WETTABILITY AND RATE EFFECTS ON END-POINT RELATIVE PERMEABILITY TO WATER

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Abstract

Relative permeability to water at residual oil saturation, $k_{rw}(S_{or})$, is usually considered to be invariant with water flow rate. However, this may only be true in strongly water-wet cores. Variations in the end-point relative permeability to water have been documented in weakly water-wet and mixed-wet Berea sandstone cores. Capillary numbers for these tests were high enough to avoid capillary end effects, but usually not so high as to mobilize residual oil. Experiments in strongly water-wet cores demonstrated that $k_{rw}(S_{or})$ is independent of flow rate, as expected. In cores made mixed-wet or weakly water-wet by contact with crude oils, however, $k_{rw}(S_{or})$ increased significantly with increasing flow rate over a wide range of flow rates, even after the mobilization of residual oil ceased. Hysteresis was observed between increasing and decreasing flow rates and between repeated cycles of increasing and decreasing flow rates. After extended periods at high water saturation, with or without flow, the mixed-wet and weakly water-wet cores became more water-wet. This change toward more water-wet conditions, indicated by increased rates of water imbibition, was accompanied by significant increase in $k_{rw}(S_{or})$. A microscopic model of fluid redistribution within the pore space is suggested to explain the rate-dependence of water relative permeability end-points in mixed-wet porous media.

Introduction

Relative permeabilities that describe the flow capacity of one fluid in the presence of others have often been measured in laboratory corefloods at displacing rates well in excess of those typical in an oil reservoir, with the aim of minimizing the contribution of capillary forces (Rapoport and Leas, 1953). Implicit in these tests is the assumption that relative permeabilities would not be affected by changes in flow rate. This assumption has long been questioned, but the issue remains unresolved. For water-oil two phase flow, some researchers have reported that flow rates do not affect relative permeabilities (Sandberg *et al*., 1958; Ehrlich and Crane, 1969; Labastie *et al*., 1980). Others contend that the influence of flow rate can be ascribed entirely to capillary end effects and propose correction methods (Odeh and Dotson, 1985; Qadeer *et al*., 1988). Heaviside *et al*. (1987) reported that relative permeabilities varied with flow rate, apart from any significant influence from capillary end effects.

Although flow rate may influence relative permeabilities at any saturation, the best-defined conditions exist when only one phase is flowing. Thus, we focus in this study on changes with flow rate in the end-point permeability to water in the presence of a residual saturation of oil for several wetting conditions.

Reports of rate-dependent relative permeabilities at residual oil saturation are few. Morrow *et al*. (1983) found that $k_{rw}(S_{or})$ was sometimes sensitive to pressure gradient before oil mobilization in strongly water-wet Berea sandstone. Crude oil-treated, weakly water-wet Berea sandstone showed an increase in $k_{rw}(S_{or})$ before oil mobilization, while the variation of $k_{rw}(S_{or})$ with flow rate was partly reversible (Morrow *et al*., 1986). Heaviside *et al*. (1987) found that $k_{rw}(S_{or})$ was much lower for low rate floods than for high rate floods in intermediate-wet North Sea sandstone. Kamath *et al*. (1995) reported that $k_{rw}(S_{or})$ values were sensitive to injection rates for short, low-permeability, intermediate-wet mudstone cores.

Experiments

Materials

Oil: Two crude oils, one from the Sulimar Queen oil field located in southeastern New Mexico and another from the Spraberry oil field in western Texas, were used to generate mixed-wet conditions in Berea sandstone cores. The oils were laboratory samples from which the most volatile fractions had been removed. A refined mineral oil, Soltrol-130, was used for tests at strongly water-wet conditions in Berea sandstone. Properties of each oil are listed in **Table 1**.

Table 1: Properties of oils

Oils	Density at 20°C (g/ml)	Viscosity at 20°C (mPa.s)	n-C_5 Asphaltenes (wt%)	Acid #	Base #
				(mg KOH/g oil)	
Sulimar Queen crude	0.835	5.84	3.0	0.16	0.62
Spraberry crude	0.850	9.93	0.8	0.32	2.83
Soltrol-130	0.757	1.59	-	-	-

Brine: Three synthetic brines were used (**Table 2**). All brines were prepared with distilled water and reagent-grade salts, filtered through a 0.45 μm Millipore prefilter, and deaerated prior to use.

