# FRACTIONAL WETTABILITY AND PETROPHYSICAL PARAMETERS OF POROUS MEDIA

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**Abstract** This paper describes the effects of fractional wettability on flow properties. The synthetic cores are made of mixtures of a fraction 1-f of water-wet sand and a fraction f of oil-wet sand (silicone-treated). The fraction f varies from 0 to 1. The wettability change induced by efficient chemical grafting of organo-chlorosilane molecules on sand was found to be stable over three months. Amott and USBM tests show that the wettability of the samples is reproducible. There is a strong relationship between the wettability indices and the fraction f of oil-wet sand.

The capillary pressure ($P_c$) and the relative permeability ($k_r$) curves of the samples were obtained in both drainage and imbibition. The resistivity ($I_R$) indices were measured.

$P_c$-curves exhibit a continuous evolution with f. At a given $I_R$, the brine saturation is larger for high f values. So, the saturation exponent n increases as f increases. The values of $k_r$ (and $I_R$) are different in drainage and imbibition conditions and there is a strong correlation between the importance of hysteresis and the fraction f.

## INTRODUCTION

The effect of wettability on flow properties is of major importance for reservoir simulations and well treatments. The term "wettability" defines the relative tendency of aqueous or oil phases to coat the solid or to fill the pore space of the rock under capillary forces. It is now accepted that most reservoirs have no strong preference for either oil and water (Cuiec, 1991). Often, both oil and water spontaneously imbibes the rock samples.

This phenomenon cannot be interpreted through the contact angle concept. This theory supposes that the core has a uniform wettability. With this assumption, only one fluid can imbibe spontaneously and only if the contact angle is less than 60° (Morrow, 1971).

On the other hand, fractional wettability may explain the spontaneous imbibitions in both fluids. In this approach, it is assumed that a fraction of the rock is strongly water-wet while the other is strongly oil-wet (Brown, 1956; Fatt, 1959; Salathiel, 1973). Salathiel, 1973, introduced the term "mixed wettability" for a special type of fractional wettability in which the oil-wet surfaces form continuous paths through the largest pores. So, fractional and mixed wettability lead to the idea that wettability is heterogeneous in reservoir rocks. This assumption has been confirmed by Fassi, 1991, who showed through Cryo-SEM studies on sandstone that the kaolinite of the rock has an hydrophobic behaviour while illite, quartz and feldspar grains are preferentially water-wet. The spontaneous imbibitions of both oil and water can be attributed to the networks of these minerals in the sandstone.

In this paper, we used the fractional wettability concept which takes into account the heterogeneous mineral composition of the medium and seems to be more realistic than the contact angle concept.

We have experimentally studied the effect of fractional wettability on flow properties and petrophysical parameters on porous media with a well controlled wettability. These media are mixtures of water-wet and oil-wet sands. In the first part of this paper, the technique of chemical grafting of silane molecules on sand and its stability is described. In the second part, the variation of several petrophysical properties is studied when the fraction of non-wetting sand is varied, in both drainage and imbibition. Results are presented for capillary pressure, wettability indices (USBM, Amott and Amott-IFP), relative permeabilities and resistivity indices.

## POROUS MEDIUM WITH A WELL CONTROLLED WETTABILITY

### Porous Media

Porous media with a well controlled wettability are obtained by mixing a fraction f of oil-wet sand with a fraction 1-f of water-wet sand (0< f <1). The size distribution of the sand grains is 70-100μm. Water-wet sand is obtained by washing natural sand with boiling sulfonitric acid to eliminate the clay. A chemical treatment called silanation renders this sand oil-wet.

### Silanation

Silanation corresponds to the substitution of the hydrogen atoms of silanol groups by organylsilyl agents (Figure 1). The operating procedure is described in Lombard, 1991.

$$\text{-Si-OH} \quad + \quad \text{X-}\overset{R1}{\underset{R3}{\text{Si}}}\text{-R2} \quad \text{---->} \quad \text{Si-O-}\overset{R1}{\underset{R3}{\text{Si}}}\text{-R2}$$

**FIGURE 1: Principle of silanation**

Silane treatments often have allowed the calibration of wettability tests. Amott, 1959, used sandpacks formed by mixing silicone treated sand with cleaned sand (Amott test). Donaldson, 1969, used consolidated cores previously treated with silane solutions of various concentrations (USBM test).

Wettability measurements, n-heptanol adsorption tests, floatation tests, experiments under CT-scanner proved that the treatment was efficient, homogeneous and stable over three months. The Total Organic Carbon values measured on silanated SiC powders indicate a coverage of 1.8 silane layers on average.

## CAPILLARY PRESSURE

All the capillary pressure curves $P_c(S_w)$ are obtained by a centrifugation method adapted for unconsolidated samples (Figure 2).

