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Now, I look forward to putting knowledge into practice.

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Abstract

Global warming is a key concern for human society and anthropogenic emissions must be reduced. To aid this development, carbon capture and storage has showed a great potential. Here, carbon dioxide is captured from large emitters and stored in geological formations. Until now, economic profitability of this technology has been limited to the oil and gas industry. The CCS technology is more easily implemented in the oil and gas industry as the investment and operating cost can be justified with the high carbon dioxide tax, infrastructure and reservoir knowledge. Outside of the hydrocarbon industry, the startup phase of any CCS project will require high initial investment in regard to capture facilities, transporting infrastructure, terminal and storage sites. To compensate for these expenditures, substantial volumes of CO₂ must be injected into the subsurface. The Northern Lights project is the world's first full scale carbon capture and storage development with third-party customers. In this large-scale project profitability will be generated by obtaining a high injection rate. To ensure technical feasibility, multiple geological studies have been performed; however, CO₂ has not yet been injected into the formation. Therefore, the possibility of unforeseen geological events rises.

When CO₂ is injected to the storage site, geochemical interactions are imposed. The reactions can alter the rock properties, causing lower injection rates. Experience from CCS operations like the Norwegian Snøhvit and Sleipner project, where salt precipitated and sand built up close to the injection well respectively, has proven that injectivity challenges can have fatal consequences. In this thesis three different scenarios are developed to investigate the economic outcomes of injectivity reduction in the storage formation of the Northern Lights project. The scenarios are build based on historical analogies and geochemical simulations. The simulations were performed using the PHREEQC software to model the behaviour of different mineral in the Aurora formation. The simulation showed a large amount of calcite precipitating that can potentially clog the wellbore region. Moreover, to calculate the economic outcomes a pre-tax present value analysis with data from open access sources was performed. The scenarios investigated in this study shows that a 10 % reduction in well injectivity increases storage cost with 51 % whereas in scenarios where mitigation measures are conducted the cost increase is between 4-30 %. This thesis indicates that preparing for injectivity problems is more favourable in terms of limiting the cost of storage, although upfront investment of mitigation measures might seem substantial.

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1 Introduction

There is wide academic consensus that global warming is one of the greatest challenges of modern society (Zandalinas, Fritschi, & Mittler, 2022). According to Karl and Trenberth (2003), human interfering with natural energy flows account for the majority of the human alteration on global climate. Although the greenhouse effect is a controversial phenomenon, it evidently contributes to explain why the global average temperature is rising (Karl and Trenberth, 2003). The adverse effects of long-term temperature increase show large scale impact on the global climate. Extreme weather events, such as flooding, droughts, wildfires, and hurricanes, are becoming more frequent and intense. These events are posing a serious threat to human society, infrastructure, and health, and can subsequently cause extreme financial losses (United Nations, 2022). To reduce the impact of these consequences, the global greenhouse emissions must be limited. Carbon dioxide accounts for 74 % of the total greenhouse gas (GHG) emissions (Ritchie, Roser, & Rosado, 2020). Reduction in CO₂ is thus imperative in decreasing overall GHG emissions. Minimizing the carbon dioxide emissions can be done by scaling down the consumption of fossil fuels, switching to renewable energy or by carbon capture and storage (CCS).

Carbon capture and storage has shown great potential for capturing CO₂ related to, for example, hydrogen, cement and steel production, thereby preventing the GHG from escaping into the atmosphere (Northern Lights, 2021). Carbon dioxide is captured from flue gas: a multi component gas, which is generated from the combustion processes related to the production in such (and other) industries (Corrosionpedia, 2018). Once the carbon is captured it will be transported to a geological formation for permanent storage.

The CCS technology was in 1970, first implemented at the Terrell Natural Gas facility to enhance oil recovery. Here, the primary driver for carbon injection was to increase the sale of oil (Martin-Roberts, et al., 2021). In 1996, the world's first industrial scale CO₂ storage was introduced in combination with gas production at the Norwegian Sleipner field. The CCS project was initiated by the high percentages of CO₂ in the produced gas in combination with the increasing taxes for releasing carbon to the atmosphere (Martin-Roberts, et al., 2021). CCS can also be financially viable when the captured CO₂ is used for enhanced oil recovery (Global CCS Institute, 2019) where CO₂ is injected into an oil reservoir to push the oil towards the

production well. However, usage of the CCS technology outside of the oil and gas industry is currently expensive and holds a low revenue potential (Norwegian Ministry of Finance, 2018). Justifying investment in such solutions has so far not been possible for other industries. If economic feasibility can be proven for large scale CCS projects, there is great potential for significantly reducing the impact of anthropogenic climatic changes.

In 2020, the world's first full scale CCS project third-party customer was launched. The Northern Lights project, a joint venture of Equinor, Shell and Total Energies, aims to develop CCS to become commercially viable. In order for the CCS industry to become commercial, there has to be a sequestration site and a market for carbon. No emitter will capture CO₂ if it cannot be stored, and no storage site will be built if there are no customers (Northern Lights, 2021). The Norwegian government has therefore made significant investments to aid the development of the CCS industry. The large investments have been dedicated to the transportation ships commonly referred to as "Longship" (Norwegian Ministry of Petroleum and Energy, 2020). The Northern Lights project will collect captured CO₂ from large emitters all over Europe by these ships and inject the CO₂ into a geological formation for permanent storage, enabling CO₂ storage for third-party companies (Northern Lights, 2021). The ambition is to store 5 million tonnes of CO₂ every year. In comparison the Norwegian Sleipner and Snøhvit CCS projects is currently storing 1.7 Mt CO₂ per annum, which is equivalent to 3-4 % of the Norwegian annual emissions (Norwegian Ministry of Finance, 2018; Martin-Roberts, et al., 2021). Because the project does not account for carbon capture operations, such companies will experience an explosive growth. There has been a lot of interest around the Northern Lights project and in 2021 the EU innovation fund decided to give fundings to four CCS projects, where all four was pointing to Northern Lights for the transportation and storage solution (Bellona Foundation, 2022).

The Aurora formation is the prospective aquifer for CO₂ to be permanently stored in the Northern Lights project. The formation is located offshore in the North Sea, west of Bergen in Norway. In 2019 project was awarded EL001, the first exploitation license for injection and storage of CO₂ (Norwegian Petroleum Directorate, 2019). Exploration well 31/5-7 was drilled in 2020 to investigate reservoir properties and sealing capacity (Norwegian Petroleum Directorate, 2022). This well will be converted to an injection well in 2024 when the project is scheduled to start. Additional wells will be drilled to obtain scalable injection volumes (Northern Lights, 2021).

The saline aquifer is a stratigraphic storage unit characterized by high porosity and permeability, allowing for large quantities of CO₂ to be injected. The overlying caprock is impermeable, preventing CO₂ from leaking to the atmosphere (Norwegian Petroleum Directorate, 2022). Multiple geological studies have been performed; however, CO₂ has not yet been injected into the formation (Lothe, Bergmo, & Grimstad, 2019; Thompson, Andrews, & Bjørnarå, 2021; Sundal, Miri, Ravn, & Aagaard, 2015). Nevertheless, this is a risk of unforeseen geological events. One example is mineral precipitation that could lead to a pressure build up. Any CCS project can be compromised by overpressure, which reactivation of faults, induce seismicity or break the seal (Chiaromonte, White, & Trainor-Guitton, 2015). Moreover, previous CCS projects has proved that geochemical interaction between the injected CO₂-formation, water and rock can cause catastrophic outcomes. For example, salt precipitation in the near wellbore region is likely to have caused massive pressure to increase during CO₂injection at Snøhvit (Hansen et al., 2013).

When CO₂ is injected to a geological formation, it will impose multiple geochemical reactions between the rock, the formation water, and the CO₂. These reactions will initiate mineralogical changes, in terms of minerals dissolving or precipitating (Miri, 2015). The effect of these processes can both act as a barrier or assist the injection. Mineral precipitation could lead to clogging the pore network near the wellbore. Whereas, mineral dissolution could aid the injection, and create more space for the CO₂ to pass through (Miri, 2015). The governing factor of these processes is the initial mineral composition of the geological storage site. The Aurora formation is located 2800 meters below the seabed, and the reservoir covers a wide area. Thus, any meter-scale core-samples from the sandstone only represent a small fraction of the total reservoir (Aabø, Dramsch, Würtzen, Seyum & Welch, 2020). For these reasons, the behaviour of the CO₂-brine-rock interactions must be predicted through different analysis, such as geochemical simulations. However, every simulation model has limitations and can only indicate future outcomes. Deviations from the simulation model are possible, and so are unexpected geological features. Commercial scale CCS projects will require millions of tonnes to be stored every year and if injectivity is reduced it can serve fatal environmental and economic consequences.

In this thesis three different scenarios are developed to investigate the possible economic outcome of injectivity reduction. The scenarios are built on previous injectivity challenges as well as geochemical simulations conducted to investigate the occurrence of mineral

precipitation at the Aurora formation during CO₂ injection. Because the Northern Lights project is a pioneer for the CSS industry, it is important to prove that injecting carbon dioxide into the ground is a taggable and safe operation. Furthermore, the project's success is critical in terms of setting an example for the industry to demonstrate that it could hold commercial viability.

1.1 Research question

As discussed above, multiple geological studies have been conducted to investigate the storage potential of the Aurora formation. However, there is still a risk of unforeseen geological events. If they occur, they can be mitigated or be ignored. Therefore, this thesis aims to answer:

To what extent will mitigation measures affect the storage cost for scenarios with reduced injectivity?

The Northern Lights project was chosen as the framework for answering this research question. The project provided the associated cost and formation properties. Three different scenarios with lowered injectivity were developed based on historical events from previous CCS projects, namely Snøhvit and Sleipner. Moreover, a geochemical simulation model of mineral precipitation at the Aurora formation was performed. This allowed for a more detailed investigation of the prospected storage formation.

2 Background

“Carbon, Capture and Storage (CCS) refers a set of technical solutions with the aim of reducing CO₂ emissions to the atmosphere” (Ringrose, 2020). CO₂ is mainly captured from the flue gas produced from industrial processes such as cement and steel factories, but it is also possible to extract the CO₂ directly from the atmosphere (air capture). Once the carbon dioxide is captured, it is compressed and transported to a suitable geological formation for long-term storage (Ringrose, 2020). Figure 2.1 illustrates different capture, transport and storage opportunities and techniques.

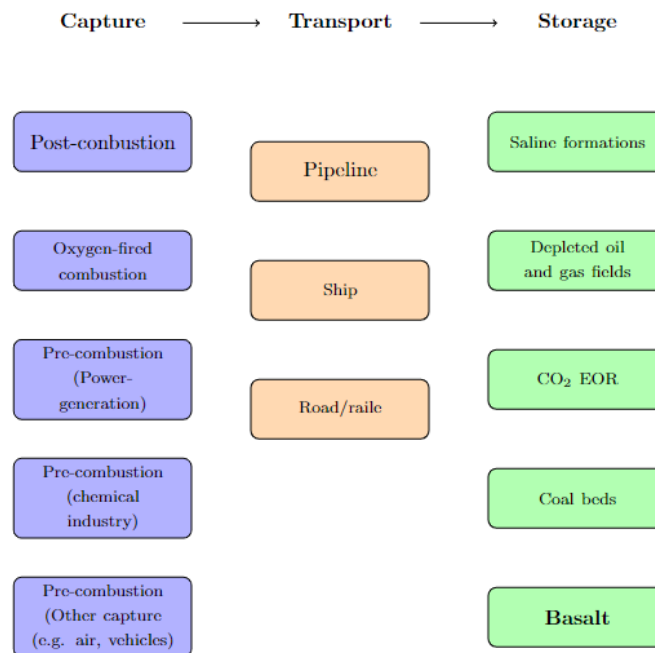


Figure 2.1. Overview of CCS technologies (Ringrose (2020))

2.1 Physical properties of CO₂

An important concept for CCS projects is to understand how CO₂ behaves under different temperature and pressures. This is particularly important when it comes to the presence of different impurities in the CO₂ stream after the capturing process (Ringrose, 2020). It should be recalled that CO₂ is naturally in gas phase but will be pressurized and transported as liquid while stored as a supercritical fluid in geological sites. This process is elaborated on further in the section below.

2.1.1 Phase Diagram

The CO₂ phase diagram is an important aspect of CCS operations. Figure 2.2 describes the behaviour of CO₂ under various pressures and temperatures. At atmospheric conditions of 1 bar and 20 °C, CO₂ exist in a gaseous phase. To make the CCS processes more efficient, the gas is compressed into liquid state. During the transportation stage, CO₂ is typically pressurised and cooled, shown as “big ships” and “small ships” in figure 2.2.

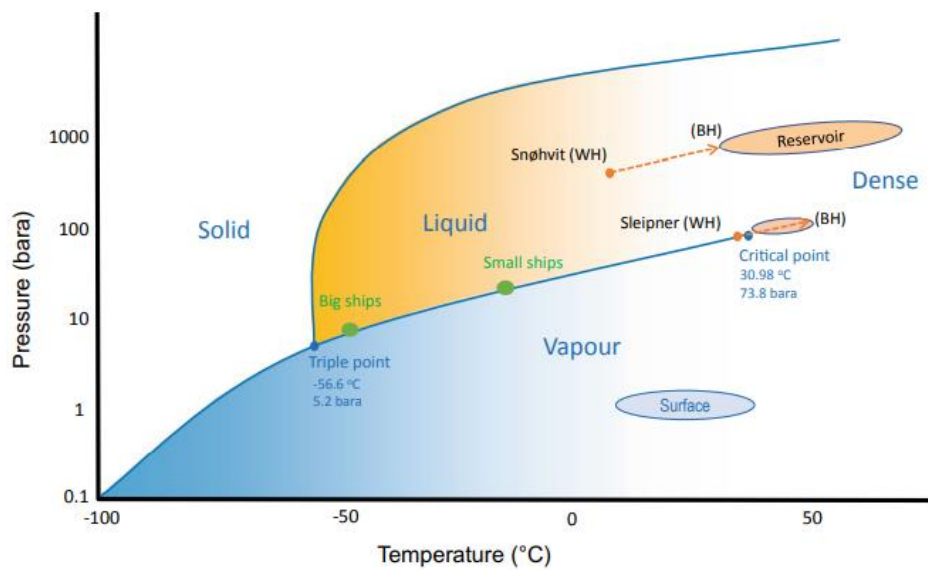


Figure 2.2. CO₂ phase diagram with typical paths and conditions for CO₂ storage operations (Ringrose 2020)
Approximate wellhead (WH) and bottom-hole (BH) conditions for the Sleipner and Snøhvit projects are indicated.

Once the cooled CO₂ is injected, it will heat up due to the geothermal gradient. At Snøhvit, CO₂ is pressurized to 140 bars when entering the wellhead (WH), but still in the liquid phase. However, at the bottom-hole (BH) conditions (depth 2400 m and pressure of 350 bars) the CO₂ flows into the reservoir in a dense supercritical phase. For temperatures above 31.1 °C and pressure higher than 73.9 bar, CO₂ appears to be in a supercritical state, where it has a gas-like viscosity and a fluid-like density. Temperatures and pressures above the critical point is referred to as the dense phase. At the Sleipner field, CO₂ is injected just below the critical point and appears into a two- phase region (Ringrose, 2020) given the shallow depth of the storage site (low pressure).

