Prediction of Gas Injection Performance for Heterogeneous Reservoirs

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Authors:

Martin J. Blunt

Franklin M. Orr Jr.

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Department of Petroleum Engineering
Stanford University
Stanford, CA 94305-2220

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Abstract

This quarterly report outlines progress from April 1, 1998 to June 30, 1998 in the DOE project 'Prediction of Gas Injection Performance for Heterogeneous Reservoirs'.

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1 Executive Summary

This project performs research in four main areas: laboratory experiments to measure three-phase relative permeability; network modeling to predict three-phase relative permeability; benchmark simulations of gas injection and waterflooding at the field scale; and the development of fast streamline techniques to study field-scale flow. The aim of the work is to achieve a comprehensive description of gas injection processes from the pore to the core to the reservoir scale. In this report we provide a detailed description of our measurements of three-phase relative permeability.

2 Introduction

Gas injection in oil reservoirs offers huge potential for improved oil recovery. However, successful design of a gas injection process requires a detailed understanding of a variety of different significant processes, including the phase behavior of multicomponent mixtures and the approach to multi-contact miscibility in the reservoir, the flow of oil, water and gas underground, and the interaction of phase behavior, reservoir heterogeneity and gravity on overall performance at the field scale. This project attempts to tackle all these issues using a combination of theoretical, numerical and laboratory studies of gas injection. Described

in detail as follows are the results from our laboratory measurements of three-phase relative permeability.

3 Results and Discussion

Understanding the dynamics of three-phase flow is essential for optimizing enhanced oil recovery and vadose zone remediation processes. The ultimate recovery of oil and other non-aqueous phase liquids (NAPLs) depends on the residual saturations and relative permeabilities of each of the phases. In particular, the wettability of the porous media affects the placement of the fluids in the porous media and the relative permeabilities.

Three-phase relative permeabilities have been measured in a variety of experiments. For instance, Oak *et al.*[1] used a steady state method for Berea sandstone cores. Vizika and Lombard[2] studied three-phase drainage in porous media of varying wettability, although they obtained permeabilities only from the outflow data. Lombard and Lenormand[3] obtained two-phase relative permeabilities in fractionally-wet sand, using a steady-state technique. However, despite this growing body of literature on three-phase flow[1, 4] we still lack a simple physical understanding of three-phase relative permeability that is grounded on direct experimental measurement.

In this report we study the gravity driven displacement of oil and water by gas, which is called gravity drainage. This is an important three-phase process that occurs during gas cap expansion in an oil reservoir and when NAPLs migrate through an unsaturated soil. Gravity drainage is also relatively easy to study experimentally and its analysis avoids consideration of hysteresis effects, which can be very significant in three-phase flow.[5, 6]

Sahni *et al.*[7] used CT scanning to measure oil and water relative permeability during three-phase gravity drainage in water-wet media and studied the effect of spreading coefficient. Zhou *et al.*[8] performed three-phase gravity drainage in sandpacks that were mixtures of oil-wet and water-wet grains. They measured the saturation distribution at the end of drainage and interpreted the results in terms of the pore scale arrangement of fluid.

We extend Sahni *et al.*'s[7] measurement of permeabilities to oil-wet and fractionally-wet (a 50-50 mix of oil-wet and water-wet) media. In addition we measure the gas relative permeability using an analogue experiment in which we directly measure the gas saturation and pressure gradient. Thus we obtain all three permeabilities for three-phase gravity drainage, in water-wet, oil-wet and fractionally-wet sandpacks. We find that the results can be readily explained in terms of the pore scale fluid configurations.

3.1 Materials and Methods

We chose sandpacks as our porous media as they are easy to characterize and they are easily sectionable for destructive saturation measurements. We used clean industrial sand (no. 60, Corona Industrial Sand Co., Corona, CA) which was initially water-wet. The sand was sieved with a size 120 sieve to remove any fine particles. We made 15 kg of the

Table 1: Fluid densities (kg/m^3) [$\rho_w = 1025 \text{ kg/m}^3$], interfacial tensions (mN/m) and oil spreading coefficients (mN/m).

