LABORATORY MEASUREMENTS OF CAPILLARY AND ELECTRICAL PROPERTIES OF ROCK SAMPLES AT RESERVOIR CONDITIONS : EFFECT OF SOME PARAMETERS

by

Daniel G. LONGERON
Institut Français du Pétrole
BP 311 - 92506 Rueil-Malmaison (France)

ABSTRACT

The evaluation of saturations and thus oil reserves from resistivity logs requires laboratory determination of both the cementation factor (m) and the saturation exponent (n) under conditions as representative as possible of reservoir ones. A special laboratory equipment using actual fluids (crude oil and formation brine) at reservoir temperature and under effective overburden pressure has been developed. Saturation was varied by the porous-plate technique adapted for reservoir conditions. Drainage (water saturation decreasing) and imbibition (water saturation increasing) were investigated to evaluate the hysteresis effect. Prior to the test, the effect of overburden pressure on porosity and on the formation factor can be studied. To evaluate the effect of wetting properties, the resistivity index and the oil-brine capillary pressure were measured, for each rock sample, first with refined oil and then with crude oil. In addition, wettability indices were determined using Amott-IFP test.

Data were collected with cores from sandstone and carbonate reservoirs. These measurements indicate that the restoration of the effective overburden pressure gave an increase for the cementation factor (m) depending on the nature of the rock sample. The value of the saturation exponent (n) obtained when using crude oil was generally higher than the one obtained with refined oil. This increase of n was attributed to the change in the wetting properties. Saturation exponent increases up to 2.9 as the core becomes more oil-wet. Finally, this paper emphasizes the need to determine electrical and capillary properties under conditions close to the ones prevailing in the reservoir.

INTRODUCTION

The water saturation in oil reservoirs is generally estimated from resistivity well logs. The interpretation of these logs is based on two equations worked out by Archie[1]:

$$FR = \frac{Ro}{Rw} = a \times Ø^{-m} \qquad (1)$$

$$IR = \frac{Rt}{Ro} = Sw^{-n} \qquad (2)$$

in which FR is the formation factor and IR is the electrical resistivity index. Equations (1) and (2) were determined for strongly water-wet clean formations (sandstone or unconsolidated sand with no clay). Here, a value of 2 for m and for n generally gives acceptable results for calculating the water saturation, Sw, determined by the following equation :

$$Sw = [\, a \times Ø^{-m} \times \frac{Rw}{Rt} \,]^{1/n} \qquad (3)$$

resulting from the combining of Equations (1) and (2).

The values for coefficients m and n are mainly obtained from laboratory tests performed on samples assumed to be representative of the reservoir to be investigated. But such tests are usually performed with simulated fluids and under ambient laboratory conditions, which differ greatly from reservoir conditions (pressure, temperature, effective stress, etc.). The values of m and n obtained by such tests and applied without correction to interpret resistivity logs sometimes lead to Sw values that contradict the ones obtained by other methods (preserved core analysis, etc.) or are incompatible with production observations.

A great deal of research[2-8] has been done on the influence of operating conditions (effective stress, temperature) on the measurement of the formation factor, hence on m. Reference 8 contains a detailed bibliographic study of this aspect. For nonclayey rocks, the influence of temperature is almost nil on the formation factor. In general, the increase in FR is greater than that linked solely to the reduction of Ø. Hence m depends on the effective stress.

The influence of operating conditions on the IR/Sw law and thus on n has received much less attention. This is probably linked to difficulties in performing truly representative laboratory experiments. As for m, it seems that the influence of temperature on n is slight or negligible, except for clayey rocks[9]. A good analysis of the causes of errors when using porous-plate technique to evaluate saturation exponent was presented by De Waal et al. [10]. They have also presented an alternative technique (continuous injection technique) to provide accurate measurements of n in 14 days. The data obtained in this study suggest that the stress effects on n are limited. The effective stress can cause a limited increase or decrease in the value of n depending on the type of rock (standstone or carbonate) and on how the effective stress is restored[4,5,7,8,10].

Initial research on the influence of wettability on the resistivity/water-saturation law[11-13] was done by making the pore surface entirely hydrophobic by a chemical treatment (Dri-film, silicone-containing products, etc.). Extremely high values of n (5 to 10 and sometimes even 20) measured under such conditions were strongly contested by log analysts because they led to resistivities of 10^6 to 10^9 Ωm, which are values never encountered in reservoirs. Swanson[14] pointed out the nonrepresentativity of these results under field conditions, since covering all the pore walls of dry rock still does not simulate the way polar crude-oil components could cross through or help rupture residual formation-water films under field conditions. He compared the n-values measured with either neutral oil or crude oil. For drainage the values were nearly the same with three Berea sandstone cores, and so Swanson felt that there would be practically no difference in the distribution of residual water when neutral oil or crude oil was used. However, the one comparison made with a core of Austin limestone does show a great difference, since n increases from 1.63 with neutral oil to 2.22 with crude oil.

Donaldson[15] measured values of n up to 8 for Berea sandstone made oil wet by contact with an 8° API heavy crude oil. The bibliographic review made by Anderson[16] in 1986 concludes that, with the exception of highly water wet rocks, the IR/Sw relation is affected by wettability, especially for low values of Sw. He also concludes that, unless the reservoir is strongly water wet, the value of n must be measured with preserved or restored samples so as not to underestimate the value of Siw. Likewise, Mahmood et al.[8] described a technique of measuring the m and n coefficients under reservoir conditions. This last reference also gives a bibliographic review. Lewis et al.[17] gave values of n from 1.2 to 5.2, depending on the wettability and effective stress.

Recently, Sœndena et al. [18] have compared capillary pressure and resistivity index measurements performed at room and at reservoir conditions on sandstone samples. They fournd that Siw and n increase when reservoir conditions are restored and they related the differences to a change in the wettability preference (from neutral to oil-wet).

The effect of saturation history (drainage or imbibition) has been also investigated by Sanyal et al. [5], Lewis et al.[17] and more recently by Wei Jiu-Zhi and Lile [19]. They found that drainage/imbibition saturation exponents are not significantly different, except for strongly oil-wet cores [19].

Considering the great variation of m and n reported in the literature and the dependence on operating conditions, the research described in this paper was undertaken with the following aims : (i) developing an experimental technique for determining the cementation factor and the saturation exponent under reservoir conditions (pressure, temperature, formation fluids, etc.) ; (ii) making a contribution to the study of the dependency of these factors on various parameters, especially the effective overburden pressure, the saturation history, and the wettability of the reservoir rock. For this last point, we systematically compared the IR/Sw relation obtained for sandstone and carbonate reservoir rock samples as well as for the brine/refined-oil and the brine/crude-oil pairs. The samples were first cleaned, and their wettability was determined by Amott/IFP test.

