NUMERICAL AND EXPERIMENTAL INVESTIGATION INTO THE EFFECTS OF VISCOSITY AND INJECTION RATE ON RELATIVE PERMEABILITY AND OIL RECOVERY

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ABSTRACT
Relative permeability is one of the most basic, yet problematic, parameters used in reservoir engineering and is extremely important for predicting oil recovery. Traditionally, water-oil relative permeabilities are determined in the laboratory for a given injection rate and viscosity ratio, usually higher than those encountered in the reservoir. Then simulation studies are carried out for a different (usually lower) rate and viscosity ratio using the same relative permeability curves. The validity of this approach, to our knowledge, has not yet been fully investigated.

In this paper we report the results from a series of well-characterised unsteady state water floods in bead-packs and detailed simulations performed on the same system. The aim of this study was:

- to investigate the effect of oil-water viscosity ratio on relative permeability and oil recovery curves
- to investigate the effect of water injection rate on relative permeability and oil recovery curves

The use of bead-packs rather than cores enabled us to control the homogeneity and wettability of the porous medium and to visually observe the fluid flow patterns during each experiment. Displacements were performed at two viscosity ratios and three different injection rates and the relative permeabilities were determined using the JBN unsteady-state method. It was observed that the shape of the JBN derived relative permeabilities changed significantly with both viscosity ratio and rate. This was despite the fact that the interfacial tension and contact angle were very similar for all displacements. All measured experimental data (permeability, porosity, rate, viscosity ratio and relative permeability) were then input into a simulator in order to evaluate the possible errors that might arise in field scale simulation from using relative permeabilities determined at one rate and viscosity ratio to predict waterflood performance for a different rate and viscosity ratio. Our results indicate that, at least for the fluid system

investigated, oil and water production cannot be simply predicted by changing the viscosity ratio.

INTRODUCTION

Water flooding is probably the most widely used method of oil recovery used by the petroleum industry. An analytical solution was originally obtained by Buckley and Leverett [1] and has since become familiar to generations of graduate reservoir engineers as a means for estimating breakthrough time and recovery for a given set of relative permeability curves, capillary pressure function and viscosity ratio. Further analysis by Johnson, Bossler and Naumann [2] produced a method to enable petrophysicists to determine the relative permeabilities of a given core sample from a water-oil displacement through that sample. This so-called 'unsteady state' method of determining relative permeability has the advantage over the steady state method as it is a much quicker way of obtaining relative permeability curves. However there is an ongoing debate as to which technique is more representative of the actual reservoir displacement process during waterflooding and integration of different methods is advisable whenever possible.

The problem with both techniques for determining relative permeability (over and above issues of core wettability restoration/preservation) is that they typically use analogue fluids and different flow rates from those encountered in the reservoir. The assumption is that the measured curves can be used directly in a reservoir simulator, for reservoir fluids and flow-rates, without adjustment. This assumption is supported by the work of Donaldson *et al.* [3] and Geffen *et al.* [4] for example, who did not find any influence of viscosity for fluids on relative permeabilities. However, other authors [5,6,7,8,9] found that end-point saturations in waterfloods depend to a great extent on viscosity. Furthermore some investigators have reported laboratory tests indicating increasing oil recovery with water injection rates [10,11,12,13] while others found the flooding behaviour to be independent of flow rate [14,15]. Recently, Al-Gharbi and Blunt [16] presented a dynamic pore scale network able to represent the effect of flow rate and viscosity ratio on relative permeability and oil recovery.

Although there has been a significant body of work in the recent literature showing that relative permeability of near-critical fluids (gas condensates) in the near-well bore region may change considerably as a function of capillary number [17-25], there has been very little recent work investigating the same effects for waterflooding. Not only will flow rate be different between laboratory measurement and reservoir displacement, even in waterfloods rate will also vary with distance from the well-bore in waterfloods. Moreover existing capillary number correlations for relative permeabilities [25] rely upon capillary numbers whose only dependence on viscosity is through the displacing fluid viscosity [26,27,28], despite the evidence cited above for a dependence upon mobility ratio.

