

THE INFLUENCE OF INTERFACIAL TENSION ON WATER-OIL TWO-PHASE RELATIVE PERMEABILITY

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Abstract

Water-oil relative permeability, related to all two-phase flow properties, characterizes two-phase flow and displacement processes in porous media. Therefore, relative permeability is inherently complicated, and its functional form is difficult to determine in a particular reservoir study. For example, adding various chemical agents into the displacing aqueous phase during alkaline-surfactant-polymer combination chemical flooding significantly changes interfacial tension (σ) on water-oil interfaces, and also increases the degree of difficulty in measuring such changes in the laboratory. To overcome the limitations of the existing laboratory measurements of relative permeability, which are applicable only for high ranges of interfacial tension (e.g., $\sigma > 10^{-2}$ mN/m), we present a comprehensive experimental study of two-phase relative-permeability functions in much lower, realistic interfacial tension water-oil systems. In particular, we have (1) developed an improved steady-state method of measuring water-oil relative permeability curves; (2) proved that the two critical values, N_{C1} (0.0005) and N_{C2} (0.1) or σ_{C1} (3mN/m) and σ_{C2} (10^{-2} mN/m) exists, observed in capillary number or interfacial tension with the selected water-wetting cores under laboratory temperature conditions; (3) shown that a logarithmic relation exists between water-oil two-phase relative permeability and interfacial tensions. The experimental results and proposed conceptual models will be useful for feasibility studies, optimal designs, and numerical simulations of different chemical flooding operations in oil reservoirs.

Introduction

With increasing demand for oil, and at the same time large decreases in newly discovered worldwide oil reserves in the past few decades, more efficient development of oil and gas from existing reservoirs, using enhanced oil recovery (EOR) methods, has received greater attention. Since the 1970s, as a result of industry-wide efforts to improve oil recovery rates, many EOR techniques have been developed and applied to various oil fields.

From the viewpoint of fluid flow mechanics, there are two main forces acting on residual oil drops: viscous and capillary forces. Microscopic displacement efficiency with an EOR method depends on the relative influence or ratio of these two forces. Melrose and Brandner (1974) define capillary number as the ratio of viscous forces and capillarity [1]:

$$N_c = \frac{\mu_w V_w}{\phi \sigma_{wo}} \quad (1)$$

where N_c is the capillary number; μ_w is the viscosity of aqueous or displacing phase; V_w is the flow rate of the displacing phase; ϕ is the effective porosity of formation; and σ_{wo} is the water-oil interfacial tension.

By altering interfacial tension between water-oil (water-gas or oil-gas) phases, surfactants cause significant changes in two-phase flow behavior. Among the earlier efforts, Talash (1976) presented a modified Naar-Wygel equation exponential function [2] to describe the relationship between relative permeability and normalized saturation under low interfacial tension conditions. As the literature indicates, many studies have been carried out regarding two-phase flow and displacement processes under different interfacial tensions (Bardon and Longeron, 1980 [3]; Chisholm et al., 1990 [4]; Asar and Handy, 1988 [5]; Haniff and Ali, 1990 [6]; Ronde, 1992 [7]; Conway et al., 1995 [8]; McDougall et al., 1997 [9]; Mulyadi et al., 2002 [10]). The majority of these studies, however, were performed for either oil-gas or water-gas two-phase systems. In addition, the ranges of interfacial tensions covered in these investigations were limited mostly to 10^{-1} to 40 mN/m (or higher than 10^{-2} mN/m). This is mainly because it is difficult to conduct such experiments and measurements (i.e., involving low interfacial tensions) under laboratory conditions, because of the complexity in chemical properties and their variations, such as chemical reactions and adsorption effect.

In the 1990s, field pilot tests were carried out, using the alkali-surfactant-polymer combinational flooding approach, at several oilfields in China. Using a dynamic method, Wang et al. (2002) [11] and Lu et al. (2003) [12] measured end values of relative permeability and remaining residual oil saturation for low interfacial tension water-oil systems. They showed the effects of water-oil interfacial tension on the end values of relative permeability under transient displacement. By comparing with laboratory measurements, the modified model was found to fit well for relative permeability curves near both ends of saturation ranges, but not well for the middle portion of the curves because of the difficulties encountered in their measurements.

Experimental Procedure and Method

To eliminate the effects on measurements of complex chemical processes occurring at water-oil interfaces on measurements, we adopted a steady-state method for measuring water-oil relative permeability within a low-interfacial-tension system.

Measurement and Instrument

A schematic or flow chart of the experimental setup, instruments, and procedure of this study is shown in Figure 1. And a tensometer (TX500C) was used for measuring interfacial tension.

Test Fluids

To make the experiment and measurements repeatable, the oil used in this study is called “model oil,” which has been systematically treated to remove its active components. Brine, consisting of 5,000 mg/L of NaCl (sodium chloride), is used in the water-oil system as the aqueous phase. Chemical components, 2SY+NaCl (0.5%wt)+NaOH.