Oil	ρ_0	γ_{ow}	γ_{go}	γ_{gw}	C_{so}
n-octane	703	51.2	21.1	72.0	-0.3
n-decane	730	51.4	23.7	72.0	-3.1

sand oil-wet by soaking it in a mixture of 20 % crude oil (Thums Inc., Long Beach, CA) and 80 % iso-octane for 24 hours.[9] This oil-wet sand was then rinsed with iso-octane and air-dried. The fractionally-wet sand was a 50-50 mixture of the oil and water-wet sands. We define f as the fraction of water-wet sand, thus the water-wet, fractionally-wet, and oil-wet sand have $f = 0, 0.5, 1$, respectively.

For our fluids, we chose n-octane or n-decane for the oil phase, 10 % NaBr by weight brine for the water phase, and air for the gas phase. Interfacial tensions were measured using the pendant drop technique.[10] Table 1 shows the fluid properties.

3.1.1 Oil and Water Relative Permeabilities

Before and during gravity drainage, we used a dual energy CT scanner to obtain in-situ measurements of the water and oil saturations. This CT method and the calculation of permeabilities from the data are described in greater detail in Sahni *et al.*[7] The core holders were standard Hassler-type with an overburden fluid (water at 50 psi) and a rubber sleeve. The sand was packed into the rubber sleeve of diameter 7.6 cm and length 67 cm. The experiment was then calibrated by scanning the core when it was dry, when it was saturated with brine, and when it was saturated with oil. Scans were taken every 2 cm and at energy levels of 80 kV and 140 kV. Using this calibration and a standard linear interpolation of CT number with density, the water, oil, and air saturations could be obtained during a three-phase experiment. The saturations were averaged over each slice to give the average water, oil, and air saturation every 2 cm along the core.

Before drainage each core was set to connate water S_{wc} or residual oil S_{or} saturation as described below. The core was saturated with the most wetting fluid (water for water-wet, oil for oil-wet) and then displaced with 5 pore volumes of the intermediate wetting fluid (oil or water). This produced an initial condition of S_{wc} for the water-wet pack and S_{or} for the oil-wet pack. Separate experiments were performed after an additional flooding of 5 pore volumes of the most wetting fluid to produce an initial condition of S_{or} for the water-wet pack and S_{wc} for the oil-wet pack. For the fractionally-wet pack there is no most-wetting fluid, and an initial condition of S_{or} was achieved by flooding a 100% oil-saturated pack with water from below. Once the desired initial condition was reached, gas (air) was allowed to enter the top of the system, while water and oil drained out of the bottom under

gravity. The pack was periodically scanned over a period of several weeks to record the saturation distribution versus time.

We can directly compute the oil and water relative permeabilities from the known evolution of the saturation profile over time. The flux of each phase is calculated from the time evolution of the saturations, and the head pressure is the sum of the gravitational pressure (the density of each phase) and the capillary pressure, which in turn is a function of the saturation. Capillary pressures were obtained from analog experiments performed on exactly the same type of packing with the same fluids. The fluids are left to drain for at least three weeks until capillary/gravity equilibrium is obtained. Then the sand is removed from the pack in 3 cm increments and the pore fluids are run through a gas chromatograph (GC). The GC provides an exceptionally accurate and sensitive measurement of saturation. From the measured saturation distribution, the oil/water, gas/oil and gas/water capillary pressures can be inferred.[7]

The capillary gradients are greatest near the bottom of the column where they equal the gravitational gradient, but are small compared to the gravitational gradient near the top of the column where the saturation is roughly constant with position. The calculation of permeabilities can thus be done by ignoring the capillary pressures if it is performed over a region where the saturation data satisfies the above condition. This was done for the oil-wet and fractionally-wet cases where only data between 10 and 30 cm from the top of the chamber was used in the calculation. For the water-wet case, the results were analyzed with and without capillary pressure data with similar results.[11] The water-wet data we show includes the capillary pressure correction.

3.1.2 Gas Permeability

We have developed a procedure to measure directly the gas relative permeability in the sand packs, for two-phase flow (gas and water). The sand is packed into a 60 cm column made out of 20 separate 3 cm long sections of polycarbonate plastic tubing (2.54 cm diameter) which are held together with shrink tubing. Nine of the plastic sections in the column contain a small port through which the pressure of the gas phase can be measured. Thus we can measure eight separate pressure drops along the column during gas flow.

