SURPRISING TRENDS ON TRAPPED HYDROCARBON SATURATION WITH WETTABILITY

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ABSTRACT
We use a three-dimensional mixed-wet random network model representing Berea sandstone to extend our previous work on relative permeability hysteresis during water-alternate-gas (WAG) injection cycles (Suicmez *et al.*, 2007). We compute trapped hydrocarbon saturation for the following displacement sequences: primary drainage followed by gas injection to different initial gas saturations, S_{gi}, followed by water injection until all the gas and oil is trapped. We study four different wettability conditions; water-wet, weakly water-wet, weakly oil-wet and oil-wet. We demonstrate that the amount of oil and gas that is trapped shows a surprising trend with wettability which cannot be captured using previously developed empirical trapping models.

INTRODUCTION
The use of physically-based properties for three-phase flow – such as relative permeability and capillary pressure – that properly reflect the pore structure and wettability variations in the reservoir may give very different predictions than using empirical correlations that extrapolate two-phase data (Stone, 1970; Stone, 1973; Baker, 1988). The emphasis in this paper will be on predicting the amount of oil and gas that can be trapped. It has been proposed that the relative permeability is a unique function of the flowing (non-trapped) fluid saturation (Carlson 1981; Blunt, 2000). Hence relative permeability could be predicted only if the trapped saturation is known.

Jerauld (1997) suggested that the total hydrocarbon (oil and gas) trapped in a three-phase system would be up to 20% greater than the waterflood residual oil saturation during two-phase flow. He supported this hypothesis by showing experimental data from a wide variety of oil fields including Prudhoe Bay. He concluded that unless the system is strongly water-wet, the trapped gas and residual oil saturation should be approximately independent since they are not necessarily competing to occupy the same pores. Kralik *et al.*, (2000) studied a comprehensive set of experimental data obtained from an oil-wet sandstone reservoir. They suggested that gas trapping not only depends on its own saturation but also on wettability and the relative amounts of the other two phases. It was shown that in oil-wet reservoirs trapped gas saturation can be significantly lower during waterflooding since gas may become the intermediate-wet phase which inhibits the water to gas snap-off displacements during water invasion. This explanation is similar to that for water-wet systems in which residual oil saturation is lower for intermediate-wet systems than water-wet systems (Jadhunandan and Morrow, 1995).

In this work, we apply pore-network modeling as a tool to estimate the trapped hydrocarbon saturation. Using our network model, we will compute the trapped oil and gas saturations separately and relate it to the initial gas saturation and wettability of the system for a particular saturation path (gas injection followed by waterflooding). The properties of the Berea sandstone network, analytical computations of the threshold displacement pressures and transport properties have already been discussed in the literature (Øren *et al.*, 1998; Hui and Blunt, 2000; Piri and Blunt, 2005; Suicmez *et al.*, 2007). We are not going to present all details of our model in this paper: however two- and three-phase fluid configurations do deserve a brief introduction.

GENERIC FLUID CONFIGURATIONS

For the vast majority of pore and throat elements, one or more phases may reside in them simultaneously. Generic two- and three-phase fluid configurations are shown in Figure 1. We assume the system is initially 100% saturated with water and strongly water-wet. Once non-wetting phase (oil) migrates into the system during primary drainage, it invades the center of the element and changes the wettability of the central portion of the pore/throat where oil is in contact with the solid.

