Simulation CO_2 storage in the North Sea

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Abstract

Use of fossil fuel has resulted in emission of large amounts of CO_2 to the atmosphere, which increases the risk of global heating. There is a lot of research going on regarding CO_2 capture and storage. The Paris Agreement, a global agreement on the reduction of the climate change, was adopted in December 2015 and signed by 174 countries in April 2016. The agreement aims to keep the global temperature rise in this century well below two degrees Celsius. According to the International Energy Agency (IEA), about 120 billion tons of CO_2 have to be captured and stored in the period from 2015 to 2050 to ensure that the increase in temperature will be kept below this limit. This implies that more than 3000 carbon capture and storage plants must be operative within 2050. Norwegian Petroleum Directorate has estimated that the theoretical storage capacity on the Norwegian Continental Shelf is 80 billion tons of CO_2. As a comparison, Norwegian emission of CO_2 is about 50 million tons per year.

The purpose of this paper is to simulate the storage of CO_2 in an aquifer in the North Sea. Simulations using OLGA and Rocx are carried out on a limited part of the aquifer. Three different cases where run to study the distribution of CO_2 in the aquifer with time and the CO_2 storage. By comparing the cases, it was found that in all the cases CO_2 was evenly distributed in the aquifer with time independent on the injection area and the length of the production well compared to the length of the aquifer. The CO_2 storage was calculated to be 2590 ton, 3795 ton and 2560 ton for Case 0, Case 1 and Case 2 respectively. Case 2 had a CO_2 injection area of 21m^2, whereas Case 0 and Case 1 had a simulated injection area of 10605 m^2 and 21210 m^2. Case 2, with the smallest injection area, is the most relevant case because real injection of CO_2 occurs through orifices in vertical or horizontal injectors.

Keywords: OLGA, Rocx, CO_2 storage, CO_2 phase diagram, CO_2 distribution, aquifer.

1 Introduction

When the Norwegian government signed the Kyoto agreement in 1997, they had negotiated an agreement where Norway was allowed to increase the emissions of green house gases by 1% compared to the 1990 levels. In fact, the greenhouse gas emissions increased by 8% between 1990 and 2010

Due to this, Norway initiated actions to reduce the increase in emissions, and by 2016, the greenhouse gas emissions were reduced to 3% higher than 1990 levels (Statistics Norway, 2017).

The Norwegian government has the ambition to develop cost-effective CO_2 capture and storage technologies and to realize at least one full-scale CO_2 capture demonstration facility by 2020 (Stortinget, 2013). Gassnova has developed an idea study, "Exploration of possible full-scale CO_2 handling projects in Norway", where several sources of emissions and storage locations have been considered as current candidates. During the autumn 2015, the government decided to continue the project in a feasibility study. CO_2 capture studies have been conducted with three industrial actors, and according to these studies, it is concluded that it is technically possible to realize a CO_2 handling chain in Norway. Smeaheia, located just east of the Troll field, is especially drawn up as a good solution. Statoil concluded based on the study that the Smeheia solution has the least risk, greatest operational flexibility and greatest potential for future capacity expansion. (Olje- og energidepartementet, 2016). The United Nations Inter-governmental Panel on Climate Change (IPCC) concluded that capture and storage of CO_2 may account for as much as one half of emission reductions in this century (Norwegian Petroleum Directorate).

The aim of this paper is to study the storage capacity and the distribution of CO_2 in an aquifer when different injection areas are used.

2 CO_2 storage in aquifers

There is significant technical potential for storing CO_2 in geological formations around the world. Saline aquifers are candidates for such storage. Environmentally sound storage of CO_2 is a precondition for a successful Carbon Capture and Storage (CCS) chain, and therefore mapping, qualification and verification of storage sites are important. Geological formations on the Norwegian continental shelf are considered to have potential for storage for large quantities of CO_2. This paper is focused on the storage capacity in an aquifer east of the Troll field. (Norwegian Petroleum Directorate).

