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Analysis of Shaly Sands
Using Neutron and Density Logs

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ABSTRACT

Two conductive materials exist in shaly sand formations contributing to the bulk conductivity: one is clay with its bound water and the other is free formation water. The model is expressed physically as a parallel-resistance network and has been widely used. Although, this model has existed and been used for a long time, some of the parameters of the model have not been determined properly. The reason is that the model is related to some geometry factors that seem undefinable with real data. In 1987, Xiaochun Ma developed a method that gives a solution to this problem.

Ma's model used neutron and density logs to analyze shaly sand formations and generated a simulated resistivity curve to be compared to the actual resistivity recorded in a well. The model removes the shale effect from the resistivity logs and gives a more representative water saturation index in oil bearing zones.

Ma's model has been reviewed, restated and applied to two well logs from different basins. The model has been extended to include gas bearing shaly sand formations. The extended model can be applied in oil, gas or water saturated shaly sand formations. Reservoir parameters such as effective porosity, water saturation and shale fraction can be determined from the extended model.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

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INTRODUCTION

Shales are common constituents of many reservoir rocks. Aside from the effect on porosity and permeability, their importance stems from their electrical properties which greatly influence the determination of fluid saturation. Shale mainly consists of silt (predominantly very fine-grained quartz) and clay minerals.

Most clay minerals are structured in sheets of alumina-octahedron and silica-tetrahedron lattices. Generally there is an excess of negative electrical charges within the clay sheets. The substitution of Al^{+++} by ions of lower valence is the most common cause of this excess charge. To maintain the electrical neutrality of clay particles, positive ions compensate for local imbalance.

When clay particles are immersed in water, the Coulomb Forces holding the positive surface ions are reduced by the dielectric properties of water. The positive ions leave the clay surface and move relatively freely in a layer of water (bound water) near the surface and contribute to the conductivity of the rock.

The Archie water saturation equation, relating rock resistivity to water saturation, assumes that the formation water is the only electrically conductive material (see Archie 1942). The presence of another conductive material

(i.e. shale) means that either the Archie equation must be modified to accommodate the existence of this material or a new model be developed to relate rock resistivity to water saturation in shaly formations.

Since 1950 several shaly-sand models have been developed (see Worthington, 1985, and Ma, 1987). Each tries to incorporate an excess conductivity term resulting from the presence of shale in sandstone formation, into Archie's' rock resistivity-water saturation equation in one way or another.

One model that describes the effect of clay on the electrical properties of shaly-sands as a conductive path through the rock in parallel with the path through the pore system leading to a decrease of bulk resistivity, has been conceptually accepted and mathematically developed by many investigators (see Worthington 1985). This model has the following form:

$$C_o = X\ Cs + Y\ C_w \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ (1)$$

In the above equation C_o is the conductivity of water saturated rock, C_s and C_w are the conductivity of solid (clay with its bound water) and fluid (water). X and Y are called geometry factors representing the geometry of the conductive paths associated with the solid and fluid

accordingly.

However, the model faces some practical limitations when applied to real-log data interpretation. The problem encountered is that in the model the geometry factors X and Y are a function of pore space structure and seem to be undefinable with real data.

Ma (1987) attempted to solve this problem by using the concept of tortuosity. His method can be used with direct application of Archie's equations and establishes a relationship between the tortuosity, porosity, and formation resistivity factor as follows:

$$T^2 = \phi F \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (2)$$

Here, T = tortuosity, ϕ = porosity and F = formation factor. Using relation (1) and (2) Ma evaluated the effect of clay on resistivity log in shaly sand formations.

Ma's model assumes that a 100% shale formation contains not only matrix rock (i.e. silt) and clay minerals with their bound water as conventional shale model suggests, but also contains free formation water which has the same properties as the free formation water in sandstone.

Since Ma's model requires a knowledge of some critical initial values such as resistivity of clay with its bound

water, density of clay, neutron response to clay etc., these initial values are determined in a 100% shale zone near the sand zone of interest. In practice this requirement is usually satisfied. The model uses neutron and density porosity responses and the clay index value proposed by Kukal and Hill (1986) to determine the above clay initial values. These values are then used to determine the volume fraction of clay, bound water, and effective porosity in the interval of interest of the well. This gives the basis to evaluate the shaly sand formation under consideration.

Ma's model also generates a simulated resistivity curve primarily based on neutron and density porosity logs. The curve can be used to see how well the resistivity model simulates the real earth.

The purpose of the present study is to first review and restate the principal topics in Ma's work and then extend his method to include the evaluation of gas bearing shaly sand formations.

Review of the Model

Before introducing the shaly sand resistivity model proposed by Ma (1987), a brief description of shaly sand formations will be given and some concepts that will be used in developing the model will be discussed.

Description of Shaly Sand Formations:

Shaly sand is formed when shale which is considered to consist of silt and clay minerals occurs in clean sandstone. In most clean sands the formation water can freely move and therefore we refer to such water "free formation water".

On the other hand, the dimensions of the pore structure in shale is so small that shale as a whole has almost zero permeability and the formation water can not move freely. Silt mainly consists of fine grained quartz and the water in the silt pores is considered to have the same chemical properties as that of free formation water.

Clay minerals are essentially layered hydrous aluminum silicates. There is usually an excess of negative electrical charge within the clay sheets. The substitution of Al^{+++} by ions of lower valence (the structure of the crystal remains the same) is the most common cause of this excess charge. Positive ions cling to the surface of clay sheet in a hypothetical dry state. When clay particles are immersed in water,

the Coulomb Forces holding the positive surface ions are reduced by the dielectric properties of water. The positive ions leave the clay surface and move relatively freely in a layer of water (bound water) close to the surface. The electrical balance must be maintained so that the positive ions remain close to the clay water interface. Clay with its adsorbed water (bound water) is called "wet clay". It is this wet clay that contributes to the conductivity of the rock.

One of the typical properties of clay minerals is that they contain a considerable amount of hydrogen. In well logging terminology, the hydrogen index (HI) is a measure of hydrogen concentration in a material. The HI of water is approximately 1.0. If the matrix material of water saturated rock contains no hydrogen, the HI of the rock is approximately the porosity of the rock. The HI value of clay minerals varies from mineral to mineral (0.12 - 0.36). Table 1 lists the main clay minerals and some of their properties.

Perhaps the most difficult property of clays to define is their densities. There is no constant density value for a given type of clay because the percentage of constituents of each clay mineral can vary. The range of clay density values is 2.2 - 3.2 g/cm^3.

Natural radioactivity is another characteristic of some

Table 1

Hydrogen Index And Density of Clay Minerals

Mineral	Formula	HI	Density
Kaolinite	$Al_4[Si_4O_{10}](OH)_8$	0.36	2.61
Chlorite	$(Mg,Al_4,Fe)_{12}[(Si,Al)_8O_{20}](OH)_{16}$	0.34	2.60-2.96
Montmorillonite	$(0.5Ca,Na)_{0,7}(Al,Mg,Fe)_4(Si,Al)_8O_{20}(OH)_4$	0.12	2.20-2.70
Illite	$K_{1-1.5}Al_4[Si_{7-6.5}Al_{1-1.5}O_{20}](OH)_4$	0.12	2.64-3.20

clays. Clay minerals have Potassium (K) with traces of Thorium (Th) and Uranium (U) concentrations. Typically, shale exhibits high K and low U and Th values. Most of the radioactivity in shales is from K of clay minerals.

Although clay properties vary according to type, within a specific area, or a certain interval of a well, clay properties are assumed to be constant. This is an assumption usually employed in conventional formation evaluation. In this paper it is assumed that the distribution of clay minerals in a 100% shale zone is the same as in shale present in nearby shaly sandstone.

The Concept of Tortuosity and Its Relation to Porosity and Formation Factor:

It is well known that the resistivity of fluid saturated rock depends on the resistivity of the fluid filling in the effective (connected) pore spaces and the pore structure, assuming that the matrix rock material is not conductive. It is nearly impossible to describe the pore geometry of a real rock. It is too complex.

To simplify such a problem, consider a rock with cross-sectional area S and length L and porosity ϕ. Put the effective pore spaces together to form a fluid channel with cross-sectional area Se and length L_e (see Figure 1). Here,

Le represents the path length of the pore channel along which electrical current flows, and Se represents the cross-sectional area of the pore channel. This conductive fluid channel controls the resistance of the rock and we can write the following relationship.

$$\frac{R_o\ L}{S} = \frac{R_w\ L_e}{S_e}$$

In the above equation R_o represent the resistivity of the bulk rock saturated with fluid of resistivity R_w.

Multiplying the numerator and denominator of the left side of the equation by L, and the right side by Le, gives:

$$\frac{R_o\ L^2}{S\ L} = \frac{R_w\ L_e^2}{S_e\ L_e}$$

Note that S_eL_e is the pore volume and SL is the bulk volume of the rock. The above equation can be rewritten as:

$$R_wL_e^2SL = R_oL^2S_eL_e$$

Dividing both sides by L^2SL gives:

$$R_w\ (L_e\ /\ L)^2 = R_o\ (S_eL_e\ /\ SL)$$

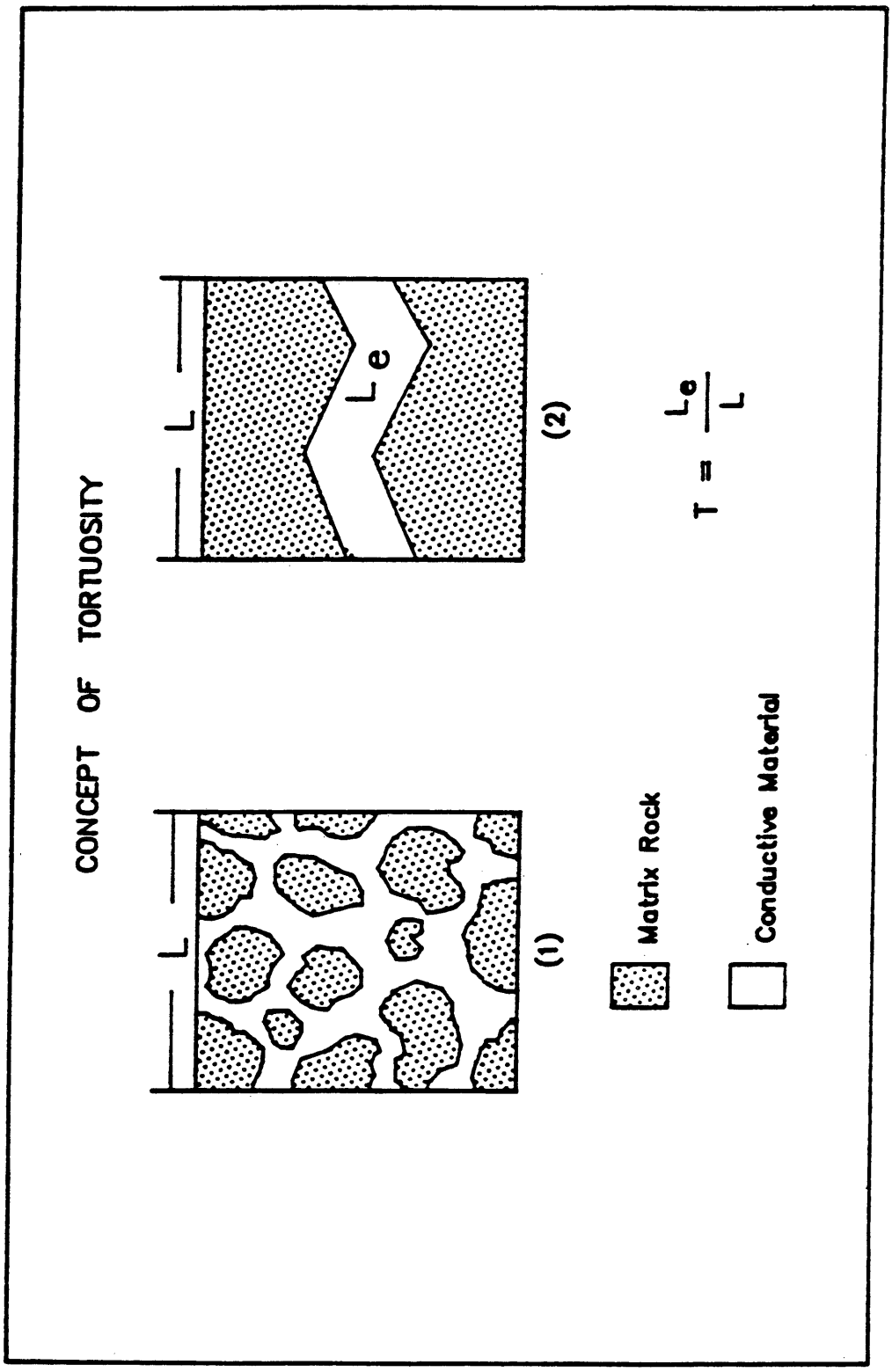

Figure 1. The concept of Tortuosity. (1) True formation. (2) Simplified formation.

Finally dividing by R_w gives:

$$(L_e / L)^2 = R_o / R_w \ (S_e L_e / SL)$$

Or $(L_e / L)^2 = F \phi$

Here, (L_e / L) is defined as tortuosity, the length of the path of a fluid passing through a unit length of rock, and is denoted by T. F is the formation resistivity factor and ϕ is the porosity. The equation then becomes:

$$T^2 = \phi F \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (3)$$

Now that we have briefly covered the concepts needed in developing the shaly sand resistivity model proposed by Ma, the model itself is introduced.

The Shaly Sand Resistivity Model

In water bearing shaly sand formations, The conductive materials are usually considered to be fluid (material 1) which totally fills the effective pore system and shale which is conductive solid (material 2). The conductivity of the formation is controlled by these two elements acting in parallel. The matrix of the formation is considered to be non-conductive. Hence as stated in relation (1), we can express the conductivity of the water saturated rock (C_o) as:

$$C_o = X\ C_s + Y\ C_w$$

Now consider a certain volume of such rock with cross-sectional area S and length L. The <u>conductance</u> of the formation is the sum of the conductances of the paths through materials 1 and 2 . The relationship can be expressed as:

$$\frac{1}{R_o L / S} = \frac{1}{R_1 L_1 / S_1} + \frac{1}{R_2 L_2 / S_2} \quad \ldots\ldots (4)$$

where R_o is the bulk resistivity of the formation, R_1 and R_2 are the resistivities of materials 1 and 2. S_1 and S_2 represent the cross-sectional areas of material 1 and 2. Multiplying both sides of the equation by L/S and rearranging, we get the <u>conductivity</u> relationship:

$$\frac{1}{R_o} = \frac{1}{R_1} * \frac{S_1 L}{L_1 S} + \frac{1}{R_2} * \frac{S_2 L}{L_2 S} \quad \ldots\ldots(5)$$

Comparing equation (5) to equation (1), we conclude that the geometry factors X and Y can be expressed as:

$$X = S_1 L \,/\, L_1 S \,, \qquad Y = S_2 L \,/\, L_2 S \,.$$

It is obvious that determining X and Y from the above expression is difficult in practice. In order to find a meaningful and easy to determine expression for X and Y, some mathematical procedures are taken. Multiplying the numerator and denominator of the X term by $L*L_1$ and the numerator and denominator of the Y term by $L*L_2$, we obtain:

$$X = (L^2/L_1^2)\ (L_1 S_1/LS), \quad Y = (L^2/L_2^2)\ (L_2 S_2/LS) \quad \ldots\ldots(6)$$

we see that $L_1 S_1 / LS$ and $L_2 S_2 / LS$ are the volume fractions of materials 1 and 2 (denoted as ϕ_1 and ϕ_2 respectively). L/L_1 is the reciprocal of tortuosity of the path through material 1, L/L_2 is the reciprocal of tortuosity of the path through material 2 .

From the forms of Equations (5) and (6) we can see that both resistance elements can be studied separately. The

first term in the right side of equation (5) represents the part of the conductive volume occupied by material 1 . In studying this term the parts occupied by material 2 and matrix rock can be considered non-conductive. Similarly the second term in the right side of equation (5) represents the part of the conductive volume occupied by material 2 . In studying this term the parts occupied by material 1 and matrix rock can be considered non-conductive. Figure 2 conceptualizes this model.

Using equation (3), we can express the tortuosities of material 1 and 2 as $\phi_1 F_1$ and $\phi_2 F_2$. The new expressions for X and Y then become:

$$X = (1 / \phi_1 F_1) \phi_1 = 1 / F_1$$
$$Y = (1 / \phi_2 F_2) \phi_2 = 1 / F_2$$

As a result equation (5) can be written as:

$$1 / R_o = X / R_1 + Y / R_2 \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (7)$$

where $X = 1 / F_1$ and $Y = 1 / F_2$. The geometry factors X and Y are now expressed in meaningful, easy to determine expressions. They are expressed such that they depend only on "geometry structures " of the conductive paths.

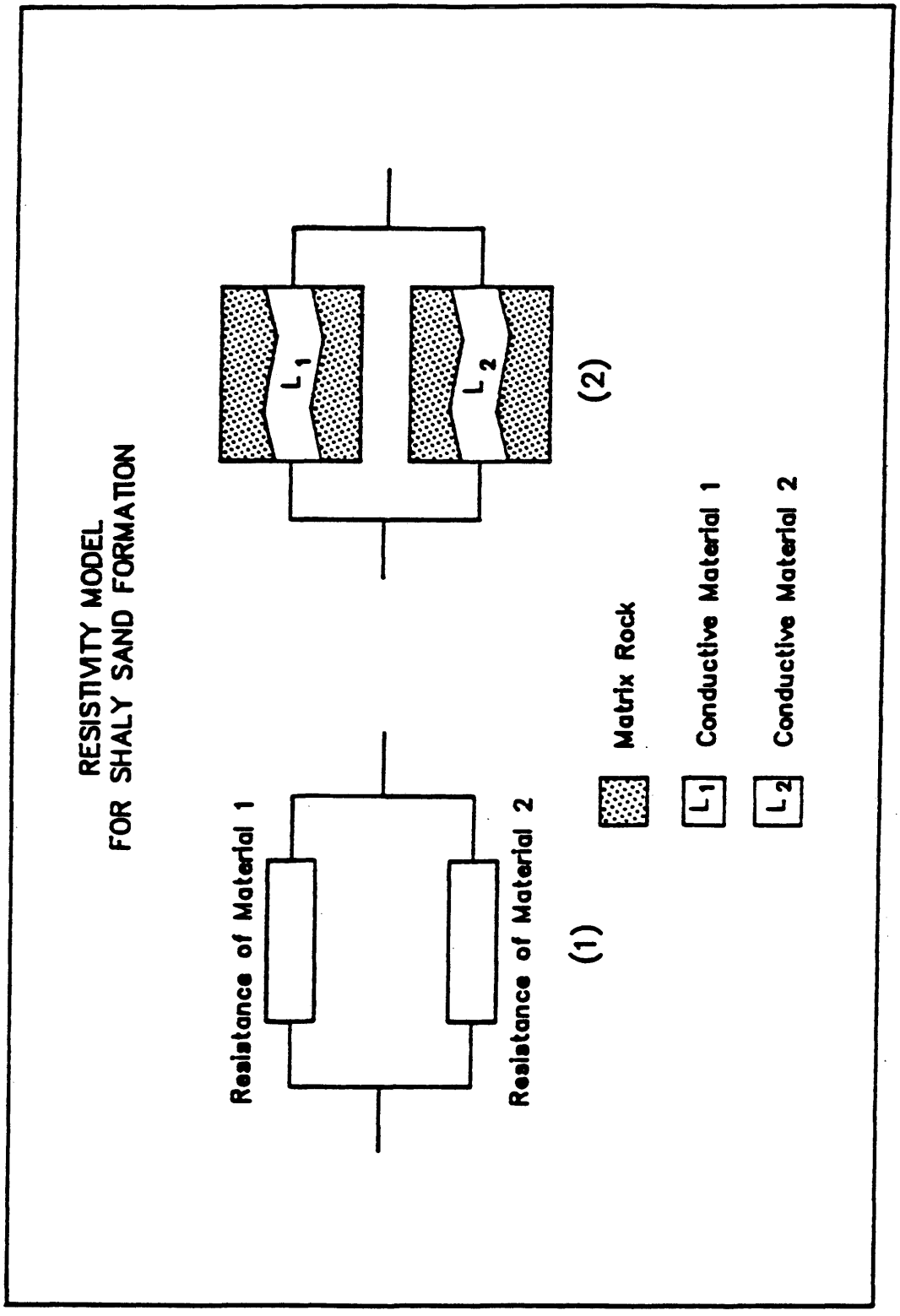

Figure 2. Resistivity model for shaley sand formation. (1) Parallel-resistor network. (2) Physical model with two components.