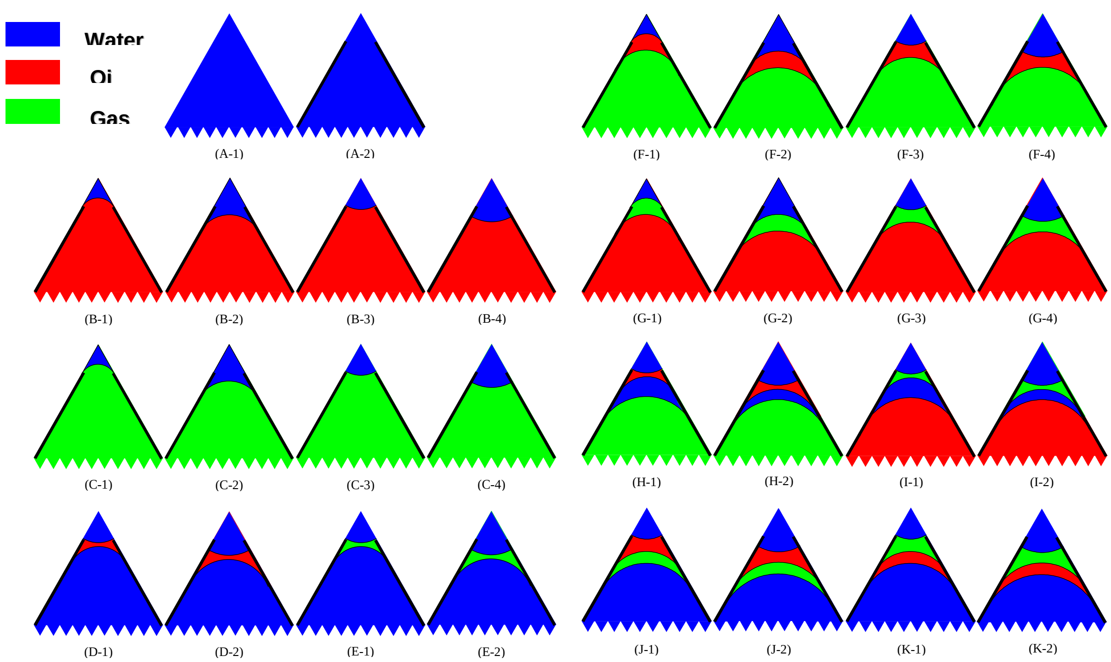


Figure 1. One, two- and three-phase fluid configurations for a single corner. The bold solid line indicates the regions of the surface with altered wettability. From Piri and Blunt (2005).

RESULTS AND DISCUSSION

The contact angles used to represent water-wet, weakly water-wet, weakly oil-wet and strongly oil-wet systems are shown in Table I. We conduct four sets of simulations with different initial gas saturations (S_{gi}) for each wettability condition. We use same interfacial tensions (oil spreading system) used during our previous work (Suicmez *et al.*, 2007 – σ_{ow} = 48 mN/m, σ_{go} = 19 mN/m, σ_{gw} = 67 mN/m).

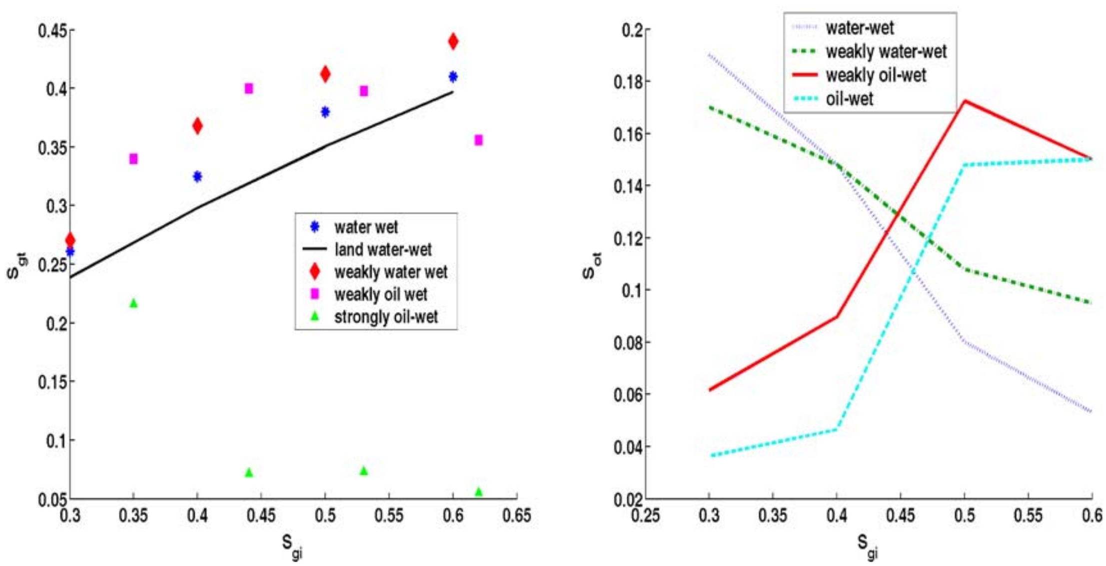
Table 1. Contact angles used to represent different wettability conditions. The ones shown in the table are the advancing values. Receding values of θ_{ow} and θ_{gw} are 20 degrees lower than the advancing ones. During primary drainage θ_{ow} is assumed to be zero. Note that the gas-water contact angle θ_{gw} is computed by using Bartell-Osterhof (1927) constraint.

