CO2 Storage – Group Design Project

GROUP 6 (JOHANSEN B)
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Project objectives

The main objective of the project given in course TPG42566- CO_2 storage is to design a full chain offshore CO_2 storage project, starting from industrial plants to capture the CO_2 before emission to the atmosphere, to the transportation stage where different approaches can be utilized, ending up with storing the transported CO_2 to a possibly permanent geological storage site. The annual rate of 5 million tonnes of CO_2 needs to be injected in a chosen reservoir for 20 years, meaning in total, there should be a reservoir with a capacity of at least 100 million tonnes of CO_2, undoubtedly in reservoir condition. The scope and methods in the project that needs to be answered are the following:

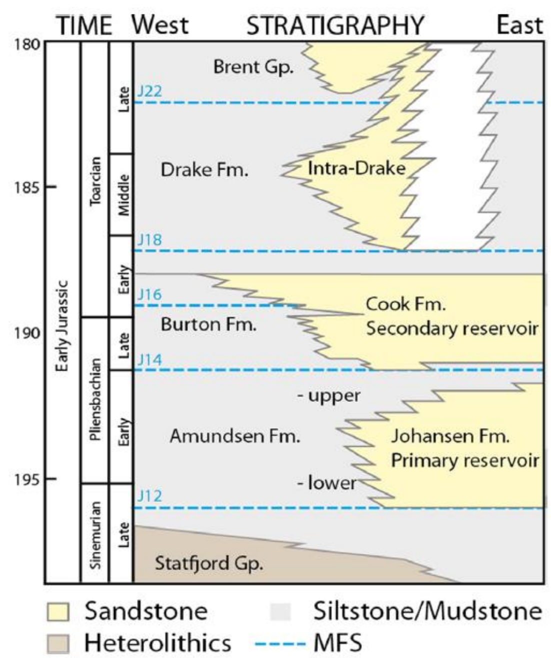
- The design should cover transport from the outlet from an onshore capture plant to an offshore platform situated over the selected storage site.
- Use analytical or semi-analytical methods and assume an ideal reservoir geometry
- The selected sites are chosen based on the site selection exercise, where the geology of the site should be based on published 'type wells or nearby exploration wells
- The design should specify pressures, flow rates, basic well design and number wells, and the compression stages from the capture plant to the wellhead and down to the reservoir
- The design should estimate the effective storage capacity, expected pressure limits and the expected storage efficiency for the chosen well placement system
- A reservoir monitoring programme should be specified.
- Key project uncertainties and risks should be identified.

Everyone in the group has made an effort to meet all the tasks with reasons and arguments. To reach our goals, we tried to have different assumptions depending on the task, which is fair given that we had little tools available at our disposal. The project has been divided into different sections, where in all the tasks have been answered. The sections are the following:

- Johansen Formation Geology
- Reservoir Analytical Interpretation
- Capture Plants and Transportation
- Well Design and Compression Stages
- CO_2 flow process
- Reservoir Monitoring Plan
- Uncertainties and Risks
- Final evaluation

1. Johansen Formation Geology

The Johansen Fm. consists of the fine-grained sandstones and siltstones, creating a large westward- and northward- prograding and wedging sandstone body represented as an extensive delta (Marjanac, 1995). The Lower Jurassic Johansen Fm. sandstones (Dunlin Gp) depicts shallow-marine deposits at the Horda Platform (Vollset & Doré, 1984). Multiple interlayers of siltstone and mudstone with low porosity values are detected within the Johansen Fm. associated with flooding events (Sundal et al., 2016). The observed siltstone/mudstone interlayers are witnessed laterally over a kilometre scale. Frequent calcite cemented sandstones (carbonate layers) have been recognized mainly <1 m thick within the Johansen Fm. (Sundal et al., 2015). The Johansen Fm. has more than 2000 m depth, extending west into the northern Viking Graben area.



The crest of this formation is nearly 2300 m in-depth, with porosity and permeability values of 15-24% and 100-1000 mD, sequentially (NPD, 2014). The Johansen Formation is always associated with another formation called the Cook Formation dominated by sandstone tongues interfingering with the Drake mudstones at several distinct stratigraphic levels (NPD, 2014). The Cook Fm also overlies stratigraphically above the Johansen Fm, which in some parts of the Horda Platform entirely lies on the Johansen Fm. In some other parts, it is separated by the shaly Amundsen Fm. (Lothe et al., 2019). According to CO2 Atlas for Norwegian Continental Shelf, good reservoir properties in the Troll Field have been shown by the Johansen Formation, where the NPD suggested the southern part of the Troll Field as a potential storage site.

In addition to that, the studies done by Sundal et al. (2015, 2016) has shown that the Johansen Formation can be granted as a proper reservoir for CO2 storage for various reasons. The Johansen Fm. is capable of high residual trapping, accompanied by CO2 dissolution in formation water with 50% immobilizing CO2 over a relatively short-term period (150 years). The Johansen (including Cook) Formation is a part of The Dunlin Group, is deposited in a marine setting and is composed of two shaly units containing sandstone

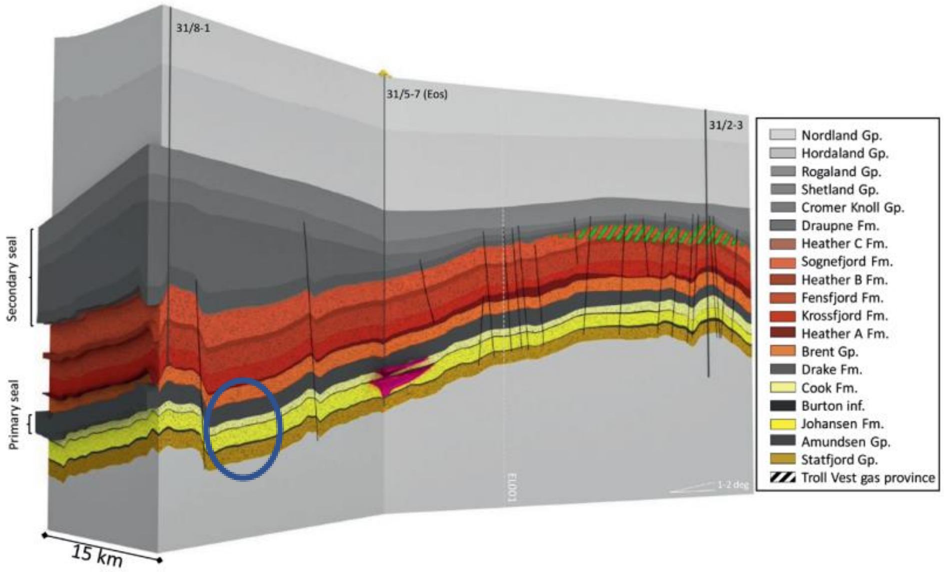


Figure 1-2. Cross sectional view of the Dunlin Group including the Johansen and Cook Formations as the reservoir units, with theDrake Formation as the secondary sealing unit followed by the shallower sealing unit on top (Furre et al., 2020)