Equation (7) expresses the parallel resistance model. In the equation, the variables are R_1, the resistivity of material 1 (the conductive solid), R_2, the resistivity of material 2 (water), F_1 and F_2, the formation resistivity factors of clay and water paths respectively.

In the next chapter methods will be developed to determine each of the variables in equation (7) from well log data.

Determination of Formation Parameters

The formation parameters used in the model are obtained mainly from Neutron Porosity (ϕ_n) and Density Porosity (ϕ_d) logs. It is appropriate to first briefly discuss the responses of these logs and a few others which will enter in our discussion.

Neutron Response:

The neutron porosity log responds primarily to the hydrogen content known as Hydrogen Index, HI, of the formation. The HI of a unit volume of free formation water is 1.0 . When a formation is shale free (clean) sand, the reading of the neutron log in liquid saturated rock is the porosity of the formation. Shaliness has a large effect on the neutron response because there is a great amount of hydrogen present in clay minerals with their bound water.

Density Response:

The density porosity log, which is usually scaled in sandstone porosity units, responds to the bulk density of formations. It is expressed as:

$$\phi_d = \frac{\rho_m - \rho_b}{\rho_m - \rho_w}$$

Here ϕ_d is the density derived porosity, ρ_m and ρ_w are

the assumed densities of the matrix and formation fluid and ρ_b is the measured bulk density. The density of shaly sand is the volume weighted average of the densities of the matrix rock, clay minerals, bound water, free formation water and hydrocarbons present.

Typically sand matrix has density of 2.65 g/cm^3, and the density of clay varies within the range of 2.2 - 3.2 g/cm^3. It is assumed that within an interval of a well being analyzed, the density of clay remains constant. The density of bound water may be as high as 1.4 g/cm^3, but has an average of about 1.2 g/cm^3 (Ruhovets and Fertl, 1981). The value 1.2 g/cm^3 is used in this paper.

Gamma Ray:

The natural gamma ray log measures the natural gamma ray emission from formations. Gamma rays are generated when the radioactive materials in the formation decay. This log is used to indicate shaliness of formations. In 100% shale zones the log records maximum values, while in clean zones it shows minimum values. Therefore, in some interpretation methods, the gamma ray log is used to calculate the volume of shale. However, the method described in this thesis is not dependant on the natural gamma ray log to determine the volume of shale

Resistivity log:

The deep investigating resistivity log measures the bulk resistivity of formations. Since hydrocarbons are non-conductive but occupy effective porosity, hydrocarbon bearing formations have higher resistivity values than their equivalent non-hydrocarbon bearing zones. A formation's resistivity value depends on the resistivity and the volume of formation water. Therefore, the formation resistivity is related to water saturation. In shaly sand formations, since the clay materials are conductive, the bulk resistivity values are affected by the presence of shale.

Now that we have briefly introduced the logs we will use in determining the formation parameters, we turn back to the resistivity model expressed in equation (7). For convenience the equation is copied here.

$$1 / R_o = X / R_1 + Y / R_2, \quad X = 1 / F_1, \; Y = 1 / F_2$$

In the above equations, we need to determine R_1, the resistivity of clay with its bound water, F_1, the formation factor of clay with its bound water, R_2, the resistivity of free formation water, F_2, the formation factor of the free formation water.

Consider a 100% shale zone. As was stated earlier, 100% shale zone is assumed to consist of matrix rock (silt), clay minerals with bound water and free formation water contained in the capillaries of silt. Here "free water" does not necessarily mean it can freely move. It is assumed that such free water has the same properties as the water in sandstone. For example, both have the same density and resistivity.

The conductive materials in the shale zone are:

1) clay minerals with bound water (conductive solid),

2) free formation water (conductive fluid).

Let R_{cb} be the resistivity of clay with its bound water and R_w be the resistivity of free formation water. For 100% shale zone equation (7) can be written as:

$$1 / R_{sh} = 1 / F_{cb}R_{cb} + 1 / F_wR_w \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (8)$$

Where R_{sh} is the bulk resistivity of 100% shale, F_{cb} and F_w are the formation resistivity factors defined by clay with its bound water and free formation water respectively.

Equation (8) can be solved for R_{cb} giving,

$$R_{cb} = R_{sh}\, F_w\, R_w \;/\; F_{cb}\,(F_w\, R_w - R_{sh}) \quad \ldots\ldots\ldots\ldots \quad (9)$$

In equation (9), R_{sh} can be read directly from logs and

R_w can be determined by any of the several methods currently used in well logging analysis from an adjacent reservoir rock. F_{cb} and F_w are still unknowns. A method to determine these variables will be given shortly.

Note that equation (7) holds for non-100% shale zones (shale volume fraction less than 1) as well. In this case, free formation water is from two parts of the formation, sandstone and shale (the silt portion of shale). Both waters have the same properties and are considered one electrolyte.

The formation factors F_{cb} and F_w can be determined using $F - \phi$ relationship expressed by Archie (1942).

$$F = a\,\phi^{-m} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (10)$$

Ma (1987) introduced a new $F - \phi$ relationship based on curve fitting through the data sets published by Waxman and Smits (1967) and Waxman and Thomas (1974). See Table 2 and Figure 3. The relationship has the following form:

$$F = A\,\phi^{\sqrt{\phi\,F}} - 1 + B\,\mathrm{Ln}\,\phi \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (11)$$

Here, A = 1.078 and B = 1.533. In equations (10) and (11), ϕ represents the volume fraction occupied by a conductive material (e.g., clay with its bound water or free formation water).

Table 2

ϕ And F Data of Clean Sand Cores

Core	ϕ	F
Data Set 1 (From Waxman and Smits, 1967): Table 1		
1-25	0.230	15.6
1-38	0.232	9.8
2-16	0.118	52.4
2-39	0.212	12.4
Data Set 2 (From Waxman and Smits, 1967): Table 3		
1-4	0.202	15.8
1-8	0.208	15.5
1-10	0.245	12.2
Data Set 3 (From Waxman and Thomas, 1974): Table 4		
3301B	0.135	38.2*

The information source only provides the values of porosity and cementation m for a sand stone core. Since the Qv value for this core is 0.06 which can be considered to be a clean rock, the formation factor is calculated with the equation:

$$F = \phi^{-m}$$

where m = 1.82.

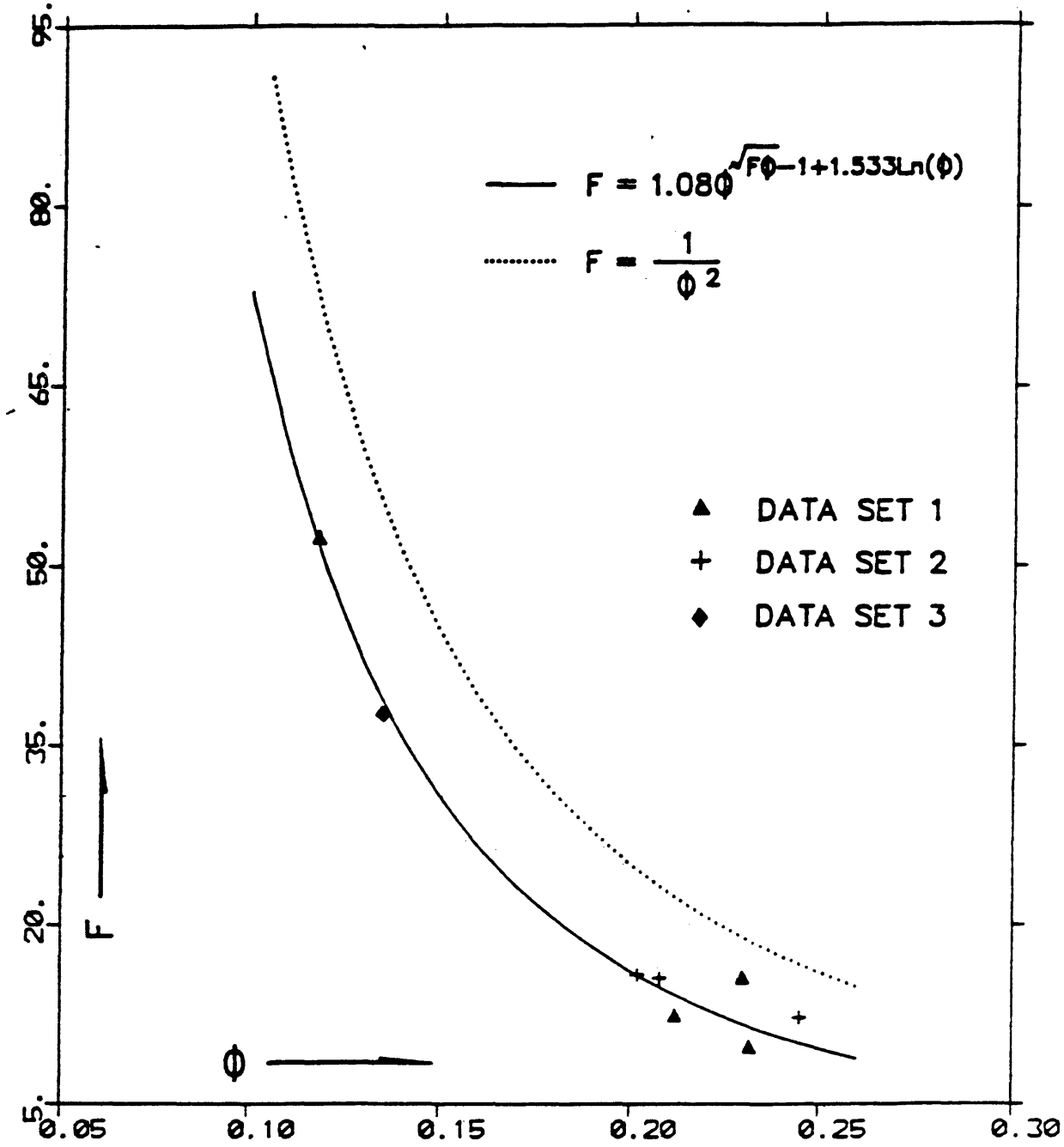

Figure 3. F-φ relationship derived from Waxman and Smits, and Waxman and Thomas' data.

To solve for F no matter which equation we use (10 or 11), the knowledge of the volume fraction of clay with its bound water and free formation water is necessary. In the following paragraphs, using neutron porosity and density porosity, we set some equations to solve for these volume fractions.

Consider a 100% shale zone. The constituents of the formation are matrix rock (silt), clay with its bound water and free formation water. The neutron response to the formation is the sum of the neutron response to each component of the formation.

$$\phi_{nsh} = V_w\phi_{nw} + V_{cl}\phi_{ncl} + V_{bw}\phi_{nbw} + V_{ma}\phi_{nma} \quad \ldots\ldots \quad (12a)$$

In the above equation, V_w, V_{cl}, V_{bw} and V_{ma} stand for volume fractions of free formation water, clay, bound water and matrix rock respectively. ϕ_{nsh}, ϕ_{nw}, ϕ_{ncl}, ϕ_{nbw} and ϕ_{nma} are the neutron response to shale, free formation water, clay, bound water and matrix rock. Similarly for the density response we can write:

$$\rho_{sh} = V_w\rho_w + V_{cl}\rho_{cl} + V_{bw}\rho_{bw} + V_{ma}\rho_{ma} \quad \ldots\ldots\ldots \quad (12b)$$

where ρ represents density.

Obviously, the sum of the volume fractions of free formation water, clay, bound water and matrix equals 1.0 .

$$1.0 = V_w + V_{cl} + V_{bw} + V_{ma} \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (12c)$$

Kukal and Hill's (1986) work indicated that generally shale contains an average of about 60% of clay minerals. Here, shale does not include free water and bound water. This "dry shale" then contains 40% of matrix rock materials. From this the relationship between matrix volume and clay volume can be expressed as:

$$V_{ma} = ((1-K)\ V_{cl} / K\ ) \quad \ldots\ldots\ldots \quad (12d)$$

where K is called clay index and is equal to 0.6 .

In the above four equations, the unknowns are, V_w, V_{cl}, V_{bw}, V_{ma}, ϕ_{ncl} and ρ_{cl}. But ϕ_{ncl} and ρ_{cl} are known within a range (ϕ_{ncl} = 0.11 - 0.36 and ρ_{cl} = 2.2 - 3.2 g/cm^3). If ϕ_{nw} is taken to be 1.0 and ϕ_{nma} is 0.0, at certain values of ϕ_{ncl} and ρ_{cl} the above equations yield:

$$V_{cl} = \frac{\rho_{sh} - \rho_w + \dfrac{(\phi_{nsh} - 1)\ (\rho_w - \rho_{bw})}{(\phi_{nbw} - 1)}}{\dfrac{(\phi_{ncl} - 1/K)(\rho_w - \rho_{bw})}{(\phi_{nbw} - 1)} + \dfrac{1-K}{K}\rho_{ma} + \rho_{cl} - \dfrac{\rho_w}{K}} \quad \ldots\ldots (13)$$

$$V_{bw} = (\phi_{nsh}{}^{-1-V_{cl}}(\phi_{ncl} - 1/K)) \; / \; (\phi_{nbw} - 1) \quad \ldots\ldots\ldots \quad (14)$$

$$V_w = 1 - 1/K * V_{cl} - V_{bw} \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (15)$$

To obtain the true values of ϕ_{ncl} and ρ_{cl}, a test zone which is a general zone (shale < 100%) is chosen nearby 100% shale formation. For the test zone we can write:

$$\phi_n = V_{w1}\phi_{nw} + V_{cl1}\phi_{ncl} + V_{bw1}\phi_{nbw} + V_{ma1}\phi_{nma} \quad \ldots\ldots \quad (16)$$

$$\rho_b = V_{w1}\rho_w + V_{cl1}\rho_{cl} + V_{bw1}\rho_{bw} + V_{ma1}\rho_{ma} \quad \ldots\ldots\ldots \quad (17)$$

$$1.0 = V_{w1} + V_{cl1} + V_{bw1} + V_{ma1} \quad \ldots\ldots\ldots\ldots\ldots\ldots (18)$$

Since in this paper it is assumed that within a certain interval of a well, clay properties do not change, clay and bound water volume fractions of the test zone can be determined as follows:

$$V_{cl1} = V_{sh} * V_{cl} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (19)$$

$$V_{bw1} = V_{sh} * V_{bw} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (20)$$

Here, V_{sh} is the volume fraction of shale in the test zone and V_{cl} and V_{bw} are the volume fractions of clay and

bound water in the 100% shale zone. Conventionally, volume fraction of shale is calculated from Gamma ray logs. Since the source of gamma rays in a formation could be materials other than shale as well, in this paper, volume of shale is calculated from the following formula (see Ma, 1987 and Davis, 1983):

$$V_{sh} = (\phi_n - \phi_d) / (\phi_{nsh} - \phi_{dsh}) \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (21)$$

Here, $\phi_{dsh} = (\rho_{sh} - \rho_{ma}) / (\rho_w - \rho_{ma})$

and $\phi_d = (\rho_b - \rho_{ma}) / (\rho_w - \rho_{ma})$

ϕ_n is the neutron porosity reading from log in the respective zone and ϕ_{nsh} is the neutron porosity reading in the 100% shale zone.

Substituting equations (19) and (20), in equations (16) and (18) and solving for the free formation water term (V_{w1}) gives the expression for free water volume fraction (call it V_{w11} here).

$$V_{w11} = \phi_n - V_{sh} (V_{cl} \phi_{ncl} + V_{bw} \phi_{nbw}) \quad \ldots\ldots\ldots\ldots \quad (22)$$

Similarly, equations (17) and (18) give another expression for the free water volume fraction:

$$V_{w12} = \phi_d - V_{sh} (V_{cl} \phi_{dcl} + V_{bw} \phi_{dbw}) \quad \ldots\ldots\ldots\ldots (23)$$

where, $\phi_{dcl} = (\rho_{cl} - \rho_{ma}) / (\rho_w - \rho_{ma})$

and $\phi_{dbw} = (\rho_{bw} - \rho_{ma}) / (\rho_w - \rho_{ma})$

Let df = $| V_{w11} - V_{w12} |$. For the true value of ϕ_{ncl} and ρ_{cl}, df should be minimum. Varying ϕ_{ncl} from 0.12 - 0.36 and ρ_{cl} from 2.2 -3.2 g/cm^3, each pair of (ϕ_{ncl}, ρ_{cl}) gives a value for df. Summing up the values of df for each pair of (ϕ_{ncl}, ρ_{cl}) over all the depth points within the test zone, the value of (ϕ_{ncl}, ρ_{cl}) corresponding to the minimum sum are chosen to be the approximate values for ϕ_{ncl} and ρ_{cl}.

After finding ϕ_{ncl} and ρ_{cl}, equations (13) - (15) are used to calculate the volume fractions of clay (V_{cl}), bound water (V_{bw}) and free formation water (V_w) in the 100% shale zone. The volume fraction of clay with its bound water (V_{cb}) is simply the sum of V_{cl} and V_{bw}.

Using equation (10) or (11) the above volume fractions give the formation factor of clay with its bound water (F_{cb}) and free formation water (F_w) for the 100% shale zone. R_{cb} can be directly obtained from equation (9).

The free formation water in any other zone is obtained by using equations (22) and (23), with V_{sh} representing the

shale volume fraction in the zone being analyzed. The volume fraction of free water is then the average of the volume fractions obtained from equations (22) and (23).

$$V_w = (V_{w11} + V_{w12}) / 2$$

Our work so far has enabled us to determine all the necessary formation parameters (ρ_{cl}, ϕ_{ncl}, V_{cl}, V_{bw}, V_w and R_{cb}) by using ϕ_n, ϕ_d and R_{sh} as input parameters. In the next section we will use these parameters to calculate simulated resistivity curves.

