RESISTIVITY INDEX AND CAPILLARY PRESSURE CHARACTERISTICS OF RESERVOIR SANDSTONES IN DIFFERENT WETTABILITY CONDITIONS

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Abstract

This research focuses on resistivity index and capillary pressure saturation relationships measured on reservoir sandstones using refined oil and synthetic formation brine. The experiments mimic different displacement processes that could occur during the history of the reservoir: for example, the displacement of water by oil during the initial hydrocarbon migration, the displacement of oil by mud filtrate around the wellbore during drilling, the displacement processes during the formation of transition zones under gravity/capillary forces and during waterflooding.

The resistivity index and capillary pressure experiments were performed on UKCS reservoir samples in both "preserved" and cleaned states. Measurements of the same samples in the "preserved" and cleaned states allowed us to study the effect of surface wettability on capillary pressure and resistivity index. Based on the results from special core analysis and geochemical analysis of reservoir and core-extracted fluids, we found that oil wet surfaces in the "preserved" cores were very pervasive and hard to remove even by cleaning with strong solvents. Variations in the capillary pressure and resistivity indices have been observed for the reservoir samples when they were in different states. This has a profound effect on the use of core data for log calibration and reservoir engineering studies.

Introduction

Wettability and saturation history have an important effect on the distribution of fluids in the pore space as pressures on the oil and water phases change. Capillary pressure, Pc, is defined as the difference between the pressure of the oil, Po, and the pressure on the water phase, Pw, i.e. $Pc = Po - Pw$. Capillary pressure against saturation curves are important in the estimation of connate water volumes, transition zone location and the modelling of oil displacement either by spontaneous water imbibition and/or water injection. Much research is needed to determine the water-oil capillary properties and corresponding electrical resistivities in the full saturation history cycle, particularly for reservoirs showing intermediate and mixed wettability.

Standard methods of relating water saturation to electrical resistivity are based on the Archie saturation equation (Archie, 1942)

$$RI = \frac{R_t}{R_o} = S_w^{-n}$$

where the resistivity index, RI, is equal to the ratio of the resistivity of the sample (R_t) at brine saturation S_w over the resistivity of the sample at one hundred percent brine saturation (R_0). The resistivity index is related to the saturation of the sample and the saturation exponent, n. The saturation exponent can only be accurately determined by experimental core analysis. The standard technique for determining the saturation

exponent involves measurements in cleaned cores, usually with air as the nonwetting phase and brine as the wetting phase. This air/brine system is only representative of the drainage conditions in strongly water-wet reservoirs. When oil is displaced by water, for instance during water flooding, different distributions of fluid may prevail at the pore scale due to hysteresis effects controlled by pore geometries, initial saturation and wettability distribution at the pore scale.

A more detailed review of the effects of wettability on petrophysical properties can be found in Anderson (1986-1987), Morrow (1990), Cuiec (1991) and Buckley *et al.* (1997). In water-wet rock, the brine occupies the small pores and forms a continuous film on the grain surfaces throughout the desaturation process. In contrast, in an oil-wet rock, the brine is located in the centre of the larger pores, with an oil film contacting the grain surfaces. As the brine saturation decreases, the brine will lose hydraulic and electrical continuity, so electrical resistivity will rise rapidly as desaturation progresses. Previous work by Donaldson and Siddiqui (1987), Lewis *et al.* (1988) and Elashahab *et al.* (1995) found that the Archie saturation exponent (n) increases with increased oil wet nature.

Numerous previous workers have reported that the log-log plot of resistivity index versus saturation does not always yield a straight line (e.g., Diederix, 1982 and Longeron *et al.,* 1986). This variation of saturation exponent has been attributed to wettability variation throughout the pore space, shaliness and microporosity. For clay-free samples, particularly those with multi-modal pore size distributions, microporosity seems to be the main cause of non-linear resistivity-saturation relationships (Worthington and Pallatt, 1992). Swanson (1985) found that the resistivity-saturation plot changed slope at saturation point where the corresponding capillary pressure curve indicated a transition from intergranular porosity to microporosity.

The pore fluid distribution not only depends on wettability but also on the saturation history. Hysteresis in capillary pressure measurements has been known for a long time (Anderson, 1986). The different distribution of fluids in the pore-space during desaturation and subsequent cycles also affects the resistivity-saturation relationships (Longeron *et al.,* 1986; Wei and Lile, 1991 and Elashabab *et al.,* 1995).

The effect of wettability, hysteresis and variable saturation exponent must all be accounted for during the application of resistivity saturation relationships in the calculation of water saturation from electrical logs. This paper uses an experimental technique for the accurate measurement of resistivity and capillary pressure saturation relationships of water/oil/rock systems. Results from same sandstone samples are presented and their petrophysical implications discussed. It should be noted that in this paper drainage refers to oil displacing water and imbibition refers to water displacing oil regardless of the sample wettability.