wedges: the Amundsen Formation interbedded with the Johansen Formation, and the Drake Formation interbedded with the Cook Formation. The 'Burton' formation is used to distinguish the uppermost occurrence of the Amundsen Formation (Furre et al., 2020). It was decided to inject in the compartment west of that highlighted in figure 1-2. Therefore, it was needed to find type wells near that region to help us identify the type of formation in that area and its properties. The closest type well with sufficient information on the Johansen Formation was well 31/2-3 in the Troll Field. Gassnova published the data in 2012. This well could represent the compartment we want to inject in since it has the same stratigraphy and layer deposition, however it has a different structure and might differ in porosity and permeability.

Figure 1-3 represents the top of the Johansen formation, the top of the latter varies between 2100m & 3200m (measured from the mean sea level). The well 31/2-3, highlighted in blue, is drilled through the part of the Johansen formation, which lies at approximately between 2000m and 2100m. Our site of interest for injection lies to the south of that area (highlighted by the red circle) and is at a depth between 2800m and 3100m. Therefore, the reservoir quality and its most crucial porosity and permeability properties will probably vary between those two sites. Hence, we cannot use the data from the core or logs from the well 31/2-3 and apply them to the area of our interest to carry out our analysis and calculations. We found the data on the Eos type well 31/5-7, closer to the site we want to use for an injection operation. As shown

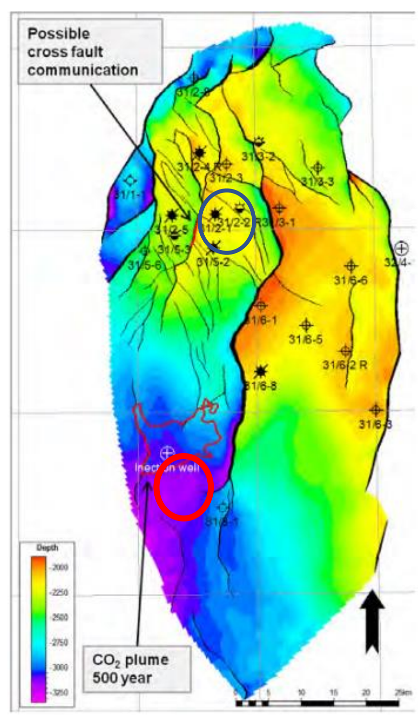


Figure 1-3. Top of the Johansen Formation (Gassnova, 2012)

in figure 1-2, the Eos well was drilled in an area south of the Troll Field as a confirmation well to test the Dunlin Group (Furre et al., 2020). Since this well was drilled through an area with the same stratigraphy and structure, which is favourable for us, it can be pretty representable of our selected storage site. To further learn about the formation in that area, we looked at the logs that ran in that well and tried to compare the findings from the logs to the cores extracted from that well. The confirmation well found fairly good quality Cook and Johansen formation sandstones. A good overview of formation tops and the respective depth of the formations of interest and their overlying and underlying shales are shown below.

Drake 2	2479	2510	2510
Drake 1	2532	2563	2563
Drake Intra Marine Shale Acoustic marker	2553	2585	2585
Cook 4	2607	2638	2638
Cook 3	2607	2638	2638
Cook 2	2611	2642	2642
Cook 1	2654	2685	2685
Burton	2664	2695	2695
Johansen Fm. 4	2671	2702	2702
Johansen Fm. 3	2710	2741	2741
Johansen Fm. 2	2721	2752	2752
Johansen Fm. 1	2735	2766	2766
Amundsen	2787	2818	2818

Figure 1-4. Dunlin Group formation tops (Equinor, 2020)

Note that if the Burton formation is mainly a shale, which seems to be about 5-7 m in thickness, it can act as a barrier to the rise of the CO2 plume if decided to inject in the lower part of the Johansen formation. The buoyant and capillary forces would then be of great importance when it comes to overcoming the entry pressure of the Burton formation to allow the CO2 plume to rise towards the Cook formation. So, the nature of the Burton formation will play a significant role in dictating the dynamics of the CO2 plume and the storage efficiency of the site that we have chosen. This, however, would be discussed at a later stage.

Figure 1-5 indicates the gamma-ray log curve of interval 2640- 2830 m, which is of interest. Looking at figure 1-5, one can observe the cook formation being relatively a clean sandstone; however, the Johansen formation is completely clean, given that the gamma-ray readings in that interval are relatively high. The gamma-ray log for the Johansen interval at the first site indicates a shaly sandstone interval, with a thin shale layer at a depth of 2750-2755 m (in comparison to the Burton shale layer's gamma reading). Then a relatively clean sandstone below that gets shaly again while transitioning into the Amundsen Shale layer. To ensure that, we went to the core analysis report to check the spectral gamma-ray of the core plugs extracted from that interval. The purpose of doing so was to check whether the high gamma-ray signal results from the shale (high gamma-ray readings from Uranium) or other radioactive sources such as Potassium, which can be found in sandstone formations. Snapshots of the intervals of interest from the spectral gamma-ray log are shown below. Note that high readings from Uranium indicate the presence of shale or a shaly formation, and high readings from Potassium indicate that the high total gamma-ray readings result from Potassium present in the formation.

