CO_2-Brine Relative Permeability Characteristics of Low Permeable Sandstones in Svalbard

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ABSTRACT

The possibility of sequestration of carbon dioxide in a saline aquifer of sandstones in Svalbard is being studied. The selected reservoir is a 300 m thick, laterally extensive, shallow marine formation of late Triassic-mid Jurassic age, located below Longyearbyen in Svalbard.

The permeability of the formation is typically below 1 mDarcy. This paper presents the experimental protocol and detailed CO_2-brine drainage and imbibition relative permeability data for two different samples of rock. Laboratory core flooding experiments at reservoir conditions were conducted on two 32 and 35 cm long sandstone samples from the depth 675 m (sample 1) and 679 m (sample 2). During the CO_2 injection, less than 20 percent of the brine inside the core was displaced. Capillary pressure measurements and simulation of the transient process was used to support the interpolation of the experimental flooding data.

Initial x-ray computed tomography scan showed no sign of fractures inside the cores, whereas after the core flooding experiments, there are visible fractures especially in sample 1. A thin section analysis on sample 1 showed that there are a lot of diagenetic iron-minerals in the sandstones like Fe-chlorite, Fe-carbonate ($FeCO_3$), and pyrite (FeS_2). A brownish output flow from the sample 1 indicates that the iron minerals inside the core have been oxidized. Dissolution of CO_2 in the brine forms a weak acid that reacts with iron-minerals like Fe-chlorite and siderite and may form a Fe-complex.

INTRODUCTION

Svalbard is located on the north-western margin of the Barents Shelf. The coal-fired power plant in Longyearbyen is small, annual CO_2 emission averaging 85000 tons/year, making it well-suited for test purposes. These considerations formed the background for establishing the Longyearbyen CO_2 laboratory–a joint effort by academic institutions and industry to establish a test facility for CO_2 capture and injection in Longyearbyen. Implementing numerical models for CO_2 storage in the saline aquifer in Longyearbyen in Svalbard will need information about CO_2-brine relative permeability and capillary pressure.

In this study, first 50 samples from different sections of reservoir were tested in order to find out which parts have highest potential for CO_2 storage. Subsequently, we performed

CO_2-brine core flooding experiments at reservoir conditions on two long samples. Drainage and imbibition relative permeability curves for CO_2-brine system were achieved. Capillary pressure measurements and simulation of the transient process were used to support the interpolation of the experimental flooding data.

GEOLOGICAL SETTING

The intended storage site is located in the Upper Triassic – Middle Jurassic Kapp Toscana Group which is capped by 400 m shale. In well Dh4, the reservoir, encountered between 672 and 970 m depth, consists of the Knorringfjellet and the underlying De Geerdalen formations [1]. A total of 50 samples of core material from well Dh4 were collected and tested for routine core analysis. Porosity values range from 5 to 20 percent, whereas permeability ranged from not measurable to 2 mD. According to the core analysis, there are four potential intervals for CO_2 injection (Figure 1).

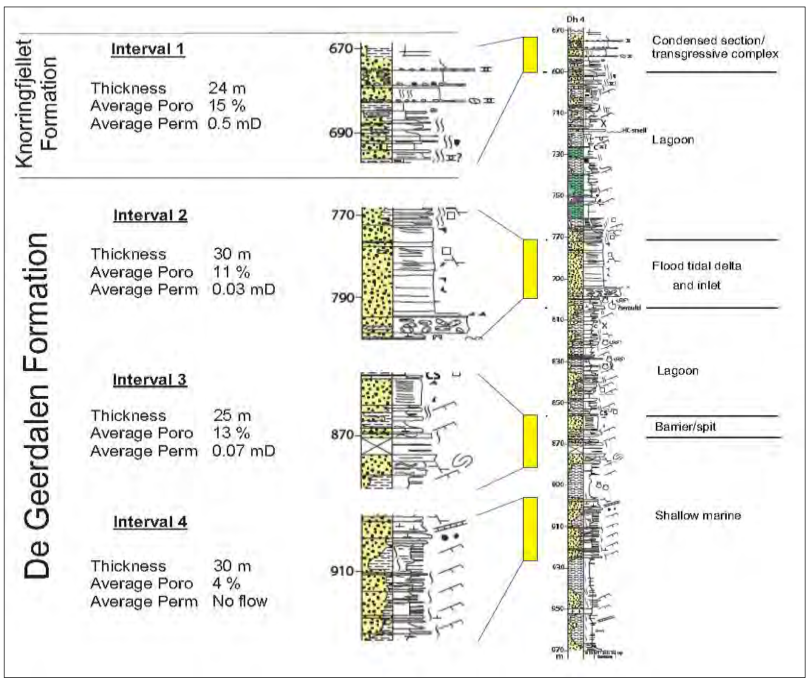


Figure 1: The potential intervals for injecting CO_2 storage [2], [3].