The motivation for this study came while conducting relative permeability measurements for water-oil and water-solvent displacements for a miscible WAG injection project [29]. In this type of displacement the oil and the solvent are first contact miscible and have similar interfacial tensions and contact angles. During our experiments (which were performed in a strongly water-wet porous medium) we noticed that the experimental water-solvent fractional flow was different from that calculated using water-oil relative permeability and solvent viscosity. It is normal engineering practice to assume that water-oil and water-solvent relative permeabilities are the same when the oil and solvent are first contact miscible [30,31]. This clearly contradicts our observations and induced further research.

In this paper, differences in relative permeability curves at different injection rates and viscosity ratios for each experiment are analysed. We test the possible errors that may result in simulation from using relative permeabilities measured at non-field rates by comparing recoveries obtained experimentally at a given rate or viscosity ratio with those predicted by simulation using JBN derived relative permeabilities at a different rate or viscosity ratio.

EXPERIMENTAL DESIGN

Grade 11 (200-250μm) Ballotini glass beads were chosen as the porous medium because they enabled a relatively homogenous sample to be constructed and the displacements followed by visualization. The beads were sealed in a Perspex box, dimensions 23cm×10cm×0.6cm. The pack's thickness was determined by the requirement that the flow be essentially two-dimensional so that direct comparison with 2D numerical simulations could be made [32-33]. Figure 1 shows a plan view of the model set up. Six inlet ports were used to ensure the injected fluid entered the pack over its entire cross-section and to establish a uniform front. The model was packed following the method described by Caruana [34-35]. All displacements were recorded using a camera and video recorder.

EXPERIMENTAL CONDITIONS

Five waterflooding experiments were performed in total. The fluid pairs used for each displacement and their properties are summarized in Table 1. ISOPAR V to represent the heavy oil phase and paraffin to represent the light oil or solvent. Before starting each experiment the model was dried, flooded with carbon dioxide, to displace all the air, and then flooded with distilled water until it was completely saturated. The pack was then mounted so that its longest dimensions were horizontal to minimise the influence of gravity on the displacement. It was then driven to irreducible water saturation with oil, ISOPAR V or paraffin depending on the experimental conditions.

Immiscible displacements were performed at rates of 1 and 5 ml/min (1.3 and 6.6 PV/hour). These rates were chosen because they allowed the experiments to be conducted in a reasonable time frame despite of being approximately two orders of magnitude larger (frontal advance rates of 20 ft/day and 103 ft/day) than those typically encountered in the

field away from the wellbore (1ft/day). It should be noted that the relative permeability curves at low rate (1 ml/min, 1.3 PV/hour or a frontal advance rate of 20ft/day) were calculated from the experimental water cut profiles assuming a Corey profile for the relative permeability curve between the end point saturations. This was because of inaccuracies in the measurement of pressure drop across the pack at this low rate.
The displacing water phase was dyed with Lissamine red to enable us to see the behaviour and the water path during the displacement whilst the displaced oil phases were colourless. Oil recovery and effluent profiles as well as the pressure drop versus time were recorded for all displacements, except the low rate water-ISOPAR displacement. JBN analysis [2] was used to determine the relative permeabilities from these data. The relative permeabilities were normalised in the JBN calculation by using the initial flow rate over pressure drop of each experiment .

PACK PROPERTIES

The porosity of the pack was found to be 38% and the permeability 29 Darcies. These are typical values for this type of beadpack [32,33,34,35,36,37]. The uniformity of the packing was checked by performed a first contact miscible (water displacing water) M=1 displacement through it and observing the displacement front. No edge effects or channelling were observed.

The drainage and imbibition capillary pressures were measured by packing the glass beads in a cylindrical glass container fitted with porous disks [34]. After each decrement in pressure the amount of water displaced was measured in a graduated burette until equilibrium was reached. Equilibrium capillary pressure curves for water-light oil and water-viscous oil are given in Figure 2. Although the glass beads have a narrow size distribution and the porosity both packs are the same, within experimental error, the pore size distribution may not be the same for both packs. Additionally capillary pressure equilibrium is a very slow process and difficult to achieve.

SIMULATION

All the experiments were simulated in order to validate experimental waterflooding and check our procedure. All the input data required by the simulator was obtained from careful characterization of the bead-pack properties. There was no history matching involved in this process.

