EXPERIMENTAL INVESTIGATION OF RESIDUAL CO_2 SATURATION DISTRIBUTION IN CARBONATE ROCK

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ABSTRACT
Carbon dioxide (CO_2) geological injection and storage have been topical research since the reduction of CO_2 from atmosphere is required as one of greenhouse gas and CO_2 has been used for the enhanced oil recovery (EOR). In order to contribute the advancement of CO_2 geological sequestration and its multiphase flow analysis, a coreflood experiment using carbon dioxide and brine on the carbonate rock is conducted with in-situ saturation monitoring by X-ray Computed Tomography (CT). CO_2 saturated brine is used in one of the experimental processes to avoid the dissolution of carbon dioxide into the brine. It is important to measure the trapped CO_2 saturation to estimate the amount of CO_2 residual trapping in the rock. The experimental result clearly shows the relationship between rock heterogeneity and residual CO_2 saturation even in the same rock sample as the injected CO_2 flows through more porous area and it is trapped at lower porosity area. Residual CO_2 saturation by capillary trapping is observed on the Middle Eastern carbonate rock. The study also gives us the insight for the CO_2-EOR with enhancing recovery and simultaneously storing CO_2 by capillary mechanism. In-situ saturation monitoring is the key to understand fluid movement and trapping. The relationships among porosity, saturation and flow rate are discussed based on the experiment and the analysis.

INTRODUCTION
CO_2 atmospheric emissions by human activity are considered to be one of the causes of global warming as the CO_2 is one of greenhouse gase. The increase of CO_2 emission affects global carbon cycle and it seems to relate recent unusual climate conditions. Therefore, to limit and reduce CO_2 emission is necessary, but it is a challenge as the primary source for the emission is energy use. Intergovernmental Panel on Climate Change (IPCC) published a special report on carbon dioxide capture and storage (IPCC, 2005) and it refers CO_2 capture and storage (CCS) is one of technical options to reduce greenhouse gas from atmosphere. CO_2 geological sequestration is considered to be a long-term storage and there are different options, such as

(1) depleted oil and gas reservoirs, (2) enhanced oil and gas recovery, (3) enhanced coal beds methane recovery and (4) deep saline aquifers. For these options, monitoring of CO_2 is necessary since one of concerns is the leakage from subsurface to atmosphere. Lower density and viscosity of CO_2 compared to brine causes the migration to the top of the geological structure and CO_2 may leak through the cap rock due to over-pressurization. Simulations of CO_2 injection and migration, therefore, have been studied by many authors (Pruess et al., 2003, Obi and Blunt, 2006). At the geological structures, four trapping mechanisms are mainly considered: (1) structural and stratigraphic trapping: the buoyant CO_2 remains as a mobile fluid but is stored under impermeable cap rocks, (2) residual phase trapping: disconnection of the CO_2 phase into an immobile fraction, (3) solubility trapping: dissolution of the CO_2 into the brine, possibly enhanced by gravity instabilities due to the larger density of the brine and (4) mineral trapping: geochemical binding to the rock due to mineral precipitation. In this paper, residual CO_2 saturation distributions in the carbonate rock are evaluated experimentally with assuming CO_2 injection into saline aquifers. Therefore, CO_2 is the nonwetting phase, and capillary trapping of the CO_2 is the important mechanism to avoid the leak from the geological storage, which can be understood by the multiphase flow experiment on the rock.

EXPERIMENT

Rock Properties

Rock samples from the Middle Eastern carbonate reservoir are used in this study. The original core is composed mainly of bioclastic grainstone and packstone with some algal fragments which form vuggy pore spaces. This rock exhibits a substantial presence of sub-micron porosity as the micro-CT image for the sister sample shown in Figure 1 with Mercury Injection Capillary Pressure (MICP) curve. The pore diameter is estimated by Washburn equation. A core plug with 38 mm in diameter and 75 mm long is used in the coreflood experiment. Prior to the coreflooding, effective porosity of the plug core is measured with the X-ray CT scanner system, which gives the average porosity of 14.0% and the three-dimensional (3D) porosity distribution as illustrated in Figure 1(c). Note there is the highest porosity region with over 20 % porosity in the lower half of the image.

Experimental Setup/Procedure

The experimental diagram and its main part with X-ray CT scanner and the core holder are shown in Figure 2. The experimental temperature is 40ºC and the overburden pressure is 2,000 psig. The key steps of the coreflood experiment are as follows:

1) Take a CT image of the plug core under dry condition.
2) Inject CO_2 and take a CT image under 100% CO_2 saturation (supercritical CO_2 condition).
3) Inject brine and take a CT image under 100% brine saturation to calculate the porosity distribution.