2.1 CO_2 storage capacity

Smeaheia is an aquifer located east of the Troll oil and gas field. A layer of the aquifer in Smeaheia, Sognefjord Delta East, is evaluated for CO_2 storage as part of a full cycle CCS pilot initiated by the Norwegian government (Riis et al., 2017). The Sognefjord Delta East aquifer, and has a permeability of 300 mD. The bulk volume is $5.54 \cdot 10^{11} m^3$ and the porosity is 0.210 (Lothe et al., 2014). The equation for calculation of the storage capacity is:

$$q = V_{Bulk} \cdot N/G \cdot \varphi \cdot \rho_{CO2} \cdot E \qquad (1)$$

where q is the mass of CO_2, V_{Bulk} is the total volume of the aquifer, N/G is the net to gross height of the aquifer, φ is the porosity of the rock, ρ_{CO2} is the density of CO_2 at reservoir conditions and E is the storage efficiency. The storage efficiency is a function of mobility ratio, the connate water saturation and the trapping coefficient and is given by (Szulczewski and Juanes, 2009).

$$E = \frac{2 \cdot M \cdot \Gamma^2 (1 - S_{wc})}{\Gamma^2 + (2 - \Gamma)(1 - M + M \cdot \Gamma)} \qquad (2)$$

The mobility ratio, M, is expressed by:

$$M = \frac{1}{\mu_{water}} \cdot \frac{\mu_{CO2}}{k_{rg}^*} \qquad (3)$$

where μ_{water} and μ_{CO2} are the viscosity of water and CO_2 respectively, and k_{rg}^* is the end point relative permeability for CO_2. The trapping coefficient, Γ, can be calculated from:

$$\Gamma = \frac{S_{rg}}{1 - S_{wc}} \qquad (4)$$

S_{rg} is the residual saturation of CO_2 and S_{wc} is the connate water saturation.

The storage efficiency, E, in the Sognefjord Delta East aquifer is 5.5% and the density of CO_2 is 0.69 ton/Rm^3 (Lothe et al., 2014). Based on these values and the total volume and porosity, the CO_2 storage capacity of the Sognefjord Delta East is calculated to be 4.09 Gtons. By comparison, Europe has an annual CO_2 emission of 4.4 Gtons.

2.2 CO_2 injection in aquifers and reservoirs

In addition to CO_2 storage, injection of CO_2 into hydro carbon reservoirs is more and more used. Depleted oil reservoirs is used for storage of CO_2, whereas injection of CO_2 into active reservoirs is used for enhanced oil recovery (EOR) and storage. Figure 1 illustrates CO_2 storage in a hydrocarbon field with enhanced oil recovery (to the left) and CO_2 storage in an aquifer (to the right) (Université Recherche, 2018).

Injection of CO_2 in an aquifer below an oil reservoir, contributes to maintain the reservoir pressure and to reduce the interface tensions between oil and water resulting in increased oil mobility. CO_2 injection for EOR provides a great environmental benefit by reducing the emission of CO_2 to the atmosphere.

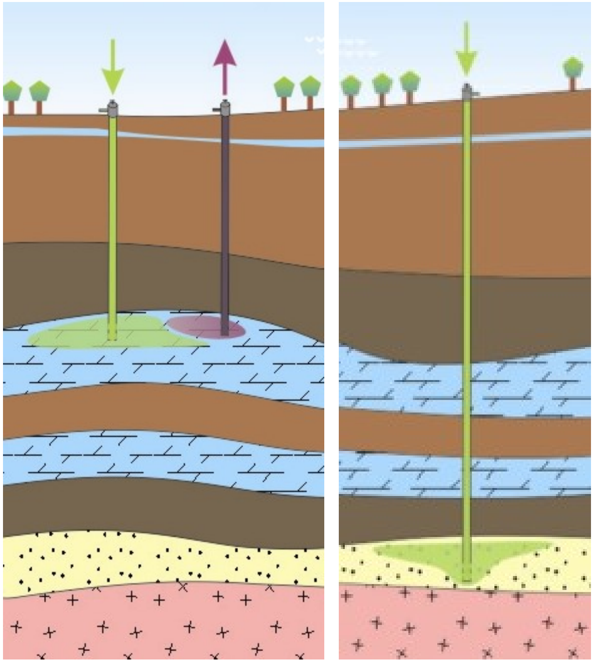

Figure 1. CO_2 storage in a reservoir with enhanced oil (Université Recherche, 2018).

