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Analysis of capillary pressure and relative permeability hysteresis under low-salinity waterflooding conditions

Xiao Wang [a], Vladimir Alvarado [a,b,*]

[a] Department of Petroleum Engineering, University of Wyoming, Laramie, WY 82071, USA
[b] Department of Chemical Engineering, University of Wyoming, Laramie, WY 82071, USA

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ABSTRACT

In this work, we analyze measurements of drainage, spontaneous imbibition and forced imbibition capillary pressure curves in conjunction with two-electrode resistivity on sandstone core samples under low- and high-salinity waterflooding conditions. State-of-the-art laboratory equipment able to work with actual reservoir fluids at reservoir conditions was designed and built to conduct these measurements. Unsteady-state coreflooding experiments under similar experimental conditions to those in the capillary pressure tests were also carried out. A black-oil reservoir simulation model was set up to history match experimental production and pressure data to obtain multi-phase flow functions. Two experiments were conducted on Minnelusa formation (eolian sand) rock samples at 93 °C with TC crude oil and synthetic brines. Placement of an oil-wet membrane on one plug end and a water-wet disk on the other end guaranteed that only one phase was able to flow through each sample end at any given time. In one experiment, a 57,491 ppm-brine (High-Salinity) was used during the imbibition process, while a 20-fold dilution of the High-Salinity brine (Low-Salinity) was used in the other experiment. Correspondingly, two unsteady-state experiments at fixed injection rate were completed on Minnelusa formation rock samples placed in the coreflooding system using comparable experimental conditions as those in the capillary pressure experiments. Comparison of high- and low-salinity experimental results shows that more noticeable capillary hysteresis toward water-wetness arose in the low-salinity experiment. High-salinity experiment results showed that the imbibition resistivity index was higher than that corresponding to drainage. History matching of the transient production data in capillary pressure experiments along with end-points obtained from unsteady-state core flooding experiments was used to obtain relative permeability curves. Availability of high-quality capillary pressure data at reservoir conditions improved the accuracy of relative permeability curves obtained from history matching unsteady-state core flooding experiments. Our results show a substantial improvement in obtaining both capillary pressure and relative permeability curves at reservoir conditions resulting from a combination of steady- and unsteady-state experiments. Capillary pressure results confirm that hysteresis is more prominent under low-salinity conditions and apparent higher oil trapping is observed during imbibition, compared to high-salinity conditions. Unsteady-state coreflooding results also show that low-salinity brine is not conducive to enhanced oil recovery in low-salinity waterflooding. Geochemical effects appear to negatively impact beneficial interfacial mechanisms proposed to benefit oil recovery such as the formation of more viscoelastic interfaces under low-salinity conditions. We conclude that coupling of fluid–fluid and rock–fluid interactions, including geochemical reactions, needs to be accounted for to better explain low-salinity waterflooding mechanisms.

1. Introduction

Capillary pressure and relative permeability are key to describe multiphase flow in porous media. Understanding of fluid distributions is necessary to better establish connections with fluid movement in reservoirs. In this sense, rock electrical resistivity serves as

* Corresponding author at: Department of Chemical Engineering, University of Wyoming, Laramie, WY 82071, USA.
E-mail address: valvarad@uwyo.edu (V. Alvarado).

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a powerful tool to evaluate these fluid distributions in porous media. These multiphase flow functions depend not only on saturation, but also on the saturation path and history, a phenomenon usually referred to as hysteresis. Multiphase flow hysteresis can originate from (1) contact angle hysteresis, which alludes to the advancing contact angle (in imbibition process) being larger than the receding contact angle (during drainage); (2) trapping of the non-wetting phase; (3) wettability alteration after a rock is contacted with crude oil, especially at a high reservoir temperature [1]. In practice, all sources of hysteresis are present and not easily distinguished in experiments.

Leverett pointed out the importance of capillary pressure in his well-known paper [2]. Significant efforts have been made to measure capillary pressure in the laboratory. A review of the capillary pressure measuring techniques has been presented by Jennings [3]. Of the various techniques, the restored-state method introduced by McCullough et al. [4] is the most accurate one, which can be modified to determine hysteresis loops during primary drainage, spontaneous imbibition and forced imbibition, in turn.

On the other hand, obtaining relative permeability curves is a complex and time-consuming process. Generally, there are two types of measuring techniques: steady-state and unsteady-state methods. The steady-state method, in which flow rates are maintained until saturation and pressure drop reach steady-state and Darcy law is used to calculate one point in relative permeability. This method is reliable, but time-consuming. Moreover, this method typically requires long plugs or composite cores (stacked short plugs) and high flow rates to mitigate capillary entry effects [5]. In contrast, the unsteady-state method is fast, but requires complex interpretation methods. Thus relative permeability is often obtained through history matching.

Electrical properties measured in well logs have been used to estimate formation porosity and in situ water saturation in hydrocarbon reservoirs. The interpretation of these measurements is based on Archie's First and Second Law.

