encountered at these depths.

Conventional oil and gas wells experience the highest pressure, immediately after they enter service. The pressure then declines until a rate or water-cut economic limit is reached. Meaning until the well starts to produce so much water it is no longer economically beneficial. CCS wells on the other hand start with low pressure right after they enter service. As more CO2 is injected into the reservoir, the pressure increases until it reaches a rate or pressure limit. This is normally determined by the integrity of the cap rock.

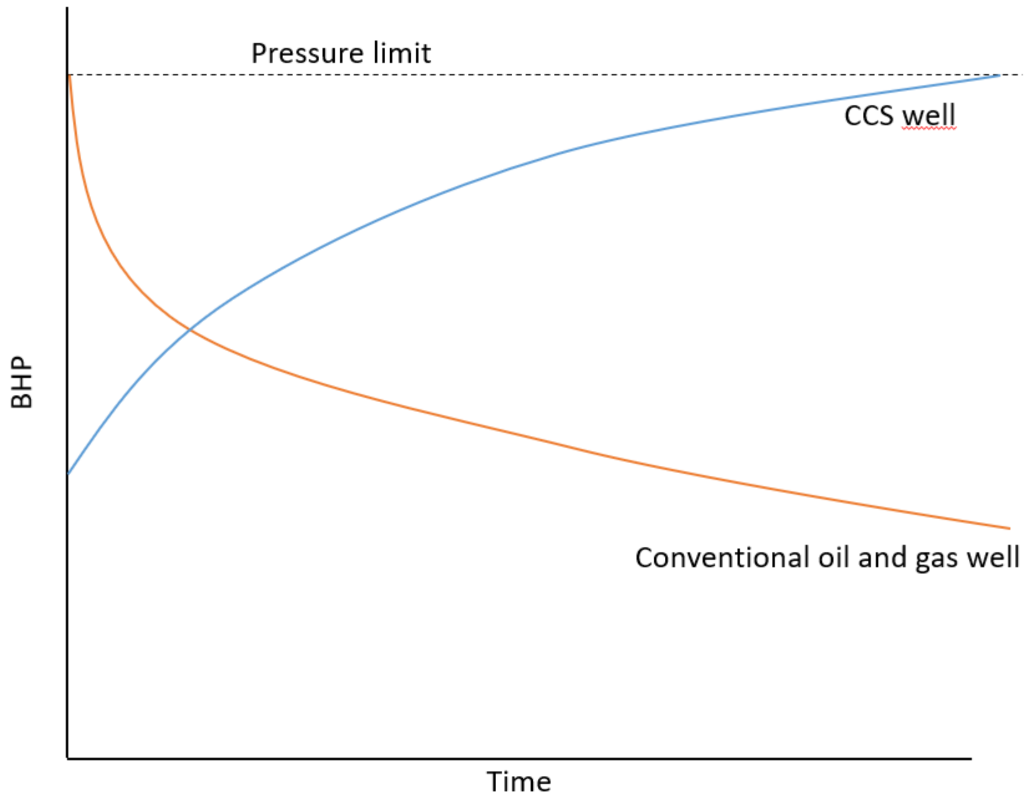

Figure 9. Illustration of pressure regimes of CCs wells compared to conventional oil and gas well. Illustration inspired from (Ceyhan, et al., 2022)

3.1.2 Design

Wellbore design is another significant difference between injection wells for CCS and oil and gas wells. Because CO2 is a reactive fluid, it can interact with the surrounding rock formations and potentially cause damage to the wellbore. To mitigate this risk, CCS injection wells require multiple layers of casing and cement to ensure that the CO2 is injected into the right formation and does not escape into other layers of rock. The proper design and construction of the wellbore is essential to ensure the long-term integrity of the well and prevent leaks.

3.1.3 Monitoring

Monitoring requirements for CCS injection wells are also typically more stringent than for oil and gas wells. CCS wells require ongoing monitoring to ensure that the carbon dioxide remains in the storage formation and does not escape into the environment. This requires specialized monitoring equipment and techniques to detect potential leaks and measure the movement of CO2 within the storage formation.

3.1.4 Injection rate

While oil and gas wells typically produce at high rates for a relatively short period of time, injection wells for CCS are designed to inject CO2 at a steady, controlled rate over a much longer period. This is important to ensure that the CO2 is effectively stored in the formation and does not escape into other layers of rock or the environment. Achieving the proper injection rate requires careful consideration of the well design, reservoir properties and other factors.

3.1.5 Drilling Process

The drilling process is as mentioned similar for both wells. Both require drilling through rock formations to reach the target reservoir. This involves the use of drilling rigs and other equipment. Both require careful planning and execution to ensure that the well is constructed safely and effectively, and that it can operate as intended over its lifetime.

3.1.6 Regulatory Compliance

Both types of wells are subject to regulatory requirements designed to ensure their safety and environmental soundness. These requirements may include permitting, monitoring, reporting and compliance with safety and environmental standards. Requirements are critical for ensuring that the wells are operated safely and effectively. What the requirements are, depends on what country control the operation permits where the well is drilled. Two different regulations will be presented in 3.5.

3.1.7 Well Testing

Both types of wells may undergo testing to assess their productivity and integrity. For injecting wells for CCS, this may involve injection testing to evaluate the wells capacity to inject CO2 into the formation. For oil and gas wells, this may involve testing to assess production rates and reservoir properties. Testing is important for optimizing the well's operation and for identifying potential problems that may need addressing.

3.1.8 Integrity

Wellbore integrity is also an important consideration for both types of wells. Oil and gas wells require multiple layers of casing and cement to ensure that hydrocarbons are effectively extracted, and that the wellbore remains stable and secure. Similarly, injection wells for CCS require multiple layers of casing and cement to ensure that the CO2 is injected into the proper formation and does not escape into the other layers of rock.

In summary, while there are some key differences between injection wells for CCS and for conventional oil and gas wells, there are also many similarities. Both types of wells require careful planning, design and execution to ensure that they can safely and effectively perform their intended functions. They also require ongoing monitoring and maintenance to ensure that they continue to operate as intended over their lifetime. However, it is important to note that the drilling process for injection wells for CCS is more complex and involves more stringent safety measures than conventional oil and gas wells. This is necessary to ensure that the stored CO2 remains safely underground and does not pose a risk to the environment. Overall, understanding both similarities and differences between these types of wells is important for developing and implementing effective drilling and well management strategies.

3.2 Types of wells used for CCS and their characteristics

Several types of wells can be involved in a CCS operation. What types are depending on the specific geological characteristics of the storage site.

Monitoring wells
Monitoring wells are used to monitor the storage formation for leaks and other changes that could impact the storage capacity and capability. Monitoring wells are drilled around the storage formation and are equipped with sensors that can detect changes in temperature, pressure and CO_2 content.

Utility Wells
These are used to reduce pressure, by removing formation water.

Production wells
CCS can in some cases, be combined with EOR, which involves injecting CO_2 into oil reservoirs to increase oil production. The production well is used to extract oil and gas from the formation, while an injection well will inject the CO_2 into the formation and force the oil and gas towards the production well.

Previous Production wells
Abandoned production wells can sometimes be repurposed for CCS. When these wells are used, they are typically drilled deeper than injection wells and may already have casing and cement in place. However, they may also have integrity issues that need to be addressed before they can be used.

Injection wells
These wells are drilled to inject CO_2 into the formation for long-term storage. To ensure safe and effective storage, pressure and temperature sensors are installed to monitor the well performance. In addition, drilling techniques and equipment used in CCS injection wells must be carefully selected and designed to prevent leaks and ensure the structural integrity of the well. The proper selection of drilling techniques and equipment is crucial to ensure that the CO_2 remains trapped underground. Overall, injection wells require specialized design, construction and monitoring to safely store CO_2 underground.

3.2.1 Different types of injection wells

The Underground Injection Control program categorizes injection wells into six different classes, depending on the depth and type of injection activity, and the potential risk of endangering underground drinking water sources. (EPA, 2022)

<u>Class 1 wells</u>: These are wells used for the disposal of hazardous and non-hazardous waste fluids into deep, isolated rock formations that are not currently being used as sources of drinking water.

<u>Case 2 wells</u>: These wells are used for the injection of fluids related to oil and gas production activities, such as brine, produced water and other fluids associated with hydrocarbon extraction.

<u>Class 3 wells</u>: These wells are used for the injection of fluids used in the extraction of minerals such as uranium, salt, and copper.

<u>Class 4 wells</u>: These are shallow wells used for hazardous or radioactive waste fluids into or above underground drinking water sources. However, these types of wells are no longer authorized for use under the Safe Drinking Water Act.

<u>Class 5 wells</u>: These are wells used for the disposal of non-hazardous fluids.

Class 6 wells: These wells are used for the injection of CO_2 for long term storage as part of CCS projects.

Each well class has specific requirements and regulations under the Underground Injection Control program to ensure the protection of underground sources of drinking water. (EPA, 2022)

The type of well that is discussed in this thesis is Class 6 wells. Wells that are used for CO_2 injection to underground formation for long-storage, called geological sequestration (GS).

3.3 Well Design of CCS injection wells

Injection wells are used for various purposes such as storing CO_2, waste disposal, enhancing oil production, mining, and preventing saltwater intrusion. They were first widely used in the 1930s for disposing of brine from oil production and helped preserve surface waters. Injection is also used to enhance oil recovery in some formations. In the 1950s, chemical companies began using injection wells to dispose of hazardous industrial byproducts, which proved to be a safe and cost-effective option. (EPA, 2022)

3.3.1 Well Design

Well design for CCS wells is an integrated process, and there are several key considerations that must be considered to ensure a safe and effective operation. Once a location is chosen, and what type of class the well will be. The drilling depth must be decided. Some other important considerations are the material to be drilled through, how large the well will be and how deep the well will be drilled.

A few assumptions and values need to be in place before the process of well design can begin. This includes pressure conditions and saturations, well trajectory, pressure and temperature constraint, and compositional variation of the sequestrated gas. Assuming these parameters are in place, the design progress will be described below.

When planning CCS injection wells, the best way to start is to begin with completion and find the required completion size for the desired CO_2 injection rate. Before doing that, it is essential to perform thermal and flow analyses for the injection of the gas. Selection of PVT is critical in this analysis. Standard PVT models for oil and gas are not applicable in CCS operations since the CO_2 concentrations are much higher than in conventional oil and gas operations. As mentioned previously, the optimal way of storing CO_2 is in a supercritical phase. This is the best and safest option for long-term storage of CO_2. Conventional oil and gas correlations do not provide accurate calculations of the density profile. The PVT models also need to consider impurities in the injection stream. It is important to have control over impurities, to make sure the calculations are correct. The existence of impurities in the injection well will affect the achievable rate of injection, which could lead to requiring more wells to match the asking injection rate (Mantovani, et al., 2012)

With the appropriate PVT models chosen, the appropriate tubing size can be decided. When deciding the tubing size, these two constraints need to be considered. Max allowable BHP, which is usually determined by the integrity of the cap rock. And max allowable wellhead pressure, usually determined by injection compressor or pump specifications. The BHP is normally the limiting constraint towards the end of the well service life. As pressure in the reservoir and bottom hole increases over time it will reach a design limit indicating time for abandonment. Tubing size needs to be so that it is possible to achieve desired injection rate right before abandonment.

When the tubing size is decided, production casing and liners are next. They need to be designed to maintain the well integrity; in case the primary barrier fails. It is also necessary to regularly inspect and test the production casing to assure well integrity. Another key factor to consider when designing the production casing and liner, is what cement is used. CO_2 resistant cement is recommended for TD to around 500ft below the caprock. Conventional oil and gas cement is acceptable from this point and up. (Ceyhan, et al., 2022)

The rest of the well is usually designed like an oil and gas well, including the intermediate and surface casing. Normally due to pressure conditions and depth it is necessary with an intermediate casing between surface casing and production casing.

3.3.2 Material selection

The well needs to be designed for CO2 exposure. As mentioned in 2.5.4, carbon dioxide mixed with water creates an acidic environment. The presence of acidic compounds in CO2 streams can lead to corrosion in pipelines and storage equipment. This is damaging to the infrastructure and increases the risk of leaks. CO2 in water will corrode carbon steel through the following reactions.

$$H_2O + CO_2 \rightleftharpoons H_2CO_3$$

$$Fe + H_2CO_3 \rightarrow FeCO_3 + H_2$$

Corrosion due to this reaction is called dewpoint corrosion. And will only happen when the metal surface temperature drops below the dew point of the injected gas. As temperature drops below the dewpoint the water vapor in the gas stream will condense to form carbonic acid, which can lead to severe corrosion of carbon steels. (Corrosion Clinic, n.d.)

Software tools can be used to predict and manage the risk for corrosion. As well as assisting in deciding the suitable material, if carbon steel or some other material is the better option.

In general, internal corrosion is normally not an issue because the CO2 gas stream is sufficiently dry. External corrosion is usually the concern when deciding material for CCS wells. There are two main concerns considering external corrosion. (Ceyhan, et al., 2022)

1. Conventional oil and gas cement may not be sufficient to weather the acidic environment and could possibly fail. To prevent this from happening, acid resistant cement should be used instead. Especially in the deepest parts of the well.
2. It is impossible to predict how the downhole environment is going to look after hundreds of years, and it is important to have a second barrier in case the acid resistant cement fails. To maintain the integrity of the well, the material of the production casing or liner and the production tubing also needs to be acid resistant.

A solution to this problem is to use corrosion resistant alloys (CRAs). CRAs are a group of metals that are resistant to corrosion and are commonly used in harsh environments where conventional materials would corrode quickly. CRAs are, however, typically more expensive than traditional metals. (Corrosion Resistant Alloys, n.d.)