The numerical program used to model the experiments has been successfully used to predict the flow patterns observed in a number of displacements [32-38]. A full description of the simulation program is given in Christie [37]. The simulations used a grid of 100 × 50. This resulted in approximately square grid-blocks, 2mm wide, which is several times greater than the dimensions of the glass beads. A grid refinement study showed that this grid size was fine enough to ensure that the flow was dominated by physical rather than numerical dispersion.

RESULTS

Viscosity Effects

There is a significant difference in the overall displacement behaviour of the water-light oil (M=1.5) and the water-viscous oil (M=10.6) displacements, despite the fact that light and viscous oil are first contact miscible and have almost the same interfacial tension with water and similar equilibrium contact angles. The relative permeabilities obtained for the two fluid systems at a flow rate of 5ml/min (6.6 PV/hour, equivalent to a frontal advance rate of 103ft/day) are compared in Figure 3.

Differences in the calculated relative permeabilities can be seen in the curve shapes despite the fact that the capillary number of the two displacements is similar (1.6×10^{-4} for water-paraffin and 2.4×10^{-4} for water-ISOPAR V). We used the capillary number definition of Moore and Slobod, (1956);

$$N_c = \frac{\mu\|u\|}{\sigma\cos\theta} \tag{1}$$

where, μ is the viscosity of the displacing phase (N s m^{-2}), u the velocity of the displacing phase (m s^{-1}) , σ the interfacial tension (N m^{-1}), θ the contact angle (degrees) .

The M=1.5 immiscible displacement (water displacing light oil) was then simulated using the water-light oil relative permeabilities. Similarly the M=10.5 displacement (water displacing heavy oil) was simulated using the water-ISOPAR relative permeabilities. Figures 4 and 5 compare the experimental results from both displacements (M=1.5 and M=10.6) at 5ml/min (6.6 PV/hour) with the simulator prediction at the same injection rate.

It can be seen that the agreement between simulation and experiment is good in all cases. There is a small difference in the character of the viscous fingering observed in the M=10.6 displacement due to the random nature in the way these fingers are created in the simulation. However the simulated recovery curve matches the experimental curve almost exactly. This confirms that we have characterised the bead-pack, the fluid properties and displacements correctly for both cases.

We then investigated if the water-light oil relative permeability curves could be used to predict, using simulation, the behaviour of the water-viscous oil displacement, by keeping these curves and changing the oil viscosity. These results are shown in Figure 6. We then used the viscous oil relative permeabilities to simulate the water flooding of light oil, see Figure 7. It is clear that the water-light oil and water-viscous oil relative permeabilities are different for each displacement (reflecting the different displacement characteristics) and cannot be interchanged. There is a difference of more than 10% between predicted and actual recovery at 1 pore volume injected in both cases. Capillary pressure effects and viscous fingering are both present in the experiment but are not included in the JBN analysis. Therefore, these effects are translated in not quantifiable changes in the “apparent” relative permeabilities obtained.

As a consequence the "apparent" relative permeabilities can be used for simulating the experiment from which they were obtained (without Pc) but fail in other conditions because they are not "true" relative permeabilities.

Rate Effects

The relative permeabilities obtained for water displacing heavy oil as a function of flow rate are shown in Figure 8. It is clear that these also vary significantly with rate (capillary number). In the case of the water-light oil displacement the capillary number varies from 3.2×10^{-5} to 1.6×10^{-4}. In the case of the water-heavy oil displacement the capillary number varies from 4.8×10^{-5} to 2.4×10^{-4}. However in the light oil case, the rate effect can only be seen in the separation of the relative permeability curves but did not affect the end-point oil saturations. Details are given in the discussion section.

The low rate displacements for both water-light oil and water-viscous oil were then simulated using the calculated relative permeabilities without including the capillary pressure curve. The agreement between simulation and experiment is very good in all cases, as shown in Figure 9. This shows that although the low rate displacements may be influenced by capillary pressure this affects the "apparent" relative permeability curve obtained by JBN analysis.

DISCUSSION

Viscosity Effects

Viscosity ratio shows considerable influence on the shape of the imbibition relative permeability curves as seen in Figure 3. The obtained relative permeabilities for the different viscosities agree with the predictions of a dynamic pore scale model [30], which shows that snap-off is a strong function of viscosity ratio, where at high viscosity ratio the wetting layer flow is significant and as a consequence snap-off is common.