Experimental Apparatus and Procedure

We use a multi-sample experimental rig for the measurements of resistivity index and capillary pressure curves (Figure 1). A core/sleeve assembly which contains a water wet membrane at one end and an oil wet membrane at the other end (Figure 2), allows the maintenance of capillary pressure across the sample and the measurement of repeated drainage and imbibition cycles. Multi-potential electrodes are used to allow the assessment of equilibrium conditions, core and saturation heterogeneity and end effects. The use of thin micro-porous oil wet and water wet membranes enables drainage and imbibition tests with significantly reduced equilibrium times (e.g. from 3-4 weeks to one week per data point) (Hammervold and Skjaevaland, 1992; Elashahab *et al*, 1995 and Fleury and Longeron, 1998).

The apparatus consists of a multi-sample coreholder. It can withstand 10,000 psi working confining pressure and a maximum testing temperature of 175 ^{0}C. Up to five rock samples can be

simultaneously tested. The samples are enclosed in multi-electrode rubber Viton sleeves, with flow of fluids and electrical current through the inlet and outlet platens positioned at the ends of the sample. The platens and flow lines are insulated from the vessel body. The membranes are sandwiched between wire mesh which forms an electrical connection between the platens and the sample. The multiple electrodes on the Viton sleeves are connected to the outside of the vessel through high pressure electrical feedthroughs.

The pore pressure system consists of two fluid interface units, one connected to the bottom of the coreholder and the other to the top. The top gas/oil interface unit is connected to a controllable gas pressure supply and from its bottom to an oil/brine interface unit. The oil/brine interface unit contains five calibrated burettes partially filled with oil and brine. A burette is connected to the top of each core sample, and used for saturation measurements. A maximum pore pressure of 250 psi can be supplied with brine volume measurements of an accuracy better than 0.1% pore volume. The oil pressure is applied through the gas/oil interface unit on the bottom of vessel, one connected to each sample. The pressure can be accurately controlled with a precision of ± 0.01 psi. The mineral oil is introduced gradually into the sample in several capillary pressure steps until irreducible oil saturation is attained within measurement time. Brine can then be injected back from the top of the samples to start the imbibition cycle and complete the drainage/imbibition hysteresis curve.

Test Procedure

The data presented in this paper are from samples tested as part of the Pegasus petrophysics research program. Reservoir core and fluid samples from the UKCS oilfields are supplied by the industry sponsors. A core plug (P2) of 38mm in diameter was cut from the oil leg of the preserved core. Initial sample preparation involved displacing the crude oil with an Isopar test oil, which is a mixture of light paraffins. Since the resistivity of the pore brine in the preserved core was unknown, the sample was flooded from an initial water saturation to a residual oil saturation by flushing the sample with formation matched brine. Drainage and imbibition cycles were measured in the multi-sample rig. A hydrostatic overburden pressure of 1,000 psi was maintained throughout the experiment. At each capillary pressure equilibrium point the displaced volume and resistivity across the sample and at intervals along its length via the contact pins were measured. This allowed the simultaneous measurement of both capillary pressure and resistivity index curves, and the monitoring of the water saturation profile along the sample. At the end of the imbibition cycle, the samples were cleaned using the Dean-Stark method to determine the end point saturation and thus back calculate all capillary pressure equilibrium saturations. After drying the porosity to helium and Klinkenberg permeability were measured. The sample was then saturated with matched formation brine and drainage and imbibition cycles were measured on the cleaned sample. The specific internal surface area was also measured by BET nitrogen adsorption on cleaned off-cuts from the same core piece. Mercury intrusion data and Amott-Harvey wettability index was measured on an adjacent preserved state sample.

Results and Discussions

Basic Petrophysical Parameters

Table 1 summarises the petrophysical data measured on P2 and adjacent samples. Sample P2 has high porosity and permeability, and has a grain density of 2.65 g/cm^3. X-ray diffraction studies of P2 off-cuts did not detect any clay material. The low specific internal surface also attests to an absence of clays within the pore space. A cementation exponent of 1.74 points to efficient electrical conduction in this moderately cemented sandstone. Amott-Harvey wettability index for the preserved state sample shows a

clear oil wet tendency. After Dean-Stark cleaning the Amott-Harvey index increased but a negative value indicates that cleaning has not changed all the oil wet areas within the pore space.

Figures 3 shows the mercury injection curve for a sample adjacent to P2. The pore size distribution derived from the mercury injection data is given in Figure 4. This sample has a unimodal pore size distribution with a maximum at about 50 μm, and very few micropores.