The problem becomes even more intricate if the injection stream contains impurities such as H2S or SO2. Some CRAs are highly resistant to CO2 corrosion, but different impurities could increase the corrosion rate due to other reactions. It is important to choose the right grade of CRAs, it is not sufficient to just choose the highest grade. It is important to keep in mind when using higher grade CRAs that certain factors could cause crackling or other issues when using these materials. These factors include temperature and type of welding techniques. (Ceyhan, et al., 2022)

In conventional oil and gas wells, working stress design is commonly used for design checks. Meaning burst, collapse, axial and the von Mises equivalent stress. These values are compared to the API performance properties and the yield strength to check the design. A minimum design factor will decide if the design is sufficient. However, in CCS injection wells, material selection is going to be the deciding factor when considering different CRA tubulars for the well. There is a significant difference between the material properties of carbon and CRA steels. Beyond about 17cr, CRA tubulars are anisotropic. (Ceyhan, et al., 2022). This is important to consider that an anisotropic triaxial design criterion should be used for design checks. Other safety factors like burst, collapse and tension also need appropriate adjustments when using CRA tubulars. (Sathuvalli, et al., 2019)

3.3.3 Load Cases

Load cases are scenarios used to analyze a system's response and its equipment. By analyzing the response, drilling engineers can design and optimize the drilling equipment so that it can withstand the loads the well most likely will experience during drilling operations. CCS injection wells experience a lot of the same load cases as in conventional oil and gas well design, here are some of the additional load cases that CCS wells will experience gathered from: Design of Carbon Capture and Sequestration CCS Wells. (Ceyhan, et al., 2022)

Injection load

Injection of CO_2 is going to add stress and pressure on the reservoir and the surrounding formation. This can cause the formation to deform or fracture. The injection rate of CO_2, as well as the geomechanically properties of the surrounding formation must be carefully considered to prevent over-pressurization and ensure proper containment within the storage zone.

Shut-in load

At some point it is probably going to be necessary to test the integrity of the well and look for any weaknesses. This is done during a shut-in. It is important during a shut-in to consider the different situations that could occur in the tubing. The tubing could be filled with CO_2, reservoir fluid or a mixture of both. (A tubing filled with reservoir fluid is only a possible outcome if the well is drilled in a depleted oil and gas reservoir). The shut-in load cases should be calculated for all the scenarios.

Bullhead kill load

When CO_2 is injected into the well, it creates an increase in pressure in the wellbore and in the surrounding formation. If the pressure becomes too high, it increases the risk of CO_2 leakage into the environment. The purpose of this load case is to verify the integrity of the wellbore and ensure that it can withstand the pressure generated by the injection stream without leaking. This is done by injecting heavy kill mud into the wellbore to increase the pressure. During this operation, the pressure is carefully monitored to ensure that it remains within safe limits and does not cause any damage to the formation or the well.

Seismic Activity

CO_2 injection can potentially induce seismic activity. Load cases must be designed to account for and withstand any resulting stress from seismic activity.

Accidental Release

If for some reason the control over the surface containment is lost, it is possible the well will experience uncontrolled flow through the tubing and accidentally release the CO_2 that is injected downhole. This could result in loss of pressure in the wellbore and lead to a collapse load on the tubing.

3.4 Drilling techniques and equipment for CCS injection wells

This chapter is modified from my semester project, Moving Drilling Operations into Deeper Waters. (Skog, 2023)

Drilling successful CCS injection wells requires careful planning, precise execution, and the use of appropriate drilling techniques. However, drilling cost can be a significant factor in determining a project's feasibility. The selection of drilling methods can greatly impact the project's overall cost and affect factors such as wellbore stability, drilling efficiency, and the well's safety and effectiveness. This chapter will explore some common drilling techniques.

3.4.1 Conventional drilling

A conventional drilling operation involves drilling a hole, running down the appropriate size of casing, then cementing the casing. After this is done a smaller drill bit is lowered through the casing before drilling a deeper hole. Then these steps are repeated until they reach the desired depth.

This is a quite simple explanation. What differs conventional drilling from the other methods that will be discussed, is that the hydrostatic pressure from the drilling fluid balances the pore and fracture pressure without the need for other pressure control systems.

3.4.2 Managed pressure drilling

Managed pressure drilling (MPD) involves specialized equipment to precisely control well pressure during drilling operations. Traditional drilling equipment is enhanced with additional choke manifold, valves, and rotational control devices to achieve the desired pressure profile. Common MPD systems include Surface Back Pressure (SBP) and Controlled Mud Level (CML).

MPD aims to manage the BHP with respect to the downhole pressure, without any influx from formation fluids. MPD allows drilling in narrow pressure windows with bottom hole pressure (BHP) close to the pore pressure. It also enables drilling through pressure zones with abnormal profiles. It can also reduce casing points and minimize non-productivity time. MPD can help increase recovery factor in mature fields and depleted reservoirs that experience narrow pressure windows. Conversely, this approach comes with additional costs, operational complexities, and increased equipment needs. Implementing this method will result in extra flat time due to operational limitations and extra operations like displacement of drilling fluids and/or running/retrieving downhole tools.

This chapter will also discuss systems that technically are not a part of managed pressure drilling but can be used as a component of an MPD system. This includes continuous circulation system and dual gradient drilling (DGD).

3.4.2.1 Surface back pressure

Surface Back Pressure (SBP) is the most common MPD system, due to its fast pressure adjustment capability. The pressure limit of SBP drilling is governed by the limit of the backpressure, which is determined by the surface equipment and fracture pressure at the weakest formation. The system normally uses a drilling fluid with a lower density, then compensating by increasing the back pressure. This is done by choking back the well. This will however lead to more time spent displacing drilling fluid between drilling and tripping. Despite these challenges, the quick adjustment of pressure due to backpressure justifies

SBPs leading position among other MPD systems. Despite that, the system's high cost and large footprint must be taken into consideration when deciding to implement this MPD system. While SBP certainly provides improved control over the BHP and allows drilling in areas with narrow pressure windows, operators should weigh the benefits against potential costs and operational complexities before committing to adopting this system.

3.4.2.2 Controlled Mud level

Controlled Mud Level systems (CML) or Low Riser Return Systems (LRRS) are designed to manage the pressure gradient in the well by regulating the mud level inside the riser. This is done by using a modified riser and a subsea pump to return the cuttings and mud to the surface. The mud level is adjusted by regulating the return pump rate. These systems are highly effective regarding controlling the pressure during drilling, tripping, cementing and during completion.

CML systems can be used in two ways. The first way is purely for ECD (Equivalent Circulating Density) compensation. A full riser is used under static conditions, and the mud level is lowered during drilling. The second option is a combination of using a heavier than conventional drilling mud while lowering the level of mud in the riser under static conditions. This second option makes it even easier to adjust and maneuver pressure while drilling.

One of the significant advantages of CML systems is their flexibility, which allows them to shift easily from CML to conventional drilling. They are also cheaper and have a smaller footprint compared to SBP systems. The difference between SBP and CML is that SBP systems use backpressure, whereas CML systems use the mud level in the riser to regulate the pressure. Another advantage of CML systems is that kicks could easily be detected by looking at change in the mud level in the riser or change in the return pump rate. In conclusion, CML systems are an efficient solution for pressure control in drilling operations. They are flexible, cost-effective, and easy to maneuver.

3.4.2.3 Conitonus circulation system

A continuous circulation system is a drilling system that allows for continuous circulation of the drilling mud during connection, drilling, and tripping. This system allows for a constant BHP by keeping the mud pumps on while adding or removing a drill pipe. With continuous circulation during connection, there is no difference in equivalent circulating density (ECD) during drilling and during connection. This results in a more efficient drilling process, allowing for continuous hole cleaning throughout the whole operation. Thus, increasing the rate of penetration (ROP) and reducing non-producing time.

As mentioned, continuous circulation system is not technically a part of MPD but can be utilized as a component by providing a way to continuously circulate drilling fluid while also maintaining control over the pressure in the wellbore. In an MPD system, pressure is controlled by adjusting the flow rate and/or the density of the drilling fluid. Continuous circulation systems maintain continuous circulation while allowing adjustments to flowrate or density to control the wellbore pressure.

This system can be utilized on all types of rigs and reduce connection time while also reducing overall risk and cost. Continuous circulation systems provide a reliable, safe, and efficient drilling technique which can lead to improved wellbore stability and better production rates.

3.4.2.4 Dual gradient drilling

Dual gradient drilling (DGD) is also not technically a part of MPD but can be used as a component as well. In MPD, the objective is to maintain constant BHP by adjusting the drilling fluid as a response to changes in the formation pressure. DGD can be used as a component by maintaining a constant BHP while drilling.

DGD stands out from the other systems because it utilizes two drilling fluids with different densities at the same time. In addition, the mud returns are not directed through the riser. Instead, a return line separate from the drill pipe is used. A mud lift system is connected to the return line and is responsible for pumping the mud back up to the rig. This allows for the heavier mud to be returned to the surface without mixing with the lighter mud.

Despite different methods for managing pressure, all DGD systems are designed to eliminate the pressure added by the drilling fluid inside the riser. By drilling closer to the natural pressure gradients, DGD systems enable drilling deeper before casing must be set. This will lead to saving costs in both equipment and operational time. To use a DGD system, some adjustments must be made to the rig, including the installation of two circulation systems, a diverter and a mud lift system. Pump-based DGD and Dilution-based DGD are both examples of DGD systems, both will be further discussed in the next sections.

3.4.2.4.1 Riserless Mud Recovery (RMR)

Riserless Mud Recovery is not a type of DGD, but is commonly used in DGD operations, because the use of multiple fluid columns can make it difficult to recover drilling mud using a conventional riser. RMR is a closed circulation drilling system used to transport mud and cuttings from the seafloor to the rig's mud treatment system. This helps prevent environmental damage by ensuring no mud or cuttings is spilled into the sea. These systems are designed to be environmentally friendly, cost-effective, and safe. They are commonly used in shallow water drilling operations where a full riser is not necessary.

A subsea mud pump is used to transport mud and cuttings from the seafloor to the mud treatment system at the rig. The closed system makes it possible to have no discharge of cuttings or mud into the sea. The density of the mud makes up the pressure barrier that prevents wellbore instability and maintains well integrity during drilling. To use RMR systems, certain modifications need to be made to the drilling rig. This includes installation of a pump above the wellhead, an anchor to keep the mud return line in place, and a pump module attached to the return line.

In conventional drilling, the top-hole section is normally drilled with sea water because of cost and environmental issues. The formations in top-hole sections are often loose, which means the hydrostatic pressure from the sea water may not be enough to support them from collapsing. In some cases, the hydrostatic pressure will be lower than the pore pressure, which will end up in the well having an influx. Using RMR for the top-hole section makes it possible to use denser mud which can provide sufficient hydrostatic pressure.

3.4.3 Underbalanced drilling

Underbalanced drilling (UBD) is a specialized drilling technique used to minimize formation damage and increase well productivity. The main principle is to intentionally reduce the density of the drilling fluid. This reduces the hydrostatic pressure in the wellbore, allowing the well to be drilled with a lower pressure than the surrounding pore pressure. This helps minimize the risk of formation damage, which can improve the productivity of the well.

UBD is typically only used in the last section of the well, when entering the reservoir. The key factor for choosing this technique is to minimize formation damage to the reservoir and increase the productivity index. The risk of lost circulation is minimal, and there is no need for disposal of hazardous drilling mud. The reason for the reduced risk of lost circulation is because the pressure on the wellbore is kept so low. By keeping the pressure so low, there will be no buildup of mud cakes, which reduces the risk for differential stickling. However, UBD is not without its downsides. Safety issues can be a concern due to the higher risk of explosion, fire and blowouts. UBD is also very expensive and cannot be applied to every well. Maintaining an underbalanced position at all times can be challenging. A sudden pulse of overbalanced pressure could potentially damage the well, especially with no mud cakes present. Another concern is that drilling with too low pressure could result in borehole collapse, which is an increased risk in UBD.

A consequence of UBD is the pressure difference between the wellbore and the formation, this difference could invite formation fluids to enter the wellbore. If the influx is large enough it could lead to a blowout. The well is already in a vulnerable situation during UBD, a blowout could be difficult to handle and could have fatal consequences.

In conclusion, UBD is a technique that can provide significant benefits in the right circumstances. By reducing the density of the drilling mud and creating a lower pressure in the wellbore, it can reduce the risk of formation damage, increase well productivity and reduce risk of lost circulation. However, it is a complex and expensive process that requires careful surveillance of the pressure.

3.4.4 Performance drilling

Performance drilling (PD) is a technique with the goal of enhancing the penetration rate. The main objective is to achieve a high rate of penetration (ROP) while using a low bottom hole pressure (BHP). This is accomplished by using a stabilized motor with a bottom hole assembly (BHA) designed to adapt to stabilizers.

The stabilized motor provides additional rotation to the bit, which enables the reduction of rotating the drill string while still drilling with a higher ROP. This reduction in drill string rotation minimizes wear on the casing and drill string, and other drilling equipment. Furthermore, the ability to rotate the bit faster than the drill string provides better angle control which gives more efficient control over doglegs and deviation.

In addition, PD can reduce hole problems caused by less open hole time, as well as reduce torque which further reduces the wear and tear on the drilling equipment. PD also has the potential to use less fuel when drilling, because the entire drill string does not need to rotate the bit. Therefore, this technique can be efficient and cost-effective, particularly in challenging drilling environments.

PD also has some downsides. The downhole equipment needs to be suitable for a higher ROP, which could mean specializing the bit, the drill pipe and more equipment. Which may increase the upfront cost of the drilling operation. Another downside is that the equipment may need more frequent maintenance, which can add to the total cost of the operation. PD can also be more complex, which requires that the drilling crew get special training to be able to perform PD. (G. Mensa-Wilmot & Ilavia, 2009)

In summary, performance drilling is a valuable technique that can enhance drilling efficiency and reduce cost, but it also requires specialized equipment and expertise.

3.4.5 Different techniques for different purposes

The different drilling techniques are suited for different purposes. Some techniques are most cost-effective, emphasizing budget considerations. Others are better suited for improving drilling efficiency, aiming to maximize the rate of penetration (ROP). And some techniques are best for minimizing formation damage.

Reducing cost

Examples of methods that can help reduce the drilling cost are CML, continuous circulation system and riserless drilling.

CML systems are very flexible, which allows them to shift easily from CML to conventional drilling. This system is also cost-effective, it can improve cost and efficiency by reducing the need for expensive drilling fluids and reducing the non-productive time. And on top it is easy to maneuver.

Continuous circulation system can be used on all rigs, and provides a reliable, safe and efficient drilling technique.

With the circulation system in riserless drilling the top-hole section can be drilled with denser mud, keeping the hole from collapsing. Drilling without a riser can also help reduce drilling cost and improve efficiency by reducing the complexity of the drilling operation.

