Formation Evaluation and Petrophysics

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CONTENTS

Introduction

This course is provided to introduce students to the nature and use of petrophysical borehole experiments in petroleum engineering and reservoir description. It consists of the following content:

There are 5 days allocated to the course. Much of this time will be spent on taught material. However, there will be some practical work. This consists of hand-calculated worked exercises in log data integration and analysis. Scientific calculators will be required.

Most days the lectures will run to will run from 8:00 am till 4.30 pm with a lunch-break from 12:00 to 1:00 pm. There may be some exercises to complete in the evening.

The Course objectives are to train the students in critical assessment of the quality and application of log data in reservoir description. By the end of the course students will become familiar with at least one method of log derived petrophysical data integration.

The Course material consists mainly of the notes and some selected classical papers.

LEARNING OBJECTIVES

Upon completion of the course, attendees should be able to accomplish the following:

- Calculate Porosity from base data and express Permeability as a function of the terms in the Darcy Equation. Demonstrate the dependence of each upon grain-size and sorting.
- Describe the origin of natural gamma radiation and the three spectral types used in FE.
- Determine Lithology from a basic set of logs.
- Conduct basic environmental corrections for SP, Gamma. Acoustic, Density, Neutron, Induction and Laterologs.
- Determine corrected Acoustic, Density and Neutron Porosities.
- Determine Rw from SP, Rwa and Hingle plots
- Determine m from Pickett plots
- Determine Sw using Archie, Simandoux and Dual water Nomograms and equations.
- Determine Vsh from logs

READING LISTS

The recommended textbooks on the subject,

Essential Reading

Schlumberger. *Log Interpretation Charts.* Schlumberger, 1988/89 - 2000

Schlumberger. *Log Interpretation Principles and Applications.* Schlumberger, 1989.

Optional Reading

Dewan, T.J. *Essentials of Modern Open-Hole Log Interpretation.* Tulsa: PennWell, 1983.

Doveton, J.H. *Geologic Log Analysis Using Computer Methods*. Tulsa: AAPG, 1994. (AAPG Computer Applications in geology, No. 2).

Serra, O. *Fundamentals of Well-Log Interpretation 1: The Acquisition of Logging Data.* Amsterdam: Elsevier, 1984.

Serra, O. *Fundamentals of Well-Log Interpretation 2: The Interpretation of Logging Data.* Amsterdam: Elsevier, 1986.

INTRODUCTION

Open-hole well logging began after the first world war, with tools being developed for the mining industry to identify the presence of metaliferous ores in the vicinity of a borehole. In 1927 the first oil well was logged by the Schlumberger brothers, Conrad and Marcell, and H G Doll. These early logs were called “electric cores” establishing a 70+ year goal of well logging; trying to establish the properties of the formations cut by the wellbore, without the need to recover a core.

Well Logging is a sophisticated form of proximal, or not so remote, sensing. Modern tools and evaluation procedures are at the cutting edge of technology. For example modern geosteering inertial navigation sensors have to be about 10 times more precise than the technology that got man to the moon.

Not only are modern tools technically advanced, there is a huge engineering effort that has gone into packaging all that technology in tubular devices that can operate under extreme conditions of high pressures and temperatures.

Of all wells drilled globally, only between 1 in 10 and 1 in 20 are cored to any extent. This means that for the majority of our evaluation we are reliant upon analyses that do not have the benefit of ground-truthing. This is a critical situation as it is the petrophysical data derived from the well logs that will be used by the company to define the value of an oil or gas asset.

The Geologists role is to locate, describe and quantify the assets of the company.

The Engineers role is to determine and mange the rate of return on these assets.

It is the Petrophysicists role to acquire and analyse measured data of known accuracy and uncertainty, and provide it in a timely way to both the Geologist and Engineer, so that they may accomplish their goals. Accomplishing this role is impossible without high quality log analysis.

