Journal of Natural Gas Science and Engineering 25 (2015) 30–38

Contents lists available at ScienceDirect

Journal of Natural Gas Science and Engineering

journal homepage: www.elsevier.com/locate/jngse

Relative permeability and capillary pressure curves for low salinity water flooding in sandstone rocks

Mohammad-Javad Shojaei*, Mohammad Hossein Ghazanfari, Mohsen Masihi

Chemical and Petroleum Engineering Department, Sharif University of Technology, Azadi Ave., Tehran, Iran

ARTICLE INFO

Article history:
Received 21 October 2014
Received in revised form
21 April 2015
Accepted 22 April 2015
Available online 4 May 2015

Keywords:
Low salinity water flooding
Salinity dependent relative permeability and capillary pressure models
Wettability alteration
Experimental
Modeling

ABSTRACT

Recently much attention has been paid to the use of low salinity water (LSW) as an enhanced oil recovery fluid. The change observed in recovery factor during LSW flooding is induced from changes in relative permeability and capillary pressure when different levels of salinity are used. However, a few researchers tried to evaluate how macroscopic flow functions depend on the salinity of the injected water. To this end, a series of oil displacement by water was performed on a sandstone rock aged with crude oil in the presence of connate water. The capillary pressure and relative permeability curves are evaluated from inverse modeling of the obtained pressure drop and oil production data. Then, the parameters of two capillary pressure and relative permeability models as a function of water saturation and salinity are determined. The results revealed that the exponents of flow functions as well as residual oil saturation changed linearly with the salt concentration. This showed wettability changed from mixed wet to a water wet condition. Moreover, the results indicated that the oil recovery enhancement is controlled by wettability alteration to a more water-wet condition and also IFT reduction.

1. Introduction

It has been observed that LSW flooding can enhance oil recovery in sandstone rock (Austad et al., 2010a; Nasralla et al., 2011; Robertson, 2007; Alagic and Skauge, 2010). In recent years much attention has been paid to LSW as an enhanced oil recovery fluid (Robertson, 2007; Webb et al., 2004; Lager et al., 2008a; McGuire et al., 2005a; Lager et al., 2008b; Hemmati-Sarapardeh et al., 2014). Better understanding of reservoir behavior to predict future performance and knowledge of how flow function such as relative permeability and capillary pressure changes with salinity is an essential. Although several researchers have been investigating the governing mechanisms during LSW flooding, a few of them tried to evaluate the role of water salinity on macroscopic flow functions. For example, Scott el al. studied the effect of salinity on only end point oil/water relative permeability (Rivet et al., 2010). Webb et al. (2008) and Seccombe et al. (2010) compared high and low salinity water/oil relative permeability without any mathematical discussion on how these functions as well as capillary pressure change with salinity. Jerauld et al. (2008) based on previous studies expressed oil recovery does not depend on salinity above and below certain thresholds of salinity. They proposed a linear dependency in relative permeability and capillary pressure curves between these two thresholds (HS and LS) without any experimental verification as follows (Jerauld et al., 2008):

$$k_{rw} = \theta k_{rw}^{HS}(S^*) + (1-\theta)k_{rw}^{LS}(S^*) \tag{1}$$

$$k_{row} = \theta k_{row}^{HS}(S^*) + (1-\theta)k_{row}^{LS}(S^*) \tag{2}$$

$$P_{cow} = \theta P_{cow}^{HS}(S^*) + (1-\theta)P_{cow}^{LS}(S^*) \tag{3}$$

$$S^* = \frac{S_o - S_{orw}}{1 - S_{wr} - S_{orw}} \tag{4}$$

$$\theta = \frac{S_{orw} - S_{orw}^{LS}}{S_{orw}^{HS} - S_{orw}^{LS}} \tag{5}$$

where θ is the interpolation scaling factor. The mechanisms involved in LSW flooding are discussed in the literature. The first mechanism considers fine clay migration and clay swelling. Detachment of oil-wet clay particles from pore walls due to LSW

* Corresponding author.
E-mail address: ms_shojaei@che.sharif.ir (M.-J. Shojaei).

http://dx.doi.org/10.1016/j.jngse.2015.04.023
1875-5100/

injection, turns the rock into a more water-wet state (Tang and Morrow, 1999; Tripathi and Mohanty, 2008). The second recovery mechanism is the increase of pH value as a result of carbonate dissolution and cation exchange (Moeini et al., 2014; Lager et al., 2008c). Similar to alkaline and surfactant flooding, interfacial tension between oil and water reduces and makes the rock more water-wet (Moeini et al., 2014; Lager et al., 2008c; McGuire et al., 2005b; Austad et al., 2010b). The third recovery mechanism suggested for LSW flooding is multicomponent ion exchange between mineral surface and the invading brine (Lager et al., 2008c). By this, organic polar compounds and organo–metallic complexes are removed from the surface and replaced with non-complex cations. Desorption of polar components from the clay/rock surface makes the surface more water-wet (Lager et al., 2008c; Ligthelm et al., 2009; Lee et al., 2010). However, due to many parameters involved with rock, reservoir fluid and injected fluid, there is no consensus on a particular dominant mechanism, but all these mechanisms lead to wettability alteration to a more water wet state (Tang and Morrow, 1999; Austad et al., 2010b). Among several parameters which affect pore scale displacements, wettability is the most important one. Wettability alteration can affect fluid distribution, residual oil saturation, irreducible water saturation, relative permeability, and capillary pressure (Anderson, 1987). In-depth understanding of wettability alteration during an enhanced oil recovery process helps to achieve an efficient oil recovery and so it is essential to model wettability alteration appropriately. Wettability alteration can be monitored by detecting the changes in relative permeability and capillary pressure curves (Shaker Shiran and Skauge, 2013). Relative permeability is normally measured by JBN and JR method (Grader and O'Meara, 1988; Bartley and Ruth, 1999). However, it misses the role of capillary pressure on displacement data. One suitable method to overcome this problem is history matching technique (Jennings et al., 1988; Yudou Wang et al., 2010; Parvazdavani et al., 2014). In this work, capillary pressure and relative permeability curves were obtained by history matching approach using core flooding experimental data. In this study, Corey equations (Delshad and Pope, 1989) for relative permeability and Skjaeveland equation (Skjaeveland et al., 1998) for capillary pressure was used to determine relative permeability and capillary pressure curves as follows:

$$k_{rw} = k_{rw}^{0}\left(S_w^*\right)^{n_w} \tag{6}$$

$$k_{ro} = k_{ro}^{0}\left(1 - S_w^*\right)^{n_o} \tag{7}$$

$$S_w^* = \frac{S_w - S_{wr}}{1 - S_{wr} - S_{or}} \tag{8}$$

$$P_c = \frac{c_w}{\left(\frac{S_w - S_{wi}}{1 - S_{wi}}\right)^{a_w}} - \frac{c_o}{\left(\frac{1 - S_w - S_{or}}{1 - S_{or}}\right)^{a_o}} \tag{9}$$

Oil and water relative permeability were obtained by specifying the exponents n_w and n_o. In addition, the four parameters of c_w, a_w c_o and a_o are necessary to characterize the capillary pressure curve. To obtain unique match for flow functions JBN data was used as the initial guess for history matching as previous studies (Webb et al., 2008; Parvazdavani et al., 2014). Tripathi and Mohanty (2008) modeled wettability alteration during low salinity water flooding numerically. They assumed Corey parameters to be a function of salinity but above a certain threshold of salinity (high salinity, X_c^{HS}) and below a certain level of salinity (low salinity, X_c^{LS}) it has no salinity dependency. The first model is related to oil displacement in sandstone in which wettability changes from oil-wet to intermediate wet (Tripathi and Mohanty, 2008). In this model it is assumed that residual oil saturation is the only salinity-dependent parameter which is:

$$S_{or}(X_c) = S_{or}^{LS} + \frac{X_c - X_c^{LS}}{X_c^{LS} - X_c^{HS}}\left(S_{or}^{LS} - S_{or}^{HS}\right) \tag{10}$$

In the second model, in addition to the residual oil saturation, the end point water relative permeability also depends on salinity (Tripathi and Mohanty, 2008), i.e.

$$k_{rw}(X_c) = k_{rw}^{LS} + \frac{X_c - X_c^{LS}}{X_c^{LS} - X_c^{HS}}\left(k_{rw}^{LS} - k_{rw}^{HS}\right) \tag{11}$$

This model represents wettability alteration from water-wet to mixed-wet. The third model introduces the wettability alteration from mixed-wet to water-wet (Tripathi and Mohanty, 2008). In this model, in addition to residual oil saturation, the oil relative permeability exponent is also a function of salinity.

$$n_o(X_c) = n_o^{LS} + \frac{X_c - X_c^{LS}}{X_c^{LS} - X_c^{HS}}\left(n_o^{LS} - n_o^{HS}\right) \tag{12}$$

In addition to the Corey equation, oil relative permeability can be modeled using the following equation (Sigmund and McCaffery, 1979; Tsakiroglou et al., 2004):

$$K_{ro} = k_{ro}^{0}\frac{\left(1 - S_w^* + h_o\right)^{m_o} + a_o\left(1 - S_w^*\right)}{\left(1 + h_o\right)^{m_o} + a_o} \tag{13}$$

where:

$$S_w^* = \frac{S_w - S_{wc}}{1 - S_{wc}} \tag{14}$$

Using curve fitting technique, m_o and a_o parameters are obtained. As in Tsakiroglou et al. (2004), the value of h_o and K_{ro} assumed to be 10^{-4} and 1, respectively.

In this study, capillary pressure and relative permeability curves are obtained by history matching technique at three levels of high, medium and low salinities. The parameters of Corey's and Tsakiroglou et al.'s (2004) equations are obtained as a function of salinity. Tripathi and Mohanty's (2008) model was used to investigate how wettability and relative permeability varied with salt concentration. Also, Linear dependency of capillary pressure and relative permeability on salinity was checked with the experimental data.

2. Experimental

The core materials used in this study were collected from Asmari Formation, one of the most important oil reservoirs in the Zagros fold and thrust belt. Table 1 shows essential core properties. Before each experiment the cores were aged for one month at the reservoir temperature (85 °C). Petrophysical properties of the core samples are shown in Table 2 and Fig. 1.

The synthetic seawater (SSW) solutions were prepared by adding different concentrations of NaCl, Na_2SO_4, $NaHCO_3$, $MgCl_2 \cdot 6H_2O$, and KCl to the distilled water. Three different salt concentrations of high salinity (1.0 SSW), medium salinity (0.5 SSW) and low salinity (0.1 SSW) were selected. The numbers represent the dilution ratio. Formation water was used to establish initial water saturation. The compositions of the SSW and formation water are shown in Table 3.

The experiments were conducted with the oil of the same