Optimizing drilling efficiency

Of the techniques presented, performance drilling might be the better one for optimizing drilling efficiency. Performance drilling is normally associated with higher costs, but also reduce cost and improve efficiency by identifying and addressing problems before they become too serious. This technique can also reduce the amount of fuel while drilling because the entire string does not have to rotate to rotate the bit. But equipment needs to be suitable for a higher ROP, which would add cost again. This method can also be more complex, which require specialized training for the crew.

Minimizing formation damage

For minimizing formation damage UBD or MPD are probably the best options.

3.4.6 Drilling equipment

This section will discuss the additional equipment required in the different unconventional drilling methods and drilling systems mentioned above.

- Rotating Control Device
  Rotating Control Device (RCD) is an important well-control equipment often used during Managed Pressure Drilling and Underbalanced Drilling.

  According to Schlumberger glossary, RCD is a pressure-control device used during drilling to make a seal around the drill string while it rotates to contain hydrocarbons or other wellbore fluids and prevent their release to the atmosphere. (Schlumberger, n.d.). By creating a seal around the drill pipe, the RCD can safely divert the flow from the annulus away from the rig floor. This makes it possible to drill, even if a kick occurs.

- Mudlift system
  A mud lift system is used in dual gradient drilling, to lift the drilling mud from the seafloor up to the drilling ring. This creates the effect of dual pressure gradients in the returning mud column. The mud lift system could be used with a conventional

riser, where the riser is filled with seawater and the mud is pumped up to the rig through return lines. The system could also be used without a riser, in a riser less drilling system. Both techniques are discussed earlier in chapter 3.4.2.4. The mud lift system consists of a subsea pump and a diverter system. The subsea pump requirements depend on water depth, mud weight and pressure losses in the return lines. The function of the diverter system is to separate the drilling mud from the seawater. (Goldsmith, 1998)

- Returnline
  Mud return line is also known as the flowline.

- Subsea mud pump
  A pump is used to circulate drilling mud. To control annular pressure during connection, additional equipment is required to monitor and control densities and flowrates. CAPM uses rotating control devices and drill string valves, or a flow stop valve to stop the drill pipe U-tube hydraulics if circulation is interrupted.

3.5 International regulations and standards related to drilling injection wells for CCS

This chapter introduces international standards and regulations governing the drilling of injection wells for CCS. Two standards will be presented, NORSOK which is the Norwegian standard and Code of Federal Regulations, which are regulations for the United States. These standards contribute to safe and efficient operation of injection wells by giving insight into the best practices, technical requirements and environmental considerations.

Injection wells used in CCS are typically a class IV Well. Regulatory requirements for these types of wells are derived from the Code of Federal Regulations (CFR), found in 40 CFR Subpart H – Criteria and Standards Applicable to Class VI Wells.

Below, §146.86 Injection well construction requirements, are presented. These cover general requirements, casing and cementing, and tubing and packer requirements. These requirements are the standard when operating in the United States.

(a) ***General.*** The owner or operator must ensure that all Class VI wells are constructed and completed to:

(1) Prevent the movement of fluids into or between USDWs or into any unauthorized zones;

(2) Permit the use of appropriate testing devices and workover tools; and

(3) Permit continuous monitoring of the annulus space between the injection tubing and long string casing.

(b) ***Casing and cementing of Class VI wells.***

(1) Casing and cement or other materials used in the construction of each Class VI well must have sufficient structural strength and be designed for the life of the geologic sequestration project. All well materials must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director. The casing and cementing program must be designed to prevent the movement of fluids into or between USDWs. In order to allow the Director to determine and specify casing and cementing requirements, the owner or operator must provide the following information:

(i) Depth to the injection zone(s);

(ii) Injection pressure, external pressure, internal pressure, and axial loading;

(iii) Hole size;

(iv) Size and grade of all casing strings (wall thickness, external diameter, nominal weight, length, joint specification, and construction material);

(v) Corrosiveness of the carbon dioxide stream and formation fluids;

(vi) Down-hole temperatures;

(vii) Lithology of injection and confining zone(s);

(viii) Type or grade of cement and cement additives; and

(ix) Quantity, chemical composition, and temperature of the carbon dioxide stream.

(2) Surface casing must extend through the base of the lowermost USDW and be cemented to the surface through the use of a single or multiple strings of casing and cement.

(3) At least one long string casing, using a sufficient number of centralizers, must extend to the injection zone and must be cemented by circulating cement to the surface in one or more stages.

(4) Circulation of cement may be accomplished by staging. The Director may approve an alternative method of cementing in cases where the cement cannot be recirculated to the surface, provided the owner or operator can demonstrate by using logs that the cement does not allow fluid movement behind the well bore.

Figure 10. Injection well construction requirements from Code of Federal Regulations, part one. (Environmental Protection Agency, 2010)

(5) Cement and cement additives must be compatible with the carbon dioxide stream and formation fluids and of sufficient quality and quantity to maintain integrity over the design life of the geologic sequestration project. The integrity and location of the cement shall be verified using technology capable of evaluating cement quality radially and identifying the location of channels to ensure that USDWs are not endangered.

(c) ***Tubing and packer.***

(1) Tubing and packer materials used in the construction of each Class VI well must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director.

(2) All owners or operators of Class VI wells must inject fluids through tubing with a packer set at a depth opposite a cemented interval at the location approved by the Director.

(3) In order for the Director to determine and specify requirements for tubing and packer, the owner or operator must submit the following information:

(i) Depth of setting;

(ii) Characteristics of the carbon dioxide stream (chemical content, corrosiveness, temperature, and density) and formation fluids;

(iii) Maximum proposed injection pressure;

(iv) Maximum proposed annular pressure;

(v) Proposed injection rate (intermittent or continuous) and volume and/or mass of the carbon dioxide stream;

(vi) Size of tubing and casing; and

(vii) Tubing tensile, burst, and collapse strengths.

Figure 11. Injection well construction requirements from Code of Federal Regulations, part two. (Environmental Protection Agency, 2010)

The Norwegian standard, NORSOK, do not have specific regulations for injection wells. Regulations for injection wells are the same as for production wells. Below are the NORSOK annular cement requirements and tubing and packer requirements.

Features	Acceptance criteria	See
A. Description	This element consists of cement in solid state located in the annulus between concentric casing strings, or the casing/liner and the formation.	
B. Function	The purpose of the element is to provide a continuous, permanent seal along hole in the casing annulus or between casing strings, to prevent flow of formation fluids and/or injection fluids, resist pressures from above or below, and support casing or liner strings structurally.	
C. Design, construction, and selection	1) A cement programme shall be issued for each cement job, minimum covering the following:	API RP 10B (entire series)
	a) casing/liner centralization giving sufficient stand-off to achieve pressure and sealing integrity across the natural sealing formation for source of inflow or entire qualified WBE length, whichever is less;	NS-EN ISO 10426-1 [9]
	b) use of fluid spacers;	
	c) effects of hydrostatic pressure differentials inside and outside casing and ECD during pumping and loss of hydrostatic pressure prior to cement setting up;	
	d) the risk of lost returns and mitigating measures during cementing.	
Added in Rev5	2) Hydraulic and displacement simulations shall be performed during planning.	
	3) For HPHT conditions and complex/foam slurry designs the cement programme shall be verified by independent (internal or external), qualified personnel.	
	4) The cement recipe shall be lab tested with dry samples and additives from the rigsite under representative well conditions. The tests shall provide thickening time and compressive strength development.	
	5) The properties of the set cement shall provide lasting zonal isolation, structural support, and withstand expected temperature exposure.	
	6) Cement slurries used for isolating sources of inflow containing hydrocarbons shall be designed to prevent gas migration, including CO_2 and H_2S, if present.	
	7) Planned annulus cement length:	
	(Rev4: Shall) a) Should be designed to allow for future use of the well (sidetracks, recompletions, and abandonment).	
	b) **General**: Should be minimum 100 m MD above a casing shoe/ window for kick tolerance purposes and minimum 200 m MD if next section will penetrate a source of inflow. Added in Rev5	
	c) **Conductor**: Should be defined based on structural integrity requirements.	

Figure 12. NORSOK regulations about annulus cement, part one. (NORSOK D-010, 2021) p.205

Features	Acceptance criteria	See
	d) **Surface casing**: Should be defined based on load conditions from wellhead equipment and operations. Top of cement should be at surface/seabed. e) **Intermediate casing:** If the casing penetrates a source of inflow, the planned cement length should be minimum 200 m MD above the source of inflow Added in Rev5 f) **Production casing/liner**: Should be minimum 200m MD above planned production packer depth. If the casing penetrates a source of inflow, the planned cement length should be 200m MD above the source of inflow. Note: If unable to fulfil the recommendation when running a production liner, the annulus cement length may be combined with previous casing annulus cement (e.g. 9 5/8" casing with 7" liner). g) Shoe track: A casing/liner should have a shoe track length of minimum 25 m MD. Added in Rev5	Added in Rev5
D. Initial verification Added in Rev5	Cement should be left undisturbed after placement until it has reached sufficient strength to withstand the applied loads. Loads should either be applied shortly after placement while cement is in fluid or low yield point plastic state and can rebound or heal (hydration has not started); or when the strength is deemed sufficient to avoid exceeding the elastic limit. 1) The cement sealing ability shall be verified through a FIT when the casing shoe/window is drilled out. 2) The cement length shall be verified by one of the following: a) Bonding logs: Logging methods/tools shall be selected based on ability to provide data for verification of bonding. The measurements shall provide azimuthal/segmented data. The logs shall be verified by qualified personnel and documented. b) Displacement calculations: Actual parameters, such as displacement rate, pressure profile, volumes and return data should be compared with simulations using industry recognized software to take into account well geometry, fluid properties and friction contribution. The implications of parameters deviating from plan should be assessed. In case of losses, it shall be documented that the loss zone is above planned top of cement. Acceptable documentation is job record comparison with similar loss case(s) on a reference well that has achieved sufficient length verified by logging. c) In addition to the above, a PIT/FIT or LOT shall be used to verify adequate formation/cement integrity. In case of a compromised cement job (due to e.g. losses), it may be acceptable to drill the next section with a good PIT/FIT/LOT if the previous casing is not a WBE in the final well configuration. (This method shall not be used for verification of annulus cement as a WBE for production or permanent abandonment purposes). Added in Rev5	

Figure 13. NORSOK regulations about annulus cement, part two. (NORSOK D-010, 2021) p.206

Injection / disposal wells are designed and used to inject liquids (water, brines, slurries or similar) and/or gases (including WAG, SWAG) into dedicated formation(s).

The well shall be constructed such that the injected media will be contained within the targeted formation zone. Measures shall be in place to detect and halt operations if out of zone injection occurs. For wells injecting at a pressure greater than the fracture closure pressure at the injection depth, the following applies:

a) the production packer shall be installed at a depth ensuring the injection or a casing leak below the production packer will not lead to fracturing of the cap rock or leak to shallower formation when applying maximum injection pressure

b) the annulus cement shall be logged and as a minimum have bonding from upper most injection point to 30 m MD above top reservoir;

c) it shall be documented that the injection will not result in a reservoir pressure exceeding the strength of the cap rock.

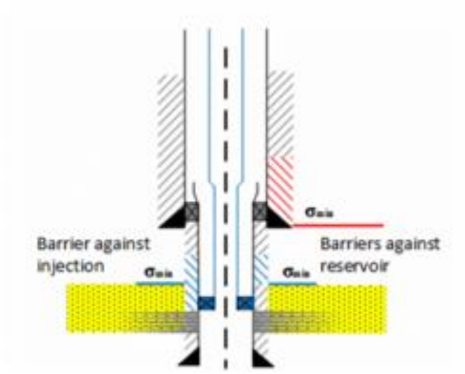

Figure 14. NORSOK regulations about Injection /disposal wells. (NORSOK D-010, 2021) p. 68

Item	Property	Requirement
a.	Long term integrity	Key integrity indicators like compressive and tensile strength, permeability and Young's Modulus should when measured over longer period, not indicate a deteriorating long-term trend. If such a trend is observed the test should continue to determine the final stable value.
b.	Permeability	Water permeability smaller or equal to 5 µD, or smaller or equal to 1000 times the formation permeability whichever is greatest. Alternatively, the zonal isolation material shall as a minimum have a combined permeability and length such that its ability to prevent fluid migration is as good or better than the cap rock it replaces.
c.	Radial shrinkage	For OH plugs / OH annular WBEs: low shrinkage. For internal, cased hole WBEs: long-term positive linear expansion.
d.	Mechanical loads	For WBEs exposed to loads outside relevant knowledge /experience envelopes (examples: geothermal, injection, high depletion, high pressure tests etc.), FEA (Finite Element Analysis) analysis should be performed and a 40 % safety factor in each individual load case should be achieved.
e.	Chemical stability	Withstand exposure to chemicals or substances that can exist without substantially affecting required integrity. Examples: H_2S, CO_2, H_2O, brines, hydrocarbons
f.	Bonding to tubulars	Shall bond properly to uncoated and de-greased steel or other tubulars in contact with it where bonding is required. If bonding cannot be achieved, the material shall be proven to have a compensating mechanism, such as expansion, that provides a hydraulic seal to casing and any exposed formation in contact with it.
g.	Effect on tubular integrity	Shall not detrimentally affect properties of tubulars in contact with barrier material.

Figure 15. Well barrier material requirements from NORSOK. (NORSOK D-010, 2021) p. 99

There are some differences between these requirements. To begin with, does 40 CFR state that: At least one long string casing, must extend to the injection zone and must be cemented by circulation cement to the surface in one or more stages. While NORSOK only requires that it should be minimum 200m MD above planned production packer depth. If the casing penetrates a source of inflow, the planned cement length should be 200m MD above the source of inflow.

But there are also similarities within the requirements, both mention that the well barriers, both the casing and the cement, must be compatible with the fluid it's expected to be in contact with. Examples: H_2S, CO_2, H_2O, brines and hydrocarbons.

NORSOK regulations currently do not encompass specific regulations pertaining to CCS operations. However, as the demand and interest for CCS operations continues to rise, there is a growing need for the development of corresponding regulations. It is highly likely that the NORSOK regulations will add requirements for CCS operations within the next few years.

3.6 Previous studies and reports on drilling injection wells for CCS and Leassons learned

This section will explore the technical aspects of well planning for CO2 injection in quadrant 10. To find the best and cheapest solution, four relevant case studies that involve CO2 injection will be studied. By studying lessons learned, the goal is to identify the most effective and efficient technical solutions for design and drilling of the injection well. This analysis will contribute to the overall goal of the master thesis, which is to find the most cost-effective solution for CO2 injection in CCS projects.

