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CALCITE PRECIPITATION IN LOW TEMPERATURE GEOTHERMAL SYSTEMS: AN EXPERIMENTAL APPROACH

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ABSTRACT

One of the most common production problems in geothermal fields is calcite (calcium carbonate) scale deposition. Calcite formed in the wellbore and in near wellbore region significantly decreases the output of a production well. Calcite scaling is experienced in almost all the geothermal fields around the world. Calcite may form from hydrolysis, boiling and heating of cooler peripheral fluids. Although there are plenty of mathematical modeling studies that try to explain the rock-fluid-carbon dioxide reaction kinetics, experimental studies are limited in number. This study presents results of computerized tomography (CT) monitored laboratory experiments where CO_2 was injected in carbonate cores at three different temperatures. Porosity changes along the core plugs and the corresponding permeability changes were reported for differing temperatures. CT monitored experiments were designed to model fast near well bore flow and slow reservoir flows. It was observed that permeability initially increased and then decreased for slow injection cases. As the salt concentration decreased, the porosity and thus the permeability decrease was less pronounced. Furthermore, rock-fluid-carbon dioxide interactions were seen to be affected by the orientation of the core plugs used in experiments. In vertical experiments, it is observed that permeability increased at the beginning, and then decreased for later times. On the other hand, for horizontal core plugs, permeability change was observed to be completely in reverse order. Because of the preferential paths, sometimes permeability alteration trend did not match with the porosity alteration trend. Experiments showed that solubility of CO_2 is larger compared to mineral trapping and temperature have great influence on chemical kinetics, thus on permeability change.

INTRODUCTION

One of the most common production problems in geothermal fields is calcite (calcium carbonate) scale deposition. Calcite blockages formed in near wellbore region or in the wellbore decrease significantly the output of the production well. Calcite scaling is experienced in almost all the geothermal fields around the world, i.e. in the Dixie Valley geothermal field, Nevada (Benoit, 1989), in Ohaaki geothermal field, New Zealand (Clotworthy et al., 1995 and Nogara, 1999), in Seltjarnarnes geothermal field, Iceland (Kristmansdottir et al., 1995) and in Coso geothermal area in California (Evanoff et al., 1995). In extreme cases, most of the production wells and surface facilities may get blocked by calcite scale and serious generation losses could be encountered, i.e. Kizildere geothermal field in Turkey (Durak et al., 1993). In some cases calcite deposition, together with anhydrite (calcium sulphate) in the wellbores were also reported, i.e. Oguni geothermal field in Kyushu, Japan (Todaka et al., 1995). Likewise in Sumikawa field, Akita, Japan, for example, CO_2-rich groundwaters are thought to have reacted with reservoir rocks to form a carbonate and kaolinite alteration assemblage (Ueda et al., 2001).

Calcite may form from hydrolysis (involving replacement of calcium alumino silicates), boiling of geothermal fluids (from fluids having high dissolved carbon dioxide concentrations and in the absence of mineral pH buffer) and heating of cooler peripheral geothermal fluids (Simmons and Christenson, 1993). In a boiling environment, platy calcite precipitates in open spaces upon loss of carbon dioxide with the carbonate species mostly controlling the pH and is described by the reaction:

$$2HCO_3 - + Ca ++ = \text{calcite (solid)} + H_2O + CO_2\ (g) \quad (1)$$

While most of the carbon dioxide is evolved at the first flash (probably due to a large gas distribution coefficient), the reaction does not always proceed to completion to right (Todaka et al., 1995). Thus, there are always components available for deposition as the fluid travels from the wellbore to the surface.

Although there are many studies related to the calcite scaling in the wellbore and in the surface lines, studies related to calcite scaling in near wellbore region is limited (Satman et al, 1999) and most of them tried to explain the rock-fluid-carbon dioxide reaction kinetics. There are only a few experimental studies. This study presents results of computerized tomography (CT) monitored laboratory experiments where CO_2 was injected in carbonate cores at three different temperatures. Porosity changes along the core plugs and the corresponding permeability changes were reported for 21ºC, 35ºC and 50ºC. CT monitored experiments modeled fast near well bore flow and slow reservoir flows.