### Samples and fluids

Gallardon sand is packed between two grids in cells with the following dimensions: inside diameter d=3cm and length L=10cm. The grids are made in two materials in order to let both the wetting and non-wetting fluids go through. One half of the disk is composed of water-wet glass fibers and the other of silanated glass fibers. The porosity of the samples is $\Phi$=40% (±1%) and the permeability K=2.3D (± 5%). Fluids are brine (15g/l NaCl, $\mu$=1.03cP, $\rho$=1010kg/m$^3$, at 20°C) and refined oil (Soltrol: $\mu$=1.55cP, $\rho$=756kg/m$^3$, at 20°C.).

### Experiments

We started with the sample saturated with brine and performed the following displacements (using the terminology defined for water-wet samples):

i) primary drainage (soltrol displaces brine, $S_w$ decreases)
ii) imbibition (brine displaces oil),
iii) secondary drainage (oil displaces brine).

The curves $P_c(S_w)$ are obtained in this way: At each drainage or imbibition step, the centrifugation speed $\omega$ determines the capillary pressure $P_c=\Delta\rho(r_2^2-r_1^2).\omega^2/2$ for drainage and for imbibition $P_c=\Delta\rho(r_1^2-r_2^2).\omega^2/2$, and an

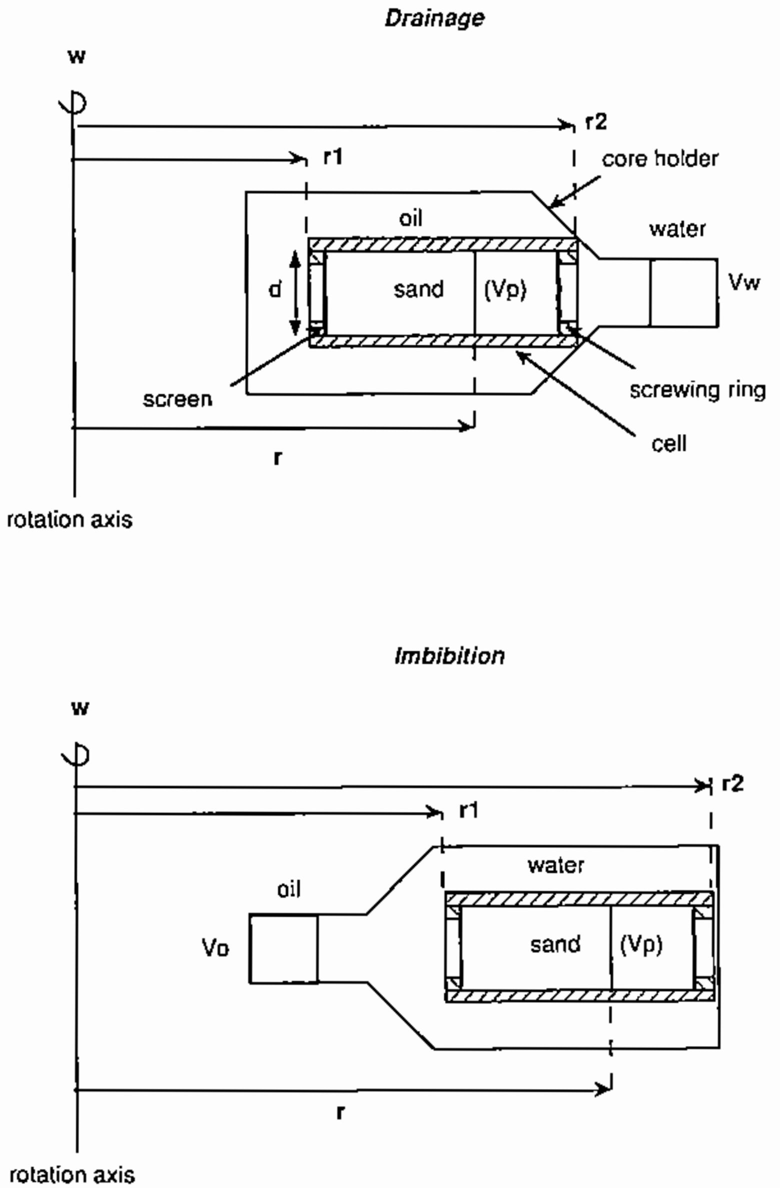


**FIGURE 2: Centrifugation technique**

average saturation of the sample $S_W$ is measured ($S_W$ is a function of the pore volume $V_p$, the water production $V_w$ and the oil production $V_o$). The experimental procedure is described in Lombard, 1991.

## Results

- Primary drainage

For the first drainage, the results are given in terms of capillary-pressure curves (average saturations) depending on the f value (Figure 3).