The first case study is called; *Drilling and abandonment preparation of CO2 storage wells – Experience from the Ketzin pilot site.* The CO2 storage pilot site at Ketzin is located west of Berlin, Germany. The site has been developed since 2004 and features one combined injection/observation well and four monitoring wells. From 2008 to 2014, a total of 67 tons of CO2 were safely injected into the sandstone units of the Stuttgart Formation. This paper discusses well design and lessons learned in drilling engineering and operations. (Prevedel, et al., 2014)

The second case study is called; *CO2 well construction: Lessons learned from United States Department of Energy sponsored projects*. It examines multiple projects on CO2 injection and monitoring wells constructed as a part of the US Department of Energy's regional CCS partnership. This partnership includes three projects. The first project: *Establishing an Early Carbon Dioxide Storage Complex in Kemper County, Mississippi.* (ECO_2S). The second: *Illinois Basin-Decatur Project.* And the third: *Ohio River Valley CO_2 Storage Project/American Electric Power Product Validation Facility Project* also called the *Mountaineer Project.* The wells from the ECO_2S project were completed as monitoring wells. The wells from the other two projects were completed as injection wells. This study compared data from wells constructed with different materials and methods. Results showed microannuls, cement contamination and formation breakdown in portions of the wells. Wells constructed for CCS are required to meet the construction standards for class IV injection wells, which are higher than conventional oil and gas wells, to ensure long-term storage of CO2 with no migration outside the storage zone. Lessons learned from this study can be applied to future CCS projects and can help redefining the requirements for injection wells. (Duguid, 2018)

The last two case studies examine and explore different options of cement to use in CCS operations. Conventional Portland cement is very vulnerable and will be degraded by CO2. These case studies explore using Portland with additives and specially designed CO2 resistant non-Portland cement. The first of the two are called: *Co2 stability of Portland cement based well cementing systems for use of carbon capture & storage (CCS) wells.* This article is based on the testing of three different Portland cement-based systems with different additives tested against conventional API class G oil well cement. (Lesti, et al., 2013). The other case study is called: *Cement degradation in CO2 storage sites: a review on potential applications of nanomaterials.* This paper provides a review of different nanoparticles and evaluates their potential applications. (Tiong, et al., 2019)

3.6.1 Drilling down to the caprock

The drilling operation can be divided into two main sections, the section down to the cap rock and the section down to the reservoir. When drilling down to the cap rock, in general CCS wells are like that of an oil and gas well. Most CCS wells will likely be drilled into depleted oil and gas reservoirs, so intermediate casing will probably be required due to the pressure regime. (Ceyhan, et al., 2022). However, this is not the case with quadrant 10.

At one of the wells at Ketzin, counter-flush airlift drilling was employed for drilling the uppermost section. This technology assured excellent borehole stability but turned out to be very time consuming and clearly reduced drilling performance. The conclusion was that airlift drilling was not competitive with classic rotary drilling techniques. Other alternative and affordable new drilling and completion technologies were also explored at Ketzin, but they have not proven to be competitive in terms of efficiency and cost-effectiveness. In fact, some of these alternative methods have even had a negative impact on well constriction efficiency. This includes lost circulation additives, poly-crystalline diamond bits, swell packers and stage cementing tools. (Prevedel, et al., 2014)

Another experience from Ketzin was that a quick and continuous penetration of formations with known loss of circulation can only be safely done by continuous addition of plugging material to the drill mud, but at the expense of controlled steady mud loss to the formation. This method has the potential to achieve a higher than conventional speed in such formations but will also result in the highest total mud loss. Which will offset the drilling cost savings gained from drilling with a higher drilling speed. (Prevedel, et al., 2014) A possible solution

One of the wells, MPC 34-1#1, drilled as a part of the ECO_2S project experienced a loss of returns during cementing when entering the surface casing. The case study concludes that the hole likely bridged to the point that ECD was raised enough to fracture the formation, so the cement began entering the formation. As a result, the cement top was lower than required by class IV requirements. The case study suggests that the bridge most likely was created by debris carried out of a deeper than usual sump below the casing. A sump this deep would most likely not be sufficiently cleaned out by normal circulation. The lesson learned from this experience is that good hole cleaning practices are important for a good cement job. Setting the casing deeper would probably have resulted in better cleanout during circulation and then the cement might have reached the surface. (Duguid, 2018) Another reason might be that there were not done a full circulation, or that another circulation should have been done before circulation. But no information about this was given.

Caliper logs from another of the wells (MPC 10-4#1) from the same project indicated severe washouts and hole enlargement over a large portion of the open hole. The well experienced several washouts. This was detected during the cementing operation, when cement contaminated mud reached the surface. Even though pump rates were maximized inside the surface casing and the area below showed signs of mud contamination and a microannuls. It is important to pay close attention when drilling to ensure appropriate penetration rate and good hole cleaning without enlarging the hole. It is impossible to have good hole cleaning if the wellbore is highly washed out. (Duguid, 2018) This is important to avoid. If one well was drilled first and washouts were observed in the upper formation, a solution could be to use riserless drilling when drilling the top-hole section for the rest of the wells in the area.

3.6.2 Drilling into the reservoir

Lesson learned from Ketzin is that drilling into permeable formation appeared to lead to formation damage, which reduced the natural permeability of the formation by allowing mud solids to invade into the rock. The case study suggests that for future drilling, drilling the reservoir section with an underbalanced mud system should be considered. If underbalanced drilling is not feasible, at least underbalanced perforation of the reservoir should be considered. (Prevedel, et al., 2014)

Underbalanced drilling is used to minimize formation damage and increase well productivity. UBD has significant benefits when used in the last section of the well. The risk of lost circulation is minimal, and there is no need for disposal of hazardous drilling mud. The reduced pressure in the wellbore reduces the risk for differential sticking, as there is no buildup of mud cakes. However, UBD is expensive and cannot be applied to every well. The reduction of pressure could potentially lead to influx of formation fluid, that could lead to a blowout. Another concern with drilling with low BHP is borehole collapse, which is an increased risk in UBD. To maintain an underbalanced position can be challenging, and sudden pulses of overbalanced pressure could damage the well.

If UBD is not possible, drilling with water-based mud is an option to avoid contaminating the reservoir. Drill-in fluid is a specially designed fluid exclusively for drilling through the reservoir section and is typically water-based. In addition to water, the fluid may contain other components like clay minerals, polymers, weighting agent, and lubricant, among others. These are added to enhance the properties of the drill-in fluid and make it more optimal for the drilling operation. (Schlumberger, n.d.)

3.6.3 Slender well design

One of wells at Ketzin, Ktzi 203, was drilled using a slim-hole concept. (Prevedel, et al., 2014). This term describes a borehole and casing program, smaller than the standard size. This technique involves drilling the sections with reduced bit diameter compared to the other wells.

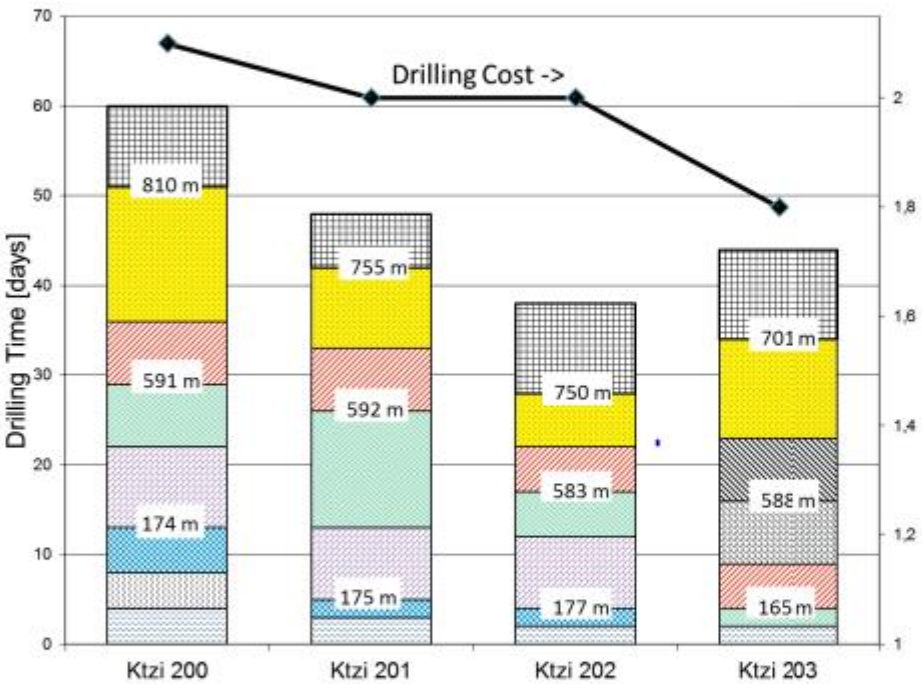

Figure 16: Drilling performance and drilling cost of same depth injection and monitoring wells at the Ketzin pilot project. (Prevedel, et al., 2014).

Slim hole reduced the cost, but it did not improve the drilling time or drilling performance in the Ketzin project. Smaller holes can increase the risk of technical failure in downhole tools and poor service from suppliers that are not familiar with slim-hole borehole conditions. Limited clearance between the casings can also restrict the installation of permanent monitoring equipment behind the casing. (Prevedel, et al., 2014)

Slim-hole casing program has a lot in common with something called slender well design. The objective of slender well design is to deliver the largest possible final casing/liner while reducing the size of the casings above, compared to a traditional well plan. This is done by choosing a smaller conductor to begin with and reducing the radial clearance between the casing sections. Slender well design can have a significant reduction on the drilling costs, this includes casing steel, drilling fluids and handling of cuttings. However, the largest cost is potentially related to the rig cost. Drilling a smaller hole makes it possible to use smaller drilling rigs than normally required. Slender well design makes I possible to us 3rd and 4th generation rigs, which has much cheaper day-rates compared to 5th and 6th generation rigs. (Hoff, 2012)

The one big issue when choosing slender well design is that the clearance between the casings is so small that there is no room to add another casing size in case the well experiences some trouble reaching target depth. In conventional drilling it is possible to set the casing earlier than target depth, and then continue drilling with the next casing size. This will not be possible in slender well design. Another issue to keep in mind is that slender well design is not possible everywhere. In formations that experience pressure anomalies, slender well design should not be utilized. Even when using MPD systems to assist the drilling operation.

3.6.4 Casing material

As mentioned in Figure 15, NORSOK requires that the well barriers can withstand exposure to the substances including CO2 without it affecting the integrity. The production casing is going to be surrounded by CO2 over many years, so the casing material needs to be resistant to wet CO2 corrosion. As mentioned in 3.3.2, a solution is to use CRAs. However, the problem is further exacerbated if the injection stream contains impurities. In some cases, 22Cr would be a better fit than 13Cr. But a higher grade could also lead to other issues. It is important to choose the appropriate grade of CRA for the well, for the safest and cheapest solution. (Ceyhan, et al., 2022)

One of the wells at the Illinois Basin Decatur Project, CCS#1, reported microannuls. Mild steel was used as casing material in the sections above the reservoir, while 13-chrome alloy was used as casing material in the reservoir. It was discussed whether this could be due to weak bonding between the cement and the casing. A possible explanation is that the bond may be weak due to the smoothness of the Cr13 casing. (Duguid, 2018) However, there were no reports of leakage in this well, indicating that Cr13 seemed to be a sufficient choice of casing material in this well.

At Ketzin one of the wells has a fiberglass reinforced compound casing material in the section below the caprock, in the reservoir, and steel casing above. Lessons learned conclude that combined steel/fiberglass casing string proved to be reliable, strong and with no restrictions to operational procedures. The non-conductive and non-corrosive fiberglass material is ideal for long-term storage. (Prevedel, et al., 2014)

3.6.5 Cementing

It is common in oil and gas drilling operations to rush the cement job to save costs. For CCS projects that is not possible, it is important to drill a hole that will facilitate CO2 storage. This requires a successful cement operation; as straight as possible and as close to gauge as possible, followed by a carefully planned completion operation. Minor changes in ROP or different pump pressure can unfavorably affect the borehole and the cement integrity of the well. (Duguid, 2018)

Cement results varied greatly between the wells in the projects of the US energy department. Integrity assessment showed that each well had integrity across the planned storage formation. However, the assessment also identified issues in each well that could affect its integrity. At each of the projects, conditions were identified that lead to micro-annuli. (Duguid, 2018)

The cement service provider for the ECO_2S project recommended a new system to use in CCS wells. This was tried in one of the wells (MPC 26-5#1). Lab testing was done prior to the cementing indicated that the system was very viscous and could be hard to mix. The system was altered and improved, so that the lab reported it adequate. During the accentual cementing the system was difficult to mix and pump rates had to be slowed down. This affected the mud removal, and sections of the well showed mud contamination in the cement sheet. The lesson learned from this experience was that lab testing is important, and results should be monitored closely to ensure that lab results also can be achieved in the field. (Duguid, 2018)

A well from the Illinois Basin Decatur Project (CCS#1) had what seemed an excellent cementing operation, but after cement evaluation logs were run months later, areas of micro-annuli were seen in the last section of the well. These micro-annuli posed no threat to well integrity, but an investigation was taken to understand what caused it. One observation was that the density of the cement going into the mixer was lower than the slurry inside the mixer. This suggests that during the mixing, hollow micro spheres were being damaged/crushed by the centrifugal pump. This would increase viscosity, which then would alter the mixing front between the lead and tail cement. This was also observed in the evaluation logs. This further confirms that differences in density and rheology between the field and in the lab can affect the quality of the cement operation, and results should be closely monitored. (Duguid, 2018)

Another theory for the micro-annuli in this well, is temperature increase due to the drilling mud. A KCI based polymer mud system was used in the well. Potassium-chloride mud has been successful in controlling troublesome shales in many wells around the world. However, due to the high shear applied to the KCI polymer mud to maintain fluid properties, the temperature at the bottom hole was elevated above the static temperature. Consequently, the formation was warmer when the cementing began, and after some time the formation cooled off. After cementing, a microannuls was detected on portions of the injection casing. It is important to consider how the drilling mud might affect other parameters in the well. Even though some micro-annuli were detected, it did not contribute to any loss of wellbore integrity. Injection pressure inside the casing was enough to close the micro-annulus. (Duguid, 2018)

Both one and two stage cementing were used in the projects of the US energy department. Most of the wells that utilized one stage cement reported excellent surface execution. Although some wells reported cement-related issues, it was concluded that other factors may have contributed to these problems. One of the wells (AEP-1) in the Mountaineer project was cemented in two stages. The first stage of cement on the injection casing was designed to run from TD to the stage collar at 5432 ft. The second stage was designed to run from the stage collar to the surface. (Duguid, 2018)

An external packer was inflated at the end of the first stage. Initially the operation seemed successful, with returns to surface. However, when logs were run later, they showed that the top of cement in the first stage was located at 7280 ft, not 5432 ft as planned. Not only did a section lack cement, but other parts also experienced poor quality of the cement. Poor quality cement was initially linked to unset cement, not enough time between installation of the cement and logging. In addition, an acid treatment was performed after cementing, before logging. The high pressure from this treatment could have created microannuls in the cement, but it does not explain the missing cement. The missing cement can be explained by gas intrusion. When the external packers were inflated, the hydrostatic pressure was reduced. This could have resulted in a gas influx right below the packers, which would have reduced the top of cement from 5432 ft to 7280 ft. (Duguid, 2018)

One or two stage cementing?
The reason for choosing a two-stage cement operation in this case study was not explicitly stated but is likely due to the well's depth. Other wells at a similar depth were cemented using one stage cementing. Such as well CCS#1 from the Illinois Basin Decatur Project at a depth of 7320 ft and wells from the ECO2S project, which were drilled and cemented at a depth between 5400-5700 ft. (Duguid, 2018).

