EFFECT OF THE SPREADING COEFFICIENT ON GAS/OIL CAPILLARY PRESSURE CURVES IN PRESENCE OF CONNATE WATER

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Abstract. This paper presents measurements of gas/oil capillary pressure curves in the presence of connate water by a centrifuge method for both positive and negative spreading coefficients. Comparison between these two cases shows two effects:

1. The residual oil saturation is found to be higher in the case of a negative spreading coefficient than in the case of a positive one,
2. Except for low oil saturation values, the capillary pressure is found to be higher in the case of a positive spreading coefficient than in the case of a negative one.

An interpretation is given based on experiments performed in network models. It leads to recommendations for performing adequate laboratory tests.

1. INTRODUCTION

In the standard approach of three-phase flow in porous media (Stone, 1970, 1973), attention is never paid to the interactions between fluid phases. Fluid/fluid interactions can be taken into account through the spreading coefficient $\mathcal{S}$ defined, for a strongly waterwet core, as the balance of the three interfacial tensions between oil (o), water (w) and gas (g) which are to be taken into account: γ_{ow}, γ_{og} and γ_{wg}, *e.g.* $\mathcal{S} = \gamma_{wg} - (\gamma_{ow} + \gamma_{og})$. This coefficient represents the force exerted on the triple line (gas/oil/water) to stretch an oil lens on a water substrate in presence of gas (Figure 1).

This spreading coefficient will, of course, rule the mechanisms of displacement through the drainage of oil films and consequently affect the flow parameters such as the relative permeabilities. For the drainage capillary pressure, the effect of the spreading coefficient is still more obvious since, as we will show, the capillary pressure is directly related to this coefficient through the apparent contact angle θ by $\cos(\theta) = 1 + \frac{\mathcal{S}}{\gamma_{og}}$.

As the notion of spreading of oil on water does not appear in two phase flow, it seems *a priori* impossible to infer the three-phase parameters from two-phase ones.

In spite of these considerations, Dumoré and Schols (1974) reported that no effect of the spreading coefficient on three-phase drainage capillary pressures could be observed. This can be explained by the fact that, since that date, very few papers have been published on this subject even though an accurate description of three-phase flow in porous media is highly needed: three phases are often all together in the porous medium during the exploitation of an oil field. For instance, three-phase systems are encountered when oil is recovered by immiscible gas injection both in secondary and tertiary conditions. It is the same when oil is recovered by waterflood in presence of a trapped gas saturation.

We focus this study on capillary pressure measurements as this is essential to adequately interpret core flood experiments and it allows us to determine the residual oil saturation which is a key factor for the oil industry. Since interfacial tensions vary a lot between room and reservoir conditions, especially for gas/oil and gas/water interfaces, the spreading coefficient may be positive or negative depending on the fluids, the P and T conditions and the wettability of the core. Therefore, it appears essential to study quantitatively the effect of the spreading on three-phase capillary pressures.

This paper is organized as follows. In section 2, we will first recall the standard approach of three phase flow in porous media. Then, in section 3, we will define the notion of the spreading coefficient and we will discuss a way to take it into account in the definition of the three-phase drainage capillary pressure. This will be illustrated by experiments performed in physical network models. In section 4, we will present our centrifuge experiments. Finally, we will look at the field case in section 5.

2. STANDARD APPROACH

Although a three-phase flow in a porous medium is a much more complicated situation than the two-phase case, the phenomenology used to describe such displacements is much more simple. It is commonly accepted that there are no effects of interfacial tensions, viscosities, or wettability on the flow parameters.

Basically, the standard approach of three-phase flow in porous media is mainly based on the derivation of the three-phase (denoted by 3Φ) parameters from two-phase data (denoted by 2Φ). The standard framework is such that the solid phase is completely wetted by one fluid phase, usually the water phase. The gas phase is thus the non-wetting phase and the oil phase is the intermediate one. The main assumption consists in assuming that the 3Φ case can be split into two 2Φ cases, the oil/water system and the gas/oil system.