Resistivity of Free Formation Water

Although we will introduce a method to determine R_w, it can be determined by any of the several procedures used in well logging industry.

As in conventional well log interpretation, the resistivity of formation water is one of the most important parameters needed for the evaluation of the proposed shaly sand model. Traditional sources of R_w information include produced water on production tests, R_{wa}, and the SP log in clean formations. In this paper, R_w is determined with the shaly sand resistivity model.

Consider a shaly sand hydrocarbon free zone and a 100%

shale zone. For the shaly sand zone we can write:

$$\frac{1}{R_o} = \frac{1}{F_{cb1}\ R_{cb}} + \frac{1}{F_{w1}\ R_w} \quad \text{.....(24)}$$

and for 100% shale zone we can write:

$$\frac{1}{R_{sh}} = \frac{1}{F_{cb}\ R_{cb}} + \frac{1}{F_w\ R_w} \quad \text{.....(25)}$$

Equations (24) and (25) can be written as:

$$\frac{F_{cb1}}{R_o} - \frac{F_{cb1}}{F_{w1}\ R_w} = \frac{1}{R_{cb}}$$

$$\frac{F_{cb}}{R_{sh}} - \frac{F_{cb}}{F_w\ R_w} = \frac{1}{R_{cb}}$$

Note that the right sides of both equations are equal. Equating the left sides and solving for Rw we obtain:

$$R_w = \frac{(1/F_w - F_{cb1}/F_{w1}F_{cb})}{(1/R_{sh} - F_{cb1}/R_oF_{cb})} \quad \text{.....(26)}$$

In this work equation (26) is used to determine R_w.

Simulated Resistivity Curve and Analysis of Hydrocarbon Bearing Zones

Simulated Resistivity Curve (R_o):

Equation (7) can be used to generate a simulated resistivity curve. Let us remember that in deriving equation (7) we assumed non-hydrocrbon bearing formation. Therefore equation (7) in fact gives us the resistivity of brine saturated rock (R_o). The principal input data in equation (7) are neutron and density porosities. The generated R_o curve can be compared to the deep induction log to see how well the model works. The R_o curve should agree with deep induction curve in the water saturated intervals. However, since neutron and density porosity tools have much shorter spacing than the deep induction log, the two curves may carry some differences. Each recorded measurement of the deep induction log is an average of the points above and below it. Removing this averaging effect from the deep induction log and making it comparable to R_o based on neutron and density logs is not an easy task. For simplicity in this paper, the simulated resistivity data is run through an averaging process as below.

$$Y_i = \frac{\sum_{k=-n}^{n} Y_{(i+k)}}{N}$$

Here, Y_i is the simulated resistivity value after the processing, $Y_{(i+k)}$ is the simulated resistivity value before the processing and N is the number of measurements (N=2n+1).

Analysis of Hydrocarbon Bearing Zones

a) Oil Bearing Zones:

According to Archie, the saturation index, SI, for shale free formation is defined as:

$$S_w^{-n} = SI = R_t / R_o \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (27)$$

In equation (27) R_t is the true resistivity of the zone and R_o is the resistivity of the formation completely saturated with brine.

In order to use equation (27) in the shaly sand formations, the shale effect must be removed from both R_t and R_o. In other words, the conductivity due to shale must be subtracted from the conductivity of the uninvaded zone and the conductivity of the water saturated zone of the formation.

The conductivity due to the shale portion of the formation can be obtained from:

$$1 / R_{sh} = 1 / F_{cb}R_{cb} + 1 / F_{w1} R_w \quad \ldots\ldots\ldots\ldots\ldots \quad (28)$$

In equation (28), F_{cb} and F_{w1} are the formation factors related to (clay + bound water) and free formation water from the silt portion of the shale in the formation. R_{cb} is the resistivity of clay plus bound water and R_w is the

resistivity of the free formation water.

The volume fractions of clay, bound water and free water from the shale portion of the formation can be obtained from the following relationships:

$$\begin{aligned} V_{cl1} &= V_{sh} * V_{cl} \\ V_{bw1} &= V_{sh} * V_{bw} \\ V_{w1} &= V_{sh} * V_{w} \\ V_{cb} &= V_{cl1} + V_{w1} \end{aligned} \quad \text{..... (29)}$$

In the above equations, V_{cl}, V_{bw} and V_w are the volume fraction of clay, bound water and free formation water in the 100% shale zone. V_{sh}, V_{cl1}, V_{bw1} and V_{w1} are the volume fractions of shale, clay, bound water and free formation water from the shale portion of the formation being analyzed. V_{cb} is the volume fraction of clay plus the volume fraction of bound water. To obtain F_{cb} and F_{w1} from V_{cb} and V_{w1}, we simply use either of equations (10) or (11).

The effective porosity of the formation is defined as V_{pe}/V_b, where V_{pe} is the effective pore space (pore space containing moveable liquid or gas) and V_b is the bulk Volume of the rock. Since the Neutron and density logs respond to oil and water very similarly, the free formation water obtained for the calculation of R_o curve can be used to find

the effective porosity. The free water fraction used in the calculation of R_o curve consists of free formation water from sand, free formation water from silt and the fraction of oil in the formation if any. To obtain the effective pore space all we need to do is to remove the free water of silt from the total water used in calculation of R_o curve. This free water in silt is V_{w1} in equation (29). Consequently,

$$\text{Effective porosity} = V_w - V_{w1} / V_b \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (30)$$

In equation (30), V_w = total volume fraction of free water in the formation (free water + oil), V_{w1}= the fraction of free water in silt, and V_b = bulk volume of the rock (in the case of this mode, V_b = 1).

b) Gas Bearing Zones:

The presence of gas in the formation affects the response of both neutron and density tools. The density log over estimates porosity (gas has low density) and the neutron log under estimates porosity (gas has lower concentration of hydrogen).

The presence of shale along with gas further complicates the problem. The presence of shale results in higher neutron porosities and slightly lower or higher density porosity

depending on the density of shale. Of course shale would not affect density porosity if the density of shale is equal to the density of the matrix (sand).

In conventional well log analysis, the problem is solved by using an independent indicator of shale (indicator other than neutron and density porosities) such as gamma ray or SP log. First, shale correction is applied to the data and then gas correction is attempted by forcing the density and neutron porosities, in a certain way, to come to agreement.

Since in the model discussed in this paper only neutron and density logs are used to analyze shaly sand formations, a new method is developed to correct neutron and density logs for gas effect in the presence or absence of shale.

Gas Effect

The density porosity is obtained from the following equation.

$$\phi_d = \frac{\rho_m - \rho_b}{\rho_m - \rho_f} \quad \text{.....} \quad (31)$$

In equation (31) ρ_m and ρ_f are the matrix and fluid densities respectively (ρ_m = 2.65 and ρ_f = 1.0). ρ_b is the bulk density of the formation and can be expressed as:

$$\rho_b = V_{sd}\rho_{sd} + V_{wsd}\rho_w + V_{gsd}\rho_g + V_{slt}\rho_{slt} + V_{wslt}\rho_w + V_{cl}\rho_{cl} + V_{bw}\rho_{bw} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (32)$$

In equation (32), V_{sd}, V_w, V_g, V_{slt}, V_{wslt}, V_{cl} and V_{bw} stand for volume fractions of sand, water in sand, gas in sand, silt, water in silt, clay and bound water respectively. w stand for water, g stands for gas and ρ represents density.

The neutron porosity of the formation can be expressed as:

$$\phi_n = V_{sd}\phi_{nsd} + V_{wsd}\phi_{nw} + V_{gsd}\phi_{ng} + V_{slt}\phi_{nslt} + V_{wslt}\phi_{nw} + V_{cl}\phi_{ncl} + V_{bw}\phi_{nbw} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (33)$$

In the above equation, ϕ_n stands for neutron porosity.

Note that in equation (32) and (33),

$$V_{sd} + V_{wsd} + V_{gsd} + V_{slt} + V_{wslt} + V_{cl} + V_{bw} = 1.0$$

The pore volume of sand can be expressed as:

$$V_{poresd} = V_{wsd} + V_{gsd} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (34)$$

and $$S_g = V_{gsd} / V_{poresd} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (35)$$

where S_g is gas saturation in the sand.

Substituting equation (32) in equation (31) and express-

ing ϕ_d and ϕ_n in terms of sand pore volume (Vporesd), we obtain,

$$\phi_d = \frac{2.65}{1.65} - \frac{V_{sd}\rho_{sd}}{1.65} - \frac{(V_{poresd} - V_{gsd})\rho_w}{1.65} - \frac{V_{gsd}\rho_g}{1.65} - \frac{V_{slt}\rho_{slt}}{1.65} - \frac{V_{wslt}\rho_w}{1.65} - \frac{V_{clay}\rho_{clay}}{1.65} - \frac{V_{bw}\rho_{bw}}{1.65} \quad \ldots\ldots(36)$$

$$\phi_n = V_{sd}\phi_{nsd} + (V_{poresd} - V_{gsd})\phi_{nw} + V_{gsd}\phi_{ng} + V_{slt}\phi_{nslt} + V_{wslt}\phi_{nw} + V_{clay}\phi_{nclay} + V_{bw}\phi_{nbw} \quad \ldots\ldots\ldots\ldots (37)$$

Differentiating equations (36) and (37) with respect to volume fraction of gas in sand (V_{gsd}), we obtain.

$$d\phi_d = \frac{(\rho_w - \rho_g)}{1.65} * d\,V_{gsd} \quad \ldots\ldots\ldots\ldots\ldots\ldots (38)$$

$$d\phi_n = (- \phi_{nw} + \phi_{ng})\, dV_{gsd} \quad \ldots\ldots\ldots\ldots\ldots\ldots (39)$$

Dividing equation (38) by equation (39) gives,

$$\frac{d\phi_d}{d\phi_n} = \frac{(\rho_w - \rho_g)}{1.65\ (\phi_{ng} - \phi_{nw})} \quad \ldots\ldots\ldots\ldots\ldots\ldots (40)$$

Equation (40) gives us the direction of gas correction (the slope of the line along which a gas point should be moved to its gas corrected position in a neutron versus den-

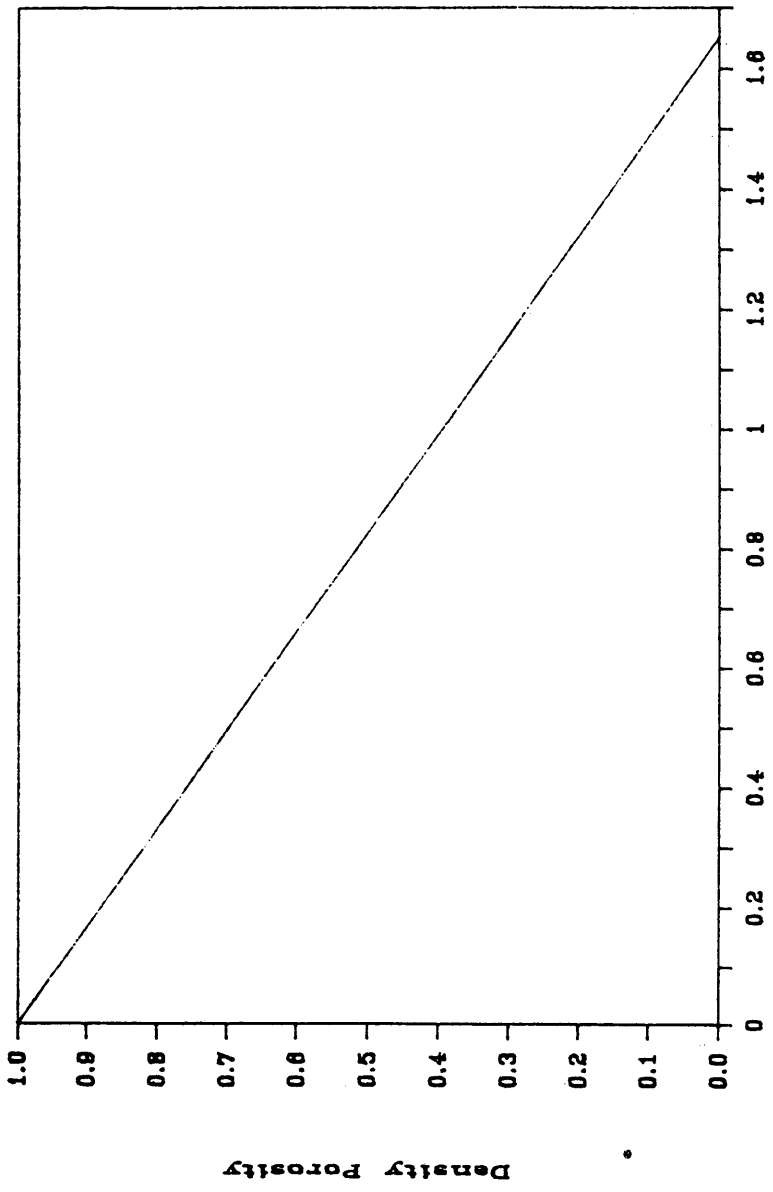

Figure 4. Gas correction is applied along a line with slope = - 1 / 1.65.

sity porosity plot). See Figure 4.

Note that equation (40) gives the direction of gas correction only. In order to apply the gas correction to neutron and density porosities, we need the magnitude of gas correction as well. In the following paragraphs a method is developed to find the magnitude of gas correction.

Figure 5 is a plot of real log data from a well drilled in shaly sand formations. The neutron and density data were taken from several intervals in the well. The data clustered on the far right of the figure are from a thick shale zone. The group of data on the far left of the figure is from a gas bearing shaly sand interval, and the group of data in-between are from several hundreds of feet of water saturated shaly sands.

Theoretically, if log readings are representative, water saturated clean sands will fall on the line with slope 1 (line 1 in the diagram). Shale zones will fall far below line 1 and gas bearing clean sands should fall above line 1. The shaly sand gas bearing zones will fall above, on or somewhat below line 1 depending on the magnitude of gas saturation and the degree of shaliness. This is exactly what has happened to the data plotted in Figure 5.

This theoretical and experimental evidence enables us to propose the following gas correction model for neutron and

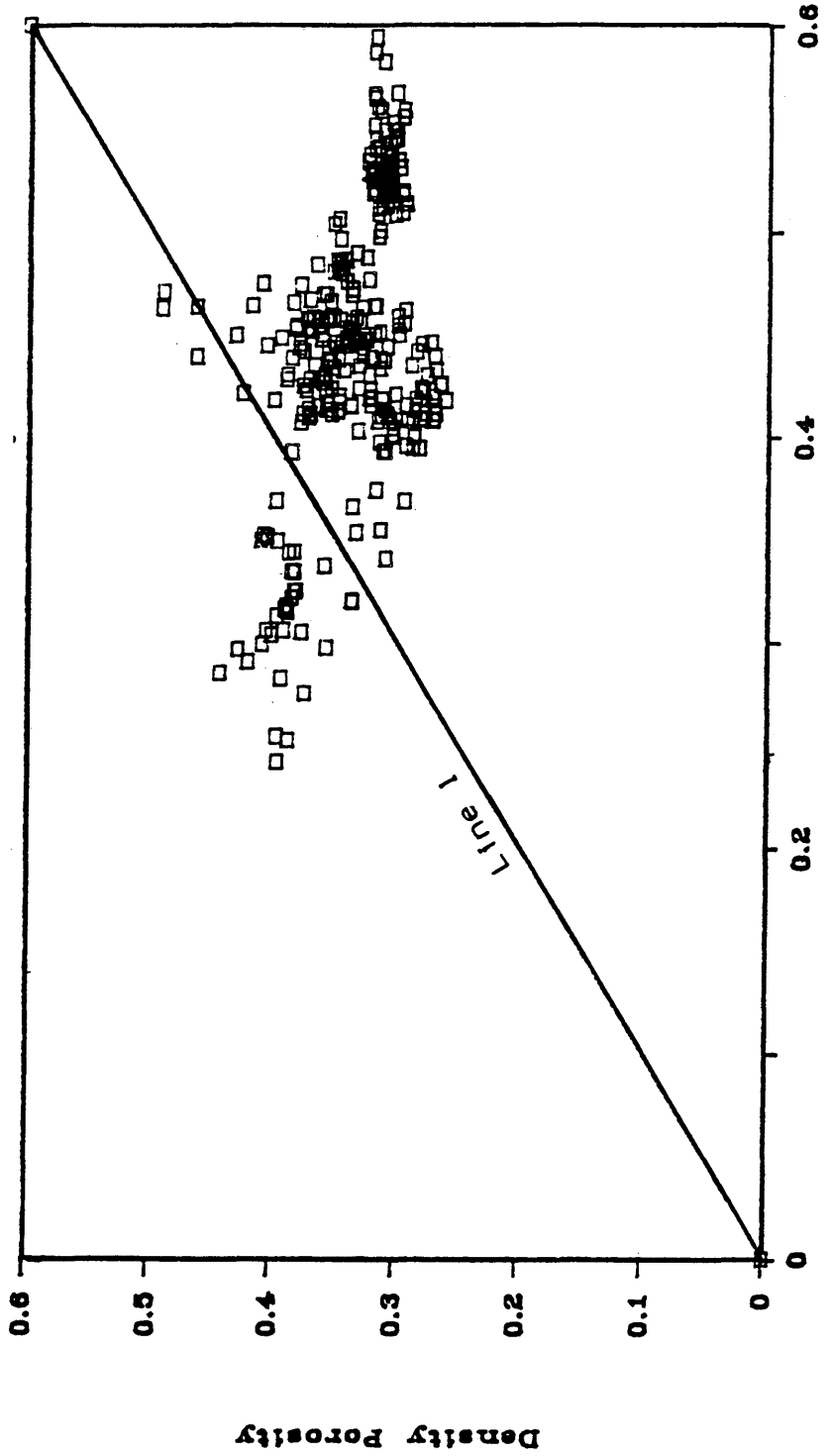

Figure 5. Well log data from a gas bearing shaly sand interval. Note that shale points have clustered to the right, gas bearing points to the left and shaly sand points in between. Liquid saturated clean sand points fall on line 1.

density logs (see Figure 6)

1. Any gas bearing point of the diagram must be moved a certain distance D along a line with slope expressed in equation (40) until the gas effect on neutron and density porosities is completely removed (gas saturation goes to zero).

2. The magnitude of the distance, D is a function of gas saturation and can be expressed as

$$D\ (S_g) = (\ d\phi_d^2 + d\phi_n^2)^{1/2} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ (41)$$

3. There are infinite lines originating at the average shale point and terminating at line 1 (see Figure 6) characterizing the lithology of the formation. Each point on these lines is a linear combination of shale and sand. The shale fraction is zero where the line intersects line 1 and the shale fraction equals to 1 at the shale point.

4. The intersection of each of the lines in 3 with line 1 gives the porosity (ϕ_{sd}) associated with the sand portion of the formation.