EXPERIMENTAL

Equipment

The diagram of the experimental device is given in Figure 1. It is identical to the one used previously by Longeron et al.[7] except for the core-holder cell. This cell was modified to be equipped with a four-electrode system for measuring the conductivity. Two intermediate electrodes (M and N in Figure 1) made of Arcap (copper-nickel-zinc) were crimped in the Viton sleeve on which the confining pressure was applied. The special shape of the intermediate electrodes (not entirely circular) and the quality of inside milling of the Viton sleeve ensured perfect sample-electrode electric contact with a minimum effective stress of 3 MPa (435 psi). Reference 7 gives a detailed description of the apparatus. Let us merely say here that the porous-plate technique using a highly water-wet capillary diaphragm placed at the bottom of the core was adapted at reservoir conditions. Despite the relatively long duration of the tests, this method was chosen because it results in a quasi uniform distribution of the water saturation beginning with the first capillary equilibrium. It has the added advantage of providing the capillary pressure curve, provided that equilibrium is reached at each pressure level imposed. Different tentatives to use an oil-wet capillary diaphragm at the top of the core were not successfull. This is why the imbibition curves were performed only down to zero capillary pressure.

Electrical conductivity is measured continuously between the terminal electrodes A and B (Figure 1) by a high precision conductimeter (+/- 0.25 %) at the frequency of 4 kHz. Two to four measurements per day were also made between the intermediate electrodes M and N, and then between A and M, and N and B. These measurements aimed to assess the uniformity of water saturation. In fact, it was proved that after 8 to 10 % of the pore volume of oil had been injected, saturation was uniform for all the tests, since the resistivity measurements between A and M and between N and B were equivalent (deviation of less than 5 %).

Procedure for Simultaneous Measurements of Resistivity and Capillary Pressure

The procedure for preparing a reservoir rock sample is given in Appendix A. Wettability was assessed for each rock sample after cleaning, using the brine/refined oil pair. Then the sample was cleaned again, saturated with interstitial water and crude oil, and aged for 7 days at 80°C. After this stage, the surface state of the reservoir rock was assumed to have been restored[20] and the wettability was evaluated. The description of the Amott/IFP test, the way the wettability index (Iw) was calculated and the cutoff values adopted for separating the classes of wettability are given in reference 20.

The stages of the test under reservoir conditions are as follows :

a) Mounting the clean and dry sample in the measurement cell (T = 20°C, effective stress = 435 psi).

b) After vacuum, saturating the sample and the capillary diaphragm with formation brine. After measuring the pore volume, brine circulation to equilibrate the rock/fluid system until the conductivity becomes stabilized. Calculating the formation factor, FR, at 20°C.

c) Heating the sample up to the reservoir temperature. Calculating the formation factor at reservoir temperature and at the effective stress of 435 psi (confining pressure = 585 psi, pore pressure = 150 psi).

d) Increasing the effective overburden pressure in stages of 400 to 500 psi up to the estimated reservoir overburden pressure. The reduction of the pore volume was continuously measured as well as the variation of the electrical conductivity of the core. Calculating the variations of porosity, formation factor and cementation exponent as a function of effective overburden pressure.

f) Capillary drainage, either with refined oil (Soltrol 130) or with crude oil from the reservoir. It consisted in performing a succession of states of capillary equilibrium. The pressure in the water was maintained constant, and the pressure in the oil was increased by stages. The first pressure increase (DP = Po - Pw) was estimated so that about 10 % of the pore volume was invaded. The time required to obtain capillary equilibrium varied but was never less than two days. Likewise, we always waited for some additional days (two to four) before making the second increase in capillary pressure. Maximum capillary pressure applied was 0.2 MPa (29 psi) for both the water/crude-oil pair and the water/refined-oil pair.

g) For some water-wet samples, an imbibition test was performed by decreasing the pressure in oil by steps, down to zero capillary pressure. This sequence enables no to obtain spontaneous Pc imbibition curve and corresponding saturation exponent value.

DESCRIPTION OF THE RESULTS AND DISCUSSION

Recently, a comparative study of measurements of FR and IR was made by the Society of Core Analysts[21]. A fairly great experimental dispersion of the electrical measurements made by 25 laboratories on model rocks was found. This is why we tested the reproducibility of our measurements, and we compared the two-electrode method with the four-electrode method for measuring the resistivity.

Reproducibility of Measurements

Figure 2 compares the IR/Sw relation obtained for two successive experiments performed on a carbonate sample (kg = 285 md) with the crude-oil/brine system. The operating conditions were identical for both tests (procedure and drainage rate, temperature, etc.). It can be seen that the IR/Sw relations are almost superimposed (saturation difference less than 0.5 % PV for a given value of IR) and lead to a value of n = 2.45 for both tests. The capillary pressure curves are also superimposed, with the exception of the terminal part where a difference of 0.7 % PV can be seen for the saturation at the maximum capillary pressure applied (29 psi). Considering the accuracy of the measurements provided by the apparatus, reproducibility is excellent. It can also be noted that the initial measurements (porosity, formation factor) are highly reproducible from one test to the other for the same sample (relative difference in porosity, $\Delta\O/\O$, less than 1 % ; relative difference in formation factor $\Delta FR/FR < 3$ %).

Comparison of Two-Electrode with Four-Electrode Resistivity Measurements

Figure 3 gives a comparison of resistivity measurements made during a drainage test performed on a sandstone sample. Starting with So = 9 % PV and until the end of drainage (So = 74.0 %), it can be seen that the ratio of the electrical resistance measured between the terminal electrodes, RAB, to the resistance measured between the intermediate electrodes, RMN, is constant and is equal to 1.54. This value of 1.54 corresponds, within 1.5 %, to the ratio of the distances between AB and MN. It can thus be concluded that the two measurement systems are equivalent, provided of course that the operating precautions given in Appendix A are respected.

Effect of Overburden Pressure on Formation Factor and Resistivity Index

Rock and Fluids Properties

The rock samples used in the present study come from a sandstone reservoir (Reservoir A) and a carbonate reservoir (Reservoir H), both having good intergranular porosity (10 to 20 % for the sandstone, 20 to 26 % for the carbonate) and a clay content of less than 2 %. Tables 1 and 2 give the principal properties of the samples. We investigated the influence of overburden pressure on the formation resistivity factor for 10 samples (4 from Reservoir A and 6 from Reservoir H).

The formation brines were reconstituted on the basis of analyses of the water from each reservoir. The electrical resistivities, Rw, were measured after the brines were placed in the presence of crushed rock material for about 1 week at reservoir temperature to reach chemical equilibrium. This precaution is indispensable with brines from carbonate reservoirs to prevent the dissolution under pressure of certain minerals (calcite, dolomite) at the intergranular interfaces where the stresss are concentrated.

Effect of Overburden Pressure on Porosity and Formation Factor.

Tables 1 and 2 give the relative variations of porosity, ΔØ/Øo,, and of formation factor, ΔFR/FR0, determined for an increase in stress from 3 to 20 MPa [435 to 2,900 psi]. Even though these variations differ somewhat from one sample to another, we computed the mean values for both reservoirs. We found that, with the increase in stress, mean relative porosity reduction was practically the same for both reservoirs (3.6 to 3.8 %). The mean relative increase in the formation factor, however, was greater for sandstone (15.2 %) than for carbonate (11.6 %).