Table 2: Properties of synthetic brines

Synthetic Brine	Salinity (mg/l)	Ionic strength (M)	Density at 20°C (g/ml)	Viscosity at 20°C (mPa.s)	pH
Sulimar Queen	230,766	4.38	1.155	1.80	7.70
Spraberry	128,363	2.24	1.085	1.32	7.06
2% $CaCl_2$	20,000	0.54	1.015	1.13	7.46

Core: All the core plugs were cut from a single block of homogeneous Berea sandstone, with an air permeability of about 800 md. **Table 3** lists the physical properties of core samples.

Table 3: Physical properties of Berea sandstone core samples

Core ID	Length (cm)	Diameter (cm)	K_{air} (md)	K_{water} (md)	Porosity (%)	Oil/Brine	Comments
B29	7.13	3.79	844	549	22.0	Soltrol-130 / 2% $CaCl_2$	
B15	5.73	3.59	786	514	22.2	Sulimar Queen oil / brine	imbibition only
B19	7.28	3.79	814	494	22.4	Sulimar Queen oil / brine	
B23	6.00	3.79	833	438	22.2	Spraberry oil / brine	imbibition only
B22	7.19	3.79	841	508	22.6	Spraberry oil / brine	

Core preparation

Establishing S_{wi}: Dried core plugs were saturated with degassed brine, then soaked in brine for one week at ambient conditions to permit equilibration, after which aged brine was displaced by fresh brine of the same composition. Cores were then flushed with oil to establish an initial water saturation, S_{wi}, of around 20% pv.

Aging in oil: To establish non-water-wet conditions, cores were immersed in the same crude oil with which they were saturated. They were aged at 80°C for two weeks. After aging, the aged oil was displaced by fresh oil.

Wetting assessment: Rate of imbibition and Amott indices (Amott, 1959) were measured to assess the wettability of cores after aging in crude oil. For each crude oil-brine combination, both spontaneous water imbibition and oil imbibition tests were performed.

Waterflood

A schematic diagram of the waterflood setup is shown in **Fig. 1**. Two Isco-314 metering pumps were combined to provide a displacing capacity of 750 ml and maximum flow rate of 400 ml/hr. Two glass columns were arranged to serve as brine reservoirs with capacity of 1300 ml. Injection brine was passed through a 0.45μm filter before entering the core. Upstream pressure was measured with a 25 psi SENSOTEC pressure transducer while the downstream pressure was atmospheric. Low values of pressure (<1 psi) were measured by a graduated manometer. The accuracy of the pressure measurement is 0.01psi. An oil-water separator was arranged downstream to accumulate produced oil. Water flow rate was calculated from the total amount of effluent with time. The overall error for the relative permeability measurement is less than 4%.

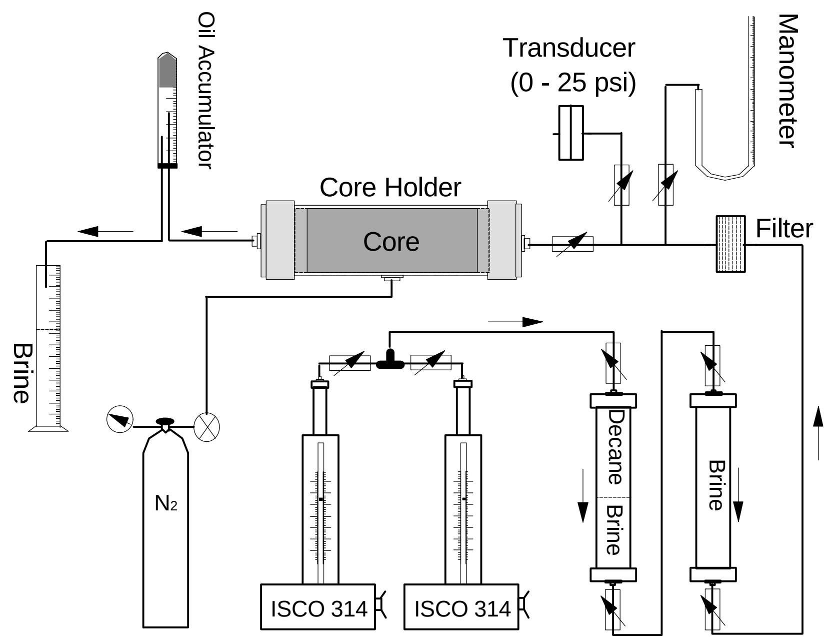

Fig. 1 Schematic diagram of waterflood setup.

