METHODOLOGY FOR DETERMINING THE DISTRIBUTION OF WETTABILITY FROM LABORATORY AND WELL LOG MEASUREMENTS FOR A MICROCRYSTALLINE/MICROFOSSILIFEROUS CARBONATE FIELD

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Abstract

Knowledge of the wettability characteristics of reservoirs can be an important parameter to evaluate and manage waterfloods and Enhanced Oil Recovery projects. This paper will present methods and initial results from a study that obtained wettability data in the laboratory and compared it to the apparent wettability obtained from conventional well logs in extensively flooded zones of high porosity, low permeability microcrystalline/microfossiliferous carbonate reservoirs.

A data base of laboratory spontaneous imbibition measurements was obtained from extracted reservoir core plugs. These plugs had been extracted with mild solvents to a wettability state believed similar to that occurring in the reservoir. Wettabilities of the plugs were determined by either an Amott Water Index or a Spontaneous Imbibition Index (ratio of measured spontaneous imbibition to highly water wet imbibition). Apparent wettabilities for the reservoir were obtained from water saturations measured by conventional well logs and saturations based upon capillary pressure correlations. Comparisons of the wettability determined in the laboratory with the apparent wettability from well logs showed similarities. Apparent wettability appeared to vary within different formations and with the porosity of the reservoir rock. The moderate to strongly water-wet character of this reservoir rock provided a probable basis for the success of a waterflood in the highly fractured reservoirs of the field and may point the direction for additional Enhanced Oil Recovery.

Introduction

Wettability is a parameter that can be measured in the laboratory on reservoir core material by a variety of methods, but no well logging tools have yet been developed which can provide a direct measure of wettability in the reservoir. The most ambitious efforts to develop such a tool have been in the area of Nuclear Magnetic Resonance (NMR) in which some studies using NMR to measure wettability have proven successful for chalk by Howard and the author[1] in the laboratory. Field trials using NMR to provide a quantitative measure of wettability are much more difficult than laboratory studies and have yet to reach fruition.

However, opportunities can and have occurred that allow estimates to be made of the apparent wettability of reservoirs from conventional well logs. Previously the author[2] introduced a methodology by which the apparent wettability of a reservoir formation could at times be obtained from evaluating the well logs of a drilled well through a formation containing hydrocarbons. This paper will extend a similar type of methodology using well logs to reservoir zones which have seen extensive water-flooding and also will endeavor to show that observed variations in the apparent wettability supported the underlying assumption in the applied methodology.

Experimental

Cylindrical plugs from the reservoir cores were extracted by mild solvents to remove wettability artifacts that can be introduced by reservoir crude oils when cores are brought from reservoir to ambient conditions. It was postulated that the strongly bound organic films control wettability behavior for the reservoir rock in this study and the extraction method was selected to preserve these films. Baldwin[3] stated that appropriate extraction can remove crude oil and still retain the more strongly bound organic films on pore surfaces. Extracted core plugs were re-saturated with n-decane and brine using the centrifuge with an angled head to obtain uniform initial water saturations. Magnetic Resonance Imaging (MRI) was used to verify the procedure for obtaining uniform saturations. Spontaneous imbibition was conducted on the bench-top using glass imbibition cells to volumetrically measure the volume of oil produced. Forced residual oil saturations were also obtained by centrifuge using an angled head. The final saturation states of the plugs were determined by extraction.

The reservoir saturations after water-flooding were obtained from well logs using an Archie[4] calculation. The well logs used for interpretation consisted of formation density tools for porosity, and a dual induction log or dual laterolog for deep resistivity. An extensive laboratory study by the author[5] previously established the interpretation parameters that were applied in the Archie calculations for the reservoir water saturations used in this study.

The reservoir rock composition was determined by mass spectroscopy. The quartz content was calculated from the silicon fraction.

Concepts

The concept of a Spontaneous Imbibition Index (SII) as a measure of wettability was previously introduced by the author[2] as the ratio of the measured spontaneous imbibition for porous media to the spontaneous imbibition that would occur if the porous media were highly water wet. It varies from 0 for no water imbibition to 1 for highly water-wet imbibition. The highly water-wet behavior of reservoir rock was obtained by a correlation in the laboratory (see Appendix A). The value of SII is equal to or slightly greater than the Amott Water Index (WI). One advantage to using SII versus WI was that once the highly water-wet correlation is determined, it reduced the measurement of wettability for each additional plug to solely a spontaneous imbibition test. The correlation equation used for wettability in this study was

$$SII = \frac{Swf - Swi}{\phi^b (1 - Swi)^c} \quad \text{..........}(1)$$

where the measured spontaneous imbibition is expressed by the numerator and the highly water-wet spontaneous imbibition correlation is in the denominator. The exponents"b" and " c" could potentially vary for different reservoir rock, but for this study were fixed at 0.17 and 2.25, respectively for all reported SII values. This equation, as obtained from laboratory data, was used subsequently to obtain the apparent wettability from well logs. To apply the equation to a reservoir requires only the determination of the in-situ saturations in the reservoir.

