Pore-scale simulation of water alternate gas injection

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ABSTRACT

We use a three-dimensional mixed-wet random network model representing Berea sandstone to compute displacement paths and relative permeabilities for water alternating gas (WAG) flooding. First we reproduce cycles of water and gas injection observed in a previously published experimental study. We predict the measured oil, water and gas relative permeabilities accurately. We discuss the hysteresis trends in the water and gas relative permeabilities. We interpret the results in terms of pore-scale displacements. In water-wet media, the water relative permeability is lower during water injection in the presence of gas due to an increase in oil/water capillary pressure that causes a decrease in wetting layer conductance. The gas relative permeability is also lower for displacement cycles after the first gas injection due to trapping of gas at low saturations. We show how to use network modeling to develop a physically-based empirical trapping model for three-phase fluid flow. The amount of oil and gas that is trapped shows a surprising trend with wettability due to the complex competition of different three-phase displacement processes. Further work is needed to explore the full range of behavior as a function of wettability and displacement path.

1. INTRODUCTION

Experimental measurements of three-phase flow are extremely difficult to perform and the results are frequently not reliable at low saturation (Oak, 1991). In addition to the measurement of saturations, pressure drops, and fluxes in three flowing phases, there are an infinite number of different displacement paths. Thus it is impractical to measure relative permeability for all possible three-phase displacements that may occur in reservoir. As a result, the universal practice in reservoir simulation studies is to estimate three-phase relative permeabilities using empirical correlations, which usually have very little or no physical basis (Stone, 1970; Stone, 1973; Baker, 1988; Blunt, 2000).

Water alternating gas (WAG) injection is one of the many improved oil recovery methods that involve three-phase fluid flow. It was originally proposed as a method to improve the sweep efficiency of gas by using water to control the mobility ratio and to stabilize the front (Caudle and Dyes, 1958; Christensen *et al.*, 1998). Although WAG flooding has been successfully applied to more than 60 oilfields worldwide, there is still an incomplete understanding of the pore-scale physics of the process and how it leads to improved oil recovery, especially in systems with non-uniform wettability. The major problems in the evaluation of WAG behavior are uncertainties regarding the prediction of the wettability and spreading conditions as well as the relative permeabilities of the phases for different injection cycles. Since gas is generally the most mobile phase during WAG flooding, the gas relative permeability controls the efficiency of the process. Gas is the most non-wetting phase in water-wet systems. As a consequence gas invades the largest pores and throats. However, during wetting phase injection (water or oil flooding), gas is displaced from the smaller pores that it occupies. Although the saturation of the gas phase may not be affected significantly, this causes disconnection of continuous gas clusters, reducing the gas phase relative permeability.

Piri and Blunt (2005a,b) presented a three-dimensional mixed-wet network model in order to simulate two- and three-phase fluid flow. A random network, generated using process-based techniques (Øren and Bakke, 2002), was used to represent the pore space in Berea sandstone. The model simulated any sequence of oil, water and gas injection. Threshold capillary pressures for all possible displacements were computed for 30 different phase configurations. Two- and three-phase relative permeabilities were successfully predicted and compared with the steady state experiments conducted by Oak (1990). They also studied secondary and tertiary gas injection into media of different wettability and initial oil saturation. In this paper we extend this work to study WAG flooding.

2. NETWORK MODELING

The fluids used in this work are assumed to be Newtonian, incompressible, and immiscible. Displacement at the pore scale is assumed to be quasi-static and capillary dominated. A displacement is defined as a change in the configuration of an element (pore or throat) in order to satisfy capillary equilibrium conditions. This can either be a displacement of a phase by another in the centre of an element or layer collapse/formation in a single corner. Each displacement has a threshold capillary pressure associated with it. The properties of the Berea sandstone network, the analytical calculations of the threshold pressures as well as the possible fluid configurations have already been discussed in the literature (Øren *et al.*, 1998; Hui and Blunt, 2000; Piri and Blunt, 2005a). The Berea network contains 12,000 pores and 26,000 throats. In the network, each pore and throat is assumed to have an irregular triangular, square or circular cross-section. Full details of the model are provided in Piri and Blunt (2005a).