2.1.2 Density

Because the vapor phase will occupy large volumes, CO₂ is compressed into a liquid state for transport and storage. This allows for larger quantities to be injected into the reservoir and reduce the cost. Figure 2.3 describes the density and the volumetric change of CO₂ as a function of depth. The blue numbers to the right of the balloons in figure 2.3 represents the volume of CO₂ at different depths. As seen in the figure, the volume will be reduced from 100 to 0.32 m³ when entering the liquid phase. This will happen at depths greater than 800 m (IPCC, 2005). Hence, suitable geological formation for CO₂ storage should be located below this critical depth.

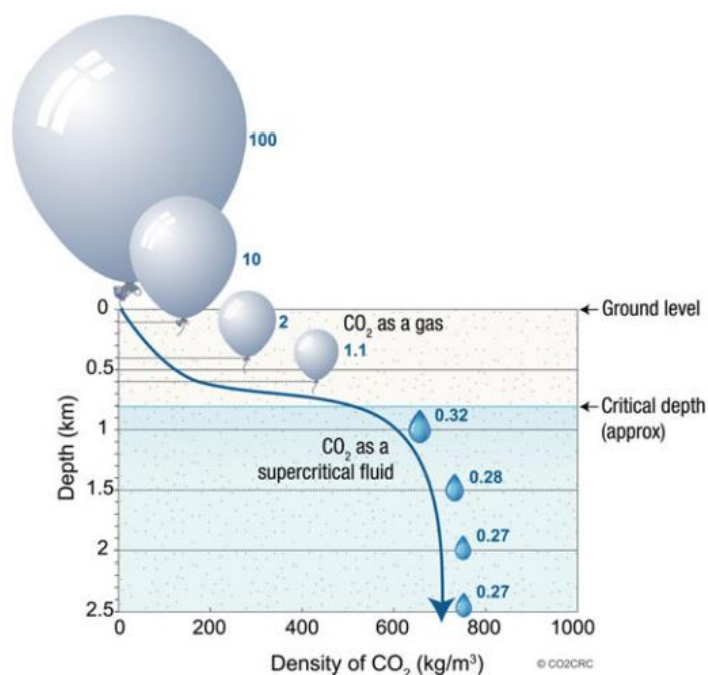


Figure 2.3. Simplified CO₂ density versus depth diagram (Ringrose (2020)).

2.2 Carbon capture and storage

2.2.1. Capture

“CO₂ capture mainly refers to the process of removing carbon dioxide from a sources of gas emissions” (Ringrose, 2020). Industrial facilities like power plants, cement kilns and steel production all utilize large combustion systems to extract and utilize energy (Ringrose, 2020). This process creates a flue gas, which is created in the combustion processes. The content of the flue gas varies depending on the different production processes, but most of the flue gases contains CO₂, water and nitrogen (Corrosionpedia, 2018). Hence, the aim of the carbon capture

process is to separate the CO₂ from this flue gas. Separation can be accomplished in a variety of ways. Industrial facilities typically utilize “post-combustion” plants, separating the CO₂ from the flue gas through a chemical absorption process. The flue gas is introduced to a solvent, which is a liquid chemical compound that binds easily to the CO₂. Once the CO₂ is absorbed by the solvent, the solution is heated. Heat is added to release CO₂ from the chemical compound (Aker Carbon Capture, 2021). Other methods of carbon capture involve adding pure oxygen to the process. The “pre-combustion” method allows the oxygen to react with a fuel forming a syngas, a mixture of hydrogen, carbon monoxide, CO₂, and water. This method maximized the power output as it generates hydrogen. CO₂ is removed from the syngas by chemical adsorption (Kearns, 2018).

2.2.2. Transport

“Transport of CO₂ involves handling and transportation from the capturing plant to the storage site” (Ringrose, 2020). The most common methods of transportation are pipeline, ships, tankers, and trains, as illustrated in Figure 2.1. The choice of transport is determined by several parameters such as cost, safety, and risk. As described previously, the most efficient way to transport the CO₂ is within the liquid phase. Gas close to the atmospheric pressure occupies very large volumes that require very large facilities (IPCC, 2005). Even though, the carbon dioxide is compressed to fill smaller volumes, transportation represents a high cost. The main drivers are distance and the quantity (IPCC, 2005). The IPCC report (2005) indicated that ships (if a marine option is feasible) is the most economic method for transport distances above 1000 km. However, ships are large CO₂ emitters as they currently are powered by fossil fuels. Thus, ships are a less attractive option when it comes to public perception/acceptance. Pipelines are thereby a more attractive option. However, pipelines are costly as the CO₂ is very reactive and may cause corrosion. Therefore, expensive stainless-steel pipes are required. Hence, for short distances (>1000 km), pipelines are the best option.

2.2.3. Geological Storage

“CO₂ sequestration refers to a long-term geological storage to isolate the CO₂ from the atmosphere. CO₂ is pumped into large subsurface reservoirs, carefully selected to ensure that the carbon does not leak to the surface”(Ringrose, 2020). There are several geological formations available for sequestration, where several is listed in figure 2.1. To serve as a suitable storage unit, the geological structure must contain a porous basin and an impermeable

barrier (Miri, 2015). These types of structures are already well known as most of the oil and gas sources is found within similar reservoirs. Sequestration sites can be found both onshore and offshore (Cooper, 2009). A more detailed description of storage sites is given in chapter 3.

2.3 Aurora formation

The Aurora Formation is the prospective aquifer for CO₂ to be permanently stored in the Northern Lights project. The aquifer is a stratigraphic storage unit characterized by high-energy sandstone wedges. Above the reservoir the marine shales of the Drake Formation are found, which serve as the primary seal (Norwegian Petroleum Directorate, 2022). The reservoir consists of both the Cook and Johansen formations. However, the two formations are treated as one aquifer due to fractures in the shale separating them from each other (Norwegian Petroleum Directorate, 2022). Studies conducted by Lothe et al. (2019) have indicated that the formation holds a sufficient storage capacity. Meaning, that substantial volumes of CO₂ can be pumped into the formation as it can withstand the pressure increase such process. Moreover, the study confirmed that migration of CO₂ to the surface is very unlikely due to the thick Drake formation shale (Norwegian Petroleum Directorate, 2022).

Figure 2.4 shows the offshore location of the sequestration site. The formation is located near the giant Troll and Oseberg fields. In 2019, the well 31/5-7 (known as EOS) was drilled to collect relevant data from the caprock and storage sites. The data confirmed the presence of good quality sandstones in the Johansen and Cook formation and sealing features in the Drake Formation (Zweigel, Vebestad, Anzola, & Lidstone, 2021). In 2021 the joint ventures (Equinor, Shell and Total Energies) were awarded with the first exploitation license for subsea injection of CO₂ on the NCS, EL001. The Aurora formation is a key concept in this thesis because it establishes the framework for the simulation models that will be used as inputs to the scenario analysis.

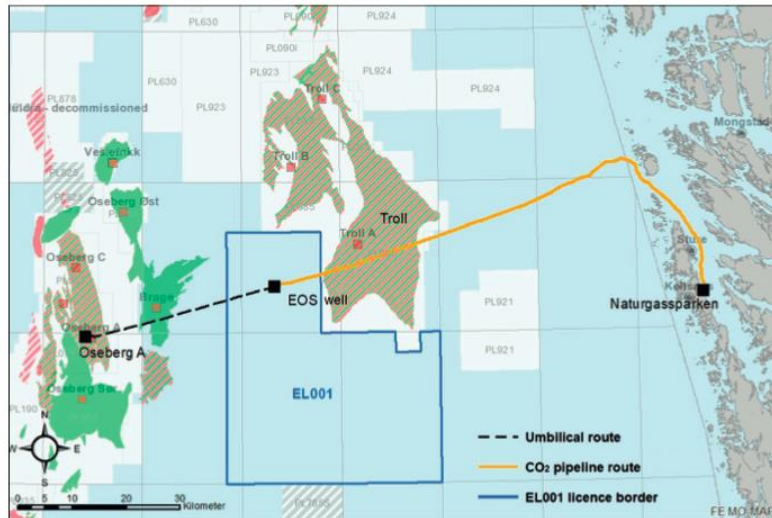


Figure 2.4: Location of exploitation license EL001 and EOS well (Norwegian Ministry of Petroleum and Energy, 2020)

2.4 Scenario analysis

Scenario analysis is a powerful tool for asking “what if” questions to explore the consequences of uncertainty. Scenarios are not predictions, but aid as a method to evaluate different visions for the future. Hence, the focus is shifted from the analytical estimations towards possible outcomes that show where different choices may lead (Duniker & Grieg, 2006). Scenario-building and analysis are widely used in projects and organisation. For instance, Equinor applied a scenario approach to their “Energy Perspectives report 2021”. The report investigated three distinct scenarios for the future energy demand. Thus, the aim of scenario analysis is not to force decision but rather reflect on possible outcomes that investigate challenges one might face.

2.4.1 Trend Impact Analysis

“There is no single widely accepted guideline or best practice for implementing a scenario analysis rather, numerous implementations have occurred” (Strelkovskiiia, Komendantovaa, Sizova, & Rovenskayaab, 2020). Subsequently, different methods of scenario development have been suggested. The trend impact analysis (TIA) is a frequently used approach to build scenarios. The method was developed in the late 1970s to account for unprecedented future events (Gordon, 1994). Figure 2.5 describe the four steps of the method.



Figure 2.5: Trend Impact Analysis

In the first step historical data is related to the issue is collected. The second step consists of the calculation of curve-fitting functions. This is done to extrapolate the trends observed from the historical datapoints. In step 3 a list of unpredicted future events that could cause deviation to form the extrapolated plot (from step 2) is identified. Finally, expert judgments are used to identify the probability of the occurrence of these unexpected events (Carvalho, 2021)

3 Geological CO₂ storage concept

This chapter investigates the literature of geological and geochemical parameters. The goal is to gain a better understanding of these concepts to give the simulations and scenarios a greater threshold.

3.1 Geological storage sites

For long-term permanent storage CO₂ is injected into various geological formations. Figure 3.1 illustrate different storage options for sequestration. In the figure, enhanced oil recovery (EOR) is described as a potential storage location. However, EOR- projects will not be discussed section as it is beyond the scope of the thesis. Only sequestration sites used for full-scale CCS development are taken into consideration.

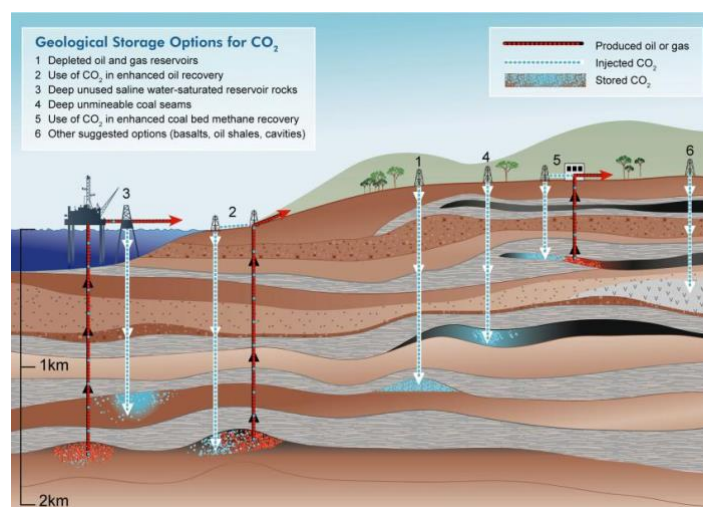


Figure 3.1. Options for storing CO₂ in deep underground geological formations (IPCC, 2005)

3.1.1 Saline Aquifers

Saline aquifers are referred to as “deep sedimentary rocks saturated with formation water or brine containing high concentrations of dissolved salts” (IPCC, 2005). Platform 3 and 4 in figure 3.1 shows injection in saline aquifers in offshore and onshore facilities, respectively. Saline aquifers are a prime candidate for CO₂ storage as they contain enormous quantities of water (IPCC, 2005) To be considered as a potential sequestration unit they must fulfil the following properties:

- **Size:** the reservoir must be large enough to store commercial volumes (IPCC, 2005)
- **Porosity and permeability:** the aquifer should have substantial porosity to be able to full the pores with the injected carbon dioxide. Permeability is important to ensure sufficient flow throughout the reservoir (Cooper, 2009).
- **Depth:** To inject the CO₂ in a dense phase the reservoir should be located at depths greater than 800 m. At such depths the carbon dioxide will exist in supercritical or liquid state. This will lead to a better injectivity since the density difference between the in-situ brine and CO₂ has approximately the same viscosity (Ringrose, 2020).

3.1.2 Depleted oil and gas fields

Depleted oil and gas field offers a great potential for long-term geological storage. Platform 3 and 5, in figure 3.1, represent depleted oil and gas reservoirs. These reservoirs are strong candidates for CO₂ storage for numerous reasons. First, the integrity and safety of the structural trap is proved by the oil and gas that has accumulated within the reservoir for millions of years. Secondly, an extensive mapping of the physical reservoir properties such as structural and stratigraphic characterization is already conducted. Third, dynamic models of how the oil and gas will flow inside the reservoir has also been extensively studied. Fourth, the fields have a detailed dataset of the pressure management though the years of production. Finally, some of the infrastructure is already in place (IPCC, 2005). All of these factors will contribute to lower the development cost of a CCS project as well as decreasing the development time.

3.1.3 Coal seams

Coal seams can be highly permeable and porous due to natural fractures. The structure of coal is represented by a dual-porosity arrangement consisting of micropores (coal matrix) and macropores (cleat network) (Vishal & Singh, 2016). The injected CO₂ will thus flow as a free

gas in the cleats and then diffuse through the microporous network to get adsorbed by the coal matrix. Early laboratory experiments revealed that coal could adsorb roughly twice as much CO₂ as methane by volume. (Shi & Durucan, 2005) There are three trapping mechanisms, contributing to safely sequester CO₂ in coal formation: adsorption, absorption and physical trapping. Adsorption is the most important storage mechanism in high-pressure coal seams, accounting for approximately 95% of the trapping (Shi & Durucan, 2005). Coal bed storage could either take place in un-mined seams or as a method of enhancing methane production similar to CO₂ utilization in EOR projects. Even though coal seams make good candidates for storage due to the high permeability and trapping mechanisms, it is argued that coal seams have minor available volumes (Vishal & Singh, 2016).

