Experimental Study of Wettability Alteration in Carbonate Fractured Porous Media using Computed Tomography

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Abstract

Oil recovery from naturally fractured reservoirs is mainly controlled by water spontaneous imbibition into matrix blocks. However, imbibition rate and ultimate recovery value are mostly affected by wettability of the reservoir rocks and their pore structure. The present paper focuses on the study of wettability alteration of matrix blocks in fractured porous media, for a more favorable condition to water spontaneous imbibition. Further the research aims to investigate the mechanisms involved in the transfer of fluids at the matrix-fracture boundary.

Several experiments were carried out at bench scale involving coreflooding of outcrop dolomite with brines of designed salinity. The rock samples were carefully prepared to exhibit fractures of controlled geometry and storage/flow parameters as well as to bear oil as the preferred wetting fluid.

Injection of synthetic brines with different compositions was carried out at a constant injection rate. In addition to the evaluation of the produced fluids, Computed Tomography (CT) scans were performed along the tests to study the distribution of water saturation in matrix media.

Oil recovery in fractured reservoirs occurs at a much slower rate than in conventional reservoirs. It was observed that at the beginning of brine injection there was a rapid oil recovery, corresponding to the stored oil in the fracture, which is followed by a recovery at constant rate, but considerably at a much slower pace. This occurs because the oil recovery is dependent upon of water imbibition within the matrix, to promote the oil displacement in the direction of the fractures. As the samples were aged, their wettability was mixed/oil-wet, and the low affinity between matrix and brine led to a lower spontaneous imbibition rate. Moreover, it was observed that by injecting designed salinity brines there was an increase in the oil recovery at the secondary recovery stage, and in the imbibition rate into the matrix.

Introduction

Fractured porous media flow presents great challenges and among them the difficulty in flow prediction, mainly by the high conductivity of fractures and the reduced sweep efficiency. In addition, oil recovery from carbonates is influenced by the porous surface affinity to adsorb carboxylic groups of oil, which sets the wettability towards preferential to oil [1].

Some studies have shown that carbonate surfaces with wettability preferential to oil when in contact with designed salinity brines promote oil desorption from the porous surface [2 and 3]. There are several theories which explain the possible mechanisms that allow the oil recovery increase, among them the multi-component ion exchange and the calcite dissolution models stand out [4 and 5].

The main focus of this paper is on oil recovery by the injection of design salinity brines. The purpose is to evaluate how the mechanisms of brine imbibition into the rock matrix is affected when of the injection of water at different salinities.

Experimental Methodology

Rocks and Fluids

In the present study, dolomite outcrops from Silurian formation, originated from Thornton formation (Illinois, United States) were used. Gas porosity was measured using an UltraPore 300 Porosimeter from CoreLab Instruments without overburden pressure and gas permeability was measured on an UltraPerm 500 Permeabilimeter from CoreLab Instruments using an overburden pressure of 600 psi.

Two different injection sequences were studied: DFD1.1 (Sequence 1) - primary recovery injecting formation water (FW), secondary recovery with the injection of seawater (SW), and tertiary recovery with injection of seawater 20 times diluted (SW20d); and DFD1.2 (Sequence 2) - primary recovery with injection of seawater (SW) and secondary recovery with injection of seawater depleted of sodium chloride (SW0NaCl). The composition of each brine is presented in Table 1.

The oil used in the experiments is from a Brazilian pre-salt field with a density of 0,9 g/cm^3 and a viscosity of 11,3 cp at 70 °C.

Preparation of samples

At each experiment a composite set of 3 samples placed in series was used. The preparation of the samples consisted of an initial cleaning phase with toluene and methanol followed by the basic petrophysical characterization. An artificial fracture was then induced through a longitudinal bore with a 4 mm diameter. The fracture was filled with sand and at the inlet and outlet faces a small piece of metal screen was placed to trap sand in the fracture. Porosity and permeability of the fractured samples were determined.

One of the major difficulties in the study of fractured porous media in the laboratory scale is to use samples with a uniformly distributed initial water saturation. In order to overcome this difficulty, the evaporation method was to used to render a controlled initial saturation condition, as proposed by Springer (2003) [6]. An initial water saturation (Swi) of 10%

was adopted. To achieve the initial water saturation was necessary to use a brine with a 10 times higher concentration than the original brine (FW10d ~ 1.924.200 ppm instead of FW ~ 192.420 ppm). After brine saturation, samples were placed in a desiccator and its mass controlled to reach 10% water saturation. This method assumes that there is no precipitation of brine and that there is an uniform redistribution of water in the sample. Oil saturation was realized by vacuuming the core samples to a level higher than water evaporation pressure so to admit the oil. Samples were pressurized up to 3.000 psi for 24 hours. A dynamic aging process was performed at 90 °C for 20 days and consisted of periodic injections of 2 porous volumes using a flow rate of 0,01 mL/min.