CO_2 can be injected into an aquifer as liquid, gas or as supercritical fluid. Figure 2 shows the phase diagram for CO_2. The critical point for CO_2 is 72.9 atm. and 31˚C, which implies that CO_2 very often is injected as supercritical fluid. The Sognefjord Delta East aquifer is located at an average depth of 1750 m (Lothe et al., 2014), and the pressure is ranging from about 170-200 bar. At these conditions, the CO_2 density is reported to be 690 kg/m^3 and is in supercritical condition. (Lothe et al., 2014).

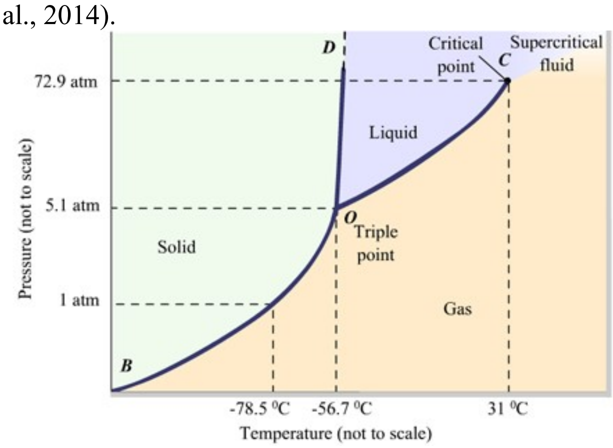

Figure 2. Phase diagram for CO_2.

A significant pressure depletion in in the storage site of the formation, will bring CO_2 into the gas phase. If this happens, the storage capacity will be significantly decreased due to the density difference between the gas phase and the supercritical phase.

When injecting CO_2 for storage, it can be a challenge to obtain even distribution of CO_2 in the aquifer. In homogeneous aquifers, the anisotropic condition is important for the distribution of CO_2. Anisotropy is the ratio vertical to horizontal permeability. Vertical or horizontal wells are used for injection of CO_2 to an aquifer. The use of horizontal wells does not improve the storage efficiency significantly, and vertical wells provide higher storage efficiency than horizontal wells under strongly anisotropic conditions. Horizontal wells are preferable if the goal is to sequester a large amount of CO_2 in a short period. (Okwen et al., 2010)

3 OLGA and Rocx

OLGA is a software developed to simulate flow of oil, water and gas in pipelines and process equipment. Rocx is a near-well reservoir simulator, which can be combined with OLGA and enables the user to specify the reservoir properties in the near-well area. The coupling between OLGA and Rocx accounts for the dynamic wellbore/rock interactions, which is not directly possible by separate reservoir and well models. (OLGA Handbook). The inputs and set-up for Rocx and OLGA are presented in the following.

3.1 Rocx

Reservoir properties as porosity, saturation, permeability, relative permeability and capillary pressure are input parameters to Rocx. In addition fluid properties as viscosity, density, bubble point and gas/oil ratio are needed for the simulations. Initial and boundary conditions are set for the reservoir. Rocx gets information from OLGA regarding pressure and pressure drop in the well and through the inflow devices. Based on the reservoir and fluid information and the information given in OLGA, the production or injection rates are calculated.

The porosity is the storage capacity of an aquifer, and is defined as the ratio of the pore volume to the total rock volume. Pores can be interconnected with other pores or completely isolated. The different types of pores are shown in Figure 3. To describe the types of porosity, effective and absolute porosity are used. The effective porosity is the volume of the interconnected pores to the total volume of the rock, and is used in reservoir engineering calculations. The absolute porosity includes the total pore volume. (Tarek Ahmed, 2006).

Saturation is defined as the fraction of the pore volume occupied by a particular fluid. In an aquifer, the saturation is given as water and gas/CO_2 saturation (Tarek Ahmed, 2006).

Permeability is referred to as absolute permeability, effective permeability and relative permeability. The absolute permeability is a rock property, and is defined as the capacity and ability of a reservoir to transmit fluids. Absolute permeability is defined from Darcy's law as:

$$\dot{Q} = \frac{k \cdot A}{\mu} \cdot \frac{dP}{dL} \tag{5}$$

where $\dot{Q}$ is the fluid volume flow, k is the permeability, μ is the viscosity of the flowing fluid, A is the cross section flow area and dP/dL is the pressure drop per unit length. The permeability is given in Darcy (D). (Tarek Ahmed, 2006).

