

## **THE ROLE OF PORE GEOMETRY IN THE INTERPRETATION OF SHALY SANDS**

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Knowledge of the degree of excess conductivity of a reservoir rock is fundamental when evaluating the water saturation of hydrocarbon reservoirs. Two conducting pathways, bulk and surface conduction, can co-exist within the interconnected pore geometry of reservoir rock systems. Bulk conduction occurs when the sample is under an electric field and the ions in the electrolyte are the major current source. Surface conduction arises along pore walls where cations are held on net-negatively charged mineral surfaces. The excess conductivity is a laboratory derived parameter which is used to evaluate the water saturation of shaly reservoirs in conjunction with wireline log data.

Traditionally, the excess conductivity is derived from the measurement of the cation exchange capacity of crushed, and dried core samples. These data are not representative of the charge-electrolyte distribution within the original rock pore geometry. Intrinsic excess conductivity can, therefore, only be measured on preserved core samples which give a direct measure of the electric current carried by bulk and surface ions within a 3-dimensional pore geometry. Present methods used to determine the excess conductivity confine the samples in a conductivity cell at low confining pressures (typically 400psi).

New experimental data have revealed that the laboratory derived excess conductivity decreases with increasing confining pressure. This is partly due to the simultaneous change in formation factor but it is also due to changes in surface tortuosity. The rate of change seems to be dependent on the pore geometry of the rock. In this study the pore geometry has been defined by the Archie cementation exponent  $m$ . In general the higher the value of  $m$  the lower the pore aspect ratio and vice versa. This association has been used to establish a relationship between excess conductivity at reservoir pressure and that at 400 psi. Failure to measure excess conductivity at reservoir pressures, or to compensate at the application stage, could result in errors in water saturations calculated from shaly sand equations using core and log data.

## INTRODUCTION

Evaluation of "shaly" reservoirs has long been regarded as a major problem in hydrocarbon exploration and production. The accuracy to which shale effects can be determined from core analysis has been regarded as dependent upon the quantity of "shale" in the reservoir rock. The establishment of the degree of shaliness is therefore important for the calculation of hydrocarbon reserves in reservoir evaluation.

In a clean sand it is assumed that the rock is water-wet, of low surface area and the conductivity can be accounted for solely by the geometry of electrolytic conduction through the bulk pore fluids, (Archie, 1942).

Most reservoir sandstones contain clay minerals, which give rise to regions of microporosity and high surface area. In these systems, a measurable enhancement of conduction may occur at the clay/electrolyte interface, which is coincident with the pore walls. It is this excess conductivity due to minerals of high surface area in the presence of a low salinity electrolyte that gives rise to a second conducting pathway. A measure of this excess conductivity, which is a laboratory-derived parameter, is required before the water saturation of shaly sands can be evaluated.

Historically, reservoir shaliness has been measured in the laboratory by one of three methods; wet chemistry cation exchange capacity (CEC) (Hook, 1983); membrane potential (MP) (Waxman and Thomas, 1974), (Thomas, 1976); and excess conductivity (X) by the multiple salinity technique, (Hill and Millburn, 1956), (Waxman and Smits, 1968). The CEC method involves crushing and sieving a dry core sample, thus destroying the 3-dimensional pore/grain geometry. This technique is notoriously inaccurate when samples have very low clay mineral content or when depositional clay clasts are dispersed and are falsely assumed to be pore lining clays. CEC cannot be obtained by any downhole logging tool and is therefore the least satisfactory of the three shale parameters. The MP method is measured on preserved core plugs and is based upon an empirical relationship between a measured voltage and wet chemistry CEC, (Patchett, 1975). Membrane potential, too, cannot be measured downhole by logging tools and it is experimentally difficult to perform accurately in the laboratory. The excess conductivity (X) is determined on preserved core plugs where the saturated rock conductivity ( $C_Q$ ) is obtained by measuring the conductivity of the rocks, when fully saturated with an electrolyte solution, as a function of varying electrolyte salinity ( $C_w$ ). Under most circumstances this method will give the best representation of shale effects for the correct pore/clay/electrolyte distribution.

The purpose of this paper is to determine the effect of confining pressure upon the evaluation of excess conductivity of reservoir rocks of varying pore geometries. A key factor in this evaluation process is the quantification of the excess conductivity on core samples which possess the correct 3-dimensional pore geometry, representative surface area/clay mineral distribution and

electrolyte salinity. It is essential to establish how excess conductivity (X) and the intrinsic formation factor (F\*) vary with pressure. We report new measurements made on core samples to determine X and F\* at overburden pressures between 400 and 5000 psi. A chart has also been derived to show how X at reservoir pressure can be estimated from a measurement made at 400 psi in the laboratory.