There is a difference in the preparation of samples DFD1.2 and DFD1.2. The inlet face of first core and the outlet face of last core of DFD1.2, samples were sealed with epoxy to ensure that flow is forced through the fracture.

Experimental apparatus

The experimental apparatus consisted of an injection system, a core holder, a backpressure, a collector for produced fluids and a bypass system, as outlined in Figure 1. Experiments were performed at 70 °C and at 600 psi, controlled by a backpressure.

The injection rate used was 0,05 cm^3/min. The low injection rate, correspondent to half of the injection rate used in several displacement experiments presented in literature, is considered to warrant that the dominant flow mechanism is the spontaneous imbibition into the matrix. So, fluid flow is governed by capillary and not by viscous forces. CT scans were regularly performed to evaluate the variation of the fluid saturation over time and at the end of 30 days the injection brine was replaced by a brine with different composition.

Computed Tomography

Computed tomography was used to determine porosity and fluid saturation along the core during brine injection. The determination of porosity of the sample requires that it be totally saturated with two different fluids, since the scan measures the density of the material based on a measurement unit (voxel). Initially samples were vacuumed and a CT scan was performed, then the sample was saturated with FW10d brine and a new tomography was performed. From the difference between these two CT scans it was possible to estimate the average porosity of each slice (ϕ^{voxel}) spaced by 1,8 mm, according to Equation 1.

$$\phi^{voxel} = \frac{CT_{WS} - CT_{DS}}{CT_W - CT_A} \qquad 1$$

In the above equation, CT_{WS} and CT_{DS} correspond to the average CT of each voxel saturated saturated with FW10d brine and vacuumed, respectively, and CT_W and CT_A correspond to CT number of FW10d brine and of air, respectively. The water saturation of each voxel (S_W^{voxel}) can be determined according to Equation 2.

$$S_W^{voxel} = \frac{CT_{WF} - CT_{OS}}{\phi^{voxel}(CT_W - CT_O)} \qquad 2$$

Where CT_{WF} is the average water injection CT, CT_{OS} is the average CT number of the core saturated with oil, and CT_{O} is the oil CT number.

Results

Porosity distribution

Porosity profiles of samples allow to observe the heterogeneity of the rock sample. As the main focus of the study is the matrix, a MATLAB routine was used to eliminate the area correspondent to the fracture, and therefore to determine the average CT number corresponding only to the matrix media. Porosity profiles of the total core, the matrix only and of the fracture of DFD1.1 and DFD1.2 experiments are shown in Figure 2 and Figure 3, respectively. From these figures it can be seen that porosity profiles of matrices are practically the same as that of the total core, indicating the small contribution of the fracture to the porosity of the fractured rock.

Oil recovery

In DFD1.1 experiment the injection sequence was: FW, followed by SW and finally by SW20d. The evolution of the average water saturation of the sample matrix over the duration of the test is shown in Figure 4. Initially there was a high oil production rate, because all the oil present in the fracture was instantaneously produced, then oil production rate decreases, corresponding to the production of oil originated from the matrix. The increase in water saturation indicates that water was filling the matrix while the oil was moving from matrix to fracture, and produced from there. Figure 4 represents the increase of water saturation in the matrix, and, at the same time, represents oil production from matrix to fracture.

FW injection should not promote any change in rock wettability since there was an ionic balance previously established between the rock, the oil and FW brine. It was observed that 29,9% of original oil in place (OOIP) had been recovered at the end of 30 days and at the end the oil production reached a plateau. On the other hand, the following injection of SW, with a very different ionic composition, in particular ions with potential for the wettability alteration (sulfate, calcium and magnesium), promoted an considerable increase in the oil recovery rate, indicating an alteration of the matrix wettability. Wettability alteration is followed by oil desorption of the porous matrix and, as presented in Figure 4, resulted in a slight increase in oil recovery from the begging of SW injection. The incremental oil recovery value was 31,4% of OOIP. A constant of oil production rate is evident throughout the SW injection. For the injection of SW20d, however, oil recovery did not increase so significantly, and 12,6% of additional OOIP was recovered.

In the DFD1.2 experiment the injection sequence used was: SW followed by SW0NaCl. The volume of oil recovered at the end of 30 days of SW injection was approximately 32,5% of the OOIP, which was not very different from the oil recovery observed with the FW injection in the DFD1.1 test. The difference is that in the DFD1.2 test the recovery rate remained practically constant over time. SW0NaCl injection showed a significant increase in recovery of about additional 40 % OOIP, as shown in Figure 5.