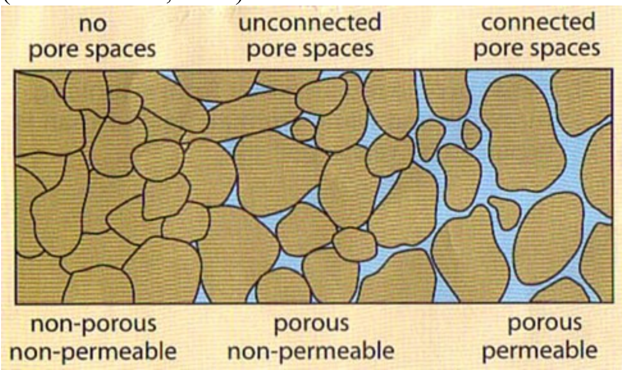

Figure 3. Different types of pores in a rock

Effective permeability is a function of the reservoir saturation and the characteristic of the rock, and is measured directly on small core samples in the laboratory. The effective permeability is measured for oil, water and gas/ CO_2. The relative permeability is the ratio of the effective permeability of a fluid to the absolute permeability. The relative permeability of each phase depends on the saturation of the different phases in the reservoir. (Tarek Ahmed, 2006).

In this study, the relative permeability curves implemented in the Rocx model are based on experimental data from literature. The relative permeability curves can also be calculated by using the Corey model for CO_2 and water. The Corey model (Rocx Online Help, 2007) for water is expressed by:

$$K_{rw} = K_{rwoc}\left(\frac{S_w - S_{wc}}{1 - S_{wc} - S_{or}}\right)^{n_w} \tag{6}$$

where S_w is the water saturation, S_{wc} is the irreducible water saturation, S_{or} is the residual oil saturation, K_{rwoc} is the end point relative permeability for water at maximum water saturation, and n_w is the Corey exponent. (Rocx Online Help, 2007). Typical values for the Corey exponent for water are $n_w = 2\text{-}3$. When CO_2 is injected into an aquifer, the residual and endpoint relative permeability changes. Figure 4 shows an example of relative permeability curves for CO_2 and brine as a function of the CO_2 saturation (Paterson et al., 2011).

Rocx is calculating the aquifer or reservoir properties as a function of time. The main focus in this paper has been to study the changes in saturation of CO_2 and water with time. Techplot has been used to plot the changes in fluid saturation in the aquifer.

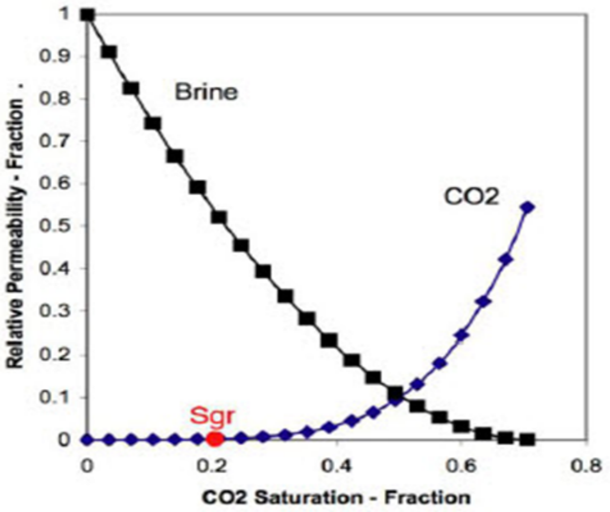

Figure 4. Relative permeability curves for CO_2 and water (Paterson et al., 2011)

3.2 OLGA

OLGA is a one-dimensional transient dynamic multi-phase simulator used to simulate flow in pipelines and connected equipment. The OLGA simulator is governed by conservation of mass, momentum and energy equations for the different phases (OLGA Handbook).

The well or injector design can be specified in OLGA. Figure 5 shows a set-up for injection of CO_2 for EOR in an oil reservoir tested by Vesjolaja et al. (Vesjolaja et al., 2018). Pressure sources are used for the injection points. However, it was concluded that injection of CO_2 directly to the reservoir, was not possible. The reason was that in the available OLGA/Rocx model, the only option was to use the black oil model, which was not compatible with CO_2 injection (Vesjolaja et al., 2018). The effect of CO_2 injection was therefore simulated by changing the relative permeability curves.