2.1 Double Displacement Mechanisms

In two-phase static network models, a fluid phase is able to move and contribute to displacement events only if it is connected to the inlet or outlet. In three-phase flow, however, the displacement of trapped clusters is vital for predicting recovery mechanisms: for instance oil that is trapped during waterflooding becomes reconnected by gas through the pore-scale migration and coalescence of oil clusters. Our model only considers double displacement. There are six possible double displacements out of which only double drainage (gas displacing oil and displaced oil displacing water) was included in the model developed by Piri and Blunt (2005a), since the authors were mainly interested in tertiary gas injection. However, to simulate WAG injection appropriately, where both oil and gas are trapped, we extended this model by including two other double displacement processes: double imbibition (water displacing trapped oil that displaces gas) and imbibition-drainage (water displaces trapped gas that displaces oil) (Suicmez et al, 2006). Since we do not consider oil injection and water is almost always continuous, the three other double displacement mechanisms are ignored.

When a double displacement is carried out, the displacement can be considered as two single displacements. The first one is a continuous phase displacing a trapped phase, and the second one is displaced trapped phase displacing another continuous phase. To perform the displacement, we first increase the trapped phase pressure to the threshold pressure of the second single displacement (trapped phase displacing the continuous phase). Then, by adding this difference to the threshold pressure of the first single displacement (continuous phase displacing the trapped phase), we can calculate the threshold pressure for the double displacement event. It is given as:

$$P_{DD}^{threshold} = P_{first}^{threshold} + P_{second}^{threshold} - P_{trapped} \tag{1}$$

where P is the pressure, DD stands for double displacement, *first* is the displacement of trapped phase by a continuous phase, and *second* is the displacement of the continuous phase by the displaced trapped phase.

3. COMPARISON WITH EXPERIMENT

We will use the network model to predict an experimental dataset (Oak, 1990) before using the model to predict trends in behavior with wettability. Piri and Blunt (2005b) successfully predicted the relative permeabilities of tertiary gas injection experiments conducted by Oak (1990) and then predicted the behavior in an oil-wet system. They showed that double drainage allows oil to become reconnected when gas is injected, discussed the differences in oil relative permeability as a function of water and gas saturations and demonstrated that the oil relative permeability for secondary gas injection is proportional to the square of the oil saturation. We extend this work by simulating cyclic gas/water injection experiment conducted by Oak (1990). Current empirical relative permeability models are unable to predict this data accurately (Spiteri and Juanes, 2004). Although the wettability and the spreading conditions of the medium are not presented in the experimental work, we assume a water-wet and spreading oil system (Table 1). The same properties have successfully predicted Oak's two-phase data and three-phase gas injection relative permeability (Valvatne and Blunt, 2004; Piri and Blunt, 2005b). The success of these studies suggests that the fluid properties are representative of the experiments and that the Berea network is an adequate description of the Berea cores studied by Oak.

TABLE 1. The interfacial tension and contact angle values used in our model to predict Oak's experiments (1990).

σ_{gw} (mN/m)	67
σ_{go} (mN/m)	19
σ_{ow} (mN/m)	48
θ^{r}_{gw} (degrees)	36.6 – 57.3
θ^{r}_{go} (degrees)	10 – 50
θ^{r}_{ow} (degrees)	43 – 60
θ^{a}_{gw} (degrees)	55.2 – 77.2
θ^{a}_{go} (degrees)	30 – 70
θ^{a}_{ow} (degrees)	63 – 80

Figure 1 shows the experimental displacement path for a case where there are cycles of water and gas injection. Gas injection is performed into water and residual oil and then water is injected again until both gas and oil are trapped. The match to the saturation path using network modeling is good as are the predictions of relative permeability (Figures 2-4). Gas is the most non-wetting phase and a significant decrease in the gas relative permeability is observed during secondary water injection (Figure 2). The reason for this is that water traps gas, principally through snap-off, which is predicted accurately by the pore-scale model confirming other experimental and numerical studies (Skauge and Larsen, 1994; Svirsky *et al*., 2004). As can be seen from Table 2, there are a significant number of water to gas snap-off displacements during secondary water injection, although the most common mechanism is piston-like advance.