Establishing S_{or}: Cores were waterflooded at constant flow rate to establish residual oil saturation. The flow rate for these initial waterfloods was 8 ml/hr.

Tests of varying flow rate: After residual oil saturation was established, flow rate was increased in steps. At each flow rate, injection continued until the pressure drop across the core was stable. The flow rate and pressure drop were then recorded to calculate a value for water relative permeability end point,

$$k_{rw}(S_{or}) = \frac{\mu_w L}{K_w \Delta p A} Q_w \tag{1}$$

where K_w is permeability to water, μ_w is water viscosity, Q_w is water flow rate, Δp is pressure drop, L and A are length and cross section of core sample, respectively. Thus $k_{rw}(S_{or})$ is defined here as water relative permeability at residual oil saturation compared to single phase water permeability K_w.

Details of the experimental procedures are given elsewhere (Wang, 1998).

Results and Discussion

Strongly water-wet conditions

Outcrop Berea sandstone is strongly water-wet (Amott index to water $I_w = 1$, Amott index to oil $I_o = 0$). Over a wide range of flow rates, the relationship between flow rate and pressure drop was shown to be constant for water flowing in the presence of residual Soltrol-130 (**Fig. 2**), indicating that $k_{rw}(S_{or})$ is constant over the range of flow rates tested. There was no hysteresis between the steps in which rate was increased and similar tests in which rate was decreased. No oil was produced at any flow rate.

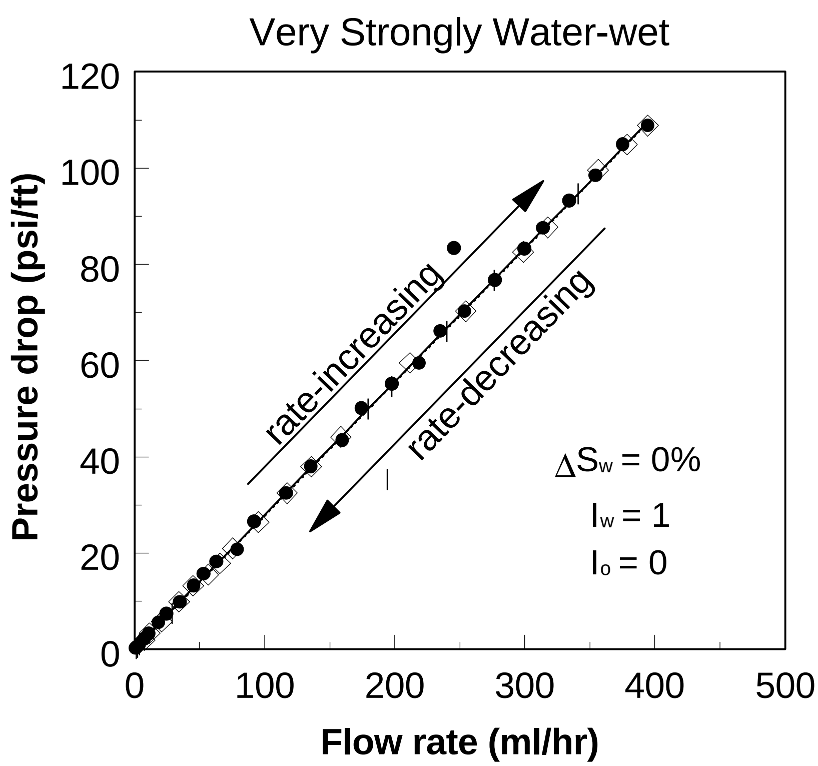

Fig. 2 In very strongly water-wet Berea sandstone, the ratio of pressure drop to flow rate of water in the presence of a residual saturation of oil is constant. No oil was produced at any flow rate.

Weakly water-wet and mixed-wet conditions

Wetting conditions tested are summarized in **Table 4**. Cores treated with Spraberry crude oil and its synthetic reservoir brine became weakly water-wet. Water imbibed more slowly than in similar, strongly water-wet cores; little or no oil imbibed. Cores treated with Sulimar Queen crude oil and Sulimar Queen synthetic reservoir brine imbibed both brine and oil and are described here as mixed-wet (Salathiel, 1973). At the microscopic level, both of these wetting conditions may involve a mixture of wetting conditions that depends on pore shape and interactions between oil components and mineral surfaces.

