ELECTRICAL RESISTIVITY AND FLUID DISTRIBUTION OF COEXISTING IMMISCIBLE PHASES

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ABSTRACT

Water saturation is commonly estimated from resistivity measurements using Archie's equations. Archie's equations state that the resistivity, ***Rt***, will depend only on the porosity for a given rock, ϕ, the water resistivity, ***Rw***, and the water saturation, *Sw*, ($Rt = a\, Rw\, \phi^{-m}\, Sw^{-n}$). The determination of the needed saturation exponent, ***n***, is based on laboratory core experiments and should therefore be independent of the method used (capillary equilibrium, continuous injection, etc.). In this work we demonstrate that this assumption is flawed. We show firstly that the fluid distribution within the pore structure affects resistivity and secondly that different displacement processes can affect the fluid distribution, and hence the resistivity. Thus, because the laboratory method for obtaining different saturations within the core affects the fluid distribution, using a particular value of ***n*** to estimate the formation water saturation must always be treated with caution.

An experimental study of the influence of flow displacement methods and fluid characteristics (interfacial tension and viscosities) upon the electrical resistivity of partially saturated media with immiscible phases has been carried out. Visual, quasi 2-dimensional models that allow the observation of the phase distribution whilst the resistivity is being measured have been used. The electrical current is transported by the ions in the water so the water distribution at the pore level will influence the resistivity. We demonstrate that even if the water saturation has a macroscopic uniform distribution within the porous medium this is not always so at the pore scale, and therefore the rocks' resistivity will be affected. This is because the electrical paths at the pore scale are made up of resistivity components; these are the basic elements for the overall resistivity of the porous medium. Using our visual observations of fluid saturations plus qualitative analysis of flow and fluid distribution at the pore scale within our micromodels we show that the changes in make-up of the resistivity components such as partially invaded pores-throats or water films, for our water-wet and oil-wet porous media have an influence on the macroscopic resistivity. The implications for resistivity measurements are discussed.

INTRODUCTION

This work is concerned with the qualitative influence of fluid displacement and rock and fluid properties upon electrical resistivity of partially saturated media.

The water saturation for hydrocarbon reservoirs is calculated from well logs using methods based on core experiments and Archie's equations. Log interpreters use Archie's equations[1,2] to obtain the water saturation, i.e.,

$$Sw = \left[\frac{Rw\, a}{Rt\, \phi^{m}} \right]^{1/n} \qquad (1)$$

where ***Sw*** is the water or brine saturation, ***Rw*** is the brine resistivity, ***Rt*** is the resistivity of a rock filled with brine and oil, ϕ is the porosity, and ***a, m, n*** are empirical constants obtained from core data in the laboratory. The saturation exponent, ***n***, is determined by replacing some of the brine by oil or gas, thereby changing the water saturation, and increasing the resistivity. According to Archie's equation the

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resistivity should be independent of the method used to achieve the saturation changes, since ***Rt*** and ***Sw*** are the only variables considered in equation (1). Therefore the same value of saturation should give the same value of ***Rt*** even if different experimental methods and fluids are used, i.e. the saturation exponent should be a constant.

There has been much discussion of the effect of the different variables on Archie's relationships[8-11, 14] and it has been amply demonstrated that the real situation is more complicated than Archie's equation will allow. For instance, the resistivity can vary with features not considered in Archie's equations such[5] as the pore structure, wettability, external and boundary conditions, etc.

In this paper the influence of fluid distribution at the pore level is the main aspect of resistivity studied. The objective of this work is to examine the effects of fluid displacements at the pore level on resistivity and identify the variables that influence the electrical resistivity. The electrical current is transported by the ions in the water so the water distribution at the pore level distribution will influence the resistivity. A previous paper[4] identified the needed pore scale resistivity components (defined in the Appendix) which carry the electrical current and quantified the effect of fluid distribution (phase separation) under static conditions. Now we wish to develop these arguments further to consider partially saturated porous media. Visual, 2-dimensional models, whose development has been reported previously[5], have now been used to observe the effect of phase distribution caused by different displacement processes.