Table 1: List of Petrophysical Data for Sandstone Sample P2.

Helium Porosity (%)	17.01
Klinkenberg Nitrogen Permeability (mD)	1445
Grain Density (g cm^{-3})	2.65
Specific Internal Surface (μm^{-1})	1.566 - 1.906
Formation factor @ 1000psi Overburden	22.42
Archie Cementation Exponent	1.74
Amott-Harvey Wettability Index **(Adjacent Sample)**	-0.42 (Preserved) -0.10 (Cleaned)

Geochemistry

Geochemical analysis was performed on oil samples extracted during preparation of both preserved and unpreserved cores and compared to that of a production crude oil from the same reservoir. The fluid extracted from the preserved sample consisted of a mixture of the original pore fluids and the displacing test oil. A pore fluid extract from an adjacent unpreserved sample was also collected by flushing with toluene. A sample of production crude oil was also analysed. The relative abundance of polar organic nitrogen compounds (carbazoles and benzocarbazoles) and polar oxygen compounds (fluorenones and benzofluorenones) for each sample has been obtained by mass spectrometry. Bennett and Larter (1998) suggested that these polar compounds may affect reservoir wettability. Table 2 summarises the relative abundance of each compound.

Table 2 Relative Abundances of Fluorenones and Carbazoles

Fluid Source	Fluid Type	Carbazoles	Benzocarbazoles	Fluorenones	Benzofluorenones
Preserved Sample	Extract plus test oil	-	-	-	-
Unpreserved Sample	Extract plus Toluene	++	++	++++	++++
Crude		++++	+++	-	-
Test Oil (Isopar)		+	+	-	-

Qualitative Scales
-     Compound Absent
+   Minor/Trace
++   Low/Average
+++   Abundant
++++ Highly Abundant

It is interesting to note the differences in abundance of the polar organic compounds between fluids displaced from the preserved and unpreserved samples. Since the preserved core was stored in kerosene,

during storage the remaining crude oil within the pores was diluted by mixing with the kerosene. The fluid extract from the preserved sample was obtained by displacing the crude/kerosene mixture with our test oil. The preserved sample extract contained no detectable carbazoles, benzocarbazoles, fluorenones or benzofluorenones. Pore fluids from the unpreserved sample were extracted by displacement with toluene. The polar solvent, toluene, has extracted the polar organic compounds and they were detected by the geochemical analysis. The polar fluorenones may be adhering to the sample surface and are only extractable by cleaning with a polar solvent such as toluene. These adsorbed organic species may be the cause of oil wet surfaces. The crude oil sample contained abundant carbazoles and benzocarbazoles but no fluorenones or benzofluorenones. The fluorenones and benzofluorenones are adsorbed onto the pore surfaces and not displaced when the crude oil is produced, these compounds can only be extracted by cleaning with a polar solvent such as toluene. Care must be taken when interpreting these results as pore fluids may be contaminated with drill mud components. Even though these results should be viewed with caution they demonstrate that geochemical analysis can be a useful tool in determining reservoir wettability.

Capillary Pressure

Capillary pressure curves of drainage and imbition for sample P2 in preserved state is shown in Figure 5. The majority of the pore space was desaturated at capillary pressures less than 5 psi, an indication of open pore structures found in high permeability sandstones. The lowest water saturation attained during drainage was at 0.39 pore volume fraction unit. This high water saturation is common in oil wet rocks where capillary continuity between pore waters can easily be lost, and isolated ganglia of water formed. There was no saturation change during spontaneous imbibition, as the capillary pressure reduces from the highest value to zero. The lack of spontaneous water imbibition is to be expected in a sample with a large percentage of oil wet surfaces.

Figure 6 shows the capillary pressure data obtained for P2 after Dean-Stark cleaning. This sample has had most of the oil wet surfaces cleaned and changed to water wet. The predominately water wet character of the cleaned sample results in a low water saturation at the end of drainage of 0.11. Water films coat the pore surfaces which allows the maintenance of capillary continuity even at low water saturations and thus low drainage saturations. Spontaneous water imbibition was noted for the cleaned sample and the residual oil saturation at the end of forced imbibition is lower than that obtained for the preserved sample. It must be remembered that cleaning did not remove all oil wet surfaces so the sample has both oil wet and water wet areas. This allows the formation of both water and oil films spanning the sample and thus low irreducible water and residual oil saturations. This phenomenon has been modelled in pore scale wettability modelling studies (Dixit *et al* 1996), indicating that moderate wettability produces high oil recovery during waterflooding.