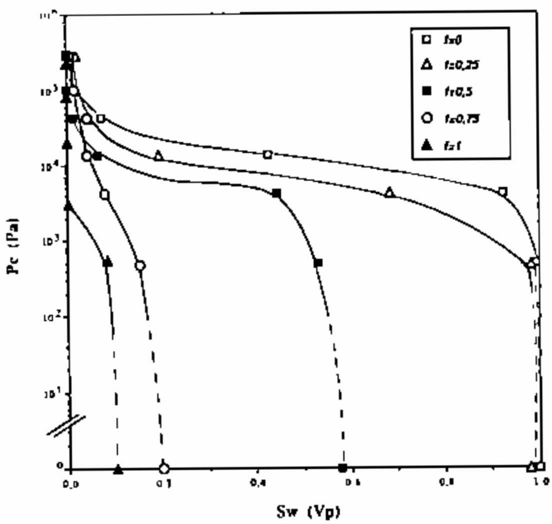


**FIGURE 3: Primary Drainage: Pc-curves for $0 \leq f \leq 1$**

The points on the $S_W$-axis correspond to the spontaneous displacements of brine by oil ($P_c$=0). Such displacements occur only for f greater than 0.25. This point will be studied later. All the curves have the same shape and for a given saturation, the capillary pressure decreases as f increases. Fatt, 1969, observed the same phenomenon with capillary pressure curves obtained on the same sand mixtures by the porous plate method (Figure 4). Similarly, Morrow, 1971, observed a

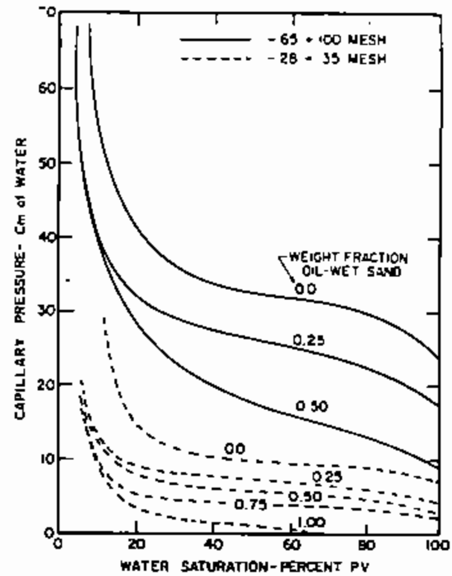


**FIGURE 4: Primary Drainage: Fatt's results. Pc-curves obtained by the porous plate method on mixtures of oil-wet (fraction f) and water-wet (fraction 1-f) sands.**

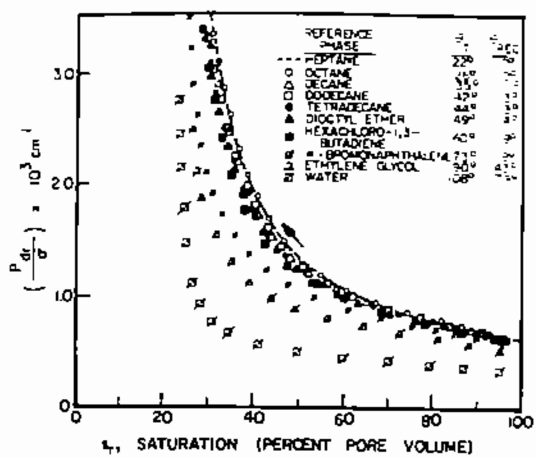


**FIGURE 5: Primary Drainage: Morrow's results. Pc-curves obtained by the porous plate method on teflon cores. He used different pairs of fluids to vary the contact angle and so the wettability.**

decrease of $P_c$ (measured by the porous plate method at a given saturation) with the contact angle θ. He used sintered porous Teflon cores and various fluids to vary θ (Figure 5). However, Fatt and Morrow did not find any spontaneous displacement of brine by oil (except for f=1, Figure 3).

• Imbibition and secondary drainage

The curves were obtained for the fractions f =0; 0.25; 0.5; 0.75; 1. The method of Forbes, 1991, is applied to transform the centrifuge production data into local saturation values. Figure 6 is an example of a $P_c$ versus average and local water saturations curve obtained for f=0.25. The local saturations are the true saturations and will be used for the wettability measurements. Figure 7 represents the $P_c(S_w)$ curves for f=0.25 and f=0.75 (local saturations). The shape of the capillary-pressure curves depends on the fraction f. This implies that the areas under the imbibition and second drainage curves vary with f. As f increases, the area under the drainage curves becomes smaller and the area under the imbibition curves becomes larger. These areas represent the energy which is necessary to displace the fluids and are related to the USBM wettability test.

## WETTABILITY INDICES

### Wettability tests

Various methods for determining the wettability are described in Anderson, 1986, and Cuiec, 1991. We used three methods to determine the wettability of our porous media:

• USBM method: Donaldson, 1969, used a centrifuge method to obtain capillary pressure curves of consolidated samples. The area A1 under the secondary drainage curve and the area A2 under the imbibition curve lead to the wettability index $WI_{USBM}=\log(A1/A2)$: thus, for water-wet samples $WI_{USBM}>0$, whereas for oil-wet samples $WI_{USBM}<0$.