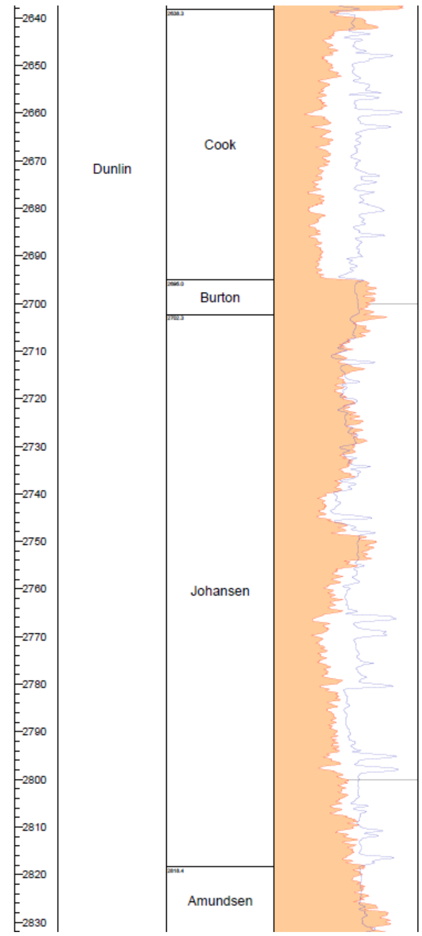


Figure 1-5. Interval of interest log (Equinor, 2020)

The spectral gamma-ray shows that the cook formation is relatively clean; however, we can see an increase in the gamma-ray curve in the Burton formation. The increase in gamma-ray is due to an increase in the spectral Potassium and Uranium values, indicating that the Burton formation is probably a mix of siltstones and mudstones. Throughout the Johansen interval, one can see relatively higher potassium spectral values than that found in the cook formation, which is the main reason behind the increase in the total gamma-ray counts ($GR_{Cook} < GR_{Johansen}$). At a depth of 2745 m in the Johansen formation interval, there exists an increase in the spectral Potassium and uranium values compared to the upper part of the Johansen formation, and then a decrease in those values to the normal values encountered in the upper Johansen part. According to Sundal et al. (2015), multiple interlayers of siltstones and mudstones within the Johansen and Cook formations are observed. This explains both formations' high potassium readings and relatively essential uranium readings, especially in the Johansen formation. As shown in the Spectral gamma-ray curves, the heterogeneity is more evident in the Johansen Formation than in the Cook Formation. The Burton formation is shown to be a mix of silt and mudstones with high sealing capabilities. Therefore, the Burton formation between the Cook and the Johansen formation shouldn't be disregarded and assessed as a "net" interval in the "Net to Gross" ratio. Thus, the noticeable increase in the gamma-ray reading in the Johansen formation is probably due to a mudstone rich layer that may act as a barrier within the formation (from 2748 m-2755 m); hence, it should be disregarded as a "net" interval within the Johansen formation interval.

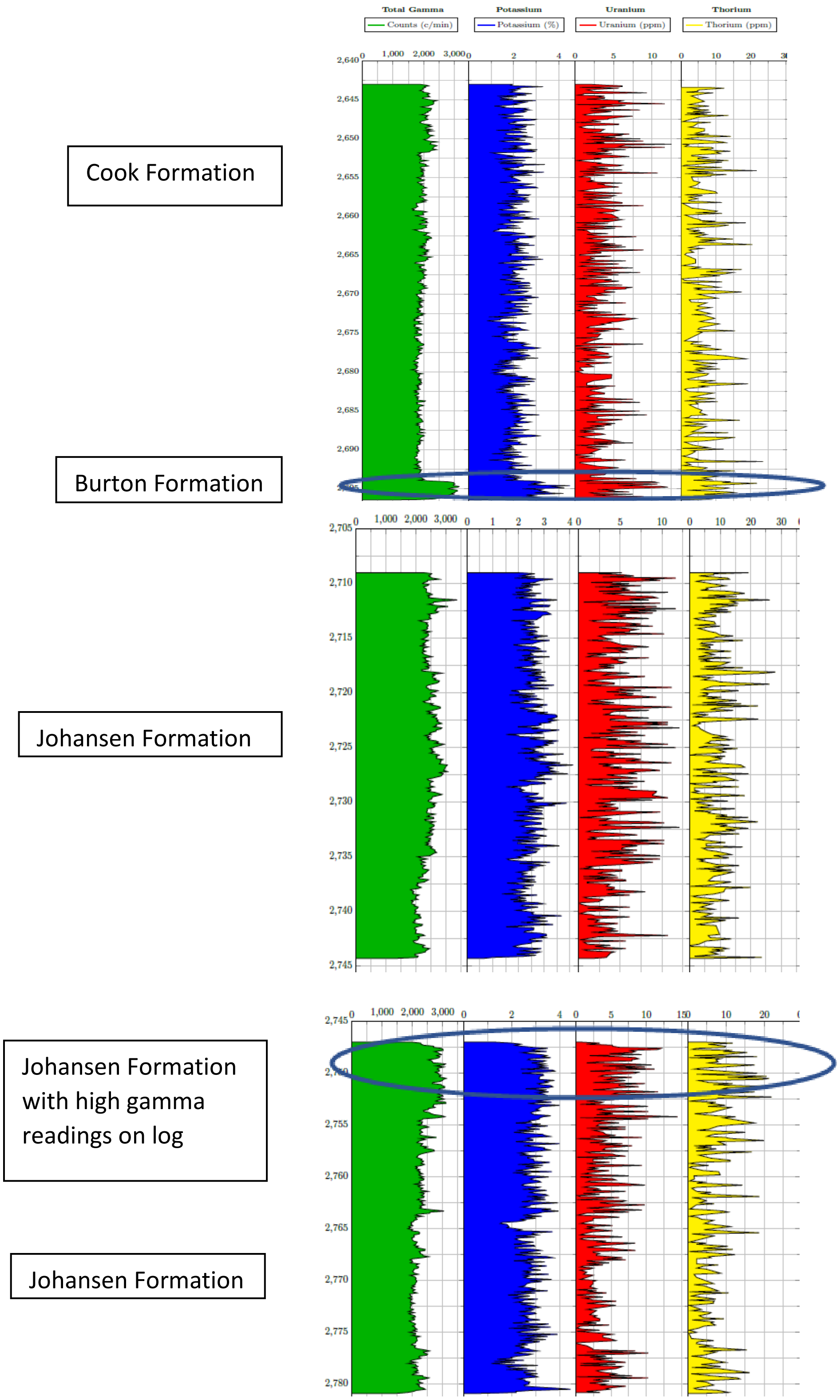


Figure 1-6. Spectral gamma log for the interval 2640 - 2780 m (Equinor, 2020)