### HISTORY OF THE SHALY SAND CONCEPT

Archie (1942) clearly stated the requirements for clean sand behaviour. Any deviations from Archie's original conditions could result in shaly sand behaviour. Work on shaly sands was later published by Winsauer and McCardell (1952), then brought to prominence by Waxman & Smits (1968) and comprehensively reviewed by Worthington (1985). Waxman & Smits shaly sand equations were therefore an extension of the Archie (1942) clean sand model, in which the ratio of the fully saturated core plug resistivity to the saturating electrolyte resistivity is presumed constant for varying electrolyte salinities. From this Archie defined a new electrical parameter F which relates to fully saturated conditions.

$$F = R_o/R_w \quad (1)$$

where  
 F = formation factor  
 $R_o$  = resistivity of the fully saturated rock  
 $R_w$  = saturating electrolyte resistivity.

The formation factor can also be related to porosity through the expression

$$F = \phi^{-m} \quad (2)$$

where  
 $\phi$  = porosity  
 m = cementation exponent.

Equation (2) is sometimes called the first Archie equation. The second Archie equation relates rock resistivity at different levels of desaturation

$$I = 1/S_w^n \quad (3)$$

where  
 I =  $R_o/R_t$   
 $R_t$  = resistivity of rock saturated with brine/hydrocarbon  
 $S_w$  = water saturation  
 n = saturation exponent.

The Waxman and Smits (1968) model modifies equation (1) to include the shaly term and also uses conductivities instead of resistivities

$$C_o = C_w/F^* + X \quad (4)$$

where  $F^*$  = intrinsic formation factor; and  
 $X$  = excess conductivity due to shale effects.

As stated earlier,  $X$  has in the past been estimated by two methods, membrane potential and cation exchange capacity (CEC), both of which have inherent disadvantages. The use of the Archie equation would only account for the electrical conduction through the interconnected pore geometry and not for the conduction due to shale effects at the rock/electrolyte interface. The Waxman and Smits model accounts for both these phenomena.

The wet chemistry CEC method using crushed, sieved dry core samples is an oil industry standard method. It provides an indirect estimate of  $X$  via the equation

$$X = (B.Q_v)/F^* \quad (5)$$

where  $B$  = is an empirical constant  
 $(3.83)(\text{mhos.cm}^2.\text{meq}^{-1})$   
 $Q_v$  = number of exchange cations/unit  
 pore volume ( $\text{meq.cm}^{-3}$ )

This model assumes a constant value of  $B$  for an electrolyte of any salinity and that the bulk and surface conductivities have the same geometric factors governing conduction, i.e.  $F=F^*$ .

Several methods are in common use to determine  $Q_v$ , which encompass, the wet chemistry CEC; sodium acetate, ammonium acetate and barium chloride. All of these methods suffer from the same inherent problems. Samples are crushed and sieved, thus destroying the original grain/pore geometry and creating a higher surface area/surface charge. All exchange sites are presumed to take part in conduction when the rocks are under an electric field at a given frequency.

The membrane potential method is an alternative method for determining  $Q_v$  (Waxman and Thomas, 1974). This method has a major advantage over wet chemistry CEC in that it can be measured on preserved core plugs. The problem associated with this technique is that it is based upon an empirical relationship between measured voltage and wet chemistry CEC from a crushed rock database (Patchett, 1975).

The excess conductivity (multiple salinity) method was first used by Hill and Millburn (1956) to measure the conductivity of reservoir sands. This is the same

method that is in use in laboratories today. Accurate measures of reservoir shale effects can be obtained easily on miscibly cleaned, preserved core samples.  $X$  is determined from a plot of saturated rock conductivity ( $C_o$ ) versus saturating electrolyte conductivity ( $C_w$ ). This is a straight line relationship with the intercept on the ordinate axis being the value of  $X$ . The inverse of the gradient defines the intrinsic formation factor,  $F^*$ . This has proved to be an acceptable technique for determining  $X$  because it is not based on any empirical assumptions and encompasses the 3-dimensional pore geometry of the sample.

Once the correct  $X$  has been established, the water saturation from resistivity logs can be determined from:

$$F^* = (C_w \cdot S_w^n) / (C_t - X \cdot S_w^n) \quad (6)$$

where  $C_w$  and  $C_t$  are the inverse of  $R_w$  and  $R_t$ .