• The Amott-IFP and Amott methods combine two spontaneous imbibition measurements and two forced displacement measurements. One difference between the two tests is the forced displacement technique: centrifugation

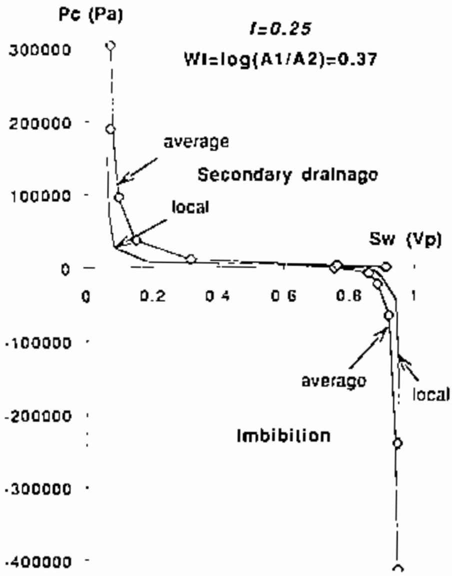


FIGURE 6: Imbibition an Second Drainage: Average and local water saturations for f=0.25.

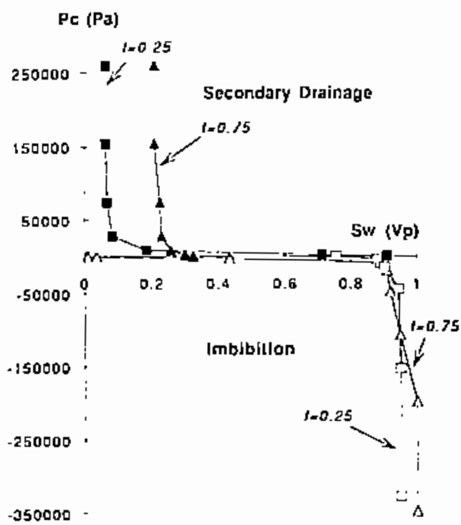


FIGURE 7: Imbibition an Second Drainage: f=0.25 and f=0.75.

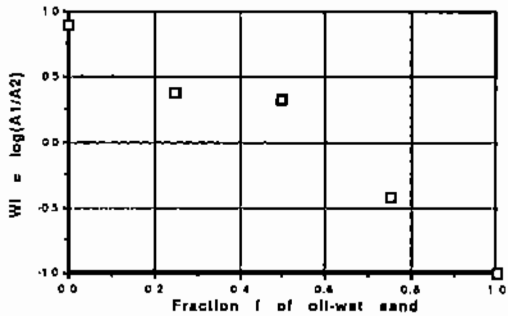


**FIGURE 8: USBM wettability index versus f.**

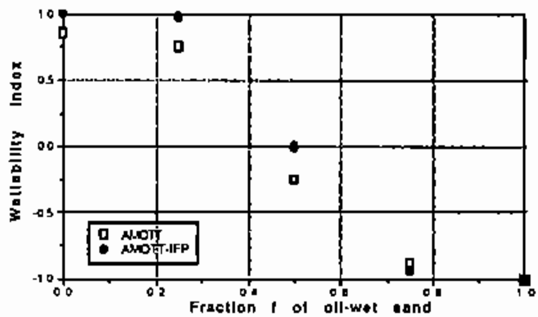


**FIGURE 9: Amott and Amott-IFP wettability indices versus f.**

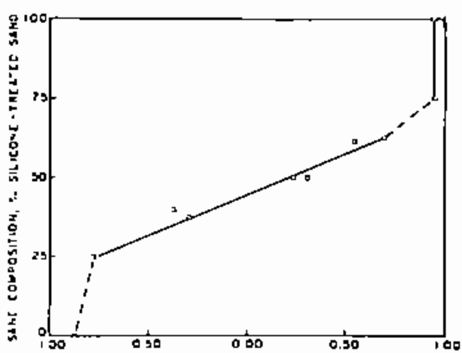


**FIGURE 10: Amott's results. Amott wettability index versus f.**

displacement for the Amott test and flowing displacement for the Amott-IFP test.

The results of our measurements are shown in Table 1 and are plotted in figures 8 and 9.

**Table 1: Wettability Indices**

| f | 0 | 0.25 | 0.50 | 0.75 | 1 |
|---|---|---|---|---|---|
| $WI_{Amott\text{-}IFP}$ | 1 | 0.97 | 0 | -0.95 | -1 |
| $WI_{Amott}$ | 0.86 | 0.75 | -0.24 | -0.87 | -1 |
| $WI_{USBM}$ | 0.89 | 0.37 | 0.32 | -0.42 | -1 |

These figures show that the wettability indices decrease as f increases. Furthermore, the variation of $WI_{Amott}$ and $WI_{Amott\text{-}IFP}$ with f shows two plateaus in the ranges 0-0.25 and 0.75-1 (Figure 9), in good agreement with Amott's results (Figure 10). We do not observe such a phenomenon with $WI_{USBM}$, certainly because the USBM test does not take into account the spontaneous imbibitions of the fluids.