Table 4: Summary of wetting conditions

Oils	I_w	I_o	Designation
Soltrol-130	1	0	strongly water-wet
Spraberry	0.7	<0.1	weakly water-wet
Sulimar Queen	0.3	0.1	mixed-wet

Results from the tests in which water flow rate was varied through cores with residual saturation of oil showed that the relationship between pressure drop and flow rate was nonlinear for both the weakly water-wet and mixed-wet cores. Initially small amounts of oil were produced. **Figs. 3a** and **3c** show the change in pressure drop with increasing flow rate, accompanied by production of a small amount of residual oil. In subsequent cycles of increasing and decreasing flow rate, oil production ceased, but some hysteresis remained between the rate-increasing and rate-decreasing portions of the cycle (**Figs. 3b** and **3d**).

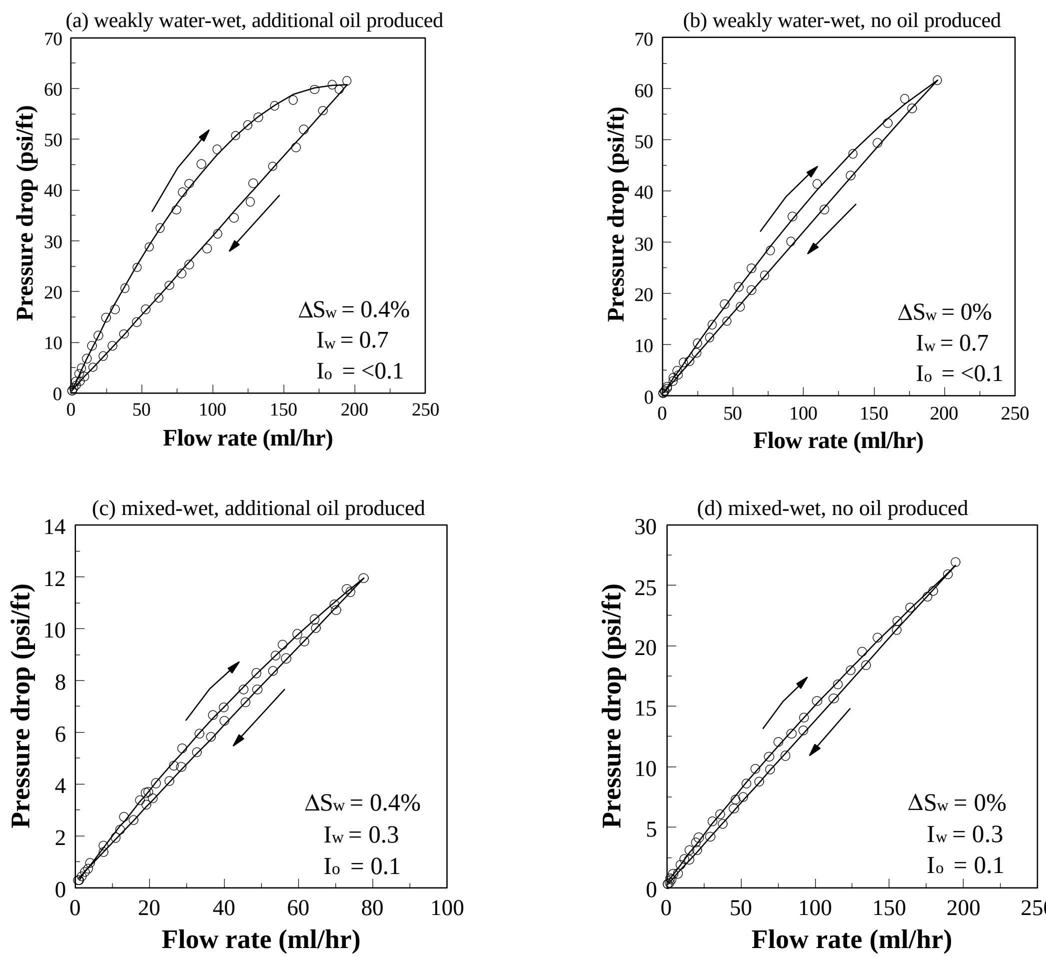

Fig. 3 In weakly water-wet and mixed-wet Berea sandstones, the ratio of pressure drop to flow rate of water in the presence of a residual saturation of oil is not constant during rate increasing step, with or without oil produced.