For a well drilled through a formation which has been flooded extensively by water, Swf is obtained from the deep well log readings and Swi must be obtained by capillary pressure calculations or other means for the connate water saturation. To be meaningful, this assumes the saturation, Swf, to be established by the capillary pressure behavior of the reservoir rock so that it represents a spontaneous imbibition saturation end-point rather than a viscous displacement saturation end-point.

Results and Discussion

To determine if capillary forces for spontaneous imbibition or viscous forces dominate the ultimate displacement of hydrocarbons in the reservoir required comparing the displacement behavior of the reservoir rock in the laboratory with the behavior of the reservoirs designated A and B in this study. Laboratory application of viscous forces appeared to drive the reservoir rock to an increasing water saturation end-point with increasing porosity (Figure 1) and to an increasing water saturation end-point with decreasing water wetness (Figure 2). In contrast, the water saturation end-point from spontaneous imbibition would increase (by definition) with increasing water-wetness. If the water saturation from forced displacement is used to calculate SII, the value of SII would be equal or greater than one (Figure 3). Thus, changes in water saturations for the water-flooded reservoir zones that calculate a SII greater than or equal to one are zones which may be viscously displaced. If the reservoir zones have been extensively flooded and SII is significantly less than one, the reservoir zone was considered to be at a spontaneous imbibition end-point and the calculated apparent wettability was meaningful.

It would be expected that a reservoir could spatially have some varying degrees of capillary dominated and viscous dominated displacement. To eliminate this ambiguity, only zones which had under gone extensive waterflooding were evaluated in this study. It will be shown below, that the zones examined for these reservoirs clearly show capillary domination of the oil displacement process and consequently provided validation for the calculated apparent wettabilities.

Laboratory Wettabilities. The reservoir core plugs used in the laboratory study of wettability came from various wells and formations. For the two selected formations, the purity of the microcrystalline/microfossiliferous carbonate varied significantly between them with formation A containing little quartz and formation B containing varying amounts of quartz. There was no attempt to establish a causal relationship between the varying wettability and the composition of the reservoir rock for the two formations. The quartz content of the reservoir rock can affect the capillary pressure relationship to water saturation and was used primarily for developing capillary pressure correlations.

Apparent Wettability for Formation A in Well A. Formation A was waterflooded in a pilot test of the original A well with the injection of over 20 million barrels of sea water. A twin well A was sidetracked approximately 50 to 100 feet away after the pilot was completed and provided an estimate of the water-flooded saturations (Swf) for formation A. To obtain the initial connate water saturation (Swi) for the twin well A, a capillary pressure curve was derived using a neural net to match the connate water saturation in the original well which was subsequently applied to the twin well. Input to the neural net was depth, porosity and quartz content of the reservoir rock. It was trained to an average error of 4 percent. Knowing Swf and Swi, Equation 1 was applied to the well log data and the resultant apparent wettability in terms of SII versus depth of the twin well A is shown in Figure 4. Depth is reflected as a normalized depth which is merely a reference to a particular depth divided by a convenient depth interval. As defined, normalized depth allowed direct comparisons between common zones in a structured reservoir. The thickness of formation A is in excess of 200 feet.

The wettability variation of the flooded zone with porosity (Figure 5) and water saturation variation with porosity (Figure 6) are inconsistent with viscous displacement and non water-wet reservoir behavior. The downward trend of water saturation with porosity would not be expected for viscous displacement of the hydrocarbons since the higher porosity rock was more permeable and should preferentially flood. If the reservoir was flooded to the viscous end-point, the water saturation in the reservoir would be expected to increase with porosity as in Figure 1. The trend from the well logs, however, is more consistent with the trend exhibited by the spontaneous imbibition end-points of Figure 1. A similar argument can be made for wettability variation which tracks with the water saturation. Calculated wettabilities less than one indicated capillary dominated displacement of the hydrocarbons. The zone below the normalized depth of 1.3 is less clear as the apparent wettability approaches one. However, the abrupt change in wettability was due to a sudden change in porosity from 30 plus percent to about 20 percent. This portion of the zone was consistent with the wettability and water saturation trends of the rest of formation A. This formation appears to be strongly water-wet with capillary domination of the hydrocarbon displacement process.