**Percolation threshold:**

The particular role of the values f=0.25 and f=0.75 for the wettability indices and for the spontaneous displacements can be explained by percolation theory. Indeed, $p_c$=0.25 is the 3D-percolation threshold for random mixture of conductive (fraction p) and non-conductive (fraction 1-p) beads (Clerc, 1980). This electrical analogy is explained in figures 11, 12 and 13: Under the threshold 0.25, the mixture of beads is not conductive (Figure 11). In the sand grains mixture, the wetting grains do not form a continuous path and the wetting fluid cannot spontaneously go through the medium (Figure 12). Above 0.25, the bead mixture is conductive (Figure 11). In the same way, there is a continuous path of the wetting grains through the sand mixture and the wetting fluid can spontaneously percolate (Figure 13).

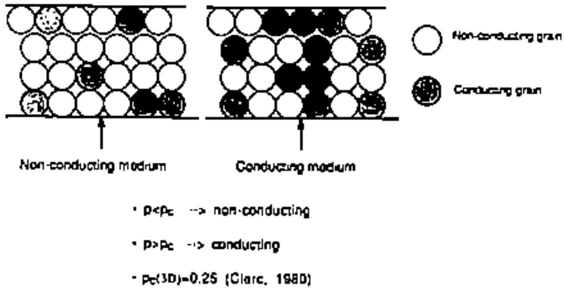


**FIGURE 11: Analogy with the conductive media: Percolation theory.**

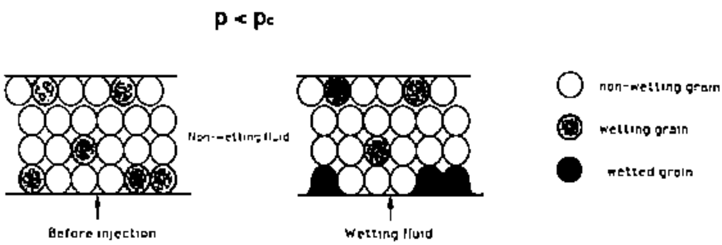


**FIGURE 12: Analogy with the conductive media below the percolation threshold.**

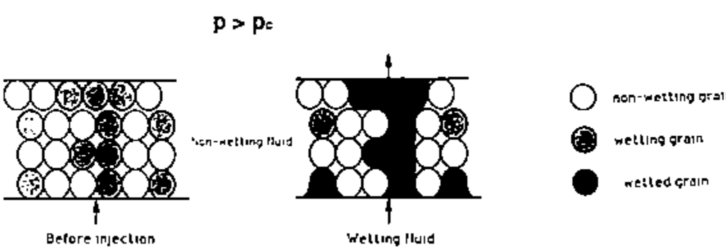


**FIGURE 13: Analogy with the conductive media above the percolation threshold.**

## RELATIVE PERMEABILITY

### Experiments

The relative permeabilities were obtained with the steady-state (Penn-State) method. The standard set-up is shown in Figure 14 . Oil and water are injected in the cell with a constant total rate $Q_t=Q_o+Q_w$=200ml/h. At a given water rate fraction $f_w=Q_w/Q_t$, when the equilibrium is reached, the water level in the separator gives the average saturation $S_w$ in the medium. The cell has an inside diameter of 2cm and a length of 40cm. To avoid the end effects, the differential pressure $\Delta P$ is measured at 4cm from the extremities.

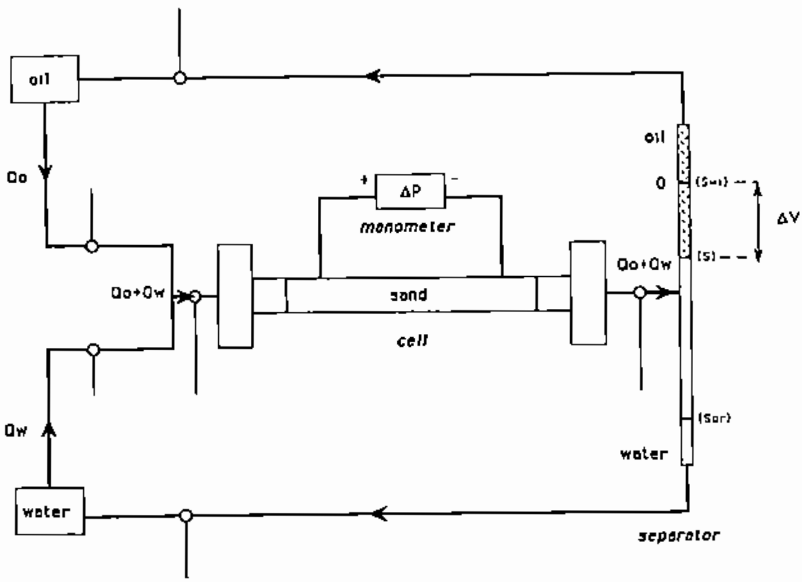


**FIGURE 14: Relative permeability measurement: Steady-State method.**

The oil and water relative permeabilities are calculated with the formula:

$$K_{re} = \frac{\mu_e.L}{S.K}.\ Q_e/\Delta P$$

$$K_{rh} = \frac{\mu_h.L}{S.K}.\ Q_h/\Delta P$$

K is the absolute (water) permeability and S the cross section area of the sample. For all experiments, the capillary number is: $Ca=\mu.V/\gamma= 10^{-5}$.