## EXPERIMENTAL TECHNIQUES

### Samples Studied

The samples used (referred to throughout the text as A,B,C,D,E,F, and G) came from five North Sea reservoirs and one Alaskan reservoir. They were chosen to possess a wide range of porosities and excess conductivities.

### Sample Preparation

The original pore fluids were removed by miscible cold solvent cycles of methanol/toluene at ambient temperature. After the final cycle of methanol the samples were then flushed with one of the test brines, which was a solution of 50,000 ppm sodium chloride.

### Measurement Procedure

The samples were loaded in hydrostatic Hassler cells and were then pressured to 400 psi by a non-conducting oil- sleeve system. To ensure that the samples were completely saturated they were flowed under a back pressure of 200 psi with the 50,000 ppm brine. This ensured that any air left in the system was dissolved out after 12 hours of fluid flow.

The resistance of the sample was then measured using a Hewlett Packard variable frequency LCZ meter at successive pressures ranging from 400 to 5000 psi. The sample resistance was measured with different electrolyte salinities at each pressure step and the electrolyte resistivity was also measured from a collected sample of the electrolyte solution. After each suite of excess conductivity measurements had been made the pressure was increased.

Following the final pressure step, the sample was checked for any permanent deformation effects by recording pore volume changes. The samples were then flushed with methanol to remove any excess salt and were then dried at 105 °C prior to helium porosity measurements.

### Other Measurements

Scanning electron microscopy (SEM), pore size distribution (PSD), surface area (SA) and clay contents from XRD were examined to describe the pore morphology. Sample offcuts were used for these analyses. Example data are given in Figure 1 and Table 1.

## ANALYSIS OF RESULTS

Table 2 shows that the value of X decreases with pressure for each sample. The Archie cementation exponent, m increases with pressure.

The decrease in X is believed to be further accentuated by pore throats becoming sealed off as compaction occurs, which will electrically isolate the pore and hence reduce the contribution of the clay conductivity to the overall conductivity measured on the sample. This will have two effects. First, it will increase the surface tortuosity of the sample (of the interpretation of X adopted by Worthington, Pallatt and Toussaint-Jackson, 1989). Second it should be noted that while X decreases with overburden pressure, shale effects might not. The reason is that the increase in F\*, which causes a reduction in X, also causes a reduction in the "clean sand" term  $C_w/F^*$ . The correct indication of shale effects is given by the ratio

$$X/[(C_w/F^*) + X]$$

and it is the change in this ratio that determines how shaliness affects formation evaluation (under fully saturated conditions). The significance of this reduction in X when evaluating water saturation from wireline logs can be shown by the following example calculation.

### Example Calculation

N.B. In this example experimental data from sample G are used and therefore the core is fully brine saturated, i.e.  $C_t=C_o$ ; assume  $n=2$ .

STEP 1.	Rearrange	$C_t = (C_w \cdot S_w^n / F^*) + X$
	to give	$S_w^n = [(C_t - X) \cdot F^*] / C_w$