2. Reservoir Analytical Interpretation

The Equation that is used to calculate the mass of the CO_2 that can be stored in the site of interest is shown below:

$$M_{CO2}(kg) = A\,.\,h\,.\,\phi\,.\frac{N}{G}\,.\,\rho_{CO2}\,.\,\varepsilon\,.\,(1 - S_{wirr})$$

M_{CO2}: Mass of the CO_2 stored (kg)

A: Area of the site (m^2) h: Total thickness of site of interest (m)

ϕ: Porosity

$\frac{N}{G}$: Net to Gross ratio

ρ_{CO2}: density of the CO_2 (kg/m^3)

ε : Storage efficiency (fraction)

S_{wirr}: Irreducible water saturation (fraction)

$M_{CO2}\ (Mt) = M_{CO2}\ (kg)\,.\,10^{+9}$

				Core Data				
Formation tops	Depth (m TVD MSL)	Depth (m TVD RKB)	Depth (m MD RKB)	Core No.	Depth(m)	K(H)mD	K(V)mD	Porosity(H)
Cook 1	***2654***	***2685***	***2685***	Core 02	2643.00 – 2696.42 m	1152	797	20.7
Burton	2664	2695	2695					
Johansen Fm. 4	2671	2702	2702					
Johansen Fm. 3	2710	2741	2741	Core 03	2709.00 – 2744.28 m	394	283	25.5
Johansen Fm. 2	2721	2752	2752					
Johansen Fm. 1	2735	2766	2766					
Amundsen	2787	2818	2818	Core 04	2747.00 – 2780.90 m	953	840	19.5
Eriksson	2801	2832	2832					

Table 2-1. Core analysis report summary (Equinor, 2020)

After acquiring the average porosities of each of the Johansen and Cook formation from the cores extracted through the type well (EOS), finding the irreducible water saturation for the Johansen formation (the same saturation value for the Cook formation were assumed), and taking into account the "net"

Formation	Net Thickness	A (m2)	Total Thickness	N/G ratio
Cook Formation	57	40000000	57	1
Johansen Formation	109		116	0.94

Total thickness of Johansen Formation - Siltsone layer thickness in the middle of Johansen

Swir	Storage Efficiency	Density CO2 (kg/m3)	Mass CO2 (kg)	Mass CO2 (Million tons)
0.2	0.3	830	3.13E+10	31.300
			7.38E+10	73.827
				105.127

Table 2-2. Storage capacity estimation for both the Johansen and Cook formations

thickness of each of the Johansen and Cook formation based on the analysis of the log data acquired above, a first estimate on the mass of CO2 that can be stored is obtained. The mass of the CO_2 we want to store, which amounts to 100 Mt, is impossible with our first initial values ($\varepsilon = 0.1, S_{wirr} = 0.337$), since we got a total of 26.152 Mt that can be stored. Therefore, we have decided to assume a smaller $\mathrm{S_{wirr}} = 0.2$ and much larger storage efficiency of $\varepsilon = 0.1$ in order to get the total mass of CO_2 stored shown above. A storage efficiency of 0.1 is quite high for a CCS project, however it is needed for us to reach the goal of storing 100 Mt of carbon dioxide in the subsurface.

We believe that $\varepsilon = 0.1$ can be reached if the mobility ratio can be decreased. We proposed the "Composition Swing Injection" in which CO_2 can be injected with some control over the CO_2 front, in which segregation and fingering can be reduced. The composition of the injected stream would be changed and manipulated to reduce the gravity override, hence the gravity to viscous ratio; therefore, this will lead to a more uniform gas-water front, further increasing the sweeping efficiency around the injection area. The property of the stream can be designed in a way to lower the viscosity and density contrast in the reservoir, leading to an enhanced storage capacity.

3. Capture Plants and Transportation

A vital component of a CCS scheme that is often overlooked is the transportation system. Carbon dioxide can be transported between capture points and storage sites by pipe, road tanker, or ship. CCS logistics will likely develop into a combination of pipelines and ships for long distances, similar to the transportation of natural gas and pipes and tankers for shorter distances. However, the significant difference is that natural gas is a product with high commercial value. Optimized transport solutions that dynamically follow volume developments are required. Fast-to-implement and low-CAPEX ship transport could be used to work in tandem with pipeline schemes. The carbon dioxide is transported in the dense

Table 3-1. Typical conditions and properties across the shipping chain

Properties	Units	Typical LNG	Typical CO_2 buffer storage and transport by ship	Typical CO_2 buffer storage and transport by road	Typical CO_2 transport by pipelines
Fluid	–	Liquid	Semi-refrigerated liquid	Semi-refrigerated liquid	Semi-refrigerated fluid (dense phase)
Density	kg/m^3	450	1163	1078	838
Density ratio (liquid/gas)	–	600	568	545	424
Pressure	MPa (gauge)	0.005	0.65	2	7.3–15
Temperature	K	113	221	243	293

or supercritical phase. Operating in this regime reduces viscosity and surface tension while increasing density. This is, therefore, the most efficient way of transporting carbon dioxide by pipeline; also, this phase transition leads to very effective use of the pore space as CO2 in the subsurface occupies a much smaller volume than at the surface.

In the case of transportation of CO2 by ship (or by road or rail-freight tanker), the CO2 is compressed to be held just above the boiling line (Fig. 3.3), with smaller shipping solutions opting for higher pressure and higher temperature (e.g. around − 20 °C and 20 bar for ships of around 1000–2000 tone). But for larger-scale shipping with larger tanks, the pressure needs to be reduced, requiring chilling the CO2 to around −45 °C. The CO2 will then need further compression at the storage site to reach the required injection wellhead pressure. These transport and surface handling solutions for CO2 storage operations all use established technology. However, a good appreciation of phase behaviours is essential. Because real CO2 capture streams are not pure and have minor impurities (e.g. CH4, H2S and H2O), the accurate determination of the phase behaviour becomes more challenging (see De Visser et al. 2008; Chapoy et al. 2013).