Sample preparation

The plug samples were taken outside fractures in order to avoid breakage. The uppermost 24 meters of the Knorringfjellet Formation exhibit the highest porosity and permeability values. For more analysis we chose two samples from Interval 1. The petrophysical properties of both cores are summarized in **Table 1**.

Table 1: Samples properties

Property	*Depth, m*	*Length, cm*	*Diameter, cm*	*Porosity*
Sample 1	675.16-675.48	31.98	4.75	10 %
Sample 2	679.58-92	34.75	4.75	3.5 %

The sample 1 represents fine grain marine sandstone with distribution of quartz cement and stylolites. In sample 2, very fine-grained sandstone is strongly influenced by compaction and quartz cementation. Figure 2 shows an optical micrographs of sandstone for sample 1, cemented by siderite (brown), Fe-rich clay (green), and pyrite (black). Porosity is mainly isolated dissolution pores (blue) and micropores in fibrous clay, explaining the low permeability.

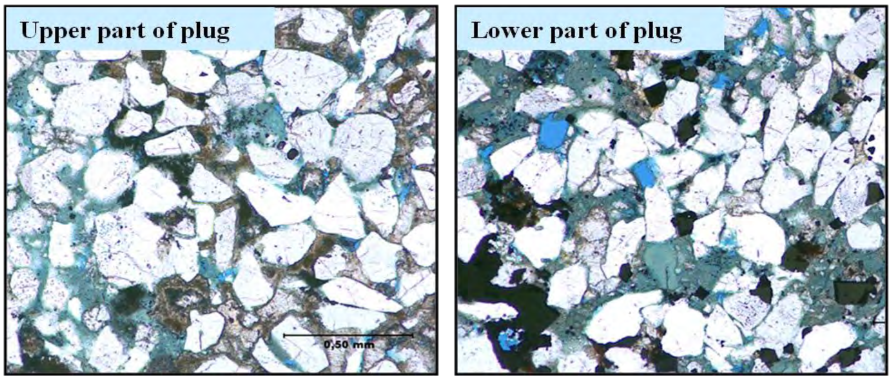


Figure 2: Optical micrographs of upper and lower parts of sample 1

EXPERIMENTAL PROCEDURE

The following procedures were applied for each of the experiments:

1. The core was placed vertically in the core testing apparatus and was evacuated to remove trapped gas and 200 bar net reservoir overburden pressure was applied. Then the samples were saturated with 1% NaCl brine;
2. Pore pressure was increased to desired reservoir value above 75 bar while the working temperature is maintained at 20^{o}C which is close to reservoir temperature;
3. CO_2-saturated water (saturated at pressure of 80 bar and room temperature) was used to displaced the saline water until a constant gas/water (GWR) ratio of 36 Sml/Sml and stabilized baseline permeability at the 100% water saturation level was obtained;
4. CO_2 injection began at a constant rate (0.01-0.5 Rml/min) and at the pressure of 80 bar and temperature of and 21^{o}C. The pressure at production outlet was fixed at 75 bar to keep CO_2 as liquid phase. The injection process was continued until at stabilized pressure drop no more water was produced. The gas and water flow rates and the pressure drop during the core flood were monitored. At the end, to verify end point saturations, the samples were weighed [4] [5];
5. The samples were cleaned and dried and the procedures 1 and 2 were repeated. The samples were flooded by CO_2 until stabilized baseline permeability at the 100% CO_2 saturation level is obtained. CO_2-saturated water were used to displace the CO_2 until at stabilized pressure drop no more CO_2 was produced;

The procedure number 5 represents an imbibition process which was applied at zero water saturation. This procedure was conducted because the samples are very tight and CO_2 flooding process was affected by capillary end effect. And the resulting sample from drainage process was not the right sample to be used for imbibition process. Then we applied the procedure number 5. Capillary pressure measurements were performed to determine the actual residual saturations. Later on with the simulation of the transient process, the experimental flooding data were interpolated to the actual residual saturations.

Initial x-ray computed tomography scan showed no sign of fractures which were visible in sample 1 after the core flooding experiments (Figure 3). During the CO_2 injection, brown water was produced from the core 1. The brownish output flow from the sample 1(Figure 3) indicate that the iron minerals inside the core have been oxidized. Dissolution of CO_2 in the brine forms a weak acid that reacts with iron-minerals like Fe-chlorite and Sidereite and may form Fe-complex.