	θ_{ow}	θ_{go}	θ_{gw}
Water-wet	30 - 50	0	25 – 42
Weakly water-wet	60 - 90	0	50 – 73
Weakly oil-wet	100 - 150	0	80 – 110
Oil-wet	150 - 180	0	110 – 116

Figure 2a shows the trapped gas saturation as a function of the initial gas saturation. We obtain a reasonable match with the Land's trapping model (1968) for a water-wet system. Once the system becomes oil-wet, the amount of trapped gas is dependent on the ability of the gas phase to form layers between the water clusters in the corner and in the center of the pore and throat elements. In a weakly oil-wet medium, gas is still the most non-wetting phase and cannot form layers. Hence, the amount of trapping is similar for a weakly water-wet system. For a strongly oil-wet system gas is not the most non-wetting phase; it is intermediate-wet and water is the most non-wetting phase – see Table 1. When water invades into system (following gas injection), it occupies the pore space with layers of gas in between the center and corner – configuration E-2 in Figure 1. As the initial gas saturation increases, so does the final gas phase pressure. Hence the proportion of elements with gas layers after water invasion increases with increasing initial gas saturation. These layers maintain connectivity of the gas phase and result in less trapping. Hence we see a somewhat peculiar trend in trapping: the amount of trapped gas *decreases* with increasing initial gas saturation.

The decrease in the residual oil saturation with an increase in the initial gas saturation has already been discussed in the literature (Holmgren and Morse, 1951; Kortekaas and Poelgeest, 1991). The trend with wettability though has not been discussed before. Figure 2b shows that there is a crossover in the curves for a weakly water-wet and water-wet system. We obtain more layer collapse events in a weakly water-wet medium leading to more oil trapping when the initial gas saturation is high. If the initial gas saturation is large, then the final gas/oil capillary pressure is also large and hence the gas/oil interface penetrates a long way into the corner of the pore space. This means that the oil layers are relatively thin in many of the pores and throats. Therefore, when we inject water into the system, water may collapse these layers without moving the oil/water/solid contact. As a consequence, the wettability of the system does not affect the threshold capillary pressure for layer collapse; for all four different wettability conditions, the displacement requires exactly same threshold pressure. However, the same layer collapse capillary pressure does not imply that layers are equally stable during a displacement, since this threshold capillary pressure has to be compared to the capillary pressures for other displacements. Water may displace oil and gas by piston-like advance, snap-off and pore filling. For all these displacements, the threshold water pressure increases with increasing oil/water contact angle. Hence, for a strongly water-wet system, water will displace oil and gas, filling pores and throats at a lower water pressure than that necessary to collapse oil layers. As a consequence, oil will remain connected and the degree of oil trapping will be small. Furthermore, since the principal mechanism for trapping of gas is snap-off by water, little gas will be trapped, since snap-off will not happen, since water will not contact gas directly due to stable oil layers.

For oil-wet systems, the amount of oil trapping at low initial gas saturation is low as we expect. As the oil/water contact angle increases, oil layers may form in the pore space and these layers provide continuity of the oil and mean that little oil is trapped during waterflooding. However as the initial gas saturation increases, implying less initial oil in the system, the trapped oil saturation *increases.* As mentioned above, as the system becomes more oil-wet, layer collapse events become more common since they are favored in comparison to direct displacement of oil and gas by water. Layer collapse is favored for both weakly and strongly oil-wet systems. However, slightly less oil is trapped for the strongly oil-wet case. This is because, as with low and zero initial gas saturations, where there is water to oil displacement, oil layers form and maintain connectivity of the oil clusters, giving less trapping.



(a) (b)

Figure 2. Comparison of trapped gas (a) and oil (b) saturation as a function of initial gas saturation.

CONCLUSIONS

We have studied oil and gas trapping in three-phase flow using pore-scale network modeling. The results show some surprising trends with saturation history and wettability due to the complex competition between three-phase displacement processes. It is difficult and time-consuming to investigate the full range of behavior by conducting experiments. Pore-network modeling is a useful tool for understanding multiphase flow in porous media and, in particular, to determine sensitivities for different displacement processes and wettabilities. From a practical perspective it is possible to study a wide range of different displacement scenarios by altering the predetermined input parameters and initial conditions and it may be possible to use the results, eventually, to propose a more physically-based model for three-phase relative permeability than the expressions currently used in the industry.

Among the puzzling results presented in this paper are: the increase in oil layer collapse with increasing oil/water contact angle; the increased oil and gas trapping for a weakly water-wet system compared to a water-wet system; the decrease in trapped gas with increasing initial gas saturation for a strongly oil-wet system; and the increase in trapped oil with increasing initial gas saturation for weakly and strongly oil-wet systems. In all these cases a simple analysis of the problem would predict the opposite behavior. It is only through a careful analysis that these results can be explained. This illustrates the need to have detailed models of the displacement process that capture the three-phase displacement physics as carefully as possible. Furthermore, all these results were obtained from just one set of simulations where water injection started from the same initial configuration in the pore space regardless of wettability; had we considered more complex saturation paths with more than one water injection cycle, the results may well have been even more complex.

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