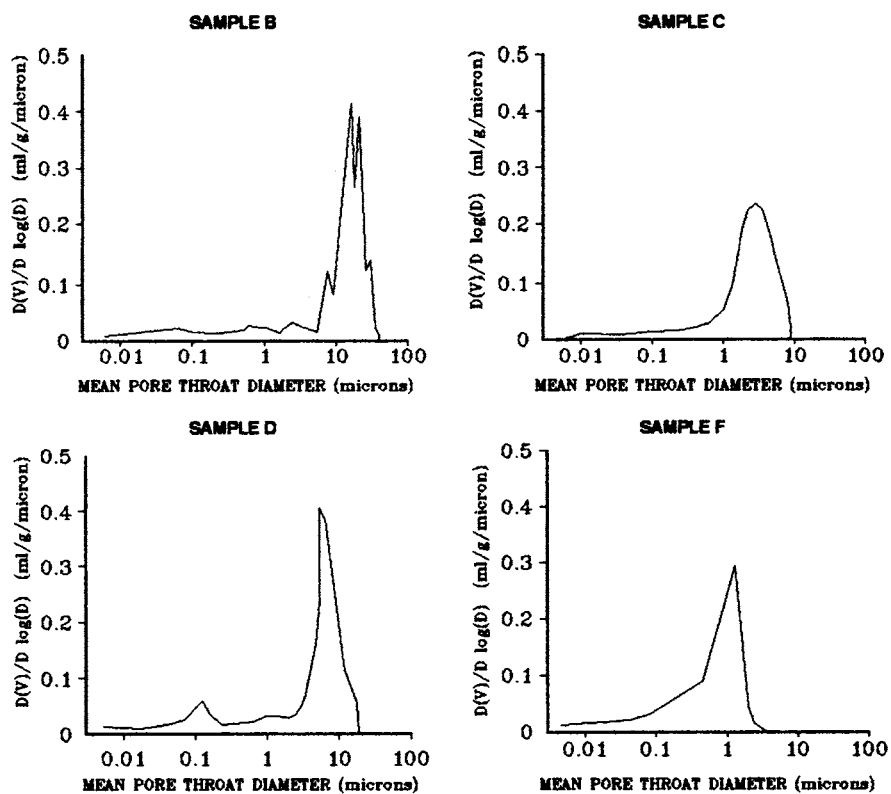


FIGURE 1 Sample pore size distribution

TABLE 1 XRD data

Sample	% Whole Rock Bulk Volume		
	Illite	Kaolinite	Chlorite
B	2	12	1
D	12	-	6
E	6	2	3
F	6	1	1

TABLE 2 Sample tables to show variation of X and m with pressure.

*Sample A*

PRESSURE (PSI)	X (S/m)	POROSITY (%)	m
400	0.086	10.72	1.70
1,000	0.074	10.39	1.72
2,000	0.065	10.09	1.74
3,000	0.057	9.92	1.76
5,000	0.050	9.67	1.78

X CONSTANT = 2.006  
X GRADIENT = -0.384

*Sample B*

PRESSURE (PSI)	X (S/m)	POROSITY (%)	m
400	0.032	23.15	2.29
1,000	0.030	22.96	2.31
2,000	0.030	22.80	2.33
3,000	0.028	22.70	2.33
5,000	0.026	22.52	2.34

X CONSTANT = 0.969  
X GRADIENT = -0.0086

*Sample C*

PRESSURE (PSI)	X (S/m)	POROSITY (%)	m
400	0.0015	10.58	1.91
1,000	0.0013	10.47	1.92
2,000	0.0012	10.38	1.94
3,000	0.0012	10.31	1.96
5,000	0.0011	10.23	1.98

X CONSTANT = 1.592  
X GRADIENT = -0.235

*Sample D*

PRESSURE (PSI)	X (S/m)	POROSITY (%)	m
400	0.0093	26.62	2.17
1,000	0.0086	26.40	2.19
2,000	0.0083	26.20	2.20
3,000	0.0082	26.08	2.22
5,000	0.0078	25.68	2.23

X CONSTANT = 1.352  
X GRADIENT = -0.138

*Sample E*

PRESSURE (PSI)	X (S/m)	POROSITY (%)	m
400	0.0364	24.65	2.22
1,000	0.0359	24.41	2.25
2,000	0.0352	24.16	2.27
3,000	0.0343	24.01	2.28
4,000	0.0330	23.86	2.29
5,000	0.0328	23.79	2.30

X CONSTANT = 1.256  
X GRADIENT = -0.093

*Sample F*

PRESSURE (PSI)	X (S/m)	POROSITY (%)	m
400	0.0289	23.58	2.32
1,000	0.0285	23.38	2.08
2,000	0.0277	23.16	2.09
3,000	0.0280	23.01	2.37
4,000	0.0274	22.89	2.37
5,000	0.0271	22.79	2.38

X CONSTANT = 1.142  
X GRADIENT = -0.0535



- STEP 2. If pressure = 400 psi  
 $F^* = 32.76$  :  $X = 0.0318$  S/m  
 $C_t=C_o = 0.106$  S/m :  $C_w = 2.447$  S/m  
 Then  $S_w = \underline{0.997}$  ie. fully saturated
- STEP 3. If at 5000psi but we use correct  $F^*$  value obtained from log data and X from laboratory measurement made at 400psi.  
 $F^* = 36.93$   
 $X = 0.0318$  S/m  
 $C_t=C_o = 0.092$  S/m :  $C_w = 2.447$  S/m  
 Then  $S_w = \underline{0.953}$   
 i.e.  $S_w=95.3\%$  (4.7% error in  $S_w$ )
- STEP 4. If we use correct  $F^*$  and X at 5000psi  
 $F^* = 36.93$   
 $X = 0.0262$  S/m  
 $C_t=C_o = 0.092$  S/m :  $C_w = 2.447$  S/m  
 Then  $S_w = \underline{0.997}$   
 ie.  $S_w=100\%$ , which is correct

From the above calculation if the correct values for  $F^*$  and X are not used in the Shaly Sand equation (4), the water saturation obtained will be grossly underestimated by about four saturation units. The similarity of estimates in steps 2 and 4 underscores the earlier point about distinguishing between shale parameters and shale effects.