An unexpected observation is the noticeable water relative permeability hysteresis (Figure 3) evident in both the experiments and the predictions. Since water is the most wetting phase, it is not trapped and resides in the smallest elements of the pore space. The traditional thinking is that as a consequence the water relative permeability is a function of its own saturation only and does not display any hysteresis (Stone, 1970). However, we find that the water relative permeability is lower for the second water injection (water injected into a high gas saturation) than for the first (water displacing oil with no gas present). Once we introduce gas into the system, oil no longer occupies the biggest pore and throat elements. Instead gas, which is the most non-wetting phase in a water-wet system, moves oil into smaller pores and throats by single and double displacement. Most of this oil is trapped. In the network model, if trapped clusters become reconnected, the continuous phase pressure is increased to that of the trapped phase (van Dijke and Sorbie, 2002; Piri and Blunt, 2005a). This approach allows the oil/water capillary pressure to increase during gas injection through the reconnection of previously trapped oil, as observed in micromodel experiments (van Dijke *et al.,* 2004). When water re-injection commences, the oil/water capillary pressure increases sharply. This increase in capillary pressure means that oil pushes water further into the corners of the pore space. As water is pushed into the corners, this conductance decreases sharply, causing the observed decrease in water relative permeability. After the first water injection, oil is disconnected and has a zero relative permeability. During gas injection the oil is reconnected due to double drainage when gas pushes oil into smaller elements. Since volume is conserved, the oil now occupies more pores and throats and quickly fills a sufficient fraction of the network to become connected. The oil relative permeability is then finite but decreases as further gas invasion displaces oil. At the end of gas invasion, the oil relative permeability is close to zero, as connected oil resides in only a few smaller elements and in oil layers. When water is re-injected, the oil relative permeability again increases slightly, as double imbibition allows trapped oil clusters to reconnect. Because the oil is becoming connected and disconnected through repeated flooding cycles, both the experimental and numerical data are noisy, but we predict the experimental trend in behavior.

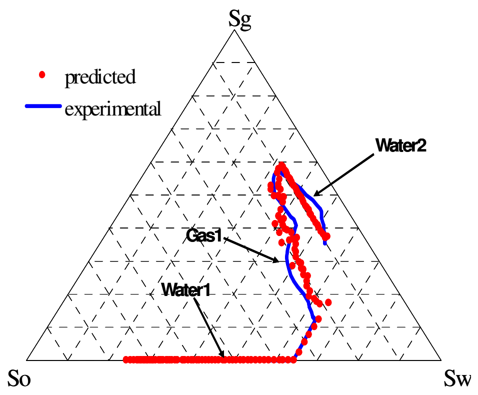

FIGURE 1. Comparison of measured and tracked saturation paths for cyclic gas and water injection. Experiment 4 – Sample 6 of Oak experiments (Oak, 1990).

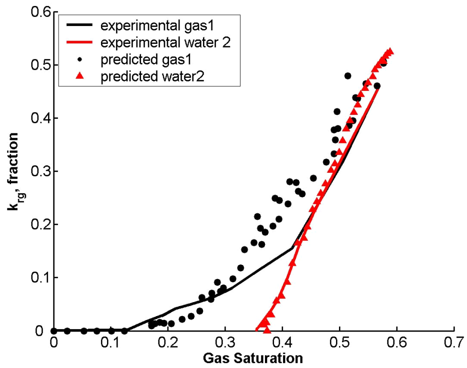

FIGURE 2. Comparison of measured and predicted gas relative permeabilities.

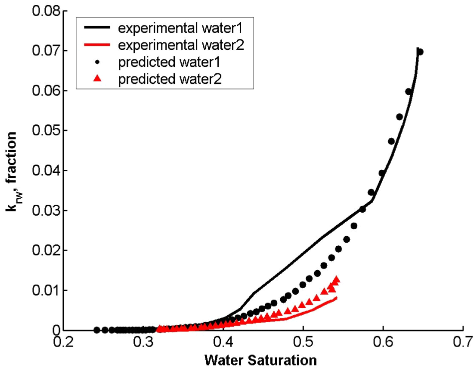

FIGURE 3. Comparison of measured and predicted water relative permeabilities.

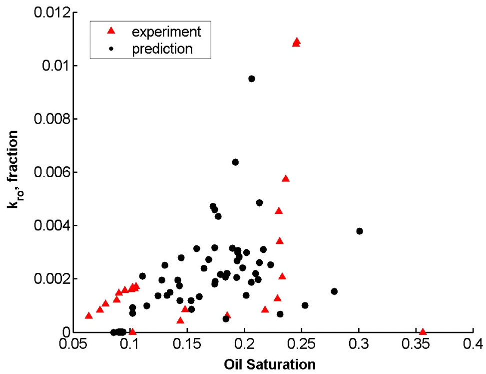

FIGURE 4. Comparison of measured and predicted oil relative permeabilities.

TABLE 2. Statistics for water to gas displacements during the secondary water injection process for the saturation path shown in Fig 5.