We also noticed that different viscosity ratios resulted in different water relative permeability end points. Previous results presented by Lefevre du Prey [5] also show a lower water relative permeability curve for an unstable displacement (high viscosity ratio) than for a stable displacement. In our case, 10% difference in remaining oil (at 2 pore volumes injected) was obtained when the viscosity ratio was increased from 1.5 cp to 10.6 cp. This was reflected in the oil recovery curves shown in Figure 5.

A difference of 8% in oil recovery (at 1 PVI) was observed when the recovery of viscous oil was predicted using the light oil relative permeability and the real oil viscosity. This shows the inadequacy of this type of practice. It can be concluded that each set of "apparent" relative permeabilities obtained by the dynamic displacement technique, (JBN in our case), represents the conditions that the experiment was carried-out but cannot be used to predict behaviour under different viscosity ratios.

Rate Effects

The process of oil displacement on water flooding is controlled by both viscous and capillary forces [8]. The competition between these forces is specified by the capillary number, see equation (1). The capillary pressures shown in Figure 2 give an indication of the magnitude of these forces even if these curves may not be fully representative of the flooding experiment.

We find that the capillary number for the water-light oil and water-heavy oil displacements varies from 3.2×10^{-5} to 2.4×10^{-4}. Thus these displacements have been performed at an intermediate capillary number when compared to the micro-model experiments by Lenormand and Zarcone [41]. They are also lower than in the experiments reported by Mott et al [24] and Boom et al [17,18]. Furthermore the behaviour of the relative permeabilities with capillary number is opposite to that reported by Boom et al [17,18]. In our results the relative permeability of the wetting phase decrease as rate increases and the relative permeability of the non-wetting phase increases.

For water displacing light oil, the change in flow rate from 5ml/min (6.6 PV/hour) to 1ml/min, 1.3 PV/hour) represents a small change in capillary number, which was enough to change the displacement behaviour and that was clearly reflected in the separation of recovery and water-cut curves. It should be noted that, although both displacements are influenced by capillary effects (intermediate value of Nc), this is represented in both cases through the “apparent” relative permeability curves. These relative permeabilities were used successfully to simulate recovery and water cut at the same conditions that they were obtained by JBN.

On the other hand, for the same range of capillary numbers, relative permeability and recovery curves were obtained for the water-viscous oil when the injection rate was changed. This is due to high viscosity ratio and its effect can be clearly seen in Figure 8 (b). It is worth noticing that the residual oil saturation was obtained after more than 10 PV of water injected.

Our experimental results are in good agreement with the dynamic network results [30]. At microscopic level, relative permeability curves are close to straight lines at high injection rate. As flow rate decreases, capillary forces increase which leads to more deviation from straight lines. At a very low injection rate, capillary forces dominate and snap-off is significant which is reflected by the sharp reduction in the relative permeability curves.

CONCLUSIONS

We have used a combination of well-characterised experiments and simulations to investigate secondary recovery from water flooding. Validation of some assumptions were tested, namely that relative permeabilities determined from unsteady state displacements at high rate using a high viscosity ratio can be used directly in simulation to model lower rate, lower viscosity ratio waterfloods.

From our experimental and numerical results, within the range of capillary numbers tested, we can conclude:

- Viscosity ratio and injection rate have a strong influence on oil recovery and water-cut curves of unsteady state experiments.
- The relative permeabilities obtained only from JBN and a single unsteady state experiment are "apparent" as they cannot be used to predict the production or flow at other conditions. Multiple measurements and methods are needed to obtain the true relative permeabilities and separate these from other effects.
- Further analysis is required to confirm the implications of these results for field water injection. We believe that this may affect the evaluation of EOR projects such as first contact miscible WAG injection where both water and a miscible gas/solvent are injected into the reservoir. Some practical engineers may assume that the water-oil and water-solvent relative permeability curves can be scaled simply by the viscosity ratio even if the curves are "apparent" relative permeabilities.

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Table 1. Fluids properties used in the displacements.