EXPERIMENTAL APPARATUS AND PROCEDURE

The experimental apparatus consisted of, X-ray CT scanner (3rd generation Philips Tomoscan TX60), injection system, core holder, and data recording system (Figure 1). The injection system was made up of a constant displacement pump, CO_2 bottle, gas flow meter controller, and a pressure transducer. For horizontally aligned experiments a Hassler type X-ray transparent aluminum core holder wrapped with Fiberfrax insulation and carbon fiber materials to minimize x-ray scanning artifacts is used (Akin and Kovscek, 2003). For vertically oriented experiments a core holder placed in a water jacket that enabled fast adjustment of the system temperature at a constant level was used. Carbonate core plugs drilled from Midyat formation located in Diyarbakir, South East Turkey, were used in all experiments. Midyat rock is mainly a heterogeneous carbonate with vugs and fractures. The core plugs contained mainly calcite with 5% alteration. For vertically aligned experiments epoxy coated core plugs of 10.7 cm long and 4.72 cm in diameter as opposed to 7 cm long and 3.81 cm ones in horizontal experiments were used. Table 1 gives physical properties of the core plugs used in the experiments. The system confining pressure was kept at 500 psi using a manually operated hydraulic pump. The temperature of the system was kept at the desired temperature using an electronic temperature controller with an accuracy of 0.1°C and a heating rod. In all experiments prior to start CO_2 was injected into the core plug in order to remove possible air stuck in pores. Core plug was then saturated with NaBr brine. NaBr brine as opposed to NaCl brine allowed an accurate determination of the porosity. Breakthrough time and pore volume of the core plug were determined at this stage. Pressure readings obtained from a pressure transducer (accuracy %0.1) were recorded when the brine flow reached steady conditions using a data logger. Prior to each experiment reference dry CT scans (Table 2) of 8 equally separated volume elements (slices) were acquired and after each CO_2 injection period (approximately 10 pore volumes) permeability and porosity of the core plugs were measured. At the end of each CO_2 injection period the core plugs were re-saturated with brine and reference wet CT scans were shot at the same locations. Porosity of each slice was then obtained by averaging porosities obtained in a circular region of interest that is slightly smaller than the diameter of the core plug. The porosity for a slice was obtained using the following equation (Akin and Kovscek, 2003).

$$\phi = \frac{CT_{wr} - CT_{ar}}{CT_{w} - CT_{a}} \qquad (2)$$

In this equation subscripts w and a represent brine and CO_2 CT numbers, whereas wr and ar refer to brine-saturated and CO_2-saturated rock, respectively. The distribution of porosities and raw CT images (Fig. 2) showed the heterogeneous nature of the core plugs. Experiments were conducted at differing injection rates (3, 6 and 60 cc/min), temperatures (20, 35 and 50ºC) and brine salinities (0, 2.5, 5 and 10 weight percent).

Table 1. Physical properties of the core plugs used in the experiments

Plug	D cm	L cm	Initial ϕ %	Initial K md
1	4.72	10.7	2.4	44
2	4.72	10.7	11	23.4
3	3.81	7	22.3	451.9
4	4.72	10.7	-	19.9
5	4.72	10.7	26.8	58.7
6	4.72	10.7	24.4	38.6
7	3.81	7	10.3	2.9
8	3.81	7	-	79.0

Table 2. CT scan parameters used in the experiments

Scan time	3 seconds
Field of view	16 cm
Current	250 mA
Voltage	130 kV
Slice thickness	10mm
Positioning accuracy	±1 mm

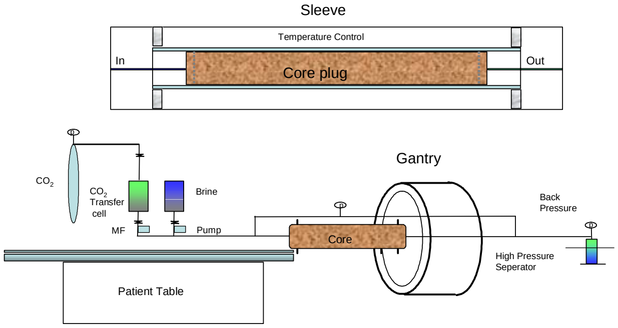

Figure 1. Experimental setup.

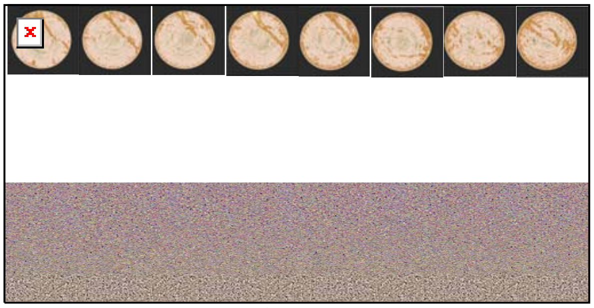

Figure 2. Locations of CT slices and sample CT images taken along the core plug (injection is from left to right).

RESULTS AND DISCUSSIONS

Figures 3 through 6 presents the results of experiments conducted with varying temperatures (Fig 3), brine salinities (Fig 4), core orientations (Fig 5) and injection rates (Fig 6).