Resistivity Index

Figure 7 shows a log-log plot of resistivity index against water saturation for both drainage and imbibition cycle on the preserved sample P2. The gradient of this resistivity index line yields the saturation exponent, n, which is not constant over the saturation range. Values of between 5.46 and 5.81 were calculated from the drainage data. These relatively high values are related to the oil-wet character of the preserved core that influences the microscopic fluid distribution within the pore network. Very little hysteresis it seen between the resistivity data for drainage and imbibition.

Saturation exponent is reduced significantly after cleaning for both drainage and imbibition (Figure 8). Drainage yielded a saturation exponent of 2.56 and imbibition 2.71. Cleaning lead to a change from oil-wet to an intermediate wettability, allowing the formation of a more continuous network of water filled pores and water films thus reducing the resistivity at a given saturation compared to the oil wet preserved sample.

Drainage of the cleaned sample is analogous to the primary drainage of the reservoir when oil first migrated into the pore space. The imbibition data obtained from the preserved sample is representative of the movement of oil out of the pore space by waterflooding. It is interesting to join these two data sets in a single resistivity index saturation plot (Figure 9). This shows the large degree of hysteresis obtained after the oil has altered the pore surfaces to oil wet. This has been observed in pore space modelling studies at Imperial College in which computer generated pore networks are used to simulate primary drainage, wettability alteration and imbibition (Man and Jing 1998). If resistivity data is to be used to calibrate logging responses of infill wells and estimate remaining oil saturation, this hysteresis effect must be considered as application of the drainage data for an imbibition cycle could lead to erroneous estimations.

Conclusions

Wettability plays an important role in determining the fluid movement, distribution and electrical conduction during desaturation processes. The results from this paper show that samples with an oil-wet tendency have higher irreducible brine saturations and higher Archie saturation exponent values than samples with water wet-surfaces.

The prudent application of geochemical and special core analysis (e.g. capillary pressure and resistivity index data from preserved and cleaned samples) offers the potential for more accurate evaluation of reservoir wettability. It should be noted that factors determining fluid distribution within the pore space are numerous and one should avoid the use of oversimplified 'rules of thumb' to deduce wettability and reservoir performance.

Nomenclature

n = saturation exponent
Pc = capillary pressure (psi)
Po = pressure on oil phase (psi)
Pw = pressure on water phase (psi)
RI = resistivity index
R_t = resistivity of sample (Ohm-m)
R_o = resistivity of sample at 100% water saturation (Ohm-m)
S_w = fractional water saturation