	Displaced Phase		***Displacing Phase***		***Interfacial Tension***	***Contact Angle***
	Fluid	***Viscosity (cp)***	***Fluid***	***Viscosity (cp)***	***(mN/m)***	θ
Immiscible, M=1.5	Paraffin (light oil)	1.52	Red water (water)	1.01	38	53
Immiscible, M=10.6	ISOPAR V (viscous oil)	10.56			38	67

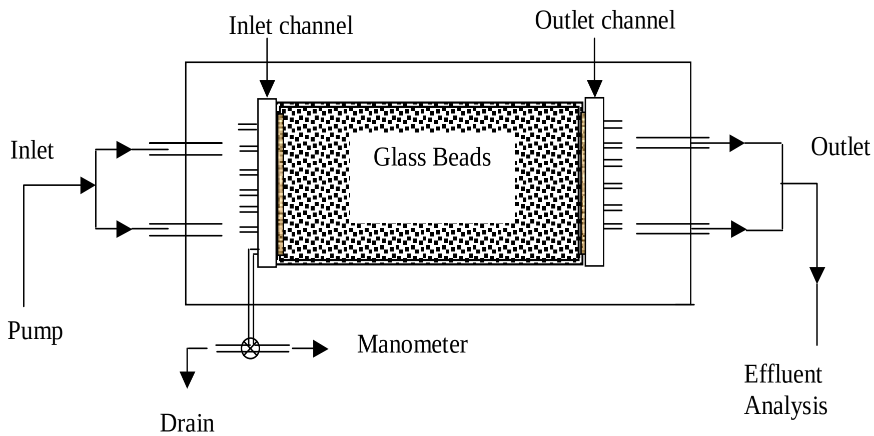


Figure 1. Plan view of the experimental set-up.

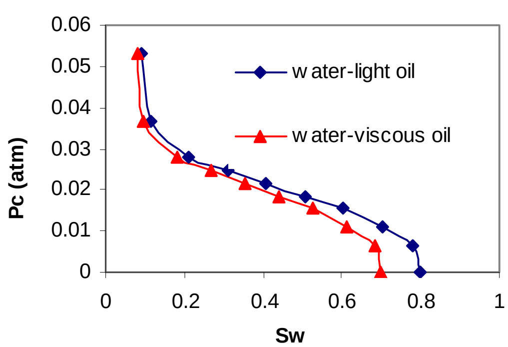


Figure 2. Equilibrium capillary pressure curves for imbibition process, for light and viscous oil.

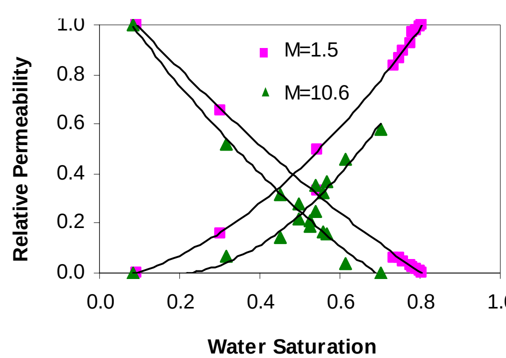


Figure 3. Relative permeability curves obtained from experiments for water displacing light oil (M=1.5) and water displacing heavy oil (M=10.6) at a constant injection rate of 5 ml/min.

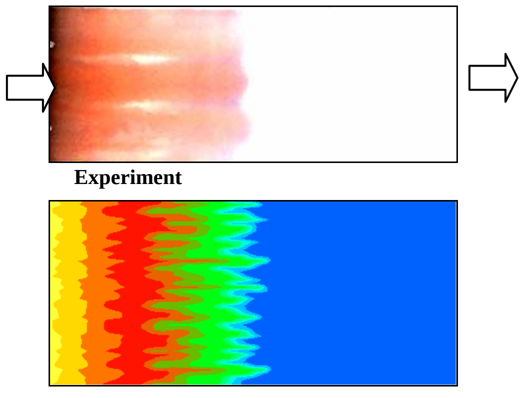


Figure 4. Fluid distribution during waterflooding for M=10.6 displacement after 0.2 PVI. The initial irreducible water saturation is 8%.