Furthermore, a different behavior was found for the two types of samples, even though the rate of loading ($d\sigma/dt$) was of the same order of magnitude (0.3 to 0.5 Mpa/hr [43.5 to 72.5 psi/hr]). The sandstone was deformed immediately, whereas the carbonate underwent delayed deformation at each step of loading. Fig. 4 shows the reduction in PV with time for Sample 5. It shows that after a 3 MPa [435 psi] increase in stress applied in 8 hours, several days are required to obtain equilibrium. Equilibrium is indicated by the lack of variation of the PV during 2 days. At the last step of loading (from 16.7 to 20 MPa [2,420 to 2,900 psi]), it was necessary to wait for 14 days. Nonetheless, this deformation is reversible. After unloading, the PV and sample sizes were found to have returned to their initial values before the load was applied.

The variations in the formation factor as a function of porosity were determined at the two levels of overburden pressure investigated. Fig. 5 relates to Reservoir A (sandstone) and Fig. 6 to Reservoir H (carbonate). Although the number of samples was small and the porosity range restricted, we assumed that variations in the formation factor with porosity are represented by a law having the standard form $FR = \frac{a}{\text{Ø}^m}$. For sandstone (Fig. 5), we found different values for coefficients a and m, depending on the stress level : a = 1.38 and m = 1.66 for σ_0 = 3 MPa [435 psi], and a = 0.87 and m = 1.96 for σ = 20 MPa [2,900 psi]. On the other hand, Fig. 6 shows that variations in the formation factor of carbonate samples are effectively represented by a single equation ($FR = \frac{0.56}{\text{Ø}^{2.17}}$)at low and high effective stress. This relation concerns low-permeability samples (0.001 to 0.002 μm^2 [1 to 2 md] because we did not use the measurements made with Sample 5 (kg = 0.110 μm^2 [110 md]).

An analysis of these measurements shows that the impact of effective stress on the relation established between FR and Ø for carbonate is negligible. On the other hand, for sandstone, disregarding the influence of effective stress on FR and Ø leads to underestimating the formation factor, thus underestimating water saturation. The lower the porosity, the greater this underestimation will be. For instance, for Ø = 0.130 (Fig. 5), we find that FR = 41.0 forσ_0 = 3 MPa [435 psi] and FR = 47.0 for σ= 20 MPa. [2,900 psi] ; i.e., an underestimation of the formation factor by 15 %, which, in a clean reservoir with saturation exponent n = 2, would lead to underestimating Sw by 7.5 % in relative value.

Effect of Overburden Pressure on the Resistivity Index.

Fig. 7 (sandstone A) shows the influence of overburden pressure on the resistivity index during drainage. Drainage at high effective stress gives an excellent linear IR/Sw relationship for Sw values lower than 0.90 on a log-log diagram. But the extrapolation of this relationship with a constant slope n* for the Sw range between 0.90 and 1 does not meet the origin Sw = 1, IR = 1. This slight shift upward at the beginning of drainage is not clearly explained. Consequently, the value n* = 2.11 has been calculated from the best straight line running through the IR values obtained from Sw lower than 0.90. Following this approach it can be seen in Fig. 7 that the influence of effective stress is very slight ; n* increase from 2.08 to 2.11.

For the carbonate H (Fig. 8), we have reduced the two equations obtained in drainage to the best straight lines running through IR = 1 and Sw = 1. This also gives very close n-exponent values for both levels of effective stress : n = 1.65 (low stress) and n = 1.63 (high stress). The restoration of the effective stress on the carbonate does not significantly affect the n-exponent value.

It is interesting to note that the effective stress has an effect for the carbonate sample on the value of Siw obtained at the end of drainage. For an identical level of capillary pressure (0.2 MPa [29 psi]), Siw is lower at high effective stress (0.194) than at low effective stress (0.226). This difference of ΔSiw = 3.2 % PV is significant because it is 10 times higher than the accuracy of saturation measurements. For the sandstone sample, no difference was observed in Siw values.

These findings should not be systematically generalized to other reservoir rocks.

Resistivity Index – Comparison Between Drainage and Imbibition.

We tried to check whether the resistivity/water-saturation law is the same when water saturation decreases (drainage) or increases (imbibition). Naturally, in evaluation of initial oil reserves, the drainage curve is the most useful one because this is the process that probably took place when the hydrocarbons were being deposited. In some reservoirs (or some parts of a reservoir such as the transition zone), however, oil was probably displaced by imbibition during its history in the reservoir. Likewise, for evaluating saturations in a reservoir that has already been subjected to waterflooding, the imbibition curve is the one that should be used.

Figure 9 shows the resistivity index curves obtained for the strongly water wet sandstone A. A first drainage followed by an imbibition and then by a second drainage were performed. The corresponding capillary pressure curves are given Figure 10. Actually, it was found that a resistivity hysteresis corresponds to the well-known hysteresis for capillary pressure, because of a different distribution of fluids during drainage and imbibition. During the first drainage, Archie's equation is effectively verified with a value of n=2.08 for the saturation range covered (from Sw=1 to Siw=0.28). During imbibition, however, two values of slope n* can be determined, n*=d(log IR)/d(log Sw). For Sw=0.38, a great change in slope n* can be detected. The values of n* as a function of the water saturation range are for 0.28<Sw<0.38, n*=2.56 and for 0.38<Sw<0.586, n*=1.56 (Fig. 9). For a given resistivity index value, the corresponding water saturation is less on the imbibition curve than on the drainage curve. The maximum difference observed was ΔSw=4% PV for IR=6. During the second drainage, the curve for the variation of IR is similar to the one obtained during imbibition, except in the 0.586-to-0.38 range of water saturation (2%

PV for Sw offset). For water saturation values lower than 0.38, these curves can be superposed.

Similar experiment has been conducted on a carbonate sample from reservoir H. For drainage, the resistivity/water-saturation equation has the form defined by Archie up to Sw=0.45, with n=1.58. A Sw=0.45, a change of slope is observed. The average value of n* calculated in the 0.45-to-0.226 range is 1.83 (Fig. 11). In this figure, a resistivity hysteresis can also be seen between drainage and imbibition. The imbibition curve can also be separated into two parts, with two values of n* depending on the Sw range ; for 0.226<Sw<0.37, n*=1.80 and for 0.37<Sw<0.448, n*=1.23.

As opposed to sandstone A, water saturation with a fixed IR value is greater during imbibition than during drainage. The maximum difference (ΔSw=5.3% PV) is obtained at the end of imbibition with Sw=0.488 in the zone where n*=1.23.

These measurements have been performed on two strongly water wet samples. Due to the limited number of tests, these results can not be generalized. Howewer it must be noticed that drainage imbibition saturation exponents are different.

Effect of Wettability on Electrical and Capillary Properties

The aim of this part was to determine the possible variation of n with the wettability index for reservoir rocks having different wettabilities. For this, we systematically performed two capillary drainages per sample, first with refined oil (Soltrol 130) and then with crude oil from the reservoir. The samples were first cleaned to make them as water wet as possible, and their wettability was assessed. Then, after preparation of the core, the first drainage was performed with the refined oil. After the samples were cleaned again, their surface state was restored and the wettability was evaluated with the brine/crude oil pair. After preparation of the core a second drainage was performed with the crude oil.

