STUDY OF PETROPHYSICAL PROPERTIES ALTERATIONS OF CARBONATE ROCKS UNDER CARBONATE WATER INJECTION

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ABSTRACT
Carbon dioxide (CO_2) injection in reservoirs promotes rock-fluid interactions, which depends on rock nature, brine composition, partial pressure of CO_2, temperature as well as operational conditions. The rock-fluid interactions cause changes in the petrophysical properties, modifying both porosity and permeability of the rock. The present study aims to study the effects of water injection with dissolved CO_2 on the petrophysical properties of carbonate rocks. The effects are evaluated experimentally by displacement runs on a long core of an outcrop coquina. The work emphasizes the evaluation of permeability changes along the length of the core, using a coreholder equipped with multiple pressure taps. The experiments were conducted in dynamic regime, at T=22°C and P=2,000 psi and flow rates of 0.5, 1 and 2 cc/min. X-ray Computerized Tomography (CT) was used to determine porosity alterations during the experiments and the differential pressure drop was used to calculate permeability and its changes along the rock sample. Results show that porosity increased steadily with the accumulated volume of water injected. Permeability increased sharply at the higher flow rates and the changes were unevenly distributed along the core.

INTRODUCTION
The occurrence of reactions between the CO_2 enriched brines and carbonate rocks, has been reported in several applications. The interaction between fluids containing CO_2 and the rock is often found in the literature associated with matters of capture and underground storage of gas. In accordance to Ott et al. 2013 [1] reactions may influence the fluid-flow field, i.e. reactive transport, and the mechanical rock properties, which might degrade, leading to uncertainties with respect to the rock integrity in the affected region. Luquot and Gouze [2] analyzed the dissolution of carbonate rocks submitted to flow of aqueous solutions. In the experiments, measurements of salinity and pH were carried out at different positions along the flow and then it was possible to classify the mass transfer processes both near wellbore and further, where the dissolution becomes increasingly uniform. Zekri et al. [3] observed that the CO_2 injection at supercritical state

alters rock permeability and that the alteration is related to the rock composition. Taking it into account, the changes must be evaluated along time for the particular rock in consideration, due to the heterogeneities present in the reservoirs.
An important characteristic associated to the CO_2 injection in reservoirs is the presence of chemical interaction between the fluid and the rocks. With the CO_2 injection in the reservoir, a fraction of the gas dissolves into the formation brine or into the injection water, producing carbonic acid (H_2CO_3), which dissociates as charged particles with potential to interact chemically with the rock minerals (calcite, dolomite, anhydrite). These reactions are known to geochemists to provoke dissolution or precipitation, depending on the direction they manifest. They are a function of the rock nature, the brine composition, the partial pressure of CO_2 and the thermodynamic conditions. The movement of the fraction of CO_2 dissolved in the formation water is dependent on the transport mechanisms (diffusion or convection) and the reaction kinetics [4]. The mass transfer between the fluid and the rock relies on numerous parameters, such as: partial pressure of CO_2, concentration of cations in the formation water, the injection flow rate, the reactive surface area, porosity, permeability and tortuosity of the medium, among others.

The presence of the rock-fluid chemical interaction may change the pore structure and modify the permeability of the rock, which is a key parameter to the flow in reservoir engineering. The present paper reports an experimental investigation on the permeability and porosity changes of a carbonate rock with the injection of carbonate water.

PROCEDURES

Materials

The carbonate rock used in the study was extracted from a coquina outcrop, from Morro do Chaves formation, in the Sergipe-Alagoas basin, Brazil. Three fluids were employed in the experiment: a sodium chloride (NaCl) brine at 35 kppm concentration as the initial saturation fluid, a sodium iodide (NaI) brine at 35 kppm as the dopant and a sodium chloride brine at 35 kppm saturated with CO_2 at 2,000 psi as injection fluid.

Methods

The experiments were performed on the experimental setup made up basically by the following devices: a positive displacement pump to guarantee a measurable and continuous flow, high pressure vessels for the fluids conditioning, a special coreholder with multiple pressure taps connected to differential transducers referenced at the inlet point and a backpressure system at the outlet port. The coreholder was composed of an aluminum cylinder, with an epoxy and carbon fiber jacket around the sample. The experimental apparatus is schematized in Figure 1.

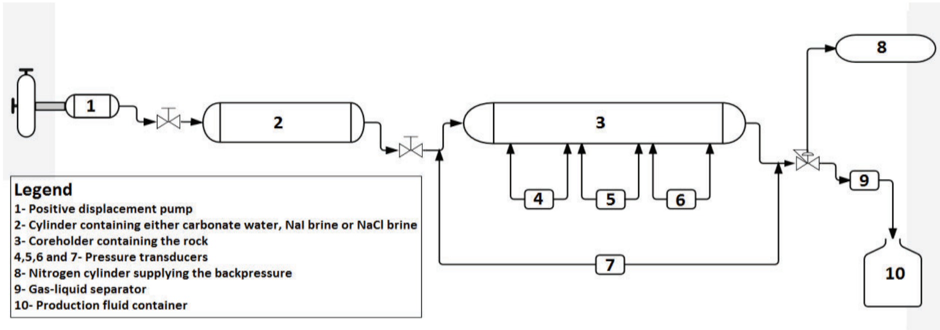

Figure 1. Scheme of the experimental apparatus.