4) Inject CO_2 saturated brine and take a CT image under 100% CO_2 saturated brine saturation.
5) Inject brine again to saturate the core.
6) Inject CO_2 at the designed flow rate until no more brine is produced and the pressure difference becomes stable. In-situ saturation monitoring is conducted by the X-ray CT during the CO_2 flooding experiment. Some CO_2 dissolve to the brine and the process takes time to stabilize.
7) Inject CO_2 saturated brine to confirm the CO_2 trapping in the rock sample.

Our previous paper describes a full detail of coreflood procedure with in-situ saturation monitoring by X-ray CT under designated temperature conditions (Okabe et al., 2006) as well as the accuracy of the CT measurements (Oshita et al., 2000). The accuracy of CT derived porosity and saturations depends on an attenuation contrast of X-ray between fluid phases. In this study, 15wt% NaI is used as a dopant to the brine phase and the accuracy of the measurements of porosity and saturations is evaluated at ±1 Bulk Volume% and ±2 Pore Volume%, respectively. The temperature is kept at 40ºC during the experiment and the overburden / pore pressures are 2,000 / 1,420psig. Fluid permeability measured in the course of the above steps is 6.7md for the plug core. Both CO_2 flood and waterflood are conducted at a flow rate of 0.5cc/min except the flow rates for the CO_2 injection are changed to 1cc/min and 4.5cc/min after 5 and 10PV, respectively.

RESULTS

The carbonate core plug shows strong heterogeneity in terms of the porosity and the saturation distributions illustrated in Figure 3. CO_2 flows through porous areas (lower parts of the horizontal cuts in each figures), which is similar to the water injection to the mixed-wet carbonate rock. As shown in Figure 3(a) and (b), CO_2 firstly dissolves into the brine phase as the saturation change is not clearly shown. The difference of CT value between brine and CO_2 saturated brine is very small as the density contrast is little. The saturation change, however, is observed after 2PV CO_2 injected in Figure 3(c) as the density contrast between CO_2 and brine can be captured by CT value. At the 5PV injection, the flow rate is increased from 0.5cc/min to 1cc/min and then 4.5cc/min at the 10PV injection. The average water saturation is decreased to 0.6. In order to estimate the residual CO_2 saturation with rock heterogeneity and to confirm the capillary trapping of CO_2, CO_2 saturated brine is then injected as shown in Figure 3(g)-(i). The water saturation cannot be restored to the initial condition even after 7.5PV injection and the heterogeneous water saturation distribution is observed. The residual CO_2 saturation distribution correlates the porosity distribution as shown in Figure 4(b). The trapped CO_2 saturation in this carbonate rock is 0.23 on average, which excludes the amount of dissolved CO_2 into brine.

CONCLUSION

In order to visualize and understand the CO_2 saturation distribution in the rock sample, the coreflood experiment using CO_2, CO_2 saturated brine and reservoir brine is conducted with in-situ saturation monitoring by X-ray CT. CO_2 saturated brine is used to avoid the dissolution of carbon dioxide into the brine in order to measure the residual CO_2 saturation. The experimental result clearly shows the relation between rock heterogeneity and residual CO_2 saturation even in the same rock sample. The injected CO_2 flows through more porous area and it is trapped at lower porosity region. The trapped CO_2 saturation in the experiment is 0.23 on average, which excludes the amount of dissolved CO_2 into brine. Residual CO_2 saturation by capillary trapping is observed on the Middle Eastern carbonate rock. The study also gives us the insight for the CO_2-EOR with enhancing recovery and simultaneously storing CO_2. In-situ saturation monitoring is the key to understand fluid movement and trapping. For the future work, microstructures of the rocks and fluid interactions will be investigated by the pore-scale modeling.

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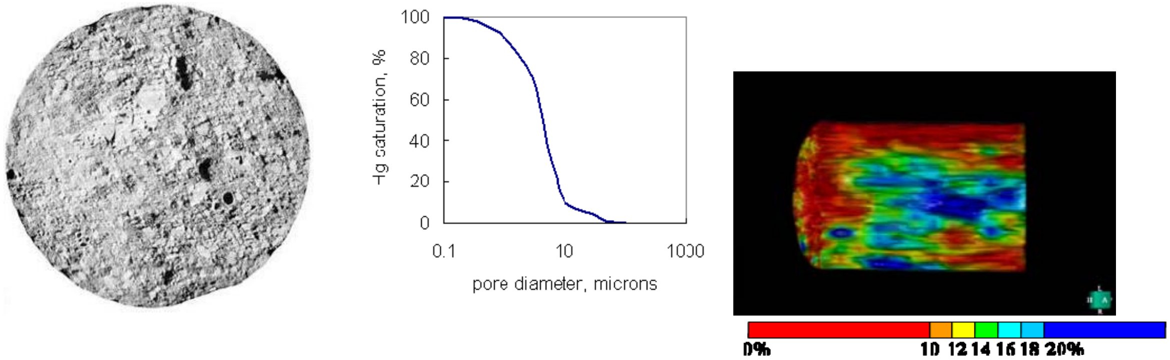