Rock and Fluid Properties

The 9 rock samples used in this investigation come from four sandstone reservoirs (A, B, C and D) and three carbonate reservoirs (E, F and G). Their clay content was less than 2 %. Table 3 gives a brief geological description and their principal petrophysical characteristics. For the carbonate reservoirs E and F, one sample from the main two facies were investigated.

The brines were reconstituted on the basis of analyses of water from each reservoir and previously equilibrated by contact with crushed rock at reservoir temperature. The equivalent NaCl concentration of the different brines was in the range of 5 to 150 g/L, leading to resistivity values in the range of 0.02 to 0.120 Ωm at reservoir temperature. The main physical properties and chemical analysis of various crude oils are given in Table 4. The formation brine/crude-oil interfacial tension values were in the range 16 - 24 mN/m, depending on the reservoir.

Description of the results

Tables 5 and 6 give the wettability indices, Iw, and the saturation exponent values, n, obtained for each rock sample in both cases, i.e. after cleaning and with refined oil as displacing fluid and, then, after restoration with crude oil as displacing fluid. It is recalled here that Iw can have values ranging from + 1 (strongly water-wet) to - 1 (strongly oil-wet). Iw = 0 means that the core has no preferential affinity for either oil or brine (neutral or intermediate wettability).

The results are separately commented hereafter following the nature of the rock.

• Sandstone reservoirs (Table 5)

After cleaning, 3 out of 4 samples were strongly water wet (Iw >= +0.90). In spite of a cleaning with a quite sophisticated procedure, the last sample (from reservoir D) remained of neutral wettability ($Iw \sim 0$). Meanwhile, for all these cases, similar values were obtained for n (between 2.0 and 2.08 - considered as standard values for sandstone reservoirs).

After restoration, the sample from the reservoir A remained strongly water wet (Iw = + 0.82). The samples from reservoirs B and C initially strongly water wet became respectively oil wet (Iw = -0.30) and neutral (Iw = 0.02). The sample from the reservoir D, neutral after cleaning remained neutral after the restoration procedure. For 3 out of 4 samples, n is higher after restoration (9 to 41 %). The main increase for n, from 2.05 up to 2.90 was observed for the sample B, which was initially water wet and became oil wet after restoration. Fig. 12 shows the IR/Sw relationships obtained on this sample with refined and with crude oil. The last sample (from the reservoir D) showed a slight decrease in the value of n.

- **Carbonate reservoirs (Table 6)**

After cleaning, the five carbonate samples were neutral or even oil wet (Iw = -0.28 for sample E1 and Iw = - 0.52 for sample F1). n strongly changes from one reservoir to another one (from 1.58 to 2.39). Similar changes are also observed from one facies to another one for a given reservoir (2.23 for E1 and 1.68 for E2.).

After restoration, for 3 samples (E1, E2 and F2) the rock becomes more hydrophobic (Iw = - 0.35 to - 0.88). For these samples, n obtained after restoration is higher than n obtained after cleaning (from 9 to 30 %). Conversely, for sample G, where wettability was not affected by restoration, n does not significantly change (2.39 to 2.21).

The sample F1 has a strong vugular nature and some vugs or microfractures are filled with bitumen which was in impossible to remove by cleaning. Fig. 13 shows that the IR/Sw relationships obtained after cleaning and after restoration are identical. This is not surprising since no wettability change was observed. But, the relationships are not of the type proposed by Archie ($IR = Sw^{-n}$) with n constant for all Sw values. The relation has the form defined by Archie solely at the beginning of drainage, until Sw = 0.7 (n = 2.41). Afterwards, for Sw < 0.7, a great change in slope is seen. The value of n^* [$n^* = d(\text{Log } IR)/d(\text{Log } Sw)$] is 1.28 for the saturation interval between 0.35 and Siw = 0.18. The porosimetric characterization of the rock by mercury injection linked the form of the IR/Sw relation to the structure of the porous medium. The volume of the vugs corresponds to about 26 to 28 % of the total porosity. This assessment confirms the value of Sw = 0.7 for which the change in the value of n^* is found. The vugs and some fissures, locally impregnated with bitumen, are oil wet and lead to a relatively high value of n^* (n = 2.41) for a carbonate. Subsequently, the invasion by oil of the intergranular porosity, which is less oleophilic than the vugs, causes a progressive decrease in the value of n^* (n^* = 1.28

in the vicinity of Siw). The slope of the straight line running via the origin and via the last drainage point gives a value of n = 1.58.

The capillary pressure curves (Pc/IFT versus Sw) are compared in Figure 14. They are superimposed in the water saturation interval between Sw = 1 and Sw = 0.6. Then, for Sw < 0.6, they are offset by about 4 % PV in saturation. Considering the bimodal structure of the porous network, this difference of 4 % PV must not be considered as meaningful, and this is all the more so as the two curves seem to attain the same limit at the end of drainage.

Sample E1 has also an interesting behavior. It has a preferential affinity for oil (with a slight mixed wettability nature)[22]. This is observed in the spontaneous displacements wettability test and confirmed when comparing adimensional capillary pressure curves (Pc/IFT), presented in Fig. 15. The curve obtained with crude oil is below the one obtained with soltrol 130 in the Sw interval between 0.7 and 0.3. For example, at Sw = 0.35, the crude-oil/brine Pc/IFT is four times lower than the Soltrol 130/brine Pc/IFT. The relative position of these curves suggests that larger pores invaded preferentially at the start of drainage are wetted on the average by crude oil. On the contrary, smaller pores corresponding to the vicinity of Siw seem to be water wet no matter what oil is used for drainage, since the asymptotic parts of the Pc/IFT curves are similar (Figure 15).

The IR/Sw relations obtained with both oils are compared in Figure 16. It can be seen that the value of n measured with the crude oil is 10 % higher than that obtained with the refined oil, i.e. 2.45 and 2.23 respectively. This difference is greater than the accuracy of the measurements. It undeniably shows that n increases when the affinity of the rock for oil increases (Iw going from - 0.28 to - 0.88). For this sample, which was already partly oil wet after cleaning, the increase in n is relatively slight.

Tentative Synthesis

Figure 17 gives the value of n versus the wettability index (Iw) for all the samples. The arrow shows the direction of variation of Iw and n when going from cleaning to restoration.

Whatever the nature of the rock, it is observed that for 7 out 9 samples, n increases when the affinity of the rock for water decreases. This result is in agreement with previous results obtained in similar investigations. It is explained by the fact that, if the rock is oil-wet, the brine is less well connected that if the rock is water wet. At a given water saturation, in an oil-wet system, there is more disconnection and isolation of globules of brine than in a water-wet system. A portion of brine is trapped or isolated where it is unable to contribute to electrical conductivity. As a consequence, the resistivity of the core increases. It can be noticed that no value of n is higher than 2.90. The greatest increase in n is obtained for the Sandstone E that was initially strongly water-wet after cleaning and became quite strongly hydrophobic after restoration. However, even without any significant variation in the wettability index, the value of n seems to depend on the nature of the oil (refined or crude) when the rock is neutral (Samples D and G).