2.1. Derivation of the 3Φ relative permeabilities.

In strongly waterwet conditions, 3Φ relative permeabilities related to water and gas phases are very simple: these phase parameters are found to depend only on their own phase saturation. The only one problem is concerned with the oil relative permeability which depends on both water and gas saturation.

Except for some models based on the use of capillary pressure data to derive flow parameters (Corey, 1956; van Genuchten, 1980; Parker and Lenhard, 1987; Delshad and Pope, 1990), all the models are based on the definition of the 3Φ oil relative permeabilities from the two two-phase ones: the water/oil and the gas/oil curves (Stone, 1970,1973; Fayers, 1984).

Of course, it would be interesting to avoid to use such relationships for which the physics is not firmly stated.

2.2. Derivation of the 3Φ drainage capillary pressures

Since the pioneering work of Leverett in 1941, a large number of papers dealing with 3Φ relative permeabilities have been published; however very few papers have dealt with 3Φ capillary pressures. These have been essentially produced by the team of Parker and Lenhard (1987).

These papers first assume, and then aim at experimentally proving, that 3Φ capillary pressure curves can be very easily deduced from 2Φ capillary pressure curves. The facts that justify such a procedure are the following:

- 3Φ imbibition capillary pressure (water/oil displacement in presence of trapped gas saturation occurring, for instance, for waterflooding following a primary recovery by depletion) is identical to the 2Φ water/oil imbibition curve,
- 3Φ drainage capillary pressure (gas/oil displacement in presence of water occurring for any gas injection (there is always water, at least, at irreducible water saturation) and especially during tertiary recovery by gas injection) is identical to the 2Φ gas/oil drainage curve.

These results greatly simplify the problem since it allows one to derive 3Φ relative permeabilities which do not depend explicitly on the 2Φ curves. This dependency is taken into account through the capillary pressures.

Though the authors claimed that they had proven experimentally their assumptions (Lenhard and Parker, 1987), these assumptions appear to be very strong and need to be questionned.

3. SPREADING COEFFICIENT AND 3Φ DRAINAGE CAPILLARY PRESSURE

In this paper, we will deal only with the gas/oil drainage in presence of irreducible water saturation. It seems *a priori* that for such a system, since three interfacial tensions have to be taken into account, the physics to be considered is much more complicated than for the 2Φ case. Thus it is difficult to admit that 2Φ results can be extrapolated in such an easy way to the 3Φ case.

As we are interested here in quasi-static displacements occurring during a capillary pressure experiment, we only want to investigate the role of the interfacial tensions exerted between the phases. In the 2Φ case, besides miscibility, this role leads to the concept of wettability. For the 3Φ case, this leads to the notion of spreading (first mentionned in the petroleum litterature by Dumoré and Schols, 1974). Unfortunately, these authors did not get practical results.

Before developing this idea, it is necessary to define this notion of spreading coefficient (Rowlinson and Widom, 1982; Joanny, 1987).

3.1. Definition of the spreading coefficient

In the 2Φ case, the balance between superficial and interfacial tensions rules the ability of the solid to be preferentially covered by one phase or another. In the 3Φ case, we will consider that the medium is perfectly wetted by a given fluid phase, say the water phase. We will thus consider, as usual, the wettability classification towards the solid phase: the water phase is the wetting phase, the gas phase is the nonwetting phase and the oil phase is the intermediate one. Balance between interfacial tension (see Figure 1) rules the ability of oil phase to spread on water in presence of gas.

As for the 2Φ case, it is possible to define an apparent contact angle θ between the gas/oil meniscus and the water substrate. When horizontally projected, this balance is written, in the case where a position of equilibrium can be reached:

$$\gamma_{og}\cos(\theta) + \gamma_{ow} = \gamma_{wg} \qquad (1)$$

where γ_{ij} is the interfacial tension exerted between the phases i and j with $i, j = o, w, g$. In fact, instead of only one angle, three angles should be introduced. However, in the following, we will keep this definition for sake of simplicity.