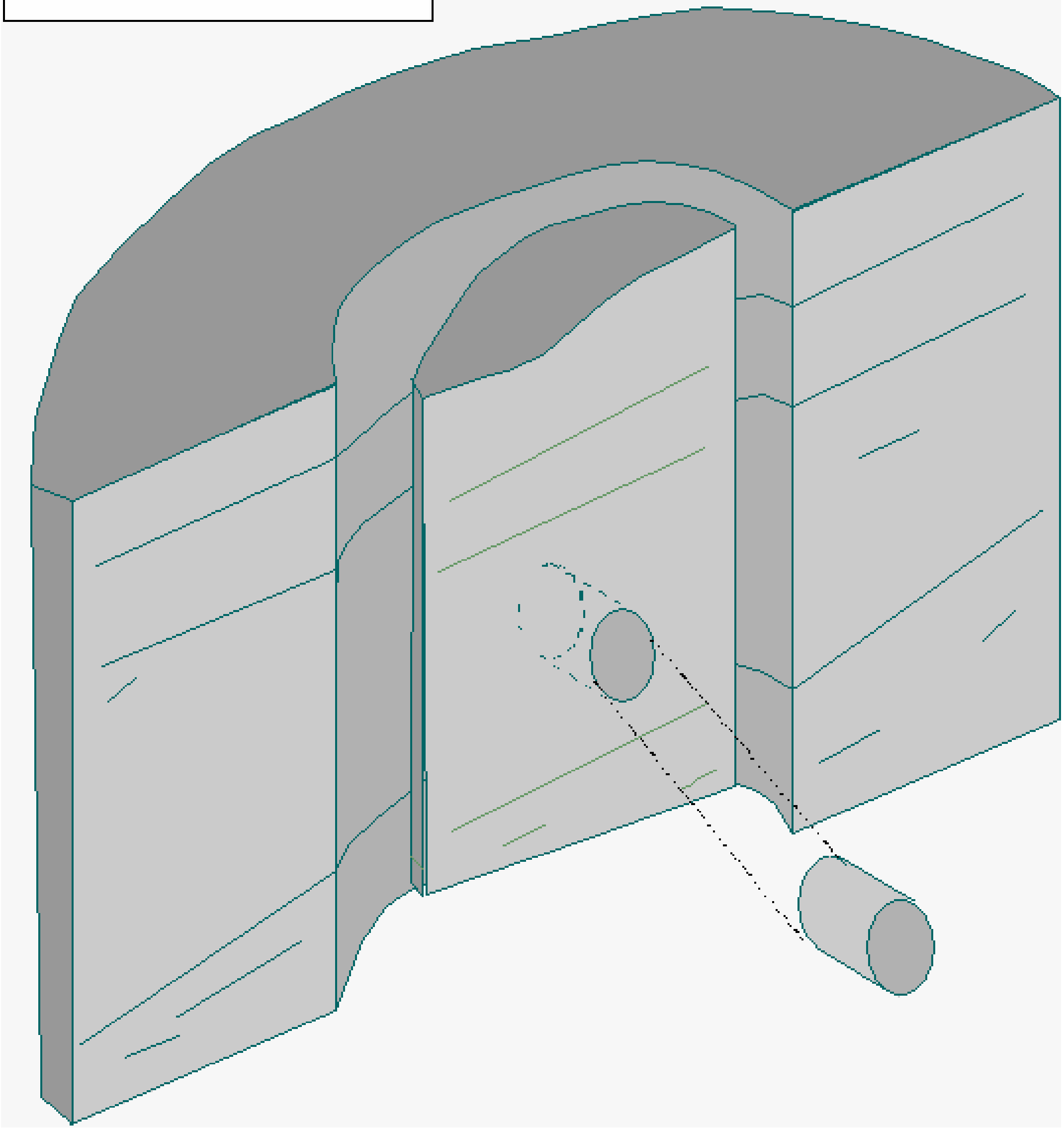
CHAPTER 1.

FUNDAMENTAL PROPERTIES

Petrophysics: Rock and Fluid Properties That Influence Both Well Log and Core Based Formation Evaluation

Physico-Chemistry

- Chemistry - Mineralogy
- Bulk Density
- Storage Capacity - Porosity
- Flow Capacity - Permeability
- Natural Gamma Activity
- Electrical Properties
- Fuid Saturation
- Fluid Distribution



CHEMICAL AND MINERALOGICAL COMPOSITION

Reservoir rocks are composed of assemblages of specific minerals, which can be detrital or authogenic in origin. However, hydrocarbon reservoirs vary widely. Hydrocarbons have been produced from serpentinite, ryolites, granites and diorites as well as the more common sedimentary rocks. In reservoir description the physico-chemical properties of the minerals forming the rock may significantly affect the evaluation method. Core analysis is no exception and care must be taken before establishing an analytical programme. Some typical rock-forming minerals and the impact of their properties are listed below.