3.1.4 Basalt formations

Another method of CO₂ sequestration is injection into basaltic formations. Basalt is made up of highly reactive rocks with high concentrations of divalent cations such as Ca²⁺, Mg²⁺, and Fe²⁺ (Snæbjörnsdóttir, et al., 2020). When CO₂ is injected such formations, it will initiate a natural carbon mineralization process. Minerals such as calcite (CaCO₃), dolomite (CaMg(CO₃)₂), or magnesite (MgCO₃) will very quickly precipitate. These minerals will ensure that the carbon will be stable for a geological time, as the CO₂ is stored in minerals (Snæbjörnsdóttir, et al., 2020). Hence, the primary advantage with this method is that there is a minor risk of leakage as CO₂ will be trapped in solid form and is not able to migrate to other formations. This storage method is relatively new and field tests are currently being conducted. The aim is to reach a scale-up potential for commercial utilization. (Snæbjörnsdóttir, et al., 2020).

3.2 Selection criteria for storage sites

Cooper (2009) identified capacity, injectivity and containment as the three critical characteristics for CO₂ storage. These outlined parameters will be discussed in the following sections. In addition, monitorability is also evaluated as important criteria for storage, and will therefore also be addressed in the following sections.

3.2.1 Capacity

The capacity describes the volumes of CO₂ that can be storage within the geological formation. It is important that the storage sites can hold large volumes of CO₂ in order to make them commercially viable. Capacity is determined by several factors, including formation thickness, storage site area, and porosity. (Cooper, 2009) . To estimate the available pore space for CO₂ storage equation 3.1 is used (Ringrose, 2020)

$$M_{CO_2} = V_{\phi}\rho_{CO_2}\epsilon \quad (3.1)$$

V_{ϕ} is the available pore volume for fluids to be stored, ρ_{CO_2} is the density of the CO₂ and ϵ is a correlation factor to include the effects of fluid dynamics.

3.2.2 Injectivity

Injectivity ensures that a sufficient amount of CO₂ is introduced to the formation. A high permeability is required for the carbon dioxide move quickly into the porous space. It is especially critical to have a high permeability scheme in place near the well bore. If the permeability in this area is lowered, a pressure build up will be introduced as there are less pores available for CO₂ to pass through, the injected gas will push against clogged pores increasing the pressure. High reservoir pressure is not favourable as it can fracture the formation and from leakage paths (Chiaromonte, White, & Trainor-Guitton, 2015). Therefore, CO₂ injection of is a very delicate operation. Experience from field development has proved that CO₂ injection might come with challenges. Thus, having an agile injection plan is very important (GeoScience & GeoEnergy Webinars , 2020). The section below contains examples of incidents in which the injectivity was altered.

3.2.2.1 Historical injectivity challenges

To illustrate the different causes of permeability reduction, past experiences is investigated. In 1996, the Sleipner field started to inject CO₂ (Martin-Roberts, et al., 2021). The project was the worlds first dedicated storage facility. Prior to the Sleipner project CO₂ had been used for enhanced oil recovery. The start-up phase for the Sleipner project did not go according to the plan and the scheduled injection rates were not met (Ringrose, 2020). The project was faced with sand- influx due to the unconsolidated Utsira sand formation (Pawar et al., 2015). This effect commonly referred to as “the skin effect”. It is imposed by sand building up at the outer

part of the injection well. As a mitigation strategy sand screen was installed. However, they only improved the injection rates to a limited extent (Ringrose, 2020). The problem was solved by re-perforating the injection interval and installing sand and gravel packs. This well intervention resulted in a steady flow of CO₂. (Pawar et al., 2015)

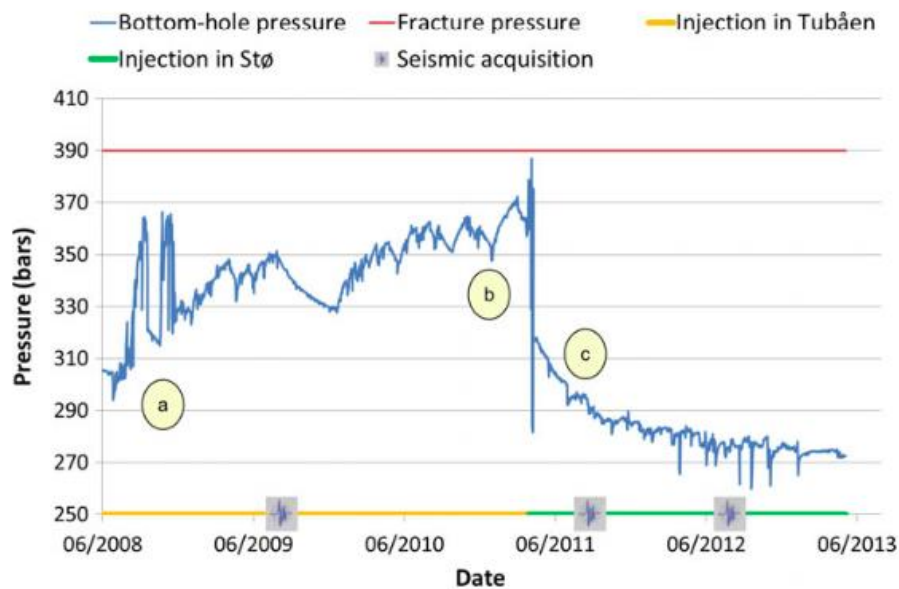


Figure 3.2. Pressure history at the Snøhvit CO₂ storage site (Ringrose, 2020)

The Snøhvit CCS project started production in 2008 injecting approximately 0.7 Mt/y (Martin-Roberts, et al., 2021). However, only months after of production started Hansen et al. (2013) reported a pressure build up near the injection well. The incident has been thoroughly study in the later years (Nooraiepour, Fazeli, Miri, & Hellevang, 2019; Miri (2015). The incident has shown strong evidence of salt precipitation (Hansen et al, 2013). The physics behind the concept of salt precipitation is described in more details in section 3.3.4.1. The pressure drop is illustrated in figure 3.2 (a). This incident demonstrated that geochemical reactions could have a short-term impact on mineralization in the reservoir. To remove the formed salt crystals, episodic slugs of Methyl- ethylene- glycol (MEG) solution was injected to dissolve the crystals (Nooraiepour, Fazeli, Miri, & Hellevang, 2019). The mitigation strategy was proved successful. However, as represented in figure 3.2 (b), the pressure in the Tubåen formation continued to increase over time. Injection into such formation proved to be limited due to geological barriers in the formation causing. As shown in the figure, the pressure almost exceeded fracturing pressure in 2011. Large overpressures can alter the seal integrity, reactivate faults, and induce seismic (Chiaromonte, White, & Trainor-Guitton, 2015). Therefore, the CO₂

injection at the Snøhvit field was ultimately moved to a shallower formation (Stø). As seen in figure 3.2 the pressure curve is continuous for the whole period, meaning that injection in the Tubåen formation was still performed while drilling and preparing for injection in the Stø formation.

3.2.3 Containment

The containment of the CO₂ plume is composed of several trapping mechanisms. The primary mechanism of CO₂ containment is referred to as physical trapping (Cooper, 2009). It relates to a physical barrier that ensures that the CO₂ does not leak to the atmosphere or other nearby formation i.e., shallow groundwater. The physical barriers are commonly referred to as seals or caps. They are characterized by low permeability and can be both of vertical and lateral proportion, depending on the geological trapping of the reservoir. Caprocks are usually shales, mudstones or evaporite layers (Cooper, 2009). The caprock must tolerate the pressure build up from the underlying reservoir to avoid cracks where the CO₂ could migrate. Therefore, the sealing capacity needs to be confirmed by a detailed analysis to ensure the integrity of the storage site (Kirby & Bentham, 2005). Moreover, the seal needs to be continuous to cover and contain the volumes of injected carbon. It should also have a large thickness to prevent any potential breach caused by geochemical or/and geo-mechanical effects to ensure that the CO₂ is safely stored for thousands of years (Cooper, 2009). With time chemical trapping mechanisms will be introduced. Chapter 3.3 gives a more detailed description of these mechanisms.

3.2.4 Monitorability

The ability to monitor the CO₂ plume plays an important role for CO₂ storage. Since a large fraction of the CO₂ will be stored in a dense phase, it will move within the reservoir after the injection has stopped. To see how the plume develops and compare it to the simulation models, monitoring is required. Because CO₂ can migrate to larger distances, potentially outside the reservoir, CCS licenses cover greater areas than a regular oil and gas license (Overå, 2019). Before injection a static and dynamic model of the CO₂ plume is made to predict how the plume will develop. However, geological survey cannot predict everything in the subsurface (GeoScience & GeoEnergy Webinars, 2020). Therefore, it is important to monitor after the

injection and see if the plume behaves as predicted. Figure 3.3 shows a simplified monitoring strategy from the Northern Lights project.

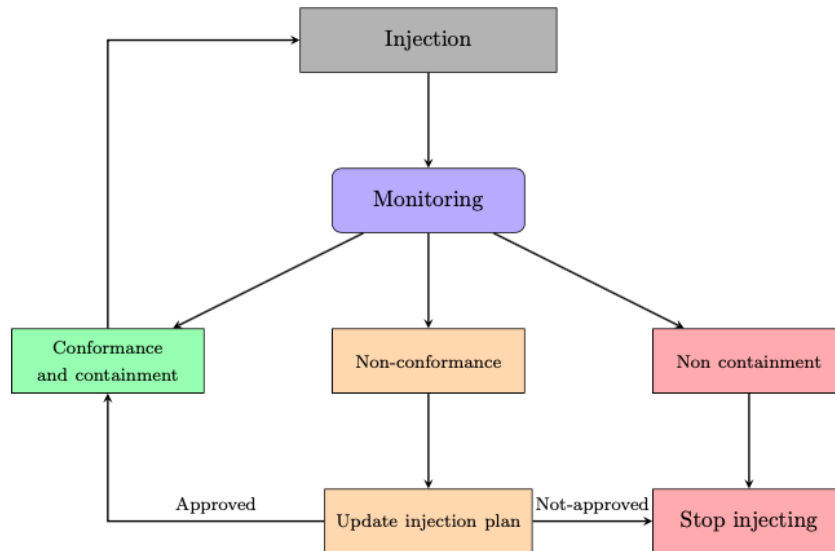


Figure 3.3: Monitoring strategy, modified from (Overå, 2019)

If there is a conformance with the build model, proving that the CO₂ does not leak, the injection will proceed as scheduled. However, if there is a non-conformance with the model and the survey after injection, a full investigation must be done to understand why the model was wrong. This adaptive approach requires the operator to be able to change the well completion plan. Lastly, if the monitoring shows a no containment of the reservoir, the injection is stopped (Overå, 2019).

3.3 Trapping mechanisms

Sequestration of CO₂ in geological formations is achieved through multiple trapping mechanisms. For saline aquifers structural, residual, solubility and mineral trapping is the mechanisms keeping the injected carbon dioxide within the geological formation. However, they can also cause fatal outcomes for CCS operations. Figure 3.4a illustrates the four mechanisms as a function of time after injection for saline aquifers. Figure 3.4b illustrates trapping within mafic formation where only two trapping mechanisms is present. The storage security increase with time as the supercritical CO₂ is being trapped by the different mechanisms.

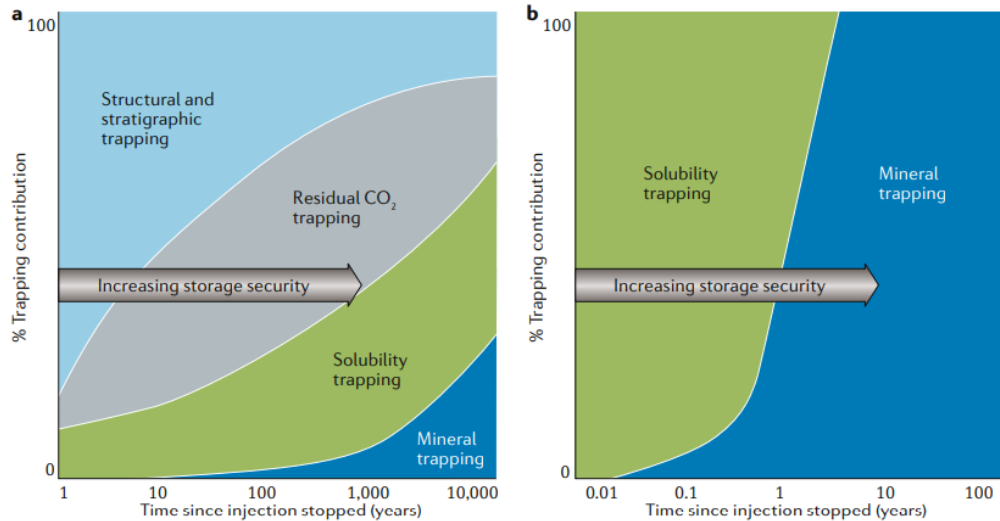


Figure 3.4. Comparison of CO₂-trapping mechanisms for CO₂ injection. Snæbjörnsdóttir et al. (2020,) a) saline aquifers b) basalt formations

3.3.1 Structural trapping

The primary trapping mechanism that keeps CO₂ within the sequestration site is known as “structural trapping”. It refers to the trapping of CO₂ below an impermeable rock that physically prevent the CO₂ from migrating to the surface (Miri, 2015). Because the injected carbon dioxide denser than the formation water, it will rise until it reaches the caprock. This effect is introduced by the buoyance forces. The CO₂ will not penetrate the caprock as it holds a capillary pressure greater created by the low permeability formation (Song & Zhang, 2013). A suitable caprock should have a sufficient thickness and a large lateral extent to ensure an effective seal with a greater strength to hold free CO₂ (Song & Zhang, 2013). Structural trapping aslo applies to hydrocarbons, where oil and gas is stored in the subsurface for millions of years. The most common structures for trapping are anticlinal formations and sealed fault bocks (Song & Zhang, 2013).

3.3.2 Residual trapping

Residual trapping refers to the “capillary trapped droplets of the injected CO₂“ (Miri, 2015). When CO₂ is injected, a buoyance forces will cause the carbon dioxide to move up towards until it reaches the caprock. As carbon dioxide is injected, a large CO₂ plume will be formed. During displacement, the front and tail of the plume will undergo a drainage and imbibition process, respectively (Hosseini & Jafarpour, 2012). In the front: CO₂ will force the saline water out of the pores. At the tail: the drained water will be absorbed by the porous rock. This

phenomenon will cause the some of the CO₂ to lose the connection with the plume. Consequently, CO₂ droplets are trapped and immobilized inside pores surrounded by water. The immobilized CO₂ saturation is safely stored within the medium due to capillary forces. When two immiscible fluids are in contact with each other in a narrow pore channel, the strong adhesive force of the wetting fluid will trap CO₂ droplet. To initiate a displacement of the trapped CO₂ droplets, the pressure needs to exceed the threshold pressure (Miri, 2015). The degree of trapping is controlled by several factors, especially the pore throat size, the interfacial tension, and the wettability (Ringrose, 2020).

3.3.3 Solubility trapping

Solubility trapping represents “the amount of CO₂ that is dissolved into the formation water” (Miri, 2015). The solubility trapping also account for dissolution of the trapped CO₂ droplets. With time the immobilized CO₂ droplets will dissolve into the water coating the pores. Solubility trapping is favorable in terms of effective and safe CO₂ storage as the CO₂ no-longer exist as a separate phase, eliminating the bouncy effect (IPCC, 2005).