As a consequence, in all cases, it is thus recommended that crude oil be used for assessing saturation exponent from laboratory tests. If not, the n-value should be underestimated, leading to an overestimation of initial oil in place.

CONCLUSIONS

1. The porous-plate technique combined with the four-electrode measurement of electrical resistivity was adapted to the reservoir conditions. The accurate and reproducible determination of the capillary pressure and resistivity index was possible under reservoir conditions.

2. The influence of overburden pressure on cementation factor is stronger in sandstone samples than in carbonate ones. Due to the small number of plugs investigated, this finding cannot be generalized. However a series of laboratory measurements under stress is indispensable especially for low porosity sandstone.

3. The impact of the restoration of overburden pressure on the n-exponent value depends on the type of reservoir rock. For the sandstone studied, n increases slightly when the stress increases. For the carbonate, n decreases slightly, as does Siw.

4. The resistivity/water-saturation is not one-to-one. It depends on the microscopic distribution of fluids, hence on the direction of saturation variation (drainage or imbibition). For the strongly water-wet samples studied,

the drainage/imbibition relationships are not very different since a maximum difference of 5% PV of saturation was observed.

5. The study of the dependence of saturation exponent on wettability, performed for a limited number of samples did not enable the results to be generalized. However, the following tendencies were observed.

5.1. The four samples from sandstone reservoirs were neutral or strongly water wet after cleaning. After restoration of the surface state, the affinity for oil increased appreciably for only one sample, the other three remaining neutral or strongly water-wet.

5.2. The five samples from the three carbonate reservoirs were neutral or clearly oil wet after cleaning. After restoration of the surface state, the affinity of the rock for oil increased appreciably for three samples and remained stable (neutral or strong for oil) for the other two samples).

5.3. The value of n increased when the affinity of the rock for oil increased. A maximum increase of about 40 % for n was found when the initially water-wet sandstone became strongly oil wet. In this case, the value of Siw is underestimated by 50 % when a value of n determined under nonrepresentative conditions of in situ wettability is used.

5.4. For sandstone and carbonate samples which were neutral or strongly water wet after cleaning, and for which no significant change was observed in wettability after restoration, the value of n determined by crude-oil drainage was different from the one obtained with refined oil. In all cases it is thus recommended that crude oil be used for assessing n in the laboratory.

5.5. On the other hand, for a vuggy carbonate sample strongly hydrophobic after cleaning and restoration, the nature of the oil had no influence on the resistivity/water-saturation relation. However, this relation did not have the form defined by Archie ($IR = Sw^{-n}$). The equation consisted of two straight-line segments in a log-log diagram. In this case, it is recommended that n be assessed in as wide a water-saturation range as possible.

5.6. For carbonate reservoirs, the n-value can greatly be affected by the pore structure. As a consequence, it is strongly recommended to evaluate n on a representative sample from each facies.

Nomenclature :

a = structural parameter in Archie's equation
FR = formation resistivity factor
IR = resistivity index, Rt/Ro
kg = permeability to gas (air or nitrogen), md
m = cementation factor
n = Archie's saturation exponent
p = pressure, psi [kPa]
Pc = capillary pressure ; for water/oil system, Pc = po - pw, psi [kPa]
Ro = resistivity of rock sample 100 % saturated with brine,Ω.m
Rt = rock resistivity when saturated with brine and oil (or gas), Ω.m
Rw = resistivity of brine, Ω.m
Siw = interstitial water saturation
So = oil saturation
Sw = water (brine) saturation
T = temperature, °F [°C]
γ = IFT or surface tension, mN/m
σ = effective stress=external pressure-pore pressure, psi [kPa]
Ø = porosity

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Table 1. Sandstone rock properties, Reservoir A

	Sample			
	1	2	3	4*
Gas permeability at $\sigma_o = 3$ MPa (md)	10	10	7.3	40
Porosity at $\sigma_o = 3$ MPa, ϕ_o	0.144	0.150	0.195	0.184
Formation resistivity factor at σ_o, 3 MPa, F_{RO}	33.7	33.1	21.3	22.1
Porosity at $\sigma = 20$ MPa, ϕ	0.137	0.143	0.189	0.181
Formation resistivity factor at $\sigma = 20$ MPa, F_R	40.4	41.4	23.2	23.6
$\Delta \phi/\phi_o = [(\phi_o - \phi)/\phi_o]$ 100	4.9	4.7	3.1	1.6
$\Delta F_R/F_{RO} = [(F_R - F_{RO})/F_{RO}]$ 100	19.9	25.1	8.9	6.8

* Sample used for I_R measurements.

** Porosity under stress is calculated from $\phi(\sigma) = (V_{po} - \Delta V_p)/(V_{to} - \Delta V_p)$, where V_{po} = PV at σ_o, V_{to} = total volume at σ_o, and ΔV_p = reduction in PV.

Table 2. Limestone rock properties, Reservoir H

	Sample					
	1	2	3	4	5*	6
Gas permeability at $\sigma_o = 3$ MPa (md)	1.1	1.5	1.7	1.9	110	1.2
Porosity at $\sigma_o = 3$ MPa, ϕ_o	0.204	0.231	0.246	0.241	0.260	0.261
Formation resistivity factor at $\sigma_o = 3$ MPa, F_{RO}	17.4	13.3	11.4	12.3	13.3	10.4
Porosity at $\sigma = 20$ MPa, ϕ	0.197	0.225	0.236	0.231	0.249	0.249
Formation resistivity factor at $\sigma = 20$ MPa, F_R	19.1	14.6	12.4	13.6	15.8	11.7
$\Delta \phi_o/\phi_o = [(\phi - \phi_o/\phi_o)]$ 100	3.4	2.6	4.1	4.1	4.2	4.6
$\Delta F_R/F_{RO} = [(F_R - F_{RO})/F_{RO}]$ 100	9.8	9.8	8.1	10.6	18.8	12.5

Table 3. Rock Properties

Reservoir	Kg (md)	ϕ (%)	F_R	m	Geological Description
Sandstone A	40	18.4	22.1	1.84	Micaceous and Felsparic Sdst with minor chlorite and kaolinite
Sandstone B	900	21.9	17.1	1.87	Porous Felsparic Sdst. with Kaolinitic cement - Presence of Pyrite.
Sandstone C	72	30.5	8.2	1.77	Fine Sdst. with micaceous and argillaceous beds.
Sandstone D	480	23.4	14.0	1.82	Fine to medium Sdst. with calcareous cement.
Carbonate E1	285	18.5	21.4	1.82	Bioclastic Miliolae and Micritic Limestone
E2	15	18.4	26.0	1.92	Grainstone-Packstone Limestone with pellets and echinoderm fragments
Carbonate F1	14	18.6	88.0	2.66	Vuggy dolomicrosparite-Vugs up to 4 mm in size- Bitumen in vugs and cracks.
F2	55	15.0	55.0	2.11	Dolomicrite with minor quartz-Some pellets + oolithes
Carbonate G	505	25.3	15.6	2.00	Lime Grainstone - Packstone with intergranular and matrix porosity.