(a) tomographic image (b) MICP curve (c) 3D porosity distribution

Figure 1. (a) A grey scale tomographic image of the carbonate subsample with 5 mm in diameter and the voxel size 2.8μm. (b) Mercury Injection Capillary Pressure (MICP) experimental data for the subsample. Note that only ≈50% of the pore space is connected via resolvable throats in the micro-CT image data. (c) three-dimensional (3D) porosity distribution of the plug core (horizontal cut) used for the coreflood experiment.

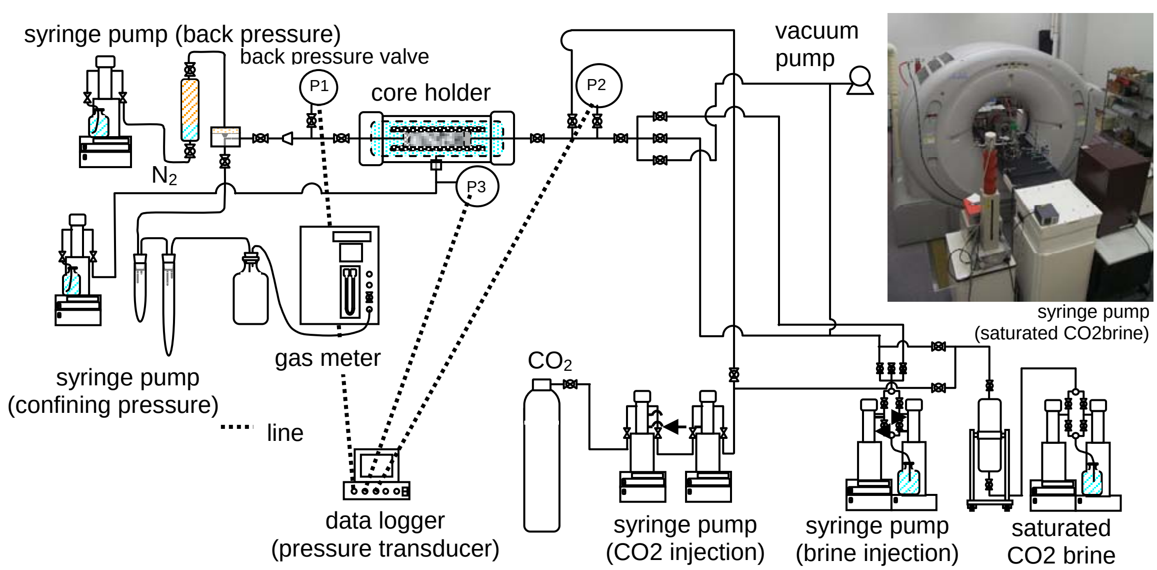

Figure 2. The X-ray CT coreflood system with developed temperature control units for designed temperature conditions. The orange rubber heater covers the coreholder and the line heaters are attached to the fluid injecting lines. The diagram on the right is typical coreflood experimental system.