5. The actual magnitude of distance D is found when the computed resistivity, R_{tc}, from

$$1 / R_{tc} = 1 / F_{cb}R_{cb} + 1 / F_{w1}R_w + 1 /F_wR_w \quad \ldots\ldots\ldots(42)$$

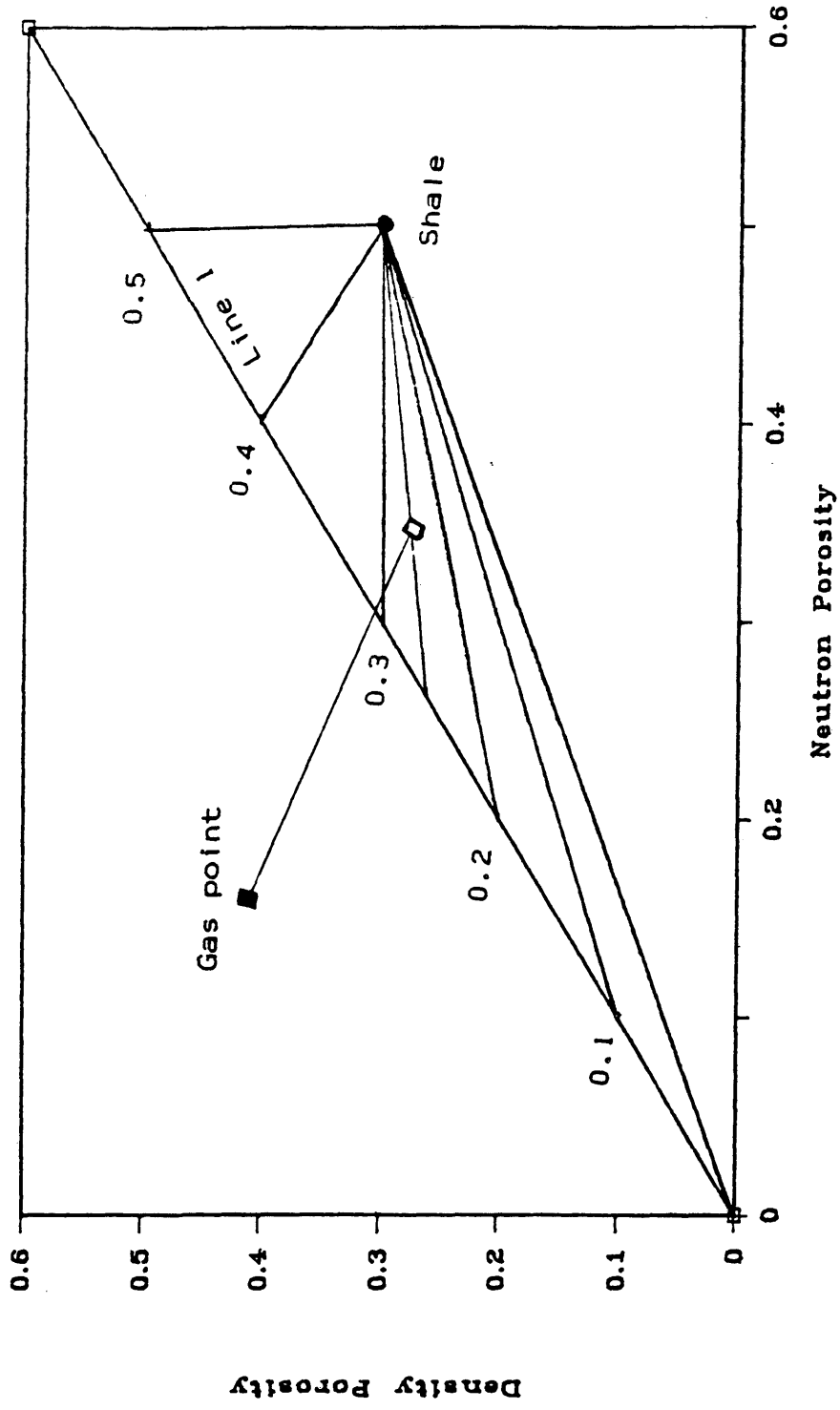

Figure 6. A diagram showing average shale point, a typical gas point and sand porosity (scaled on line 1).

matches the recorded resistivity.

In equation (42) F_{cb}, F_{w1} and F_w are the formation factors associated with clay + bound water, free water in silt and free water in sand.

The free water in sand can be obtained from,

$$V_w = \phi_{sd} * BVSD * (1 - S_g) \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (43)$$

S_g is the gas saturation in sand and BVSD is the bulk volume of sand. An expression for S_g can be found as follows.

$$V_{gsd} = S_g \, V_{poresd} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (44)$$

V_{poresd} is the pore volume in sand.

$$dV_{gsd} = dS_g \, V_{poresd} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (45)$$

Combining equations (38) and (45) and equations (39) and (45) gives us:

$$d\phi_d = \frac{(\rho_w - \rho_g)}{1.65} \, V_{poresd} \, dS_g \quad \ldots\ldots\ldots\ldots\ldots \quad (46)$$

$$d\phi_n = (- \phi_{nw} + \phi_{ng}) \, V_{poresd} \, dS_g \quad \ldots\ldots\ldots\ldots\ldots \quad (47)$$

Since $D = (d\phi_n^2 + d\phi_d^2)^{1/2}$, substituting equation (46)

and (47) in the expression for D and substituting V_{poresd} by ϕ_{sd}*BVSD (BVSD + bulk volume of shale = 1) gives us:

$$dS_g = \frac{D}{\phi_{sd}*BVSD[(-\phi_{nw} + \phi_{ng})^2 + ((\rho_w - \rho_g)/1.65)^2]^{1/2}} \quad \ldots(48)$$

Since neutron and density tools are shallow investigating tools, equation (48) gives gas saturation in or around the flushed zone (S_{gxo}). This gas saturation is less than the gas saturation seen by Deep Induction (ILD) tool (S_g). As a result the resistivity calculated from equation (42) may not match the recorded resistivity (ILD).

One solution to this problem is to compare the calculated resistivity from equation (42) to a resistivity curve obtained by a resistivity tool with similar depth of investigation as those of neutron and density tools.

Another solution would be to correct the water saturation obtained from $S_w = (1 - S_g)$ as follows.

$$S_w/S_{xo} = [(R_{xo} / R_t) / (R_{mf}/R_w)]^{1/2} = \text{Ratio}$$

Then, $S_w = S_{xo}$ (Ratio) or in our case $S_w = (1-S_g)$(Ratio).

In the above expressions, S_{xo} and R_{xo} are the water saturation and resistivity of the flushed zone, R_t is the resistivity of uninvaded zone, R_w is the brine resistivity and R_{mf}

is the resistivity of mud filtrate.

Dewan (1983) has suggested using the following relationship,

$$(1-S_{gxo})^2 = (1-S_g)$$

Here S_{gxo} is the gas saturation in the flushed zone and S_g is the gas saturation in the undisturbed zone.

Since we did not have a micro - resistivity curve available, we used a factor S_w^{-n} in equation (42) to compensate for the too high water saturation obtained from $S_w = (1-S_g)$ expression. The modified version of equation (42) is:

$$\frac{1}{R_{tc}} = \frac{1}{F_{cb}R_{cb}} + \frac{1}{F_{w1}R_w} + \frac{1}{F_wR_wS_w^{-n}} \quad .....(49)$$

In equation (49) $S_w = (1-S_g)$ and n is the saturation exponent. In this paper gas corrected neutron and density porosities were obtained based on resistivity match between resistivities from equation (49) and Deep Induction (ILD).

Application of The Model

The resistivity model proposed by Ma, reviewed and restated in this paper was applied to two well logs from different basins. These logs were mainly from shaly sand formations. The identities and specific locations of the wells are kept confidential. Each well was divided into several intervals. In each interval the combination of gamma ray, SP, resistivity, caliper, sonic, neutron and density logs were used to locate a thick uniform shale zone . Effort was made to avoid choosing washout shale zones. Adjacent to each chosen shale zone, a test zone, a general shaly sand zone, was also chosen. From each pair of shale and test zone, formation parameters in 100% shale zone such as volume fractions of clay (V_{cl}), bound water (V_{bw}), free water, (V_w), density of clay (ρ_{cl}), neutron response to clay (ϕ_{ncl}), resistivity of clay + bound (R_{cb}) and resistivity of free formation water (R_w) were obtained (see Figures 7 - 8 and Table 3). These formation initial values were used in generation of simulated resistivity (R_o). Let us now present some examples of simulated resistivity curves obtained.

The first three examples are from a well drilled in Louisiana. The geology encountered is mainly shaly sands with only one oil bearing zone. The model was applied on

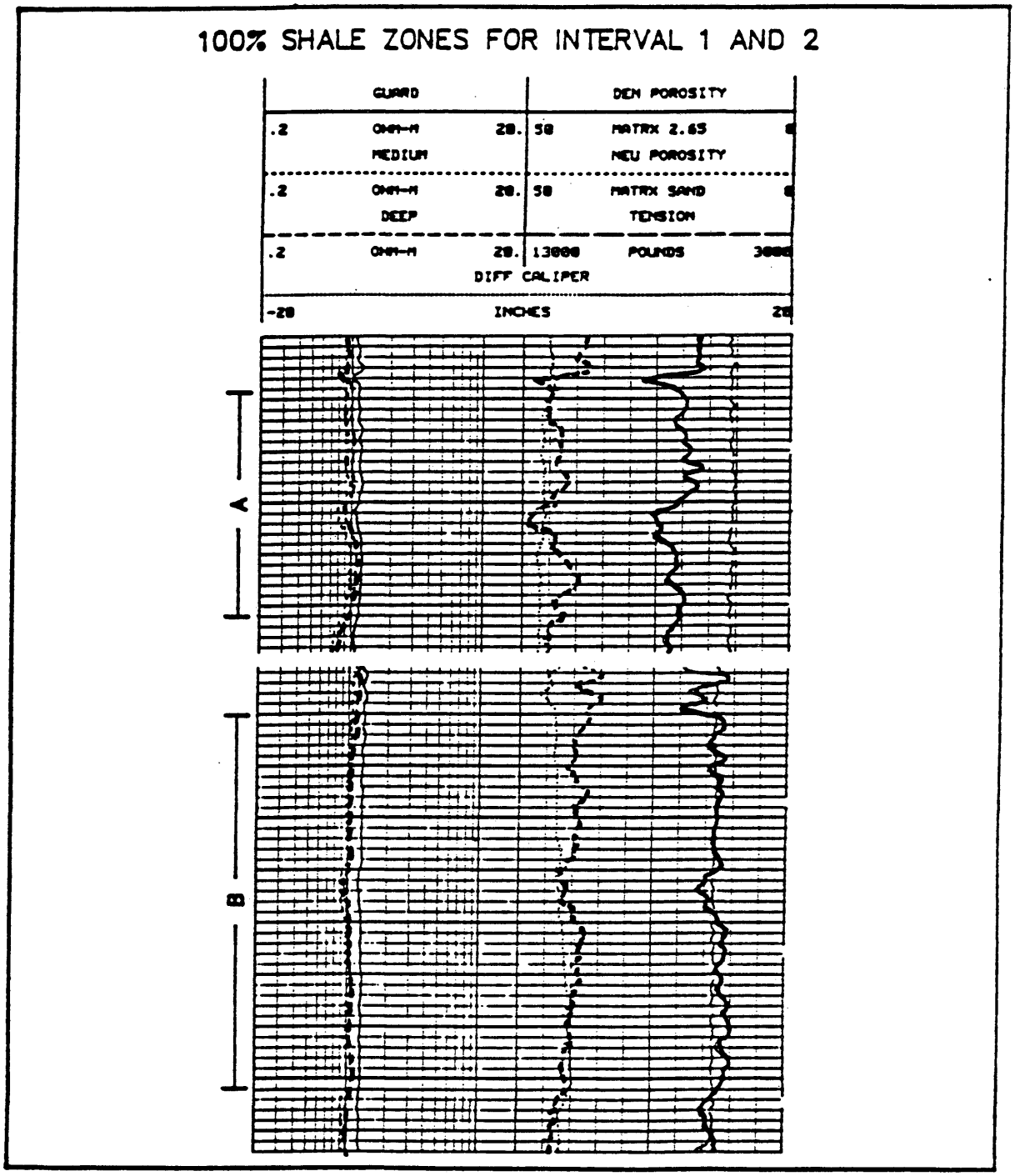

Figure 7. Examples of 100% shale zones. Zone A is at 5478 - 5522 feet and zone B is at 6730 - 6802 feet.

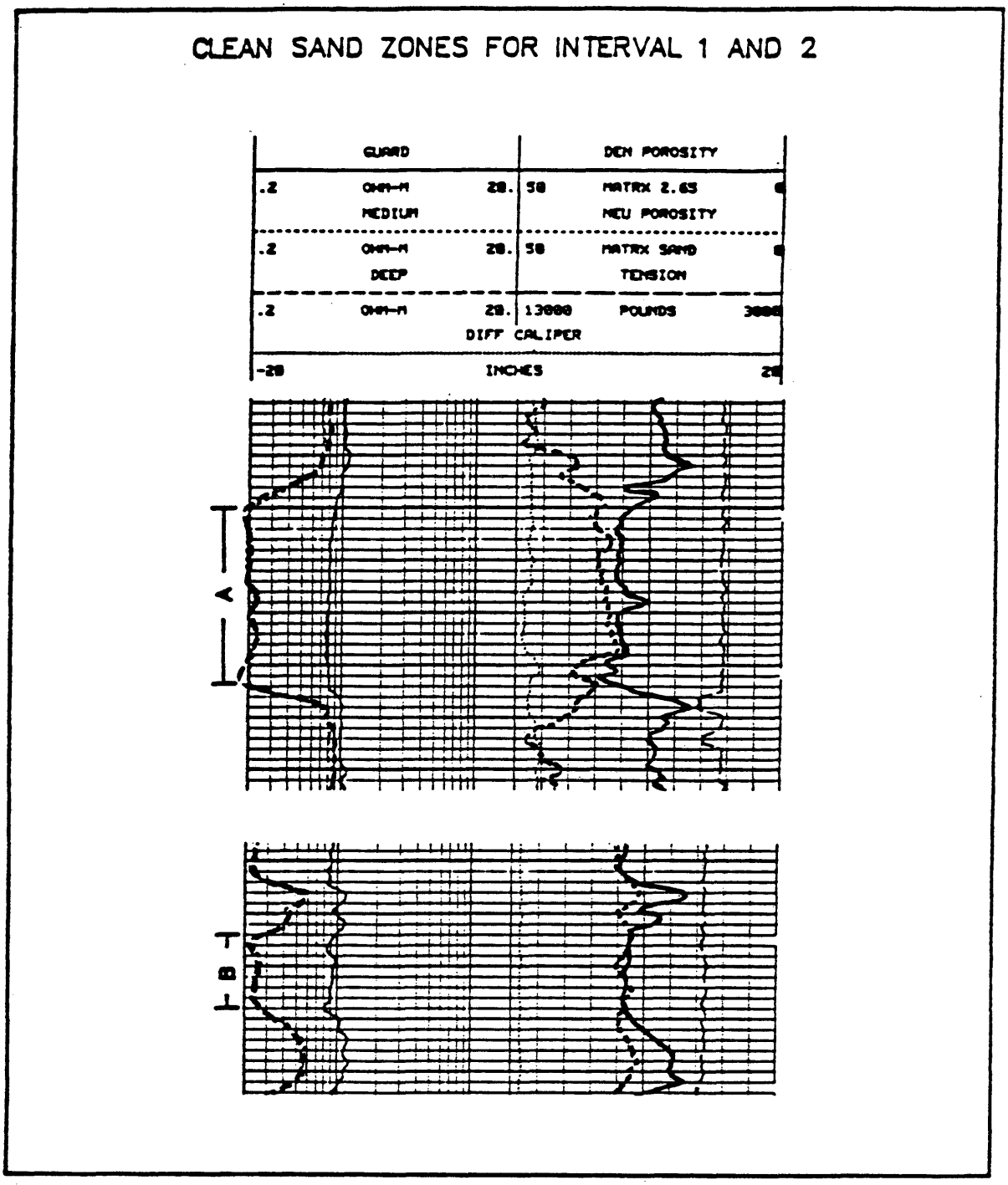

Figure 8. Examples of relatively clean sand zones. Zone A is at 5550 - 5584 feet and zone B is at 7064 - 7078 feet.

Table 3

Input Shale Data And Initial Clay Values

Parameters	Zone A	Zone B
Log data from shale zones		
ϕ_n	0.43	0.40
ϕ_d	0.20	0.13
R_{sh}	1.0 ohm-m	1.0 ohm-m
Clay parameters determined in shale zones		
ρ_{cl}	3.03 g/cm^3	2.89 g/cm^3
ϕ_{ncl}	0.14	0.33
V_{cl}	0.406	0.47
V_{bw}	0.250	0.145
V_w	0.073	0.0706
R_{cl}	0.959 ohm-m	0.825 ohm-m
R_w	0.0265 ohm-m	0.0304 ohm-m

this data set first by Ma in 1987. The model was reapplied on the data and similar results were obtained. The results shown in Figures 9 - 11 are the original work of Ma. The solid curves are the simulated resistivities and the doted curves are the recorded resistivities (ILD). Since these intervals are water saturated, The computed and recorded resistivities both represent R_o. Theoretically, the two curves should have identical values. However, since the real earth is much more complex than our model and also we are dealing with measurements from different tools (neutron and density versus induction tool), it is not easy to obtain identical values for both curves. Model errors, instrument errors associated with each tool, measurement errors and in our case specifically the different averaging processes associated with the measurements of neutron and density tools versus induction tool are some of the causes to be named for the differences between the two curves. Having this in mind, we still see a good agreement between the two curves .