Acknowledgements

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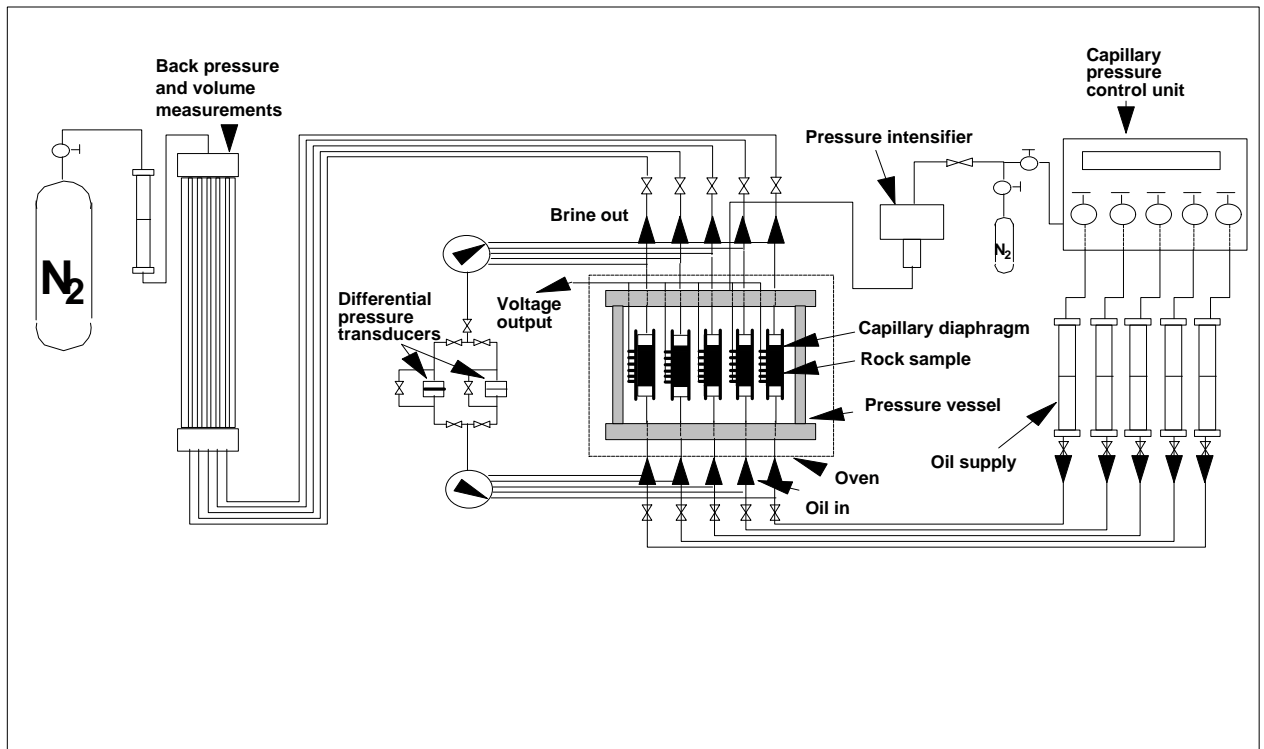
Figure 1: Schematic of the Multi-Sample System for Measuring Electrical and Capillary Characteristics of Rock Samples.
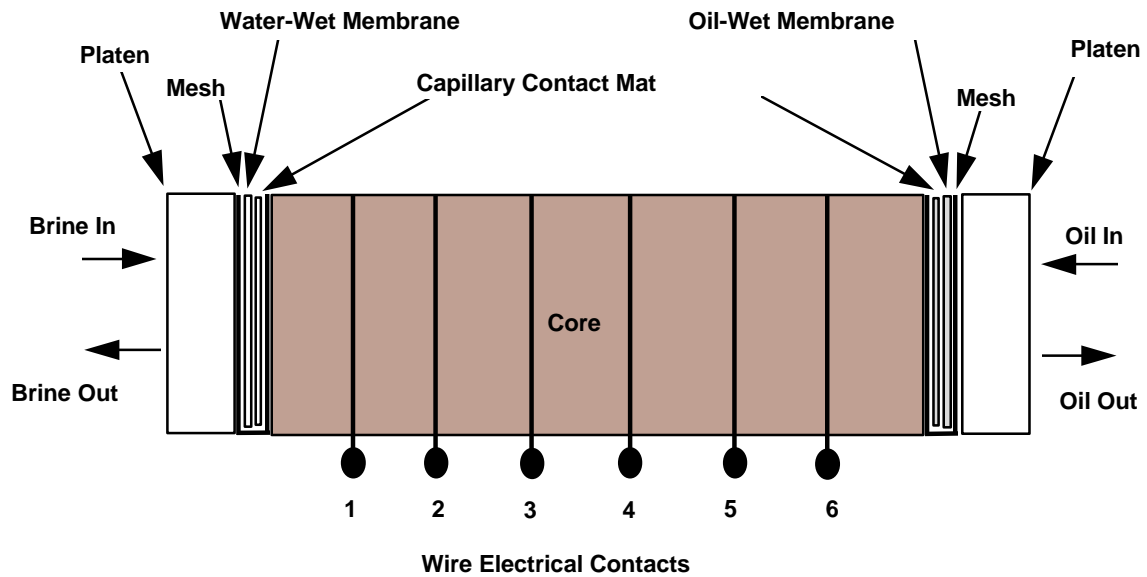
Figure 2: Multi-Electrode Core Sleeve Assembly with Membranes.
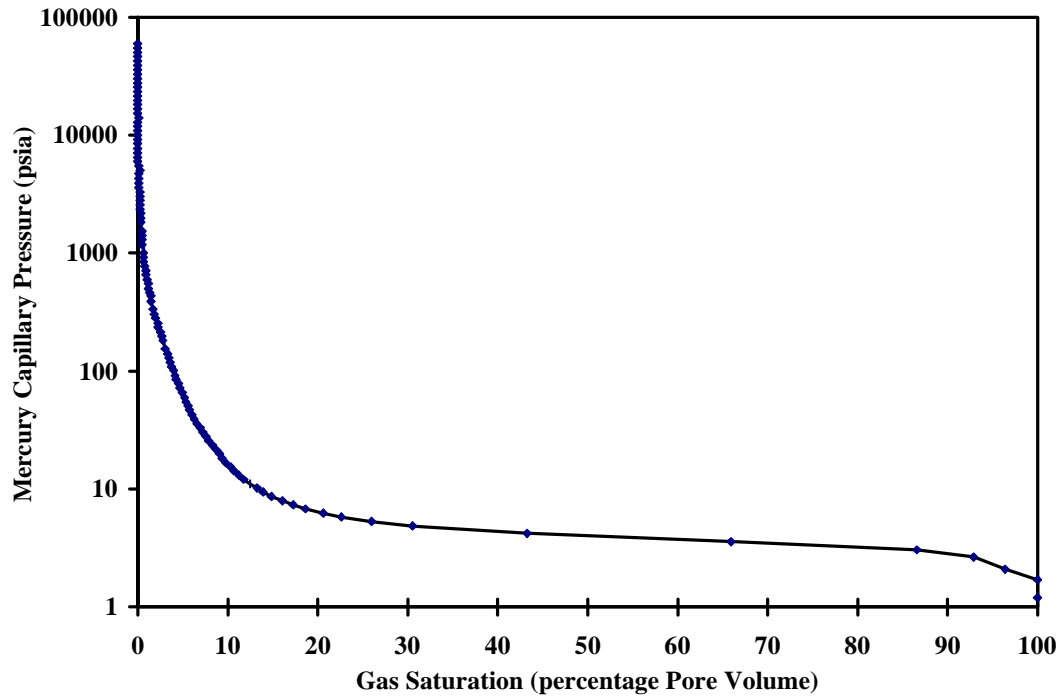