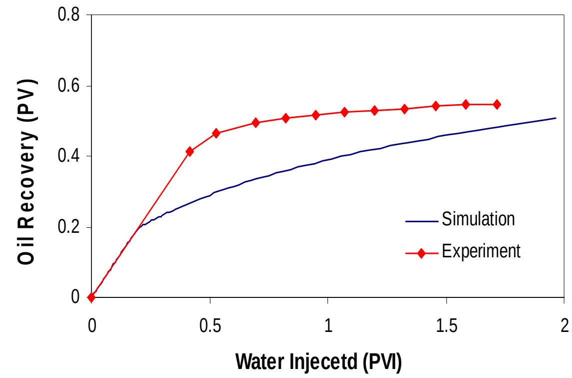


Figure 6. Simulating water-viscous oil displacement using water-light oil relative permeabilities curves.

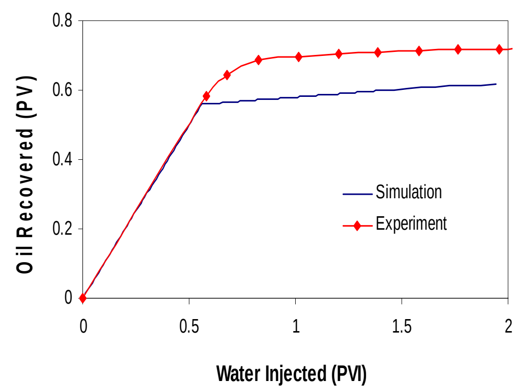
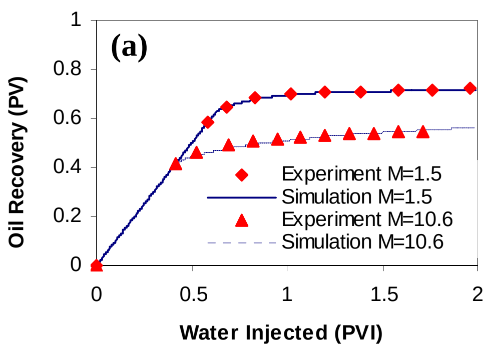


Figure 7. Simulating water-light oil displacement using water-viscous oil relative permeabilities curves.



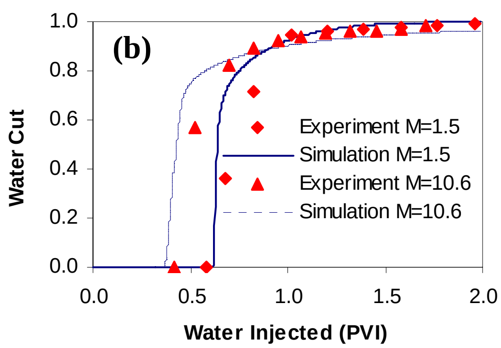


Figure 5. Comparison of a) oil recovery b) water cut for M=1.5 and M=10.6 displacements obtained from experiment and simulation.

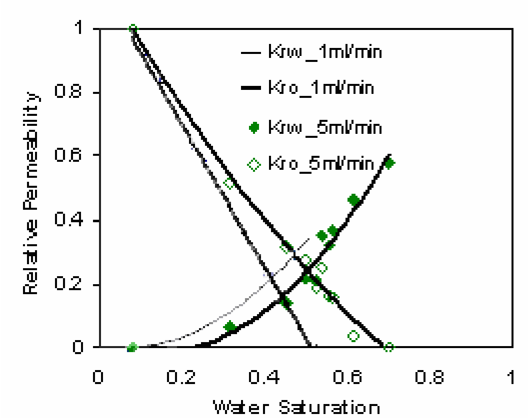


Figure 8. Relative permeability curves for water-viscous oil at different injection rates.

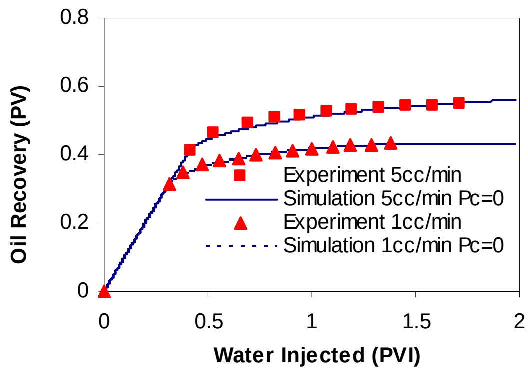


Figure 9. Oil recovery curves for water-viscous oil at different injection rates.