Hysteresis can also be demonstrated between repeated cycles of increasing and decreasing flow rate. As shown in **Fig. 4**, three consecutive tests over the same flow-rate range (1 to 200 to 1 ml/hr) gave different results. Pressure drop decreased steadily from cycle to cycle while the hysteresis between the rate-increasing and rate-decreasing portions of each cycle declined.

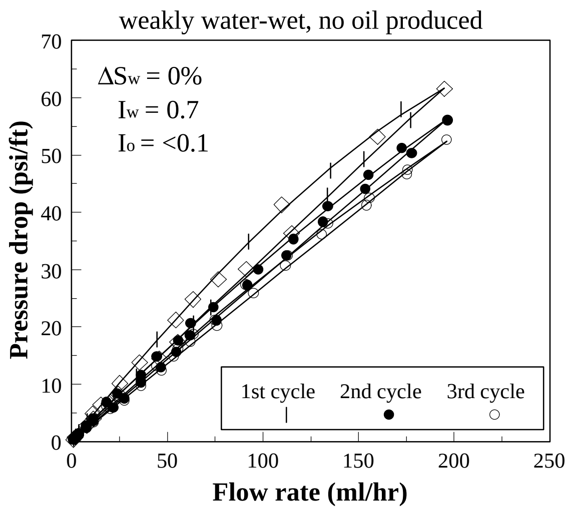

Fig. 4 The rate dependence persists through repeated cycles, without any oil production.

Effect of extended exposure to brine

Some cores were immersed in brine for one month after an extensive series of rate tests with flow rates up to 200 ml/hr. Subsequent rate tests over the same range of flow rates showed a systematic decline in pressure drop—and thus an increase in $k_{rw}(S_{or})$—after aging in brine (**Fig. 5a** and **5b**). There was no change in the residual oil saturation during aging, nor was any oil produced during the course of the variable rate tests. Hysteresis between rate increasing and rate decreasing steps was reduced (**Fig. 5a**) or vanished altogether (**Fig. 5b**).

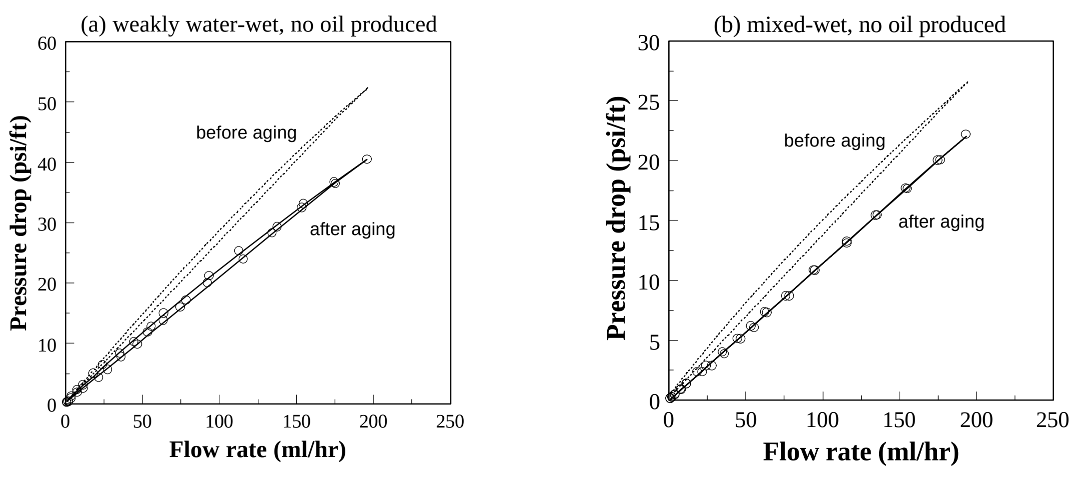

Fig. 5 Aging weakly water-wet and mixed-wet Berea sandstones in brine for one month at residual oil saturation generally decreases the pressure drop and reduces the hysteresis between rate-increasing and rate-decreasing steps. No oil was produced.