Dissolution of CO₂ is explained due to the occurrence of three mechanisms: diffusion, convection mixing and chemical interactions (Miri, 2015). At the boundary of free gas phase and the formation water, CO₂ dissolves into the water until an equilibrium state is reached. This mechanism is referred to as molecular diffusion and is driven by the difference in the chemical potential (Song & Zhang, 2013). The diffusion mechanism will contribute to dissolve great amounts of CO₂ in gas phase into the formation water (Miri, 2015).

When CO₂ dissolves into the brine the mixture becomes slightly denser, approximately 1-1.5% higher (Miri, 2015). This will initiate a convection process. The CO₂- brine mixture will start to migrate downwards, as the solution has become heavier. It is pulled down due to the gravity. Subsequently, unsaturated formation water will rise and fill up the porous space. With time CO₂ will again dissolve in the water, pulling the solution down. This phenomenon is referend to as *convective mixing or density-driven mixing* (Miri, 2015). Moreover, solubility trapping can be explained by chemical interactions. The chemistry of the solution changes when CO₂ dissolves in water. The reactions are depicted in Equation 1-4 (Steel, Liu, Mackay, & Valer, 2016).



As CO₂ is exposed to the formation water it will form a weak carbonic acid, shown in equation 2.2. Adding more carbon dioxide will cause the equilibrium to shift to the right, increasing the concentration of carbonic acid. Because the carbonic acid is weak and unstable, it will dissociate, forming H⁺ and bicarbonate. This reaction will cause a rapid drop in the pH level as more H⁺ is present in the solution. Some of the formed bicarbonate will split into hydrogen and carbonate ions (equation 2.4). Divalent ions present in the formation water will attach to the carbonate ions and form solid carbon minerals. This process is referred to as mineralization and will be further described in the section 2.3.4.

3.3.3.1 Factors Affecting CO₂ solubility

The total amount of dissolved CO₂ in the brine is dependent on several factors such as the pressure, and temperature and salinity of the formation water (Song & Zhang, 2013). The rate of dissolution, on the other hand, is more dependent on the contact area of the plume and the undersaturated brine, as well as the diffusion process. (Miri, 2015). Figure 3.5(a) and 3.5(b) shows how the solubility will behave under increased pressure and salinity.

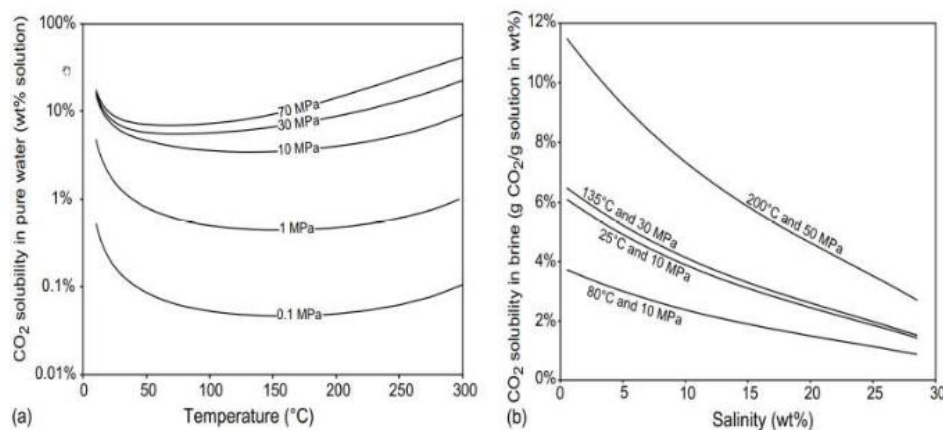


Figure 3.5: Variation of CO₂ solubility in water: (a) with temperature and pressure; and (b) with salinity, for various conditions representative of sedimentary (Bachu and Adams, 2003)

Figure 3.5 (a) illustrate the relationship between solubility, pressure, and temperature. Here, solubility is shown to decreases with temperature and increases with pressure. The observed effect can be explained by Henrys law (Belford, 2021):

$$C = k \cdot P \quad (3.6)$$

C represents the concentration; k is the Henrys law constant and P represents the partial pressure of the gas that dissolves.

The law states that the concentration of the dissolved gas at equilibrium is directly proportional to the partial pressure of the gas (Steel, Liu, Mackay, & Valer, 2016). Hence, if the partial pressure increases, the concentration of the dissolved gas will also increase. Furthermore, the figure shows that an increase of temperature will have the opposite effect. Temperature increases cause kinetic energy to rise, which causes intermolecular bonds to break. As a result, gas molecules will leave the solution. (Florida State University, u.d.). In a sequestration process, the objective is to store as much CO₂ as possible, thus CO₂ should be kept in the solution.

Figure 3.5 (b) shows that increasing salinity will reduce the solubility. When more salt is added to the water, less gas will dissolve due to the presence of electrolytes. The water molecules will be attracted to the salt ions reducing the number of free H⁺ and O²⁻ ions in the solution that can capture and disassociate the gas molecules (Steel, Liu, Mackay, & Valer, 2016). In addition, higher salinity levels will also lessen the convection mixing as the density change will be reduced (Miri, 2015).

3.3.4 Mineral trapping

“Mineral trapping is the process of incorporating CO₂ into a stable mineral phase through geochemical interactions with formation minerals and organic components” (Song & Zhang, 2013). As explained in the previous, some of the CO₂ will dissolve into the brine creating an acidic environment. This phenomenon will introduce multiple geochemical reactions that may alter the porosity and permeability of the host rock. The reactions are determinate by the rocks mineralogical composition and the species present in the formation brine. Some reactions may be favorable, assisting in chemical containment. Whereas others might introduce a risk of lowering the permeability in the region near the injectivity well (Benson & Cole, 2008). Hence, the time frame for the mineralization process is an important measure (Miri, 2015).

As presented in figure 3.4 (a) mineralization in saline aquifers are typically the slowest trapping mechanisms. It is not until 1000 year after the injection has stopped the trapping mechanism show a significant effect. This is due to the silicate-bound divalent metals needed for carbonate formations. These types of minerals have a low rock reactivity; thus, mineralization will be slow. (Snæbjörnsdóttir, et al., 2020) However, mineralization in basalt formation is much faster and will start to form within years. Mafic or ultramafic rock has a high concentration of reactive minerals that promotes in-situ carbonization. To achieve an even faster mineralization process, CO₂ is dissolved into water before injection (Snæbjörnsdóttir, et al., 2020). As seen in figure 3.4 (b), solubility trapping occurs as the first mechanism followed by mineral trapping. Because CO₂ is dissolved into the water at the surface before injection, the mineral trapping will serve as the major trapping mechanism.

3.3.4.1 Salt precipitation

Salt precipitation has shown to be a real threat to field scale CCS projects (Eiken et al., 2011) Numerous experimental and numerical studies have demonstrated the phenomenon's destructive impact on rock properties. (Miri, 2015; Nooraiepour, Fazeli, Miri, & Hellevang, 2019; Berntsen, et al., 2019; Hansen, et al., 2013) Salt precipitation can be explained by the incident when dry or undersaturated supercritical CO₂ is injected to a geological formation filled with water (Miri & Hellevag, 2016). When water evaporates, the formation water that is left behind will become highly salty (Miri & Hellevag, 2016). With time, the aqueous solution will reach its solubility limit as there is no available space the ions in the formation water to be dissolved. Once this limit is reached, salts will start to precipitate out of the solution and salt crystals will form in the porous medium (Nooraiepour, Fazeli, Miri, & Hellevang, 2019). Hellevang & Muri (2016) compared previous studies that had investigated the effects of salt precipitation on permeability. In contrast to the common perception of the concept (as explained above), they discovered two previous research papers that reported improved injectivity as a result of salt precipitation. Absolute permeability may be reduced during CO₂ injection due to salt precipitation. Simultaneously, evaporation of trapped water may provide more space for CO₂, increasing relative permeability. However, the following 12 studies investigated by Hellevag and Muri, found lower permeability when salt precipitation occurred. In addition, industrial experiences have shown a pressure increase in relation to salt formation (Hansen, et al., 2013)

4 Business model

4.1 European Emission Trading Scheme

An important driver for the CCS technology is the European Emission Trading Scheme (ETS). The trading scheme creates a financial incentive for emitters to cut back their CO₂ emissions. ETS is a cap-and-trade programme, where emitters are given limited allowances for how much CO₂ they can release to the atmosphere. Not all plants are regulated and monitored but the threshold for the regulations varies from industries and is based on the production capacity (European Commission, 2022). The regulated companies are given a fixed number of allowances to cover their emissions. If companies exceed the cap, they are faced with significant fines (European Commission, 2022). However, if the company does not use all its allowances, it has the option to sell or bank them. For instance, if a company has exceeded their cap, they can purchase allowances from other businesses. Hence, the allowances become the currency in the trading market. Over time, EU will gradually lower the cap causing a supply squeeze (Dechezlepretre, 2017). Because demand is not expected to decrease, the carbon price will increase. Subsequently, the cap-and-trade system will create a carbon market. As the price of emitting CO₂ to the atmosphere will increase, companies can justify investment in low carbon solution (Dechezlepretre, 2017).

4.1.1 ETS price development

The evolution of the carbon price is becoming an important measure for large emitters. With the numbers of assigned allowance being reduced every year, the carbon price increases. CO₂ emission will thus create a significant cost. However, investing in low-carbon technology is expensive. In order for the investment to lower the costs, it must be lower than the ETS price. Different companies have tried to predict the carbon price development. Figure 4.1 represents different price forecasts, where an overall increasing trend is observed.

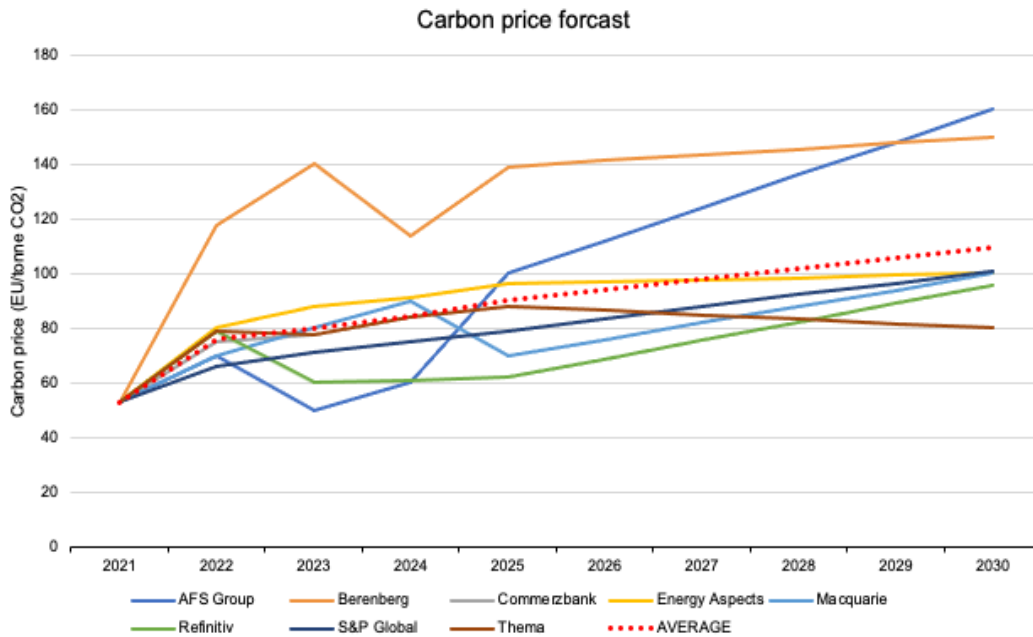


Figure 4.1: Comparison of different predictions of the carbon price (E. Wollebakk, personal communication, 13. May 2022)

4.2 CCS project execution

An important challenge for CCS development has been identifying the business model. No emitter can justify investing in capture technology without having a location for storage. Subsequently, the storage provider will not develop a sequestration site without knowing that there is a market for CO₂ to be stored (Northern Lights, 2021). This “chicken and egg problem” has raised the question of where CCS projects should start.

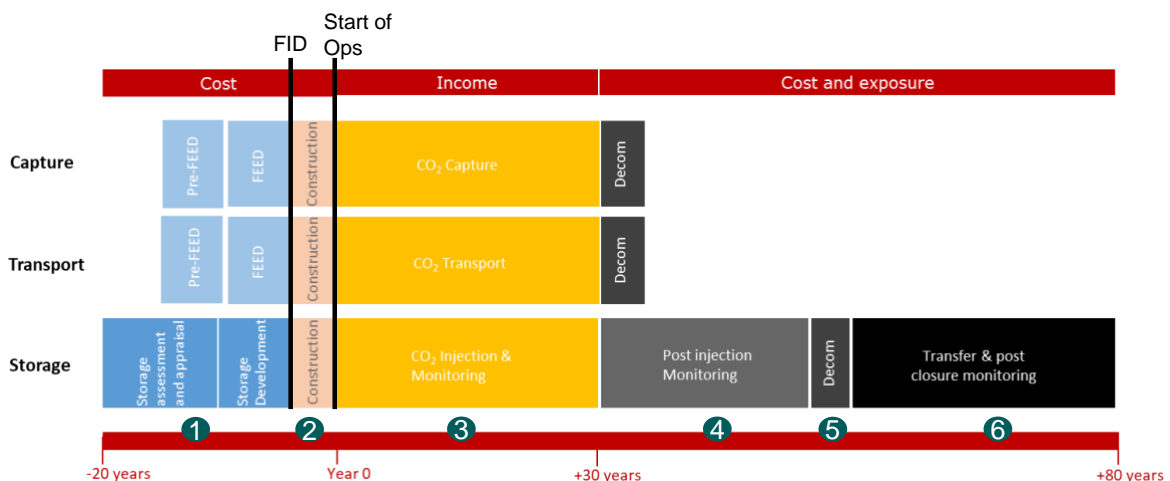


Figure 4.2: Illustration of a general CCS project development (T. Berly, personal communication, 13. May 2022)

However, from a technical perspective, the storage site should always be the initial step (T. Berly, personal communication, 13. May 2022). Without a reservoir there is no point of carbon capture. Figure 4.2 illustrates a general CCS project development. The figure is divided into six phases with capture, transport and storage separated into individual posts.

Phase 1 is represented by different studies evaluating the storage capacity, containment and injectivity. As seen in the figure, the projects start with evaluating the storage site. After a proper investigation of the feasibility of geological CO₂ storage, FEED studies for capture and transport are conducted in compliance to the identified reservoir parameters. In Phase 2, the Financial Investment Decision (FID) is made, representing the go/no go decision for the project. If the company has a belief that their investment will pay off, they will proceed with the project.