Introducing the spreading coefficient $\mathcal{S}$ as:

$$\mathcal{S} = \gamma_{wg} - (\gamma_{ow} + \gamma_{og}) \qquad (2)$$

this leads to:

$$\cos(\theta) = 1 + \frac{\mathcal{S}}{\gamma_{og}} \qquad (3)$$

As such, equilibrium is possible only if the spreading coefficient is negative since $|\cos(\theta)| \leq 1$. In this case, oil does not cover completely the water phase. Thus, direct contact between gas and water are possible and would have to be taken into account. In the case where $\mathcal{S}$ is found to be positive, then an equilibrium configuration can not be achieved, and consequently oil spreads totally on water.

3.2 Effect of the spreading coefficient on the 3Φ drainage capillary pressure

As the capillary pressure is proportional to $\cos(\theta)$ through the Leverett's function:

$$P_c = \gamma_{og} \cos(\theta) \sqrt{\frac{\phi}{k}} J(S) \tag{4}$$

by accounting for the relationship between the contact angle and the spreading coefficient, we can expect the following:

1. All the curves are identical for any positive value of the spreading coefficient, as the contact angle remains equal to zero (see Figure 2a),
2. As soon as the spreading coefficient becomes negative, the capillary pressure is lowered since $\cos(\theta)$ is lowered (see equation (4) and Figure 2 a,b),
3. The more negative the spreading coefficient is, the lower the drainage capillary pressure becomes.

Therefore the capillary threshold P_{c0} must be seen as a function of the spreading coefficient such that:

$$P_{c0} = \text{constant} \quad \text{if} \quad \mathcal{S} > 0 \tag{5}$$

$$\frac{\mathrm{d}P_{c0}}{\mathrm{d}\mathcal{S}} \geq 0 \quad \text{if} \quad \mathcal{S} \leq 0 \tag{6}$$

Of course, these results can not be foreseen in the standard approach as it is not assumed that the three phases can be present together at the same location.

3.3. Effect of the spreading coefficient on the residual oil saturation

The spreading coefficient can also modify the capillary pressures through the value of the residual oil saturation S_{om}. The fact that S_{om} depends on $\mathcal{S}$ has already been underlined by Chatzis *et al.*

(1988) and by Oren and Billiotte (1990). In fact, as for the capillary threshold, the residual oil saturation must be seen as a function of $\mathcal{S}$ such that:

$$S_{om} = \text{constant} \quad \text{if} \quad \mathcal{S} > 0 \tag{7}$$

$$\frac{\mathrm{d}S_{om}}{\mathrm{d}\mathcal{S}} \leq 0 \quad \text{if} \quad \mathcal{S} \leq 0 \tag{8}$$

The fact that the residual oil saturation increases when the spreading coefficient becomes more and more negative can be understood by pore scale mechanisms. For instance, in a capillary tube, if $\mathcal{S} \leq 0$ the oil films become unstable and the oil phase is easily broken into ganglia. Another explanation can be seen by use of network models where interconnexions between pores can be taken into account. A substantial increase in the drainage pressure is necessary for filling out any oil pocket, in case of negative spreading coefficient. Thus the trapping of oil is made easier (see Figure 3).

3.4. Experiments in network models

In order to deal with the effect of the spreading coefficient on the residual oil saturation, we have performed two kinds of displacements in a network model for first a positive then a negative spreading coefficient value. On Figure 4 (a,b), we show the oil phase distributions (in white) at the very moment of the breakthrough.

The network physical model is made of glass and has been obtained by the now standard method of etching. The conduits are 100 μm in diameter and 200 μm in thickness. For reaching a positive value of the spreading coefficient $\mathcal{S} = 15.7$, and visualizing the phases, we have used water colored by Rhodamine B for the water phase, Octane colored by Oracet Blue B for the oil phase and air for the gas phase. For the negative case $\mathcal{S} = -2.5$, we have used water with isobutanol for the water phase, Soltrol colored by Oracet Blue B for the oil phase and air for the gas phase.