Apparent Wettability for Formation A in Well B. Formation A in the initial well B was a waterflood injection well for over 5 years that was sidetracked after casing collapse. Its replacement well was drilled about 200 feet from the initial injection well. This well is located nearly on the opposite side of the field from well A. Swf was obtained from the saturations measured in the replacement well. The initial well B did not have a good suite of well logs, so to determine Swi, a neural net was used to derive a capillary pressure curve from the pre-waterflood well logs of a nearby producing well in the same manner as described previously. It was trained to an average error of 7 percent (this is more than adequate for accuracy). Equation 1 was used to calculate the apparent wettability (Figure 7). The same trends (Figures 8 and 9) and the same arguments apply to formation A of well B as applied to formation A of well A. Formation A in this well appeared strongly water wet and the hydrocarbon displacement appeared to be capillary dominated. The increase in water-wetness below a normalized depth of 1.25 occurred without the significant porosity decrease similar to that which occurred in well A, but the overall wettability-porosity trends still prevailed. This well confirmed the results found in well A.

Apparent Wettability for Formation B in Well B. This formation was flooded along with formation A, but was at a different depth. The interval evaluated in this formation exceeds 300 feet. Swf was obtained from the log saturations. Swi was calculated from a capillary pressure correlation derived from a neural net match of the pre-waterflood well logs of the same interval in a nearby well. It was trained to an average error of 4 percent. The apparent wettability versus normalized depth (Figure 10) and the trends with porosity (Figures 11 and 12) supported the same conclusions reached previously for formation A. More of this formation appeared to be moderately water-wet (normalized depth interval 0.2 to 0.45). The increase in water saturation at the bottom of this formation was not a zone of decreasing porosity, but appeared to be a zone of decreasing quartz content of the reservoir rock.

The apparent wettability measured in these reservoirs appeared to be consistent with the production behavior of the field in which they resided. The ongoing waterfloods are producing little water compared to injected quantities which tends to confirm the water-wet character of the field. The inability of viscous displacement to recover movable oil near injection wells suggests that EOR may be warranted. For a reservoir where the oil recovery is dominated by spontaneous imbibition of water, one possibility would be to make the reservoir more water-wet with chemical additives.

Conclusions

1) Apparent wettability can be calculated from saturations that are determined by conventional well log interpretations for zones in some reservoirs that are extensively water-flooded.

2) The variation of apparent wettability with porosity and the variation of log measured water saturation supported the key assumption in the methodology, that spontaneous imbibition was the dominant oil displacement mechanism in these carbonate reservoirs.

3) Variations in apparent wettability were different for different formations, but the examined formations ranged from moderate to highly water wet.

4) The water wetness of the microcrystalline/microfossiliferous carbonate rock decreased with increasing porosity.

5) Laboratory determination of saturations and wettability using extracted core plugs provided an initial estimate of reservoir wettability and potential reservoir behavior under viscous and capillary dominated hydrocarbon displacement. The laboratory spontaneous imbibition results indicated wettabilities that were similar to apparent wettabilities for the reservoir.

Acknowledgments

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Nomenclature

a	Constant
b	Constant
c	Constant
DSw	Change in water saturation from spontaneous imbibition
DSwh	Highly water-wet change in water saturation from spontaneous imbibition
DSwf	Change in water saturation from forced imbibition
ϕ	Porosity
SII	Spontaneous Imbibition Index
Swf	Water saturation after forced displacement or spontaneous imbibition of water
Swi	Initial water saturation or connate water saturation
WI	Amott Water Index

References

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3. Baldwin, B. A.: "Water Imbibition and the Characterization of North Sea Chalk Reservoir Surfaces," SPE preprint 14108 (1986); SPE Formation Evaluation. Vol. 3., 125-130 (1988).

4. Archie, G. E.: "The Electrical Resistivity Log as an Aid in Determining Some Reservoir Characteristics," Petroleum Technology (January, 1942).

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Appendix A

The Spontaneous Imbibition Index (SII) is defined as:

$$SII = \frac{DSw}{DSwh} \qquad \text{(A-1)}$$

It is an index only for water-wet porous rock as defined, but could be defined for any wetting fluid. The highly water-wet denominator was determined by developing correlation which relied on the Amott water index (Note that extracted core plugs in this study do not spontaneous imbibe oil and consequently, water indices are equivalent to the Amott Relative Displacement Indices). A relationship of the form (assuming that Swf versus WI was linear in the range of interest, WI > 0.2) was proposed:

$$DSw + DSwf = (a - a * WI) + \phi^b (1 - Swi)^c \qquad \text{(A-2)}$$

and rearranged to result in a quadratic equation of the form:

$$a * WI^2 - (a + \phi^b * (1 - Swi)^c) * WI + DSw = 0 \qquad \text{(A-3)}$$

which was solved for WI. The laboratory determined Swi, DSw, porosity, and WI were measured on a set of 37 reservoir core plugs. By a non-linear least squares regression of the one viable solution to the quadratic equation, the correlation parameters, a, b, and c, were determined as 0.075, 0.17, and 2.25 respectively. The square of the residuals was 0.98, indicating an excellent fit of the laboratory data. Recognizing that the Amott water index is one when highly water-wet and that the forced imbibition component is zero, the correlation for highly water-wet imbibition of the reservoir rock was obtained from equation A-2 as:

$$DSwh = \phi^b (1 - Swi)^c \qquad \text{(A-4)}$$

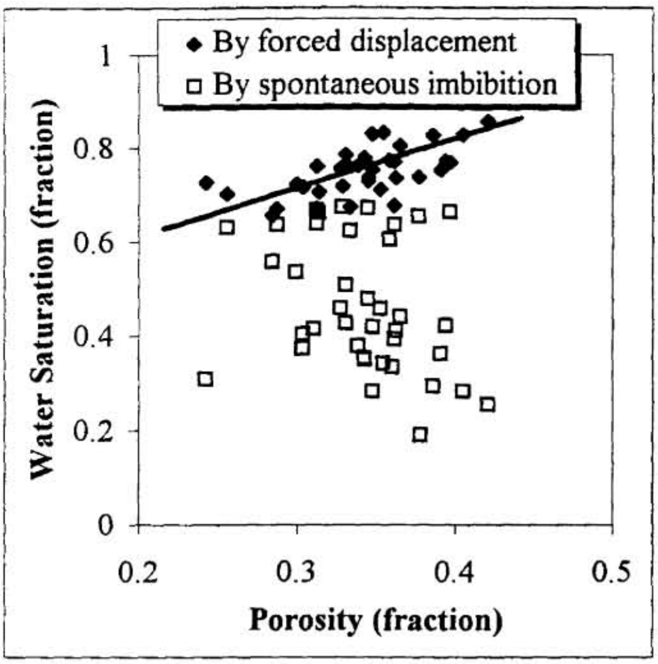

Figure 1 - Water saturation variation with porosity from laboratory measurements.

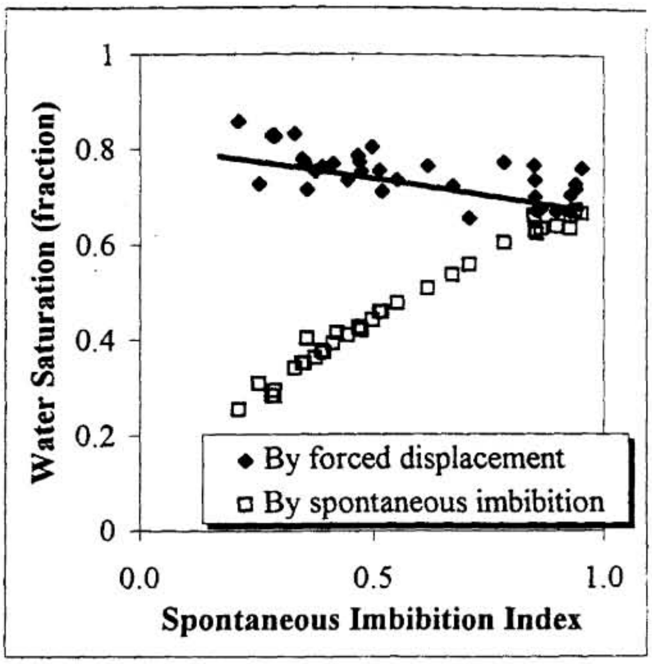

Figure 2 - Water saturation variation with wettability from laboratory measurements.

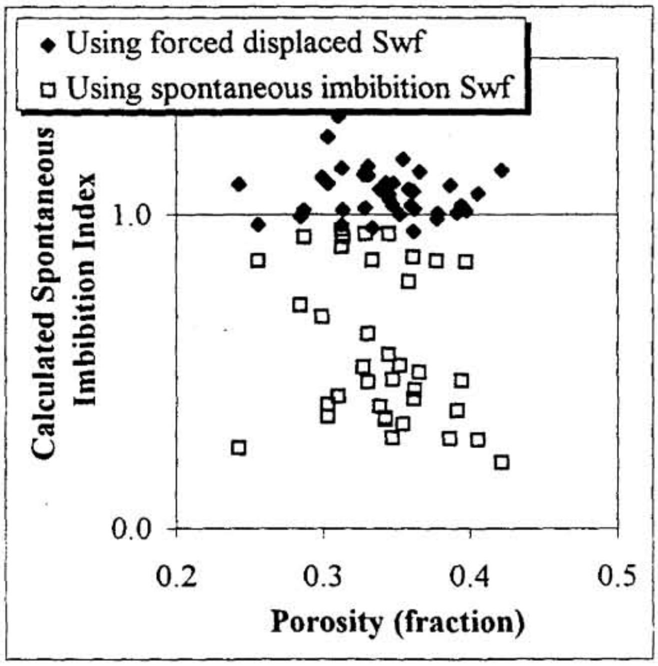

Figure 3 - Calculated wettability variation with porosity from laboratory measurements.