Phase 3 represent the operating time for the project. It is within this phase the income is generated. Companies will pay the operator for storing CO₂. To withstand a commercial feasibility, the price of CO₂ sequestration should be lower than the ETS price. Customer and sectors that serve a strong potential for CCS technology is typically cement plants, steel plants and bioenergy (Northern Lights, 2021). Decarbonization of these industries has proven to be difficult. For example, cement production is based on crushing rocks and burning rocks. When the rock is heated, a chemical process called calcination is initiated. This process causes CO₂ to be released from the rock (Norcem). Today, there are no sufficient materials or technologies that could replace cement. Thus, the cement industry serves as a good candidate for CCS.

Furthermore, Phase 4 include decommissioning of the capture and transport solutions. However, the storage site still needs to be monitored, proving that the CO₂ plume is contained within the reservoir. Monitoring is required for several years after production stop. Therefore, it is an important post for the financial calculations. Phase 5 and 6 represents the end of the project, where the operator hands over the monitoring responsibility to the government. From this point on it is the state that will cover the cost of monitoring.

4.3 The Northern Lights project

4.3.1 Background Overview

The Northern Lights project is part of the Norwegian government's full-scale CCS initiative. The project is scheduled to receive captured CO₂ from emitters in the Oslo area, for storage within a saline aquifer in the North Sea. The goal is to scale up production providing a CO₂ option for third-party companies all over Europe (Northern Lights, 2021). Figure 4.3 shows a conceptual sketch of the project. As seen in the figure, Northern Lights only handle transportation and storage. This will require emitters to invest in capturing facilities, creating a business opportunity for capturing companies. The Northern Lights project begins with large ships collecting the captured carbon from the emitters. The ships will transport and deliver the CO₂ to an onshore facility located at Øygarden Norway. Here the CO₂ will be temporarily stored in large tanks before it will be transported through a pipeline to the Aurora formation for permanent storage (Northern Lights, 2021). The Northern Lights project is a joint venture between Equinor, Total Energies and Norske Shell, all holding equal ownership of 33 %. The project has received a sufficient amount of funding both by the Norwegian State and EU (Norwegian Ministry of Petroleum and Energy, 2020).

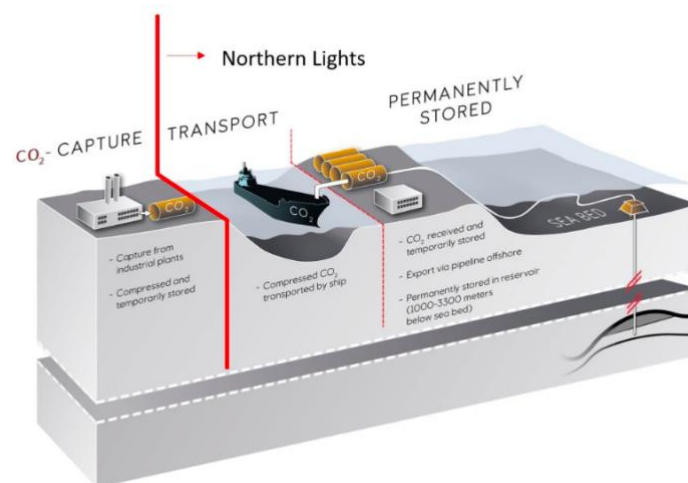


Figure 4.3. Northern Lights conceptual sketch (Equinor, 2020)

4.3.2 Project development

Northern Lights is responsible for developing and operating CO₂ transport and storage. Subsequently, the CO₂ is captured by the emitter itself. The project is divided into two phases. The first phase will prove the different characteristics and properties of the geological

formation. In phase 2 the capacity will be scaled-up to a commercial level. The development is illustrated by figure 4.4.

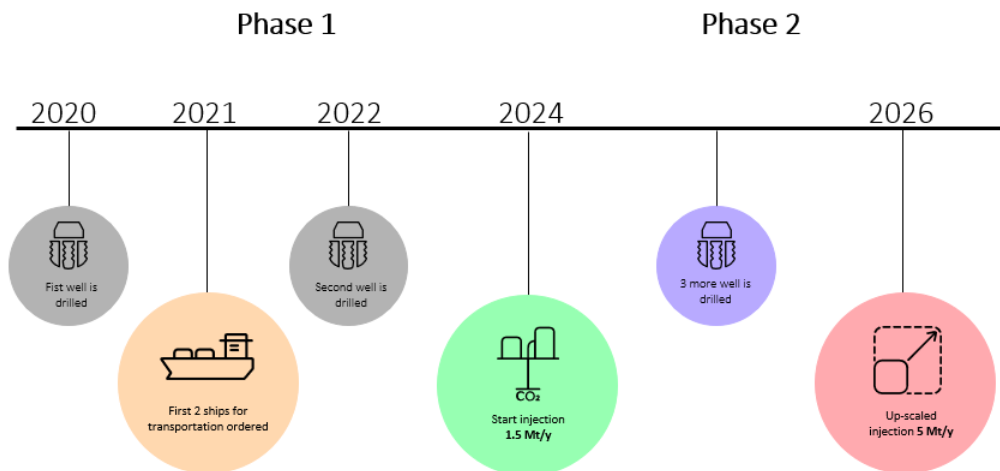


Figure 4.4: Illustration of Northern Lights project development

2.8.3.1 Phase 1

During phase 1 of the project, 1.5 Mt CO₂ will be injected per annum. Half of the injected CO₂ is sourced from two industrial plants in Norway, Fortum Oslo Varme (waste) and Norcem Brevik (cement). The remaining capacity is found from European customers. The construction of the infrastructure and ships started in 2021 and is expected to be completed by mid- 2024 (Northern Lights, 2021). The 2019 exploration well 31/5-7 will be converted into an injecting well. A second well is also drilled. Phase 1 is heavily funded by the Norwegian State, as they are responsible for 80 % of the investments made in the Longship project. This includes sizing the receiving terminal, offshore pipeline, and the umbilical to offshore storage site to accommodate for additional volumes (Northern Lights, 2021).

2.8.3.2 Phase 2

The goal of Phase 2 is to increase capacity to 5 million tonnes of CO₂ per year. Phase 1 sizing of the transport network has facilitated for increased injection rated. However, three additional wells must be drilled to reach this goal. The phase will be largely commercial funded. Phase 2 is highly dependent on an emerging CCS marked. The Norwegian State has helped to solve the "chicken and egg" problem discussed in section 2.7. With the scale-up, emitters will see CO₂ sequestration as a viable option, allowing investments in capturing plants to be justified. The ambition is to get Phase 2 operational by 2026 (Northern Lights, 2021).

4.4 Financial parameters

To build a cash flow analysis that investigates the cost of storage, a set of financial concepts must be introduced. This section will describe the equations used to measure the cost of storage.

4.4.1 Time value of money

“A dollar received today is always worth more than a dollar received tomorrow”

The time value of money is an important concept for financial calculations. It states that a sum of money is worth more now, than it will be at a later date because of the potential for earnings in the interim. Subsequently, the dollar received today could be reinvested and yield a greater earning (Fernando, 2021). To account for this concept, financial calculations convert future cash flows to present value. Meaning that a cost or income in the future will be converted to today’s value of money. This is done using equation 4.1.

$$PV = \sum_{i=1}^n \frac{C_i}{(1+r)^{t_i}} \quad (4.1)$$

C_i is the cash flow at year i , r is the discount rate and t_i is the time in years

4.4.2 Capital and operational expenditures

Capital expenditures (CAPEX) are any expenditures related to purchase, improve or maintain long-term assets. Long-term assets are often plants, property, buildings, or equipment. CAPEX is a term that is frequently used when starting a new project, and it refers to the cost of developing new buildings or factories. For CO₂ storage projects, this is related to costs from developing the pipeline system, injection platforms, well equipment etc. (Fernando, Capital Expenditure (CapEx), 2022).

Operational expenditures (OPEX) are all cost incurred during the operational stage of a project. The expenses are customary that keeps the business running. Common examples OPEX is wages and rent, utilities, and salaries (Ross, 2021).

4.4.3 Levelized cost

When companies are looking into the cost of an CCS project the cost is often “levelized”. This means that the cost is represented per tone CO₂ injected. This allows emitters of different size to easily calculate the overall cost of a carbon storage project (E. Wollebakk, personal communication, 13. May 2022). The levelized cost is calculated by dividing the project's present value by the present value of the CO₂ volumes stored. In addition, this thesis suggests a penalty cost. This cost represents the expenditures of CO₂ that has to be released to the atmosphere if geological storage is not possible for a short-time period. For instance, penalty costs can be imposed by well interventions or maintenance work.

Equation 4.2 represents the calculation of levelized storage costs.

$$\frac{\left(\sum_{t=1}^n \frac{I_t + M_t + WI_t + P_t}{(1+r)^t}\right)}{\sum_{t=1}^n \frac{M_{CO_2}}{(1+r)^t}} \quad (4.2)$$

I_t= Investment expenditures (CAPEX) in year t

M_t= Operational expenditures (OPEX) in year t

WI_t= Well intervention expenditures in year t

P_t= Penalty costs in year t

M_{CO₂}= CO₂ stored in year t

n= project lifetime

5 Geochemical simulations

In this chapter the geochemical simulation using the PHREEQC software is performed. First, an analysis of how different ions can affect the CO₂-water-rock interaction are investigated. Then the simulations of possible mineral precipitation at the Aurora field is conducted. The results obtained from the analysis will further be used as inputs for the scenario analysis.

5.1 Geochemical modelling approach

The simulation of mineral trapping was performed using PHREEQC- a geochemical simulation tool widely used for both at academic institutions and industries. The programme holds a large database with thousands of balanced chemical reaction equations. It allows for a variety of geochemical calculations and can solve complex problems using linear or non-linear system of equations (USGS, 2021). The PHREEQC software was selected for the thesis as it is capable of one-dimensional transport and batch-reaction to analyze the dissolution and precipitation of different components into the solution, ion-exchange, pH etc.

A conceptual diagram of the steps taken to evaluate how different ions will affect the mineral trapping is illustrated in figure 5.1. The environment and the input values used to develop this model is presented in step one and two. The model is run in step three and four. Finally, the results are visualized in step five.

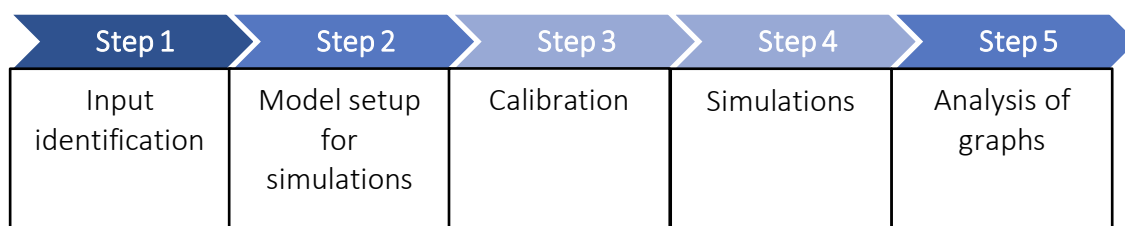


Figure 5.1: Method used to for the geochemical analysis

First, a detailed investigation of how different ions will affect the mineralization process was performed. In this simulation individual ions at different concentrations were dissolved into pure water to be exposed to a rock sample. Pure water was used such as no other species could interfere with the selected ions. In practice, the water-CO₂-rock interactions are very complex. Dissolution of one element can initiate dissolution or precipitation of another. For simplicity,

this thesis focusses on a set of pre-chosen ion, namely potassium (K^+), natrium (Na^+) and calcium (Ca^{2+}). These ions are chosen because they are commonly observed in the formation brine in geological sequestration sites.

5.2 Model set-up

To build evidence for the scenario analysis a simulation model was built to investigate the occurrence of mineral precipitation. Simulations were preferred over lab experiments as they can simulate independent of time. Geochemical reactions can take over thousands of years to equilibrate, whereas simulation models can equilibrate solution within seconds. In this work, a simple 1-D model at core scale was assumed for the simulations of the equilibrium of the CO_2 /brine/sandstone interaction during injection of carbon dioxide. The model is based on the local equilibrium for the mineral in the aqueous phase. This behavior is controlled by fast reactions, where the law of mass action is used to find the equilibrium composition of the system (Fatah, Mahmudad, Bennour, Gholami, & Hossain, 2022). This law is expressed by equation 5.1.



PHREEQC starts to model the chemical reactions of the formation water and the CO_2 from the chemical reactions in the database. This reaction will create an acidic environment causing minerals to dissolve/precipitate. The simulations were performed at 50 °C and for a pressure of 8 MPa. To ensure that the rock was completely saturated with CO_2 , 10 moles of CO_2 were injected. Figure 5.2 shows a conceptual diagram of the on-dimensional model of CO_2 injection into the sandstone.



Figure 5.2 Conceptual diagram of simulation, Modified from- (Fatah, Mahmudad, Bennour, Gholami, & Hossain, 2022).

Obtaining relevant reservoir data from the Aurora formations has been challenging. Equinor drilled an exploration well (31/5-7) in 2020 where four cores were cut into the well in addition to collecting fluid samples at different depths (Norwegian Petroleum Directorate, 2022). However, the mineral composition obtained from the cores has not been published. Data used to conduct the simulations was thereby collected from similar geological settings. was taken from the upper layer of the Shahejie Formation in the Dongying Depression, China. This study was chosen as the sample was taken from a saline aquifer at the similar depths as the Aurora formation. Because the initial mineral composition data is not collected directly from the Aurora saline aquifer, the simulations hold a great uncertainty. Thus, the quantitative values generated from the analysis is less important. However, the overall general trend of precipitation and dissolution is the main objective for the simulations. The mineral composition and amounts in mol used for the simulations are presented in table 5.3.

Table 5.1: Mineral compositions of the rock sample (Liu et al., 2019)

Mineral	Chemical Formulae	Amount [mol]
Quartz	SiO_2	0.588
Calcite	$CaCO_3$	0.133
K-feldspar	$KAlSi_3O_8$	0.025
Albite	$NaAlSi_3O_8$	0.025
Dolomite	$CaMg(CO_3)_2$	0.083
Pyrite	FeS_2	0.011
Anhydrite	$CaSO_4$	0.007
Ca- Montmorillonite	$Ca_{0.165}Al_{2.33}Si_{3.67}O_{10}(OH)_2$	0.005
Kaolinite	$Al_2Si_2O_5(OH)_4$	0.036
Chlorite	$Mg_5Al_2Si_3O_{10}(OH)_8$	0.001
Illite	$K_{0.6}Mg_{0.25}Al_{2.3}Si_{3.5}O_{10}(OH)_2$	0.021

Moreover, the fluid samples from the exploration well 31/5-7, have been publish. The analysis was conducted by Intertek for Equinor. The simulations conducted is built on the formation water composition at 2743.5 m depth from this report. The reservoir temperature was not defined in this report and was also challenging to obtain. Therefore, the values were obtained from different studies analyzing the Aurora reservoir (Wei and Saaf, 2008; Massoudi et al., 2021). Wei and Saaf (2008) used an initial aquifer temperature of 100 °C to estimate the storage capacity of the Johnson formation. As mentioned in chapter 2 section 2.3, the Aurora formation consists of both the Cook and Johansen formations and is separated by a permeable shale. More recent studies conducted by Massoudi et al. (2021) claims to have improved input values for

both the upper (Cook) and the lower (Johansen) reservoirs. The study applied a min/max temperature of 95 and 110 °C, respectively. Based on these findings, the reservoir temperature was assumed to be 100 °C. Table 5.2 gives the data collected for the analysis of the solubility of the Aurora saline aquifer. Based on the input data used by Massoudi et al. (2021), the pressure is assumed to be 270 bar for the aquifer. The equilibrium model set-up was assumed to be the same as for the evaluation of the different ions present in the solution.