In terms of the thermodynamics, all projects require a good understanding of the phase behaviour, not only for the overall system design but also to handle operational changes rate fluctuations and thermal effects can lead to significant changes in properties of the CO2 stream (both in the well and in the reservoir). The industry utilizes three forms of transportation using ships, pipelines and trucks. This project has proposed the transportation approach utilizing ships and pipelines. Transport of CO2 for sequestration requires implementing both a coordinated and efficient transportation network as such pipelines are the most obvious solution, particularly where a constant flow from the CO2 capture sites is required. Where economies of scale do not justify pipelines as the transportation method in a CCUS project, other possibilities include ships, railway and motor carriers. These are economically viable when emitters do not have direct access to a suitable pipeline or when the captured quantities are insufficient to justify pipeline construction. Access to adequate seaport facilities or proximity to the sea or railway system is one factor that impacts decision-makers. Pipeline and carrier transport of CO2 is comparable in cost for similar capacities when distances of 250 km or more are considered, as shown in figure 3-1. This comparison has proved helpful in identifying pipeline and water carriers as the leading transportation solutions for CCUS.

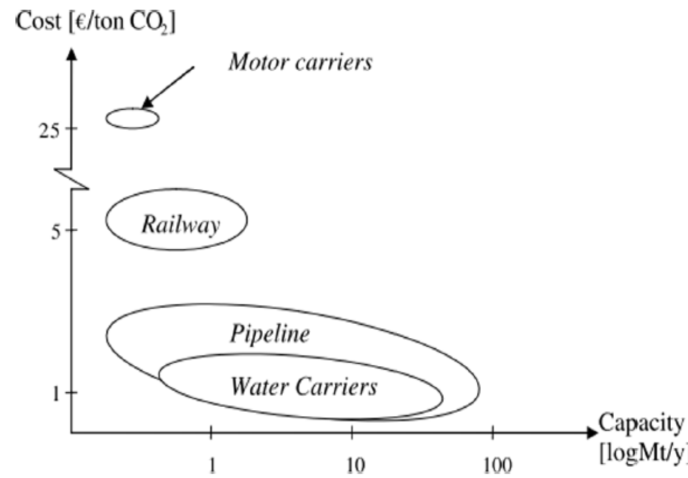


Figure 3-1. Cost and capacity for transportation alternatives at 250 km

Pipeline technology showed the best performance indicators concerning operational costs and consumption of utilities, with shipping being more advantageous only in relation to the required capital expenditure. For this reason, shipping was deemed as a temporary solution for the first CCUS deployments to contain upfront costs and investment risk before transitioning to pipeline infrastructure when larger capture quantities become available. Also, pipelines show better performance than shipping with regards to fuel, electricity, and water consumption in the chain, generating a transportation system with an overall lower greenhouse gas emission footprint. The value of this study to decision-makers stretches beyond economic considerations by recognizing the importance of life cycle assessment in selecting the best transport alternatives

There are four capture plants; Slagen oil refinery, Mongstad oil refinery, Norcem Brevik and Repsol oil refinery. Mongstad oil refinery and Norcem Brevik already have completed capture plants, so the amount of captured CO2 is known, but two other refineries don't have a completed capture plant, so the amount of CO2 can be different after capture plant facility completion. As mentioned before, pipelines are the most financially reasonable way for transporting CO2. However, as the exact amount of CO2 should be specified in pipeline transportation, we decided to use temporary shipping transportation for those plants which are not completed yet. Also, we planned onshore storage on the western coast of Norway, located at a distance of 80 kilometres from the underground storage platform. Although constructing this storage plant increases the expenses, having an onshore storage site is extremely necessary. We need a facility to maintain the CO2 pressure and temperature before injecting it into the platform.

Table 3-2. Summary of the capture and transportation plant for the Johansen project

Capture Plant	Amount of CO2 captured (Mt)	Distance from the west coast (Km)	Transportation Plan
Slagen Oil Refinery	1.5	485	Ship
Repsol Oil refinery	1.5	211	Ship
Norcem Brevik	0.5	413	Pipeline
Mongstad Oil Refinery	1.5	65	Pipeline

4. Well Design and Compression Stages

According to the thickness of the layers, which hardly passes 30 m in all of the intervals, it is better to drill multiple vertical wells rather than one or two horizontal wells for the following reasons:

- Thin layers would be more difficult and more costly to penetrate using horizontal wells. The possibility of fault is much higher than vertical wells.
- By drilling the horizontal well, it is possible to do the injection in one or more layers in a vast area with a vertical permeability larger than the horizontal permeability. But in our section, the horizontal permeability is generally greater than vertical permeability, and the area is not that vast to establish two or more horizontal wells.
- Since the horizontal permeability is high enough in this field, by drilling 2 or 3 vertical wells at maximum, we could cover all the 10 Km length area to inject CO2.

In addition, 5 Mt of injection per year is needed for 20 years, which is impossible using only one vertical well. The reason is that with increasing the flow rate for one well, the injection pressure will be too high, which will cause many problems such as fracturing the formation, reactivating the faults, and exceeding the fracture pressure. We suggest drilling two vertical wells at the depth of 2900 m, with 2 kilometers distance besides each other. The main argument is that the main driving force of CO2 migration is the gravitational force, meaning the CO2 plume tends to migrate upwards. With drilling two wells following each other, the pressure build up resulted from the first well behind the second well can cause overpressures which is not favorable. Thus, drilling two vertical wells besides each other, however with sufficient distance, will lead to a more efficient CO2 storage with less concerns about the formation or caprock failure. Two wells can be drilled simultaneously and injecting 2.5 Mt of gas per year which is equivalent to 6850 tonnes per day which again equivalent to around 3,660,00 Sm3 per day.

$$\frac{2.5\ Mt}{year} \times \frac{10^6\ t}{1\ Mt} \times \frac{534\ Sm^3}{1\ t} \times \frac{1\ year}{365\ days} = 3{,}657{,}534\ \frac{Sm^3}{day}$$

According to the below diagram, the pumping pressure gauge on the wellsite would be our reference to do calculations. To overcome the formation pressure and designate an injection starting point, we would set a minimum pumping pressure to find out what pressure is it expected to start the injection. Since our injection point is at 2900 mD, the formation PT properties at this point are:

$P_f = 289.8 \text{ bar}$

$T_r = 98.93\ ^\circ\text{C}$

Formation	Depth (m)	Formation Pressure (bar)	Formation Pressure (psi)	Temperature (C)	Average Pressure (bar)	Average Pressure (psi)	Average Temperature (C)	Total Average Temperature (C)
Johansen Fm. 4	2619.2	270.1693	3971.48871	90.79	237.9883	3498.42801	90.58	92.869375
	2699.95	205.8073	3025.36731	90.37				
Johansen Fm. 3	2710.5	272.116	4000.1052	91.28	273.446625	4019.665388	91.7325	
	2719	272.9672	4012.61784	92				
	2731.5	274.2539	4031.53233	90.51				
	2733.5	274.4494	4034.40618	93.14				
Johansen Fm. 2 & 1	2743	275.4659	4049.34873	95.85	272.44005	4004.868735	94.675	
	2751	269.4142	3960.38874	93.5				
Johansen Fm. 1	2756	276.7638	4068.42786	94.1	274.7042	4038.15174	94.49	
	2761	277.1729	4074.44163	94.51				
Injection Point	**2900**	**289.8**	**4260.06**	**98.93**	**289.8**	**4260.06**	**98.93**	**98.93**

Table 4-1. Formation report with pressure, temperature values (Equinor, 2020)

The data acquired in table 4-1 comes from 3 sections of core analysis:

Liquid CO2 Properties											
Temperature			Pressure			Density				Specific Weight	
[K]	[°C]	[°F]	[MPa]	[bara]	[psia]	[mol/dm3]	[g/l] = [kg/m3]	[lbm/ft3]	[sl/ft3*10-3]	[N/m3]	[lbf/ft3]
287.43	14.30	57.70	5.00	50.00	725.00	18.80	**827.30**	51.65	1605.00	8113.00	51.60

Table 4-2. Rock properties of the Johansen formation from three core data (Equinor, 2020)

Core No.	K(H)mD	K(V)mD	Porosity(H)	Gr.Density(H)	Depth(m)	Length(m)
Core 02	1152	797	20.70	2.66	2643.00 – 2696.42 m	53.42
Core 03	394	283	25.50	2.69	2709.00 – 2744.28 m	35.28
Core 04	953	840	19.50	2.68	2747.00 – 2780.90 m	33.9

Table 4-3 CO2 properties at standard condition (accquired from https://www.engineeringtoolbox.com/carbon-dioxide-density-specific-weight-temperature-pressure-d_2018.html

Considering the safety factors, we will assume that the pumped CO2 would be in liquid phase at the well column to set our minimum pumping pressure. Then, we calculate the minimum injection pressure according to that:

$$\rho_{\text{liquid co2}} = 827.3 \ {}^{\text{kg}}\!/_{\text{m}^3}$$

$$P_{\text{hydrostatic}} = \rho g h \qquad P_{\text{hydrostatic}} = 827.3 \times 9.82 \times 2900 = 235598494 \text{ Pa} = 235.6 \text{ bar}$$

According to the above calculations, the minimum injection pressure at the wellhead would be:

$$P_{\text{wh min}} = P_f - P_{\text{hydrostatic column}}$$

$$P_{\text{wh min}} = 289.8 - 235.6 = 54.2 \text{ bar}$$

According to the Gassnova's 2012 report, the maximum allowed buildup pressure is 42 bar**,** and the buildup pressure should not exceed this limit. Therefore, by taking a 20% safety factor into account, the maximum pumping pressure is calculated as:

$$P_{wh\,\text{max build-up}} = \text{Safety Factor} \times P_{\text{max build-up measured}}$$

$$P_{\text{wh build-up}} = 0.2 \times 42 = 33.6 \text{ bar} \qquad P_{\text{wellhead max}} = 54.2 + 33.6 = 87.8 \text{ bar}$$

With the calculations above, the minimum and maximum pressure at the wellhead would be 54.2 and 87.8 bar, respectively. Having the formation pressure as 289.8 bar, we need the pressure at the bottomhole to be more than the formation pressure in order to make the CO2 able to enter the formation and invade the pores. The bottom-hole pressure can be simply estimated from the wellhead and hydrostatic pressure:

$$P_{bh} = P_{wh} + \rho \mathrm{gh}$$

We calculate the minimum and maximum possible bottomhole pressure, where the minimum bottomhole pressure is equal to the formation pressure:

$$P_{bh\,min} = P_{wh\,min} + \rho \mathrm{gh} = 87.8 + 235.6 = 289.9 \text{ bar}$$

$$P_{bh\,max} = P_{wh\,max} + \rho \mathrm{gh} = 87.8 + 235.6 = 323.4 \text{ bar}$$

Setting wellhead pressure in the range of 65 to 70 bar, the bottom hole pressure will be:

$$P_{bh\,65} = P_{wh\,65} + \rho \mathrm{gh} = 65 + 235.6 = 300.6 \text{ bar}$$

$$P_{bh\,70} = P_{wh\,max} + \rho \mathrm{gh} = 700 + 235.6 = 305.6 \text{ bar}$$

The range of bottomhole pressure between 300 and 305 bar will have sufficient difference compared to the formation pressure, which is 289.9, leading to an efficient flow from the wellbore to the formation. It should be noted that according to the fracture gradient in sedimentary basins (Ringrose, 2020), at the depth of 2900 m, the fracture pressure would be approximately 400 bar. So even with a pressure buildup in the formation which will not most probably exceed 20 bar, still there is a huge difference between the formation pressure and the fracture pressure.

According to the plan given in the transportation plot of this project, we would need:

- Two compressors for two pipelines come from the Carbon Capture plants of 2 different factories.
- Two compressors should be placed in the storage and pumping plant (one as an operating unit and one as a standby unit).
- Two compressors on the platform are positioned in the wellsite location (one as an operating unit and one as a standby unit).