Results and Discussion

Surfactant-Flooding Characteristics and Interfacial Tensions

The relationship between residual oil saturation and interfacial tension, under the different interfacial tensions of this study’s core-fluid system, can be further quantified using a regression analysis. Fitting and statistical analysis of experimental data yields the following expression:

$$S_{or} = \frac{1}{A + B \cdot e^{N_c}} \quad (r^2=0.9799, F_{stat}=635) \quad (2)$$

where A and B are constants related to cores and experimental conditions, and r and F_{stat} are the correlation coefficient and F-test of statistics, respectively. As shown in Figure 2, the results of using Equation (2) (labeled as “calculational”) match the experimental data points well.

The experimental results indicate that there exists a certain correlation between residual oil saturation after water flooding operations, and water-oil interfacial tension under different surfactant concentrations within fluid systems. With the selected water-wetting cores under laboratory temperature conditions, for example, there are two critical values, N_{C1} (0.0005) and N_{C2} (0.1) or σ_{C1} (3mN/m) and σ_{C2} (10⁻²mN/m), observed in capillary number or interfacial tension (Figure 2). When $N < N_{C1}$ (or $\sigma > \sigma_{C1}$), the first critical point, residual oil saturation of the water flooding remains at about 0.40. This residual saturation of 0.40 appears to be unvarying with changes in interfacial tension within this range. On the other end of the curve, as shown in Figure 5, residual oil saturation is also kept as a low-level constant for $N > N_{C2}$ (or $\sigma < \sigma_{C1}$). For the intermediate values of capillary number (i.e., $N_{C1} > N > N_{C2}$), Figure 5 shows that residual oil saturation rapidly decreases with increasing capillary number (or decreasing interfacial tension). In other words displacement efficiency increases significantly with decreasing interfacial tension.

Figure 3 displays the normalized relative permeability curves for two-phase flow for different interfacial tensions. It appears that only small differences appear in both oil and water relative permeability curves for $N < N_{C1}$ ($\sigma > \sigma_{C1}$). Significant changes in normalized relative permeability curves occur as capillary number change when $N > N_{C1}$.

Relative Permeability Model for Low Interfacial Tension

Many studies (e.g., Fulcher et al., 1985 [13]; Kumar et al., 1985 [14]; Brooks and Purcell, 1952 [15]) have shown that water-oil relative permeability for two-phase flow systems is

a function of saturation, rock-pore characteristics, temperature, interfacial tension, and capillary number. Even though a number of different forms of relative permeability functions have been proposed, simple exponential equations have been among the most widely used relationships in reservoir simulation and groundwater modeling (Honarpour et al., 1986 [16]). In our experiment, water and oil viscosities and displacement rate remain constant. Therefore, relative permeability from our experiments is considered as a function of saturation, interfacial tension, and properties of core pores only. Based on the experimental measurements, we propose the following two-phase-flow relative permeability models:

$$k_{rw}^* = (S_w^*)^{n_w} \quad (3)$$

and

$$k_{ro}^* = (1 - S_w^*)^{n_o} \quad (4)$$

where S_w^* is the normalized wetting, aqueous phase saturation; k_{rw}^* is the normalized aqueous-phase relative permeability; k_{ro}^* is the normalized oil-phase relative permeability, respectively.

The two exponential indexes, n_w and n_o , can be related with interfacial tension and pore size distribution parameters, λ_w and λ_o , as

$$n_o = n_o(\square_{wo}, \lambda_o) \quad (5)$$

and

$$n_w = n_w(\square_{wo}, \lambda_w) \quad (6)$$

Based on our experimental data and line-fitting results, the two-phase relative permeability model, Equations (5) and (6), has the form:

$$k_{rw}^* = (S_w^*)^{[0.9371 \cdot \log(\sigma_{wo}) + \lambda_w]} \quad (7)$$

and

$$k_{ro}^* = (1 - S_w^*)^{[0.1960 \cdot \log(\sigma_{wo}) + \lambda_o]} \quad (8)$$

where λ_w and λ_o are constants for water and oil relative permeability, respectively, for the same rock type. The two parameters, λ_w and λ_o , should be determined from pore properties of core samples such as pore size distribution, tortuosity, and phase distribution within pores (wettability). With the sandstone outcrop cores associated with the fluids of this study, curve fitting of the experimental data leads to $\lambda_w = 3.81$ and $\lambda_o = 2.0$.

It appears that as interfacial tensions decrease, two exponential indices also decrease. This will make both water and oil relative permeability curves tend to be straighter. As shown in Figure 4, the exponential indices are still not close to one, even with very low interfacial tensions ($\sigma = 0.01$ mN/m).

Therefore, the corresponding relative permeability curves are still not yet straight lines.