Type of cement
Several different options for cement have been presented in the case studies, the different suggestions could be divided into two main solutions. Portland cement with different additives or highly engineered non-Portland CO2 resistant cement. First the cement used in the different projects sponsored by the United States Energy department will be discussed. All of the wells from the ECO_2S project utilized Portland cement with pozzolan additives either as lead or tail cement. Other types of cement that were used in these wells are NeoCEM and LiteCRETE. Well CCS#1 from the Illinois Basin Decatur Project was cemented with 1,100 sacks of lead cement, 65/35 cement-pozzolan and 950 sacks of CO2 resistant cement.

Well	MPC 26-5 #1	MPC 34-1 #1	MPC 10-4 #1
Surface Casing	12.25-in Open hole with 9-5/8-in 40lb/ft LTC J-55 set at 2489'. Cemented to surface	12.25-in Open hole with 9-5/8-in 40lb/ft LTC J-55 set at 2495'. Cemented to surface	13.5-in Open hole 10-3/4-in 45.5lb/ft BTC J-55 set at 2505'. Cemented to surface
Surface Cement	50 bbls 10.5 ppg Spacer	30 bbls 10.5 ppg Spacer	30 bbls 10.5 ppg Spacer
	Lead: 210 bbls 65/35 cmt-poz 6% gel 1.97 cu.ft/sk 12.4 ppg	Lead: 246 bbls 65/35 cmt-poz 6% gel 2.1 cu.ft/sk 12.0 ppg	Lead: 233 bbls 65/35 cmt-poz 6% gel 2.1 cu.ft/sk 12.0 ppg
	Tail Cement: 69 bbls Class A 1.18 cu ft/sk 15.6 ppg	Tail Cement: 59 bbls Class A 1.18 cu ft/sk 15.6 ppg	Tail: 65 bbls Class A 1.18 cu ft/sk 15.6 ppg
	Logging confirmed cement to surface	Logging confirmed cement to surface	Logging confirmed cement to surface
Long String Hole Size	8.5-in	8.5-in	9.875-in
Total Depth	5,877 ft	5,748 ft	5,440 ft
Mud Weight	9.4 ppg	9.4 ppg	9.1 ppg
BHST	135 °F	140 °F	128 °F
Long String Casing	5-1/2-in 17lb/ft Cr13-85 JFE-Bear 5865 ft -3,002 ft and 5-1/2-in 17lb/ft L-80 LTC 3,002 ft-surface	5-1/2-in17lb/ft Cr13-85 JFE Bear 5705 ft -2,846 ft and 5-1/2-in 17lb/ft L-80 LTC 2,846 ft-surface	7-in 29lb/ft Cr13-85 JFE Bear 5,440-2,792 ft and 7-in 26lb/ft N-80 LTC 2792 ft-surface
Centralization	Centralization: One centralizer every joint for first 66 joints (3,140ft), every other joint to 2,435ft and every third joint to surface	Centralizer every joint for first 68 joints (2,906ft), every other joint to 2287 ft and every third joint to surface	Centralizer every joint for first 65 jts (2,792ft), every other joint to 2,531ft and every third joint to surface
Primary Cement	well cemented to surface in one stage	well cemented to surface in one stage	well cemented to surface in one stage
	50 bbls 11.0 ppg spacer	50 bbls 10.5 ppg spacer	60 bbls 11.0 ppg spacer
	Lead: 65/35 cmt-poz 6% gel 1.92 cu ft/sk,12.7 ppg	Lead: 160 bbls 65/35 cmt-poz 6% gel 1.95 cu ft/sk 12.5 ppg	Lead: 327 bbls LiteCRETE lead at 11.5 ppg.
	Tail Cement: NeoCEM 1.13 cu ft/sk, 14.5 ppg	Tail Cement: 182 bbls 50/50 cmt-poz, 1.27 cu ft/sk, 14.5 ppg	Tail: 155 bbls 50/50 cmt-poz 1.27 cu ft/sk 14.5 ppg
	Displaced with 134 bbls fresh water	Displaced with 131 bbls fresh water.	Displaced with 202 bbls fresh water
	Note: Mixability problems with tail	Note: Lost returns after dropping the	Note: Full returns. 140 bbls mud-

Figure 17. Project ECO2S well construction details. (Duguid, 2018).

Based on the experience from CCS#1 another well from the same project, well VW#1, were cemented in a similar way. With 725 sacks 65/35 cement-pozzolan lead and 800 sacks of CO2 resistant cement. The last project of the three is the Mountaineer project. Well AEP-1 from this project was cemented with the following construction plan in Figure 18. (Duguid, 2018)

Tubular Name	Borehole Total Depth (ft)	Sacks of cement	Type of cement
30-in Conductor	42	--	Class A
26-in Conductor	102	250	Class A
20-in Shallow Surface	259	490	Class A
13-3/8-in Shallow Intermediate	1,818	940, 120	50/50 poz mix lead, Class A tail
9-5/8-in Intermediate	3,906	300	Class A
7-in Deep Intermediate	6,288	294, 120	65/35 poz mix lead, Class A tail
4-1/2-in Injection Casing	9,190 plugged to 8,552	360, 320	Stage 2: 65/35 poz mix lead with Class A tail Stage 1: C-poz. Stage collar at 5,432 ft.

Figure 18. Construction details from well AEP-1, from the Mountaineer project (Duguid, 2018)

The wells from ECO_2S project reported no leakage, suggesting an appropriate well design. However, these wells were completed as monitoring wells and would not have been exposed to the same type of loads as an injection well.

Both CCS#1 and AEP-1 performed as needed and kept the CO2 isolated in the storage formation. This is an interesting observation since the design of the two wells were different, suggesting different options could be suitable for the same well. In execution the injection string in the AEP-1 well was not even cemented from TD to surface. Which makes it in conflict with the regulations from 40 CFR § 146.68 – Injection well construction requirements, Figure 10. AEP-1 were also cemented with Class A cement. None of the other case studies have presented Class A cement as a viable solution. However, it was not discussed in the report whether the type of cement in this well could have affected the problems experienced. (Duguid, 2018)

The case study on *CO2 stability on Portland cement based well cementing systems for use on CCS wells*, presents crackling as a result from expansion during CaCO3 crystallization as one of the most critical phenomena in CCS wells. Cracks can provide pathway for further migration of CO2. The same study confirms that any Portland cement system, even with additives, inevitably will be subject to carbonation. However, this study also argues that with cement from TD to surface the time it will take to migrate will be so long that it will be acceptable. Worst case in this study observed a migration of 60 cm/year. (Lesti, et al., 2013).

The same study also presents a problem that has repeated itself in other studies as well. Microchanneling due to poor hole cleaning, before cementing. The example that this study provides is incomplete removal of mud filter cake before cementing. After the cement is in place the mud cake could dehydrate and shrink. This can create microchannels behind the cement, which would provide pathways for CO2 to migrate. Since several cases presented poor hole cleaning as an issue, it could be useful to consider adding one or more rounds of circulation before cementing, to improve the hole cleaning.

Other cement options this case study presents are slag cement (CEM III) blended with reactive filler. This solution obtained the best result from the tests. The study also suggests that chemical admixtures such as latex polymers or cellulose ethers did not provide sufficient solutions, and therefore are not recommended. The tests also showed that conventional API class oil well cement demonstrated a low rate of carbonation, but significant amount of cracking. (Lesti, et al., 2013).

The last paper; *Cement degradation in CO2 storage sites: a review on potential applications of nanomaterials*, concluded that nanoparticles showed promising results when added to the cement. However, it appears that the combination of two or more nanoparticles can lead to agglomeration and create unfavorable changes in the cement properties. Nanosilica was deemed one of the best nanoparticles, due to its lower cost and pozzolanic activity. Nanoclay is also cheap but does not possess the same go pozzolanic activity. Nanoalumina has better performance than Nanosilica, but is less used due to higher costs. Nanotitanium does not have any pozzolanic activities but has photocatalytic properties that could potentially help decrease migration of CO2. However, nanotitanium might not be suitable in CCS injection wells due to its instability in high-pressure and high-temperature environments. (Tiong, et al., 2019)

Many different options for cementing have been mentioned above. Please note that the presented test results from both; *Cement degradation in CO2 storage sites* and *CO2 stability on Portland cement based well cementing systems for use on CCS wells,* are solely based on laboratory tests and not on actual well data. It is crucial to consider this distinction when evaluating the findings in the two case studies. As a result, it would be inappropriate to recommend their usage based solely on these laboratory results. Nonetheless, the reports highlight their promising results that warrant further investigation and exploration to better understand their potential application.

The results from both, *Experience from the Ketzin pilot site,* and *Lessons learned from United States Department of Energy sponsored projects*, are based on actual well data. While it is true that both AEP-1 and CCS#1 from the US experienced defects, the two wells successfully kept the stored CO2 in the isolated formation. The fact that AEP-1 can be described as a success, whilst not meeting the requirements for IV wells from the CFR, raises the question of whether the current requirements might be too strict. NORSOK do not present the same requirements.

4 Analysis and planning of CO_2 Injection Well in the North Sea: A Comparative Study of Technical and Economic Solutions

4.1 Analysis of quadrant 10 in the North Sea

The Norwegian Ministry of Petroleum and Energy announced in March an offer for two new exploration permits related to CO_2 storage on the Norwegian Continental Shelf in the North Sea. One of these areas is quadrant 10, located southwest of Stavanger and northeast of the UK continental shelf. The exploration permit gives companies the opportunity to explore potential CO_2 storage areas and identify geological structures suitable for CO_2 storage. Quadrant 10 has previously been explored for oil and gas, but the permit will now include an assessment of the potential for CO_2 storage in the area. (Olje- og energidepartementet, 2023)

In this chapter, we will analyze Block 10 in the North Sea as a potential area for CCS projects, with the goal of identifying the most cost-effective solution for drilling CO_2 injection wells in this area. A brief overview of the geological characteristics of the block will be provided, including results of previous explorations in the area, as well as key assumptions and parameters.

4.1.1 Geological charactersization of quadrant 10

As mentioned earlier quadrant 10 is located southwest of Stavanger and northeast of the UK continental shelf and is a part of what is called the Norwegian-Danish Basin. The four exploration wells are 10/4-1, 10/5-1, 10/7-1 and 10/8-1. (Norwegian Petroleum Directorate, n.d.)

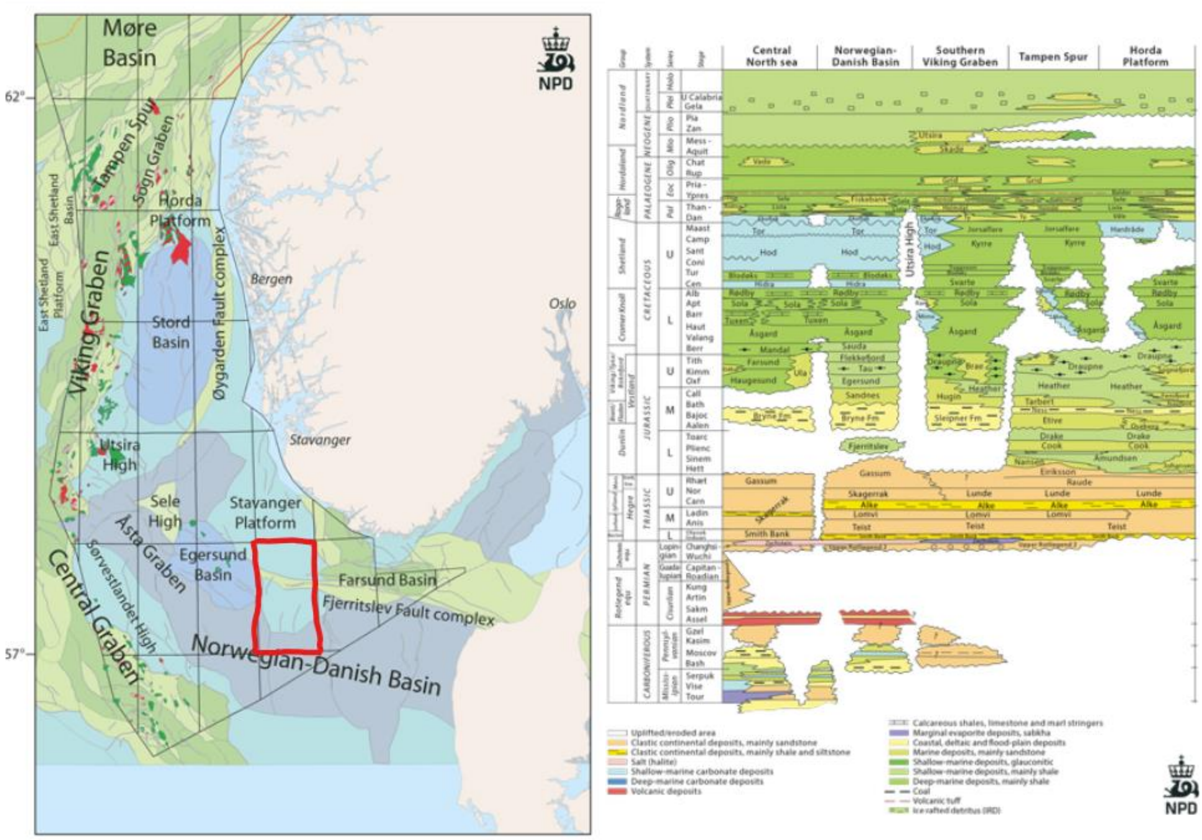

Figure 19. Red square marks quadrant 10 in the North Sea. (Norwegian Petroleum Directorate, n.d.)