#### RELATIONSHIP BETWEEN RATE OF CHANGE IN X AND PORE GEOMETRY

From Table 2 it can be seen that the Archie cementation exponent,  $m$  varies with pressure as well as X. It has long been thought that  $m$  is related to the pore shape within the rock, but very little work has been done on rock samples to quantify this relationship. The only notable published work was that by Jackson et. al. (1978), who studied grain shapes on unconsolidated artificial samples at ambient conditions. The data from our experimental work show that  $m$  increases with pressure for a sandstone and this would imply that there is a change in the pore geometry occurring if overburden pressure is applied. It was also noted that the rate of decrease in X was greater for the samples with low  $m$  values than for samples with a high value of  $m$ , (see Figure 2.)

In order to discover what is causing the differential rate of decrease in X with pressure SEM photographs were taken for each sample. These revealed differing pore geometries for the extreme values of  $m$ , as shown in Figures 3 and 4. For

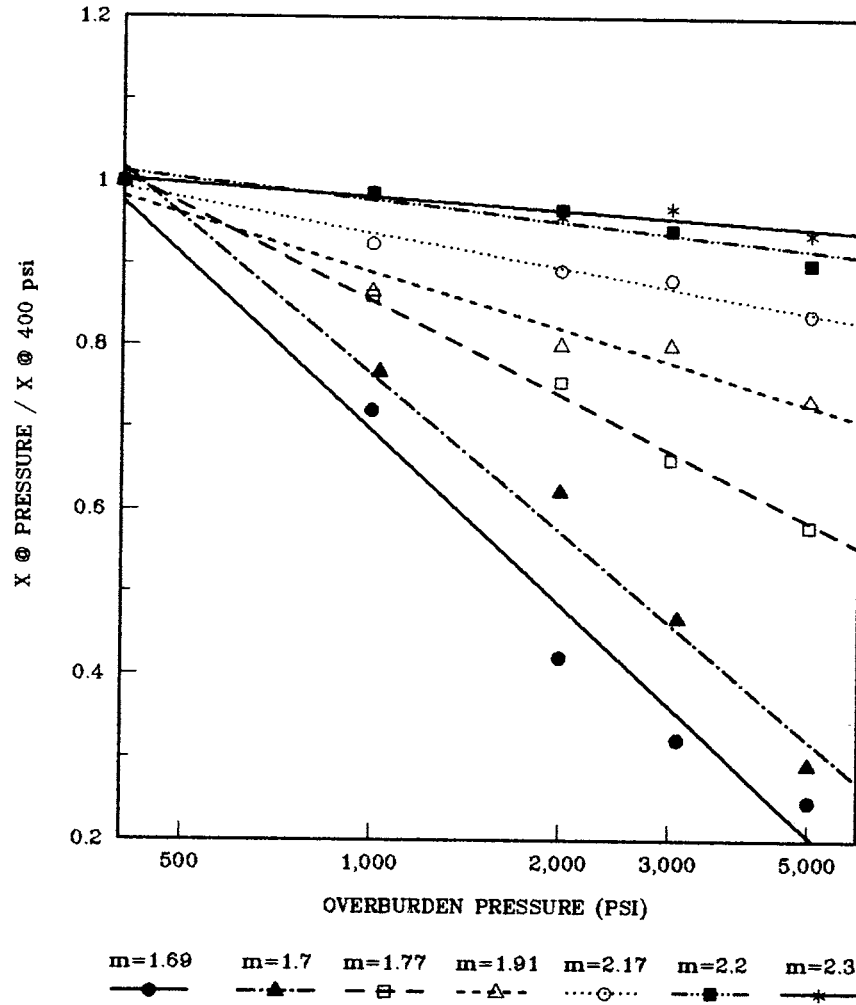
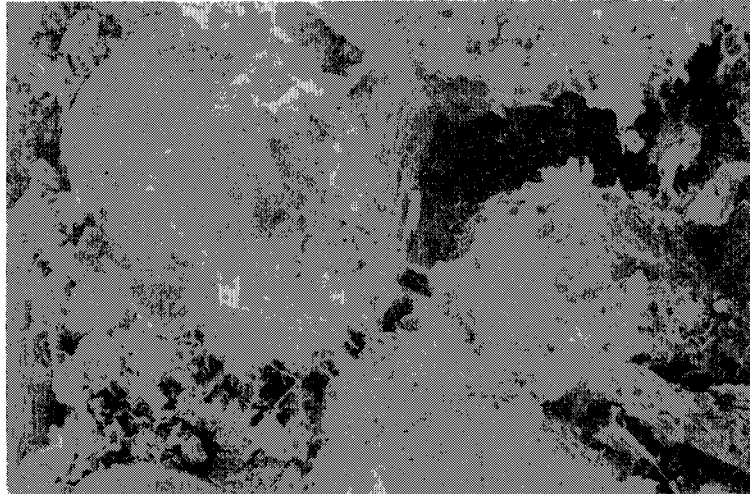
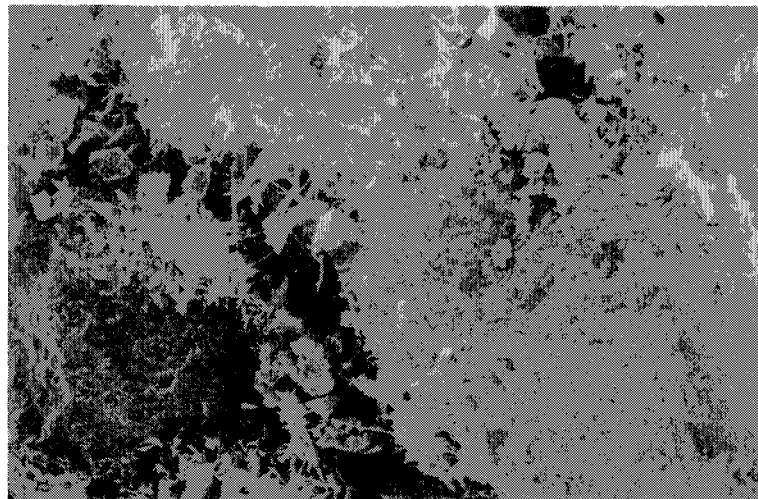