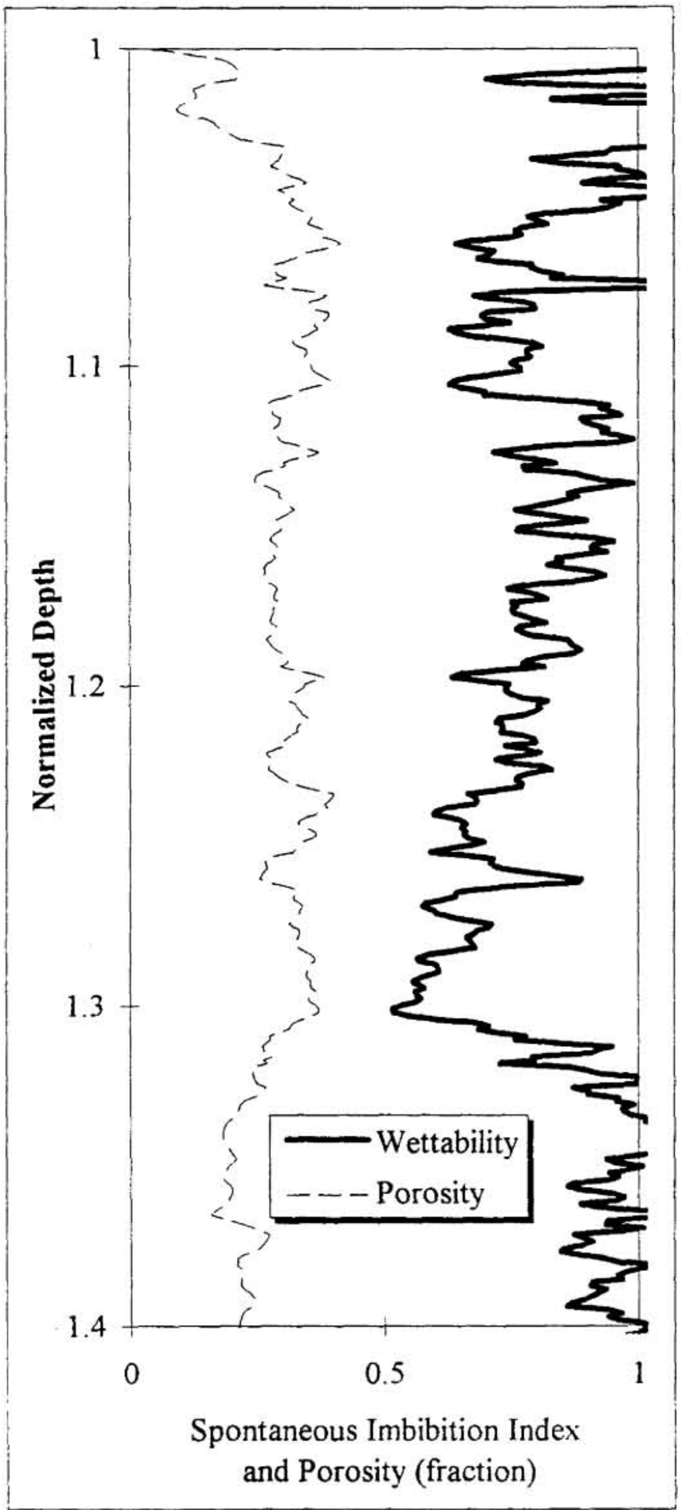

Figure 4 - Wettability and porosity variation with depth for formation A of well A.

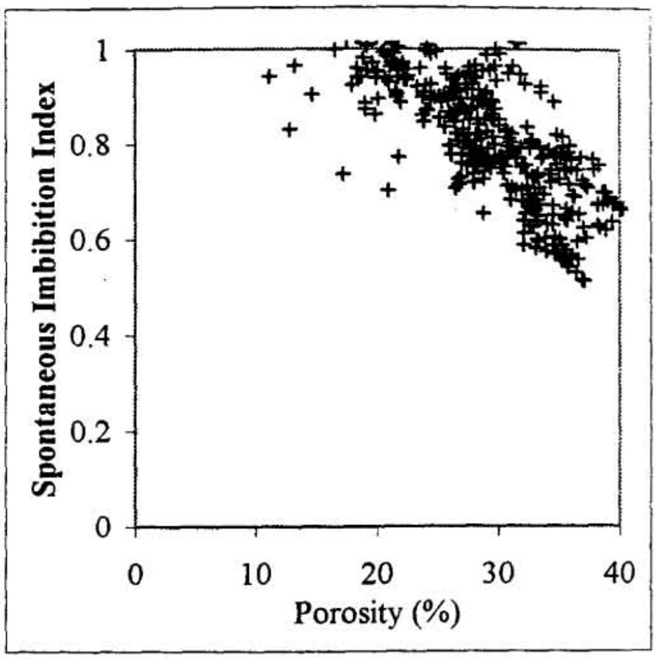

Figure 5 - Wettability variation with porosity as for formation A of well A.