It appears that according to the spreading coefficient value, these distributions are different. For $\mathcal{S} < 0$ the oil phase is distributed in ganglia which are less numerous than in the positive case and less stretched. An image analysis treatment reveals a coefficient of stretching - defined as the ratio of the largest diameter to the size measured in a perpendicular direction - which is 5.5 for $\mathcal{S} < 0$ compared with 9.1 for $\mathcal{S} > 0$. This is consistent with the fact that for $\mathcal{S} > 0$ there are oil films which do not exist for $\mathcal{S} < 0$. Thus, we can notice that first the residual oil saturations are different according to the spreading coefficient value and second that the distribution of the oil phase is different too.

3.5 A 3 Φ DRAINAGE CAPILLARY PRESSURE EQUATION

In the former paragraph, we have qualitatively investigated the role of the spreading coefficient upon a 3 Φ drainage capillary pressure curve.

It is possible to express the dependency of both the capillary pressure threshold and the residual oil saturation with the spreading coefficient with a simple relationship. Let take the following 2Φ equation for the capillary pressure as a power function of the reduced gas saturation $\overline{S_g}$:

$$P_c = P_{c0} + \overline{S_g}^{\alpha} \tag{9}$$

For the 3Φ case this reduced gas saturation is defined as follows:

$$\overline{S_g} = \frac{S_g}{1 - S_{wc} - S_{om}} \tag{10}$$

thus, the reduced gas saturation becomes dependent on the spreading coefficient through S_{om}.

As such, the 3Φ capillary pressure curve can be expressed as follows:

$$P_c = P_{c0}(\mathcal{S}) + \overline{S_g}^{\alpha}(\mathcal{S}) \tag{11}$$

with the variations of P_{c0} and S_{om} being as represented on the Figure 5.

4. CENTRIFUGE EXPERIMENTS

In order to check our theory, we have performed experiments of capillary pressure measurements where the spreading coefficient was varied. In order to get the capillary pressure data, we have used the centrifuge method (Forbes, 1991). The porous medium was made of unconsolidated waterwet sand with 40% in porosity (ϕ) and 2.3 Darcy in permeability (k). The characteristics of the system porous medium + fluids are given in Figure 6.

We have performed four kinds of experiments in order to get positive, nul and negative spreading coefficient values. We have verified that both porosity and permeability were not modified. In order to get a very negative spreading coefficient value (even if it is certainly not a realistic situation), we have used a silanated sand sample. Therefore, in this case, the water and oil phases were playing the inverse roles as before and thus, water/gas interfacial tension was tending this time to increase the contact angle at the triple line.

4.1. Experimental results

All the results are gathered on Figure 7. In order to compare the different experiments, we have represented the variations of a dimensionless drainage capillary curve. To get such a curve, we have divided the capillary pressure by the interfacial tension between the gas phase (non wetting phase) and the intermediate phase. As we have used different samples, we have also taken into account the porosity and the permeability in the definition of this dimensionless capillary pressure.

Our experimental results show that the spreading coefficient modifies the capillary pressure values as was expected (see Figure 6): the residual oil saturation increases as soon as the spreading coefficient becomes negative but remains constant, and close to zero, for any positive value. Concerning the capillary pressure threshold, it is decreasing for negative spreading coefficient values but this trend is not strong for slightly negative values of the spreading coefficient.

For a large negative value obtained with the silanated sample, this threshold is reduced to zero as expected.

5. APPLICATION TO THE FIELD CASE

We can wonder if it is possible, at reservoir conditions, to be faced with situations where the spreading coefficient is not strongly positive and can even be negative.

According to Firoozabadi (1988), water/oil interfacial tension, at reservoir conditions, takes on the values between 20 and 40 $mN.m^{-1}$. Gas/oil interfacial tensions can take values between 0 and 10 $mN.m^{-1}$. As gas is often mainly composed of methane it is interesting to look at the water/methane system, under temperature and pressure. Hough *et al.* (1951) report some measurements of water/methane systems. They indicate that it is quite possible to find values less than 30 $mN.m^{-1}$ for a pressure of about 350.10^5 Pa and a temperature around 410 °K.