Grain Density	Mineral	Composition
2.65	Silica	SiO_2
2.01 - 2.16	Opalescent silica	$SiO_2(nH_2O)$
2.57 - 2.64	Chalcedony	SiO_2 (crypto-crystalline)

Amorphous silica has a high water content and a high surface area. This results in suppression of resistivity logs and potential errors in effective porosity measurement. Grain density based porosity calculation can be significantly in error.

2.55 - 2.63	K-Feldspars	$(K, Na)(AlSi_3O_8)$
2.62 - 2.76	Plagioclase Feldspars	$(Ca\ [Al_2Si_2O_8])$

Feldspars have little effect on core analysis, but high potassium forms can confuse gamma-ray interpretation from down-hole logs. Again, grain density may be affected and hence porosity calculations.

2.71 - 3.96	Carbonates	$(Fe)/(Ca, Mg)\ CO_3$

The dolomitisation of a limestone can reduce the crystal volume by up to 12%, resulting in higher porosity. However, dolomite or siderite cements in sandstones result in porosity reduction. High grain density can create problems with log analysis.

2.30 - 2.96	Sulphates	$(Ca)SO_4\ (2H_2O)$

Gypsum and anhydrite are the commonest naturally occurring sulphates. There is a dehydration cycle from one to the other. Gypsum is 48% water by volume but is rarely found at depths greater than 1000 m and not at all below 2000 m. Liberation of this water results in a commensurate increase in porosity, hence, care must be taken in core analysis. Sulphate scale complexes can be precipitated from mixing sea-water with formation water in water-injection, while common in injector and producer wells and surface equipment, these are rarely encountered in cores, although at least one example from the Scott Field in the N. Sea exists.

Grain Density	Mineral	Composition
2.07	Sulphur	S

Free sulphur can occur in petroleum reservoirs. It is of low density and high solubility in hot water solutions, and poses real problems in those fields where it occurs.

Grain Density	Mineral	Composition
4.30 - 5.254	Iron Oxides	Fe_2O_3 - Fe_3O_4 - α-FeO.OH

Hematite, Magnetite and Goethite all have high densities and range from ferro – para - non magnetic. Hematite and Magnetite can also be semiconductors in situ. Goethite, when in its Limonite form, can contain abundant water, which may be liberated under heating. However this form is not common in the deep subsurface and is occasionally seen as the principal mineral in oolitic ironstones or, more commonly, as a weathering product in outcrop samples.

Grain Density	Mineral	Composition
4.95 - 5.03	Iron Sulphide	FeS_2

Pyrite is a common metallic mineral that can act as a semi-conductor in the formation. It is formed under reducing conditions in organic rich environments. Its high density can significantly affect the bulk density of a formation. When present as a disseminated mass, electric log interpretation must account for its conductivity.

Grain Density	Mineral	Composition
2.40 - 2.77 - 3.30	Micas	

Muscovite: $K_2Al_4[Si_6Al_2O_{20}](OH,F)_{,4}$

Glauconite: $(K,Ca,Na)_{\approx1.6}(Fe^{3+},Al,Mg,Fe^{2+})_{4.0}Si_{7.3}Al_{0.7}O_{20}(OH)_{4.0}$

Biotite: $K_2(Mg,Fe^{2+})_{6\text{-}4}(Fe^{3+},Al,Ti)_{0\text{-}2}[Si_{6\text{-}5}Al_{2\text{-}3}O_{20}\}(OH,F)_4$

Muscovite (Sericite), Glauconite and Biotite can be found in sedimentary rocks, in decreasing order of abundance. Muscovite - Sericite tends to cause fines problems in water injection and production. The high potassium content of the micas results in a high natural gamma (γ) radioactivity. Glauconite is iron rich and can also contain smectite layers (cf. below)

Grain Density	Mineral	Composition
0.9-1.1 - 1.8	Solid Hydrocarbons Gilsonite Bitumen	