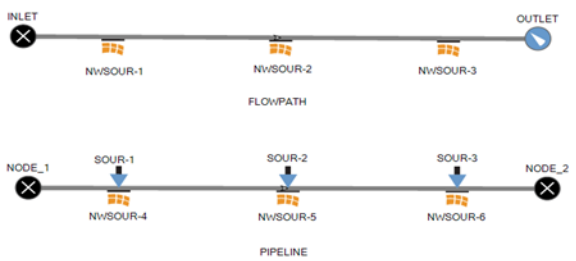

Figure 5. CO_2 injection design in OLGA (Vesjolaja et al., 2018).

In this study, the simulations are carried out by assuming that CO_2 with a constant pressure is injected continuously from the bottom of the aquifer. The constant CO_2 pressure is specified in Rocx as the pressure boundary condition.

In addition to the injector or well geometry, fluid properties and conditions, initial and boundary conditions, time steps and production/injection period are specified as input to OLGA. The results are plotted as trend plots (selected parameter as a function of time) or as profile plot (selected parameter as a function of location in a well/injector).

4 Results

Simulations have been carried out using the simulation tool Rocx in combination with OLGA.

4.1 Input data to OLGA and Rocx

The characteristics of the aquifer were chosen based on the available information about the Smeaheia aquifer. The aquifer is simulated as a homogeneous rock with an average porosity of 0.21 and horizontal permeability of 690 mD. The CO_2 is injected as supercritical fluid with density 711kg/m^3. The rock is defined as sandstone. The characteristics of the Sognefjord Delta East aquifer are listed in Table 1 together with the characteristics used in the simulations.

The simulated aquifer has a length, width and height of 105 m, 101m and 100 m respectively. The horizontal CO_2 injector is assumed located in the bottom of the aquifer, and is specified as a constant pressure boundary condition. To simulate the pressure difference between the injector and the aquifer, a well is located in the upper part of the aquifer. The boundary condition for the well is constant outlet pressure. Figure 5 presents a schematic overview of the simulated aquifer.

The CO_2 drive pressure from the bottom of the aquifer is 175 bar and the pressure at the outlet of the well is set to 130 bar. The number of control volumes in x-, y- and z-direction are 5, 21 and 10 respectively. It was assumed that the initial saturation of water in the aquifer was 100%.

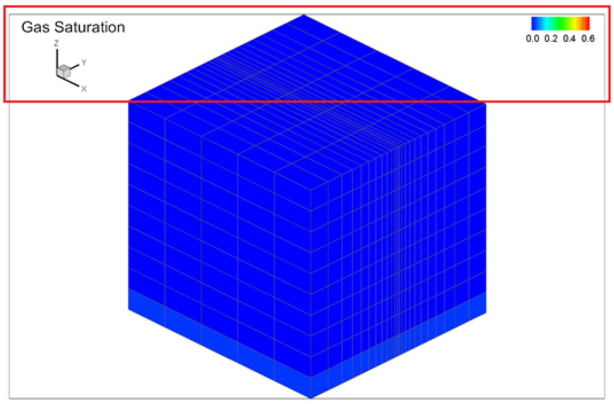

Figure 6. Schematic overview of the simulated aquifer.

The design of the well was developed in OLGA and is presented in Figure 7. The well includes connection to the aquifer via the sources (NWSOUR-1, NWSOUR-2, NWSOUR-3). The “leaks” (LEAK-1, LEAK-2, LEAK-3) represent the flow from the annulus (PIPELINE) through the open valves (VALVE-A, VALVE-B, VALVE-C) to the production pipe (FLOWPATH). Packers are presented as closed valves (VALVE-1, VALVE-2) and are used to avoid annulus flow. The outlet pressure from the well is 130 bar, and is specified as a boundary condition in the pressure node.

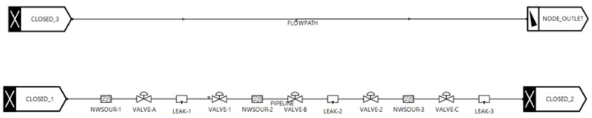

Figure 7. Well design including valves, packers, sources and leaks.

A summary of the input parameters to OLGA and Rocx are presented in Table 1, and the relative permeability curves used in the simulations are shown in Figure 8.