The second sets of examples are from a well drilled in offshore of Southern U.S.. Again the geology is mainly shaly sands. In this well the only known productive zone is a gas bearing zone. The productive zones of both wells will be discussed later. Figures 12 - 14 show application of the

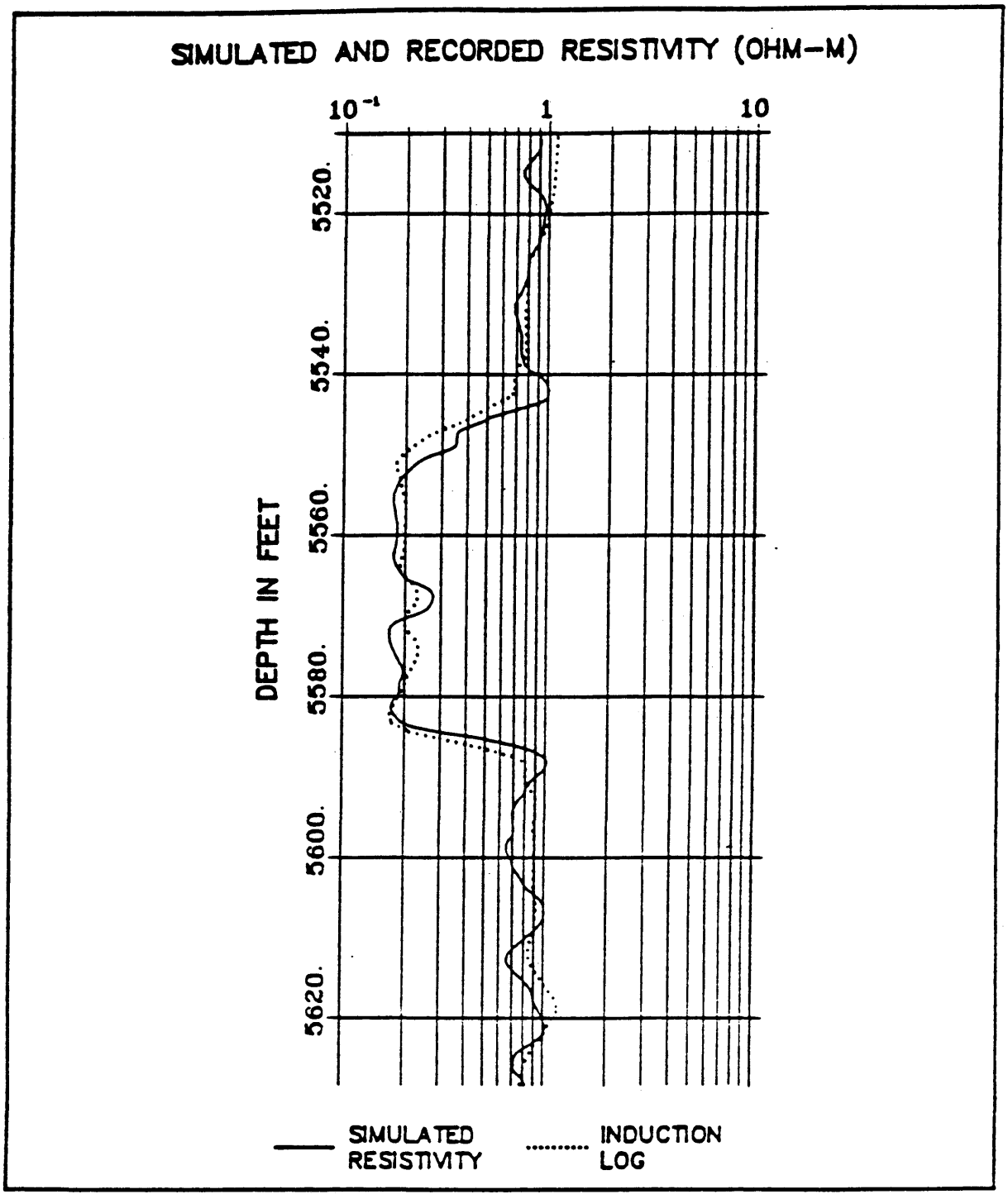

Figure 9. Example of simulated resistivity and ILD at 5510 - 5630 feet.

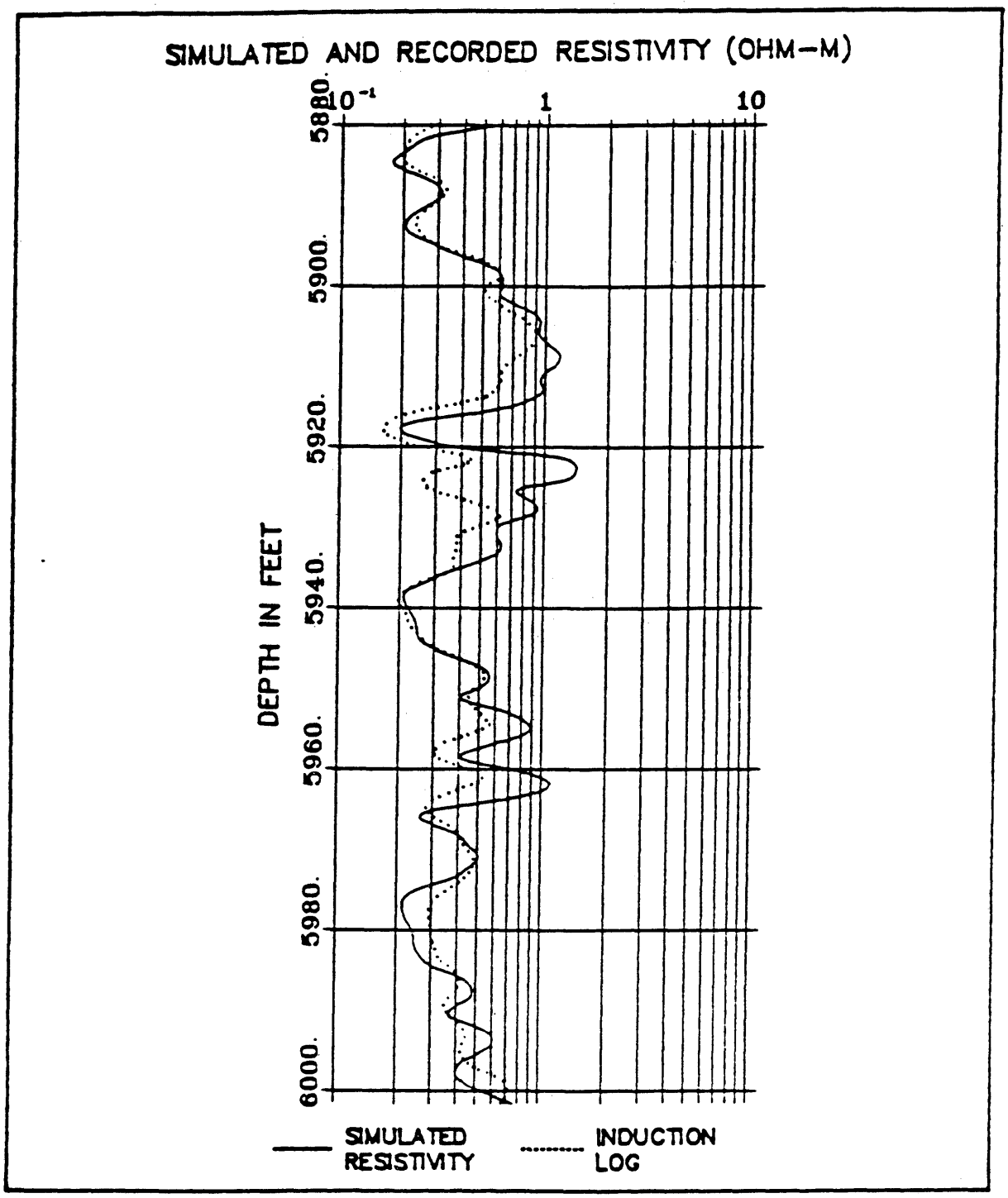

Figure 10. Example of simulated resistivity and ILD at 5880 - 6000 feet.

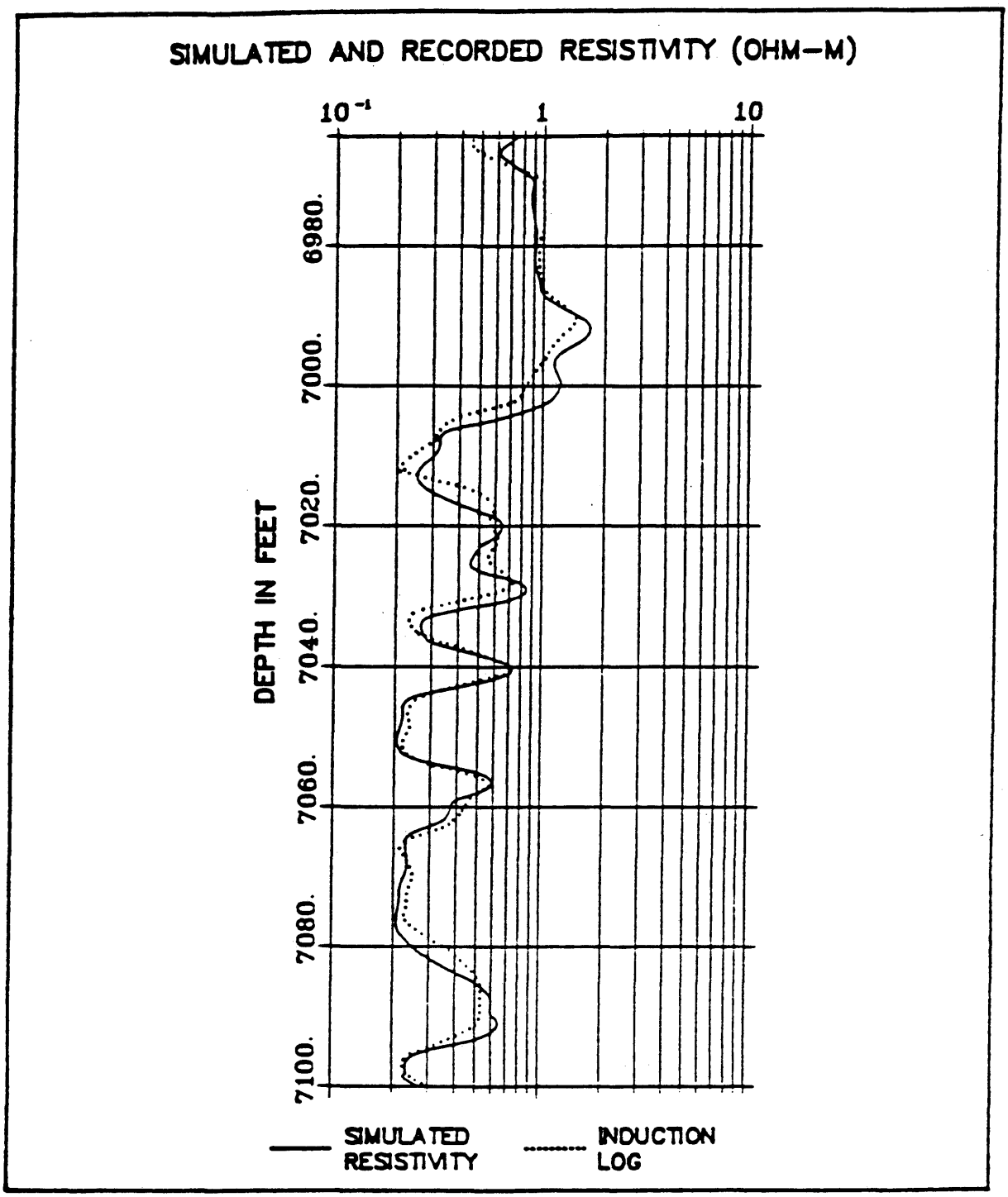

Figure 11. Example of simulated resistivity and ILD at 6970 - 7100 feet.

model on three different intervals of the well.

In each of the figures the lines with dots show simulated resistivity curves and the smooth lines show the recorded deep induction (ILD) curves. Figure 12 covers 400 feet of the well (2900 - 3300 feet).

Figure 13 covers another 400 feet of the well. In this interval, the only gas bearing zone of the well is located at 3530 - 3552 feet. The clear separation of simulated resistivity and deep induction in these depths confirms the presence of gas bearing zone.

There are two thin layers of shale also in the gas bearing zone (see depths 3535 and 3540 feet). Both of them are reflected in the two resistivity curves. The separation of the two curves decrease at these shale layers.

In Figure 14 one of the points worth mentioning is the relatively poor agreement between simulated resistivity curve and ILD from 3570 to 3650 feet. One possible explanation for this poor agreement is that the zone in question has a different shale type than the shale from which the formation initial parameters were obtained (3300 -3330 feet). Therefore another shale zone (3780 -3800 feet) and a test zone (3830 -3850 feet) was chosen and the formation initial parameters were derived. With the new formation initial parameters a better agreement between simulated resistivity

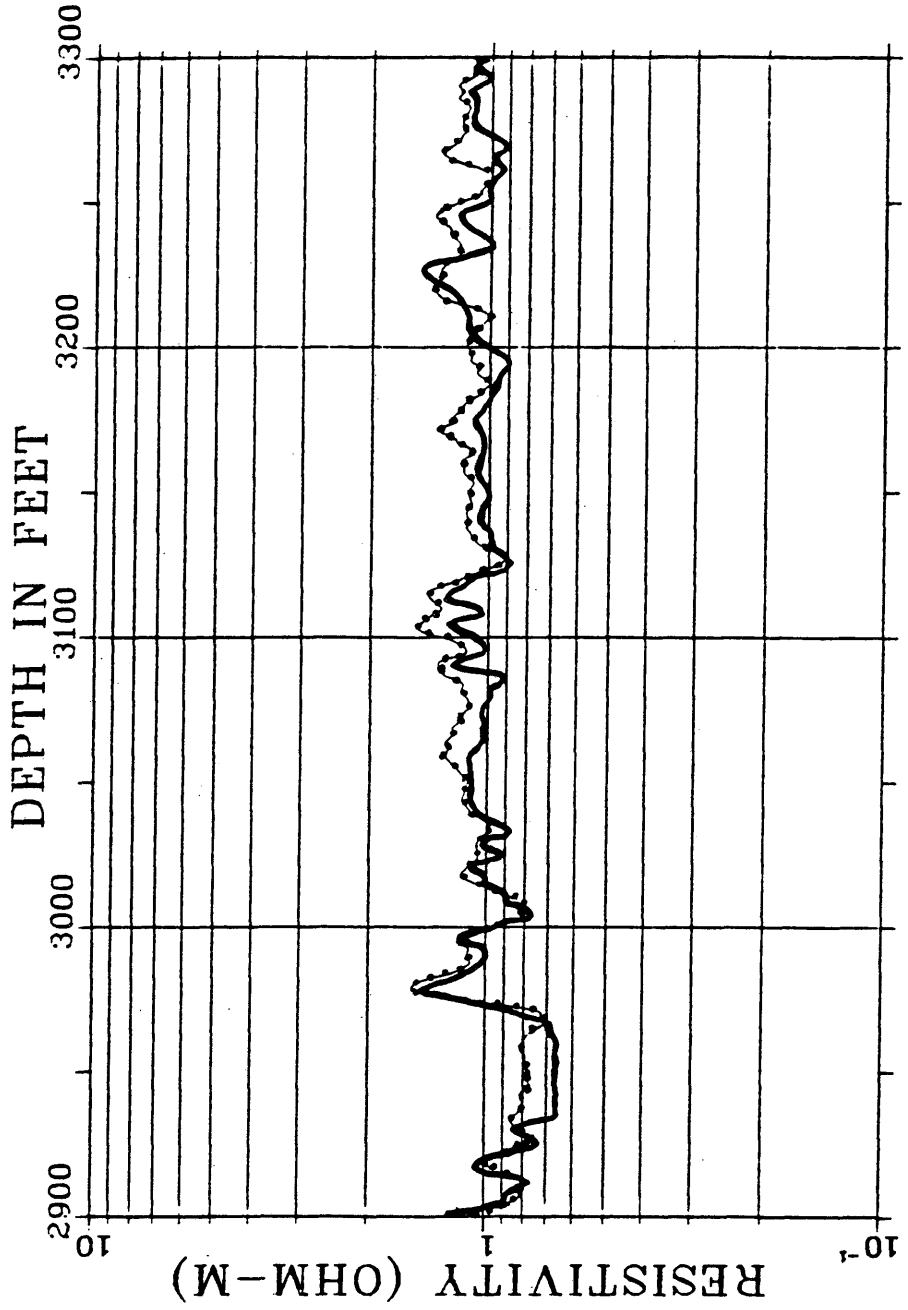

Figure 12. Example of simulated resistivity (curve with dots) and ILD (smooth curve) at 2900 - 3300 feet.

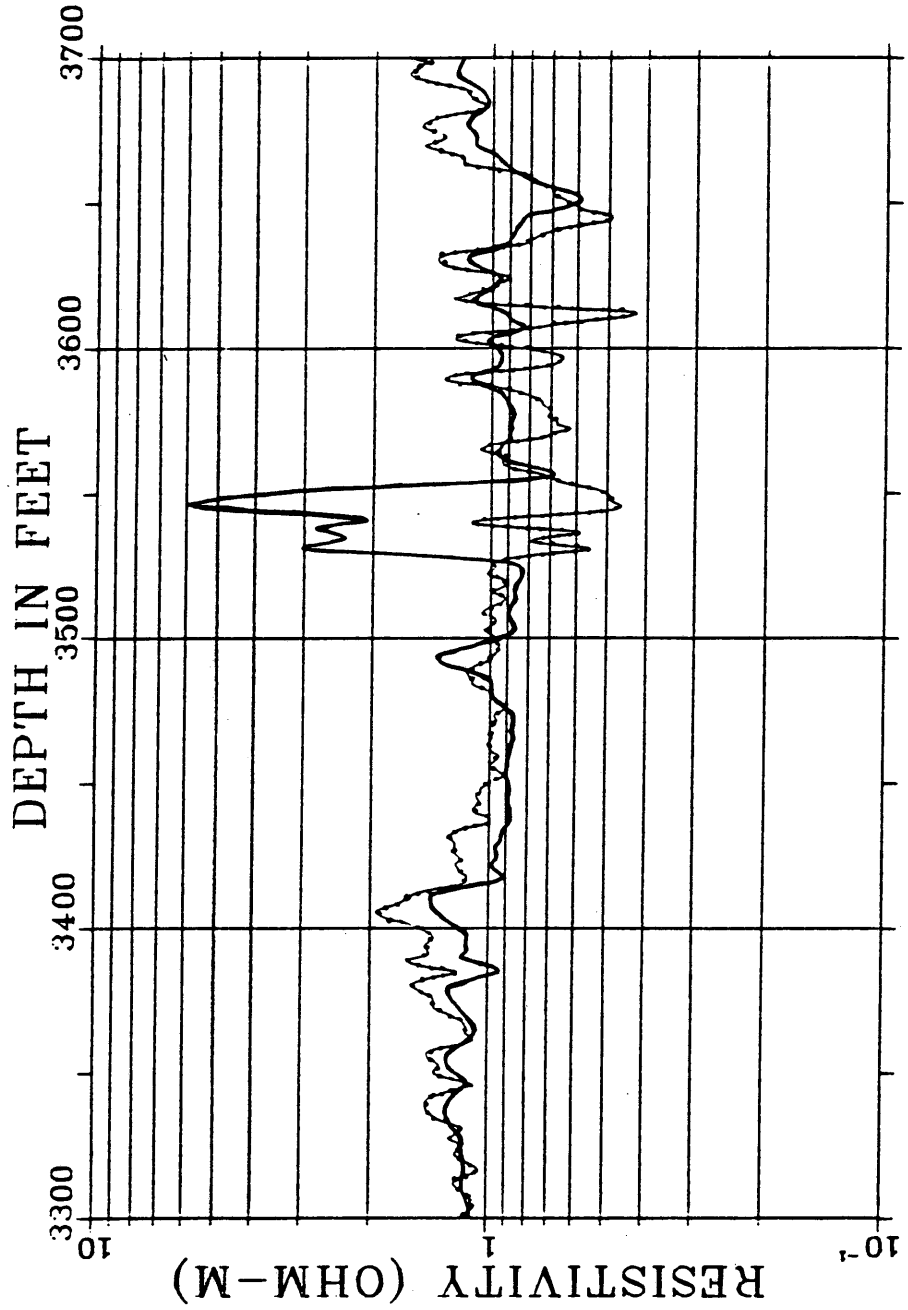

Figure 13. Example of simulated resistivity (curve with dots) and ILD (smooth curve) at 3300 -3700 feet.