Coals

Amber

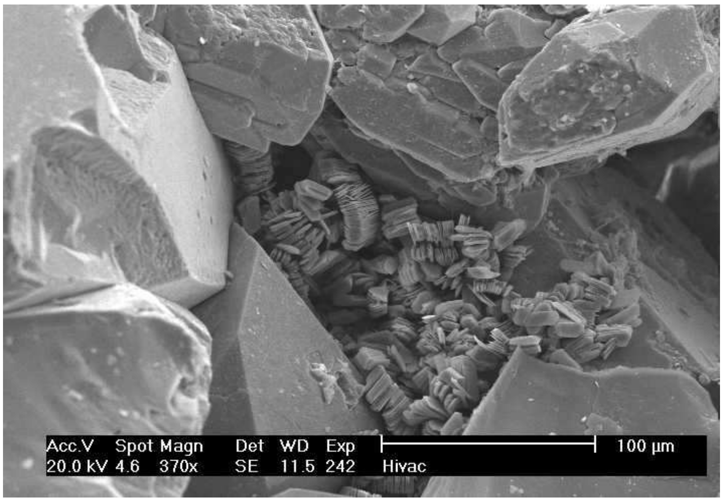
Low grain density and a propensity for non-pyrobitumens to dissolve under solvent extraction can cause problems, both in the lab and down-hole. High temperature distillation can result in cracking and the production of ‘oil’ from these solids.

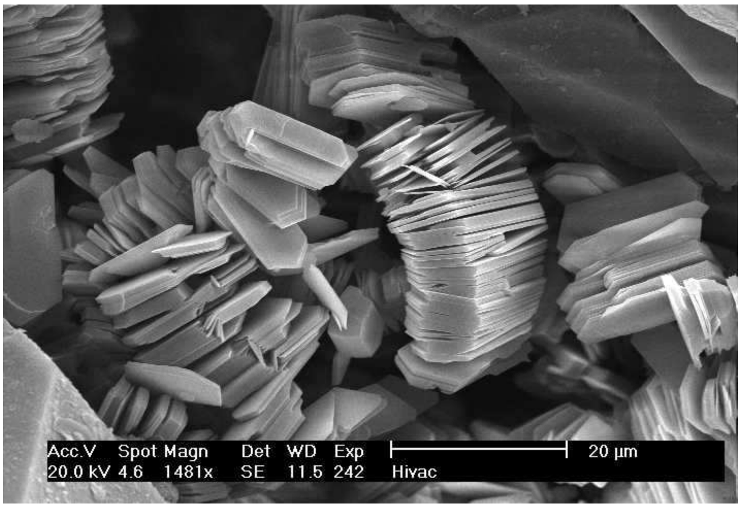
Clay Minerals

Grain Density	Mineral	Composition	CEC meq/100g
2.60 - 2.68	Kaolinite	$Al_4[Si_4 O_{10}\}(OH)_8$	**1-10**

A chemically stable clay in sediments. However, it is prone to simple mechanical damage and is easily transported as mobile fines under fluid flow. Clay stabilisers, such as poly-hydroxy-alumina can be used to fix the fines, or $HBFO_4$, Fluoroboric acid, used to fuse the clay. Kaolinite may be found as a layer in complex mixed layer clays, commonly with smectite