Table 1. Characteristics of Troll aquifer field and the simulated aquifer.

Parameter	**Troll aquifer**	**Simulated aquifer**
Water density	1023	Calculated at reservoir conditions
CO_2 density	711 kg/Am^3	711 kg/Am^3
Porosity	0.21	0.21
Permeability	690 mD	x- and y- directions: 690 mD z-direction: 69 mD
Volume aquifer	$5.54 \cdot 10^{11}$m^3	$1.06 \cdot 10^6$ m^{3}and $2.12 \cdot 10^6$ m^3
Thickness		100 m
Aquifer pressure	175 bara	175 bara
Aquifer temperature	54 °C	54 °C
Initial water saturation	-	1
Irreducible water saturation	-	0.2
Residual CO_2 saturation	-	0.2

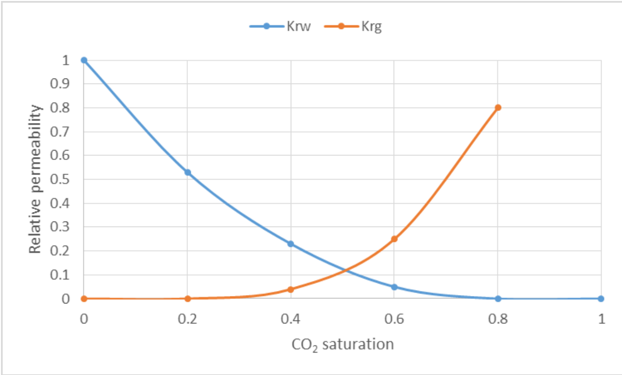

Figure 8. Relative permeability curves for water (blue) and CO_2 (red).

4.2 Results

Three different cases were simulated, Case 0 (Base case), Case 1 and Case 2. In Case 0 and Case 2, the length, width and height of the aquifer are 105m, 101m, 100m respectively. In Case 1, the length of the aquifer is increased to 210m, whereas the width and the height are the same as for Case 0 and Case 2. The well is located in the top of the aquifer, and has a length of 105m for all the cases. In Case 0 and Case 1, it was assumed that CO_2 was injected continuously from the whole bottom area of the aquifer. In Case 2 CO_2 was injected through only one control volume with area 105 m^2. The conditions for the cases are mainly selected to study the effect of the injection area and the aquifer length on CO_2 distribution and storage in the in the aquifer. The model is not validated to give exact results about CO_2 saturation and storage in the aquifer as a function of time. Also, the pressure drive (175-130 bar), which gives the injection rates, is set high to reduce the required simulation time. A grid resolution test is not performed in this study, but has earlier been performed by the research group for similar cases. The mesh is found to be acceptable to see whether the injection method and reservoir length have an effect on the distribution and storage of CO_2 in an aquifer. Figure 9 presents the distribution of CO_2 in the aquifer after 0, 20, 50 and 80 days. It can be seen that the CO_2 is equally distributed over the x-y area, and are moving gradually towards the top section with time. After 80 days, the average saturation of CO_2 in the aquifer is about 50%.

The results from simulation of Case 1 are presented in Figure 10. In this case, the length of the well (105 m) is half of the aquifer (210 m) and is located on the left side of the upper surface. Due to the location of the well, the CO_2 is not evenly distributed in the aquifer, and after 120 days, the water saturation in the upper right part of the aquifer is still about 100%.

Figure 11 shows the location of the CO_2 injection in Case 2, and Figure 12 gives the distribution of CO_2 in the aquifer after 30, 60, 90 and 105 days. As can be seen, the distribution of CO_2 with time is very different when the CO_2 is injected from a small area. The CO_2 is not distributed equally with height in the aquifer, and large areas contain about 100% water.