Essentially the logical links are:

i. resistivity and fluid saturation is not unique,

ii. macroscopic uniform saturation does not mean pore level uniformity (pore level components of resistivity),

iii. the method of saturation change produces different fluid distributions and therefore affects the saturation index.

The electrical path at the pore scale is due to elements of conducting salt water. There are a number of different patterns, here called **resistivity components** (the Appendix gives the definitions). These are the basic elements creating the overall resistivity of the porous medium at a given water saturation. An analysis of the way the fluids are distributed and how this distribution is affected by viscosity, interfacial tension and fluid velocity in imbibition/drainage can indicate the way in which laboratory resistivity experiments should be conducted, especially in generating fluid distributions, to represent the reservoir conditions.

RESISTIVITY INDEX AND FLUID DISTRIBUTION CAUSED BY DISPLACEMENT

The influence of fluid structure on the resistivity index at constant saturation and fluid properties has been reported [4]. In order to understand the influence of fluid distribution (at pore level) upon the macroscopic electrical resistivity we have used a special technique to produce two liquid phases in-situ. The experimental method consisted in generating two liquid phases in-situ using the controlled phase behaviour of a system of three components (2,6-lutidine+water+NaCl). This system has a lower critical solution temperature and when heated above this temperature separates into two liquid phases, one rich in lutidine and the other water rich (and electrically conducting). Therefore, the two immiscible liquids are generated inside the model (in-situ). The resistivity was measured while microscopic observations of the fluids were carried out at the pore level over the whole micromodel. The fluid system has uniquely defined physical properties (interfacial tension, densities and viscosities at each temperature); more details can be found in references [4] and [5]. This method for generating the two liquid phases ensured a uniform *macroscopic* distribution of the fluids within the porous medium, but visual observations showed that this uniformity does not extend to the *pore level*. We found that different resistivity components can be formed at this level (see Appendix) which correspond to different arrangements of fluids. The phase distribution and corresponding resistivity was studied in water-wet micromodels with water saturation in the range 20 to 100%. The resistivity index values can be seen in Figure 1 as a function of water saturation. The changes in resistivity index were due to changes in fluid distribution since in our experiments all the other variables remained constant. Changes of up to 40 % can be seen. Observations of the fluids in the micromodels at the pore level showed that an increase of drops/ganglia size left some pores filled only with water while others were filled with a large "oil" ganglia with a thick water film. As the conduction paths had different combinations of resistivity elements for our water-wet models, the resistivity decreased with the increase in size of non-wetting ganglia. The value of resistivity was dependent on the fluid characteristics, their distribution structure and the saturation.

We have now developed our technique further to study the effect of fluid displacement and rock and fluid properties, including oil-wet porous media, upon two-phase fluid distributions at the pore level and their consequent effects upon resistivity.

INJECTION OF IMMISCIBLE FLUIDS

The displacement of one fluid by another within a porous medium is a complex process and depends on several variables, including the wettability of the solid (e.g. water-wet or oil-wet), the physical properties of the fluids (viscosities, densities and interfacial tension) and the rate of injection of the displacing phase. The displacements can be classified as drainage (decrease in the wetting fluid saturation) or imbibition (increase in the wetting fluid saturation). During displacements, the flow mechanisms that occur at the pore scale affect the fluid distribution within the porous media, and therefore will influence the values of resistivity. This is because the electrical resistivity in partially saturated media is affected by the brine saturation but also depends strongly on the position of the fluids within the porous medium.

We shall now examine the influence of the flow displacement and fluid characteristics on the resistivity behaviour. We have made a qualitative analysis of how water saturation, fluid viscosities, velocities and interfacial tension affect the fluid distribution at the pore scale and the resistivity index. Our experiments in partially saturated micromodels and the external conditions used reproduce the fluid distribution and phenomena that occur when the techniques of capillary equilibrium and continuous injection are used.