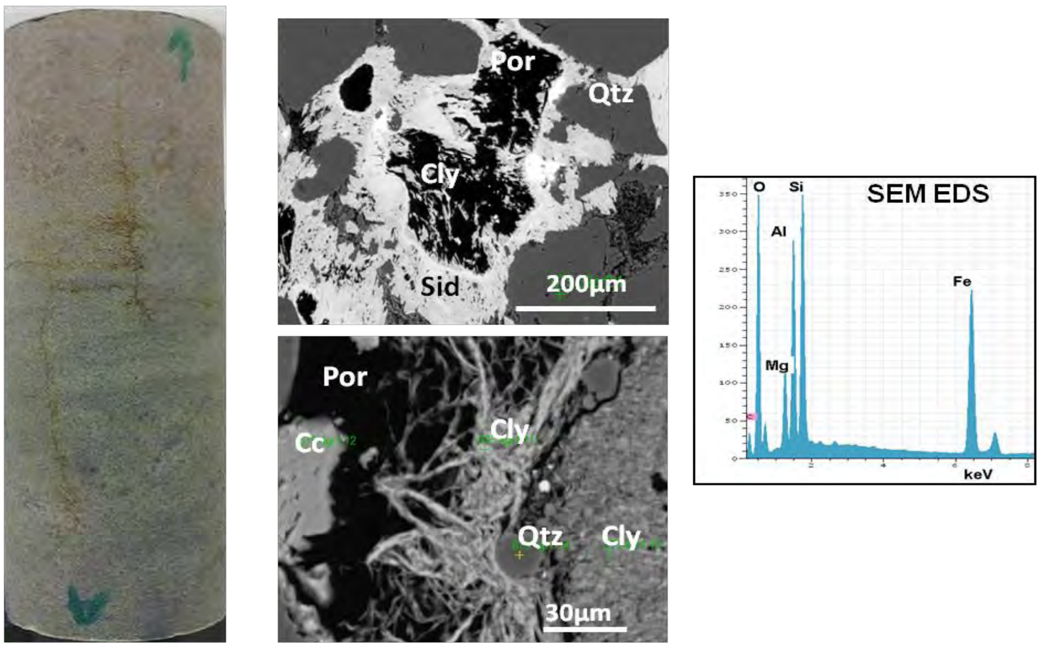
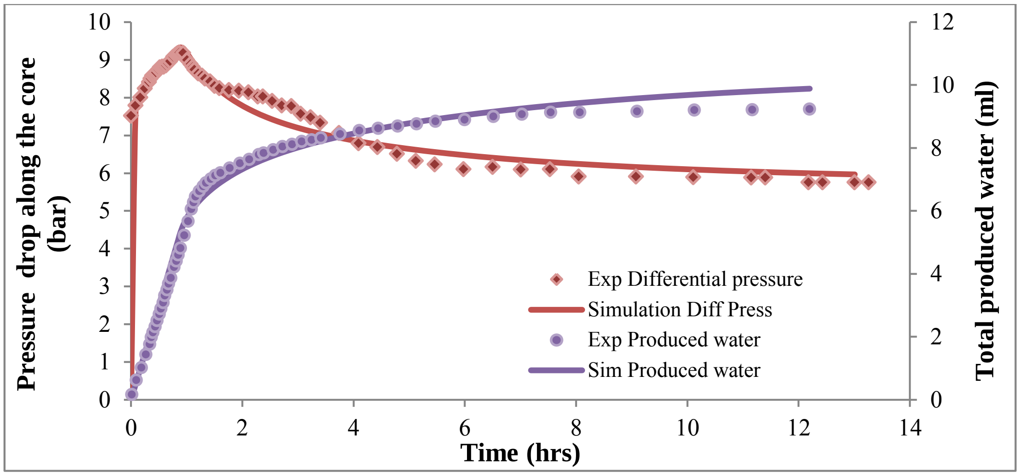


Figure 3: Core 1 after CO_2-brine flooding test, SEM backscattered electron images showing details of siderite (Sid), clay minerals (Cly), calcite (Cc) and porosity (black). Qtz = quartz grains. Note the fibrous structure and iron-rich composition (see EDS spectrum) of the clay mineral chlorite.

SIMULATION STUDY

The simulation tool employed in this study is Sendra 2011.3. The simulator can accurately interpolate the CO_2-brine relative permeability by matching the experimental data. Figure 4 shows the experimental and simulation results for CO_2-brine flooding on samples. Figure 5 shows the relative permeability curves which were achieved by simulation. In simulator, the end point saturations were set from centrifuge capillary pressure data. And then the relative permeability curves were tuned to these points by matching the experimental data.