Conclusion

This paper presents a comprehensive experimental study of two-phase relative permeability functions in a low-interfacial-tension water-oil system. By analyzing the experimental data, the following results and conclusions can be drawn:

1. A new steady-state method for measuring relative permeability data has been developed. This new steady-state method (with the designed experimental system) can be used to measure entire relative permeability curves, including low interfacial tensions, accurately and efficiently.
2. There exist two critical values or points, N_{C1} (0.0005) and N_{C2} (0.1) or σ_{C1} (3mN/m) and σ_{C2} (10^{-2} mN/m), for the systems of fluids and porous media used in this study.
3. Residual oil saturation tends toward zero as interfacial tensions are reduced as low as $\sigma = 10^{-2}$ mN/m from $\sigma = 3$ mN/m. In addition, relative permeability curves for both water and oil phases become straighter with decreasing interfacial tensions.
4. The experimental data and their analysis indicate that relative permeability for the low-interfacial-tension water-oil system is described by $k_r = S_w^{*A \log \sigma_{wo} + \lambda}$.

There have been few studies in the literature regarding water-oil relative permeability behavior in multicomponent-mixture chemical flooding, with reported investigations mostly carried out using gas-oil systems. This work attempted to fill the gaps in studies of water-oil systems under low interfacial tensions. We have found that it is not only more difficult to measure experimental results for a low-interfacial-tension water-oil system, but there also may exist more than one explanation for the observed flow phenomena. Thus, further studies are needed.

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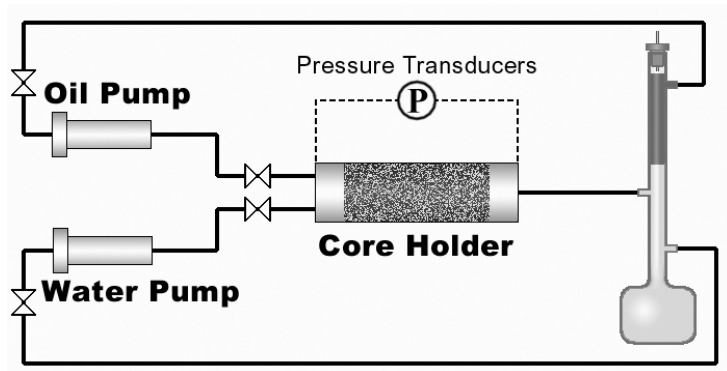


Figure 1. Schematic diagram of the apparatus and experimental setup

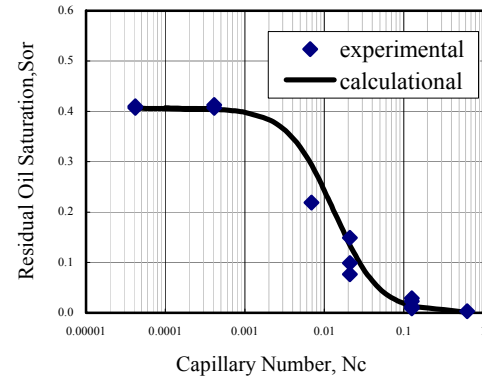


Figure 2. Experimentally determined residual saturations as functions of the capillary number

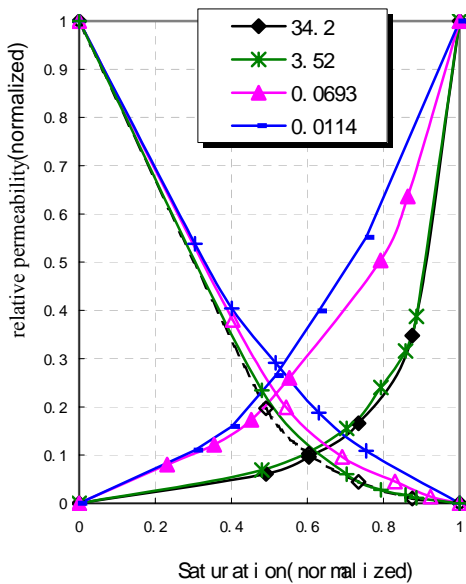


Figure 3. Normalized water-oil relative permeability curves for different interfacial tension values

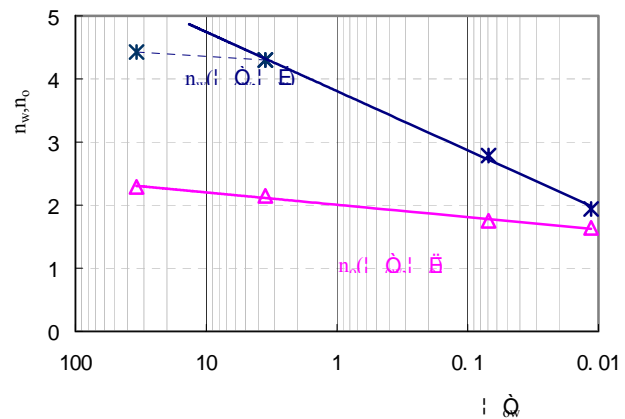


Figure 4. Correlations between interfacial tensions and exponential indexes, n_w and n_o .