Kaolinite

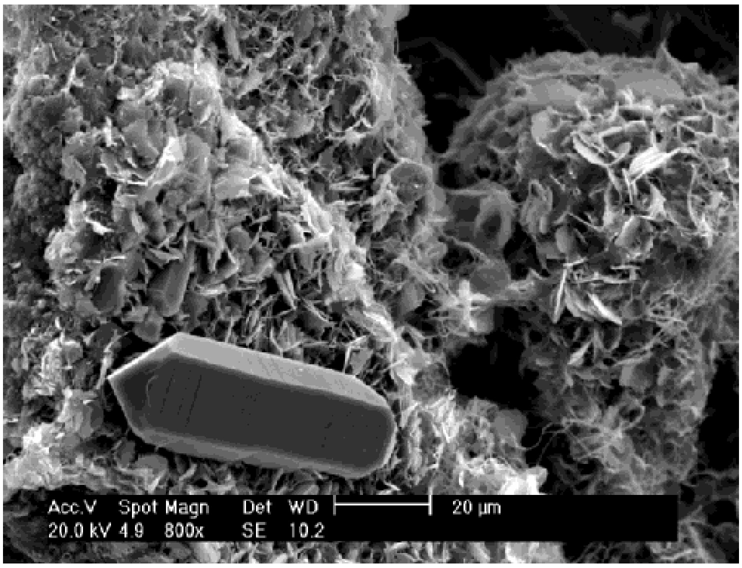


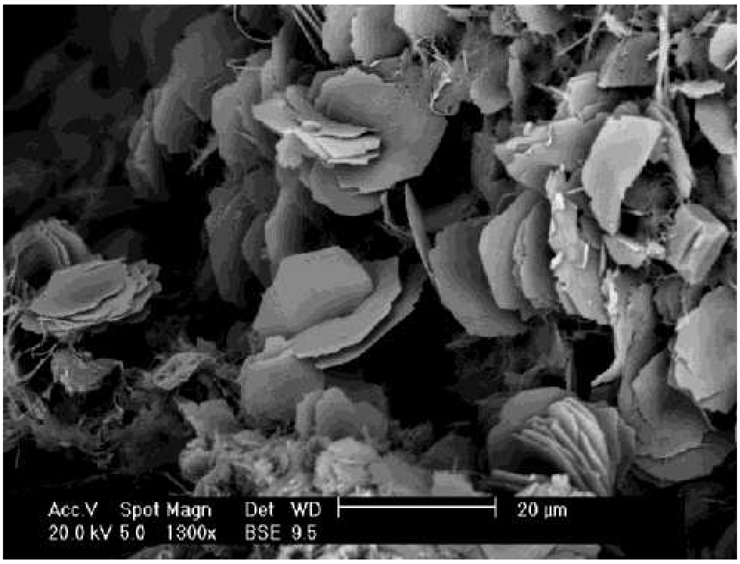


Grain Density	Mineral	Composition	CEC
2.60 - 3.30	Chlorite	$(Mg,Fe^{2+},Fe^{3+},Mn,Al)_{12}[(Si,Al)_8O_{20}](OH)_{16}$	**<10**

Normally not a swelling clay unless incorporated as a mixed layer system with smectite. An iron rich clay, which has an adverse reaction with mud acid, HCl-HF, to produce $Fe(OH)_3$, a gel that can impair permeability. Pre-washing with a chelating agent or a sequestrant, such as citric, or acetic acids, prevents this reaction. Authigenic chlorite commonly displays a roseate habit, resulting in abundant micro-porosity. The water saturation in this micro-porosity can suppress electric log responses, however, the presence of chlorite also suppresses silica cement growth, resulting in porosity preservation at depth.

Chlorite

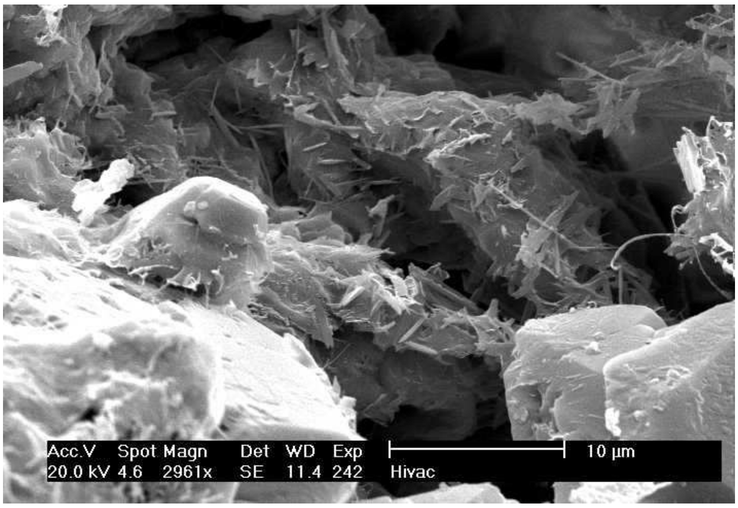


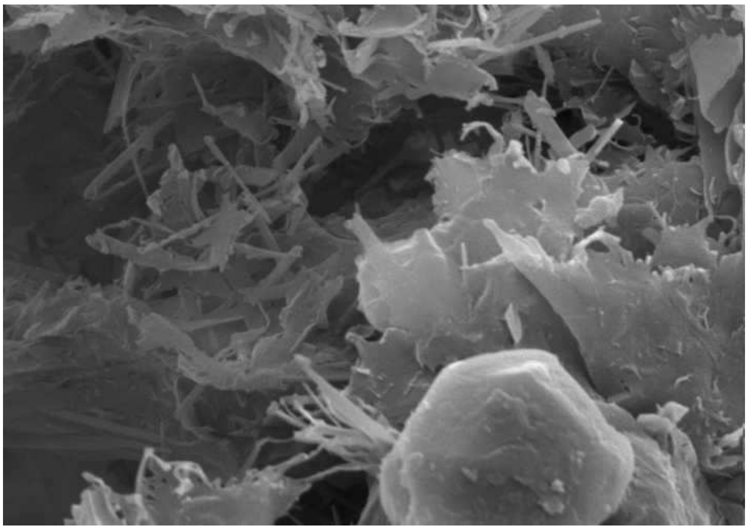


Grain Density	**Mineral**	**Composition**	**CEC**
2.60 - 2.90	<u>Illite</u>	$K_{1.5-1.0}Al_4[Si_{6.5-7.0}Al_{1.5-1.0}O_{20}](OH)_4$	**10-40**