What had changed in the cores during the aging period in brine was indicated by another sequence of Amott imbibition tests. An increase in the rate at which water imbibed shows that cores became more water-wet. Typical imbibition results are illustrated in **Fig. 6** where the amount of water or oil imbibed is plotted as a function of dimensionless time, t_D, both before and after the flow-rate tests and aging in brine. Dimensionless time has been defined by Ma *et al*. (1997) as:

$$t_D = \sqrt{\frac{K}{\phi}} \frac{\sigma}{\sqrt{\mu_w \mu_o}} \frac{t}{L_c} \tag{2}$$

where K is permeability, ϕ is porosity, σ is interfacial tension, μ_w and μ_o are viscosities of water and oil, respectively, t is time and L_c is a critical length that depends on geometry and the imbibing fluid's access to the core.

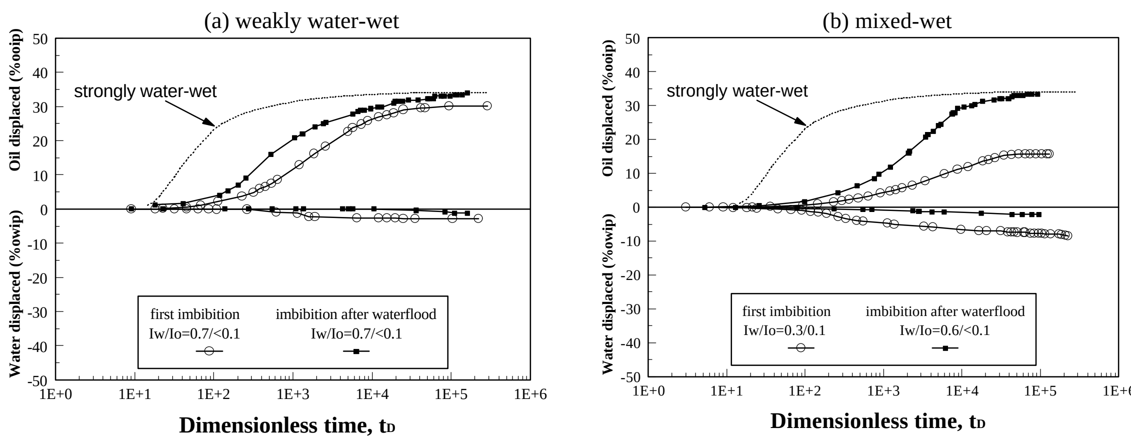

Fig. 6 Cores subjected to extensive water flush and long term aging in brine appear to become more water-wet.

Relative permeability to brine—low-rate unsteady state and high-rate end-point values

A 1-D finite element simulator was used to estimate relative permeabilities by history matching low-rate waterflood data. Equation 1 was used to calculate permeability from the flow rate and pressure drop data obtained during the variable rate tests. In **Fig. 7**, both the unsteady state relative permeabilities and the end point values are plotted. In the initial, high-rate tests, some oil was mobilized and relative permeability to water increased along an extrapolation of the low-rate curve (**Fig.7a**), consistent with previously reported results (Heaviside *et al.*, 1987; Labastie *et al*., 1980). Lower values of the capillary number are required to mobilize residual oil in cores that are not strongly water-wet (**Table 5**). Increased $k_{rw}(S_{or})$ values were also measured in subsequent tests in which no additional oil was produced.