Therefore, it is quite possible to get spreading coefficient values negative or positive depending on the respective values of the tensions. For instance, let take $\gamma_{ow} = 20\,mN.m^{-1}$, $\gamma_{og} = 5\,mN.m^{-1}$ and $\gamma_{wg} = 30\,mN.m^{-1}$. This gives $\mathcal{S} = 5\,mN.m^{-1}$. On the contrary, if $\gamma_{ow} = 35\,mN.m^{-1}$, $\gamma_{og} = 10\,mN.m^{-1}$ and $\gamma_{wg} = 25\,mN.m^{-1}$, this gives $\mathcal{S} = -20\,mN.m^{-1}$.

As such, in order to optimize a gas injection process, one has to take into account the gas composition so as to ensure that the spreading coefficient is not negative. Moreover, in order to perform, at laboratory conditions, experiments representative of a field case, one has to scale the spreading coefficient value.

6. CONCLUSIONS

In this paper, we have investigated the effect of the interfacial tensions on a 3Φ drainage capillary pressure curve, through the effect of a single coefficient which is the spreading coefficient.

We have presented how this coefficient could affect a 3Φ capillary pressure curve. We have shown, by explanations based on pore scale mechanisms that a negative spreading coefficient may lower the capillary pressure threshold and increase the residual oil saturation.

We have shown that, at reservoir conditions, we can expect negative or positive spreading coefficient values which will determine the recovery process.

This justifies that this spreading coefficient be explicitly taken into account in the equations describing three-phase flow in porous media. That is what we have done for the expression of the 3Φ drainage capillary pressure.

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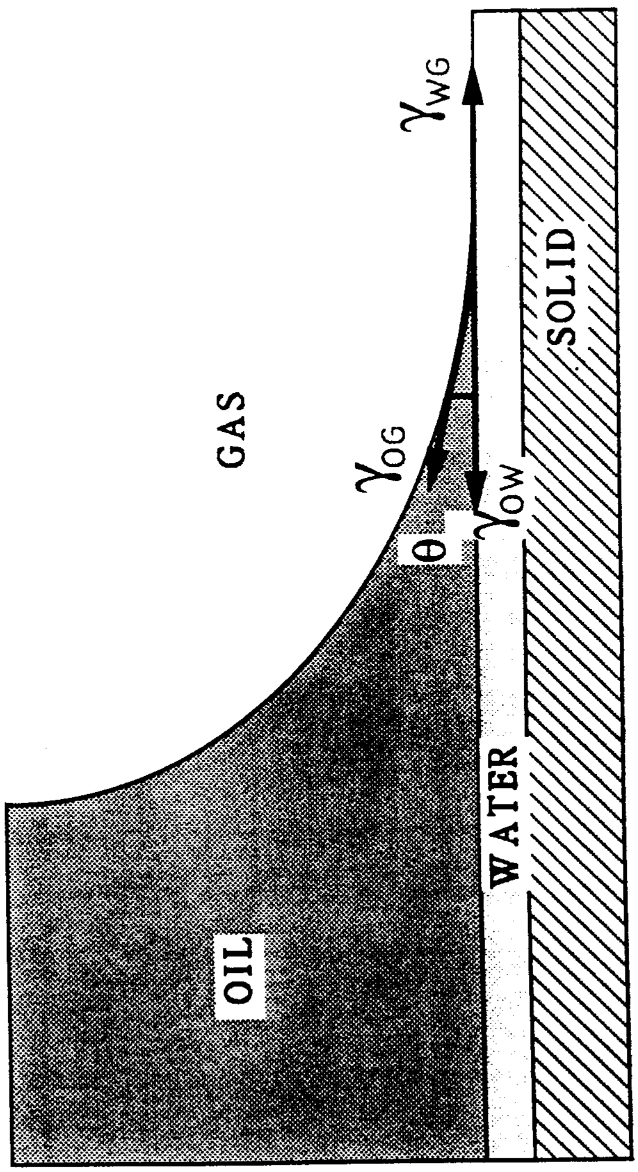


Figure 1: Definition of the spreading coefficient
(see text)