We first measure the single phase gas permeability by flowing known rates of CO_2 through the column and measuring the pressure drops across each section using a manometer. The column is then filled with de-gassed water from below and the water is circulated until all of the original CO_2 is displaced or dissolved. Gas is then injected at a known rate at the top of the column, displacing the water out the bottom. This injection is continued for several hours until the pressures have stabilized and the gas and water phases are in equilibrium. Due to capillary effects, the distribution of water varies along the sand pack, with a high water saturation (and low gas saturation) near the outlet and a low water saturation (and high gas saturation) near the inlet. The pressure drop is measured between each section, which gives the gas relative permeability. The column is sectioned and the

water and gas saturations are obtained gravimetrically.

3.2 Results

In Sahni *et al.*[7], the relative permeabilities were measured for water-wet sand using three different oils: n-hexane, n-octane and n-decane to represent systems with different spreading coefficients.

We have additionally measured the relative permeabilities for oil-wet and fractionally-wet sand, and the gas permeability of all three sands. Figure 1 shows the resulting relative permeabilities for oil and water for all three sandpacks with octane as the oil. Note that we can measure saturations as low as $S = 0.01$, with relative permeabilities spanning over six orders of magnitude. Figure 2 shows the measured gas relative permeabilities.

The following features are observed in the measured relative permeabilities:

1. The permeabilities of the most wetting fluid (water in water-wet media, oil in oil-wet media) are similar for the whole saturation range. Both can be well described by a simple power law $k_r \sim S^\alpha$, where $\alpha \approx 5$. However, a lower saturation is reached in the oil-wet medium than in the water-wet medium.
2. At high saturations, $S > S_{or}$ (S_{wc}), the permeabilities of oil in water-wet media and water in oil-wet media are similar. Both can be well described by a simple power law $k_r \sim S^\alpha$, where $\alpha \approx 4$.
3. At low saturations, $S < S_{or}$ (S_{wc}), the permeabilities of oil in water-wet media and water in oil-wet media are very different. The oil relative permeability remains finite at low saturations with a power law of $k_r \sim S^\alpha$, where $\alpha \approx 2$. The water relative permeability drops off quickly, tending to zero at water saturations of $S_w \approx 0.1$.
4. The gas relative permeability for the oil-wet medium is roughly a factor of two smaller than that for an identical water-wet medium.
5. For the fractionally-wet sand, the oil, water and gas relative permeabilities are between the oil, water and gas relative permeabilities in the water-wet and oil-wet sands.

3.3 Pore Scale Explanation

All the features listed above can be understood qualitatively by considering the pore scale configuration of fluids. We discuss each observation in turn.

1. Similarity of the relative permeability of the most wetting phase in water-wet and oil-wet media.

Water-Wet Sand, $f=0$

Fractionally-Wet Sand, $f=0.5$

Oil-Wet Sand, $f=1$

Figure 1: Measured oil and water relative permeabilities for water-wet, 50% fractionally-wet, and oil-wet sand during three-phase gravity drainage. The solid lines are fits to the data at high saturations.

Figure 2: Measured gas relative permeabilities for water-wet ($f = 0$), 50% fractionally-wet ($f = 0.5$), and oil-wet sand ($f = 1$) during gravity drainage. The gas relative permeability in oil-wet sand is roughly a factor of two smaller than that for identical water-wet sand.

The most wetting phase occupies the smallest pores, and corners, grooves, and crevices in the wider pores. If we compare strongly and uniformly water-wet and oil-wet media, we would expect the configuration of the most wetting fluid to be similar for both systems at the same saturation. The exact functional form of the relative permeability depends on the porous medium and is not universal. The only general feature is that k_r should asymptote to a zero connate saturation, indicating that the wetting phase remains connected, albeit poorly, through wetting layers in crevices of the medium down to very low saturation. In the experiments, the lowest wetting phase saturation observed depends on the largest capillary pressure reached – it takes an infinite capillary pressure to reach zero saturation. In the water-wet medium, the gas/water capillary pressure at the top of the column at the end of the experiment is

$$P_{cgw} = (\rho_w - \rho_g)gh, \quad (1)$$

where h is the height of the column (67 cm for our column), assuming capillary/gravity equilibrium, and $P_{cgw} = 0$ at the bottom of the pack.