FIGURE 2 Plot to show effect to m on rate of decrease in X with overburden pressure

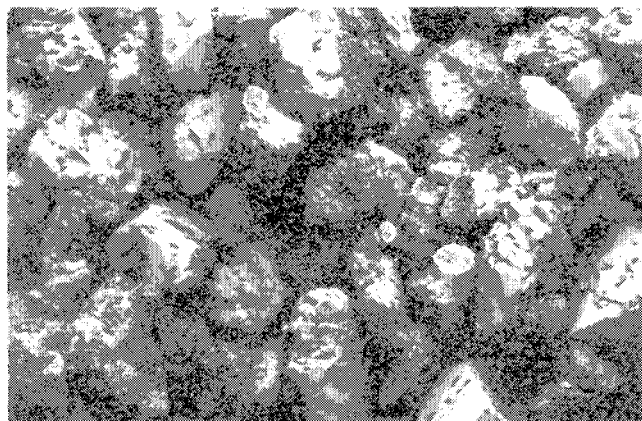


100  $\mu\text{m}$

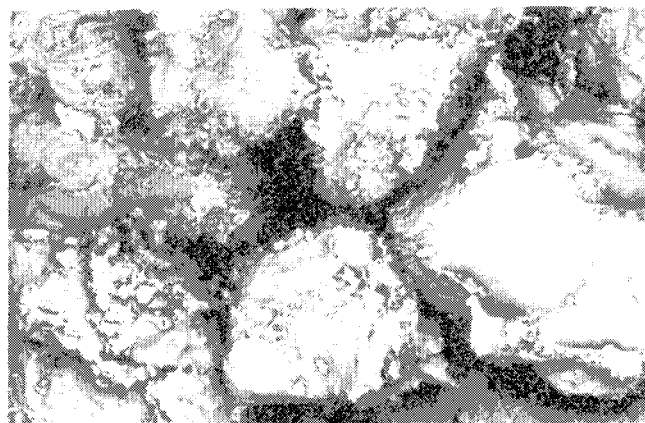


100  $\mu\text{m}$

FIGURE 3 Typical slit shaped pores with  $m=2.3$



100  $\mu\text{m}$



100  $\mu\text{m}$

FIGURE 4 Typical star shaped pores with  $m=1.69$

high values of  $m$  the pore geometry exhibits a 'slit-shaped' appearance, with a low aspect-ratio. For low  $m$  values the pore geometry shows a 'star-shaped', high aspect ratio appearance. This forms a strong agreement with the work Jackson et al. The reduction in  $X$  is faster in star shaped pores as they are closed off at a much faster rate because the pore throats are of a much smaller diameter than the internal pore diameter. This will then electrically isolate the pore. An increase in tortuosity also occurs during compaction which makes the rock much less conductive. In slit-shaped pore geometries the rate of decrease in  $X$  with pressure is much slower as the pores have low aspect-ratios, which will mean that the pore throats will close up at almost the same time as the middle of the pore closes. Therefore, until the point is reached when the slit-shaped pores are completely closed as a result of sufficient overburden pressure, they will still conduct current through the electrolyte and hence through any clay minerals lining the pore walls. Figure 5 shows the effect of pore isolation and change in tortuosity with pressure.