The sample was saturated with the 35 kppm NaCl brine and then flushed with the contrast fluid, the 35 kppm NaI brine. After that, the tests with carbonated water were performed at the flow rates of 0.5, 1 and 2 cc/min. The operating conditions were 2,000 psi and 22°C. Differential pressures were measured at points along the core as shown in Figure 1 by appropriate sensors (nVision Crystal Engineering Corporation). The permeability was evaluated by the pressure drop along the sample. The pressure was measured in six different points along the sample and also on the inlet and outlet valves, resulting in eight pressure taps, as schematized in Figure 2.

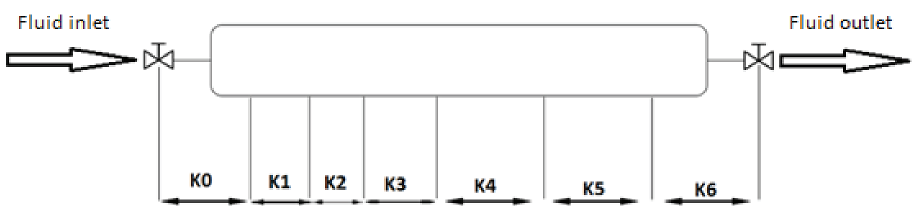

Figure 2. Scheme of the permeabilities evaluated during the test.

Porosity was evaluated by X-ray computerized tomography (Siemens CT scanner model SWFVD30C), using the software Syngo. The images had a 0.5 mm resolution and each scan acquired 69 images along the sample.

RESULTS

Porosity

A MatLab™ routine was used to calculate the porosity of each section. These data were acquired by the continuous CT scan along each test cycle. Porosity was calculated in accordance to Equation 1, where CTn, CTrock and CTfluid represent the mean CT number for the system in a given time, the rock CT number and the fluid CT number respectively.

$$\varphi = \frac{CTn - CTrock}{CTfluid - CTrock} \tag{1}$$

Figure 3 shows the behavior of the mean porosity, which showed a steady increase of its values with the increase of the accumulated volume of water injected. A slightly greater increase was observed at the beginning of the test, when a flow of 1 cc/min was used. The overall increase across the entire test was from 13% to 17%, a substantial change if one considers the volumes of a whole reservoir.

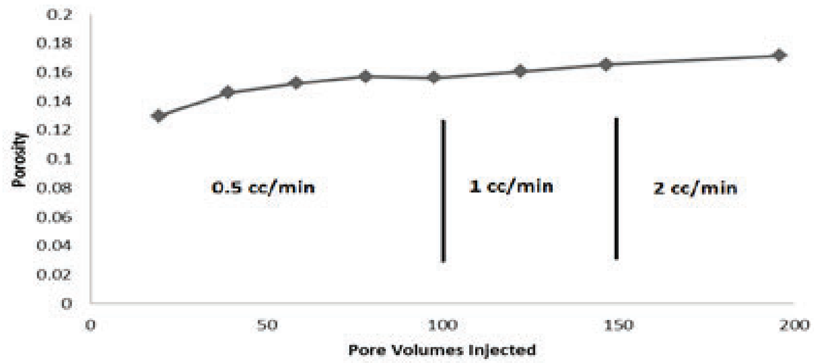

Figure 3. Mean porosity by volume of carbonated water injected.

Using data from each transversal section (69 total slices) of the CT-scan, porosity was calculated at each particular time and position. It was possible to verify porosity evolution through time along the entire core. The evolution and distribution of porosity is depicted in the 3D plot shown in Figure 4.

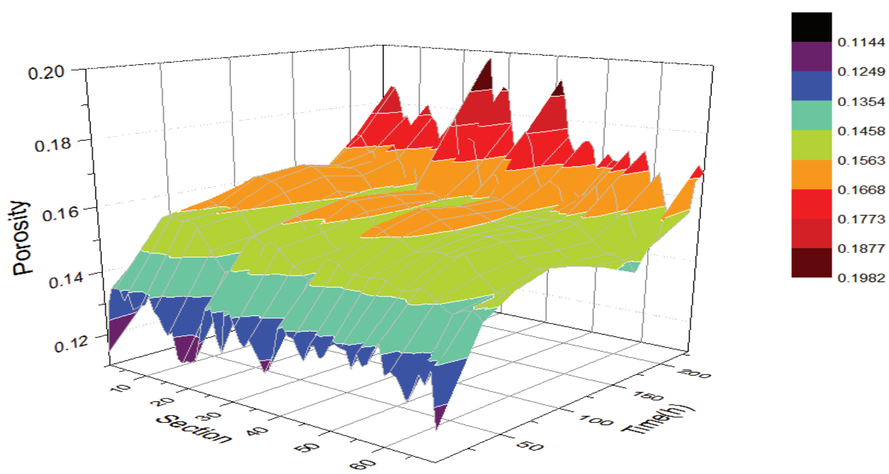

Figure 4. Evolution of porosity along whole sample through time.

