Exploring geological storage sites for CO₂ from Norwegian gas power plants:
Johansen formation

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Abstract
The Johansen formation at depths between 2400 and 2100 m has been identified as a possible candidate for storage of CO₂ from future point sources at Mongstad and Kårstø. The studied injection point in the Johansen Formation is located 80 km west of Mongstad and 600 m below the Sognefjord formation which also contains the Troll oil and gas field. Based on simulations on a reservoir model built from existing seismic and well data, the formation exhibits a robust target for permanent storage of CO₂ assuming an injection rate of 3 million tonne CO₂ per year over a 110 year period. In the worst case scenario the CO₂ will not reach the Troll gas and oil field until 150 years after injection start. At that time it is assumed that hydrocarbon production at Troll has ceased.

Keywords: CO₂ storage; North Sea aquifers; Johansen formation; Storage integrity; Long-term behaviour

1. Introduction
At Mongstad and Kårstø on the west coast of Norway there exist plans for large combined cycle gas power plants. The plant at Kårstø is already under construction. To meet Norway’s commitment to the Kyoto agreement on reduction of climate gas emissions, it has been suggested to separate and store CO₂ from large point sources. In this context these power plants may be candidates for CO₂ storage provided it can be established that suitable underground formations exists. One possible candidate for CO₂ storage is the Johansen formation in the vicinity of the Troll field, the formation lies deeper than the oil and gas bearing formations in Troll and has a potentially good seal in the overlying formations. In the following a scenario where CO₂ is injected into the Johansen formation just south of the Troll field and approximately 80 kilometres from Mongstad is investigated. This area of the formation is chosen because 3D seismic and well data exists in the area and because the thickness of the formation is adequate, between 70 and 120 meters. Figure 1 displays the location and extent of the formation and the position of the
injection well. In this study it is first assumed that the Johansen formation consists of a constrained volume with no direct communication to overlying formations. Next, a series of simulations was performed on a larger model including all the formations from Statfjord to the Sognefjord formation where it is assumed that CO₂ can flow into shallower formations either by increasing permeability in the overlying cap rock or by allowing CO₂ to pass through faults. The storage site, the lower Jurassic Johansen Formation of the Dunlin Group consists of an east-west dipping sandstone formation with several large vertical faults in the north-south direction, some with a throw of several hundred meters. The shallow part of the formation is less than 40 km from Mongstad and the formation deepens towards west to a depth of 2400 m over a distance of around 60 km. The north-western part of the formation lies around 600 meters below the oil and gas bearing formations in Troll. The formation is modelled by seven zones with alternating sand and shale, starting with sand at the top and ending with two zones of shale. The deepest shale covers the whole area of the model while the other shale zones are only present in the S-W corner of the model. These are pinching out at around 10 to 15 kilometres from the S-W corner of the model. This leaves only sand in the central and eastern part of the model except for a few isolated areas. The sand is thinning out towards the eastern border of the formation as it is getting shallower and pinches out towards the shale dominated S-W corner of the formation. The thickness of the sandy part of the formation varies from a few meters in the eastern part to around 150 m in central and western parts, Figure 2.

Figure 1  The plot shows depth map of the top of the Johansen formation. The position of the injection well is indicated by the black circle and the boundary of Troll oil and gas field is indicated by the red curve. To the right we see part of the west coast of Norway with the location of Mongstad.