	Piston-like	Snap-Off
Number	13041	963
Percentage (%)	92.6	7.4

4. HYDROCARBON TRAPPING

We will now study both oil and gas trapping for different wettability conditions. To predict three-phase relative permeabilities we need to estimate the amount of oil and gas that is trapped for any displacement sequence. Figure 5 shows the trapped gas saturation as a function of the initial gas saturation in the system. We obtain a reasonable match with the Land's trapping model (Land, 1968) for a water-wet system. However, there is an unexpected increase in the trapped gas saturation once the system becomes weakly water-wet. During wetting phase injection, there is a competition between pore body filling and snap-off events. More snap-off events have taken place in a weakly water-wet medium. This is a counter-intuitive result, since in two-phase flow snap-off becomes less favored as the contact angle increases. More gas is trapped in a three-phase weakly water-wet system, because trapped oil prevents piston-like displacement of gas during water injection. The amount of trapping in a weakly oil-wet system is similar, since gas remains the most non-wetting phase and is trapped in the larger pore spaces. Once system becomes strongly oil-wet, however, the amount of trapped gas decreases, since the gas phase is now intermediate-wet and can form layers between the water in the corner and water in the center of pore and throats. These layers are most stable when the initial gas saturation is high, and gas has forced water far into the corners of the pore space. As a consequence, the trapped saturation decreases as the initial saturation increases. This non-monotonic trend cannot be predicted by a Land-type model.

In a water-wet system, the decrease in residual oil saturation with an increase in the initial gas saturation has already been discussed in the literature (Kortekaas and Poelgeest, 1991). The trend with wettability though has not been discussed before. Figure 6 shows that there is a crossover in the curves for a weakly water-wet and water-wet system. With an increase in oil-water contact angle, oil layers between water and gas become thinner and less stable, leading to more layer collapse events. Hence the residual oil saturation in the presence of gas is higher for a weakly water-wet system. However, in the presence of water alone, the residual oil saturation is lower since there is less snap-off of oil causing trapping. For oil-wet systems, during the secondary water injection, water to oil or water to gas piston-like displacements are drainage-type displacements requiring a high capillary pressure. However, many oil layers in between gas and water may collapse at a lower pressure. The higher the gas saturation, the more oil layer collapse displacements take place, since the gas pressure is higher, which tends to squeeze oil layers. Figure 6 shows the clear increase in the trapped oil saturation with an increase in the initial gas saturation for both weakly and strongly oil-wet cases. Again, this complex behavior cannot be captured by any currently available empirical models.

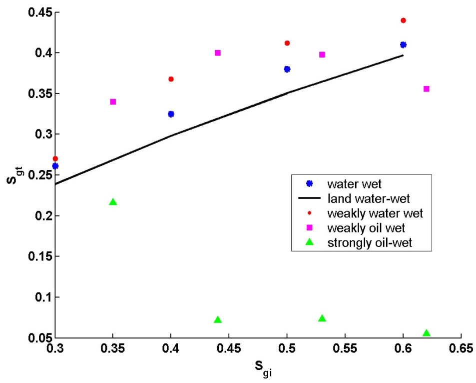

FIGURE 5. Comparison of trapped gas saturation as a function of initial gas saturation.

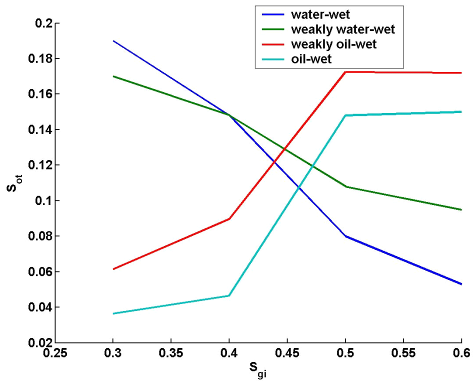

FIGURE 6. Comparison of trapped oil saturation as a function of initial gas saturation.

5. CONCLUSIONS

We extended the model developed by Piri and Blunt (2005a) by adding two new double displacement mechanisms, double imbibition and imbibition-drainage. We first validated the model by accurately predicting relative permeabilities from an experimental dataset in the literature. We then showed how pore-scale network modeling could be used to predict trapped hydrocarbon saturation during three-phase flow. We showed some surprising trends in behavior with wettability; a weakly water-wet system showed more trapping of oil and gas than a water-wet medium due to the complex competition between three-phase displacement processes. The trend in trapped oil saturation with initial gas saturation is different for water-wet and oil-wet systems. Further work is required to quantify the degree of trapping for all possible cases and to estimate the relative permeabilities as a function of flowing saturation.

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