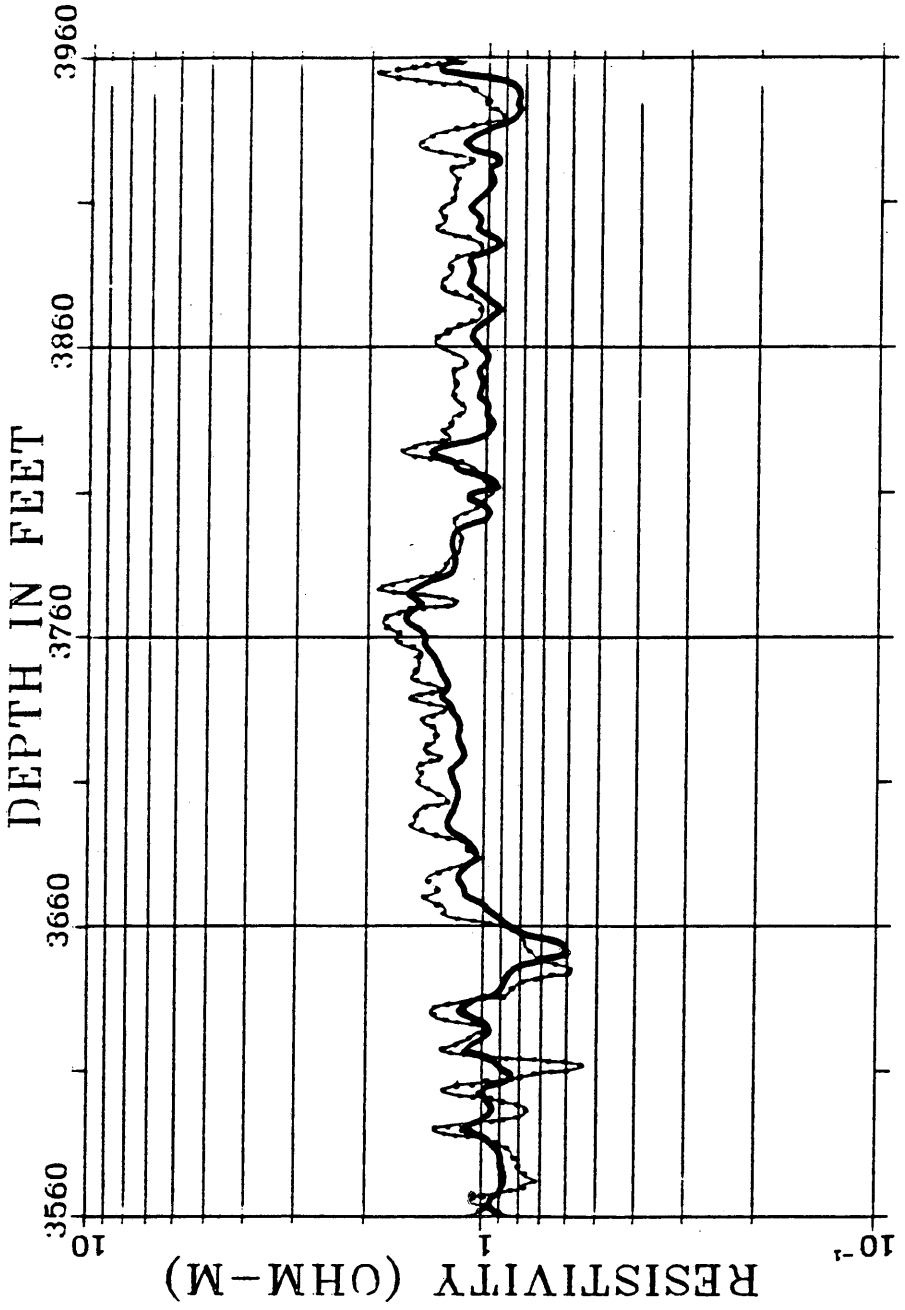

Figure 14. Example of simulated resistivity (curve with dots) and ILD (smooth curve) at 3560 - 3960 feet.

and ILD was obtained. The results are plotted in Figure 14. This result leads us to the conclusion that there is a potential for the model to be used for determining shale type or specifically clay type in shaly sands.

Application of the Model to Oil Bearing Zones:

Ma (1987) applied the model to a known oil bearing zone of a well from Louisiana. Figure 15 is a plot of simulated resistivity and recorded resistivity in that zone. Here the separation between calculated resistivity (R_o) and recorded resistivity (ILD) confirms the presence of hydrocarbons in the zone. Table 4 shows the results of saturation Index (SI) analysis in the above oil bearing zone. Note the difference between water saturation obtained by conventional methods (S_{w0}) and water saturation obtained by this model (S_{w1}). As was mentioned before, in this model the shale effect is removed from both simulated resistivity (R_o) and recorded resistivity (ILD), and only then saturation index ($SI = S_w^{-n} = R_t/R_o$) is calculated.

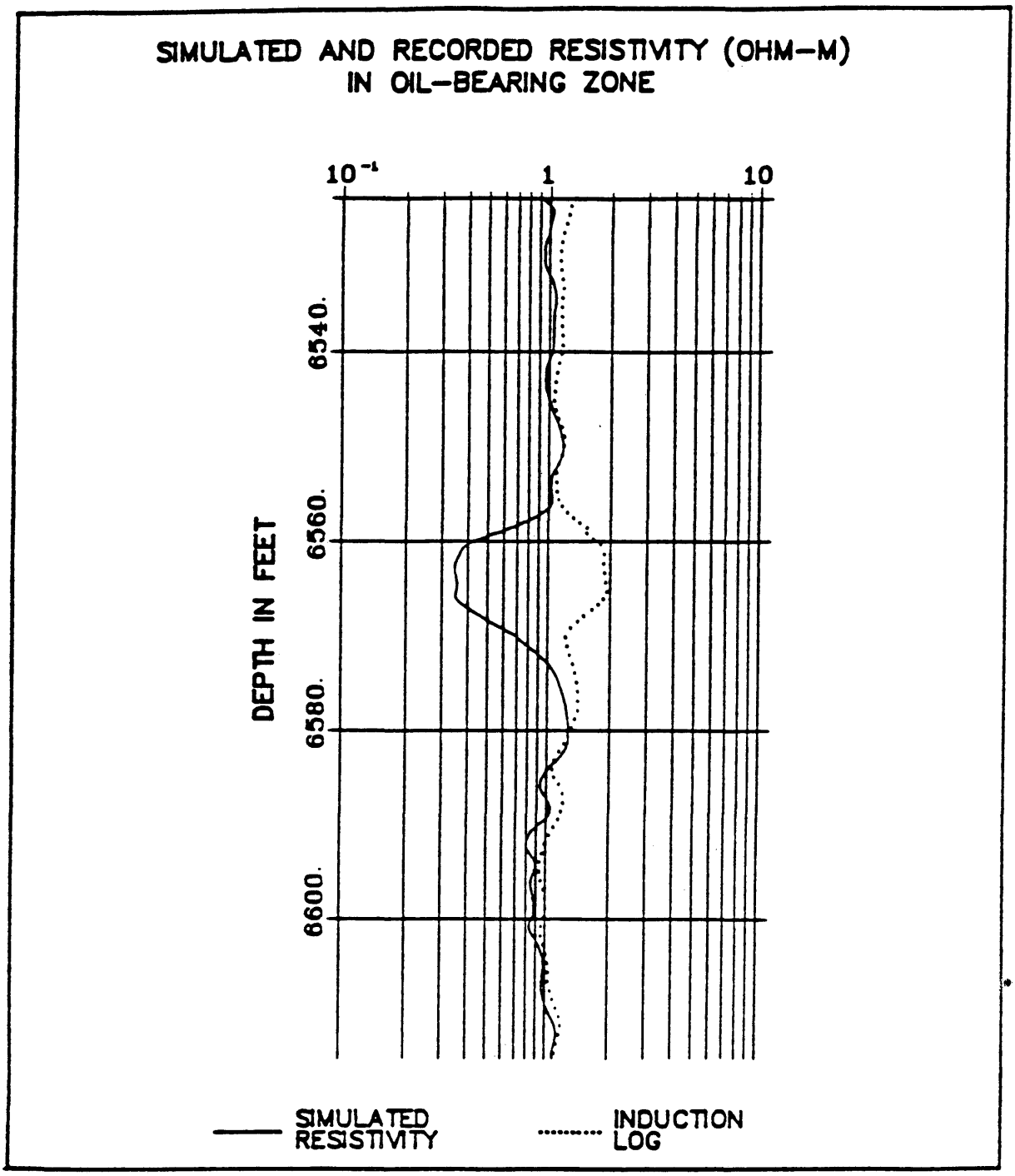

Figure 15. Simulated resistivity and induction log in oil-bearing zone at 6558-6568 feet.

Table 4

Saturation Index Analysis in Oil-bearing Zone

depth	SI0	Sw0	SI1	Sw1
6559.0	3.07	0.57	10.77	0.30
6560.0	3.61	0.53	11.06	0.30
6561.0	4.80	0.46	12.24	0.29
6562.0	5.71	0.42	10.74	0.31
6563.0	4.80	0.46	11.19	0.30
6564.0	5.13	0.44	9.50	0.32
6565.0	4.99	0.45	8.51	0.34
6566.0	5.30	0.43	8.50	0.34
6567.0	4.93	0.45	7.74	0.36
6568.0	3.04	0.57	9.93	0.32

where SI0 is saturation index with shale,

Sw0 is water saturation with shale,

SI1 is saturation index after removing shale effect,

Sw1 is water saturation after removing shale effect.

Application of the model to Gas Bearing Zones:

The only known gas bearing zone in the offshore U.S. well is located at 3530 to 3552 feet depth. The recorded and simulated resistivities of this zone are shown in Figure 16.

The neutron and density porosities of the above gas bearing zones were corrected by the gas correction method described in the paper. Figure 17 shows five curves. Each curve is marked by a different symbol. The curve marked measured resistivity is the Deep Induction curve (ILD), and the curve marked computed resistivity is the resistivity obtained from equation (49) and using the gas saturation calculated from equation (48). The computed resistivity was used to quantify the magnitude of gas correction applied to neutron and density porosities. Overall, we were able to obtain a very good match between the two resistivities.

The gas saturation curve shows gas saturation in the zone after removing the gas and shale effect from the neutron and density porosities. The sand porosity curve is the porosity of the sand portion of the formation (ϕ_{sd}).

Both of the gas saturation and sand porosity curves are in agreement with the lithology and recorded resistivity (ILD). The two troughs in the resistivity curves (see depths 3535 and 3540 feet) reflect the presence of larger fractions of shale in the formation. The sand porosity and gas

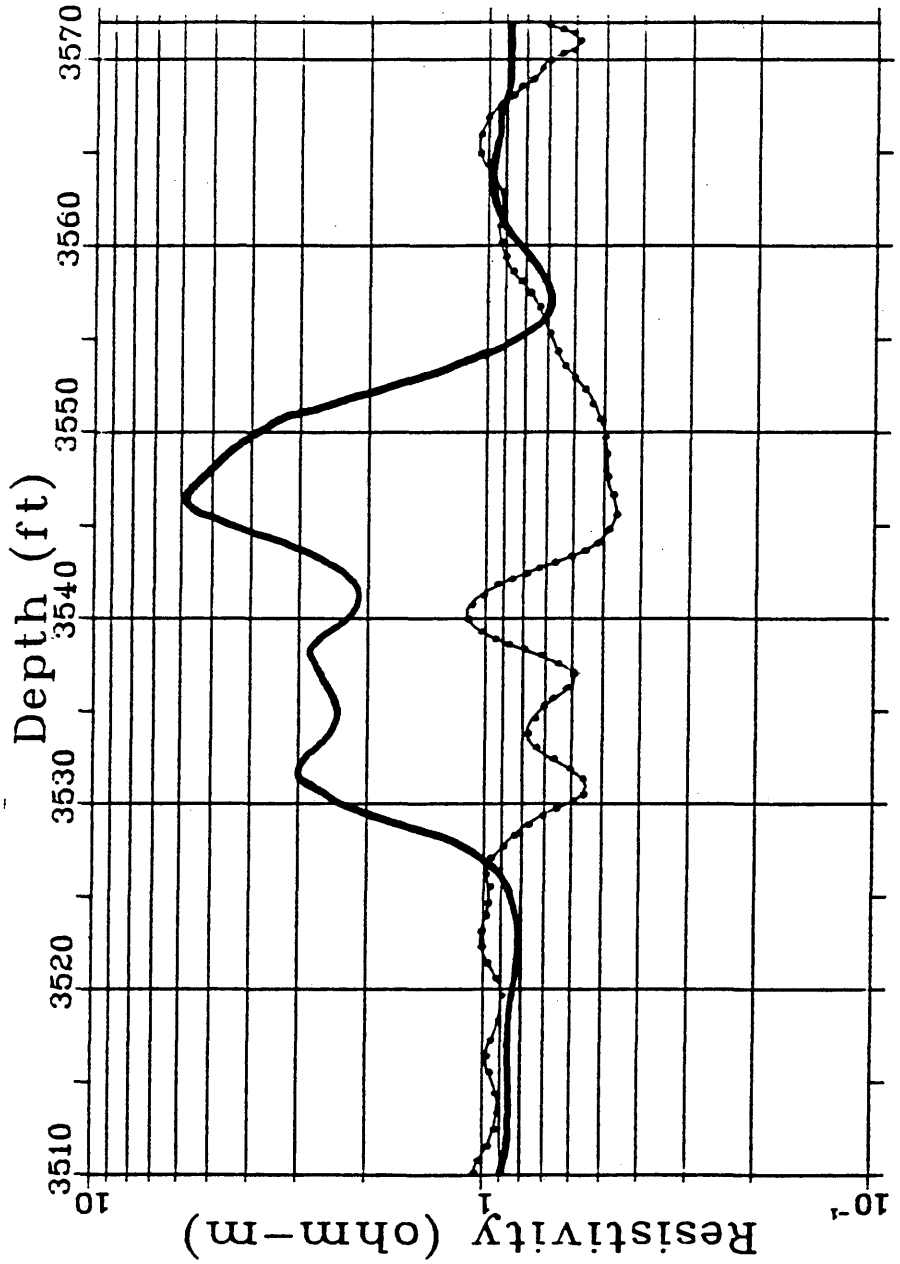

Figure 16. Simulated resistivity (curve with dots) and ILD (smooth curve) at 3510 - 3572 feet.

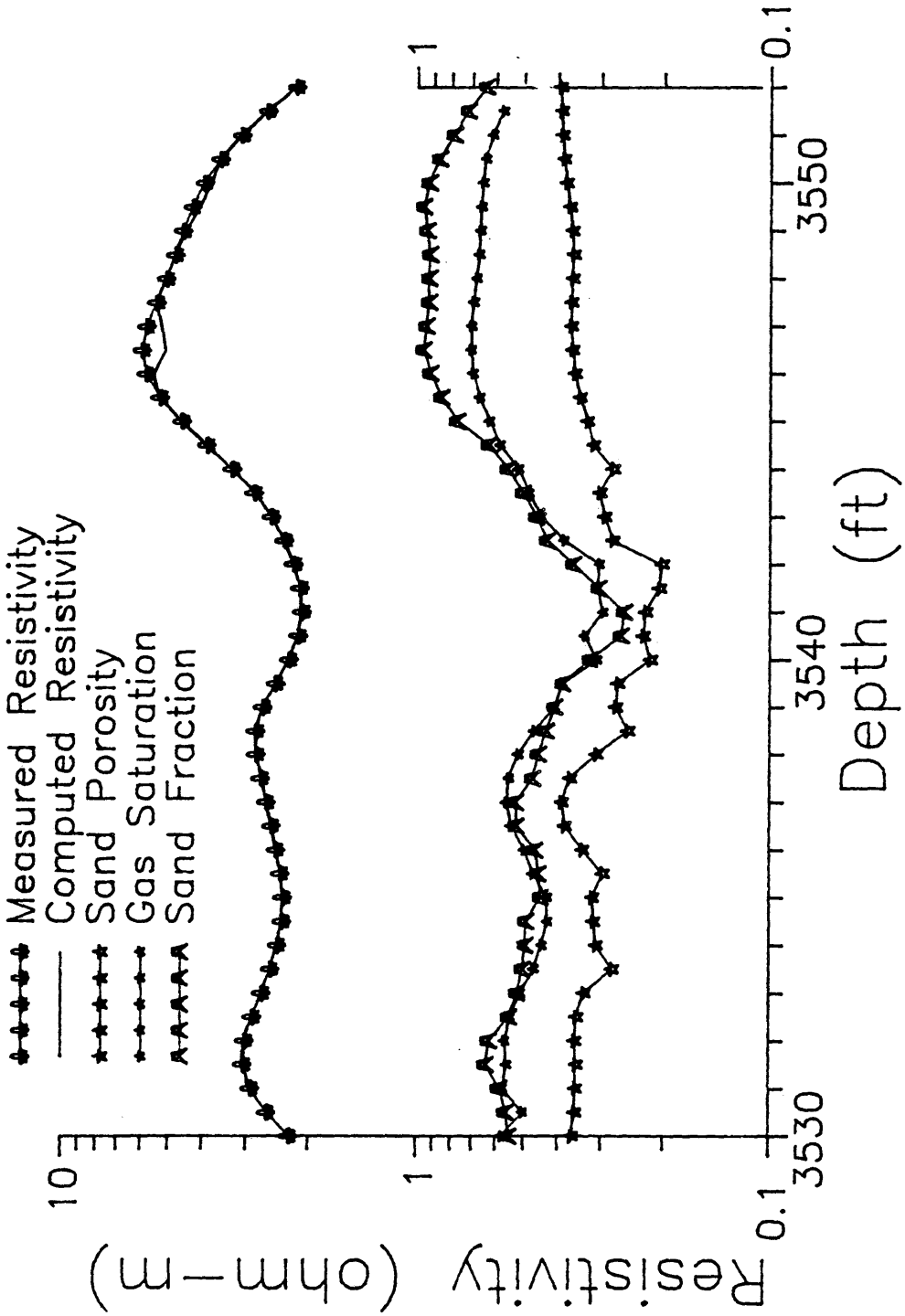

Figure 17. ILD, calculated resistivity, gas saturation, sand porosity and sand volume fraction in the gas bearing zone.

saturation also reflect this fact. Finally the sand fraction curve (slightly smoothed) shows the fraction of sand (sand + shale = 1) calculated by the model.

Figure 19 shows the simulated resistivity after gas correction is applied to the neutron and density porosities and Figure 20 shows simulated resistivity and recorded resistivity after removing the shale effect from both of the curves.

Table 5 shows the result of saturation analysis done with and without the shale effect removed. Here also we can see the improvement in the saturation index by removing the shale effect from resistivity logs.

In Table 5 another interesting result is observed in depths 3539 - 3542 feet. Since this interval is mainly shale, the saturation index obtained by this method is lower, which reflects the reliability of the method.