2. Simulation models

It is assumed that the Johansen formation initially is in hydrostatic equilibrium with a reservoir temperature of 94 °C and a formation water salt content of 5 weight-percent. The formation water viscosity, CO₂ solubility and formation volume factor used in the simulations are based on Numbere et al. [1], Diamond et al. [2] and Enik and Klara [3]. The injection gas is assumed to be pure CO₂ with properties taken from Span and Wagner [4] and Vukalovitch and Altunin [5]. Straight line relative permeabilities are used in the simulations due to the relatively large grid block sizes. Critical gas saturation and irreducible water saturation are assumed to be 5 % and 15 % respectively.
Two main simulation scenarios were investigated: Migration of CO2 within the formation assuming faults and overlying formations to be sealing and CO2 migration out of the formation through faults and overlying formations assuming non-zero fault transmissibilities and vertical permeabilities in overlying formations. Therefore, two different reservoir simulation grids were built, one representing only the Johansen formation and the other representing all the formations from the Statfjord formation to the Sognefjord formation. The models are based on 2D and 3D seismic surveys, well logs in the region and analysis of core samples from the Johansen formation. Both simulation grids were confined to a smaller section in the N-W area of the formation. An outline of the grid is shown as a closed boundary (red) in Figure 2.

The simulation model of the Johansen Formation has an average areal size of the grid blocks of 200 by 200 meters and the number of layers in the model is 18 (230250 active grid blocks). The height of the grid blocks varies from around 2-3 meters in the layers close to the top, to around 10 meters in the sand layers below, and up to 50 meters in the shale layer at the bottom of the model. Porosity in the sand varies between 0.15 and 0.29 and the porosity within a zone degrades as one goes towards the south and the formation becomes deeper. Permeability is correlated to porosity and varies between 300 and 1500 mD. Porosity and permeability in the shale layers have been set to 0.1 and 0.001 mD. Vertical to horizontal permeability ratio is 0.1.

Since the Johansen simulation model is confined and the model is smaller than the mapped Johansen formation a numerical aquifer was modelled by increasing the pore volume in the grid blocks at the boundary to the south. This was done to get a more representative volume of the aquifer in the model and to investigate pressure increase in the model as a function of aquifer volume. Three different assumptions of total pore volume size are investigated; the pore volume of the confined simulation model (21.3 \( \times 10^9 \) m\(^3\)), a pore volume equal to the pore volume of the mapped Johansen formation (171.5 \( \times 10^9 \) m\(^3\)) and a pore volume approximately three times the size of the Johansen formation (500.1 \( \times 10^9 \) m\(^3\)).

The large scale simulation grid has 48581 active grid blocks with an average areal size of 500 by 500 meters. The model has a total of 16 layers where each formation is modelled by one layer except for the Johansen formation which has 7 layers. Porosity in the model is based on well logs and degrades within each layer as we go deeper. The total pore volume in the model is 785.1 \( \times 10^9 \) m\(^3\) with an average porosity of 21.5 %. Permeability is correlated to the porosity in each layer except for Dunlin, Ness, Lower Krossfjord and Statfjord where it is constant. Figure 3

Figure 2. Thickness map of the Johansen formation showing an outline of the simulation grid (left). Simulation grid of the north-western part of the Johansen formation displaying porosity distribution (right).
displays horizontal permeability for the different layers in an E-W cross section north of the injection point (left) and a table with rock properties for each formation (right). The vertical to horizontal permeability ratio is 0.1.

The injection rate in all simulations was set to 3 million tonne CO\(_2\) per year for a period of 110 years, and the migration of the injected CO\(_2\) was simulated for periods of up to 6000 years.

<table>
<thead>
<tr>
<th>Layers in model</th>
<th>Formation</th>
<th>Porosity</th>
<th>Permeability, mD</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>U_Sognefjord</td>
<td>0.30 - 0.32</td>
<td>1000 - 2000</td>
</tr>
<tr>
<td>2</td>
<td>L_Sognefjord</td>
<td>0.16 - 0.19</td>
<td>20 - 30</td>
</tr>
<tr>
<td>3</td>
<td>Fensfjord</td>
<td>0.23 - 0.27</td>
<td>100 - 1000</td>
</tr>
<tr>
<td>4</td>
<td>U_Krossfjord</td>
<td>0.26 - 0.29</td>
<td>100 - 1000</td>
</tr>
<tr>
<td>5</td>
<td>L_Krossfjord</td>
<td>0.16 - 0.18</td>
<td>1</td>
</tr>
<tr>
<td>6</td>
<td>Ness</td>
<td>0.17 - 0.19</td>
<td>0.1</td>
</tr>
<tr>
<td>7</td>
<td>Etive</td>
<td>0.22 - 0.24</td>
<td>70 - 150</td>
</tr>
<tr>
<td>8</td>
<td>Dunlin</td>
<td>0.10</td>
<td>0.01</td>
</tr>
<tr>
<td>9-15</td>
<td>Johansen</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>16</td>
<td>Statfjord</td>
<td>0.20</td>
<td>100</td>
</tr>
</tbody>
</table>