#### **PREDICTION OF EXCESS CONDUCTIVITY AT RESERVOIR PRESSURE**

Having established that excess conductivity should ideally be measured at reservoir pressure if it is to be used in conjunction with wireline log data. It would be advantageous to be able to predict from a low pressure laboratory measurement (400 psi) what the magnitude of  $X$  will be at reservoir pressure. This will save time and money in the definition of reservoir shaliness at reservoir pressure. If the measurements were to be made at pressure, a relationship between  $X$  and pressure would have to be defined from measurements made at differing pressures, thus allowing differing pressure regimes to be accounted for across the reservoir. Limitations of laboratory equipment could also prove a problem in performing tests at reservoir pressure.

An interpretation chart (Figure 6) enables the prediction of  $X$  at reservoir pressures ( $X_p$ ) from a single measurement of  $X$  made at 400 psi, given knowledge of the cementation exponent (as it defines the rate of change in the pore geometry with pressure). The use of this chart is as follows:-

1. Measure  $X$  and  $m$  at 400psi ( $X_{400}$ )
2. Let  $(X_p/X_{400}) = a + b \cdot \log_{10}(P)$  (7)
3. Read off the appropriate values for the constant  $a$  and gradient  $b$  (Fig. 6, below) corresponding to the observed value of  $m$ , measured on the same sample.
4. Then  $X$  at reservoir pressure  $X_p = (a + b \cdot \log_{10}(P)) \cdot X_{400}$  (8)