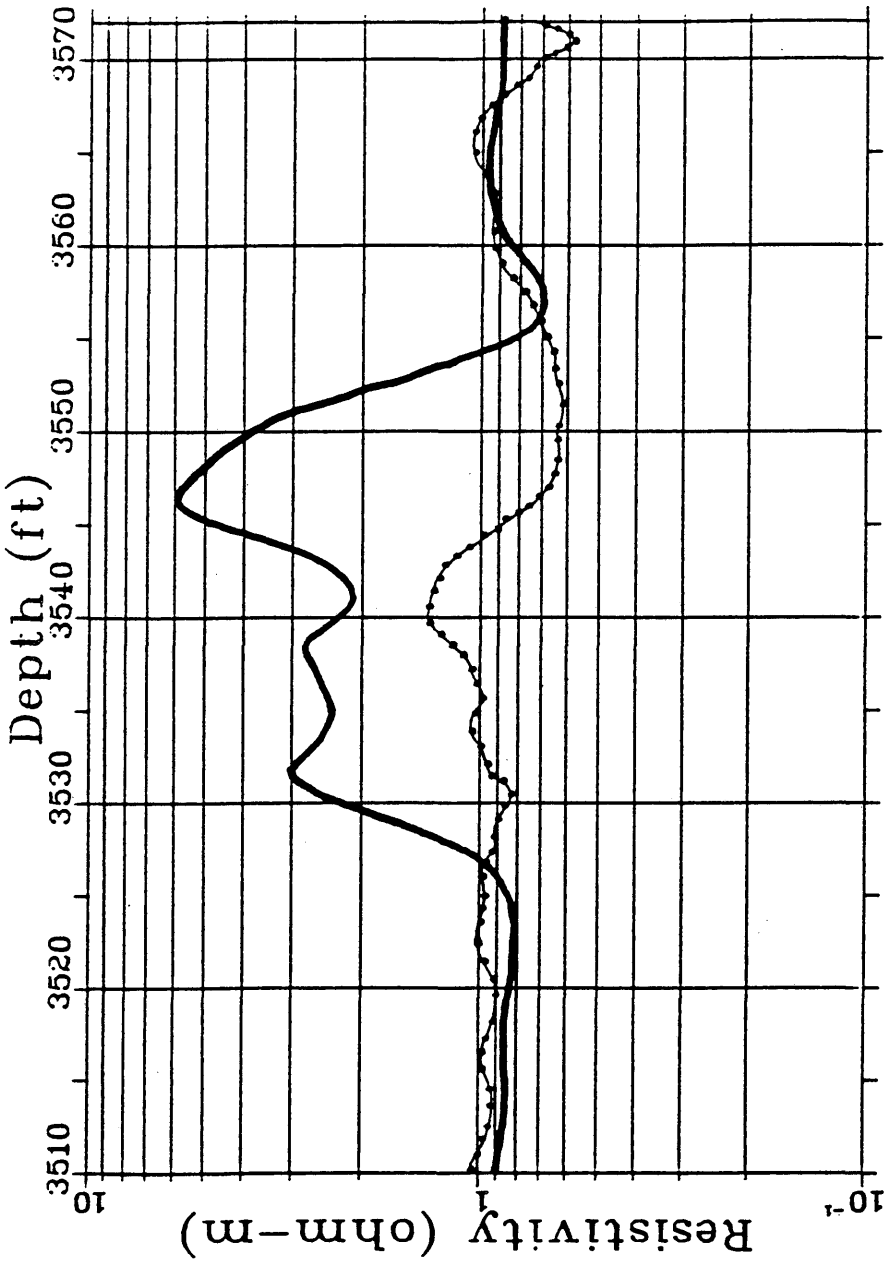

Figure 18. Simulated resistivity (curve with dots) and ILD (smooth curve) after gas correction is applied.

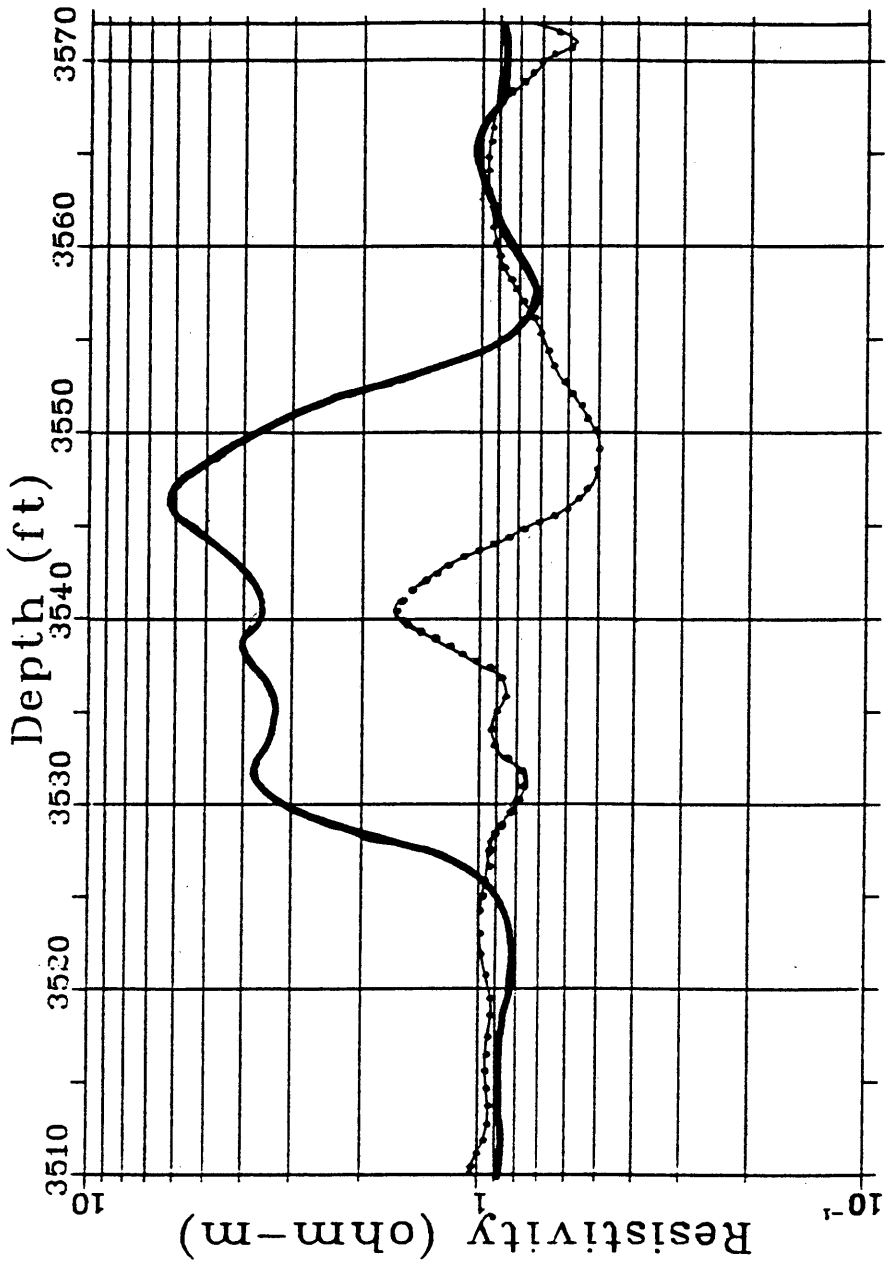

Figure 19. Simulated resistivity (curve with dots) and ILD (smooth curve) after gas and shale effect is removed.

Table 5: Saturation Index Analysis in Gas-bearing Zone

DEPTH	ILD	SI1	SW1	SI2	SW2
3530.00	2.26	2.82	0.60	5.49	0.43
3531.00	2.90	3.63	0.52	5.44	0.43
3532.00	3.01	3.77	0.52	5.25	0.44
3533.00	2.70	3.38	0.54	4.15	0.49
3534.00	2.44	3.05	0.57	3.22	0.56
3535.00	2.36	2.94	0.58	3.05	0.57
3536.00	2.47	3.08	0.57	3.96	0.50
3537.00	2.63	3.29	0.55	5.16	0.44
3538.00	2.81	3.51	0.53	4.30	0.48
3539.00	2.69	3.36	0.55	2.85	0.59
3540.00	2.27	2.84	0.59	2.09	0.69
3541.00	2.09	2.61	0.62	2.02	0.70
3542.00	2.21	2.76	0.60	2.06	0.70
3543.00	2.55	3.19	0.56	3.26	0.55
3544.00	3.30	4.12	0.49	4.32	0.48
3545.00	4.57	5.71	0.42	7.22	0.37
3546.00	5.78	7.23	0.37	10.99	0.30
3547.00	5.75	7.19	0.37	11.45	0.30
3548.00	5.06	6.32	0.40	9.87	0.32
3549.00	4.54	5.67	0.42	8.92	0.33
3550.00	3.94	4.93	0.45	8.36	0.35
3551.00	3.10	3.87	0.51	6.71	0.39
3552.00	2.17	2.72	0.61	4.33	0.48

Where :

SI1 is saturation index with shale,

SW1 is water saturation with shale,

SI2 is saturation index after removing shale effect,

SW2 is water saturation after removing shale effect.

Conclusions

1. The resistivity model proposed by Ma (1987) and restated in this paper, has been applied to several water saturated shaly sand intervals of different wells. it was shown that the model generated resistivity values in good agreement with measured resistivities.

2. In the oil bearing zone the model successfully removes the shale effect from resistivity curves and provides a useful method for analyzing oil bearing shaly sand formations.

3. A new method to extend Ma's method to gas bearing shaly sand formations is developed. This makes it possible to apply Ma's method to both oil saturated and gas saturated reservoirs.

4. The extended model provides a method to determine reservoir parameters such as water saturation, effective porosity, and shale fraction in shaly sand formations.

5. There is a potential for the model to be used for clay typing.

6. Although the extended model has given useful results in the wells where it has been applied , the model should be tested in numerous other wells and in different sedimentary basins.

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APPENDIX

More About The Gas Effect on Neutron and Density Porosities

The presence of gas in the formation affects the response of both neutron and density tools. The density log over estimates porosity (gas has low density) and the neutron log under estimates porosity (gas has lower concentration of hydrogen).

The presence of shale along with gas further complicates the problem. The presence of shale results in higher neutron porosities and slightly lower or higher density porosity depending on the density of shale. Of course shale would not affect density porosity if the density of shale is equal to the density of the matrix (sand).

In conventional well log analysis, the problem is solved by using an independent indicator of shale (indicator other than neutron and density porosities) such as gamma ray or SP log. First shale correction is applied to the data and then gas correction is attempted by forcing the density and neutron porosities, in a certain way, to come to agreement.

Since in the model discussed in this paper only neutron and density logs are used to analyze shaly sand formations, a new method is developed to correct neutron and density logs for gas effect in the presence or absence of shale.

The density porosity is obtained from the following equation.

$$\phi_d = \frac{\rho_m - \rho_b}{\rho_m - \rho_f} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (A1)$$

In equation (A1) ρ_m and ρ_f are the matrix and fluid densities respectively (ρ_m = 2.65 and ρ_f = 1.0). ρ_b is the bulk density of the formation and can be expressed as:

$$\rho_b = V_{sd}\rho_{sd} + V_{wsd}\rho_w + V_{gsd}\rho_g + V_{slt}\rho_{slt} + V_{wslt}\rho_w + V_{cl}\rho_{cl} + V_{bw}\rho_{bw} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (A2)$$

In equation (A2), V_{sd}, V_w, V_g, V_{slt}, V_{wslt}, V_{cl} and V_{bw} stand for volume fractions of sand, water in sand, gas in sand, silt, water in silt, clay and bound water respectively. w stand for water, g stands for gas and ρ represents density.

The neutron porosity of the formation can be expressed as:

$$\phi_n = V_{sd}\phi_{nsd} + V_{wsd}\phi_{nw} + V_{gsd}\phi_{ng} + V_{slt}\phi_{nslt} + V_{wslt}\phi_{nw} + V_{cl}\phi_{ncl} + V_{bw}\phi_{nbw} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (A3)$$

In the above equation, ϕ_n stands for neutron porosity.

Note that in equations (A2) and (A3),

$$V_{sd} + V_{wsd} + V_{gsd} + V_{slt} + V_{wslt} + V_{cl} + V_{bw} = 1.0$$

The pore volume of sand can be expressed as:

$$V_{poresd} = V_{wsd} + V_{gsd} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (A4)$$

$$\text{and} \quad S_g = V_{gsd} / V_{poresd} \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (A5)$$

Here, S_g is gas saturation in the sand.

Substituting equation (A2) in equation (A1) and expressing ϕ_d and ϕ_n in terms of sand pore volume (V_{poresd}), we obtain,

$$\phi_d = \frac{2.65}{1.65} - \frac{V_{sd}\rho_{sd}}{1.65} - \frac{(V_{poresd} - V_{gsd})\rho_w}{1.65} - \frac{V_{gsd}\rho_g}{1.65} -$$

$$\frac{V_{slt}\rho_{slt}}{1.65} - \frac{V_{wslt}\rho_w}{1.65} - \frac{V_{cl}\rho_{cl}}{1.65} - \frac{V_{bw}\rho_{bw}}{1.65} \quad \ldots\ldots(A6)$$

$$\phi_n = V_{sd}\phi_{nsd} + (V_{poresd} - V_{gsd})\phi_{nw} + V_{gsd}\phi_{ng} + V_{slt}\phi_{nslt}$$
$$+ V_{wslt}\phi_{nw} + V_{cl}\phi_{ncl} + V_{bw}\phi_{nbw} \quad \ldots\ldots\ldots\ldots\ldots \quad (A7)$$

Differentiating equations (A6) and (A7) with respect to volume fraction of gas in sand (V_{gsd}), we obtain.

$$d\phi_d = \frac{(\rho_w - \rho_g)}{1.65} * d\,V_{gsd} \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (A8)$$

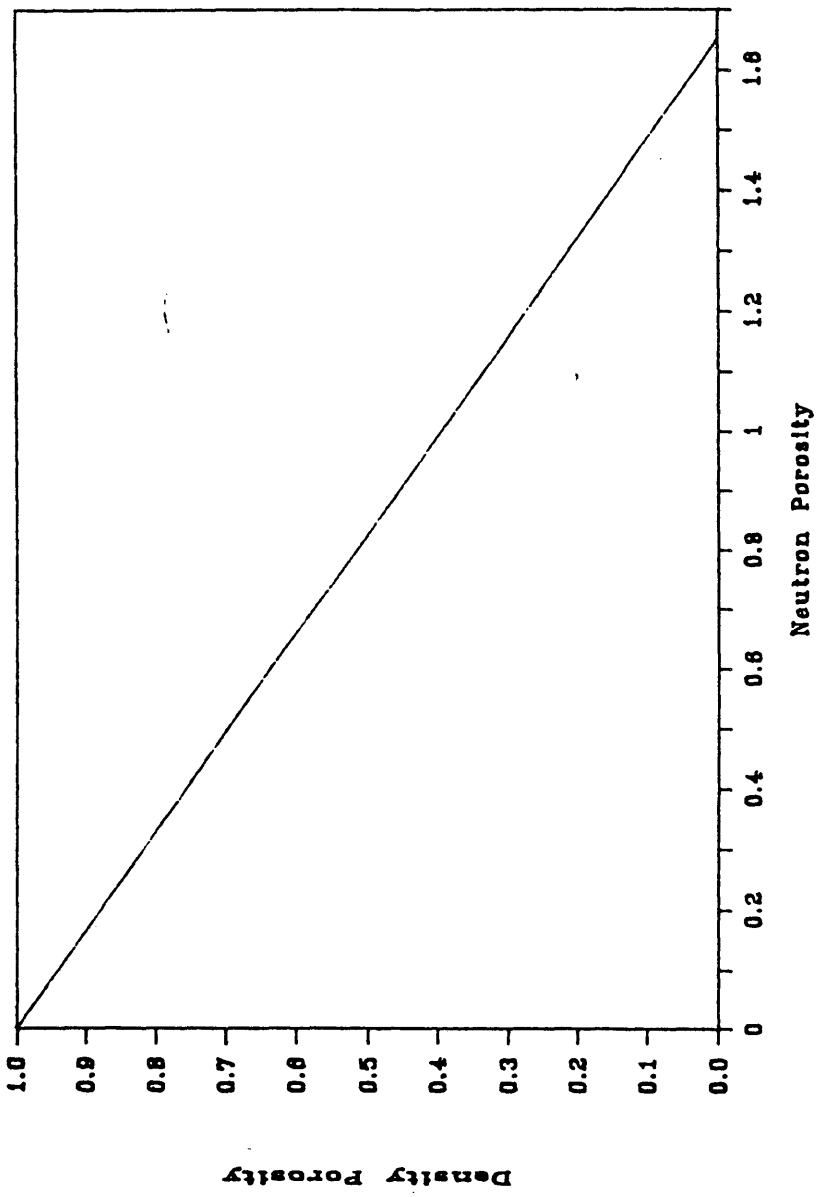

Figure A1. Gas correction is applied along a line with slope = - 1 / 1.65

$$d\phi_n = (- \phi_{nw} + \phi_{ng}) \, d \, V_{gsd} \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (A9)$$

Dividing equation (A8) by equation (A9) gives,

$$\frac{d\phi_d}{d\phi_n} = \frac{(\rho_w - \rho_g)}{1.65 \, (\phi_{ng} - \phi_{nw})} \quad \ldots\ldots\ldots\ldots\ldots \quad (A10)$$

Equation (A10) gives us the direction of gas correction (the slope of the line along which a gas point should be moved to its gas corrected position in a neutron versus density porosity plot). See Figure A1.

Note that equation (A10) gives the direction of gas correction only. In order to apply the gas correction to neutron and density porosities, we need the magnitude of gas correction as well. In the following paragraphs a method is developed to find the magnitude of gas correction.

Figure A2 is a plot of real log data from a well drilled in shaly sand formations. The neutron and density data were taken from several intervals in the well. The data clustered on the far right of the figure are from a thick shale zone. The group of data on the far left of the figure is from a gas bearing shaly sand interval, and the group of data in-between are from several hundreds of feet of liquid saturated shaly sands.