Flow Displacement Mechanisms

The fluid flow within a core or a reservoir; i.e. intermediate and macroscopic scales are the result of many pore level displacement events. These events are initiated by an imposed condition (pressure or rate), but are affected by the interaction of the local pore structure with viscous, capillary and gravitational forces[7]. The advancement of the front can be described as a series of head and neck menisci movements (Figure 2). These menisci separate the oil phase from the water phase and through their movement a phase invades the adjacent pores/throats.

Different displacement processes and flow zones can be defined at different scales [15]. Figure 2 shows the displacement zones for oil injection into a water-wet medium. These are:

a. Darcy flow of oil, where the pressure field is constant.
b. Transition oil zone, where the pressure field responds to pore scale events and saturation changes.
c. Zone of active jumps, where the pore scale displacement **controls** the pressure field.
d. Transition water zone, where the pressure field depends upon pore scale events.
e. Darcy flow of water, where the pressure field is again constant.

The zone of active jumps (c) moves along the porous media as the oil front advances. The dynamics of the events occurring in zone c govern the distribution of fluids in the zone behind the front, so the mechanics of these processes and their effects cannot be ignored in the interpretation of electrical resistivity. As a result of the pore scale events the fluid distribution and flow at higher scales (intermediate and macroscopic) may differ quite dramatically.

The zones relevant to electrical resistivity behaviour are:

i. Reservoir at water level (zone e in Figure 2, for a rock fully saturated with water).
ii. Original reservoir conditions (zone a during drainage in water-wet rocks or imbibition in oil-wet rocks).
iii. Invaded area near the wellbore (zones b/d and a during secondary imbibition or secondary drainage).

The electrical resistivity components and fluid distribution are a function of:

rock	- pore structure characteristics and wettability (oil- or water-wet).
fluid properties	- viscosity ratio between displacing and displaced fluids.
	- interfacial tension between phases, including spreading coefficients[7].
experimental conditions	- rate of injection of the displacing fluid.
	- imbibition or drainage (again wettability effects).

The influence of fluid velocity, viscosity and interfacial tension on the spatial fluid distribution are different during drainage and imbibition processes[15] . In the following sections only the effect of viscosity ratio will be described in detail, but the influence of other variables are summarised in Table 1.

Experimental

The measurements and observations were performed in glass micromodels which are 2-dimensional and transparent networks of pores and throats. The glass micromodels are initially strongly water-wet but oil-wet conditions can be achieved by treating the model with Repelcote (dimethyl-dichlorosilane). The experimental set-up used has been described previously [5, 6]. The displacing fluid is injected at a constant rate using a syringe pump. All the experiments were performed horizontally to avoid gravitational effects. The fluids used were: distilled water with aqueous glycerol solutions to increase the water phase viscosity when necessary, and decane and decane-liquid paraffin mixtures to increase the viscosity of the oil phases. Lisamine and Waxoline dyes were used to colour the water and oil phases when necessary.

Flow Fronts and Flow Scaling Parameters

The fluid characteristics and the pore structure affect the shape of the displacing front (transition zone) which in turn modifies the fluid distribution behind it and hence the resistivity values. The balance between capillary and viscous forces define the shape of the front and if the front is unstable the fingers size. If the transition zone travels through the porous medium with a length of only few pores it can be considered a flat front which leaves behind small clusters (ganglia) of the displaced fluid. When the transition zone has a length of tens of pores (with fingers) it is called a fingered front and leaves behind large ganglia or bypassed areas of the displaced fluid.

An appropriate dimensionless number for scaling our displacement experiments is the Capillary Number, N_{ca}, which relates the influence of the viscous to the capillary forces and can be expressed as;

$$N_{ca} = \frac{viscous\ forces}{capillary\ forces} = \frac{v.\mu}{\gamma} \qquad (2)$$

where v is the mean superficial velocity (front velocity), μ is the displacing fluid viscosity and γ is the interfacial tension. However, the capillary number does not identify all the variables that influence the displacement behaviour within the porous media, and so we use the relative viscosity as a complement to N_{ca}.. The relative viscosity is defined as the ratio of the viscosity of the displaced fluid to the viscosity of the displacing fluid ($\mu_{displaced}/\mu_{displacing}$). When the relative viscosity is greater than 1.0 the displacement is called unfavourable and when it is smaller than one it is called favourable. Although only two types of front are described here, there is a continuous variation between them as a function of the viscosity ratio, interfacial tensions and rate of injection.