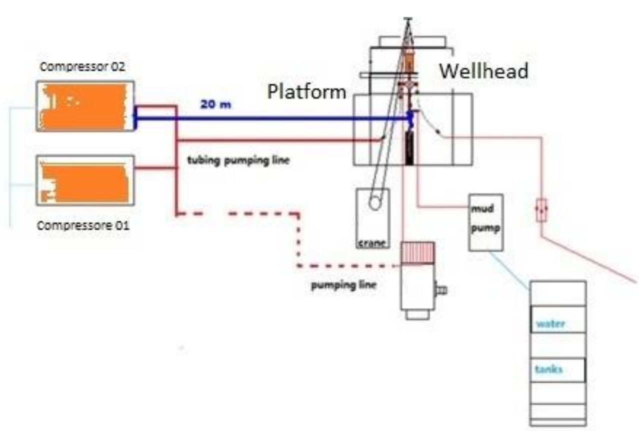


Figure 4-1. Simplified wellsite line-up diagram

5. CO2 Flow process

When the wells are prepared and completed, fluid injection into the geological formation is achieved by pumping the fluid in the liquid phase at the well head into the bottom hole, where the fluid enters the formation from the parts of the well that has been chosen for perforation. Since the reservoir has a sufficient thickness near the injection area (100 m), viscous force is the dominating force due to a high-pressure difference between the bottom hole and the reservoir, forcing CO2 out from the well and into the pore space of the surrounding rock, pushing away the brine in the drainage process. It is expected that the CO2 sweeps the brine to some extent; however, due to the very low viscosity of dense CO2 compared to the brine, flow instability is expected to happen, leading to fingering, so instead of a piston-like flow of the CO2 front into the injection formation, part of the front will flow much faster in the form of fingers. Parallel to this driving force and a bit further from the injection area (>100m), where the injection pressure has started to decrease due to pressure dissipation, the lower density of the stored dense CO2 (assumed 850 kg/m3) compared to that of brine (more than 1200 kg/m3) will cause buoyant flow of CO2 where the plum starts to moving upwards and accumulate beneath the burton formation which is composed of shales and has low permeability. Due to the presence of lateral siltstones inside the Johansen formation, it is expected that some portion of the CO2 accumulates beneath these low permeable siltstones.

The presence of being such siltstones makes the trapping process more efficient as they can pretend some portion of the injected CO2 from upward migration, where CO2 is in continuous contact with the brine, leading to the dissolution of CO2 in brine as one of the trapping mechanisms that increase the safety of the CO2 storage. The dissolved CO2 can then chemically react with the formation minerals, which is quite a slow process and takes thousands of years. It is expected that due to the low thickness of the shaly Burton, which is 7 m, the capillary entry pressure of accumulated CO2 beneath this formation exceeds capillary pressure. After some years, the CO2 plum reaches the sandy Cook formation as the secondary reservoir unit. According to Gassnova's report in 2012, two cores were representative of the Johansen Fm for relative permeability values where saturation endpoints were measured. The critical gas saturation is around 30% in the measurements, which is relatively high. It means that when the injection of CO2 into the formation stops and the brine that the CO2 displaced starts to displace the CO2 in the trail of the CO2 plume, around 30% of the total injected gas will be retained in the pore bodies and get trapped. It means the capillary trapping process, which can happen in short and long terms, will help safely store CO2 in the subsurface.

In total, we expect the plume shape to be like an inverted cone, where near the well area, the high injection pressure of CO_2 will push away the brine, at the same time, the density difference between dense CO_2 and brine will lead to gravitational forces where the plume tends to move migrate upwards until further vertical movement is blocked by the possible barriers, mainly the Burton Formation and Drake formation as the primary sealing unit. The lower part of the inverted cone plume is thicker, and as it goes higher, the cone becomes gradually thinner and thinner. On top of the plume, there is a thick sealing unit of Drake Fm with around 140 m of thickness, ensuring containment of the injected CO_2 in the reservoir. There is also a shallower sealing unit (secondary) consisting of Draupne Fm, Cromer Knoll, Shetland, and Rogaland groups as an effective barrier with a high degree of certainty. The Draupne formation is the hydrocarbon barrier for many discoveries and fields in the Norwegian Continental Shelf, and its presence has been proven by the 31/5-7 (EOS) well. Therefore, if there is any leakage from the primary sealing unit on top of cook formation after hundreds of years, the secondary sealing unit will for sure retain the CO_2 in the reservoir. It should be noted that since we're injecting in the Johansen formation, which is not a clean sandstone, as there are some siltstones inside the formation, making the formation heterogeneous, we'll get the benefit of such formation since the more CO_2 will be retained in the formation, resulting in more contact with brine and increasing the contribution of dissolution and residual trapping compared to a pure sandstone reservoir wherein CO_2 plum will migrate upwards without difficulties.

6. Reservoir Monitoring Plan

To assure safe CO_2 storage and minimize the risk of leakage, optimize injection operations, and confirm the storage volumes, it is necessary to propose short and long term monitoring plans which can be *atmospheric, near-surface,* or *subsurface* monitoring. Atmospheric monitoring is where the density of CO_2 is measured in the atmosphere using optical CO_2 sensors or atmospheric tracers. Near-surface monitoring is where the CO_2 can be measured from shallow groundwater up to the soil using satellite-based remote sensing tools. Subsurface monitoring is where tools such as downhole monitoring, well logging, fluid sampling, seismic imaging gravimetries and electromagnetic tools can be utilized to detect and quantify the injected CO_2 (Niemi et al., 2017). Suppose carbon capture and storage (CCS) should be considered a safe and reliable option for mitigating the increasing levels of CO_2 in the atmosphere. In that case, it is essential to ensure that each storage site keeps a significant part of the CO_2 isolated and away from the atmosphere for decades. If not, the decreasing effectiveness CO_2 releases; the opposite of the scope (Haugan & Joos, 2004).

MMV programme, as the short form of measurement, monitoring and verification for CO_2 storage, is divided into the following project phases (Ringrose, 2020):

- Pre-injection
- Operational
- Site closure
- Post-closure

The technical objective of proposing a monitoring programme is to address the *conformance* and verify the CO_2 plume distribution over time according to predictions and the *containment*, including activities to assure no leakage out of the storage complex. *Contingency* as the third crucial technical objective means respondents' ability to detect anomalies and take necessary actions to stop any possible leakage. Measuring wellhead pressure and temperature is the most widely used monitoring system that can be done for this project using sensitive acoustic sensors and electronics to observe any abnormal changes, which will lead to taking actions upon that. The presence of this monitoring system is vital as the active injected well is associated with the highest possibility of leakage and release of CO_2 into the sea (Furre et al., 2020; Gassnova, 2012). A permanent downhole gauge (PDG) was installed in the tubing in the well. It can measure the tubing pressure, or annulus pressure is helpful in monitoring the pressure and temperature at single or multiple points in the well. This can be an essential monitoring tool in this project. PDGs can detect the development and potential anomalies in injectivity. 3D-seismic can be acquired at different times over the injection area to detect the CO_2 plume movement. The saturation and pressure changes over time are relatively expensive tools yet exceptionally efficient for suitable containment and conformance assurance, particularly at the early stages of a project. Over time, the repeat interval between 3D seismic surveys can be longer, however for the first years of injection; it is better to repeat the seismic surveys more frequently. Time-lapse gravity field monitoring has been proven to be accurate for offshore projects to aid the assurance of the mass balance of the projects and estimating the mean of CO_2 density at reservoir conditions (Ringrose, 2020)