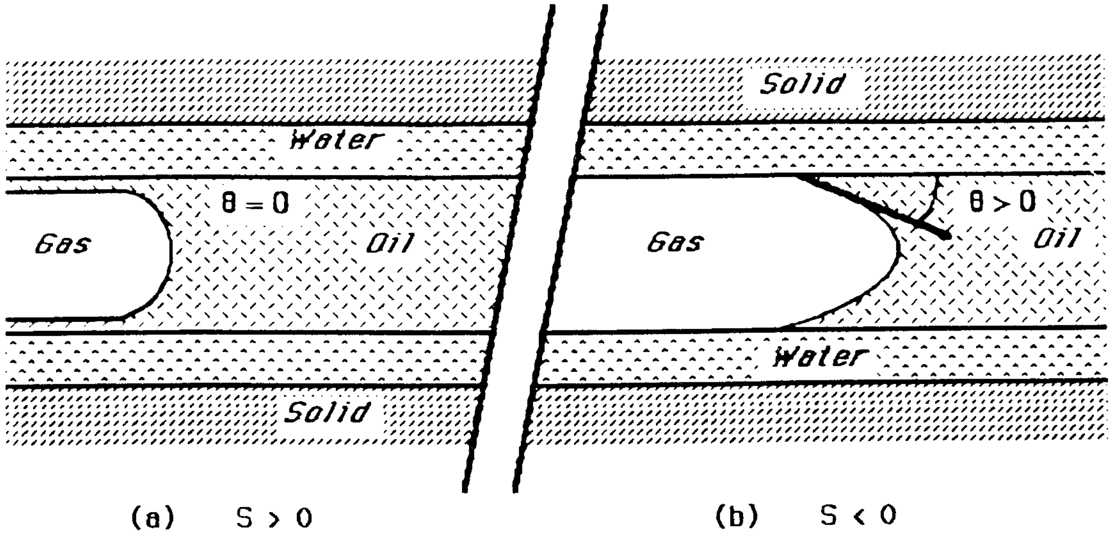


Figure 2: Pore scale distribution of fluid phases for positive (a) and negative (b) spreading coefficient values