Primary Drainage

Drainage is the increase of the saturation of the non-wetting phase and is called *primary* when the porous medium is fully saturated with only the wetting phase (fully saturated) at the beginning of the displacement. The process is controlled by events occurring in the centre of the pores-throats, so that the wetting fluid diminishes the influence of the surface rugosities and irregularities. At the pore scale the flow type can be piston like or Haines jumps or snap-off [12] depending on the pore to throat aspect ratio. The larger pores-throats are filled with the non wetting phase during the displacement and a film of wetting fluid is left on the solid. At low flow rates (lower N_{ca}) the capillary forces (interfacial tension and size of the channel) dominate the displacement, but at higher rates (higher N_{ca}) and/or a viscosity ratio (lower than 1.0) the viscous forces control the displacement.

Effect of Viscosity Ratio on Displacement and Resistivity: The effects of viscosity ratio on displacement fronts are shown in Figure 3 for a water-wet model where the aqueous phase was dyed with Lisamine red (black in the figures). At low viscosity ratios, below 1.0 (favourable displacement) the front is quite flat with only a few small fingers. The water left behind the front is located in single channels and thin films. Only a small saturation range (lower water saturations) can be achieved after the front reaches the end of the model. For viscosity ratios greater than 1.0 (unfavourable displacement) the front is highly fingered with fingers which extend over tens of pores. The water is left in large clusters (group of pores-throats) due to the by-passing of these regions. The water films are thick due to the low efficiency of the oil displacing water at the pore level. In this case, the water continues to be produced after the front arrives at the end of the model, removing the remaining water through film flow. After a "uniform" macroscopic saturation is obtained there is still a wide range of water saturation that can be obtained.

Clearly the resistivity behaviour during these various drainage experiments will be quite different. Under the favourable viscosity ratios, when a uniform saturation is achieved, the resistivity will be high because the paths will be formed by thin water films and partially invaded pores; i.e., components I and III (see Appendix). On the other hand, when unfavourable viscosity ratios are used, the resistivity will be low due to the abundance of bypassed clusters and thick films of water, and the conduction path is through non-invaded pores-throats and water films (components II and I).

Primary Imbibition

Primary imbibition is the increase of saturation of the wetting phase. For primary imbibition the porous medium at the beginning of the displacement is fully saturated with the non-wetting fluid. This process includes the migration of oil through a water saturated oil-wet rock and is dominated by the movement of oil wetting films on the solid surfaces. The advance of the wetting fluid (water in water-wet rock and oil in oil-wet rock) at the pore level is greatly influenced by the spreading characteristics of the fluid onto the solid, its rugosity and the velocity of supply of wetting phase (through filled pores and wetting films). As the non-wetting fluid can be completely or partially displaced (trapped by snap-off and by-passing) different flow types are possible (piston, snap off or film flow). In spontaneous imbibition and very low injection rates the capillary forces dominate the displacement, but in a different mode to that in the drainage case due to adhesion forces (forces between solid/ wetting fluid/ non-wetting fluid). However, at high velocities and viscosity ratios the viscous forces dominate the displacement in a similar way as for drainage [12].