The samples are led to irreducible water saturation $S_{wi}$. The water saturation is then increased by increasing $f_w$ (called "Imbibition IM"). The sample is so led to irreducible oil saturation $S_{or}$. Finally, $S_w$ is decreased by decreasing $f_w$ ("Secondary Drainage SD").

## Results

For each f value, the results are presented in terms of water and oil relative permeabilities ($K_{rw}$ and $K_{ro}$) depending on the water saturation $S_w$.

• Figures 15 and 16 show the $k_r$-curves for f=0 and f=1. We notice hysteresis only for the non-wetting phase (oil for f=0 and water for f=1). The wetting phase relative permeabilities do not depend on the saturation history. This agrees with previous results on unconsolidated porous media. Batycky, 1978, and Naar, 1962, found hysteresis only for the non-wetting phase.

However, some results concerning consolidated porous media show no hysteresis for both wetting and non-wetting phases during imbibition and secondary drainage. In addition, for the non-wetting phase, the relative permeabilities are higher in primary drainage than in imbibition (or secondary drainage). A detailed study of these works can be found in Jerauld, 1990.

Jerauld, 1990, also gives an interpretation concerning these two different behaviours of consolidated and unconsolidated porous media. His model is based on the aspect ratio (AR=pore radius / throat radius) which governs the imbibition mechanism at microscopic level:

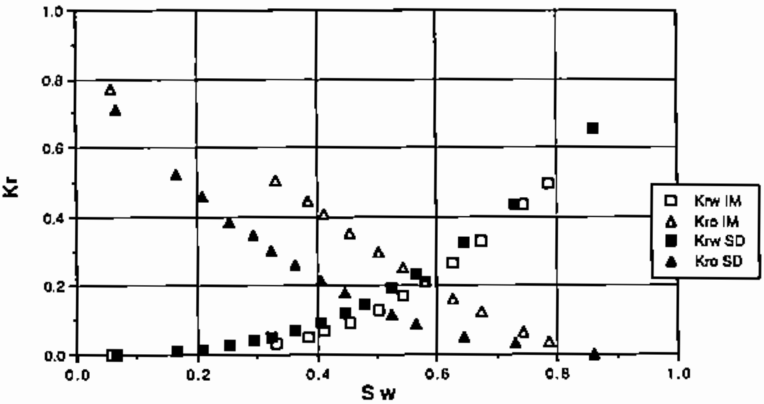


**FIGURE 15: Relative permeability versus water saturation. f=0.**

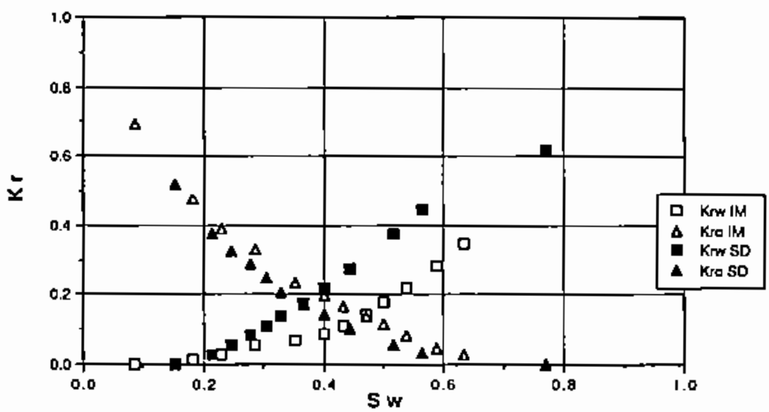


**FIGURE 16: Relative permeability versus water saturation. f=1.**

+ snap-off for high AR (consolidated porous media) and
+ retraction for low AR (unconsolidated porous media).

Note that all the previously mentionned results concern porous media with a strong wetting preference. No results on relative permeability hysteresis are available for porous media of intermediate wettability.

• Figure 17 shows the evolution of hysteresis with f. For f=0.25 and f=0.75, the curves have a similar hysteresis for both oil and water. This proves the symmetrical role of 0.25 and 0.75.

For f=0.5, the hysteresis is present only for water. Furthermore, for each f value, we have the relations: $K_{rwIM} < K_{rwSD}$ and $K_{roIM} > K_{roSD}$. This result agrees with Batycky and Mac Caffery, 1978, Poulovassilis, 1970, results.