Figure 3  An East-West cross section north of the injection point displaying horizontal permeability in the different layers for the leakage model. The table on the right lists formations present in the model with porosity and permeability range listed for each formation.

3. Simulation results

3.1. CO\(_2\) migration within Johansen Formation

In addition to the injection period, 400 years with no injection was simulated to investigate CO\(_2\) migration along the top of the formation. The base case simulation for the Johansen formation model is defined to have a pore volume equal to the mapped Johansen formation. Figure 4 shows the CO\(_2\) saturation after the injection period of 110 years (left), and after 400 years of migration with no injection (right).

Figure 4  Base case CO\(_2\) saturation in the Johansen formation after the injection period (110 years) to the left and at the end of the simulation (510 years) to the right. Observe that the migration of CO\(_2\) is controlled by the topography of the formation top.
The average reservoir pressure during injection, here defined as the pore volume weighted pressure in the simulation model, is dependent on aquifer size and increases with more than 450 bar in the small aquifer model. Such high pressure increase could lead to a breach in the sealing faults and cap rock. The lithostatic pressure at 2100 m depth in Johansen is approximately 460 bar. This is 250 bar higher than the initial hydrostatic pressure. Moss et al. [6] have compared the reservoir pressures with the lithostatic pressure gradient in several of the formations in the North Viking Graben and it is found that in general the formations can hold an overpressure of at least half of the difference between hydrostatic and lithostatic pressure. In this study it is therefore assumed that the pressure below Dunlin shall not exceed \((210 + 250 / 2)\) bar = 335 bar. The pressure at the top of the model, close to the injector, is shown in Figure 5 (left) for the base case and the small aquifer case. It is seen from the results that in the base case this pressure will not be exceeded, while the small aquifer model will only allow 15 to 20 years of injection until the design pressure is exceeded. The reasoning above is not based on any special mechanism for leak-off, nor on any assumption on cap rock shale wettability, capillary entrance pressure or fracturing pressure. It is only based on observed over-pressures in hydrocarbon fields in the same region. After the injection period the pressure decreases in the sand layers due to the dissolution of CO\(_2\) into the formation water.

Reservoir brine can dissolve approximately 50 kg CO\(_2\) per Sm\(^3\) brine. The dissolution process is mostly diffusion controlled and therefore very slow on short term. On long term, however, (>500 years) this effect may be important because induced gravity driven convection may enhance the dissolution process. Provided that the CO\(_2\) is retained underground, the final fate of the CO\(_2\) is to be dissolved in brine and further reaction with rock minerals will then be possible on very long time scales. The short term dissolution of CO\(_2\) is exaggerated in a coarse numerical grid due to numerical dispersion, and a significant amount of the injected CO\(_2\) dissolve according to the simulation results as illustrated in Figure 5 (right). After 510 years approximately 10% of the injected CO\(_2\) will be dissolved in the base case.

Figure 5  Pressure increase at the top of the formation just north of the injection point during injection (left) and amount of dissolved CO\(_2\) in the formation during injection for the different models. Observe that the small aquifer model have the least amount dissolved CO\(_2\) after the injection period. This is because less water has been contacted by CO\(_2\) due to the compressibility of the gas (and the higher pressure).