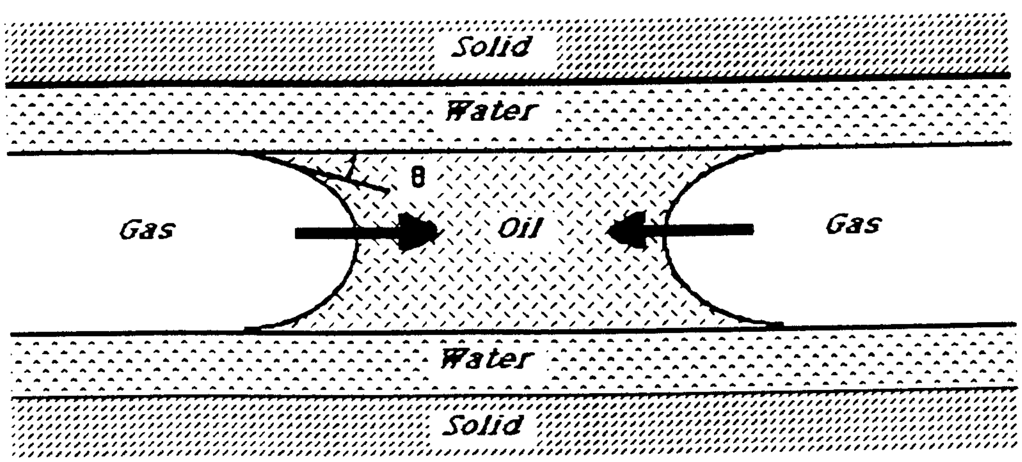
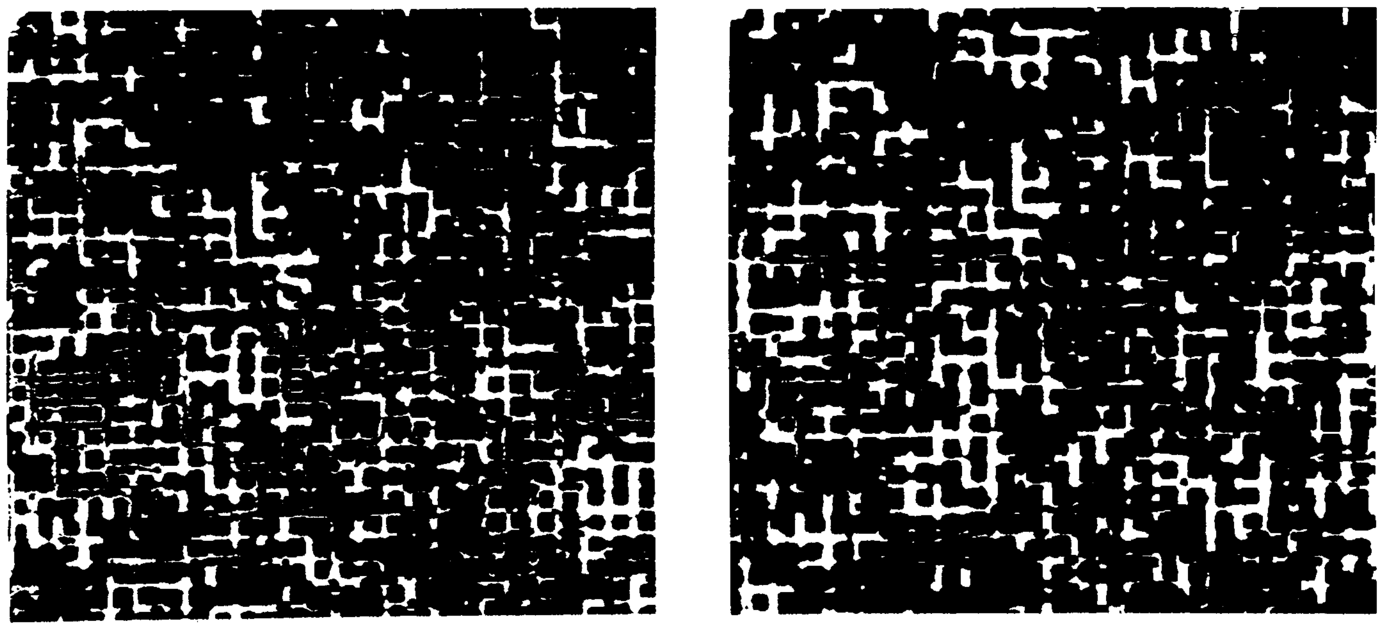


Figure 3: Effect of the spreading coefficient on residual oil saturation (see text)

Figure 4: Effect of the spreading coefficient on oil saturation distribution (in white) at the breakthrough



(a) $S > 0$ (b) $S < 0$

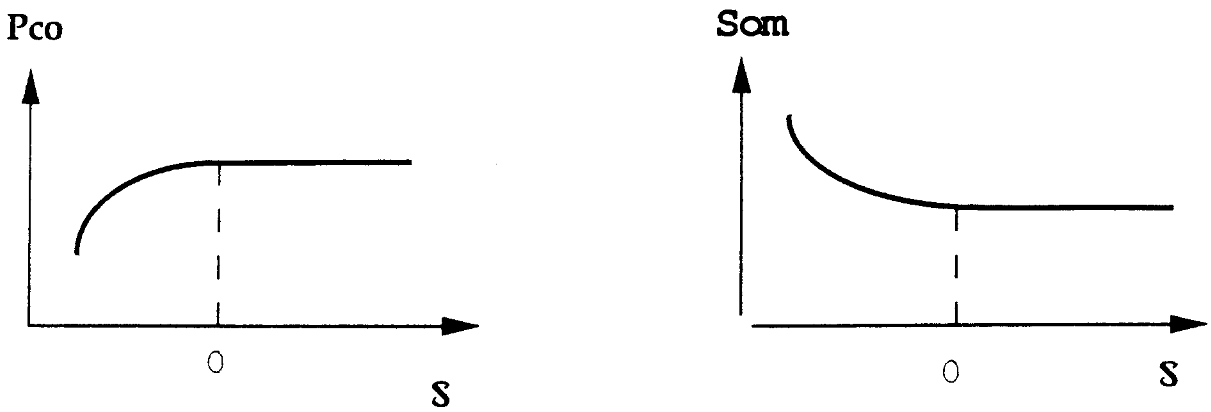


Figure 5: Effect of the spreading coefficient on the capillary pressure threshold and the residual oil saturation