Although the DFD1.1 experiment last for a longer duration, the brines used in the DFD1.2 carried more potential to alter rock wettability, which may explain the same final oil recovery in less time. Nonetheless, the whole process is very slow and oil production was at a steady low rate for 1440 hours (60 days) before reaching a plateau.

It is important to note that the recovery increments are not instantaneous. Time is necessary for the spontaneous imbibition of the new injected brine into the matrix, and for the interaction of this brine with oil and the rock surface. Only after that the dislodged oil is produced.

Water Spontaneous Imbibition into matrix media

At the beginning of injection, the oil present in the fracture was produced almost instantaneously, which corresponds to a very short water breakthrough time. Brine spontaneous imbibition into matrix is a relatively slower mechanism. The oil near the fracture-matrix boundary is first produced, and as the brine penetrates the matrix, oil that is at greater distances from the fracture will migrate towards it.

Brine imbibition occurred from the center of the samples (fracture) to the borders. Figure 6 and Figure 7 shows matrix water saturation along the length of samples over time. It is clear that there was an increase in water saturation of the matrix of the samples throughout the duration of the water injections.

Influence of boundary conditions

One of the major differences between DFD1.1 and DFD1.2 was that the inlet and outlet faces of DFD1.2 cores were partially sealed. The effects of such difference can be seen in Figure 6 and Figure 7. In DFD1.1 the formation of a water front is clear at the inlet face near brine injection. In spite of the high permeability of the fracture, the capillarity of the sample at the inlet face allowed the brine to flow not only through the fracture but also across the face of the matrix block. For this reason the water saturation was higher in the matrix region near the inlet face. The border effect diminishes as the flow moves towards the fracture while going deeper across the sample length. This higher saturation in the inlet face may be responsible for the higher oil production at the begging of the primary recovery of DFD1.1 test, compared with DFD1.2.

In the DFD1.2 test, as the inlet and outlet faces of the composite core were sealed, injected brine was forced to penetrate only through the fracture. Thus, the brine imbibition into the matrix only occurs across the matrix-fracture interface. Therefore, water saturation was observed to be more evenly distributed throughout the length of the samples, with changes in time occurring radially. It is worthwhile noticing that the recovery in the DFD 1.2 test was slightly higher, although the core ends were sealed, which corroborates that the brines used in the test had a greater efficiency in altering the matrix wettability, given that the samples had same capillary properties originally.

Conclusions

The present study showed that the used designed salinity brines in fractured carbonate media allowed an additional oil recovery as brine penetrates into matrix media. This oil increase was accompanied by an increase in oil recovery rate. Thus, there was not only a higher final oil recovery but also an anticipated production.

As the brine penetrates into the matrix, not only it displaces movable oil towards the fracture, but also its composition is able to desorpt oil from matrix surface, and consequently, alter its wettability towards a more water-wet condition. The wettability alteration will allow higher brine imbibition into the matrix, and more oil recovery will be recovered.

By using computed tomography is possible to see water saturation variation as the injected brine in the fracture penetrates into the matrix blocks, and to study mass transference between matrix-fracture interface. As brine imbibition through matrix blocks is a slow process, as it could be seen in the presented experiments, the proposed apparatus was able to replicate spontaneous imbibition mechanism. Also, imbibition was strongly influenced by its boundary conditions. High matrix capillarity allow brine imbibition in every faces where matrix was directly exposed to brine. In addition, viscous forces did not have great contribution on oil recovery process.

Acknowledgements

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Table 1 - Composition of used brines

	FW	**SW**	**SW20d**	**SW0NaCL**
Íon	mg/L	mg/L	mg/L	mg/L
(Na^{+})	58003,80	13664,68	683,24	1356,84
(K^{+})	3984,67	444,75	206,55	444,75
(Mg^{2+})	392,96	33,00	1,65	33,00
(Ca^{2+})	8930,78	1472,93	73,65	1472,93
(Ba^{2+})	2,81	-	-	-
(Sr^{2+})	117,98	5,92	0,30	5,92
(Li^{+})	126,07	-	-	-
(Cl^{-})	110516,13	22058,52	1270,06	3078,35
(Br^{-})	320,28	71,85	3,59	71,85
(SO_4^{2-})	79,80	2800,97	140,06	2800,97
(HCO^{3-})	55,93	42,85	2,14	42,85
TDS (ppm)	192,45	42,07	2,10	10,79