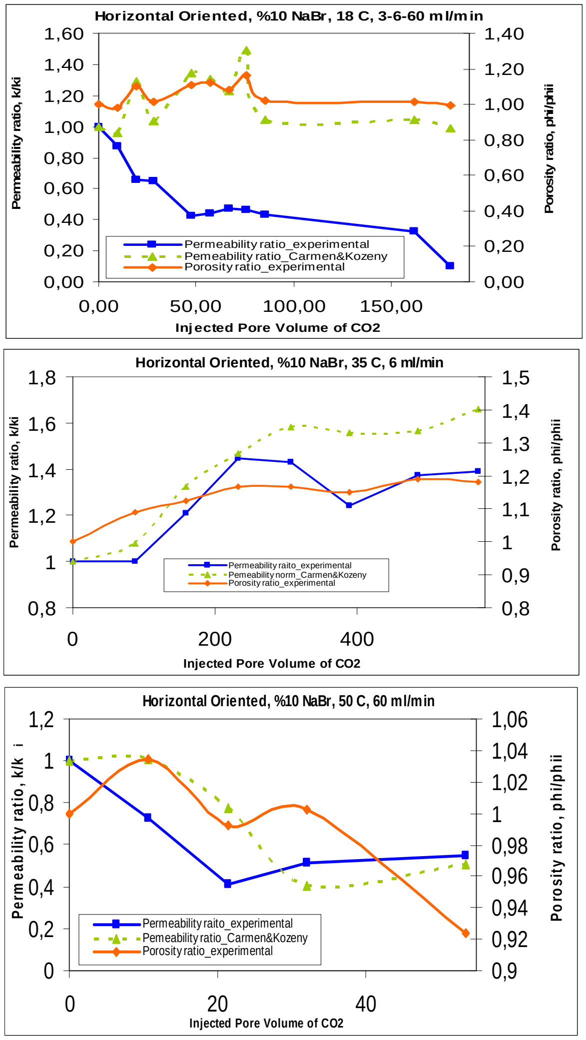

Figure 3. Effect of temperature on permeability and porosity change.

In general for vertically oriented core plug experiments, it was observed that the permeability increased and then decreased after a certain pore volume regardless of the salinity and injection rate (Fig. 5). On the other hand, for horizontally oriented core plugs the permeability initially decreased and then after a certain injection stabilized. Porosity observations however did not one to one match the permeability behavior but showed similar trends. In horizontally aligned cases the porosity stayed above the original level for a long time. Results of these experiments suggest that orientation of cores have a strong impact on permeability and porosity alteration trends. In vertically oriented core plugs due to gravitational forces CO_2 easily moves to the top of the core. This in turn increases the contact area of the CO_2 in pores near the inlet and increases chemical reaction frequency leading to the formation of carbonic acid. As the injection continues some of the dissolved calcite blocks the smaller pores along the flow path and thus results in a decrease in permeability later during the experiment. On the other hand, for horizontally aligned core plug experiments injected carbon dioxide does not move easily to the end of the core plug and forms carbonic acid near the inlet. This results in an increase in porosity near the inlet only. Calcite particles then deposit along the flow path especially near the exit which results in a decrease in permeability. CT derived porosity values support this theory as shown in Fig 7. Later in the experiment permeability keeps on decreasing until an equilibrium state where no longer alteration in permeability and porosity is observed.

The effect of temperature on calcite scaling was analyzed using three experiments conducted at 18°C, 35°C and 50°C. The latter is a typical temperature observed in shallow geothermal reservoirs in Turkey. The CO_2 injection rates covered a wide range (3 to 60 ml/min) corresponding to slow reservoir flows to fast near wellbore flows. In horizontally oriented core plugs the permeability decreased to 40% of the initial permeability after CO_2 injection then stabilized around this value for a while (Fig 3). Then it started to decrease again. This behavior was observed for two experiments with different temperatures (18° and 50°C). For the 35°C experiment, permeability stayed constant for a while and then increased. The porosity trends for these experiments followed the permeability trends. The permeability calculated from porosity using a Cozeny type equation (CMG, 2004) given below did not exactly match the observed permeability but the trend was similar.

$$K_f = K_0\left(\frac{\phi}{\phi_0}\right)^c\left(\frac{1-\phi_0}{1-\phi}\right)^2 \qquad (3)$$

In this equation, K_0 and ϕ_0 are the original or initial permeability and porosity, and c is a user defined power that is adjusted to have a match with the experimental data. Note that permeability calculated from porosity using the above equation assumes that turtousity is constant. In practice; however, as carbonic acid dissolves calcite and the calcite particles deposit, the turtousity should change continuously. For the experiments where the Cozeny type model represents the permeability change it could be speculated that the turtousity does not change or stays nearly constant.