Table 5.2: Formation water composition (Intek laboratory report at depth=2743.5MD)

Initial solution- Aurora field	
temp [°C]	100
pH	6.1
pe	4
redox	pe
Na [mg/l]	17 700
Ca [mg/l]	6 640
Mg [mg/l]	601
Ba [mg/l]	380
Fe [mg/l]	0.1
Sr [mg/l]	687
K [mg/l]	4 590
B[mg/l]	48.1
Cl [mg/l]	45 600

5.3 Mineral trapping results

First, a detailed investigation of how different ions will affect the mineralization process was performed. Secondly, the mineral trapping for the Aurora formation was simulated with the same model set-up, but in this simulation the Aurora formation water (presented in table 5.2) was utilized. The primary goal was to see how the mineralogy was altered because of the injected CO₂.

5.3.1 Calibration

The model set-up for the simulation of mineral precipitation and dissolution was calibrated against a study performed by Liu et al. (2019). The initial mineral composition was also collected from this study. Figure 5.3 represents the comparison of the results from the Liu et al. (2019) and the result generated with the built model used in this thesis. Because the selected

ions are added to pure water, only the NaCl=0 mol/L simulations from Liu et al. (2019) were compared to the PHREEQC model. From figure 5.3 show a good correlation between the models. However, there are some differences in the amount of dolomite precipitation. Approximately 20 mmol precipitated in the Liu et al. (2019) study and only 1 mmol precipitated in the built equilibrium batch model. This could be explained by the different versions and databases used in PHREEQC.

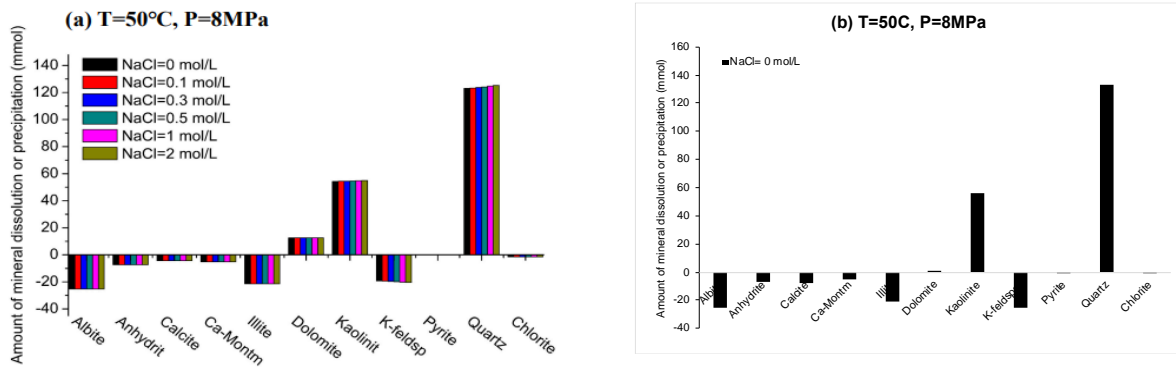


Figure 5.3: Comparison of mineral trapping simulation (a) Mineral dissolution and precipitation from Liu et al. (2019). (b) Mineral dissolution and precipitation from equilibrium batch modelling

5.3.2 Individual ions

In order to establish an understanding of the initial mineral composition, simplified simulations were performed. Individual ions, namely potassium (K^+), natrium (Na^+) and calcium (Ca^{2+}), at different concentrations were dissolved into the water. The solution was further exposed to CO_2 and the mineral composition of the rock. The aim for these simulations was to get a first impression of how the ions present in the formation water will affect the mineralization process. The simulations assume a reservoir temperature of $50^\circ C$ and a pressure of 80 bar based on the study conducted by Liu et al. (2021).

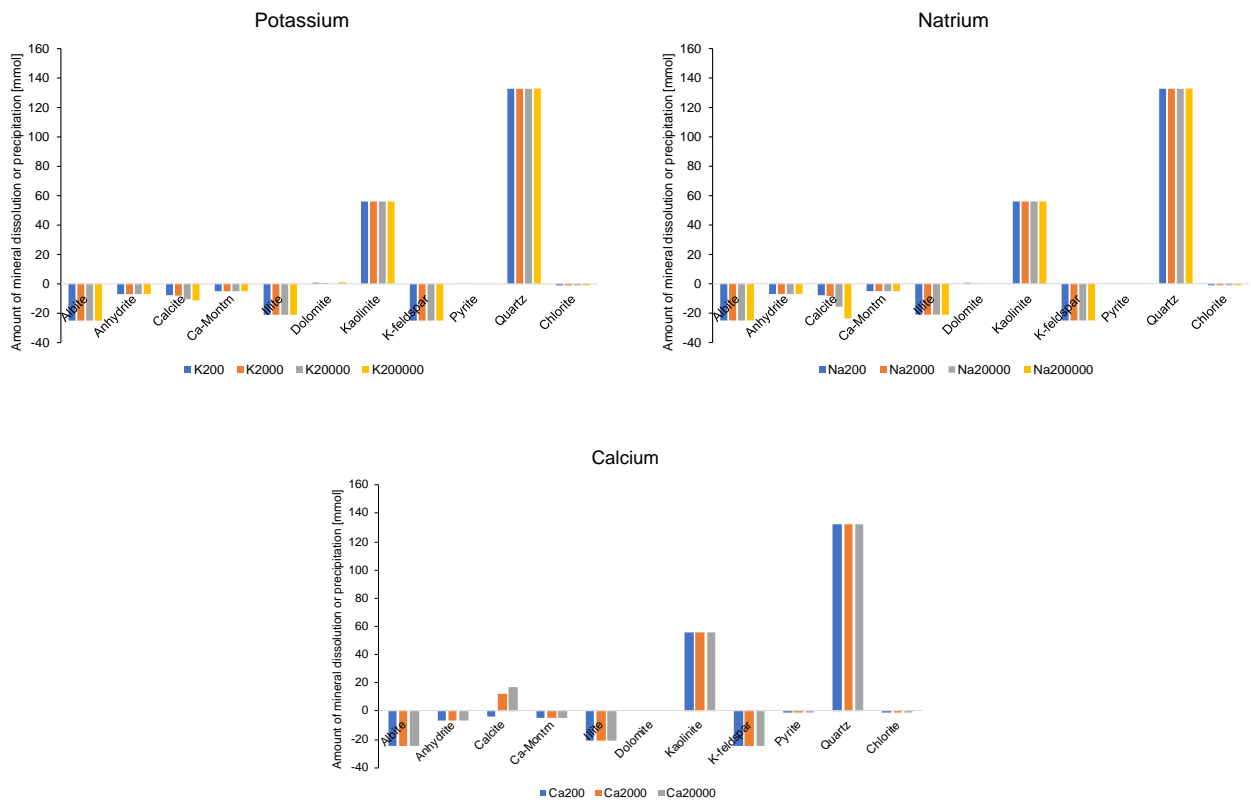
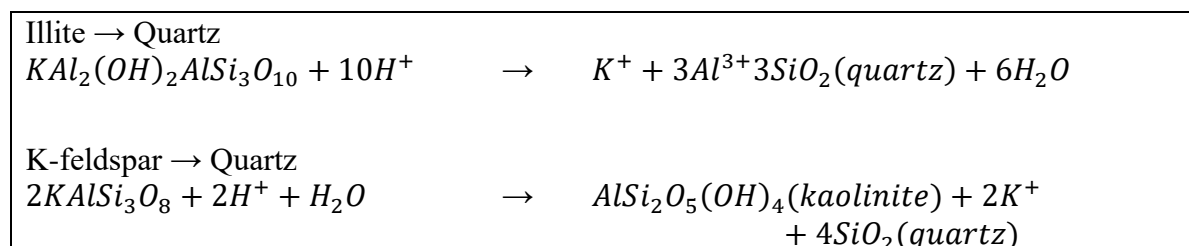


Figure 5.4: Mineral trapping with individual ions in the solution at T=50°C and P=8MPa

Figure 5.4 presents the results from the simulation of single ions present in the water. In general, crystals of albite, anhydrite, calcite, Ca-montmorillonite, illite, k-feldspar and chlorite dissolved; crystals of kaolinite and quartz precipitated. There was no observed change in the pyrite concentration. Pyrite- FeS_2 , which is made up of iron and disulphide, is a hard mineral/metal it is difficult to dissolve (King, n.d.) In addition, the initial pyrite concentration was low, thus the impact of pyrite dissolution/precipitation was minimal.

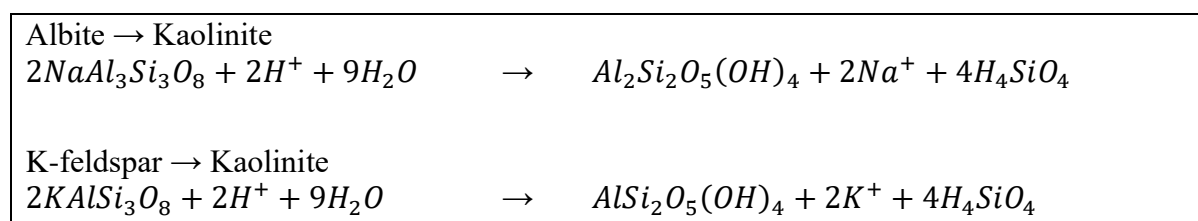
The precipitation of kaolinite and quartz was observed in all the simulations. Quartz, being the most reactive mineral, resulted in a significant amount of precipitation. The free silica-particles, coming from dissolved illite and k-feldspar will attach to the quartz surface. Illite and k-feldspar will dissolve due to the acidic environment imposed by the carbon dioxide reacting with water (Fatah, Mahmud, Bennour, Hossain, & Gholami, 2021). Table 5.3 represents the chemical equation where the dissolved illite and k-feldspar leads to quartz precipitation. In all three simulations represented in figure 5.4 the amount of quartz precipitation is approximate 135 mmol.

Table 5.3 Quartz precipitation



The behaviour of kaolinite was also consistent in all the simulations represented in figure 5.3, where approximately 56 mmol precipitated. This can be explained by the dissolution of albite and k-feldspar. The dissolution of such minerals will introduce more silica molecules into the solution. As a result, kaolinite will start to precipitate. The reaction is described in table 5.4 (Fatah A., 2021)

Table 5.4 Kaolinite precipitation



In the following a brief explanation of the observed trends in figure 5.3 in respect to the ionic concentration, is reviewed.

For the different concentrations of potassium (K) the entire output of albite, anhydrite, Ca-montmorillonite, illite, K-feldspar and chlorite dissolved. Quartz and kaolinite precipitate, 132.7 mmol and 56 mmol, respectively. Calcite is the only mineral that is altered by the ion concentration. High concentrations of potassium showed to improve the calcite dissolution. The improvement is, however, not significant, ranging from 7.7 mmol at K=200 ppm to 11.3 mmol at K= 200 000 ppm.

Sodium ions at different concentration caused the initial moles of albite, anhydrite, Ca-montmorillonite, illite, K-feldspar and chlorite to dissolve. While quartz and kaolinite precipitated. From figure 5.3 a increase in calcium dissolution is observed for higher sodium

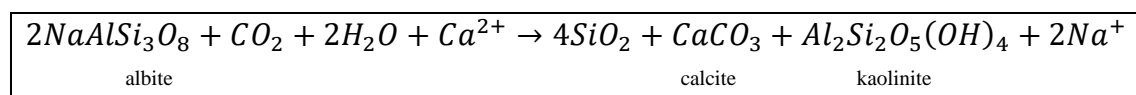
concentrations. For Na=200, 2000, 20 000 and 200 000 ppm calcite dissolved by 7.76, 8.32, 15.57 and 23.55 mmol, respectively.

Calcium (Ca) ions in the solution dissolved the initial concentration of albite, anhydrite, Ca-montmorillonite, illite, K-feldspar and chlorite. The PHREEQC- software was not able to simulate the Ca 200 000 ppm, as the values generated showed very unlikely events of dissolution and precipitation, consequently this result was ignored from the plot. The amount of calcite precipitation gradually increased with an increasing concentration of calcium ions in the solution. For instance, concentrations of Ca 2000 and 20 000 ppm in the solution caused 12.5 and 17.2 mmol to precipitate, respectively. However, for Ca 200 ppm, calcite dissolves. This can be explained by the water's capacity to dissolve ions. When the concentration is low, the calcite ions will be trapped in the aqueous solution. As the ionic concentration increases the water will be saturated with a limited amount and the rest will be used in different chemical reactions. Thus, if the concentration of Ca^{2+} ranges from 200-2000 ppm, the behavior of dissolution/precipitation is unknown. For concentrations greater or equal to 2000 ppm calcite will most likely precipitate. Calcite precipitation is related to the high concentrations of calcium in the solution reacting with carbonates ions. As CO_2 is exposed to the water it will form a weak carbon acid will be formed, this explained in chapter 3 section 3.3. This acid is unstable and will start to form bicarbonate that will easily bind to the calcium ions. Equation 5.1 shows the chemical formula of the described reaction



In addition, dissolved albite will react with the calcium ions and cause calcite to precipitate. This is exemplified in the equation below (Gaus, Azaroual, & Czernichowski-Lauriol, 2005).

Table 5.5: Albite dissolution



5.3.3 Aurora Formation

The equilibrium model built in this chapter was adapted to fit the reservoir conditions for the storage site used in the Northern Lights project. As described in section 5.2, the initial mineral composition used for the simulations was not obtained from the actual reservoir but collected

from a comparable host rock (Liu et al., 2019). The temperature is assumed to be 100 °C and the pressure was set to 270 bar, as argued in section 5.2.