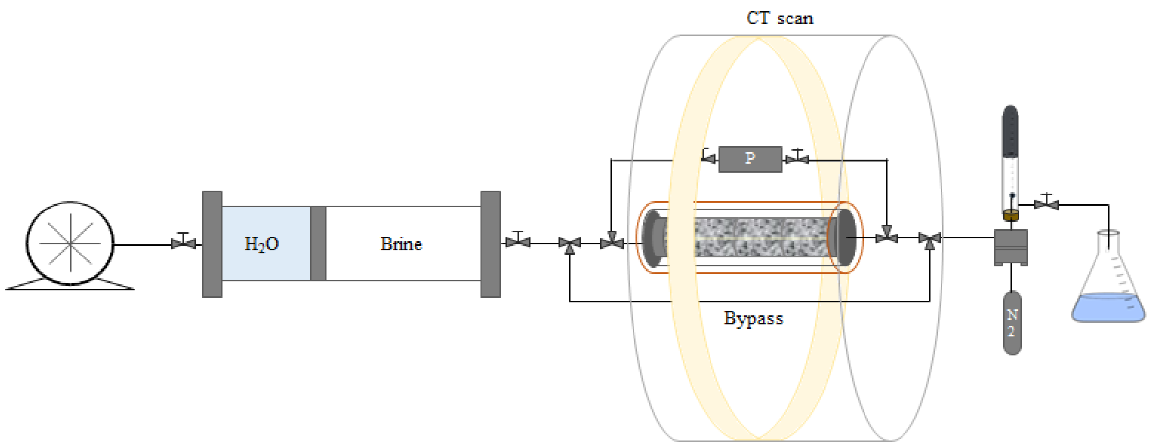

Figure 1 - Schematic experimental apparatus

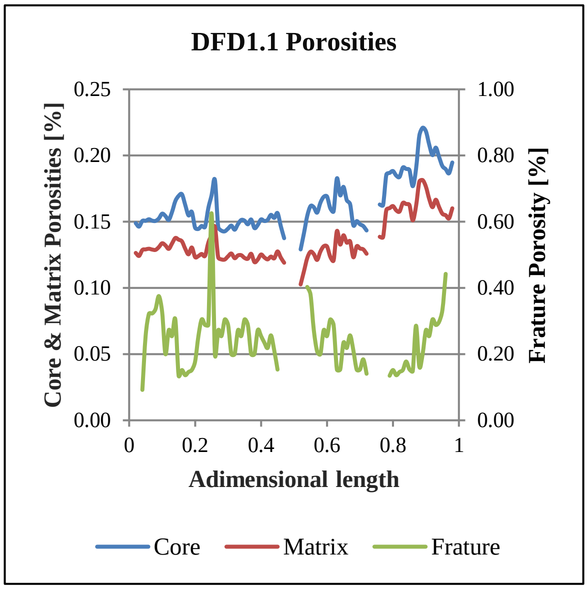

Figure 2 - Porosity profiles of the DFD1.1 test

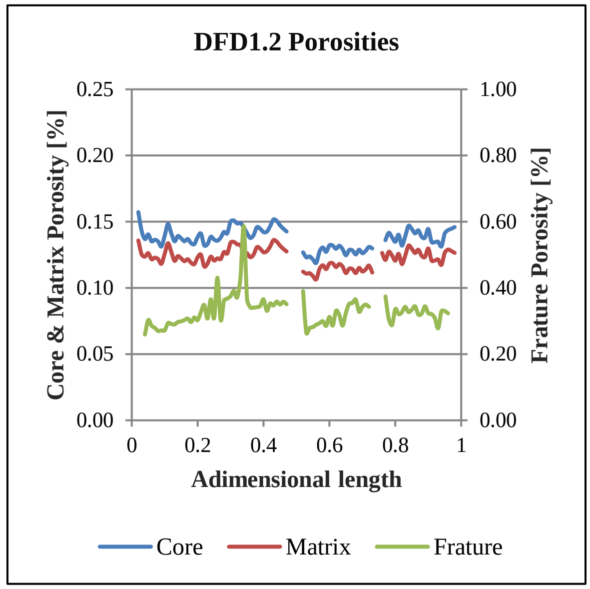

Figure 3 - Porosity profiles of the DFD1.2 test

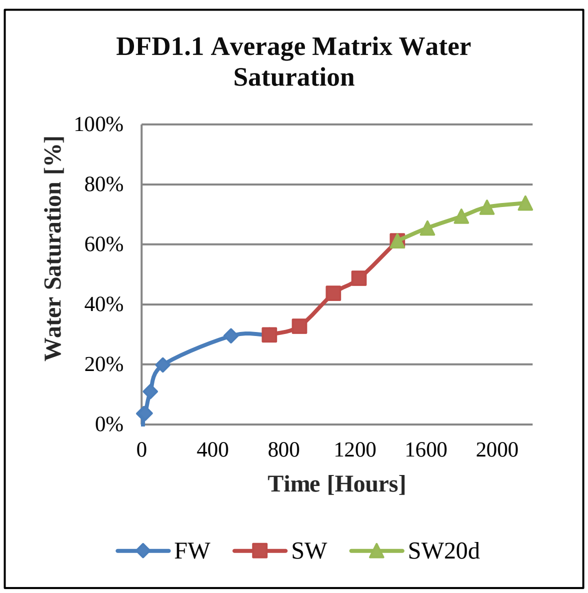