Archie's First Law goes as follows:

$$F = R_o/R_w = \phi^{-m} \tag{1}$$

where F is the formation factor, R_o is the rock resistivity when fully saturated with water, R_w is the water resistivity, ϕ is the formation porosity, and m is the cementation or porosity exponent.

Archie's Second Law is as follows:

$$I = R_t/R_o = S_w^{-n} \tag{2}$$

where I is the resistivity index, R_t is the rock resistivity when it is partially water saturated, S_w is the water saturation, and n is the saturation exponent.

Archie's First Law relates the electrical response-formation factor to porosity, whereas the second law relates the resistivity index to the water saturation. R_t and R_o can be obtained from well logs, whereas m and n have to be measured in the laboratory. Many studies have shown that the saturation exponent n can be a function of water saturation and saturation history. Moreover, many factors could influence the saturation exponent response. One factor that has been the focus of most studies is wettability. The exponent n has been found to be higher and the hysteresis more significant in oil-wet systems than in water-wet ones [6].

Tang and Morrow [7] first reported low-salinity waterflooding with the intent of increasing oil recovery over traditional waterflooding in sandstone formations. Since then, many laboratories and organizations have taken an active interest in reproducing the low salinity effect [8]. In the meantime, several operators have this technique in the field, e.g. BP [9–12], Shell [13,14] and Statoil [15]. Despite the potential of this technique, some laboratory or field trials have failed to increase oil recovery [15]. Tang and Morrow [16] proposed conditions to increase oil recovery by low-salinity waterflooding: (1) existence of significant amount of clay, (2) presence of initial water saturation, and (3) contact with crude oil to have mix-wettability. However, Morrow and Buckley [17] admit that these conditions are insufficient to the success of low-salinity waterflooding; there are many cases meeting these conditions that are not conducive to increase oil recovery. As a result, the underlying mechanisms remain the subject of controversy. The majority of the research has focused on fluid-rock interactions, and proposed mechanisms include wettability alteration, in situ emulsification and fines migration. Both Ligthelm et al. [18] and Lager et al. [19] explained how decreasing the brine concentration, especially by reduction of multivalent cations, could turn the rock more water-wet. It has been suggested that lowering the salinity level can increase the electric double layer and reduce the multivalent cation bridges between clays and crude oil. Once the repulsive force exceeds the binding force, oil is desorbed from the clay, and thus the rock turns more water-wet. RezaeiDoust et al. [20] suggested a salting-in effect, in which the solubility of organic material increases as salts are removed from water. In Alvarado et al.'s paper [21], an alternate, an additional important fluid–fluid interfacial mechanism was proposed. Alvarado et al. suggest that as the brine salinity decreases, the oil–water interfacial viscoelasticity increases, which eventually hinders snap-off, reducing oil trapping. As a result, the oil phase becomes more continuous and a higher oil recovery is realized.

In the past few years, many researchers have investigated the effectiveness of low-salinity brine using Minnelusa rock samples and crude oils. The Minnelusa formation in Wyoming is an evaporite found to often contain anhydrite. Some studies indicate that low-salinity waterflooding could increase oil recovery in these reservoirs. For example, Pu et al. [22] found in coreflooding experiments that the injection of low-salinity brine produced additional 5.8% OOIP in tertiary mode. In secondary mode experiments, the oil recovery for high- and low-salinity injections was 36.4% and 47.7%, respectively. The author attributed this effect to anhydrite dissolution. They also followed the release of dolomite crystals caused by under-saturated low-salinity brine. Whereas, Gamage et al. [23] found that when low-salinity was injected in tertiary mode, there was no additional oil recovery; when used in secondary mode, an oil recovery increase (10 22% OOIP) was observed. However, there are also some studies that did not show increased oil recovery with low-salinity brine injection. For example, Thyne et al. [24] claimed that low-salinity brine increased oil recovery only 1% OOIP in their laboratory experiments. They also analyzed 51 Minnelusa fields data and did not find a correlation between oil recovery and brine dilution. These results indicate that low-salinity waterfloding is at least uncertain in the Minnelusa formation. Fresh-water injection in this rock has been shown to cause anhydrite dissolution, which in turn alters water composition towards higher salinity and calcium content [25].

In this paper, we discuss results of quasi-static capillary pressure and resistivity hysteresis experiments at reservoir conditions using a modified porous plate method that includes an oil-wet membrane at the upper end of a core sample and a water-wet ceramic disk at the lower end. Alongside, unsteady-state coreflooding experiments are carried out at similar experimental conditions to those of the capillary pressure experiments. CMG-IMEX (Computer Modelling Group black-oil simulator) in conjunction with CMG-CMOST (Computer Modelling Group software tool for experimental design, sampling and optimization; the tool is used for Sensitivity Analysis, History Matching, Optimization and Uncertainty Analysis) are employed to history match results of capillary pressure and unsteady-state corefloods to obtain the relative permeability hysteresis. In all experiments, the connate brines are the same, while the injecting brine was either high- or