Effect of Viscosity Ratio on Displacement and Resistivity: The fluid distribution mainly depends on the wettability but is independent of which of the fluids is in hydraulic continuity[*]. For simplicity only the case of oil injection into an oil-wet rock initially saturated with brine will be described. The effect of viscosity ratio is shown in Figure 4 for an oil-wet model, with N_{ca} of 10^{-6} and in these experiments the oil phase has been dyed with Waxoline blue. At high viscosity ratios (>1) the front is very fingered, trapping

[*] Two cases of imbibition can be considered; increase in water saturation in a water-wet rock or increase in oil saturation in an oil-wet rock. In both cases only the water phase can conduct the electricity so they will have different resistivity behaviour.

the non-wetting phase in by-passed areas and forming large clusters. As a result the electrical resistivity will be low while there is a continuous path along the filaments of water (component IV) but the resistivity will become high as soon as the water paths become disconnected (isolated water without the existence of conducting films, component V). As the viscosity ratio decreases, the front becomes flatter (the length of the fingers decreases) and the non-wetting phase is trapped in smaller clusters while at low viscosity ratios the non-wetting phase is trapped in isolated pores. The electrical resistivity will be very high and will approach the value of the non-conducting fluid. The non-wetting phase trapped behind the front cannot be re-mobilised unless some of the applied conditions change (injection rate, interfacial tension, etc.) and therefore, only a very small saturation range can be obtained after a 'uniform' saturation along the porous medium has been achieved.

Effect of Combined Effects (Change of Fluids): Other experiments consisting of imbibition of water (wetting fluid) in an air (non-wetting fluid) filled glass micromodels have been compared with the imbibition of water (wetting fluid) in a decane (non-wetting fluid) filled glass model. The difference between these displacements is only due to the effect of the different physical properties of the fluids and interactions with the solid. The effect of change of fluids is shown in Figure 5 for a water-wet model, where the water has been dyed with Lisamine red. At the same capillary number the decane-water displacement is more fingered and the invaded area has a completely different shape producing a different fluid distribution. The capillary number considers three variables (front velocity, displacing fluid viscosity and interfacial tension), therefore the viscosity ratio and wettability must be the cause of the changes in behaviour. As was shown previously the decrease in viscosity ratio makes the front more flat. The wettability (spreading characteristics) which has an influence on the dispersion of the front has the same effect as the viscosity ratio.

The front is fingered for the water-decane displacement and trap the non-wetting phase in large by-passed areas and forms large oil clusters. When a continuous path of water-filled pores exists along the model the electrical resistivity will be low. On the other hand, the water-air front is more flat, so that the non-wetting phase is trapped in smaller clusters and isolated pores. The resistivity will be very low (approaching the value of the conducting phase as the capillary number increases).

The ideal experiment for determining reservoir saturation by resistivity must use a core which represents the true reservoir rock under downhole conditions. The rock must have the original wettability under reservoir pressure and temperature, with the original fluid characteristics representing the results of the processes of oil migration into the reservoir and its equilibrium attained during millions of years. Such conditions are difficult to achieve in the laboratory. Therefore only a small set of data points can be obtained. On the other hand a large number of experiments can be carried out at ambient conditions and synthetic fluids. Nevertheless, the experiments at ambient conditions must be carefully performed so that their results can be compared and integrated with the reservoir conditions.

Further experiments are now being carried out on secondary displacements (both drainage and imbibition). A secondary imbibition process means that the rock has been filled with the wetting fluid and displaced to residual saturation by the non-wetting fluid (primary drainage), then (secondary process) displaced with the wetting fluid (secondary imbibition). A secondary drainage process occurs when the rock is initially filled with the non-wetting fluid, displaced with the wetting fluid (primary imbibition) and the secondary process is displacement by the non-wetting fluid (secondary drainage).

DISCUSSION

In core laboratories world-wide various experimental techniques[3] (porous plate, capillary equilibrium, continuous injection, steady state dynamic displacements, centrifuge, evaporation) have been used to study the influence of different variables such as wettability, hysteresis, pressure, temperature, etc. The differences cannot always be compared, because each technique produces a different fluid distribution. The fluid distribution is controlled by capillary, gravitational and viscous forces as well as wettability when the fluids move through a porous rock. Thus caution must be exercised before coming to major conclusions about resistivity measurements to determine water saturation.