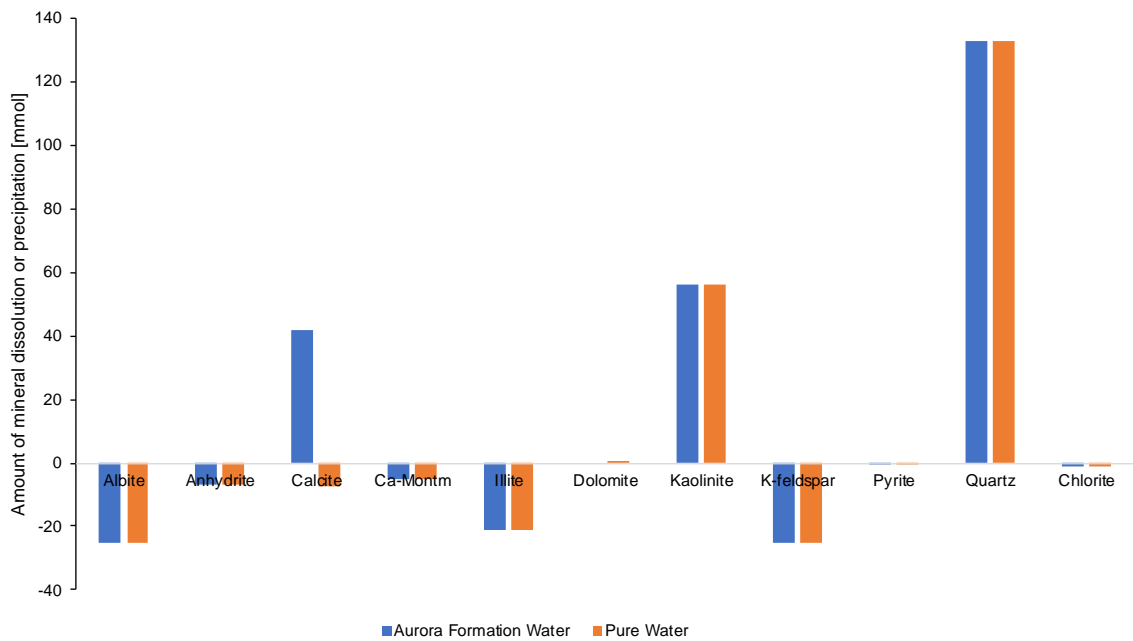


Figure 5.5.: Mineral trapping Aurora formation

Figure 5.5 show the mineral trapping for the Aurora formation. In the figure, the behavior of the minerals for different solutions are compared. The temperature and pressure conditions are the same for both simulations.

For the Aurora formation water, the initial composition of albite, anhydrite, ca-mom., illite, k-feldspar and chlorite dissolves. Calcite, kaolinite, and quartz precipitates. In comparison to the pure water, the same amount dissolves, and precipitates for all the minerals except calcite. The simulation with pure-water dissolves 7.7 mmol of the while for the Aurora Formation Water, 42 mmol precipitates. The behavior can be explained by the findings in section 5.3.2 where individual ions in the formation water was investigated. As observed from these simulations, calcite will most likely precipitate for Ca^{2+} concentrations greater or equal to 2000 ppm. From table 5.2 the formation water contains approximately 6640 ppm of calcium. Hence, the behavior is in compliance with the results in chapter 5.3.1.

As shown in the simulation, calcite will precipitate. Calcite precipitation can, as explained in chapter 3, aid the storage safety as mineral trapping is the safest form of storage. Under the

circumstances that the calcite precipitates in the outer parts of the reservoir. Consequently, it will contribute to contain the plume within the reservoir. Or it could potentially cause the permeability near the wellbore to decrease. If the precipitation happens fast enough, the CO₂ plume will not have moved towards the outer points of the reservoir where the mineralization process would be favorable. Instead, calcite might cause clogging of the pores near the injection well (Fatah, Mahmud, Bennour, Hossain, & Gholami, 2021).

6 Cost evaluation

In this chapter an economic evaluation of different mitigation strategies is performed. The objective is to investigate if the mitigation strategies will be economical viable for CCS operations. The cost of mitigating the different causes of injective reduction is high. For instance, drilling a new well is expected to cost 1140 million NOK (Norwegian Petroleum Directorate, 2022). Hence, the opportunity of not taking any measures might be more favorable in an economic perspective.

Moreover, a cost evaluation was chosen over a net-present value analysis as the uncertainties regarding the Northern Lights income is very high. Because operations are not expected to begin until 2024, there is no income statement for the project.

6.1 Scenario development

Based on the TIA approach described in section 2.4.1, a stepwise process of building the scenarios was performed. The method was adapted to fit the scope of the study. For instance, it was not possible to calculate curve-fitting functions to extrapolate the trend as there does not exist a dataset of geological unexpected events. Every reservoir and field are unique and has individual properties. Furthermore, probability measures were not taken in consideration as it was evaluated as a too complex task. Table 6.1 outline the process of developing the scenarios.

Table 6.1. Stepwise description of scenario development

	Description
Step 1. Historical data	First an extensive research of historical injectivity of CCS fields was conducted. Both NPD and Equinor contributed and shared their experience of the incidents at Sleipner and Snøhvit. Moreover, multiple papers and books was reviewed to build a knowledge bank and understand the causes and mitigations of the geological unforeseen events.
Step 2. Simulation modelling	The mineralogical behaviour of the Aurora formation was investigated by numerical simulations. First, an effort was made to understand the solubility in the field as dissolution of CO ₂ into the formation water is the primary driver for mineral changes. The behaviour of different ions was investigated for a general set-up to build understanding of the geochemical parameters. With this the mineralisation trend of the Aurora formation was studied, showing evidence of calcite precipitation.
Step 3. Scenario building	Based on the findings in step 1 and step 2. A list of unexpected injectivity events was developed. However, as the work of this thesis is limited by time, only three scenarios were chosen for the cost analysis.
Step 4. Probability measures	No probability measures were calculated in this thesis. The data base for this thesis does not allow to establish any probability measures

6.2 Scenario description

Based on the findings in chapter 3 and 5, three different scenarios were developed. It is important to clarify that scenarios are not predictions, but rather a method to evaluate different versions of the future (Duniker & Grieg, 2006). Based on an extensive review of field analogies and geochemical simulation the following scenarios are selected.

6.1.1 Scenario 1- Salt precipitation

Scenario 1 builds on the unexpected salt precipitation at the Snøhvit field. The scenario assumes that salt will clog the pores only months after the production start. The two wells in phase 1 of the field development, is damaged by this incident. The salt precipitation is observed by a pressure increase, such as Hansen et al. (2013). Because the operator had observed this effect in the Snøhvit project, the mitigating treatment was performed before significant injectivity losses. The mitigation consists of injection of MEG-water (Ringrose, 2020). It is assumed that the operation takes 40 days and fully dissolves the salt. There are no further issues with injectivity.

6.1.2 Scenario 2- Sand influx

Scenario 2 is based on the injectivity challenges experienced at the Sleipner field. The drilled wells during the development of Phase 2 of the project experience an injectivity reduction of 20% due to sand influx. In order to improve the injectivity, a gravel pack is installed (Ringrose, 2020). The installation is assumed to take 30 days. However, the gravel packs need to be replaced every 4 years (Khomehchi, Ameri, & Alizadeh, 2015).

6.1.3 Scenario 3- Calcite precipitation

Scenario 3 is built on the concerning calcite precipitation observed in the geochemical simulation for the Aurora formation. For this scenario it is assumed that the calcite forms near the wellbore, clogging the pore throats near the well (Torsæter and Cerasi, 2018). Phase 2 in the Northern Lights project involve drilling three new injection wells. In this scenario the three wells are faced with heavy calcite precipitation. The injectivity is lowered by 10% in the first one year of production. In year 2 of production the injectivity decreases by another 10%. To aid the development acidic treatment is used to dissolve pore throats clogging behaviour of the

calcite. The treatment will create wormholes branching outwards from the injection point (Torsæter and Cerasi, 2018). It is assumed that acid must be injected every 4 years with a down-time of 40 days (Castle et al., 2004).

6.1.3 Scenario 4- 10% Injectivity reduction

This scenario was created to investigate the incident of not mitigating the injectivity challenge. For this scenario it is assumed that the injectivity is reduced 10%. However, there is no significant pressure build up allowing the operator to inject at lower rate as there is no risk of fracturing the seal. In reality, the injectivity will gradually be reduced as more minerals will precipitate. Nevertheless, an average of 10% was expected in this scenario

6.3 Data collection

The financial input parameters for the analysis are found from open-source reports, and they are thus a subject of high uncertainty. However, they provide an indication of future consequences in terms of justifying investments in well interventions. There is also uncertainty in regard to the currency changes. Because the input values had different currency, they were converted to EU. The following values in table 6.2 have been fixed during the economic assessment.

Table 6.2: Initial values for the Pre-Tax Present Value calculation

Initial values for the Pre-Tax Present Value calculation	
OPEX (Phase 1)	209 million NOK ¹
CAPEX (Phase 1)	5975 million NOK ²
Operational lifetime	25 years
CAPEX (New well)	1140 million NOK ¹
Discount rate	8 % ¹

¹ DNV-GL The Norwegian Full-scale CCS Demonstration Project (Figure 12)

² Longship – Carbon capture and storage, Section 8.1.4 Investments and economics (p. 76)
Rate used for converting EU to NOK: 10.5 and USD to EU: 0.93 [25.05.2022]

6.3 Assumptions

Given the variations in the scenarios the following assumptions were considered with regards to the levelized cost estimation.

1) Project execution

- a) The injection starts mid- 2024 (Northern Lights, 2021).
- b) The captured CO₂ delivered from the customers are pure. Thus, there are no risk associated with the delivered CO₂ from third parties.
- c) The project injects at full capacity for the operational lifetime

2) Contracts

- a) Northern Lights commits ownership of the contracted CO₂. This means that if the storage facility fails, they are still responsible for the CO₂. Thereby, all risk associated with storage is assigned to them
- b) If the storage operation fails to inject the contracted volumes, Northern Lights are faced with a penalty of paying ETS price for the volumes that are released into the atmosphere.

3) Project expenditures

- a) CAPEX for development of Phase 2 is set to be 50% CAPEX for Phase 1. CAPEX assumed to reduce as the cost of reservoir modelling, field development, temporary storage units and pipelines are already established in Phase 1
- b) OPEX is tripled in Phase 2. Three new injection wells are drilled, increasing the operational costs
- c) Penalty costs are calculated by utilizing the “Average Carbon Price” forecast presented in figure 4.1 from 2021-2030. After 20230, it is assumed that the ETS follow the linear growth trend and increase by 4% each year. A maximum price cap is set to 150 €/ton CO₂ (Wollebekk E., personal communication, 13. May 2022).

4) Financial parameters

- a) Investments prior to 2022 is said to be sunk costs. The cost is in the past and cannot be changed/reversed. The decision to invest in operations for improving the injectivity is not affected by these sunk costs (Ross S., Westerfield R., Jaffe J. and Jordan B., 2018)
- b) Depreciation is not included. Not relevant for the scope of the analysis, only direct cost associated with down-time and intervention operations is included

- c) Tax is ignored. The Norwegian Directorate of Taxes concluded that payments associated with the development of Northern Lights should not be considered as taxable services (Skatteetaten, 2020)

The scenarios build on a quick mitigation of the injectivity challenges. However, different causes come with different expenditures. These are presented in table 6.3. Moreover, the time associated to mitigating the cause of injectivity reduced is referred to as “down-time”. This analysis assumes that the operator must pay a penalty for the volumes that should have been stored during the downtime. Because they are not able to be stored, they will be emitted into the atmosphere.

Tabel 6.3 Different mitigation measures and the associated cost

Mitigation solution	Cost [pr. well]	Duration	Source
MEG water	4.5 million NOK/day	30 days	(Eiane L., personal communication, 13. May 2022)
Acid treatment	1.6 mill USD/day	30 days *	(Caslte et al. 2004)
Gravel packs	8 mill \$/day	40 days*	(Khamehchi, Ameri, & Alizadeh, 2015)

* Must be replaced or re-injected every 4 years

6.4 Levelized cost

A pre-tax present value analysis was built to investigate the economic impact of mitigation solutions for the occurrence of reduced injectivity. The different assumptions and cost associated used in the analysis, have been addressed in the chapters above. With the identified expenditures and assumption, the levelized storage cost was calculated with equation 4.2. The levelized cost represents the cost of storage per ton of CO₂. The findings are illustrated in figure 6.1.

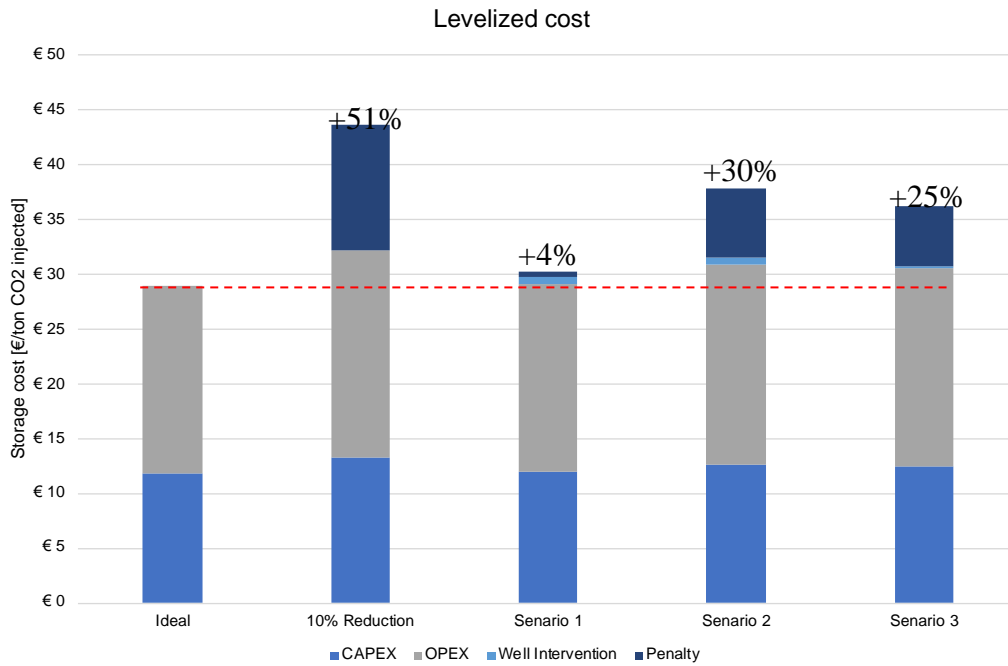


Figure 6.1 Levelized cost for the different scenarios

Scenarios with injectivity issues will be faced with a penalty fee. As described in section 6.1.4 the model assumes that Northern Lights commits ownership of the contracted CO₂. This means that if the storage facility fails, they are still responsible CO₂. When the captured CO₂ cannot be injected to the formation it will be released to the atmosphere. Thus, if the Northern Lights project has contracted storage of 5 Mt CO₂/y they are responsible for this quantity. When injectivity is reduced, they are not able to inject these scheduled volumes, the penalty cost arises. Moreover, if the storage operator chose to mitigate the injectivity challenge a production “down-time” will be introduced. The “down-time” is the period where acids or gravel packs are installed, hence CO₂ cannot be pumped into the reservoir. A penalty fee must also be accounted for in these scenarios. The fee is calculated by subtracting the scheduled 5 Mt CO₂/y with the actual injectivity (this varies with the different scenarios) and multiplying this volume by the ETS price for the given year.

Mitigating solution to increase injectivity is referred to as well interventions. In the previous section the different scenarios and solutions was described in addition to the associated cost. For example, in scenario 1 it is assumed that salt precipitation clogs the nearby well and MEG-water is injected at a cost of 270 million NOK. In addition, the wells cannot inject CO₂ for one month introducing the penalty fee. This investment must be justified to the stakeholders. In this

evaluation well intervention cost only covers the cost of treatment. The downtime is accounted for in the penalty fee calculation.