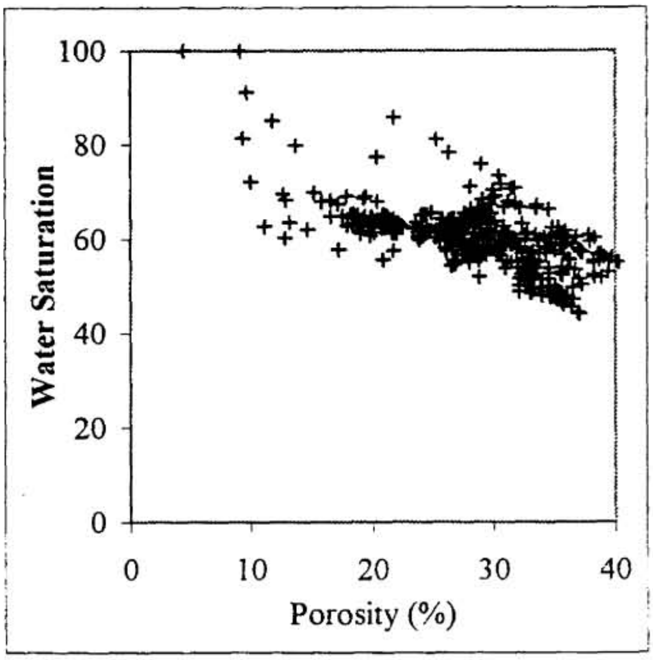

Figure 6 - Water saturation variation in the flooded formation A of well A.

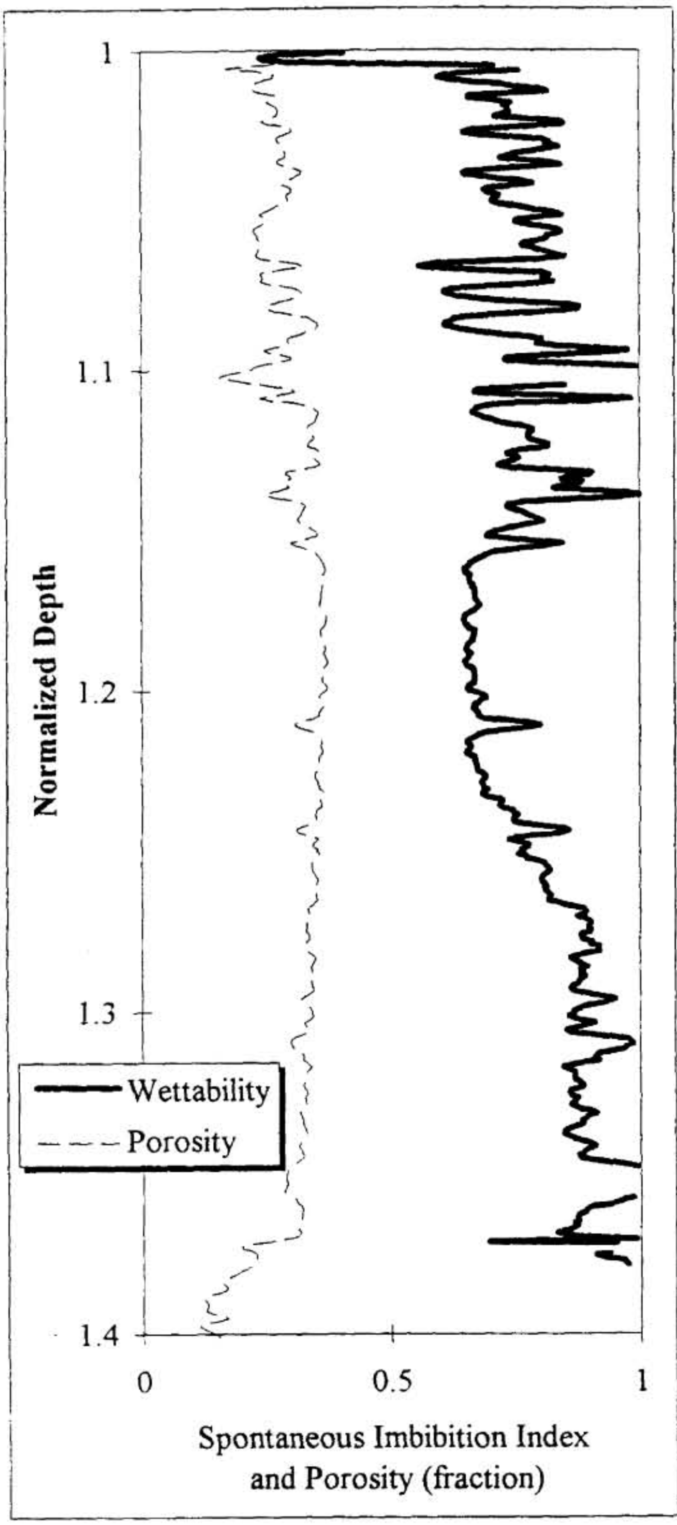

Figure 7 - Wettability and porosity variation with depth for formation A of well B.