The reservoir rocks, where oil is trapped are normally considered water-wet but surface active agents contained in the oil can be adsorbed onto the rock and alter the surface characteristics, thereby changing the wettability (to more oil-wet). If the rock in the laboratory is water-wet, the conducting fluid (brine) is also the wetting phase but if the rock is oil-wet the conducting fluid is now the non-wetting phase. The appropriate fluid distribution that represents the reservoir conditions and other processes, such as filtrate invasion, must be reproduced in laboratory resistivity experiments to ensure confidence in any conclusion of reserves based on the resistivity measurements in core tests. For example, does capillary equilibrium give the same distribution as that of constant injection? Do we get the same results if we use air-brine, paraffin-brine or a heavy oil-brine? The answer is "probably not", but the saturation exponent obtained under these different conditions are often compared. Also a saturation exponent derived in the laboratory from some displacement process may be used in practice, for log interpretation, to determine saturations which has been created by some different processes.

The resistivity components (pore level elements of the electrical path) have been identified and described for water-wet and oil-wet porous media. They are different. These different fluid distributions have different effects on resistivity. This has been verified through observations at the pore level[4]. This current work has shown that there is an influence of the fluid distribution on the electrical resistivity for a porous media containing two fluids. The pore scale events are the interaction of pore structure with the capillary and viscous forces. These events change the fluid distribution within the porous media and therefore affect the resistivity. The variables that affect resistivity in partially saturated porous media (for constant injection rate) include: pore structure, wettability, viscosity of the displacing and displaced phases and interfacial tension. During traditional laboratory resistivity index determinations the interaction of pore structure with the capillary and viscous forces will change the fluid distribution within the porous media and therefore affect the resistivity index.

During drainage (e.g., injection of oil in a water-wet rock) a flat front will leave the wetting phase in single pores-throats and as thin films, so that the resistivity will be high because the paths are formed by water films and partially invaded pores. A fingered front on the other hand will leave the wetting phase in large clusters (group of pores-throats) due to the by-passing of these regions, thus the resistivity will now be low due to the abundance of these water clusters and thick films of water and paths through non-invaded pores-throats.

During imbibition (e.g. injection of oil in an oil-wet rock), the advancement of the wetting fluid at the pore level is greatly influenced by the oil spreading characteristics on the solid, the surface rugosity and the velocity of supply of wetting phase. The resistivity will be low if there is a continuous path along the water filaments. The resistivity will become high as soon as the water filaments become broken since the electrical path now consists of water disconnected clusters (isolated water without the existence of conducting films). For a flat front, the non-wetting phase is trapped in isolated pores and the resistivity will be very high approaching the value of the non-conductor phase, while for a fingered front the non-wetting phase is trapped in larger clusters which reduces the value of the resistivity.

The techniques and fluids used to produce saturation variations for resistivity measurement should be selected according to the process and conditions occurring in the reservoir. According to Figure 1, when resistivity index and the saturation exponent are used to obtain water saturation more than 10% error can be introduced in the evaluation of water saturation. Only those processes that reproduce the distribution of fluids expected within the reservoir should be used in the laboratory to obtain the resistivity index and the saturation exponent (Figure 2). Such procedures must be used in order to increase confidence in the evaluation and interpretation of resistivity logs.

CONCLUSIONS

The fluid distribution within rock pore structure affects the resistivity. Large and small elements conduct different quantities of electricity. The way these are combined creates the total resistivity. In this paper we have examined the effects on resistivity of how the fluids are distributed within partially saturated porous media. Different fluid distributions even at the same overall saturation can give different resistivities. Conversely two similar partially saturated rock samples may have the same resistivity but different saturations depending on how the fluid saturations are distributed (i.e. how they have been set-up). We conclude that a value of resistivity to be used to determine a water saturation must be treated with caution, since the fluid distribution created in the laboratory may not be the same as that in the field and that Archie's equation does not tell the whole story.