• The results can be presented using Corey exponents. In flow simulations, the relative permeability is often approximated by an explicit function of saturation:

$$K_{rw} = \frac{K_{rw}(S_{or})}{K} \cdot S^{*Cw}$$

$$K_{ro} = \frac{K_{ro}(S_{wi})}{K} \cdot (1\text{-}S^*)^{Co}$$

with the normalized water saturation:

$$S^* = \frac{S_w - S_{wi}}{1 - S_{wi} - S_{or}}$$

Corey exponents Cw and Co have been calculated for the artificial porous media. The results are plotted in Figure 18. There is no strong influence of f on Cw and Co but we always have the relations:

$\Delta Cw = Cw_{IM} - Cw_{SD} > 0$

$\Delta Co = Co_{IM} - Cw_{SD} > 0$

$\Delta Cw \approx 0$ for f=0 because there is no hysteresis for water.

$\Delta Co \approx 0$ for f=1 because there is no hysteresis for oil.

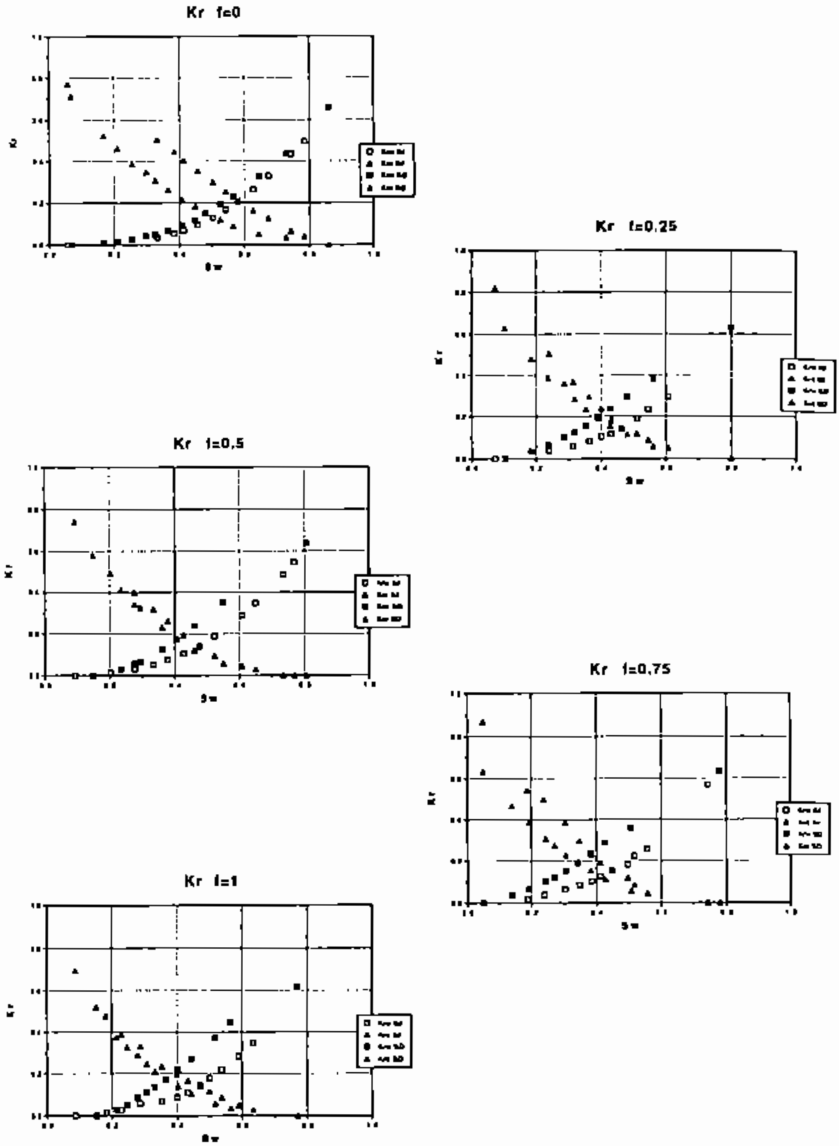


**FIGURE 17: Relative permeability: variation of the hysteresis with f.**

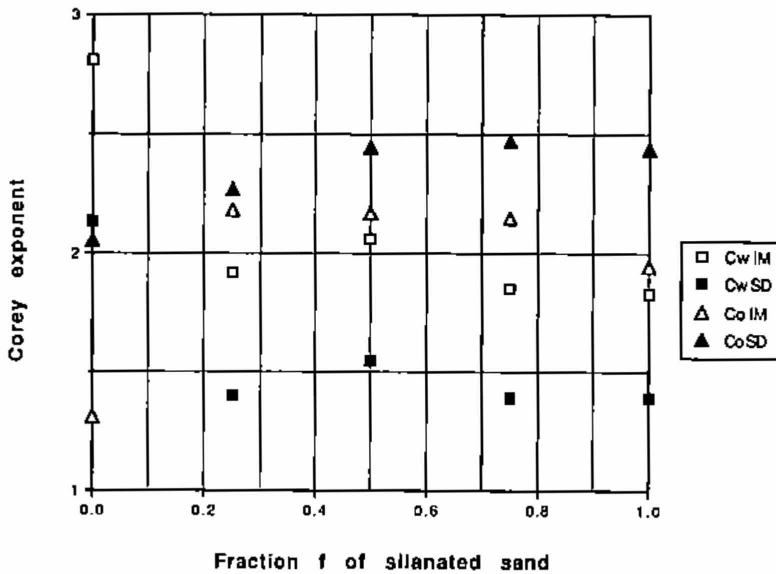


**FIGURE 18: Corey exponents versus f. $K_{rw} = a. S^{*Cw}$ and $K_{ro} = b. (1-S^*)^{Co}$**

## RESISTIVITY INDICES

### Definitions

Porosity and in-situ water saturation in oil reservoirs are commonly determined from electric logs. Their interpretation is based on the two Archie's equations (Archie, 1942):

$$F_R = R_0/R_w = \Phi^{-m} \qquad (1)$$
$$I_R = R_t/R_0 = S_w^{-n} \qquad (2)$$

(1) gives the relation between the formation resistivity factor $F_R$ and the porosity $\Phi$. $R_w$ is the resistivity of the brine. $R_o$ is the resistivity of the 100% brine-saturated formation. The exponent m is called cementation factor.

(2) gives the relation between the resistivity index $I_R$ and the water saturation $S_w$. $R_t$ is the resistivity of the porous medium at saturation $S_w$, n is called the saturation exponent.