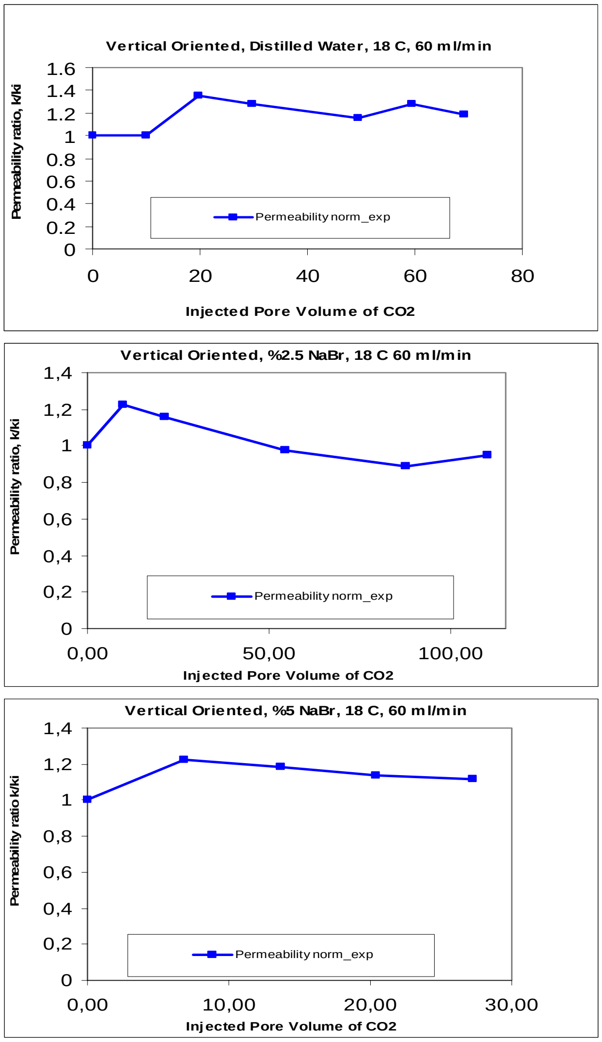

Figure 4. Effect of salinity on permeability and porosity change.

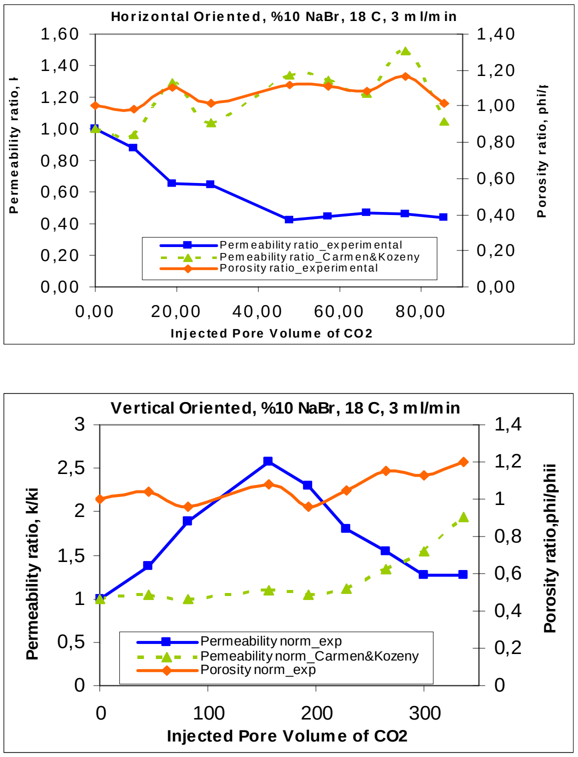

Figure 5. Effect of orientation on permeability and porosity change.

It was observed that salinity (Fig 4) and injection rate (Fig. 5) of CO_2 has no drastic effect on changes in rock properties as the salinity was increased from 0 to 5% by weight and injection rate of CO_2 was increased from 3 ml/min to 60 ml/min. It was observed that when distilled water was used the permeability increase was 40% more compared to saline cases, 20%. As the salt content of the brine increased permeability drop was pronounced more. The length of CO_2 – rock contact time and the amount of area contacted by CO_2 seems to have a more pronounced effect compared to rate effect.