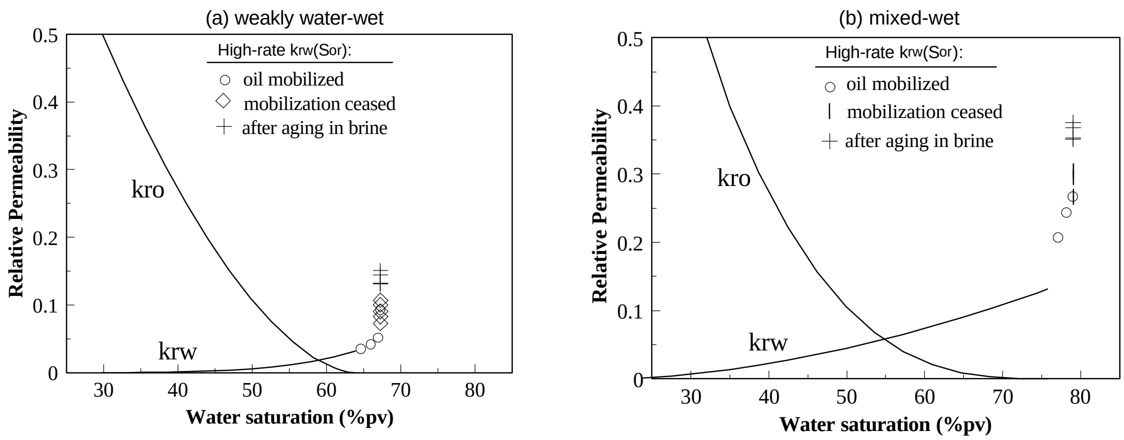

Fig. 7 Summary of relative permeabilities for weakly water-wet and mixed-wet cores from low-rate floods and from a series of waterfloods at increasing and decreasing rates.

Table 5: Critical capillary numbers ($N_c = K_w \Delta p/L\sigma$)

Wetting condition	N_c (onset of oil mobilization)	N_c (completion of oil mobilization)	reference
strongly water-wet	2×10^{-5}	1.5×10^{-3}	Chatzis and Morrow (1984)
weakly water-wet	0.9×10^{-5}	3.2×10^{-5}	
mixed-wet	0.4×10^{-5}	1.1×10^{-5}	

Capillary end-effects, assuming they occur at all under weakly water-wet or mixed-wet conditions (cf. Heaviside *et al*., 1987), are insufficient to explain the effect of flow rate on $k_{rw}(S_{or})$. Capillary end effects cannot explain the hysteresis from one cycle of increasing and decreasing flow rates to another (see **Fig. 4**). In some experiments, flow rates as high as 400 ml/hr were tested (**Fig. 8**), corresponding to $L\mu_w v$ equal to 5.6 and 7.8 cm^2cp/min for the weakly water-wet and mixed-wet cases, respectively. These values of $L\mu_w v$ are higher than even the high end of the recommended range for eliminating capillary end-effects under strongly wetted conditions (0.5-3.5 cm^2cp/min) (Rapoport and Leas, 1953; Kyte and Rapoport, 1958). Nevertheless, the flow-rate dependence of $k_{rw}(S_{or})$ persisted without production of any additional oil.

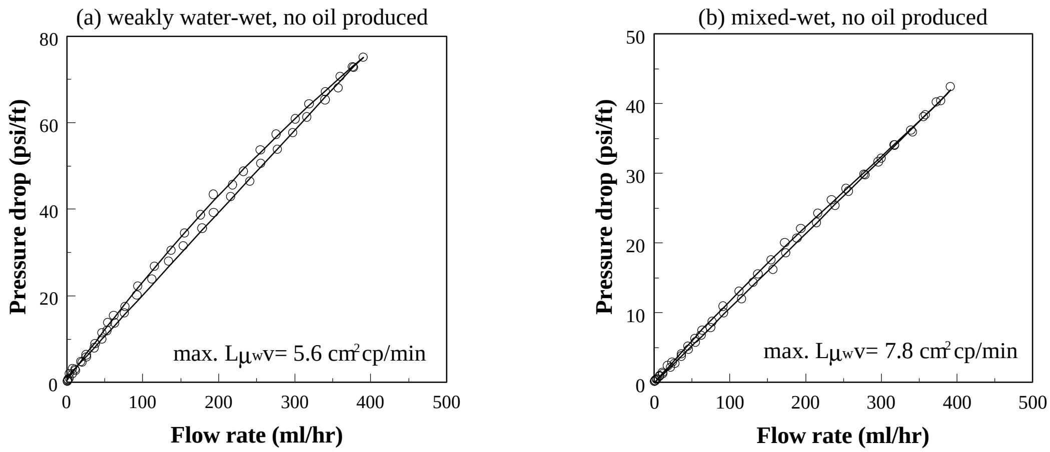

Fig. 8 Rate-dependence persisted even when flow rates were as high as 400 ml/hr. Cores were aged in brine for one month at residual oil saturation prior to rate tests.