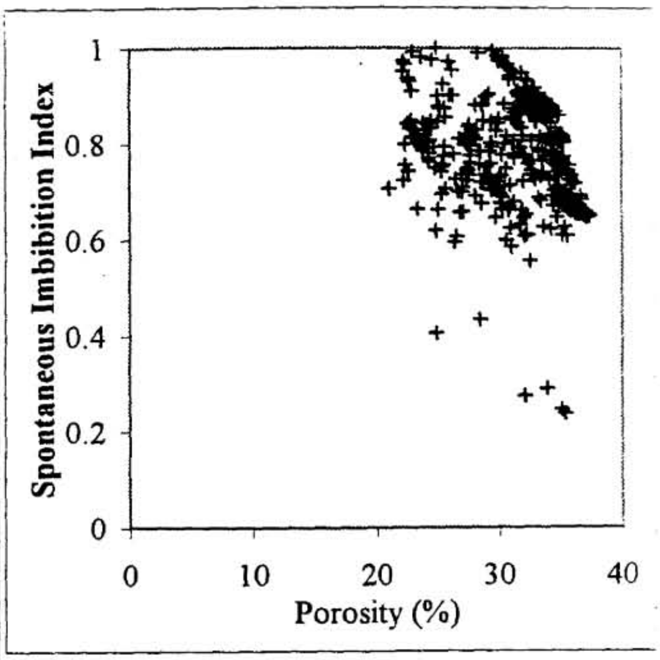

Figure 8 - Wettability variation with porosity as for formation A of well B.

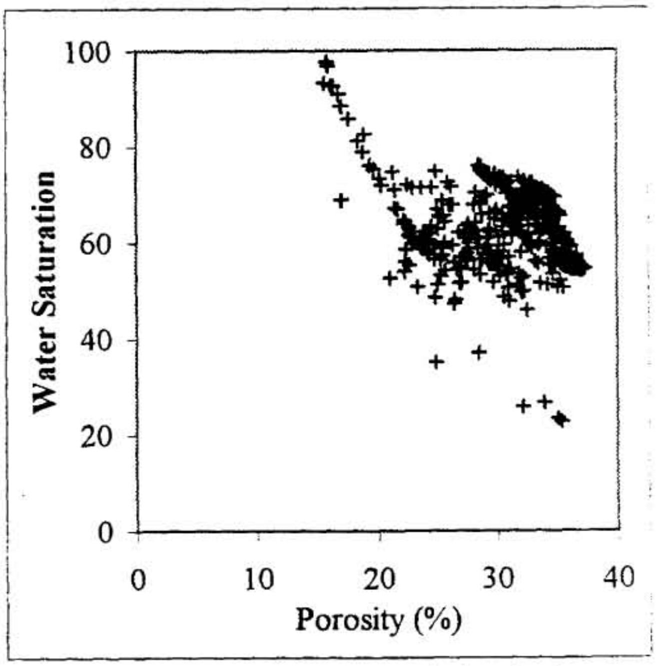

Figure 9 - Water saturation variation in the flooded formation A of well B.