k	ϕ	Swi	Sor	γ_{og}	γ_{wg}	γ_{ow}	S
Darcy	%	%	%	mN/m	mN/m	mN/m	mN/m
2.8	41	3.1	1	20	54	18.3	15.7
2.3	39	3.7	1.3	22.4	51.7	30.4	-1.1
2.8	40	2.1	10	26.3	51.7	30.2	-4.8
2.3	38	2.5	11.5	22.4	66.2	46.2	-90

Figure 6: Set of experimental data

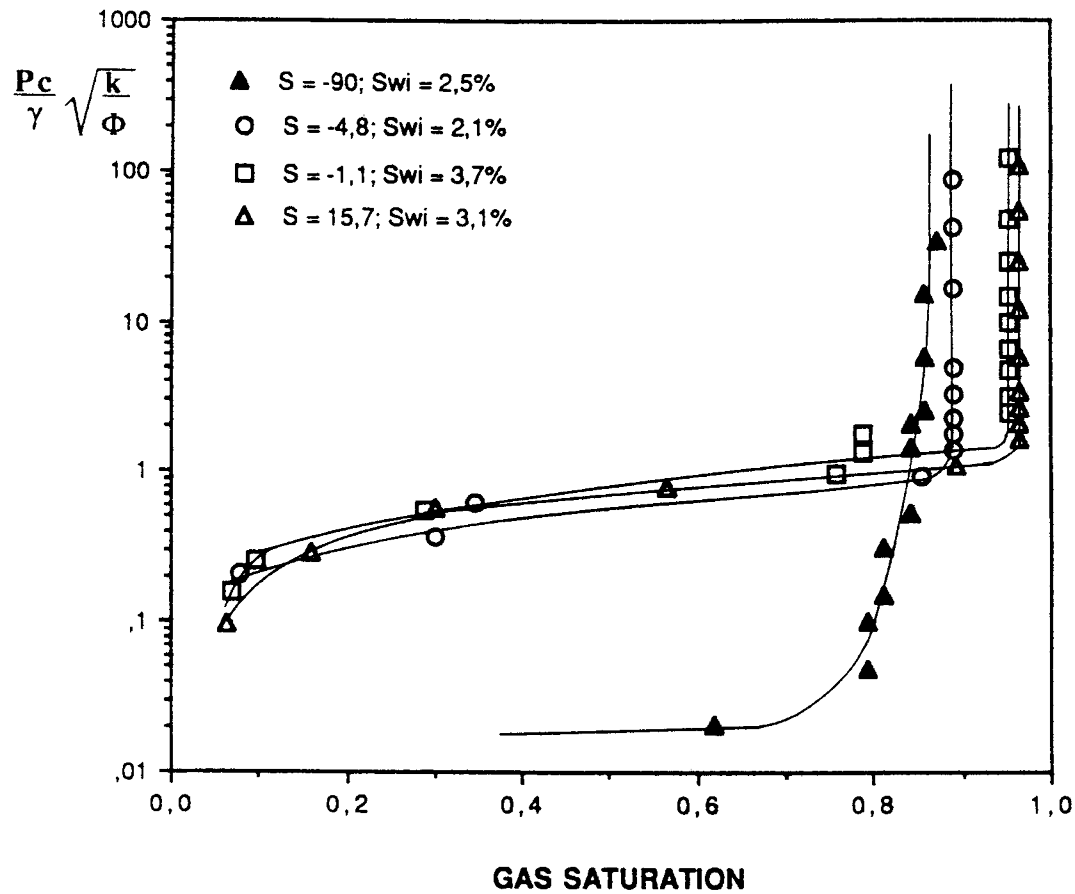


Figure 7: Effect of the spreading coefficient on three-phase drainage capillary pressures