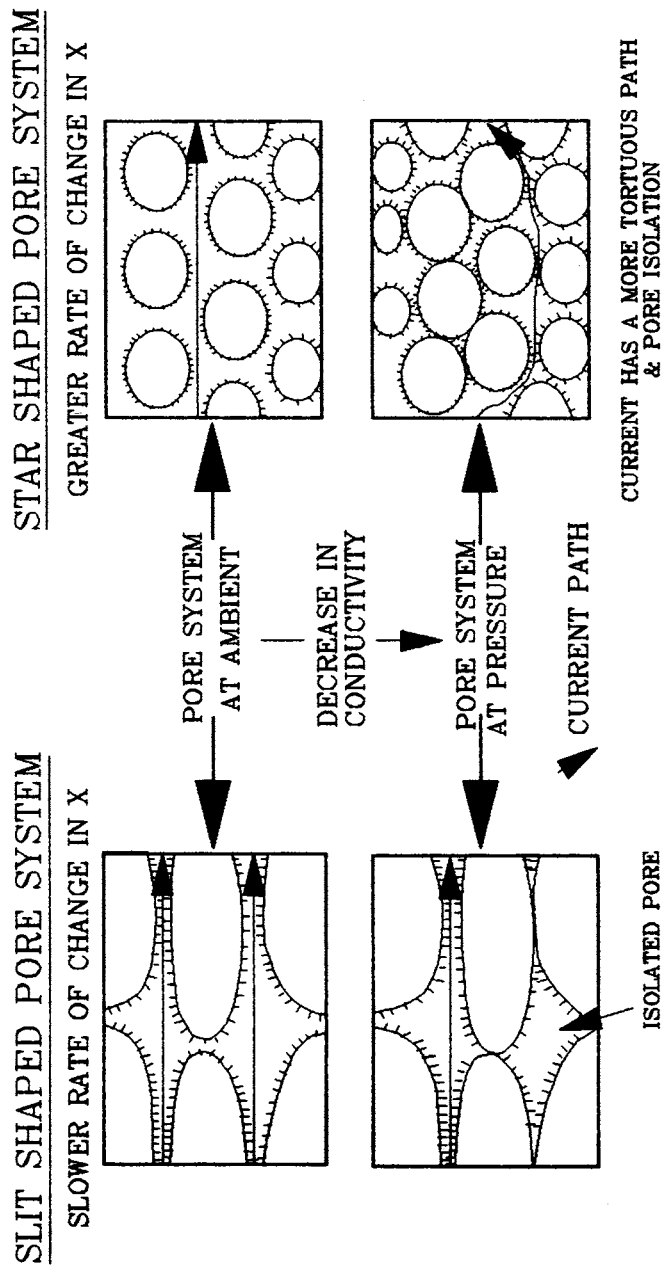
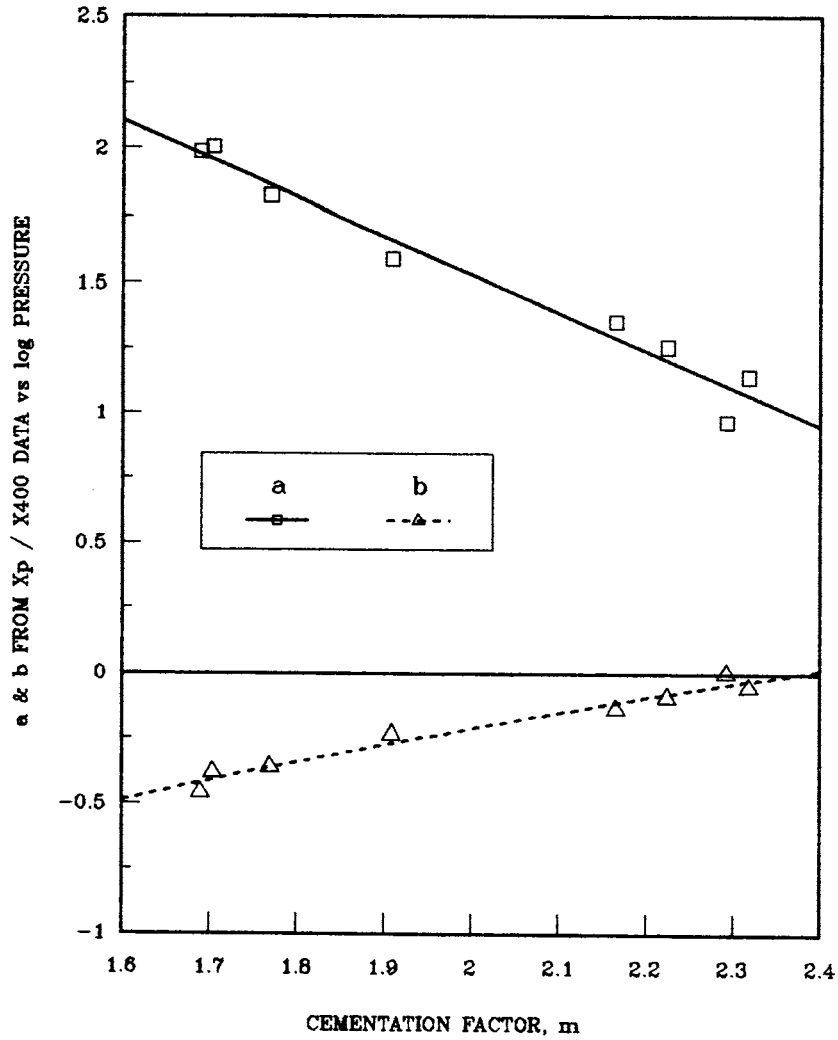


FIGURE 5 Effect of Pore Shape on Change in  $X$



EQUATIONS OF LINES

$$a = -1.442m + 4.415$$

$$b = -1.0871 - 1.234 \cdot \ln(m)$$

**FIGURE 6 Excess Conductivity Prediction Chart**

## CONCLUSIONS

The evaluation of the degree of excess conductivity of a reservoir rock is fundamental to correctly evaluating the water saturation of hydrocarbon bearing shaly reservoirs. The determination of X should, therefore be carried out under simulated reservoir pressure to account for the magnitude of the decrease in X due to tortuosity increases and to the isolation of conducting clay-filled pores. This reduction in shaliness is dependent on the dominant 3-dimensional pore geometry of the rock, which can in turn be defined by the Archie cementation exponent. Traditional methods for the determination of X may provide data that are not representative of the charge-electrolyte-salinity distribution within the original pore geometry because of poor sample preparation or the use of empirical equations. Intrinsic X can therefore only be measured on preserved core samples using the multiple salinity method which preserves the 3-dimensional rock/pore geometry. A relationship has been established between X at reservoir pressure and that at 400 psi which allows prediction of the reduction in X from data obtained at low pressure. Failure to measure X at reservoir pressures could result in significant errors in water saturations calculated from shaly sand equations when core data are input directly with log data.

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# Single Phase Permeation Properties

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