The North Sea's basic structural framework is a result of rifting during the Upper Jurassic and Lower Cretaceous periods, with some influence from older structural elements. During the Carboniferous- Permian era, there was a significant rift with volcanism, and reddish eolian and fluvial sandstones, Rotligendes, were deposited. Two basins were created, and thick evaporate sequences, Zechstein, were deposited. With enough overlying sediments, buoyancy forces caused the salt to move upwards, generating closed structures like hydrocarbon traps in the southern parts of the North Sea. In addition to the Carboniferous-Permian era, the Jurassic period also played a significant role in shaping the geological characteristics of the North Sea. During this time, large sandstone sediments were deposited, such as The Bryne and Sandnes formations, which are potential storage formations in quadrant 10. (Norwegian Petroleum Directorate, n.d.)

According to the NPD, the Sandnes formation is a well sorted and widely distributed sand, above the thicker silt and sandstones of the Bryne formation. The vertical permeability of the Bryne formation is lowered by the coaly layers developed in the formation. The connectivity in the Bryne formation is hindered by the typical development of isolated channels of the delta plain. The two formations are typically thin on the crest of salt structures, from Zechstein, and thicken in the basins. There is a limited amount of well data for constructing detailed maps of the formation. The aquifer is considered well suited for CO2 storage due to well-developed reservoir rock. In the lower cretaceous period, shale formations such as the Boknfjord formation were deposited. The Boknfjord formation could potentially serve as a cap rock of the Bryne and Sandnes formation.

720	LISTA FM
781	SHETLAND GP
1022	CROMER KNOLL GP
1298	BOKNFJORD GP
1298	FLEKKEFJORD FM
1386	SAUDA FM
1486	TAU FM
1539	VESTLAND GP
1539	SANDNES FM
1632	BRYNE FM
1836	ZECHSTEIN GP

Figure 20. List over the formations hit in well 10/7-1. Showing the Boknfjord formation above the Bryne and Sandnes formation. (Norwegian Petroleum Directorate, 2005)

The wells in quadrant 10
The picture below illustrates how the wells are positioned in relation to each other.

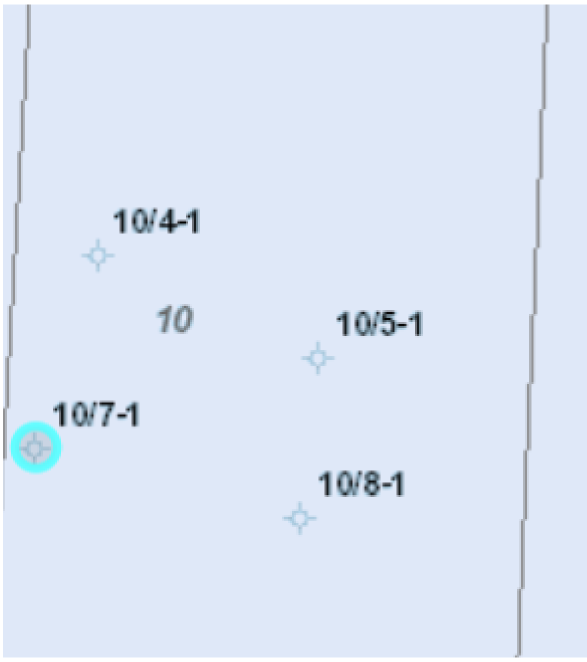

Figure 21. Picture of how the wells placed in quadrant 10. (Norwegian Petroleum Directorate, 2005)

10/4-1

(2015) was drilled with the primary objective to evaluate the presence of hydrocarbons in the Bryne and Sandnes formations. The secondary target was to reach the limestones in the Zechstein Group. (Norwegian Petroleum Directorate, 2017)

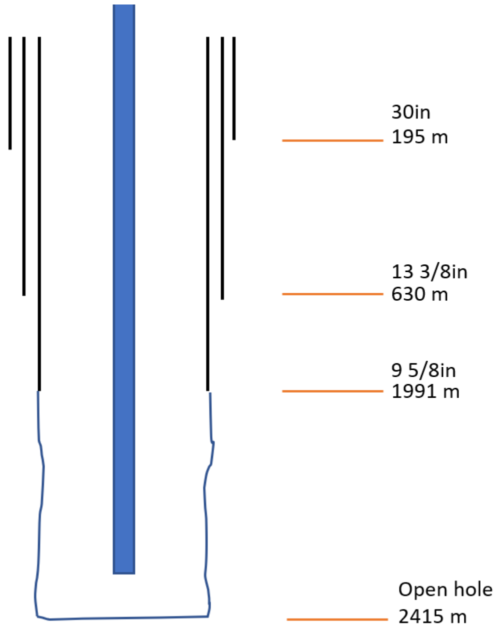

Figure 22. Illustration of well 10/4-1

10/5-1

(1976) was designed with the objective to test a tilted fault block. Primary objective was Rotligendes sands. The secondary objective was to hit the Bryne and Sandnes formation. (Norwegian Petroleum Directorate, 2005)

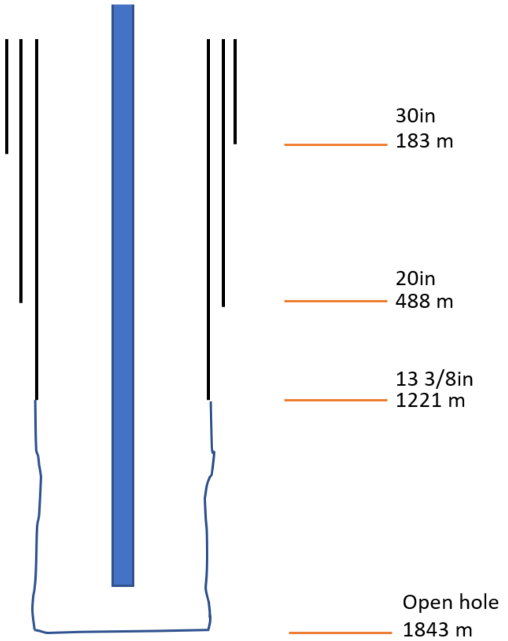

Figure 23. Illustration of well 10/5-1

10/7-1

(1992) was drilled with the objective to test an anticline over a salt wall, the Bryne formation was the target. (Norwegian Petroleum Directorate, 2005)

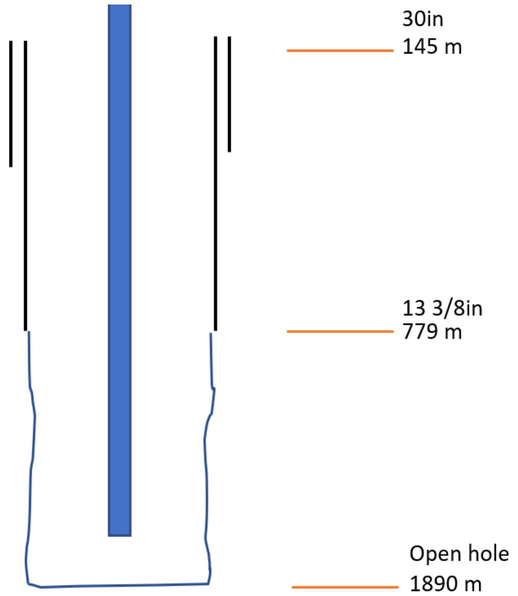

Figure 24. Illustration of well 10/7-1

10/8-1

(1970) was drilled on a salt induced anticlinal structure related to a salt pillow. The well's objective was to test the hydrocarbon potential of the Bryne and Sandnes formation. (Norwegian Petroleum Directorate, 2005)Nederst I skjemaet

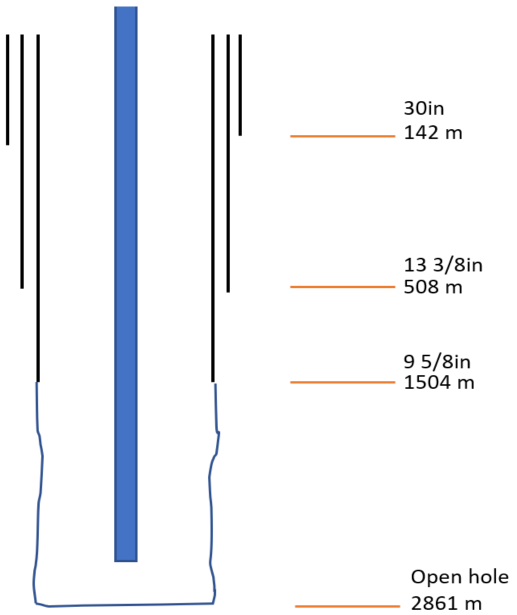

Figure 25. Illustration of well 10/8-1

4.1.2 Results from the exploration wells

10/4-1

Boknfjord formation were hit at 1842m. The well hit top Sandnes formation at 2274 m. Average porosity of the formation is 21,5% with a gross thickness of 21 m. Top Bryne formation were located at 2311 m. Average porosity is 17,4% with a gross thickness of 53 m. Water saturation is 100% in both reservoirs. The limestone reservoir from the Zechstein Group was not found, but the Zechstein GP was located at 2364 m. (Norwegian Petroleum Directorate, 2017)

10/5-1

Boknfjord was located at 1275 m. Sandnes formation was located at 1472 m, with a gross thickness of 18m. Top Bryne was located in 1490, with a gross thickness of 34 m. Bryne and Sandnes formations were found to be water wet. Shale and siltstone separate the two formations from each other. Rotligendes sandstones were not present in the well. The top of Zechstein was reached at 1597 m. A rough estimate of the porosity using the bulk density log gives an average porosity of 10% in the Bryne and Sandnes formation. (Norwegian Petroleum Directorate, 2005).

Calculations were done using this formula:

$$\varphi = \frac{\rho_{matrix} - \rho_{fluid}}{\rho_{matrix} - \rho_{bulk}}$$

Assumed values for matrix = 2,5, fluid = 1 and bulk = 2,35 (from density log).

Geochemical analysis found total organic carbon (TOC) to be moderate to high. (1-5%), in the formations above the Bryne and Sandnes formation and possibly some in the underlying formations. The TOC in the underlying formations could be caved Bryne and Sandnes formation. Rock-Eval pyrolysis indicates the kerogen is most likely gas prone. The well was deemed immature. Minor amounts of migrant hydrocarbons were detected above the Bryne and Sandnes formation by geochemical analysis. Neutron-Density log also indicates hydrocarbons in the top of the Sandnes formation. As well as in the bottom of the well, below the Zechstein GP. (Norwegian Petroleum Directorate, 2005)

10/7-1

The top of Boknfjord formation was reached at 1298 m, and the top Sandnes formation at 1539. Gross thickness of Sandnes formation is 93,5 m with an average porosity of 19,14%. The top of Bryne was located at 1634 m. The Bryne formation is divided into two distinct sections, upper Bryne with gross thickness of 113 m and lower Bryne with gross thickness 91 m. Average porosity of upper Bryne is 16,8 % and lower Bryne is 11,76%. Data indicates the Bryne and Sandnes formation is water bearing. Zechstein was reached in 1846 m. (Norwegian Petroleum Directorate, 2005)

Geochemical analysis shows TOC of 1 – 3,19% and hydrogen index (HI) of 79 to 224 mg HC/g TOC above the Bryne and Sandnes formation. Analysis of the coal in the Bryne and Sandnes formation shows TOC of 1,64-6,14% and HI of 118 to 223. Indicating hydrocarbons in the Bryne and Sandnes formations and the formation above, however, the well was found immature for oil and gas production. (Norwegian Petroleum Directorate, 2005)

10/8-1

Top Boknfjord was reached at 1367 m. Bryne and Sandnes formation was not located in this well. Zechstein GP were hit at 2825 m. Geochemical analysis show TOC of 0,1-1,5%

with the highest values in the formations below the Boknfjord formation. The well was found to be water wet. (Norwegian Petroleum Directorate, 2005)

4.1.3 Analyzis of the area

Formations that will be used for storing CO2 must meet certain criteria to ensure that the process is safe and effective. The ideal formation for CO2 storage should have high porosity and high permeability, be located at a sufficient depth to ensure that CO2 remains in supercritical state and be overlain by impermeable cap rock to prevent the CO2 from leaking.

There are two formations, that are possibly located in quadrant 10 that could be suitable for CO2 storage. The Rotligendes sandstones and the Bryne and Sandnes formation.

The Rotligendes sediments were deposited in Perm, in a warm and sandy climate that can resemble today's Sahara. The sand dunes deposited then have been turned into sandstones with good reservoir qualities. Later in Perm, seawater from the North started filling this desert area and large amounts of salt were deposited. Salt layers have low permeability and often thick, making them a good cap rock. These salt layers are often found in the Zechstein GP. (Glennie, 1983)

The Bryne and Sandnes formations were deposited much later, in the early Jurassic period. The Bryne formation is the oldest of the two and is found under the Sandnes formation. During the early Jurassic periods, the North Sea environment was characterized by fluctuating sea level. The coastline would have been shifting a lot. Rivers and streams flowing into the sea would have deposited sediments in deltaic and fluvial environments near the coastline. This is where the sediments from the Bryne formations come from. With the sea rising above these sediments, new sediments would be deposited above. These sediments would make up the Sandnes formation. The disposal environment is different for the Bryne formation and the Sandnes formation. Both formations are interbedded with silt and shales, and both have good reservoir qualities. As the sea continued to rise, sediments were deposited in deep marine and low energy environment. These sediments consist mostly of shales and silts and make up what is known as the Boknfjord formation. Which has great qualities for a cap rock.