Table 4. Physical Properties and Chemical Analysis of Oils

Oil	Viscosity at 20°C (mPa.s)	Density at 20°C (Kg/m3)	Analysis (wt, %)			
			Saturates	Aromatics	Resins + Asphaltenes	Residue
Refined	1.8	756	16.0	Monocycloparaffins		
(Soltrol 130)			84.0	Isoparaffins		
Crude A	8.8	812	61.4	22.4	13.3	2.9
Crude B	9.2	851	69.9	19.1	11.0	-
Crude C	17.3	882	64.3	26.5	9.2	-
Crude D	8.9	814	79.0	12.1	8.9	-
Crude E	7.7	804	40.1	31.3	19.6	9.0
Crude F	9.1	870	70.0	28.0	2.0	-
Crude G	6.9	838	51.1	38.1	8.4	2.4

Table 5. Sandstones
Saturation Exponent (n) Versus Wettability Index (I_W)

Sample	Oil	Temperature (°C)	After Cleaning I_W	After Cleaning n	After Restoration I_W	After Restoration n
A	Soltrol 130	40	+ 0.96	2.08		
A	Crude A	40			+ 0.82	2.26
B	Soltrol 130	97	+ 0.90	2.05		
B	Crude B	97			- 0.30	2.90
C	Soltrol 130	74	+ 0.90	2.00		
C	Crude C	74			+ 0.02	2.47
D	Soltrol 130	115	+ 0.04	2.03		
D	Crude D	115			+ 0.09	1.93

Table 6. Carbonates
Saturation Exponent (n) Versus Wettability Index (I_W)

Sample	Oil	Temperature (°C)	After Cleaning I_W	After Cleaning n	After Restoration I_W	After Restoration n
E1	Soltrol 130	80	- 0.28	2.23		
E1	Crude E	80			- 0.88	2.45
E2	Soltrol 130	80	+ 0.07	1.68		
E2	Crude E	80			- 0.46	2.19
F1	Soltrol 130	100	- 0.52	1.58		
F1	Crude F	100			- 0.58	1.58
F2	Soltrol 130	100	- 0.07	1.60		
F2	Crude F	100			- 0.35	1.96
G	Soltrol 130	96	- 0.08	2.39		
G	Crude G	96			+ 0.04	2.21

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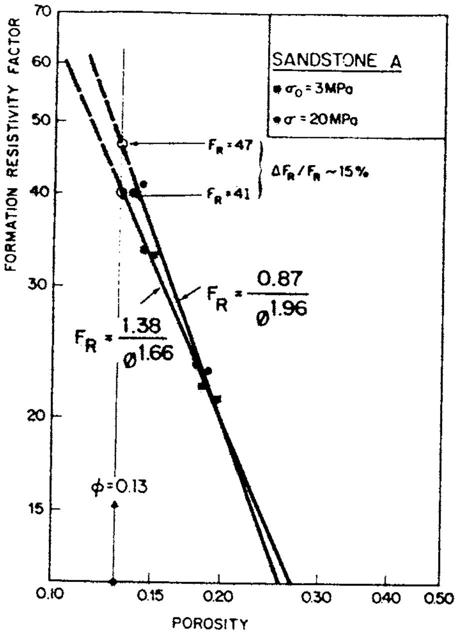

Fig. 5 - Formation factor vs. Porosity for sandstone samples at two stress levels.

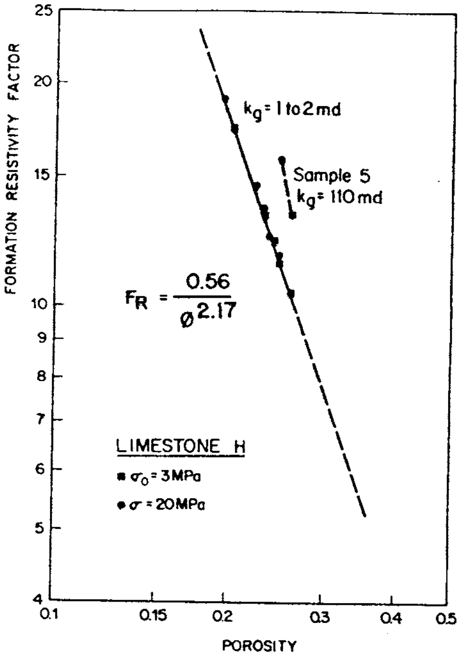

Fig. 6 - Formation factor vs. Porosity for carbonate samples at two stress levels.

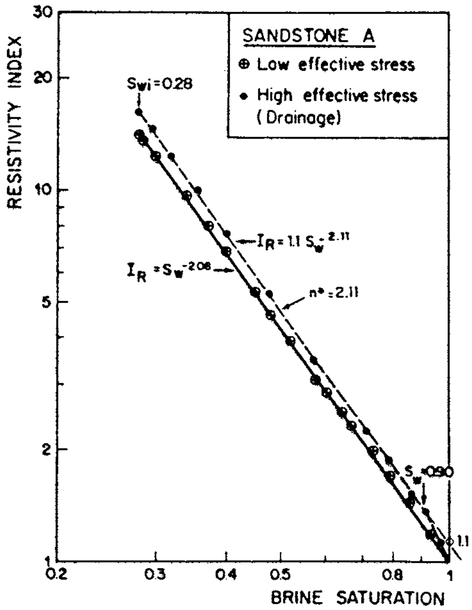

Fig. 7 - IR vs. Sw for a sandstone sample. Illustration of the increase of n due to the restoration of overburden pressure.

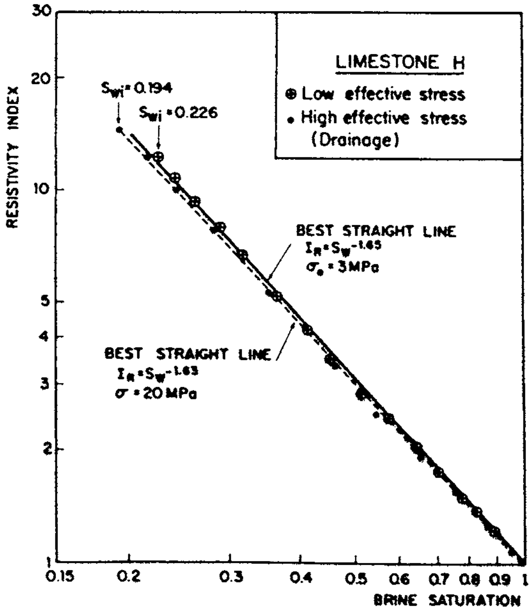

Fig. 8 - IR vs. Sw for a carbonate sample. Illustration of the slight decrease for n due to the restoration of overburden pressure.