### 3.2. Leakage to shallower formations

The risk of- and estimated time for CO\(_2\) to enter shallower formations has been investigated by allowing CO\(_2\) to migrate out of the formation. The Troll oil and gas resources are located in the Sognefjord formation in the top layer of the simulation model and several different scenarios have been simulated to estimate when CO\(_2\) will reach this formation. The horizontal permeability of the Dunlin formation has been set to 0.01 (vertical permeability is 0.001) and different fault transmissibilities have been applied. In addition, one simulation has been run with transmissibility in the Dunlin formation set to 0, i.e. all transport of CO\(_2\) into shallower formations goes over the faults.

Without explicitly setting fault transmissibilities the simulator (Eclipse from Schlumberger) calculates transmissibilities between grid blocks over a fault only based on the properties of the grid blocks and the area of their common boundary. It is therefore likely that it will over-estimate the transmissibility over faults. Multipliers 0.1 and 100 were applied to the Eclipse calculated transmissibilities for sensitivity. The fault transmissibility...
generated using the geo-modelling tool Petrel is based on the formulation by Manzocchi et al., [7], where the transmissibility over the fault zone is dependent on shale content and fault displacement. A shale content of 50% has been used as input for the Petrel Faults model. Table 1 lists the different simulation models with their fault characteristics, estimated time for CO2 to appear in the Upper Sognefjord formation and vertical permeability in the Dunlin formation. The simulations have been run for a total of 6000 years, the first 110 years with CO2 injection.

Table 1 Overview of the simulation scenarios for CO2 migration to shallower formations including estimated time for CO2 to reach the Upper Sognefjord formation.

<table>
<thead>
<tr>
<th>Model name (labels)</th>
<th>Characteristics</th>
<th>CO2 present in top layer, years</th>
<th>Vertical perm. Dunlin</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base Case</td>
<td>Fault transmissibilities calculated by Eclipse</td>
<td>505</td>
<td>0.001</td>
</tr>
<tr>
<td>Fault M01</td>
<td>Fault transmissibility multiplier set to 0.1</td>
<td>502</td>
<td>0.001</td>
</tr>
<tr>
<td>Fault M100</td>
<td>Fault transmissibility multiplier set to 100</td>
<td>260</td>
<td>0.001</td>
</tr>
<tr>
<td>Petrel Faults</td>
<td>Fault transmissibilities generated in Petrel</td>
<td>480</td>
<td>0.001</td>
</tr>
<tr>
<td>Sealing Faults</td>
<td>Faults are sealing, multiplier set to 0.0</td>
<td>4400</td>
<td>0.001</td>
</tr>
<tr>
<td>No Dissolution</td>
<td>Same as base case but without CO2 dissolution</td>
<td>150</td>
<td>0.001</td>
</tr>
<tr>
<td>Dunlin Sealed</td>
<td>Same as Fault M100 but with tight Dunlin</td>
<td>245</td>
<td>0.0</td>
</tr>
</tbody>
</table>

In all the simulated scenarios CO2 will after 6000 years have reached the top layer of the reservoir model. A critical factor when assessing the Johansen formation for CO2 deposition is the estimated time needed for CO2 to reach the oil and gas bearing Sognefjord formation. Figure 6, left, shows amount of CO2 in the top layer as function of time for the different scenarios simulated. The worst case scenario, without dissolution of CO2 into the formation water, will start to get CO2 in the top layer after 150 years while it will take more than 245 years in the other scenarios. If the faults are sealing, it would take around 4400 years for CO2 to reach to the top layer. Whether Dunlin is sealing or not does not have much effect on the travelling time for CO2, but as illustrated in Figure 6 more CO2 will end up in the top layer after 6000 years when Dunlin is sealing. Dissolution of CO2 plays an important role on a 1000 year scale, see Figure 6, right. The variation in amount of dissolved CO2 is caused by difference in the amount of water contacted by CO2 in the different scenarios. The simulations will, however, exaggerate the dissolution of CO2 into the formation water due to numerical dispersion in the relatively coarse numerical grid.

Figure 6 Amount of CO2 in the Sognefjord formation as function of time (left) and amount of free CO2 (not dissolved) as percent of injected (right).