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APPENDIX: RESISTIVITY COMPONENTS AT PORE LEVEL

As presented earlier [4] the components of the conductivity path at the pore level have been identified for water-wet and oil-wet porous media from observation of models flooded under different conditions. The electrical path can consist of one component through all the porous media or different components in series/parallel depending on the porous structure, fluid characteristics, wettability, etc. We present the components again here for ease of reference.

WATER-WET POROUS MEDIA

Three components for water-wet and partially saturated porous medium can be defined corresponding to different distributions of oil and water at the pore level.

<u>Water films</u> (**FW** or **component I**) The water phase forms a film between the surface of the solid (grains) and the oil phase. The film usually has a non-uniform thickness which depends on the local value of the capillary pressure and the shape of the pore space; i.e., it will be larger in small crevices and in less circular pore cross section. Due to the small transverse area and long length of these films they have comparatively high electrical resistivity.

<u>Non-invaded pores-throats</u> (**NPT** or **component II**) Under moderate oil saturations some pores are fully saturated with water (no oil has entered these pores). The existence of these regions is controlled by the characteristics of the pore structure such as accessibility, i.e. a region confined by small throats that prevents the oil entering the region (by-passed region), or smaller pores not invaded at medium pressures. These non-invaded spaces have a low value of resistivity and play an important role in the total resistivity.

<u>Partially invaded throats</u> (**PIT** or **component III**) The oil has invaded adjacent pores but not the throat between them. This component is usually associated with small throats surrounded by pores of easy accessibility. These throats will have a high capillary pressure and as a consequence they may not be fully invaded by oil even at very high oil saturation. Additionally the water has to be transported out of the throat through water films (high resistance to flow). Depending on the water film thickness and amount of water trapped in the throats the electrical resistivity will have intermediate values in these areas.

OIL WET POROUS MEDIA

For an oil-wet rock only two components of electrical conductivity can be defined, which correspond to different oil and water distribution of at the pore level. The phase distributions can be identified as those inverse of the water wet-rock, components **I (WF)** and **III (PIT).**

<u>Continuous water</u> (**CW** or **component IV**) Is the opposite of component I (water films), where now the oil film is covering the grains and the water is in the centre of the pore-throat space. This will occur at high water saturation and the resistivity in the areas of a continuous water path will be low to intermediate.

<u>Isolated water</u> (**IW** or **component V**) This is opposite to the partially invaded throats (component III) but is produced by different causes. As the water saturation decreases, starting with a continuous water path, instability in the water thread occurs in the throats producing a snap-off of the water. The continuity of the conductivity path is therefore broken. As the water saturation decreases further, the water ganglia (conductive phase) is further separated by a growing oil layer that makes the resistivity very high.

		Value	Front type	Resistivity Components
Drainage (water-wet)	Viscosity ratio	High	Fingered	II - I
		Low	Flat	I - III
	Rate of injection	High	Flat	I - III
		Low	Fingered	II - I
	Interfacial tension	High	Fingered	II - I
		Low	Flat	I - III
Imbibition (oil- wet)	Viscosity ratio	High	Fingered	IV-V
		Low	Flat	V
	Rate of injection	High	Flat	V
		Low	Fingered	IV -V

Table 1- Summary of variables that influence electrical resistivity during oil injection

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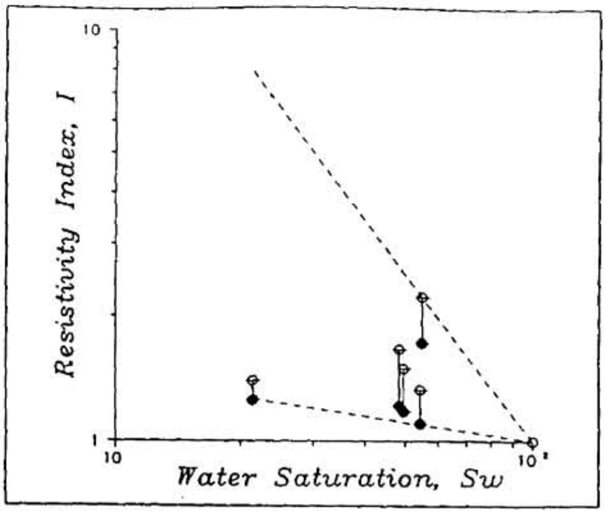

Figure 1. Resistivity index and water saturation. The vertical bars shows the variation of resistivity for different fluid distributions [4].