Theoretically, if log readings are representative, liquid

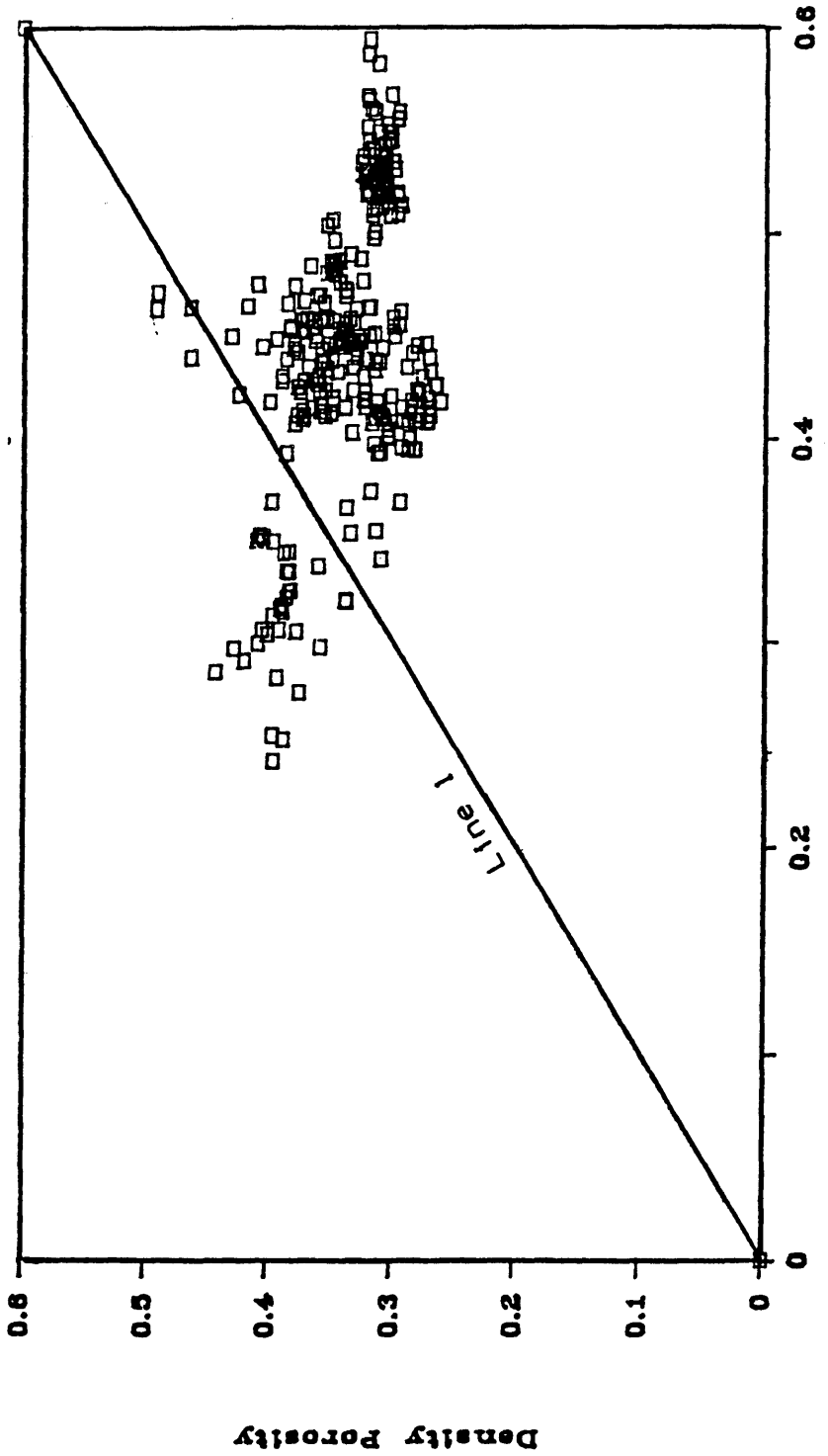

Figure A2. Well log data from a gas bearing shaly sand interval. Note that shale points have clustered to the right, gas bearing points to the left and shaly sand points in between. Liquid saturated clean sand points fall on line 1.

saturated shale free sands will fall on the line with slope 1 (line 1 in the diagram). Shale zones will fall far below line 1 and gas bearing clean sands should fall above line 1. The shaly sand gas bearing zones will fall above, on or somewhat below line 1 depending on the magnitude of gas saturation and the degree of shaliness. This is exactly what has happened to the data plotted in Figure A2.

This theoretical and experimental evidence enables us to propose the following gas correction model for neutron and density logs (see Figure A3)

1. Any gas bearing point of the diagram must be moved a certain distance D along a line with slope expressed in equation (A10) until the gas effect on neutron and density porosities is completely removed (gas saturation goes to zero).

2. The magnitude of the distance, D is a function of gas saturation of the reservoir and can be expressed as:

$$D\ (S_g) = (\ d\phi_d^2 + d\phi_n^2)^{1/2} \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (A11)$$

3. There are an infinite number lines originating from the average shale point and terminating at line 1 (shale-sand lines, see Figure A3) characterizing the lithology of the formation. Each point on these lines is a linear combination

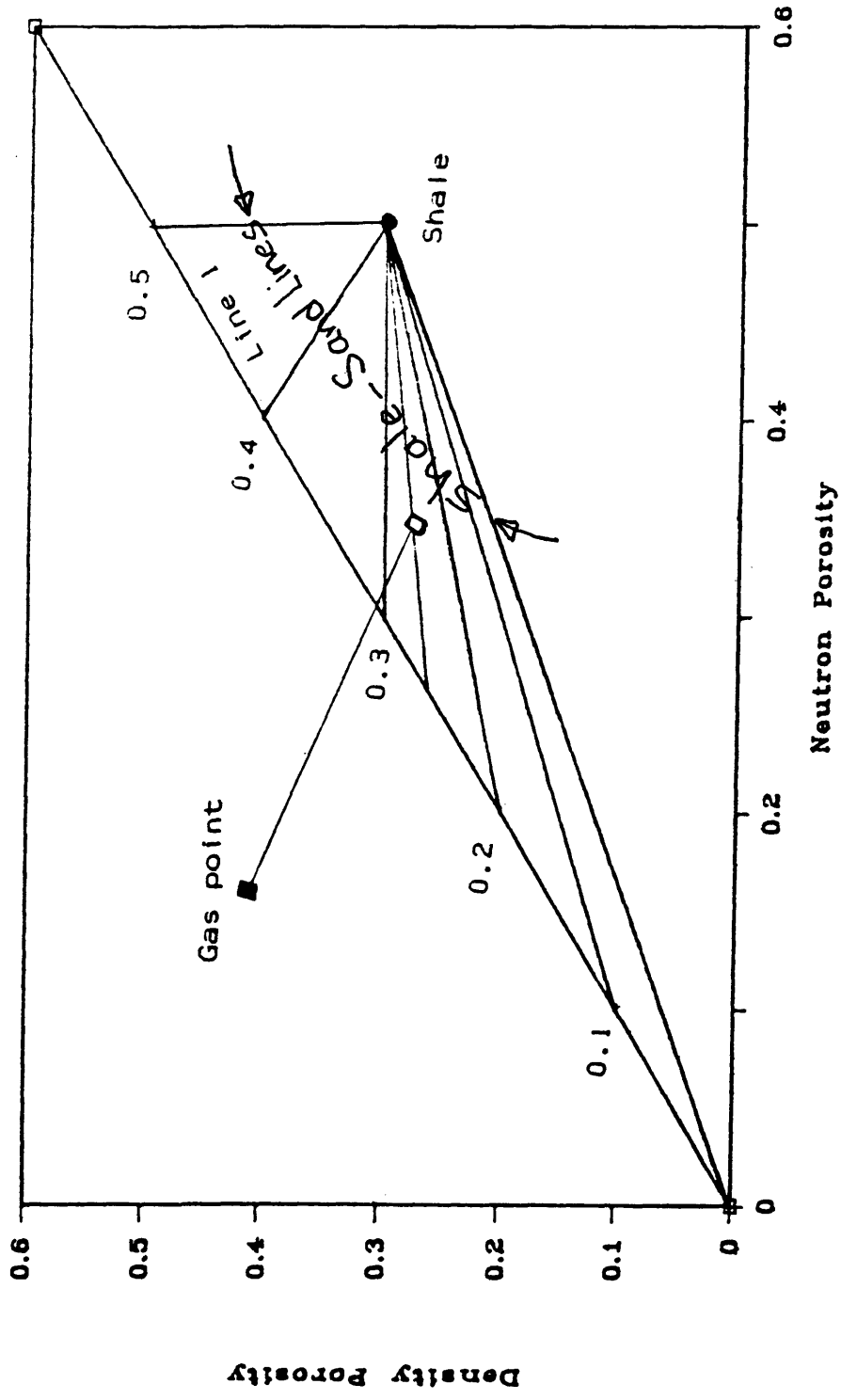

Figure A3. A diagram showing an average shale point, a typical gas point, sand porosity (scaled on line 1).

of shale and sand. The shale fraction is zero where the line intersects line 1 and the shale fraction equals to 1 at the shale point.

4. The intersection of each of the shale-sand lines with line 1 gives the porosity (ϕ_{sd}) associated with the sand portion of the formation.

5. The actual magnitude of distance D is found when the computed resistivity, R_{tc}, from

$$1 / R_{tc} = 1 / F_{cb}R_{cb} + 1 / F_{w1}R_w + 1 /F_wR_w \quad \text{.....(A12)}$$

matches the recorded resistivity.

In equation (A12) F_{cb}, F_{w1} and F_w are the formation factors associated with clay + bound water, free water in silt and free water in sand.

The free water in sand can be obtained from,

$$V_w = \phi_{sd} * BVSD * (1 - S_g) \quad \text{.....(A13)}$$

S_g is the gas saturation in sand and BVSD is the bulk volume of sand. An expression for S_g can be found as follows.

$$V_{gsd} = S_g V_{poresd} \quad \text{..... (A14)}$$

V_{poresd} is the pore volume in sand.

$$dV_{gsd} = dS_g V_{poresd} \quad \text{..... (A15)}$$

Combining equations (A8) and (A15) and equations (A9) and (A15) gives us:

$$d\phi_d = [(\rho_w - \rho_g)/1.65]\ V_{poresd}\ dS_g \quad \text{.....(A16)}$$

$$d\phi_n = (-\phi_{nw} + \phi_{ng})\ V_{poresd}\ dS_g \quad \text{.....(A17)}$$

Since $D = (d\phi_n^2 + d\phi_d^2)^{1/2}$, substituting equation (A16) and (A17) in the expression for D and substituting V_{poresd} by ϕ_{sd}*BVSD (BVSD + bulk volume of shale = 1) gives us:

$$dS_g = \frac{D}{\phi_{sd}\ BVSD[(-\phi_{nw} + \phi_{ng})^2 + ((\rho_w - \rho_g)/1.65)^2]^{1/2}} \quad \text{...(A18)}$$

Since neutron and density tools are shallow investigating tools, equation (A18) gives gas saturation in or around the flushed zone (S_{gxo}). This gas saturation is less than the gas saturation seen by Deep Induction (ILD) tool (S_g). As a result the resistivity calculated from equation (A12) may not match the recorded resistivity (ILD).

One solution to this problem is to compare the calculated resistivity from equation (A12) to a resistivity curve obtained by a resistivity tool with similar depth of investigation as those of neutron and density tools.

Another solution would be to correct the water saturation obtained from $S_w = (1 - S_g)$ as follows.

$$S_w/S_{xo} = [(R_{xo} / R_t) / (R_{mf}/R_w)]^{1/2} = \text{Ratio}$$

Then, $S_w = S_{xo} * (\text{Ratio})$ or in our case $S_w = (1-S_g) * (\text{Ratio})$.

In the above expressions, S_{xo} and R_{xo} are the water saturation and resistivity of the flushed zone, R_t is the resistivity of uninvaded zone, R_w is the brine resistivity and R_{mf} is the resistivity of mud filtrate.

Dewan (1983) has suggested using the relationship, $S_{xo}^2 = S_w$ which can be restated as:

$$(1-S_{gxo})^2 = (1-S_g)$$

Here S_{gxo} is the gas saturation in the flushed zone and S_g is the gas saturation in the undisturbed zone.

Since we did not have a micro - resistivity curve available, we used a factor S_w^{-n} in equation (A12) to compensate for the too high water saturation obtained from $S_w = (1-S_g)$ expression. The modified version of equation (A12) is:

$$\frac{1}{R_{tc}} = \frac{1}{F_{cb}R_{cb}} + \frac{1}{F_{w1}R_w} + \frac{1}{F_wR_wS_w^{-n}} \quad \ldots\ldots\ldots \text{(A19)}$$

In equation (A19) $S_w = (1-S_g)$ and n is the saturation exponent. In this paper gas corrected neutron and density

porosities were obtained based on resistivity match between resistivities from equation (A19) and Deep Induction (ILD).

Let us now discuss some of the terms in the model in details.

I) Equations of The Lines Involved:

In Figure A3 there are several lines . In the following paragraphs the equation of each of the lines is derived.

1. Line 1:

This line is the liquid saturated shale free (clean) sand line. As can be seen from the figure, the slope of this line is 1. The equation of this line is simply Y = X or

$$\phi_d = \phi_n \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (A20)$$

In the above equation ϕ_d (density porosity) is dependant variable and ϕ_n (neutron porosity) is independent variable.

2. The gas lines (The lines along which the gas points are moved):

The slope of these lines is expressed in equation (A10). There is at least one known point (ϕ_{ng},ϕ_{dg}) on these lines. Here ϕ_{ng} is the apparent neutron porosity of the gas point

and ϕ_{dg} is the apparent density porosity of the gas point. Using the Point-Slope [Y-y1 = m(X-x1)] formula and letting the slope equal to m, we obtain:

$$\phi_d - \phi_{dg} = m (\phi_n - \phi_{ng})$$

Or,

$$\phi_d = m \phi_n - m \phi_{ng} + \phi_{dg} \quad \text{.....(A21)}$$

3. The Shale-Sand Lines:

When a gas point is moved below line 1, it falls on one of the lines originating from the shale point and terminating at line 1 (Shale-Sand lines). The equation of the correspondent Shale-Sand line can be found as follows.

Two points on this line are known, the new location of the moved gas point ($n\phi_{ng}$, $n\phi_{dg}$) and the shale point (ϕ_{nsh},ϕ_{dsh}). From the two known points we can find the slope (m) of the line.

$$m = (\phi_{dsh} - n\phi_{dg}) / (\phi_{nsh} - n\phi_{ng})$$

Now using the Point-Slope formula and any of the two known points, we can find the equation of the line. Let us use the shale point.

$$\phi_d = m\phi_n - m\phi_{nsh} + \phi_{dsh} \quad \text{.....(A22)}$$

II) Sand Porosity (ϕ_{sd}):

The sand porosity is shown on line 1 in Figure A3. This porosity can be obtained by setting the equation of the gas line [equation (A21) or (A22) whichever is applicable] equal to the equation of line 1 [equation (A20)]. For example, if the new location of the gas point is above or on line 1, sand porosity is found by setting equation (A21) equal to equation (A20) and solving for ϕ_n. If the new position of the gas point is below line 1, the sand porosity would be obtained form equations (A22) and (A20).

III) Shale Fraction:

Shale-Sand lines are linear combination of shale and sand volume fractions characterizing the lithology of the gas bearing points.

If the position of the gas point (original or moved) is above or on line 1, the shale fraction is considered to be zero. If the location of the gas point is below line 1, then the shale fraction is obtained as follows:

Let the distance from line 1 (along the correspondent

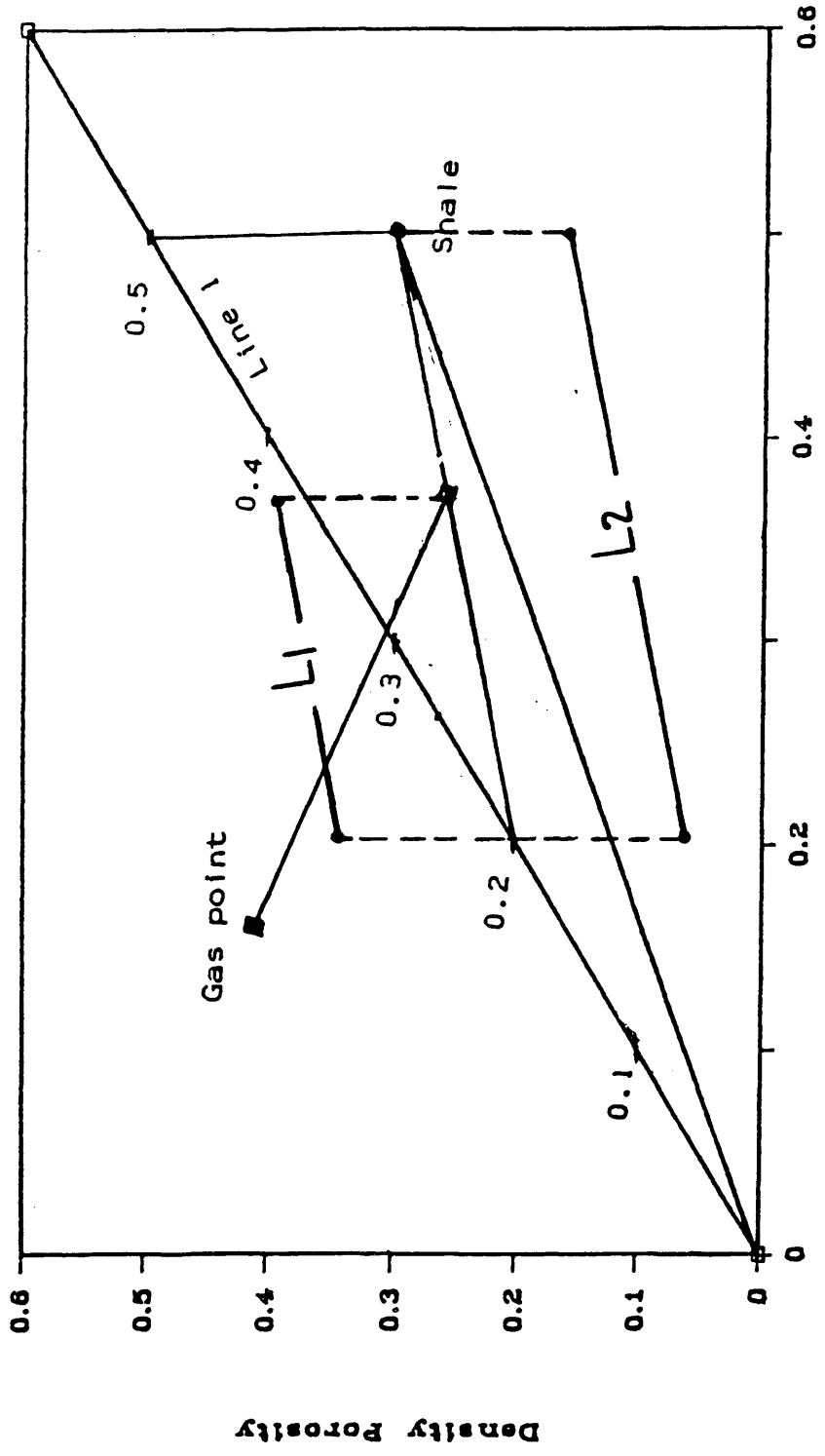

Figure A4. A diagram showing an average shale point, a typical gas point, sand porosity, and typical L1 and L2 for shale fraction determination.

Shale-Sand line) to the location of the gas point be L1, and the distance from line 1 (along the Shale-Sand line) to the shale point be L2 (see Figure A4). Then,

Shale Fraction = L1 / L2.

L1 and L2 can be expressed as follows

$$L1 = [\ (n\phi_{ng} - \phi_{sd})^2 + (n\phi_{dg} - \phi_{sd})^2\ ]^{1/2}$$

$$L2 = [\ (\phi_{nsh} - \phi_{sd})^2 + (\phi_{dsh} - \phi_{sd})^2\ ]^{1/2}$$

IV) Resistivity Match:

The resistivity from equation (A19) is computed and compared to the recorded resistivity (ILD) only when the gas point has been moved on or below line 1, since the first possible location where gas saturation could be equal to zero is on line 1. The process of moving the gas point and matching the resistivities is ended when ϕ_{sd} is equal to zero or the neutron response of the gas point reaches the neutron response of shale.

The neutron and density porosities taken from the position of the gas point that gives the best match between the recorded and calculated resistivities are considered gas corrected neutron and density porosities.