During the injection test, small solid white particles were observed to accumulate at bottom of the container of the produced fluids, evidencing the occurrence of dissolution of the rock. In accordance with Grigg et al. 2013 [5], carbonate dissolution caused changes in core permeability and porosity.

Permeability

Figure 5 depicts the variation of the average permeability of the rock sample along the duration of the experiment. Permeability remained basically unchanged up to 120 PVI (pore volumes of water injected). It is important to notice that from the beginning of the test up to 100 PVI the test was carried out at a flow rate of 0.5 cc/min. A steep increase in permeability, from 0.2 D to 12 D, was observed between 120 to 170 PVI. Such remarkable increase is associated to the formation of a preferential path to the flow which was visible at the CT images.

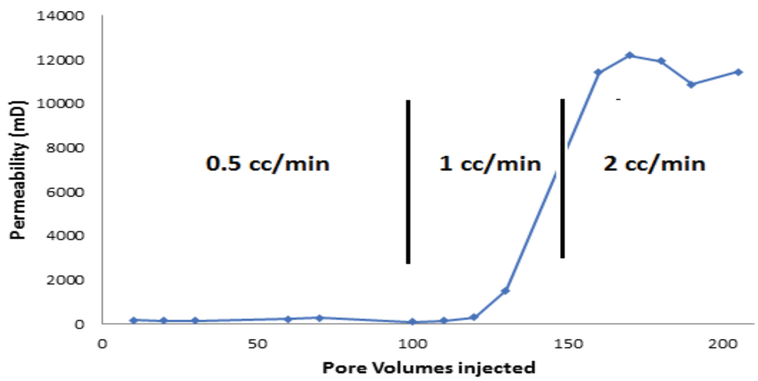

Figure 5. Mean permeability by pore volumes of carbonated water injected.

The significant change in permeability happened soon after the flow rate was raised to 1 cc/min. At 12 D the permeability curve leveled off and remained flat with the continued injection of carbonate water even when the flow rate was increased to 2 cc/min.

Through the experiments, the permeability of all regions from K0 to K6 could be evaluated along the test, and the result is shown in Figure 6. Evolution of permeability was not even through the rock sample. Sections K2 and K6 showed the greatest permeability changes at about 120 pore volumes injected, and it probably occurred due to fluid breakthrough in a wormhole which increased the permeability of the entire core. For these sections, the permeability dropped afterwards probably because of the movement of fine grains of rock which clogged some permeable channels.

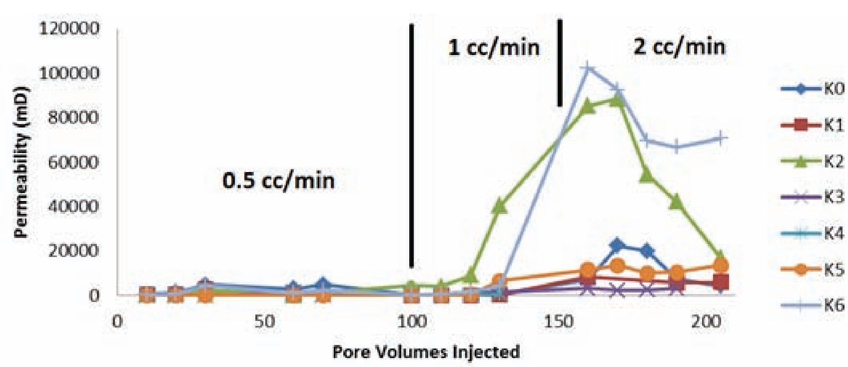

Figure 6. Permeability by sections of the sample against pore volumes injected.

CONCLUSION

It was possible to verify that both injection rate and also the interaction between rock and fluid promoted alterations on the rock petrophysical properties. The porosity showed a progressive increase through the tests. It can be verified the porosity evolution through time along the entire core. The mean porosity performance showed a steady increase of its values with cumulative volume of water injected. Porosity indicated a considerable change along all test. Initially, the outcrop porosity was 13% and in the final test it showed 17% that it represents a considerable change for a whole reservoir.
Permeability remained basically unchanged up to 120 PVI (pore volumes of water injected). It was verified that from the beginning of the test up to 100 PVI the test was carried at a flow rate of 0.5 cc/min. The experiments showed the creation of a preferential path, which increased greatly the rock permeability, showing evident when the flow rate was increased to 1 cc/min.

ACKNOWLEDGEMENTS

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