From figure 6.1, the ideal scenario shows the cost of storage with no injectivity issues during the production would result in a cost of 29 €/ton of CO₂ injected. For a 10% reduction in the injectivity, the cost will increase to 44 €/ton. If, mitigation is available such as for scenario 1, scenario 2 and scenario 3, the cost of storage will be lower than the 10% reduction scenario. In conclusion, undertaking mitigating measures to avoid reduced well injectivity, will cause storage cost to be lower than not acting (DNV GL, 2020).

The Norwegian Full-Scale CCS Demonstration Project report by DNV (2020), investigates the specific costs related the Northern Lights project. This report found the storage cost for offshore saline aquifer reservoirs to be approximately 250 NOK/ton. In comparison to the ideal storage cost calculated in this thesis of 29 €/ton (approximately 290 NOK/ton) the cost evaluation model based on open access sources show small deviations from other more comprehensive reports DNV report.

A next scenario where no measures were taken to mitigate injectivity challenges was also investigated. The scenario assumed an overall 10% reduction in injectivity throughout the project lifetime. This was done to compare it to the scenarios where mitigation strategies were implemented to see if the investments would pay off. In figure 6.1, the evaluated scenarios are compared to the event of doing nothing resulting in a 10% injectivity reduction. Here, the only the additional cost is the penalty fee. The results show that not mitigating injectivity challenges will increase the storage cost by 51% compared to the ideal case. Both levelized CAPEX and OPEX increase because less volumes are injected to the formation. In comparison to the evaluated scenarios, not implementing mitigation strategies will result in the highest storage cost, even though the mitigation solutions come with high costs and down-time.

In Scenario 1, precipitation is observed by a pressure increase. Because the operator has evaluated the risk of such geological events, it is possible to start the mitigation measures. However, the operation comes with a down-time of 30 days introducing a penalty cost. In addition, mitigation measures cost 270 million NOK. From figure 6.1, the levelized cost of storage does not increase significantly even though large investments and a penalty cost is introduced. The cost increased from 29 € to 30 €, resulting in a 4% cost increase. The total cost

increased by a 2% increase due to well intervention and a 2% increase generated from the penalty fee, compared to the ideal cost of storage. The low additional cost can be explained by the fact that the incident was mitigated prior to injectivity reduction.

In Scenario 2 the well injectivity is reduced by 20% during the first year of production. This is assumed to happen for the three wells drilled in phase 2. The mitigation measures need to be replaced every 4 years and comes with a cost of 14.8 M€ per intervention. The operation takes 30 days to complete per well. From figure 6.1, the cost of storage for scenario 2, is 38 €/ton CO₂ injected. This is a 30% increase from the ideal scenario. The cost increase originates from the penalty fee imposed during the completion operation. Such cost is responsible for 22% of the cost increase, compared to the ideal scenario cost of storage. Moreover, because less volumes are injected in this scenario the levelized CAPEX and OPEX will increase. The well intervention generated a 2% increase of the total cost of the ideal scenario cost.

In Scenario 3 the injectivity is lowered by 10% in the first one year of production. In year 2 the injectivity decreases by another 10%. Then mitigation measures will require a down-time of 40 days per well and a cost of 4.5 M€ per intervention. As observed in figure 6.1, the cost associated with the intervention has no significant impact, as it only accounts for 1% of the cost increase. However, the down-time of the operation will introduce a high penalty cost. The scenario resulted in a total cost of 36€/ton CO₂ injected, a premium cost of 25% compared to the ideal scenario. 19% of the additional cost compared to the ideal scenario cost, is related to the penalty fee and only 1% is related to the cost of the acidic treatment.

7 Discussion and future work

Global warming is a key concern for human society and anthropogenic emissions must be reduced. Extreme weather events, such as flooding, droughts, wildfires, and hurricanes, are becoming more frequent and intense. This has motivated governments, companies, industries, and others to set ambitious net-zero emission goals. For example, Equinor and EU have shown such initiatives. In the following their climate goals are presented:

- Equinor (2022) is targeting a 50 % reduction in operating emissions by 2030. In 2050 they aim at being a net zero company, cutting all emissions from production and final consumption (Equinor, 2022).
- The European Commission (EU) reports that they aim to become the world's first climate-neutral continent by 2050 (European Commission, 2022).

To aid the development towards a net zero emission future, CCS has shown a great potential. Hence, the attached technology has gained substantial interest from various stakeholders (Stephens & Van der Zwaan, 2005; NRF, 2021). Because renewable energy options are currently not able to supply the world's energy demand, hydrocarbons are still an important source to energy. Nevertheless, there is still a need to minimize the CO₂ emissions. CCS technology will thus be a key driver allowing for a more sustainable transition period (Singh, 2013, s.921; UNFCCC, 2014; Sognæss & Peters, 2020). However, CCS projects come with substantial expenditures and involve knowledge of various areas. For example, the storage site requires geologists, reservoir, and drilling engineers, whereas chemistry and process engineers are required for capture operations. Hence, the startup phase has proven to be a challenging task to implement outside of the petroleum industry.

The Northern Lights project being the world's first CCS project with third-party customers, will contribute to realize carbon capture and storage concepts. The project will cover the majority of the value-chain as both transport and storage is delivered by Northern Lights. For this project, the investments are justified by governmental funding and the large quantities of CO₂ to be stored. Here, the aim is to store 5 Mt CO₂ per annum. In comparison, the Northern Light project will inject five times the amount that is currently being injected at the Sleipner

field. This will cover approximately 10 % of the total Norwegian emissions. (Norwegian Ministry of Finance, 2018)

One of the important drivers for CCS is the financial incentive. As illustrated in section 4.1.1 and by figure 4.2 the carbon dioxide emission taxes are expected to rise. It is therefore of relevance to obtain low cost for the Northern Lights CCS project. The objective for this thesis was to investigate the cost impact of mitigation measures. In the thesis five scenarios has been analyzed to see the economic impact injectivity issues. A scenario analysis approach is a widely used methodology for events that is hard to assign probability measures (Duniker and Grieg, 2006). The exploration well, EOS 31/5-7, was drilled to collect relevant data from the reservoir. However, any meter-scale core-samples from the sandstone only represent a small fraction of the total reservoir (Aabø, Dramsch, Würtzen, Seyum & Welch, 2020). Due to the lack of data from the Aurora formation, scenarios of geological unforeseen events must be investigated. The selected scenarios are based on historical analogs from Snøhvit and Sleipner and a geochemical simulation based on the specifics of the Aurora formation.

7.1 Geochemical simulation

Scenario 3 was developed based on the geochemical simulation performed in chapter 5. However, as the analysis of the core samples was not published, a compatible rock sample collected from Liu et al. (2019) was used. As observed in the analysis, the mineral composition has a large influence on the dissolution and precipitation. It was the dissolution of albite that initiated the calcite precipitation. Subsequently, if the actual mineral composition of the Aurora formation only holds small amount of albite, the interactions might be very different.

Moreover, an equilibrium batch modelling was utilized to simulate the precipitation. The method is useful to form a first impression of how the initial concentration will develop as CO₂ is injected. From chapter 5, there was observed a significant amount of calcite precipitation. However, the models do not provide details about time and distance. Calcite precipitation can, as explain in chapter 3, aid the storage safety as mineral trapping is the safest form of storage. If the calcite precipitates in the outer parts of the reservoir, it will contribute to contain the plume within the reservoir. Subsequently, if the calcite precipitates close to the cap rock it can increase the sealing ability of the rock (Torsæter and Cerasi, 2018).

Scenario 1 could also benefit from performing a geochemical simulation to build more evidence around this case. Hence, a secondary mineral precipitation should be investigated. The likelihood of halite precipitation is significant for the Aurora aquifer as the formation water is very salt, containing high concentrations of Na^+ and Cl^- . As explained in section 3.3.4.1, evaporation regime dries out the brine present inside the pores causing halite crystals to form (Nooraiepour, Fazeli, Miri, & Hellevang, 2019). Hence, models of halite precipitation should be included in the further study.

7.2 Historical injectivity challenges

Both scenario 1 and 3 was based on historical injectivity challenges from Snøhvit and Sleipner, respectively. The injectivity reduction in both projects was initiated by different causes. At Sleipner, a sand influx reduced the injectivity significantly, which served as the basis for scenario 3. The project was faced with sand- influx due to the unconsolidated Utsira sand formation. However, the Sleipner storage formation, is located at shallower depth than the Aurora prospect which is found at 2800 m below the seabed (Pawar et al., 2015; Northen Lights, 2021). Because mechanical compaction will increase with increased burial depth, the Aurora formation might have a lower chance of sand influx (Marcussen et al., 2008).

The experiences from Snøhvit, showed that salt precipitation could cause significant pressure increases. However, for the event of salt precipitation it can be observed before causing any injectivity reduction (Hansen et al. 2013). Thus, the cause can be mitigated prior to its consequences on the injectivity. In this thesis MEG-water injection proved to be a relatively cheap mitigation measure. However, these costs identified from the specific Snøhvit field holds a great uncertainty. For future application these costs should be adjusted to the Aurora prospective.

7.3 Scenario evaluation

The cost of mitigation measure might become significant for future injectivity reduction scenarios at the Aurora formation. In chapter 6, it is stated that well interventions require large investments. For instance, injecting MEG-water to dissolve salt crystals came with a cost of 270 million NOK and a down-time of 30 days. As discussed in chapter 6, the ideal scenario

shows the cost of storage with no injectivity issues during the production would result in a cost of 29 €/ton of CO₂ injected. For a 10 % reduction in the injectivity, the cost will increase to 44 €/ton. If mitigation is taken, such as for scenario 1, scenario 2 and scenario 3, the cost of storage will be lower than the 10 % reduction scenario. In conclusion, if measures are taken to mitigate the cause it cost will be lower than not acting if injectivity is reduced by 10%.

As described in chapter 6, the penalty cost associated with the down-time to complete well interventions is the main driver for the increased cost. As observed in scenario 1 and 2, the penalty cost imposed an additional 22 and 19 % compared to the ideal scenario cost, respectively. To reduce the cost of downtime, invest in additional tanks for short-term storage could be made. This could enable the CO₂ to be stored while the well intervention was performed, to be injected at a later stage. Furthermore, simple planning can also contribute to reduce the cost. The scenarios that require measures that must be replaced within a fixed period can allow for strategic planning of the operation. For example, cement factories often have long-term contracts with constant production volumes and emissions. However, gas to power projects is often more affected by seasonal changes. In the cold winter months, more electricity is needed compared to the warm summer months (Aasen, E.Y., personal communication, 5. May 2022). Subsequently, if the well interventions are performed when the storage volumes are low, the penalty fee might be reduced. It is also important to mention that the penalty fee was calculated using the “average carbon price” in figure 4.1, that represents a forecast of the carbon price. The development of the ETS is uncertain and depends on many variables such as the technology development and the CO₂cap set by EU. With respect to this, it would be interesting to calculate the cost outcomes with different estimations of the carbon price introduced by not being able to inject the CO₂ into the geological formation.

Furthermore, the scenarios were based on different assumptions of injectivity reduction. For instance, scenario 2 assumed a 20 % injectivity reduction during the first year of production, scenario 3 assumed first a 10 % decrease followed by a 10 % decrease the next year. Lastly, the 10% reduction scenario was based on an average reduction by 10 % each year. These percentages are only assumed and not validated. Hence, they hold a great amount of uncertainty. A reservoir simulation of the permeability impact of the different scenarios might have been possible. This would have allowed for more specific measures of the permeability reduction so the volumetric losses could have been more accurate. However, with the limited time this would have been beyond the scope of the thesis.

In this thesis the constructed scenarios 1, 2 and 3, are compared to the event where no mitigation measures are taken. With no such measures taken, it is assumed that the overall injectivity will be reduced by 10 %. This is however a very general assumption as it does not specify the cause of the injectivity reduction. If a specific cause is identified, a reservoir simulation could calculate the reduction more accurately. It is therefore interesting to see how much the injectivity should be reduced in order to justify the scenarios of paying upfront investment to mitigate the cause of reduction. Using the “What-if” built-in command in Excel, these critical injectivity reductions was found. The results are presented in table 7.1. In scenario 1, 2 and 3, an additional cost is imposed by both the cost of treatment and a penalty. However, for the scenario where no measures are taken, the only additional cost will be penalty. The table 7.1 shows how much the injectivity must be reduced in order to justify investing in well interventions. For example, if scenario 2 occurs, but the injectivity reduction is only 3 %, the operator should not take any measures as the upfront investments would cause a 6,25 % price increase in relation to not perform any mitigations measures. On the other hand, if the reduction is greater than 6,25 %, mitigation measures should be taken to achieve the lowest cost of storage. Since the scenarios investigated in this thesis were compared to an overall injectivity reduction of 10 %, the most favorable option was to invest in mitigation measures.

Table 7.1: Minimum injectivity reductions to justify mitigation measures

Senario 1	0,89 %
Senario 2	6,25 %
Senario 3	5,27 %

For further improvements of the scenario analysis, a risk estimation should be conducted. This will allow for investigation of which scenario is more likely to happen during the Northern Lights project. However, this thesis indicated that preparing for injectivity problems is more favourable in terms of limiting the cost of storage if compared to injectivity reductions larger than 10 %. The approach and results might be of interest to the stakeholders and should be analyzed further.

7.3 Recommendation for further work

This section summarizes the recommendations mentioned above:

- Risk analysis to evaluate the likelihood of the geological events

- Include various carbon price estimations
- Further analyses to investigate the effect of operational planning in order to reduce down-time during well intervention.
- Further geochemical simulations
 - Quantify the permeability reduction in order to calculate the specific volumetric losses caused by the geological features
 - Identify the mineral composition specific to the Aurora formation
 - Build a kinetic batch simulation model to identify when and where the calcite will precipitate
 - Simulate secondary mineral precipitation

8 Conclusion

As global warming is a key concern for human society, anthropogenic emissions must be reduced. Carbon capture and storage has proven to be suitable in the pursuit towards a net zero emission future. The Northern Lights project is pioneer for CCS development and will be critical for the growth of the industry. Other CCS projects such as Snøhvit and Sleipner have shown that it is critical to plan for unforeseen geological features. The success of the Northern Lights project may be enhanced by drawing on this experience.

The scenario analysis presented in this thesis, based on previous field experience and geochemical simulations, has shed a light on the economic consequences of injectivity reductions. The aim of the research was to investigate if up-front investments for mitigation measures can be justified. Three different scenarios with different causes of injectivity reduction have been explored and compared to the ideal case where no measures are needed, as well as the scenario of an overall 10 % injectivity reduction. A pre-tax present value analysis with data collected from open-access sources was used to calculate the cost of each scenario. As a result, investing in mitigation measures to improve the injectivity rate for such events caused an increase in the cost of storage by 4 %, 30 % and 25 %, respectively. These results indicated that mitigating injectivity problems is to a larger extent more favourable than not investing in mitigation measures, compared to an overall injectivity reduction of 10%. For injectivity reductions less than 10 %, the up-front mitigation investments will to a lower degree be worth the expense.

9 References

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