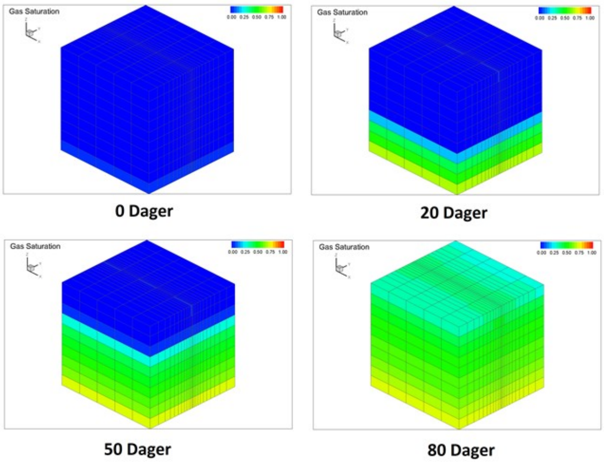

Figure 9. Distribution of CO2 in the aquifer, Case 0.

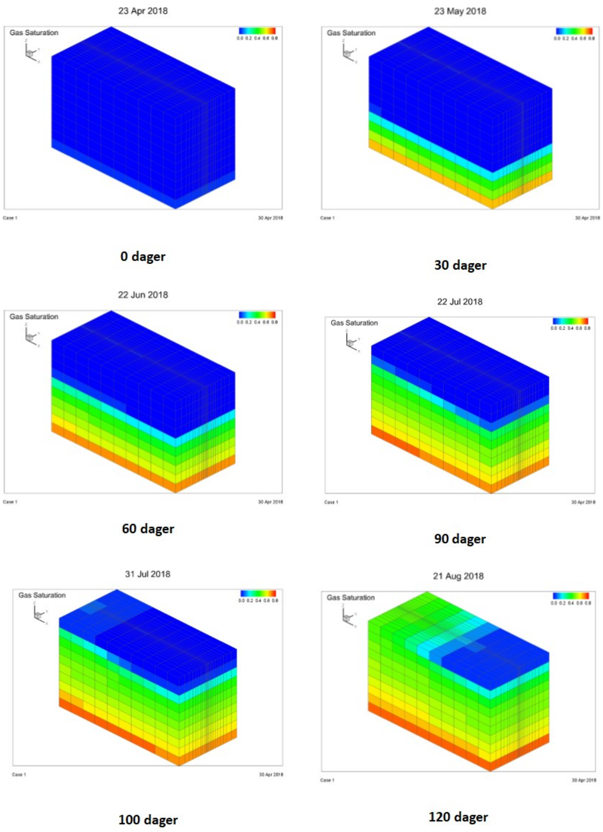

Figure 10. Distribution of CO_2 in the aquifer, Case 1.

However, after 105 days, CO_2 is about equally distributed up to a height of about 80 m. After 124 days, CO_2 breakthrough to the well occurs. The CO_2 storage for Case 2 is calculated based on 124 days.

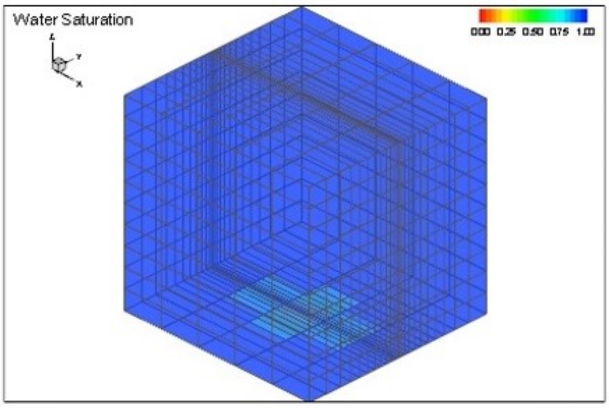

Figure 11. Injection of CO_2 from a limited area, Case 2.

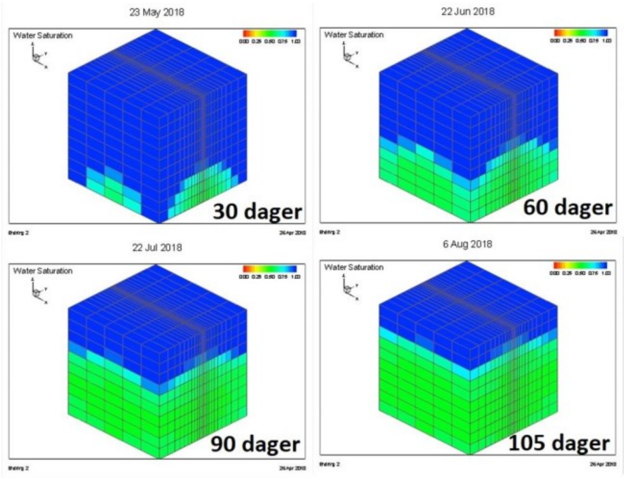

Figure 12. Distribution of CO_2 in the aquifer, Case 2.