The only well that drilled through the Zechstein with the possibility to reach the Rotligendes sandstones is well 10/5-1. However, Rotligendes sandstones were not present in the well. Based on available data from the exploration wells, Rotligendes sandstones may not be a viable option for storing CO2 in quadrant 10.

In all the wells, except 10/8-1, the Bryne and Sandnes formation is present at varying depths and thickness, suggesting faults. Well, 10/7-1 confirms a faulted anticlinal over a salt wall.

It is important to consider if the formation is deep enough to store the CO2 in a supercritical state. The Boknfjord formation is at its shallowest in well 10/5-1 and 10/7-1. The formation is at 1275 m in well 10/5-1 and at 1298 m in well 10/7-1. Based on this data, an assumption is made that the Boknfjord formation is 1275 m deep at its shallowest.

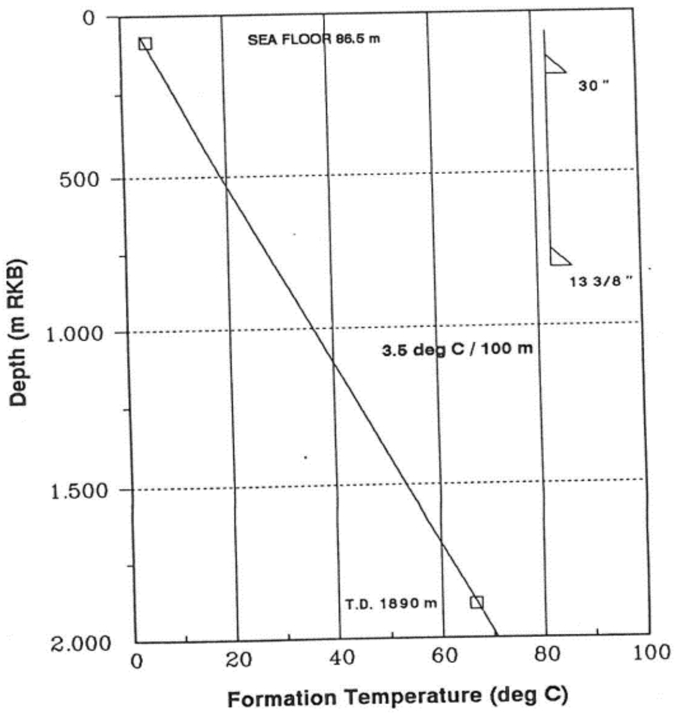

Figure 26. Geothermal gradient from well 10/7-1. The formation temperature is around 47 deg C at 1275 m. (Norwegian Petroleum Directorate, 2005)

The phase diagram for CO2 in

Figure 7, shows that the pressure in the storage formation needs to be above 73 atm and the temperature needs to be above 31,1 deg C to keep the CO2 in a supercritical state. Figure 26 show that the temperature of the formation at 1275 m deep is around 47 deg C. The pressure is calculated using this formula:

$$P = \rho * g * h$$

Assumed values for g = 9,81kgm/s^2, h = 1275 m and ρ = 650 kg/m^3.

Figure 8 (IEA, 2008). Using these values calculated pressure for CO2 at 1275 m deep is 81,21 atm. So, with pressure at 81,21 atm and temperature at 47 deg C, the stored CO2 is going to be a supercritical fluid when injected at 1275m deep.

After analyzing the available data, it can be concluded that the Sandnes and Bryne formation are good potential options for storing CO2 in quadrant 10. This can be confirmed by NPD.

> *"The aquifer is considered quite well suited for CO_2 storage due to the well-developed reservoir rocks. The aquifer is capped by the generally thick and robust mud- and clay-stones of the Boknfjord Formation."*

(Norwegian Petroleum Directorate, n.d.)

4.2 Technical analysis and well planning

When planning CCS injection wells, the best way to start is to choose the completion size for the desired CO2 injection rate. For this analysis, the desired size of the production casing is 7”.

Based on the available information, there is no higher-than-normal safety risk in quadrant 10 when drilling the upper section. Therefore, the focus should be on saving money rather than investing in unnecessary extra safety measures. While it is still important to consider safety and pressure regimes when drilling, it is reassuring that no gas has been observed above the caprock in any of the exploration wells. It is reasonable to conclude that drilling the upper section in quadrant 10 should be possible to do in a relatively safe and cost-effective manner.

Slender wells have been proposed as a cost saving solution earlier in the thesis, if it is possible to drill slender wells in the proposed area. No drilling issues that could indicate pressure anomalies or difficult pressure regimes were reported in any of the exploration wells. Assuming the area is appropriate for slender wells, a comparison has been made based on the design of the exploration well 10/5-1.

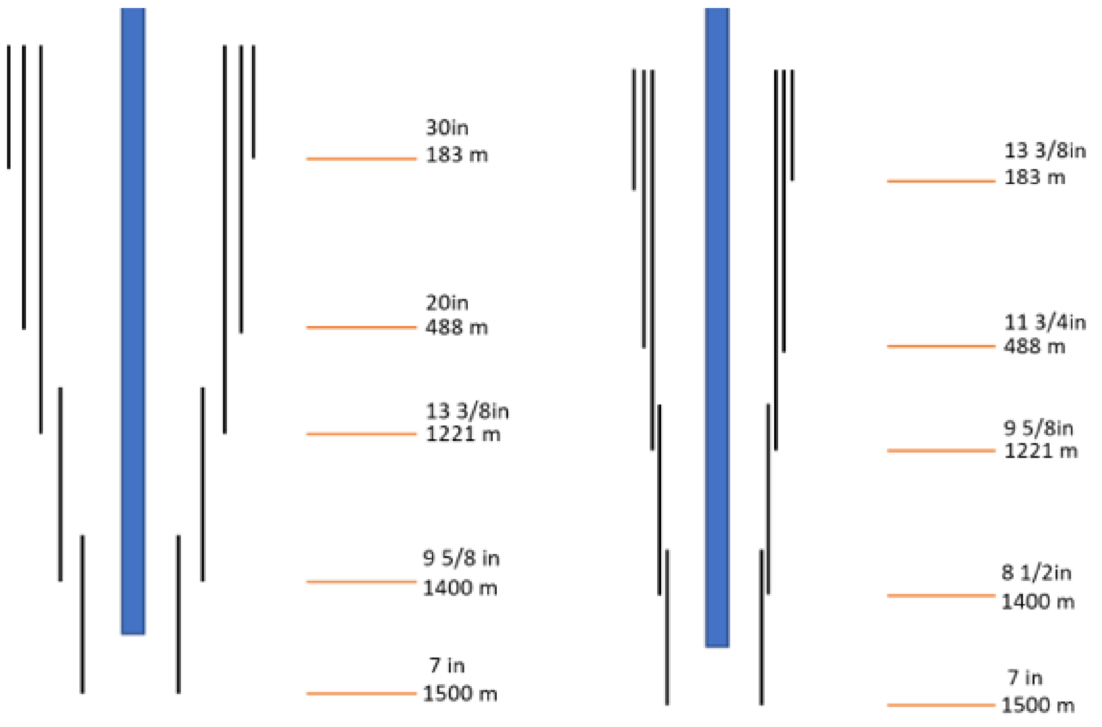

Figure 27. Illustration of Conventional well plan and Slender well plan for the same well.

The well 10/5-1 experienced washout when installing the conductor. The guide base sank 26 feet below the mud line and the 30” casing could not be stabbed through the guide base. The rig was moved 38 m and the well was drilled again. This could indicate a weak formation in the area, especially around well 10/5-1. A suggestion to this problem is to use RMR for the top-hole section.

If a slender well design is to be used, CML should be considered in a combination to that. Well 10/5-1 was drilled with 13 3/8” intermediate casing down to 1221 m and open hole down to 1843 m. The design above was only a design made to compare how injection wells could differ from each order. It is possible, by using CML that one could even enter the well with 8 ½" casing. This would mean an increase in cross section area with 47%. This could potentially increase the injection rate substantially.

Underbalanced drilling is the most expensive technique for drilling, but the high price is normally worth it by preserving the condition of the reservoir. Since there were very small traces of carbon material below the caprock, underbalanced drilling might be a viable choice in quadrant 10. But looking at a cost perspective, CML is a solution that might even be more suitable. CMLs ability to continuous pressure control and precise management of the pressure profile could also help minizine the formation damage, by drilling with the pressure just above underbalanced.

The caprocks deepest depth in quadrant 10 is 1842 m, which is about 6040 ft. Successful one stage cementing has been achieved at even greater depths. This indicates that one stage cementing is possible when completing the wells in quadrant 10. A problem here could be that the hydrostatic pressure from the cement could damage the lowest part of the reservoir and also create potential cracks. A CML system could help minimize the risk for this. The system can compensate for the hydrostatic pressure generated by the high cement layer which could make it possible to use one stage cementing in even deeper wells. By installing a CML system and using it in the drilling operation, it would be easy to transfer the same system into the cementing operation as well.

The report from the exploration wells does mention that logs indicated gas below the caprock. The main gases were C1, C2, C3, iC4 and nC4. In addition, hydrogen was reported in well 10/7-1. Appropriate gas blockers need to be chosen.

Many options for cement type have been proposed earlier in this thesis. As mentioned above, according to the case study on *CO2 stability on Portland cement based well cementing systems for use on CCS wells*, it was found that any Portland cement system, even with additives, inevitably will be subject to carbonation. The same study reported a worst-case migration of 60 cm/year. The storage formation in quadrant 10 is located at the shallowest depth in well 10/5-1. Here, the top of Sandnes was at 1472m. If would take the CO2 roughly 2400 years to reach the surface with that migration pace. Which arguably seems to be a reasonable safety margin.

Two of the case studies above have actual well data confirming successful cementing operations with Portland cement with pozzolan additives. No data related to cost and cement additives have been presented in this thesis. This is an area for future research. Pozzolan additives are only necessary in sections that can be exposed to CO2 corrosion. So, from a cost perspective it is only necessary to use pozzolan additives in the section below the caprock. Conventional Portland cement could be used when cementing the sections above.

4.3 Economic analysis and evaluation of different solutions

In this section, an evaluation of the different proposed solutions will be conducted from the perspective of cost savings. It is important to acknowledge that, to simplify the calculations, certain factors have been neglected or assumed. This economic analysis provides an illustrative demonstration of the potential cost savings associated with each solution.

Utilizing slender well drilling would potentially reduce the cost of the casing by almost 50 %. These calculations were based on the price per kilo for steel and volume of the casing. The price for steel was 951 $/ton, this number was gathered (21.05.23). (Anon., 2023). Values for ID, OD and weight are gathered from (Drilling Manual, n.d.) & (Octal Steel, n.d.)

Conventional Well						Total Weight				
OD [in]	ID[in]	length[m]	length[ft]	Weight[lb/ft]	Weight	lb	kg	ton	HRC Steel (19/05/23) [USD/T]	Price
30	28,5	183	600,24	234,3	140636,2					
20	19	305	1000,4	106,5	106542,6					
13,375	12,347	733	2404,24	72	173105,3					
9,625	9,001	179	587,12	32,3	18963,98					
7	6,538	100	328	17	5576	444824	201950	202	951	$ 192 054,58
Slender Well						Total Weight				
OD [in]	ID[in]	length[m]	length[ft]	Weight[lb/ft]	Weight	lb	kg	ton	HRC Steel (19/05/23) [USD/T]	Price
13,375	12,347	183	600,24	72	43217,28					
11,75	10,586	305	1000,4	71	71028,4					
9,625	9,001	733	2404,24	32,3	77656,95					
8,5	8,097	179	587,12	24	14090,88					
7	6,538	100	328	17	5576	211570	96053	96	951	$ 91 345,98

Figure 28. Economic comparison of price of steel between conventional well and slender well.

With a smaller well, the amount of cuttings that will have to be transported out of the mud and the amount of drilling mud that is required will also be reduced. Calculations showed that by using slender the amount of cuttings could potentially be reduced by 70 % and amount of mud with 65%. Calculations for this are found in Figure 29.

Based on the observed savings in volume of cuttings, mud and casing, it is logical to assume that there would be a decrease in the amount of cement needed. Consequently, this reduction in cement quantity is expected to lower the overall cost of the cement operation.

Conventional Well			
Volume cuttings			
Open Hole [in]	Length [m]	Volume[m3]	
36	183	120,175	
26	305	104,473	
17,5	733	113,746	
12,25	179	13,611	TOT VOL [m3]:
8,75	100	3,879	356
Slender Well			
Volume cuttings			
Open Hole [in]	Length [m]	Volume[m3]	
17,5	183	28,398	
12,25	305	23,192	
10,625	733	41,929	
8,75	179	6,944	TOT VOL [m3]:
7,875	100	3,142	104

Conventional Well			
Volume mud			
ID [in]	Length [m]	Volume[m3]	
28,5	183	75,31788643	
19	305	55,79102699	
12,347	733	56,62186703	
9,001	179	7,348384442	TOT VOL [m3]:
6,538	100	2,165943617	197
Slender Well			
Volume mud			
ID [in]	Length [m]	Volume[m3]	
12,347	183	14,13615507	
10,586	305	17,31892507	
9,001	733	30,09142903	
8,097	179	5,946461674	TOT VOL [m3]:
6,538	100	2,165943617	70

Figure 29. Economic comparison of price of cement and mud between conventional well and slender well.

Drilling slender wells offer substantial cost advantages due to the reduced volume of mud, cement and casing needed. These savings are further amplified by the potential for lower day rates. Utilizing smaller rigs with reduced day rates becomes possible when drilling slender wells. Additionally, the shorter drilling time associated with slender wells contributes to added cost savings. With the increasing interest in CCS operations and the aging of current rigs, there is a possibility of constructing new rigs, specifically tailored for slender wells. Building smaller rigs could potentially be more cost-effective since smaller components can be used. Furthermore, a smaller rig requires fewer personnel, resulting in added savings.

S&P global publishes current and historical day rates for four different rig categories. The numbers are based on an average of the high and low for each month. Percentage of contracted rigs out of the total competitive fleet supply is also presented as use percentage. The data is updated around the 15th of every month. The four rig categories are Worldwide deepwater drillships, Worldwide deepwater semisubmersible drilling units, Southeast Asia large jackup drilling rigs and Middle East large jackup drilling rigs.