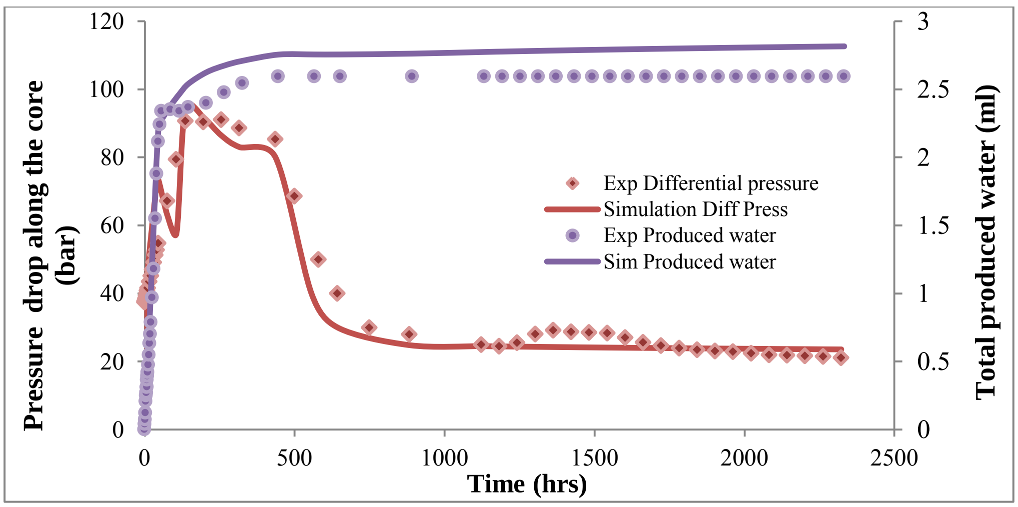


Figure 4: Simulation and experimental results for CO_2-brine flooding on core 1(upper) and on core 2 (lower)

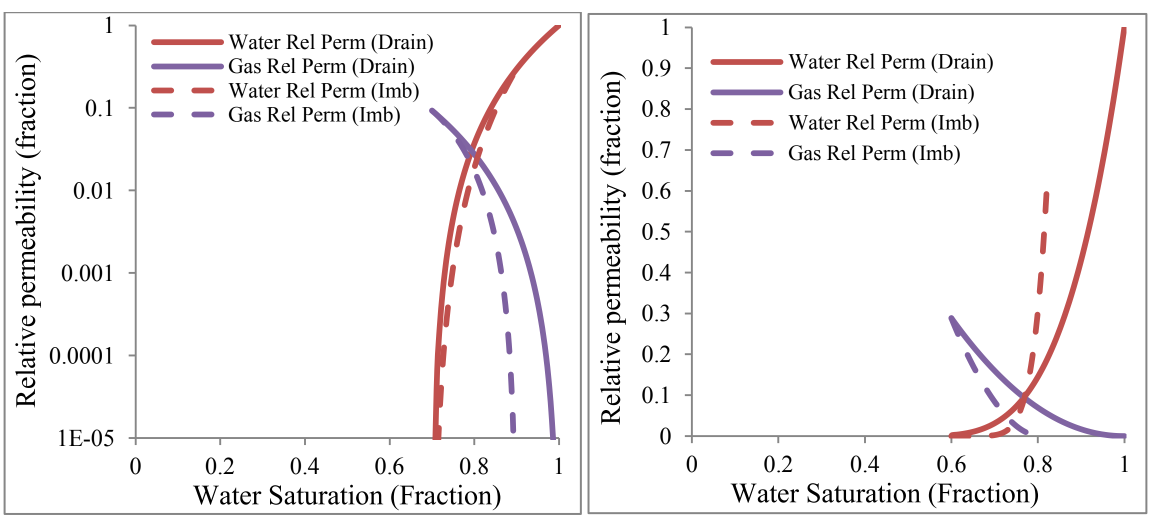


Figure 5: Relative permeability curves for core 2 (left) and core 1 (right)

During imbibition process on sample 1 the core showed better injectivity to brine. This behavior which can be seen from water relative permeability curve was most likely due to dissolution of calcite cement and iron minerals in weak acid which is formed by CO_2 dissolution in brine and formation of some micro fractures in the core. Compared to sample 1, sample 2 showed much lower absolute permeability to brine and lower displacement efficiency of brine by the CO_2 injection, resulting in high irreducible water saturations.

CONCLUSION

CO_2-brine flooding tests on two samples from the same formation showed that CO_2 can displace 30-40% of the brine. Severe hysteresis effects on sample 1 most likely resulted from changes in the rock composition and formation of new micro fractures in the core. The relative permeability characteristics of the sample 2 showed that the presence of very small amounts of residual gas saturation in the core reduced the permeability to brine significantly.

ACKNOWLEDGMENT

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