The replaced mass of water for the three cases is presented in Figure 13. The storage of CO_2 in the aquifer is calculated from Equation (1) and summarized in Table 2. The calculations are based on the mass of displaced water until breakthrough of CO_2 to the well occurs. After breakthrough, the well is mainly producing CO_2, and these periods are therefore not considered in the calculations of CO_2 storage. To calculate the storage of CO_2, the density ratio of water and supercritical CO_2 is used. The displaced water is calculated from OLGA, and is the water produced in the period before breakthrough of CO_2 to the well. The breakthrough occurred after 82, 116 and 124 for Case 0, Case 1 and Case 2 respectively. The calculated storage of CO_2 for Case 0, Case 1 and Case 2 are 2590 ton, 3795 ton and 2560 ton. By comparing Case 0 and Case 1, the storage of CO_2 is significantly higher in Case 1 because the simulated aquifer is twice as big as in Case 0, and that the storage has occurred for a longer period. Case 2 gives about the same amount of stored CO_2 as Case 0, but the storage period is longer than in Case 0 and Case 1. This is due to the small injection area used in Case 2. The injection area was 105 m^2 in Case 2 compared to 10605 and 21210 m^2 in Case 0 and Case 1 respectively. However, for all the cases, a good distribution of CO_2 in the aquifer is obtained over time.

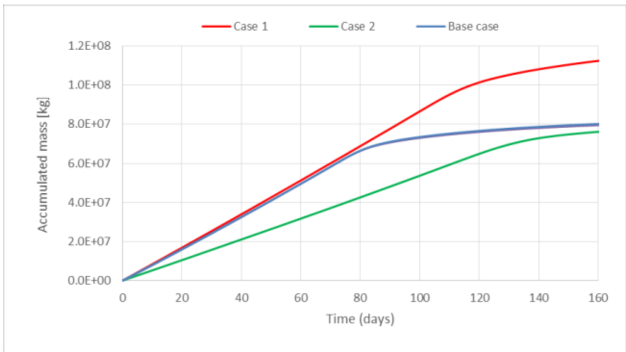

Figure 13. Displaced water during simulation of Case 0, Case 1 and Case 2.

This result is in good agreement with the results from the study performed by Okwen et al. (Okwen et al., 2010). The simulations with OLGA/Rocx managed to meet the objective of this study, which was to show the effect of injection area and aquifer volume on CO_2 distribution and storage. However, to produce more accurate results, effort has to be made to develop a robust model without the current limitations. Case 2 is the most relevant case and will be used as basis for further studies.

Table 2. CO_2 storage capacity calculated from Eq. 1.

Case	Pore volume of simulated aquifer [m^3]	CO_2 [ton] storage
Case 0	222700	2590
Case 1	445400	3795
Case 2	222700	2560

5 Conclusion

Storage of CO_2 in an aquifer in the North Sea is considered. Simulations are carried out on a limited part of the aquifer. Available information about porosity, permeability, pressure and temperature in the aquifer are used as input to the simulations. OLGA and Rocx are used as the simulation tools. Due to problems with implementing a CO_2 injector in OLGA/Rocx, a model was developed where water was displaced by CO_2 and removed from the aquifer through a production well. After a period, CO_2 breakthrough to the well occurred. Three different cases where run to study the distribution of CO_2 in the aquifer with time and the CO_2 storage for the period before breakthrough. By comparing the cases, it was found that in all the cases CO_2 was evenly distributed in the aquifer with time independent on the injection area and the length of the production well compared to the length of the aquifer. The case with the smallest injection area is the most relevant case because real injection of CO_2 occurs through orifices in vertical or horizontal injectors. It was shown that the storage capacity is dependent on injection period and volume of the aquifer, and not on the injection area. For further studies of CO_2 injection and distribution of CO_2 in aquifers a new model will be developed and validated against experimental core tests. In addition, a grid resolution test will be performed, and the driving pressure will be reduced. If possible, a CO_2 injector will be implemented in OLGA to obtain more realistic injection rates.

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