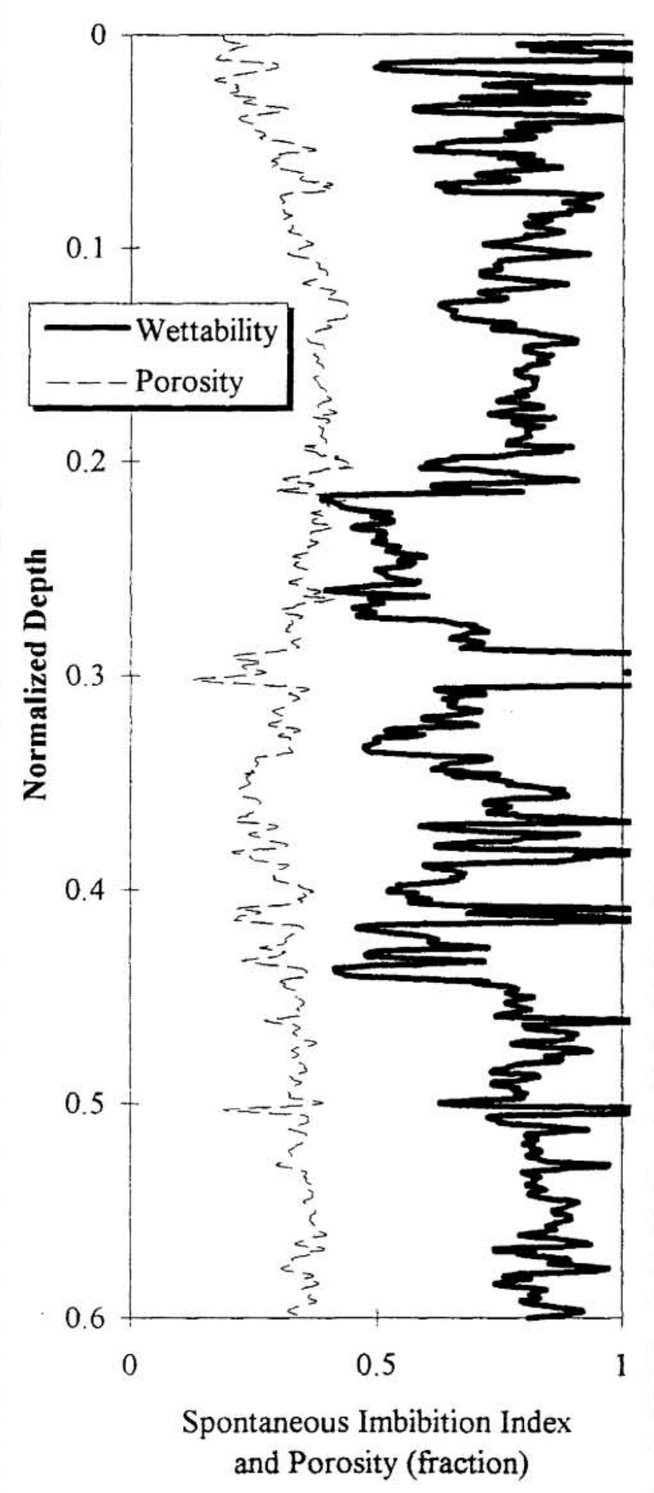

Figure 10 - Wettability and porosity variation with depth for formation B of well B.

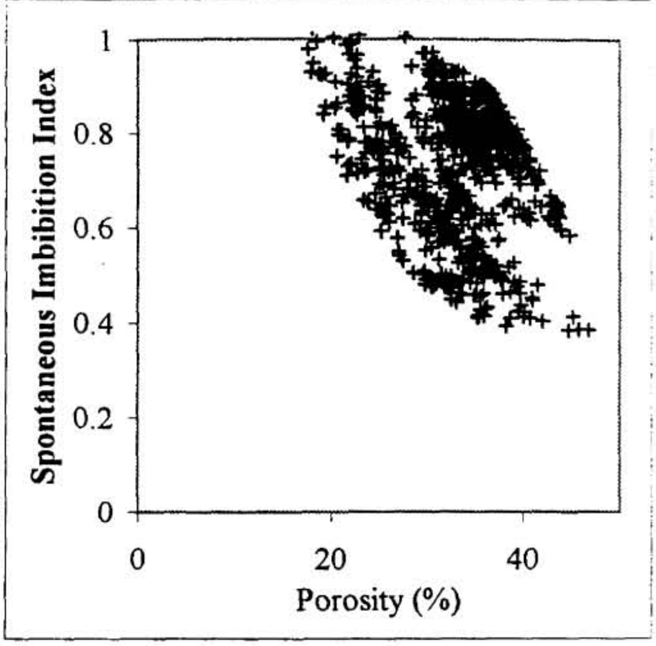

Figure 11 - Wettability variation with porosity as for formation B of well B.

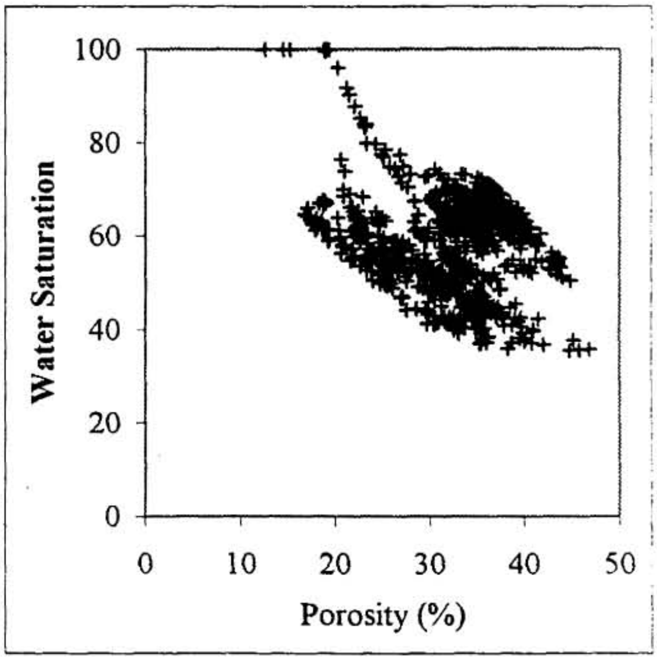

Figure 12 - Water saturation variation in the flooded formation B of well B.