## Experiments

We measured the electrical parameters m and n in the cell used for centrifugation and wettability measurements. For each f value, the cementation factor is the same m=1.5 and does not depend on wettability. Then, the resistivity is measured at $S_w = S_{wi}$ an $S_w = 1\text{-}S_{or}$. The measurements are "imbibition" measurements ($S_w$ increases from $S_{wi}$ to $1\text{-}S_{or}$). $F_R = R_t/ R_0$ and n are then calculated. The results are plotted in Figure 19. The exponent n increases with f, a result in agreement with Donaldson, 1989, Lewis, 1988, Jun-Zhi Wei, 1990. Longeron, 1989 and Longeron, 1991, also observed an increase of n with the oil wettability under reservoir conditions (small increase from 2 to 2.5). As $S_w$ decreases, the more the sample is oil-wet, the more rapidly the resistivity increases. This occurs because a portion of brine is trapped, while additional brine is isolated in dendritic fingers where it cannot contribute to the electrical conductivity.

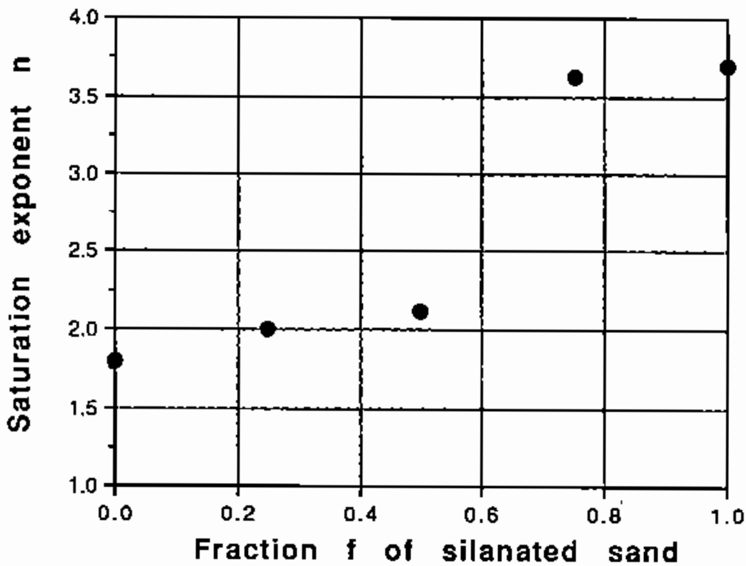


**FIGURE 19: Saturation exponent versus f. $I_R = R_t/ R_0 = S_w^{-n}$**

## CONCLUSIONS

- An artificial porous medium has been made with a well controlled wettability by mixing oil-wet and water-wet sand.
- The chemical treatment which renders the sand oil-wet is efficient and stable.
- The centrifugation technique has been used to obtain capillary-pressure curves for our porous media under both drainage and imbibition conditions. In primary drainage: At a given $S_w$, $P_c$ decreases as f increases.
- Different wettability tests have been performed on our mixtures. All the wettability indices are correlated to the fraction f.
- f=0.25 and f=0.75 appear to be particular values which correspond to 3D-percolation thresholds.
- The relative permeabilities present an hysteresis between imbibition and drainage and it varies with f.
- The saturation exponent strongly depends on f: n increases with f.

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