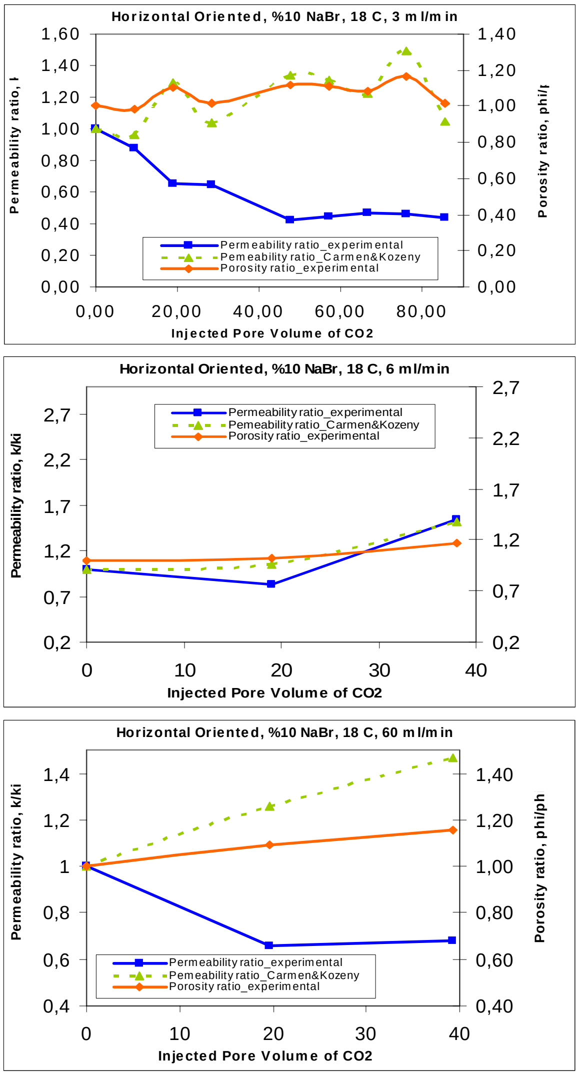

Figure 6. Effect of flow rate on permeability and porosity change.

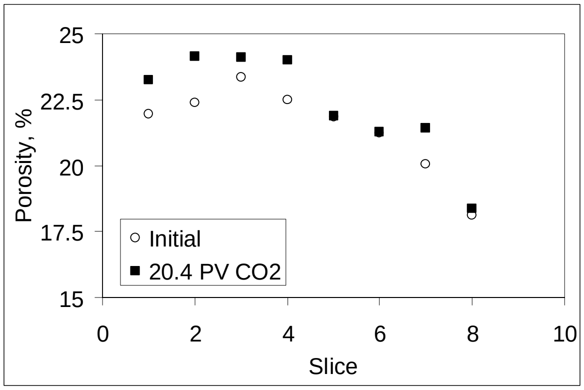

Figure 7.Porosity change observed during a horizontal experiment (10% NaBr, 18°C, 3ml/min).

The change in pH of the aqueous phase was also studied (Fig. 8). It was observed that pH of the effluent was basic as opposed to acidic in many instances. In essence the pH of the effluent closely followed the porosity change. Thus these results are in accord with the aforementioned observation, i.e., for horizontal experiments injected carbon dioxide does not move freely to the end of the core plug and forms carbonic acid near the inlet. This results in an increase in porosity near the inlet only. Calcite particles then deposit along the flow path especially near the exit which results in a decrease in permeability and an increase in pH.

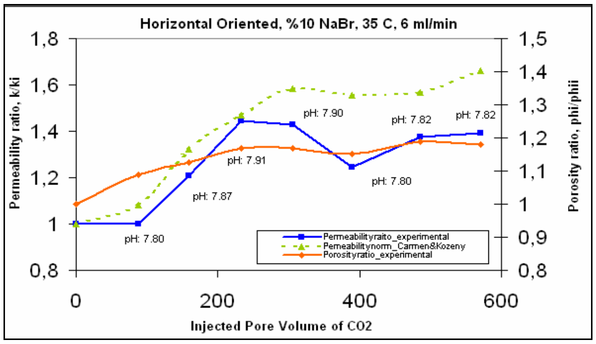

Figure 7.Porosity change observed during experiment 3.

CONCLUSIONS

Results of CT monitored CO_2 injection experiments showed that:

1. Calcite scaling is mainly influenced by orientation and horizontal flow resulted in larger calcite deposition compared to vertical flow.
2. The duration of CO_2 – rock contact and the amount of area contacted by CO_2 seems to have a more pronounced effect compared to rate effect.
3. For the temperature range studied (18°C – 50°C) permeability and porosity alteration trends were similar.
4. Once the porosity is known the permeability behavior could be predicted by a Cozeny type equation.

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