The basic mechanism that retains CO2 under ground is the capillary sealing of the cap-rock. It depends on the capillary entrance pressure which is a function of the pore size distribution in the cap-rock, the wettability of the shale and the surface tension between water and the buoyant fluid, in this case CO2. The surface tension is essentially constant and is only a function of pressure and temperature. It is usually assumed that most shales are...
water wet in its natural state when it is saturated with brine. It is, however, known that some rocks may change wettability when they are contacted with oil due to strong interaction between some of the oil components (NSO and asphaltenes) and the rock. There exists also some evidence that CO₂ may reduce wettability of shale. Chiquet et al. [8] studied the wettability of silicate and muscovite substrates and observed that the wettability was rather intermediate wet when exposed to CO₂. Hildenbrand et al. [9] observed that pressure driven volume flow could be observed for lower differential pressure with CO₂ than for nitrogen and methane when these were applied across low-permeable shales (60, 200 and 170 bar respectively). The exact mechanisms of these observations are not known and it is suggested that more studies are performed on relevant samples and cores to scrutinise the risk of unexpected low break-through pressures.

4. Conclusions

The Johansen formation exhibit a robust target for permanent storage of 330 million tonne CO₂. In the worst case scenario the CO₂ will not reach the Troll gas and oil field until 150 years after injection start. Main uncertainties are the size of the communicating pore volume, fault properties and properties of the primary sealing formation. Three different pore volumes for the Johansen formation were investigated. With a pore volume above 170 Gm³ the pressure increase is so low that the risk of breaking the cap rock due to pressure increase could be neglected. The sparse reservoir information that is available indicates that further exploration of the formation with a well and/or 3D seismic is desired for a final qualification for the Johansen formation as storage site.

The quality of the Johansen formation for permanent storage of CO₂ is characterised mainly by the following features:

- The formation is very large and can potentially store large amounts of CO₂.
- The main sealing rock is the Dunlin formation that consists of a thick shale (> 200 m).
- The formation water is at hydrostatic pressure despite that the formation is located at approximately 2100 meter depth. This is an indication that the formation water is communicating with neighbouring aquifers which reduces the risk for pressure build up during injection.
- If the formation is leaking, migrating CO₂ can be trapped in overlaying formations. The worst case scenario is that CO₂ leaks into the Troll oil and gas field. The risk that this happen within the period when there may be production at Troll (maximum 100 years) is very small. The risk for leakage to the atmosphere can thus be neglected.

In case of unexpected pressure increase there exist several remediation options. The largest risk factor is that the communicating pore volume is smaller than assumed as worst case scenario in this study. This may be difficult to explore before the injection starts. Examples of remediation options are:

- Drill a new well west of the main north-south fault and distribute the injected CO₂ in both wells or, if the injection well is not located too far from the fault and is drilled as a deviation well, it may simply be extended into the formation west of the fault.
- Relieve the pressure in the Johansen formation by connecting it to more shallow aquifers by drilling intra-formation wells between them.
- Relieve the pressure in the Johansen formation by drilling wells down flank and produce the brine into the sea, this requires that the water composition is not dangerous for marine species.

There are, however, some risk factors that may be investigated further:

- The fault west of the suggested injection point may be affected by pressure. The possibility that the pressure may open the fault so much that it creates vertical permeability in the fault has not been studied.
- 3D seismic surveys or wells in the targeted injection area should be considered. Improved understanding of the reservoir behaviour relies on collection of more data. Improved predictions could be obtained with better data. (3D seismic was gathered in the targeted area in September 2008 and is expected to be processed early next year.)
- The main sealing formation, Dunlin, should be studied further. Existing well-logs, core samples and laboratory studies can reveal its properties, e.g. sand content, mineralogy, capillary entrance pressure, wettability, permeability and fracturing pressure.
Acknowledgement

This paper is based on work funded by the Norwegian Petroleum Directorate (NPD) and is supported by the 6th framework EU-program DYNAMIS.

References