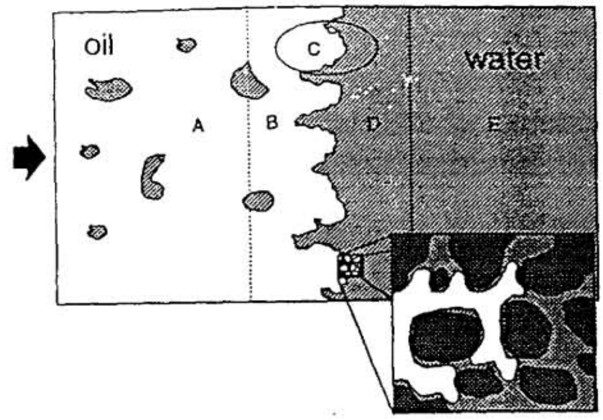

Figure 2. Flow zones and pore level events during oil injection (drainage) in a water-wet rock.

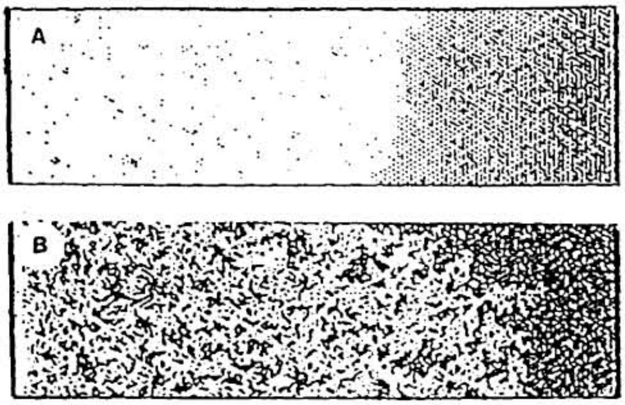

Figure 3. Drainage displacements, influence of viscosity ratio for a capillary number of 10^{-7}.
A- Low viscosity ratio, (< 1).
B- High viscosity ratio, (> 1).

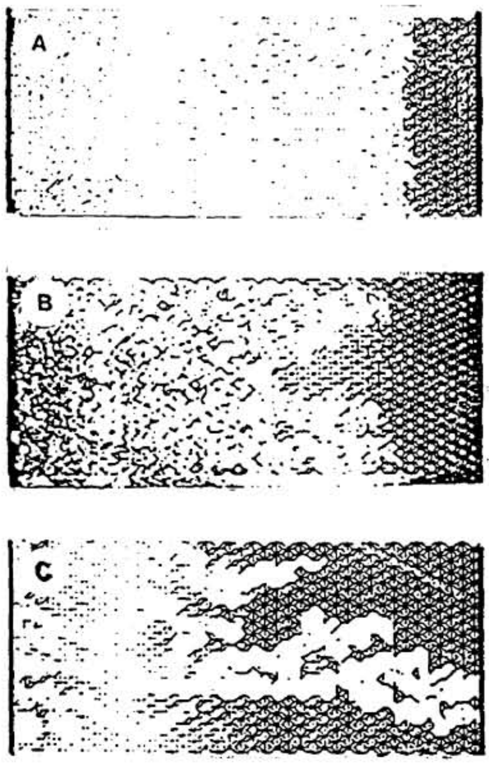

Figure 4. Imbibition displacement, influence of viscosity ratio for a capillary number of 10^{-6}. **A**- Viscosity ratio=0
B- Viscosity ratio=0.90. **C**- Viscosity ratio=30.

Figure 5. Imbibition displacement, effect of the change of non-wetting fluid for a capillary number of 10^{-7}.
A- Decane-water. **B**- Air-water.