From the Young-Laplace equation

$$P_{cgw} = \frac{2\gamma_{gw}}{r_{gw}}, \quad (2)$$

where r_{gw} is the mean radius of curvature of the gas/water interface. Hence

$$r_{gw} = \frac{2\gamma_{gw}}{(\rho_w - \rho_g)gh} \approx 21\mu\text{m} \quad (3)$$

for our experiments.

Using the same argument for the oil-wet case, the largest gas/oil (octane) capillary pressure gives

$$r_{go} = \frac{2\gamma_{go}}{(\rho_o - \rho_g)gh} \approx 9\mu\text{m}, \quad (4)$$

and

$$\frac{r_{gw}}{r_{go}} = \frac{\gamma_{gw}(\rho_o - \rho_g)}{\gamma_{go}(\rho_w - \rho_g)} \approx 2.3. \quad (5)$$

The wetting phase resides in regions of the pore space with a mean entry curvature smaller than r_{gw} or r_{go} . That r_{gw} is over two times larger than r_{go} explains why in our experiments the lowest water saturation reached in the water-wet pack ($S_w \approx 0.1$) is higher than that reached in the oil-wet pack ($S_o \approx 0.04$) – see Fig. 1.

2. Similarity of k_{ro} in the water-wet pack to k_{rw} in the oil-wet pack for high saturation.

Network modeling studies indicate that the relative permeability of a phase at high saturation is controlled by the connectivity of pores filled with that phase.[6] In the water-wet systems, oil is not the most wetting phase and is displaced by gas. Similarly in oil-wet systems, water is not the most wetting phase and is also displaced by gas. Thus the arrangement of oil-filled pores in a water-wet medium, and of water-filled pores in a oil-wet medium are, to a good approximation, similar. However, the CT experiments are not sufficiently sensitive to compare the oil and water relative permeabilities accurately at high oil and water saturations.

The actual functional form observed – $k_r \sim S^4$ – is a function of the pore size distribution and would be different for different media. However, it is noteworthy that the use of a quartic form to describe k_{ro} in three-phase flow was first proposed by Corey[12] in 1956 and is also consistent with the results from three-phase network models.[6]

3. Very different forms for k_{ro} in water-wet media and k_{rw} in oil-wet media at low saturation.

At low saturation phases may remain connected through wetting layers in crevices in the pore space. It is this connectivity which controls k_r at low saturation. The pore scale configuration and connectivity of oil and water is very different for water-wet and oil-wet media. Consider first flat water-wet and oil-wet surfaces as shown in Figure 3.

The most wetting fluid coats the surface. The contact angle between oil or water and gas, which will control the position of the phase in the pore space, is given by the balance of interfacial tensions, assuming that the solid is coated with a thick wetting film.

Figure 3: Configuration of fluids on : a) a flat water-wet surface, b) a flat oil-wet surface.

For oil in water-wet media, (Fig. 3a)

$$\cos \theta_{go} = \frac{\gamma_{gw} - \gamma_{ow}}{\gamma_{go}} = 1 + \frac{C_{so}}{\gamma_{go}}, \quad (6)$$

where

$$C_{so} = \gamma_{gw} - \gamma_{ow} - \gamma_{go} \quad (7)$$

is the spreading coefficient for oil. In thermodynamic equilibrium $C_{so} \leq 0$. [10] Using our data for octane we find $C_{so} = -0.3$ mN/m and $\theta_{go} \approx 10^\circ$.

Now imagine the three fluids in a corner of the pore space as shown in Fig. 4a. If $\theta_{ow} + \beta < 90^\circ$ and $\theta_{go} + \beta < 90^\circ$, where β is the half-angle of the corner, then a layer of oil may be present. [6, 13] These layers are on the order of micrometers thick and have been observed in micromodel experiments. [14, 15, 16] Drainage through oil layers is the mechanism by which very low oil saturations are reached during gas displacement in water-wet media. [17, 18, 19] Final oil saturations as low as $S_o = 0.001$ have been reached. [19] For a system with $\theta_{ow} = \theta_{go} = 0$, the oil layers can drain to infinitesimal thickness at a *finite* gas/oil capillary pressure, meaning that in theory, $S_o = 0$ can be achieved through gravity drainage. [20, 19] In our experiments the lowest saturation obtained is $S_o \approx 0.01$ after 7 weeks of drainage.