Measurements at the wellhead or in the downhole can be done continuously. All projects in the oil and gas industry follow the same manner since these measurements are not costly. Downhole fluid sampling can be done every year to enable the chemical analyses on the fluid in the reservoir to measure the fluid saturation changes. The cost compared to the benefit we can receive from downhole fluid sampling is low. Despite the high expenses due to conducting repeated 3D seismic surveys, they are the most efficient tool to control the project. One 3D seismic survey before any injection operation starts needed to serve as a baseline for subsequent repeated surveys. Six seismic surveys can be done during the operation period. The repeat interval between each survey gradually increases since they are costly. As time goes by, the safety of the project increases. Lastly, only three gravity surveys need to be conducted due to the costs of this monitoring tool.

Table 6-1. Summary of the proposed monitoring plan for the Johansen project

	Pre-injection	Operation									Post-injection
Monitoring Plan	0	+2	+4	+6	+8	+10	+12	+14	+16	+18	+20
Repeated 3D-seismic	✔	✔	✔	✔		✔		✔		✔	✔
Time-lapse gravity		✔			✔			✔			
Wellhead pressure	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
Downhole gauges	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔
Downhole fluid sampling	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔	✔

7. Uncertainties and Risks

Undoubtedly, CO2 injection operation projects are pretty challenging now since the industry has little experience compared to the oil and gas industry. Plus, saline aquifers as geological storage sites with the largest capacity had not been utilized for injection purposes before, leading to many uncertainties and risks that the industry needs to be aware of and gain experience over time. In this section, some of the uncertainties about the Johansen formation as the geological storage site will be explained.

Storage efficiency is a critical factor, aiding the engineers to estimate how much storage volume can be utilized to store more CO2. It was mentioned before that viscous force, which is the main driving force to push the injected fluid horizontally, will not dominate through the whole of the reservoir since the gravitational force dominates the fluid dynamics due to the density difference between the injected CO2 and the brine. Therefore, after some years of injection and conducting repeated seismic surveys, the correct storage efficiency can be calculated when it is possible to observe the movement of CO2. The effect of faults inside the reservoir, whether they act as sealing units or as conduits, is critical for estimating the reservoir's actual pore volume and pressure buildup. Prior to several years of injection, the uncertainty about the prediction of the effects of the faults is significant, and nothing can be stated for sure about their impact on the pressure buildup and CO_2 distribution in the reservoir. That's why before the operation starts, reservoir engineers try to propose different scenarios that can happen inside the reservoir to have a rough estimate of all possible situations that can happen.

Critical gas saturation, as the amount of gas that cannot be further displaced by the wetting-phase fluid (here brine), is a critical factor in estimating the amount of injected CO_2 that can be retained in the pores after being displaced brine. In the data shared by Equinor about the Eos confirmation well, no data about the relative permeability values were found. However, according to the core data of Gassnova in 2012, two cores from the Johansen formation were used for relative permeability measurements where the critical gas saturation was reported to be 0.298. It should be noted; however, this value is the only published value; it cannot necessarily represent the critical gas saturation in our selected site with a depth around 2900 m, since the core was acquired from the well 31/2-3 in the Troll Field area and with the depth of approximately 2400 m. Therefore, critical gas saturation is one of the uncertainties that need to be further measured with more accuracy and close to the proposed injected area.

Sealing integrity is one of the main risks that need to be highly taken care of. The possibility of thermal fractures that can increase in deep geological formations with higher temperature as downhole injection temperatures of the CO_2 (around 25 degrees) is significantly lower than the initial formation in situ, in this project 98 degrees. This could lead to thermally-induced stress changes in the Drake formation as the primary sealing unit and threaten its integrity. Moreover, compressing gas high might make it out of control in the formation after exceeding the formation pressure. It might make small fissures in the caprock (sealing rocks). Therefore, it might decrease the reservoir's quality.

Due to the selection of high injection depth (around 2900 m), the formation pressure is significant (around 290 bars), meaning the selected pressure at the wellhead and bottomhole should be pretty high to be able to overcome the formation pressure, leading to having flow from the wellbore to the formation. Dealing with high pressures both at the wellhead and at the bottom of the well is not always easy, and it involves some risks that need to be taken into account.

There are more risks and uncertainties and risks involved in the project. Some of the most important ones can only be clarified after several years of injection, where the data at the bottomhole and well head is generated. Seismic surveys, as well as gravity monitoring, help us have a great insight into the project. Here we tried to mention some of the most critical uncertainties and risks included.

8. Final evaluation

According to many research and studies, the Johansen Formation can be considered one of the promising geological storage sites for storing CO2. The permeability and porosity values and the thickness of the reservoir have shown good values by many analyses. It should be noted that this formation is overlaid by a thick sealing unit called the Drake Formation, which, even with some uncertainties, will most probably act as a barrier to the injected CO2. In addition to the central sealing unit, another shallow sealing unit has accumulated the hydrocarbon from the Troll Field for millions of years. These facts tell us that the leakage in the formation comes with the lowest possible risk.

It should be noted that despite some of the risks involved during the high depth of the formation, the injected CO2 will most probably remain in the supercritical phase, occupying much less volume than the gas and less concern about the possible movement of CO2 2pume to spill points and areas where plume exceeds the license. Lastly, this formation's high possible amount of critical gas saturation will lead to a more efficient residual trapping. The heterogeneity of the Johansen formation will help retain some portion of the injected CO2 from migrating up, leading to more contact between CO2 and brine, leading to a more efficient dissolution trapping. It is not easy to talk about the mineralization since it can take thousands of years to occur; however, the Johansen formation has shown that the three other main trapping mechanisms will act efficiently in this reservoir.

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