Figure 4 – DFD1.1 Average Matrix Water Saturation

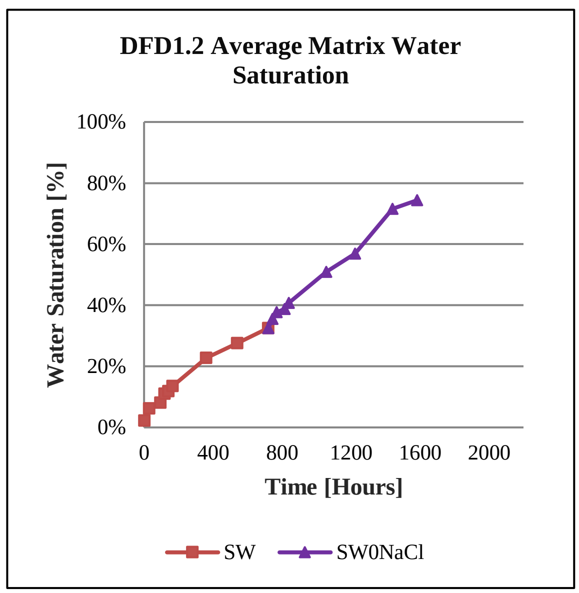

Figure 5 – DFD1.2 Matrix Average Water Saturation

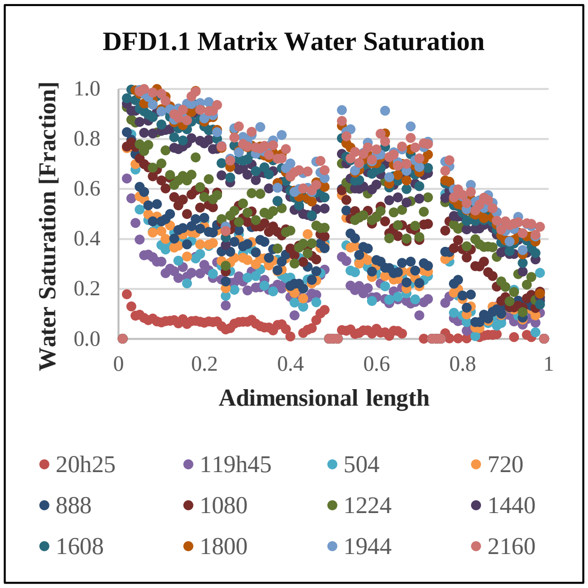

Figure 6 – DFD1.1 Matrix Water Saturation

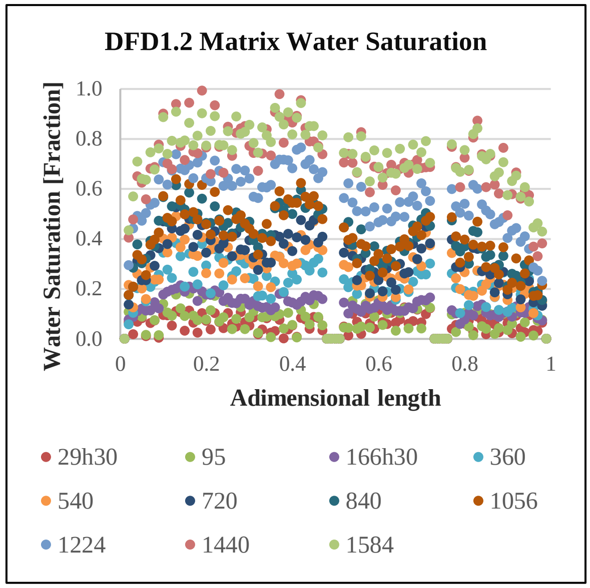

Figure 7 – DFD1.1 Matrix Water Saturation