Figure 3: Mercury Injection Capillary Pressure Against Gas Saturation for a North Sea Reservoir Sample, Adjacent to P2.
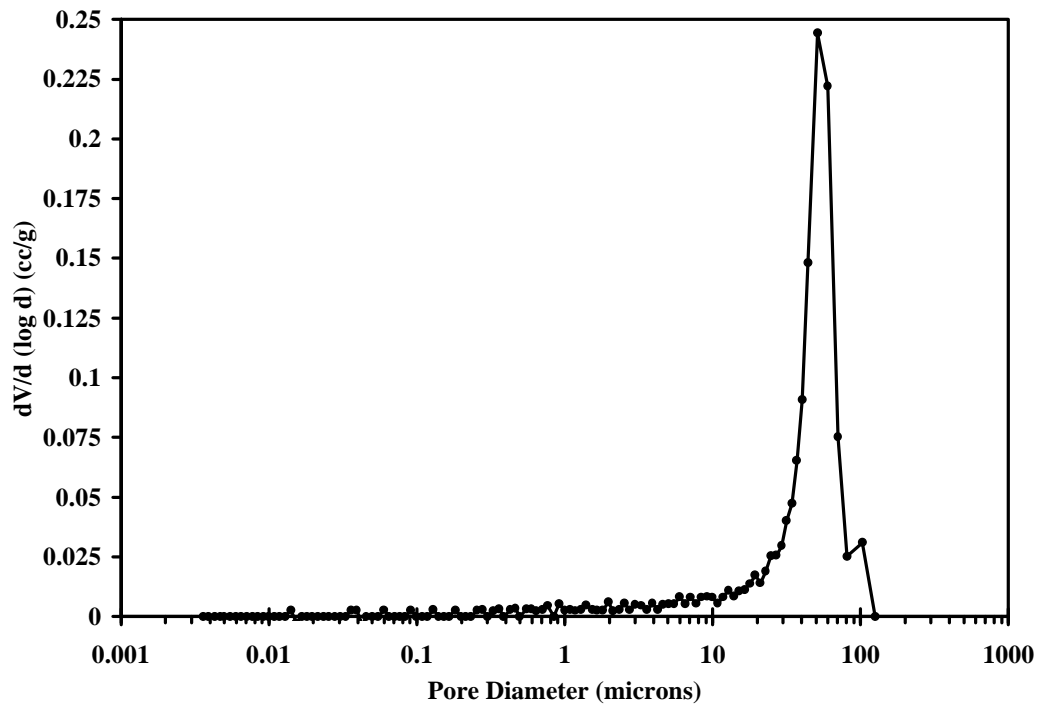
Figure 4: Pore Size Distribution for a North Sea Reservoir Sample, Adjacent to P2.
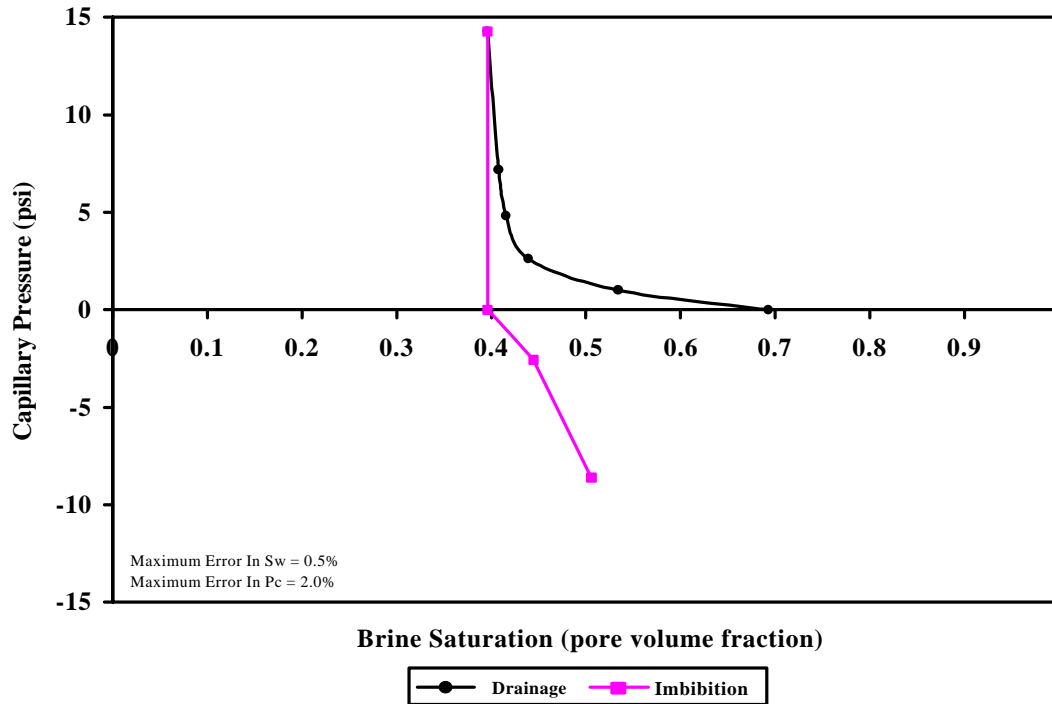
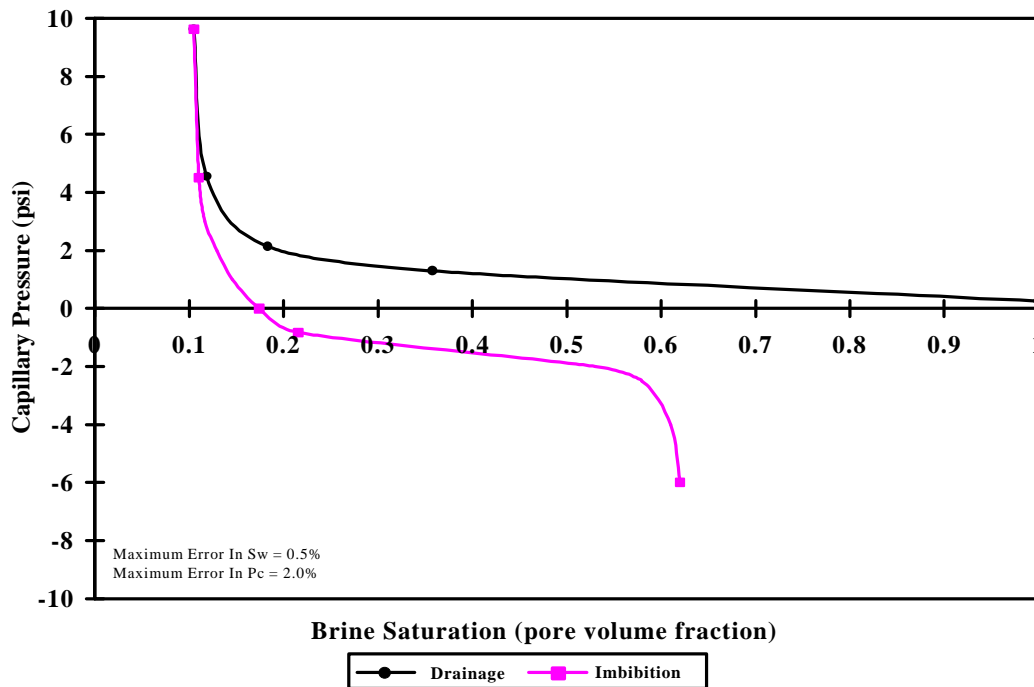Figure 5: Drainage and Imbibition Curves for North Sea Reservoir Sample (P2) in Preserved State.