Interpretation and Recommendations

In strongly water-wet porous media, oil is trapped in pores with a high aspect ratio (defined as pore diameter/throat diameter). Berea sandstone has a high aspect ratio, leading to a high residual oil saturation due to snap-off (Chatzis *et al*., 1983). Permeability to water is maintained through small, interconnected pores, as illustrated in **Fig. 9a**. Changes in flow rate below the critical value required to mobilize blobs of oil have little or no effect on the permeability of the rock/oil ensemble to water. The distribution of fluids in a mixed-wet rock is different. The configuration suggested in **Fig. 9b** is just one of many scenarios that could be envisioned depending on contact angles, pore morphology, and remaining oil saturation. Permeability to water might increase if oil is redistributed by the flow of water, whether or not oil appears at the outlet end of the core. Bridges of oil that restrict permeability at low flow rates, may break when flow rate increases. Slow redistribution of remaining oil when the core is aged at high water saturation may also affect relative permeability without substantially changing fluid saturations.

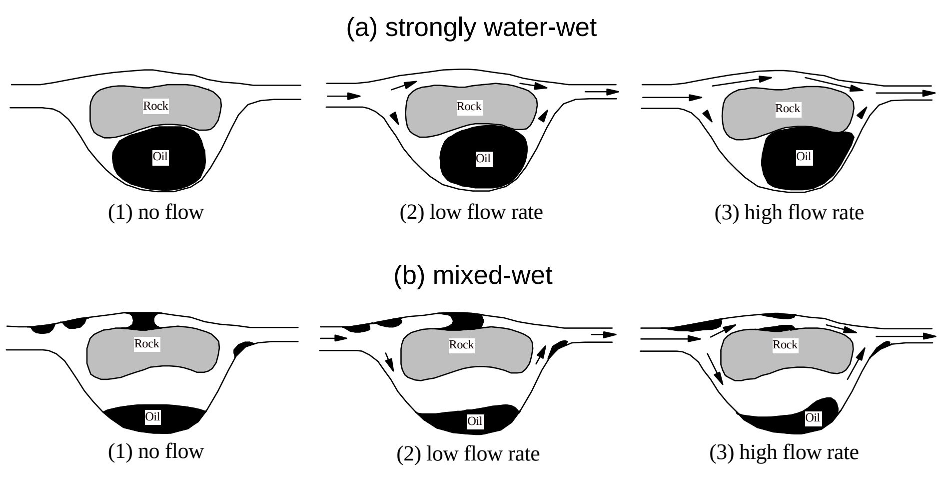

Fig. 9 Illustrations of possible mechanisms of entrapment and fluid distribution in a pore doublet. Flow-rate dependence of relative permeability to water in mixed-wet cores may be related to redistribution of oil that occurs in response to increased waterflood rate.

Given the evidence that in mixed-wet systems, relative permeabilities are not unique functions of fluid saturations, the importance of using representative wetting conditions and flow rates in laboratory core floods must be emphasized. Independent measurements of capillary pressure and local saturation measurements, combined with simulation of waterflood results, are needed to provide physically meaningful relative permeability estimates. In the field, higher water-advancing rates are experienced in near-wellbore regions than in the rest of the reservoir. The results presented here suggest that water relative permeability might, therefore, be higher in the near-wellbore region than elsewhere, and that, after shut-in, water relative permeability might be higher still.

Conclusions

- Tests of strongly water-wet Berea cores confirm, as expected, that water relative permeability at residual oil saturation is independent of flow rate over a wide range of flow rates below the critical rate at which mobilization of residual oil would occur.

- Rate dependence has been demonstrated for weakly water-wet and mixed-wet cores. Hysteresis of $k_{rw}(S_{or})$ is observed between rate-increasing and rate-decreasing measurements and from one test loop to another test loop.

- Extensive high-rate waterflooding and/or long duration of aging in brine at residual oil saturation tended to alter non-water-wet Berea sandstone to more water-wet conditions. Surprisingly, $k_{rw}(S_{or})$ increased significantly as more water-wet conditions evolved.

- Rate dependence of $k_{rw}(S_{or})$, not all of which can be attributed to capillary end effects, significantly impacts estimates of relative permeability curves. Application of high rate waterflooding results to low rate reservoir condition could lead to serious errors in prediction.

Nomenclature

A :	cross section of core sample	Q_w :	water flow rate
I_w :	Amott index to water	v :	waterflood velocity
I_o :	Amott index to oil	Δp :	pressure drop
K_{air} :	absolute permeability to air	ΔS_w :	variation in water saturation
K_w :	absolute permeability to water	μ_o :	oil viscosity
$k_{rw}(S_{or})$:	water relative permeability at residual oil saturation	μ_w :	water viscosity
L :	length of core sample	σ :	water-oil interfacial tension
pv:	pore volume		

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