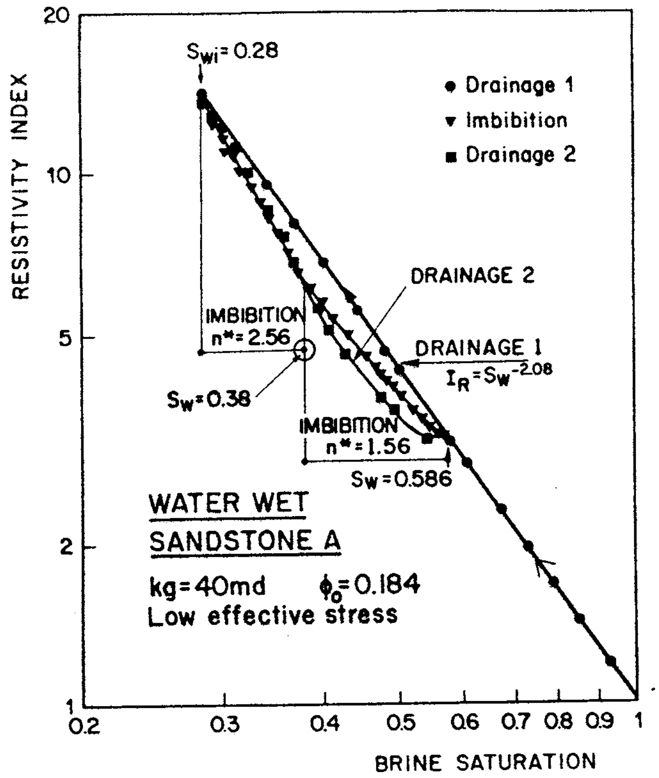

Fig. 9 - IR vs. Sw for a sandstone sample. Illustration of the hysteresis between drainage and imbibition.

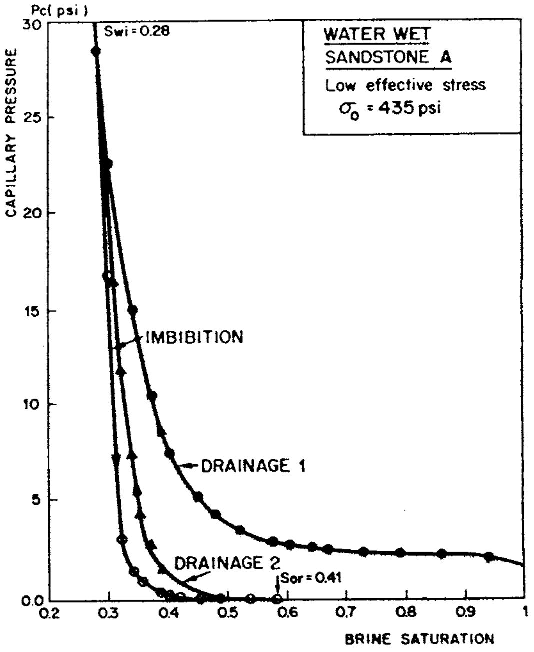

Fig. 10 - Capillary Pressure curves vs. Sw. Illustration of the hysteresis between drainage and imbibition.

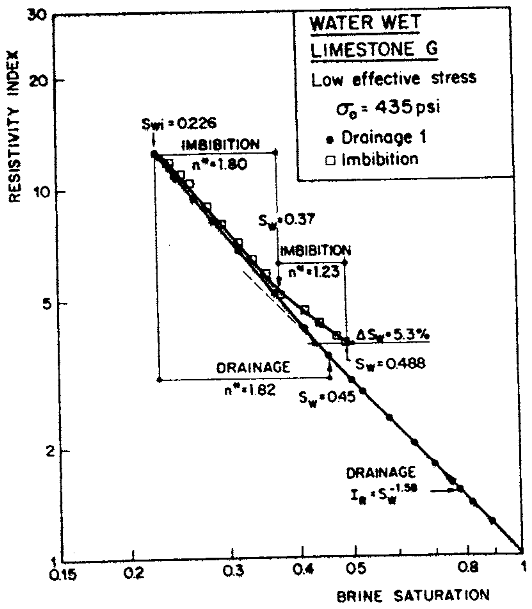

Fig. 11 - IR vs. Sw for a carbonate sample. Illustration of the hysteresis between drainage and imbibition.

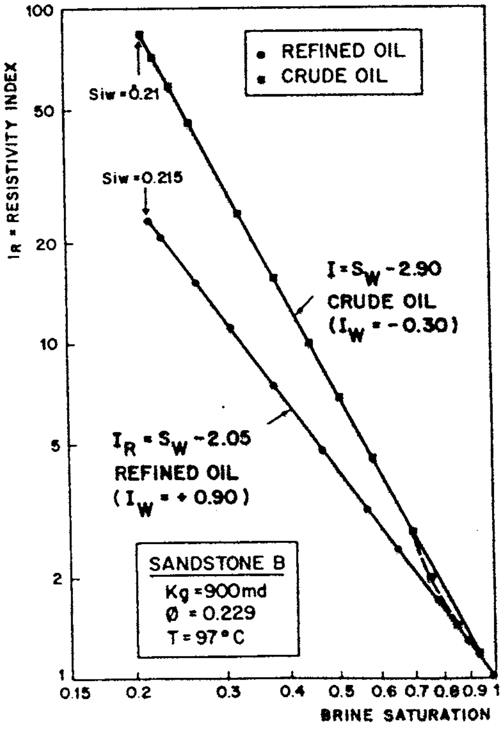

Fig. 12 - Comparison of IR vs. Sw for sandstone B. Illustration of the effect of wettability on n. n increases as the core becomes more oil-wet

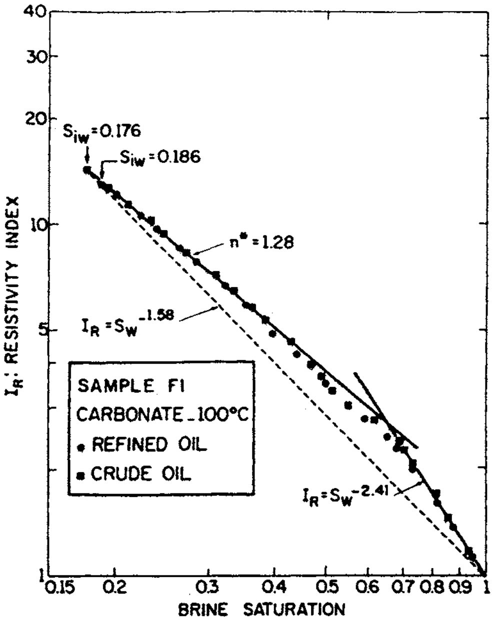

Fig. 13 - IR vs. Sw for a vuggy carbonate sample. Illustration of change in n as a function of Sw range. Absence of effect of the nature of the oil (crude or refined) on the IR/Sw relationship.