Figure 6: Drainage Capillary Pressure Curves for North Sea Reservoir Sample (P2) in Cleaned State.
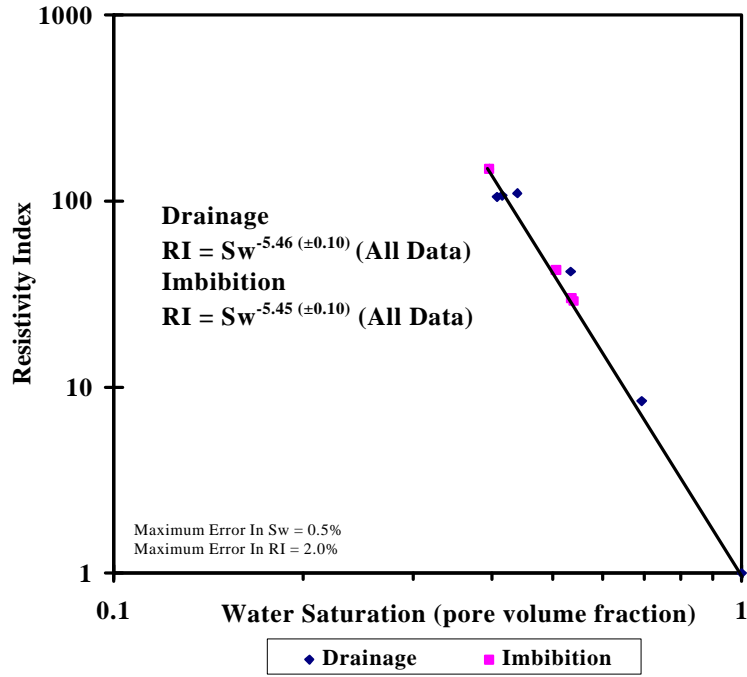
Figure 7: Resistivity Index against Brine Saturation for North Sea Reservoir Sample (P2) in Preserved State.
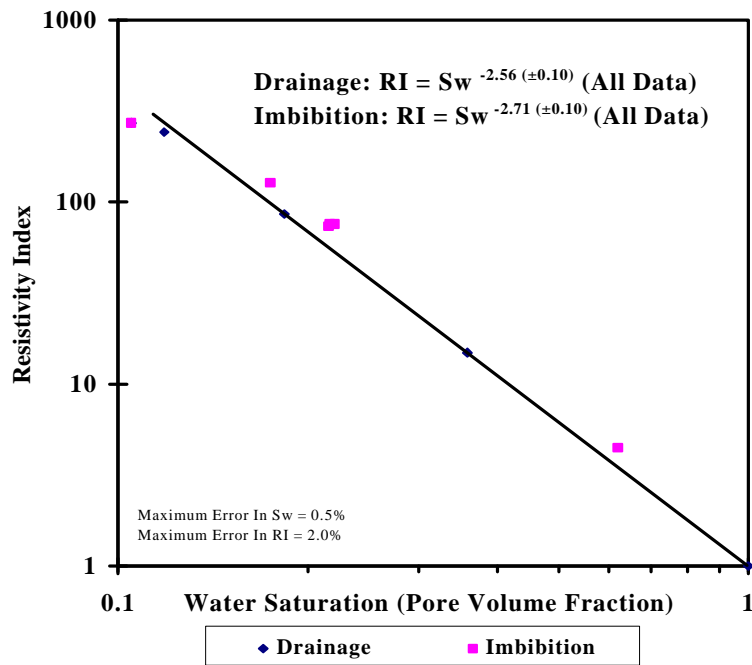