Displacement of oil below the waterflood residual oil saturation, S_{or} , requires layer drainage. In our experiments, and others on bead packs, sandpacks and consolidated sandstones a characteristic layer drainage regime with $k_{ro} \sim S_o^2$ has been observed for $S_o < S_{or}$ (see Fig 5a). [7, 21, 22] This is readily explained by examining the flow in a single angular pore (see Fig. 4a). S_o is proportional to the area of the oil in the layer. The oil conductance for Poiseuille type flow is proportional to the area squared, leading to $k_{ro} \sim S_o^2$. [6, 23] This may seem a simple argument, but it is confirmed by more detailed analysis of layer flow that has been verified against numerical solutions of the Navier Stokes equation and experiments in square capillary tubes. [23]

Figure 4: Possible configuration of fluids in a pore space corner of half-angle β : a) water-wet surfaces, b) oil-wet surfaces. Note that configuration b) is not allowed as $\theta_{gw} > 90^\circ$.

We observe layer drainage for a spreading system – loosely defined as one with $C_{so} \approx 0$, or $\theta_{go} \approx 0$. However, the situation is different for oils with a large and negative spreading coefficient.

For decane in water-wet media, our measurements of interfacial tension result in $\theta_{go} \approx 30^\circ$. Decane layers have been seen in micromodels.[16] However, decane layers cannot form in oblique wedges ($\beta > 60^\circ$), and are present for a more restricted range of capillary pressures than for octane.[6] If oil layers are not present, oil can be trapped, leaving a residual saturation at the end of drainage. In our experiments we do not observe a layer drainage regime, as shown in Fig. 5b.

For water in oil-wet media, (Fig. 3b)

$$\cos \theta_{gw} = \frac{\gamma_{go} - \gamma_{ow}}{\gamma_{gw}} = 1 + \frac{C_{sw}}{\gamma_{gw}}, \quad (8)$$

where

$$C_{sw} = \gamma_{go} - \gamma_{ow} - \gamma_{gw} \quad (9)$$

is the spreading coefficient for water. Using Table 1 we find $C_{sw} = -102.1$ mN/m and $\theta_{gw} \approx 115^\circ$. Since $\theta_{gw} > 90^\circ$, water is less wetting than gas. In Fig. 4b, water layers can occur for $\theta_{gw} + \beta < 90^\circ$, and gas layers can occur for $90^\circ + \beta < \theta_{gw}$, neither of which are possible except for gas in exceptionally sharp crevices. The absence of a layer drainage regime is evident in Fig. 5c. Note that k_{ro} for decane in a water-wet system is similar to k_{rw} in an oil-wet system. Both represent cases where the intermediate-wet fluid is non-spreading and there is no layer drainage regime.

Note that we do not observe the same layer drainage regime for the most wetting phase – instead of $k_r \sim S^2$, we observe $k_r \sim S^5$. The most wetting phase occupies the small pores and all the narrow nooks and crannies, which may be poorly connected. In contrast, oil layers in spreading systems reside over the water, and by construction therefore, are well connected throughout the porous medium.

Figure 5: Comparison of relative permeabilities. (a) A spreading system ($\theta_{go} \approx 0$) : Octane in water-wet sand. (b) A non-spreading system : Decane in water-wet sand. (c) A non-wetting system : Water in oil-wet sand.

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4. k_{rg} is lower in an oil-wet medium than in a water-wet medium.

In water-wet media, the water phase will occupy the smallest pores and crevices while the gas phase occupies the large pore spaces. In oil-wet media, the contact angle is such that neither the water phase or the gas phase wets the pore surfaces and thus the water and gas phases compete for the largest pores. Thus at equivalent gas saturations, in the oil-wet system the gas is in smaller pathways leading to a lower permeability.