Sorted by size and day-rate prices from largest to smallest, and most expensive to cheapest:

- Worldwide deepwater drillships
- Worldwide deepwater semisubmersible drilling units
- Middle East large jackup drilling rigs
- Southeast Asia large jackup drilling rigs

There are several other factors that can influence the price and suitability of a drilling rig for a particular project. While the cost of a rig is an important consideration, other factors like availability and logistics should not be overlooked. The cheapest rig may not always be readily available or conveniently located for a given project. In such cases, the need for extensive transportation and associated costs can make choosing the cheaper rig less cost-effective overall. Therefore, it is crucial to thoroughly investigate these factors to make an informed decision about rig selection. However, for the sake of the calculations these factors will not be considered.

It is worth noting that jackup rigs are typically best suited for drilling in shallow waters, generally up to depths of around 100 meters. Since the water depth at 10/5-1 is 98 meters, all the mentioned rigs can potentially be a viable option for this field.

In the figure below, day rates for the different rigs are presented.

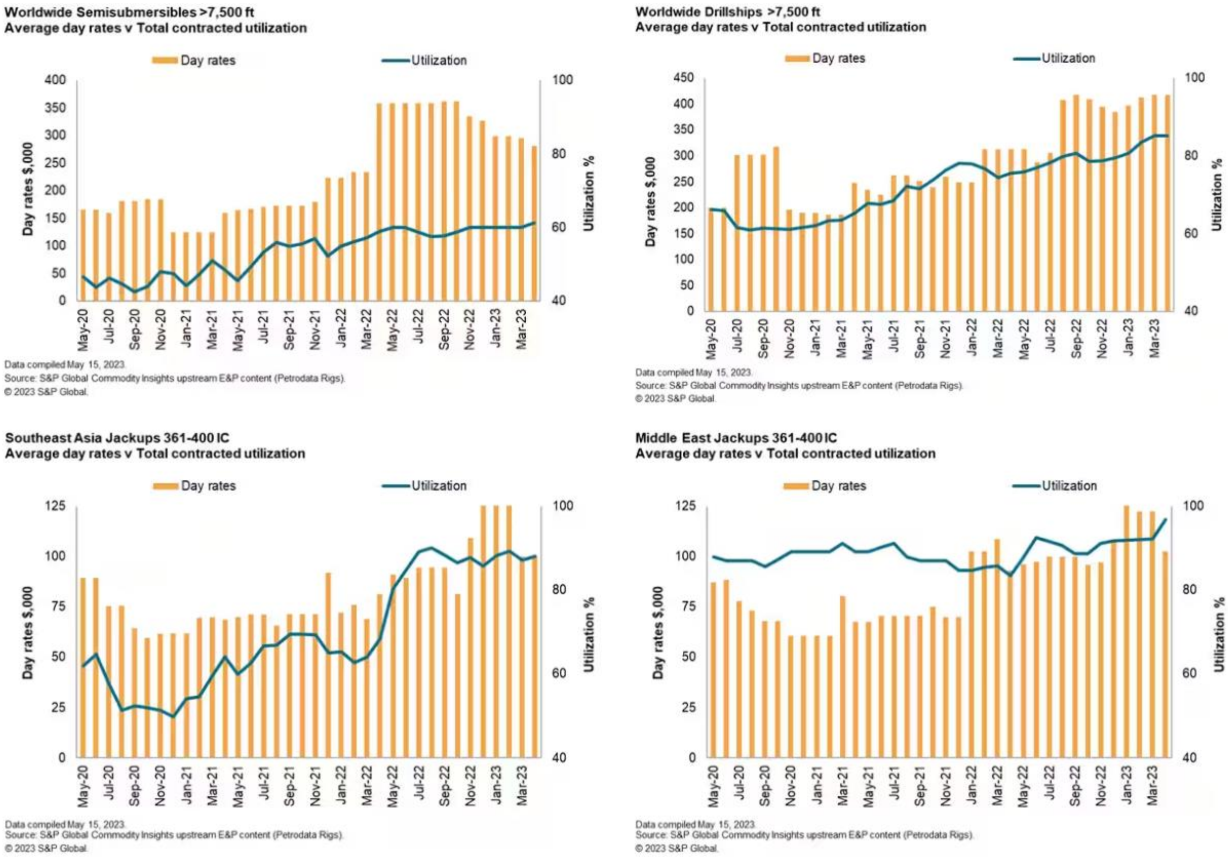

Figure 30. Offshore rig day rate trends, numbers from May 2023. (S&P Global Commodity Insight , 2023)

For the calculations, a specific number of days for the drilling operation was assumed. The operation was assumed to take 45 days in total. Then, based on the day rates from S&P Global, a rough estimate of savings was made. The mentioned scenario resulted in a maximum savings of 13,500,000 dollars only by being able to use the smaller rigs.

Type of rig	Day rate	Utilisation	Assumed	Cost
	$,000	%	nr. of days	$,000
Deepwater drillships	400	85	45	18000
Deepwater semisubmersible drilling units	275	60	45	12375
Middle east large jack up	100	85	45	4500
Southeast Asia large jackup	100	95	45	4500

Potential saving using the smaller rigs vs the larger	Savings
	$,000
Deepwater drillships vs jackup	**13500**
Deepwater semisubmersible drilling units vs jackup	***7875***

Figure 31. Day-rate calculations. Data collected from (S&P Global Commodity Insight , 2023)

One important aspect to consider is the potential weather-related delays that can affect the drilling operation. Specifically, it is crucial to assess whether smaller rigs will experience a higher number of wait on weather days and if this number will be significant enough to offset the initial cost reduction associated with choosing a smaller rig. While it is reasonable to anticipate that smaller rigs may encounter more weather-related delays, it is necessary to investigate if these delays would surpass the savings achieved through smaller rigs. The economic viability of opting smaller rigs depends on striking a balance between initial cost advantages and potential costs.

Is there another choice other than underbalanced drilling when drilling into the reservoir, could CML be an option? In case what would savings be here?

Based on information given by my supervisor I have assumed that a CML operation will cost around 150-200 000 NOK/ day. An article from the Science Direct called *Potential implementation of underbalanced drilling technique in Egyptian oil fields,* give some numbers on drilling costs for conventional wells vs underbalanced wells per day. These numbers have been used to calculate a rough estimate of what seems a logical price/day for underbalanced drilling. This came to be around 750 000 NOK. This number was bound by dividing the average clean cost for underbalanced 8-1/2" on days. (The current exchange rate is 11NOK per USD). (Fattah, et al., 2011). 10 days were assumed for drilling into the reservoir.

Drilling technique	Cost / day	days	Price	Savings
	NOK		NOK	
Underbalanced drilling	750 000	10	7500000	
CML	200 000	10	2000000	73 %

Figure 32. Cost/Day CML vs UBD. Data collected from (Fattah, et al., 2011)

By using CML instead of UBD when drilling into the reservoir, the operation can potentially reduce the clean cost for the last section with up to 73%. This corresponds to 5,5 million NOK. Which is about $500 000.

5 Conclusion and further work

5.1 Conclution

- The amount of CO_2 in the atmosphere is rapidly rising and is already greater than it ever has been over the last 3.6 million years. The world cannot continue in the direction we have been moving in for the past 60 years. The CO2 level in the atmosphere has to be reduced. Carbon capture and storage will not solve climate crisis on its own but, it has the potential to help reduce the amount of CO_2 in the atmosphere, be a bridging technology during the transition from today's energy mix and hopefully stop the relentless progression towards irreversible climate change.

- Currently, the cost of CCS worldwide is estimated to be around 600 USD per ton of CO2 stored. Given the global annual carbon emissions amount to approximately 431 million tons. The cost to sequesters all the carbon emitted annually is today about 28,8 billion per year. This number has to be reduced to be able to afford to utilize CCS in such a large scale that it will make an impact. This can be achieved by reducing the costs in smaller areas, which will accumulate to significant savings when added together.

- Co2 needs to be stored in supercritical phase. Depth and temperature of the storage formation will affect the phase of the co2. Changing the characteristics of the co2 to increase the storing efficiency. In some cases, it may be beneficial to enhance the solubility of the CO2 in water by adding surfactants. These can help increase the amount of CO2 that can be dissolved in the water and can improve the overall efficiency of the storage process. However, the use of surfactants can also have potential environmental and economic impacts that need to be carefully considered. Increasing the acidity in water can also increase the solubility of CO2. However, if the acidity is too high, it can lead to corrosion and other issues.

- CCS wells and conventional oil and gas wells have a lot of similarities, but their main difference lays in their purpose. Injection wells for CCS are designed specifically to inject CO2 into geological formations for long-term storage, while oil and gas wells are designed to extract hydrocarbons for commercial use.

- The pressure in a CCS injection well will be at the lowest at the start of injection, and increase until reaching the pressure limit of the cap rock. While conventional oil and gas well will experience the highest pressure at the beginning. Because the injection well will experience increase in pressure over time, is it important to be extra considerate of possible fractures in the caprock.

- The injection fluid's temperature can cause thermal changes in the reservoir. This can lead to cooling of the reservoir which could lead to fracking at lower pressure than normal.

- When considering well design in CCS injection wells, is it common to design from bottom to top. By beginning with completion size is it possible to make sure the last section of the well is large enough to reach desired injection rate.

- CCS injection wells needs to be designed for CO2 exposure. The material of the casing needs to be resistant towards CO2 corrosion. On solution is to use corrosion resistant alloys. In conventional oil and gas wells, working stress design is commonly used for design checks. These values are compared to the API performance properties and the yield strength to check the design. A minimum design factor will decide if the design is sufficient. However, in CCS injection wells, material selection is going to be the deciding factor. Beyond about 17cr, CRA tubulars are anisotropic. It is important to consider that an anisotropic triaxial design criterion should be used for design checks. Other safety factors like burst, collapse and tension also need appropriate adjustments when using CRA tubulars.

- Different drilling techniques have been mentioned in this thesis, and how they are suited for different operations. Some are better budget wise, while some are better for minimizing formation damage. But it is important to keep in mind that the best technique is individual for each operation. And there are many factors to consider when choosing the best one. In case of CCS injection wells, drilling down to the caprock could be done cheap and fast while drilling in the reservoir should focus on minimizing formation damage. The methods presented as the cheapest is overall associated with lower drilling costs, but there are so many factors affecting this. What is available, what is in high demand, how is the formation, is there any anomalies, etc. So sometimes the methods that is categorized as the cheapest ones, might not actually be the cheapest for that specific case.

- Both Norwegian and united states standard have been examined above and while there are some similarities, NORSOK do not include any specific requirements for CCS operations so it is difficult to even compare. It is safe to say that NORSOK is outdated and need to include CCS operations in the standard. However, even though the US standard include regulations for CCS it does not mean that these are the best to follow. While it is true that both AEP-1 and CCS#1 from *the Illinois Basin Decatur Project* and the *Mountaineer Project* experienced defects, the two wells successfully kept the stored CO2 in the isolated formation. The fact that AEP-1 can be described as a success, whilst not meet the requirements for IV wells from the CFR, raises the question of whether the current requirements might be too strict. The fact that both the wells were successful, even though they were designed differently suggest that different options for well design is possible.

- Many different options for cementing have been mentioned above. The presented test results from both; *Cement degradation in CO2 storage sites* and *CO2 stability on Portland cement based well cementing systems for use on CCS wells,* are solely based on laboratory tests and not on actual well data. It is crucial to consider this distinction when evaluating the findings in the two case studies. As a result, it would be inappropriate to recommend their usage based solely on these laboratory results. Nonetheless, the reports highlight their promising results that warrant further investigation and exploration in order to gain a better understanding of their potential application.

- Both fiberglass and CRAs were proven suitable for CCS injection wells, but this thesis has not examined any case studies on how these materials will work after many years. CCS is a relatively new technology, so it can be difficult to find good data on how these wells perform over time.

- One of the case studies found that any Portland cement system, even with additives, inevitably will be subject to carbonation. However, calculations based on the values from the same case study found that it would take the CO2 roughly 2400 years to reach the surface from the top of Sandnes formation. Which is a reasonable safety margin.

- Analysis reveals promising potential for CO2 storage in quadrant 10. The reservoir exhibits favorable characteristics for storage purposes, particularly due to its depth, which allows for the CO2 to be stored in a supercritical fluid state. These findings are further supported by the NPD (Norwegian Petroleum Directorate).

- In terms of technical advancements, alternatives like Controlled mud level (CML) and slender wells have shown promise in cost reduction. Using CML instead of underbalanced drilling (UBD) might be an option which could help reduce the cost of the drilling operation when entering the reservoir. Slender wells offer an option that reduces the drilling cost and the complexity of the operation. Initial estimates indicate that using slender wells may potentially reduce cuttings and mud volume by about 70 % each, with casing volume reduced by 50 %.

- Additionally, employing slender wells would enable the utilization of smaller rigs, potentially subtracting $13,5 million from the total drilling cost. Implementing CML instead of UBD could further reduce costs with an estimated $500,000. These are numbers for just one well, similar cost reductions could potentially be achieved across all injection wells drilled in the same field. These results show how small cuts added together can have a significant reduction to the overall cost on the CCS technology. However, it has to be emphasized that when selecting the appropriate drilling technique, cost consideration should not be the sole determining factor. The chosen techniques must be suitable for the specific well being drilled and align with the pressure regimes the well will encounter

- To gain better understanding of the economics assosiated with CCS technology, particularry with regards to drilling operations, it is imperative to consider data provided by operators. However, the insutry may be hesitant to share pricing details as this information typically falls under contract agreements between operators and suppliers.

- The calculations done in this thesis have been made based on assumption and a lot of factors have been neglected, for the simplicity for the calculations. This thesis is only intended to illustrate the possibilities that exists; further research is required to actualize and implement these cost-reducing measures.

5.2 Suggestion for further work

- Evaluation of cost reduction strategies of aspects of the drilling operations that have not been covered in this thesis.

- Find cost-effective and specialized solution for completion techniques in CCS injection wells.

- Utility and monitoring well should also be designed for CCS operations

- Investigate options to incorporate bismuth into the cementing operation used in the lower parts of the reservoir.

- Research application of nanomaterials and other additives in cement, to have better resistance against corrosive environment.

- What would it look like, re-entering the reservoir after CO2 is injected and stored over several years? How should the well be drilled, know there is a lot of pressurized CO2s stored in the formation?

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