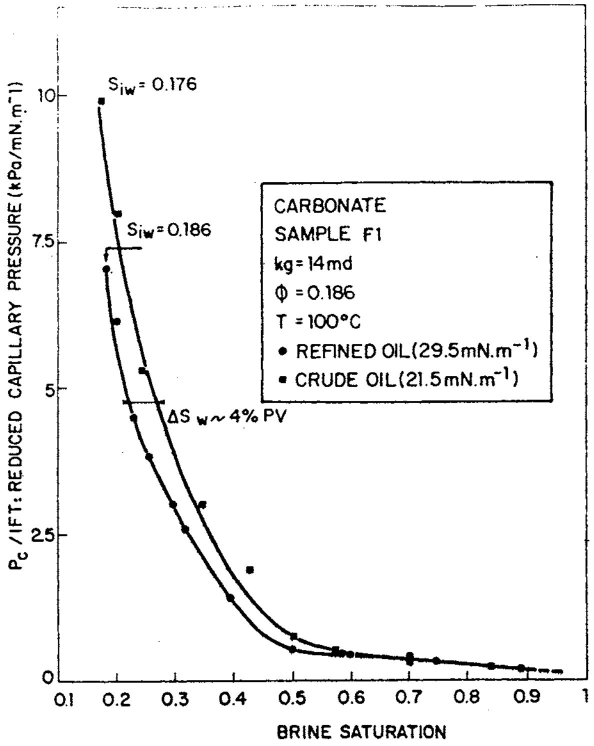

Fig. 14 - Comparison of oil-water Pc curves vs. Sw obtained on a vuggy carbonate sample with crude oil (Iw = - 0.58) and with refined oil (Iw = - 0.52).

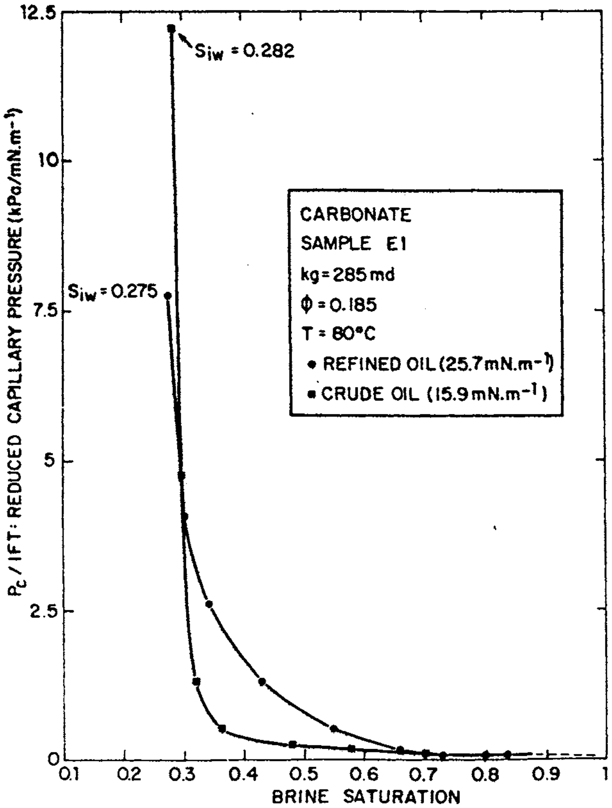

Fig. 15 - Comparison of oil-water Pc curves vs. Sw obtained on a carbonate sample with crude oil (Iw = - 0.88) and with refined oil (Iw = - 0.28).

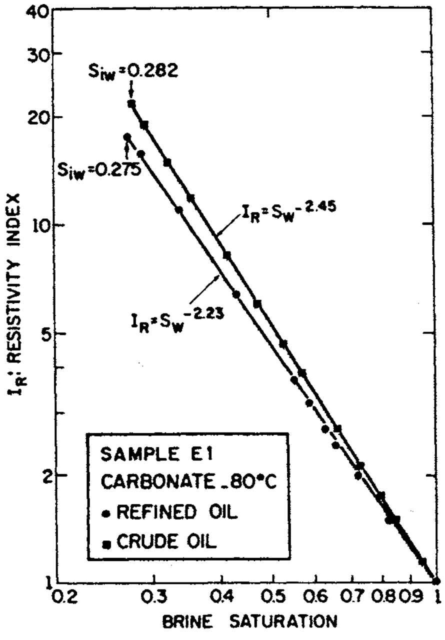

Fig. 16 - Comparison of IR vs. Sw for a carbonate sample. Illustration of the effect of wettability on n. n increases as the core becomes more oil-wet.

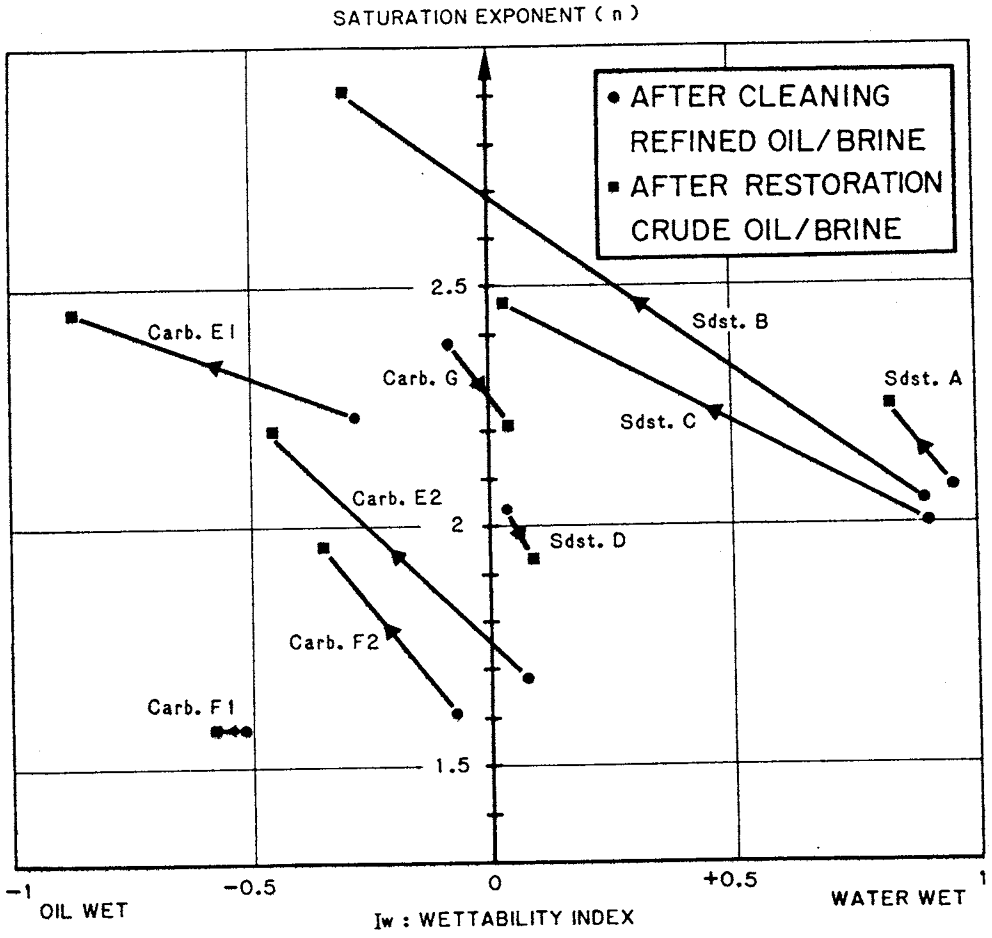

Fig. 17 - Saturation exponent values vs. Wettability indices for sandstone and carbonate samples.