It is important to note that these results are only for gas permeabilities in a two-phase system where the other phase is water. The gas permeability in an oil-wet system is likely to depend on both the oil and water saturations. This issue will be tested in later work.

5. The fractionally-wet sand has behavior intermediate between oil-wet and water-wet sand.

This last observation seems intuitively obvious. However, there are three important points to make. First, the oil in a spreading system is always connected regardless of f , since it can reside in corners as the most wetting phase or in layers as the intermediate wetting phase. Consistent with this is the observation that k_{ro} asymptotes to zero residual oil saturation, for *any* f , as shown in Fig. 1. However, unless $f = 0$, an infinite capillary pressure is required to achieve this. Second, note that the trapped water saturation for $f = 0.5$ is slightly *higher* than for $f = 1$. This is because for $f = 0.5$, the oil-wet regions are poorly connected in the pack leading to significant trapping of water. This percolation-type argument has been explored in more detail by Zhou *et al.*[8] Third, the gas relative

permeability for $f = 0.5$ is very close to the oil-wet case. This shows that the gas mobility is significantly affected even if a fraction of the pores are oil-wet.

3.4 Discussion

We have performed a series of conceptually simple three-phase experiments, which we can interpret by analyzing the fluid arrangement at the pore scale. However, the full range of behavior of three-phase flow has not been studied. In particular, in our experiments the gas saturation increased while the oil and water saturations decreased. We did not study water injection, or WAG cycles of water and gas flooding. For these cases the relative permeabilities are very likely to be significantly different.[24, 25, 6] Furthermore, we studied media with idealized wettability variations. We did not study more realistic situations where the wettability changes are induced by the contact of oil with the solid after primary drainage. Nor did we consider geologically complex media with varying mineralogies and microporosity. Nevertheless, the ability to interpret simple cases is reassuring, and gives a basis for the fundamental understanding of three-phase flow in more realistic reservoir and vadose zone settings.

3.5 Conclusions

We have used CT scanning and analogue experiments to measure directly oil, water and gas relative permeabilities during three-phase gravity drainage. Experiments were performed on oil-wet, water-wet, and fractionally-wet sandpacks, achieving data down to saturations as low as $S_o = 0.01$ and relative permeabilities that span six orders of magnitude. An analysis of the data leads to the following conclusions:

1. At low oil saturations ($S_o < S_{or}$) in water-wet media, spreading systems show a characteristic form of the oil relative permeability, $k_{ro} \sim S_o^2$. This is consistent with a theoretical interpretation of oil layer drainage at the pore scale. For a non-spreading decane system, the layer drainage regime was not observed.
2. In oil-wet media, the oil relative permeability behaves similarly to the water relative permeability in water-wet systems.
3. In oil-wet media, the water has a large and negative spreading coefficient, meaning that water layers do not form in the pore space. The water relative permeability k_{rw} for an oil-wet medium is similar to k_{ro} for a water-wet medium and a non-spreading oil.
4. In oil-wet media, the gas relative permeability is roughly a factor of two smaller than that for identical water-wet media. This is consistent with the gas and water phases competing for the largest pores in oil-wet media.

The data for all our experiments is available on our web site:
<http://ekofisk.stanford.edu/supric.html/> .

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Nomenclature

C_{so}	=	spreading coefficient of oil
C_{sw}	=	spreading coefficient of water
f	=	fraction of oil-wet sand
g	=	gravitational constant
k_{rp}	=	relative permeability to phase p
r_{gw}	=	radius of curvature of the gas/water interface
r_{go}	=	radius of curvature of the gas/oil interface
P_{cgw}	=	gas/water capillary pressure
S_p	=	saturation of phase p
S_{or}	=	waterflood residual oil saturation
S_{wc}	=	connate water saturation

Greek Letters

α	=	power law exponent
β	=	half angle of pore corner
γ_{ow}	=	oil/water interfacial tension
γ_{go}	=	gas/oil interfacial tension
γ_{gw}	=	gas/water interfacial tension
ρ_p	=	density of fluid p
θ_{ow}	=	oil/water contact angle
θ_{go}	=	gas/oil contact angle
θ_{gw}	=	gas/water contact angle

Subscripts

g	=	gas
o	=	oil
p	=	phase
w	=	water (brine)

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