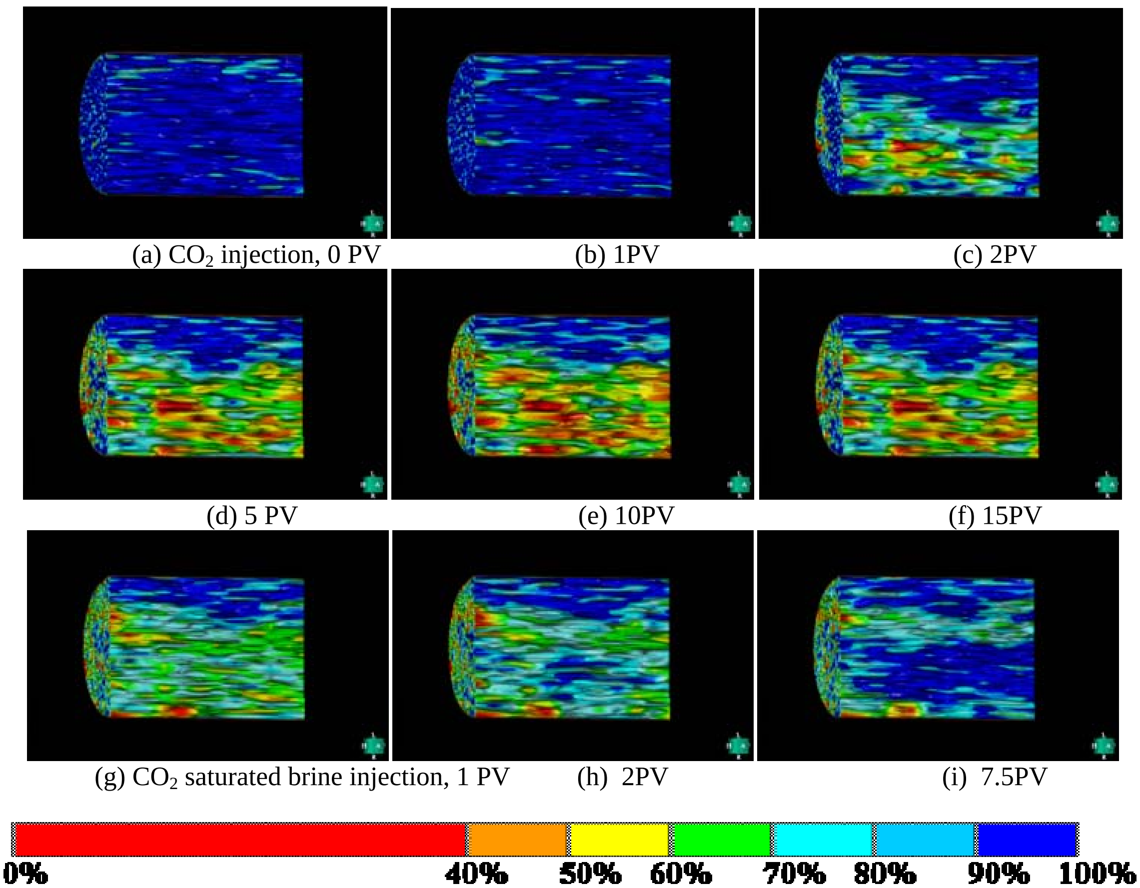

Figure 3. X-ray CT derived saturation distribution during the CO_2 flood (a-f) and post-flood by the CO_2 saturated brine (g-i) on the carbonate rock. The horizontal cuts are visualized and the scale shows water saturation.

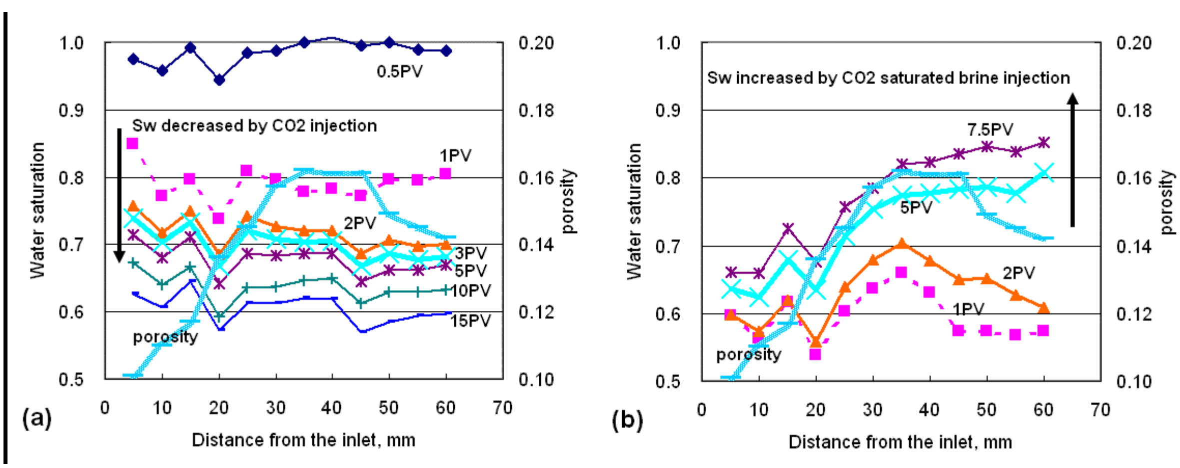

Figure 4. X-ray CT derived water saturation distribution during the CO_2 flood (a) and post-flood by the CO_2 saturated brine (b) on the carbonate rock.