Figure 8: Resistivity Index against Brine Saturation for North Sea Reservoir Sample (P2) in Cleaned State.
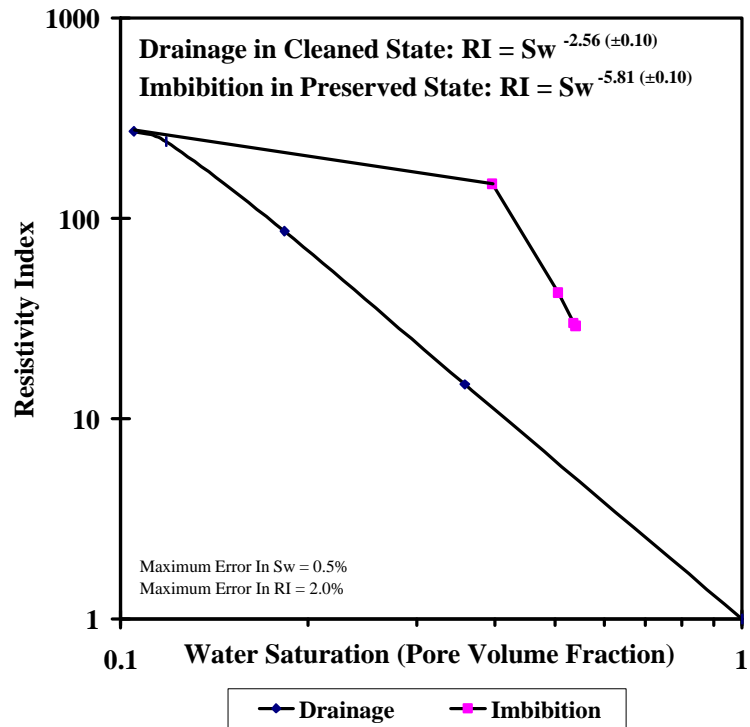
Figure 9: Resistivity Index against Brine Saturation for North Sea Reservoir Sample (P2) Indicating Hysteresis After Wettability Alteration.