Originally known to American petrologists as Hydro-muscovite, this mineral is chemically similar to the mica. However, the authigenic form is rarely seen in a simple platy form, but rather forms fibrous to blocky mats coating grains and bridging pore throats. Permeability loss due to this form has been reported. The fibrous (hairy) fines are very rate sensitive during fluid flow. In the laboratory care must be taken to avoid destruction of the fibrous clay mats. Also a component of mixed layer clays, Illite is the principal mineral source of the K_{40} radioactive isotope natural γ-ray response in shales.

<u>Illite</u>



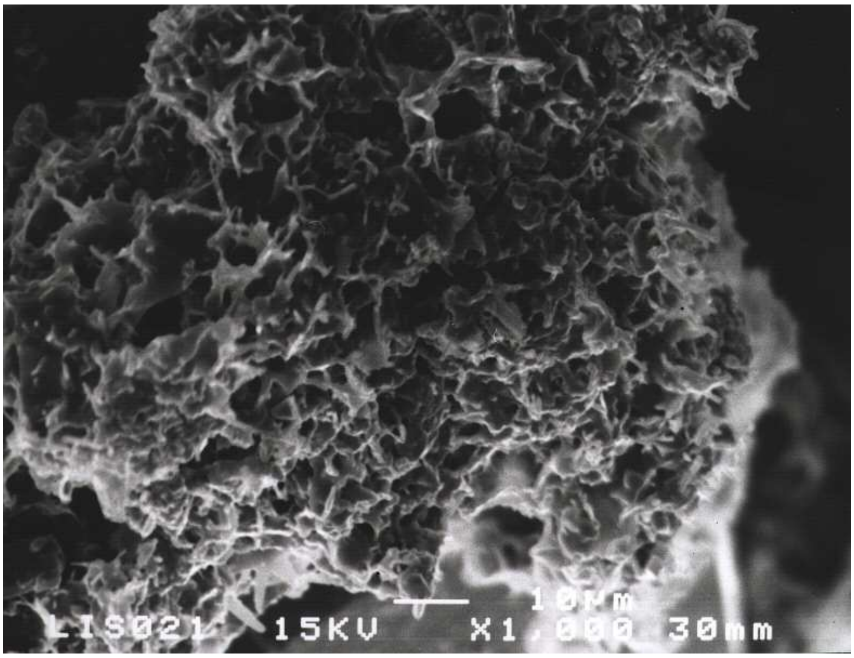


Grain Density	**Mineral**	**Composition**	**CEC**
2.00 - 3.00	Smectite	$(\frac{1}{2}\text{Ca,Na})_{0.7}(\text{Al,Mg,Fe})_4[(\text{Si,Al})_8\text{O}_{20}](\text{OH})_4.n\text{H}_2\text{O}$ $(\frac{1}{2}\text{Ca,Na})_{0.7}(\text{Mg,Fe, Al})_6[(\text{Si,Al})_8\text{O}_{20}](\text{OH})_4.n\text{H}_2\text{O}$	**80-150**

Smectites also can establish a fines problem under production. In addition to this they swell in the presence of water. Swelling is caused by the net $^1/_2$ charge imbalance in the unit cell. No ion carries half a charge, so cations attracted to the interlayer site cause further charge imbalance. The water molecule, due to its polar structure, is attracted to this site. However, the molecule is much larger than the typical mono- or divalent cations occupying this site and it pushes the unit cell apart from about 10 to 20 Å.

Clay swelling can result in severe permeability impairment. Smectites also display a sponge-like habit, with high micro porosity, often bridging pore throats. This combination, coupled with their high cation exchange capacity, gives a strong suppression of electric logs. Na-Montmorilonite is up to 33% water by volume. This water is liberated in a continuous dehydration cycle above 100° C until, with depth of burial, water-loss and heating, they convert to illite.

Smectite



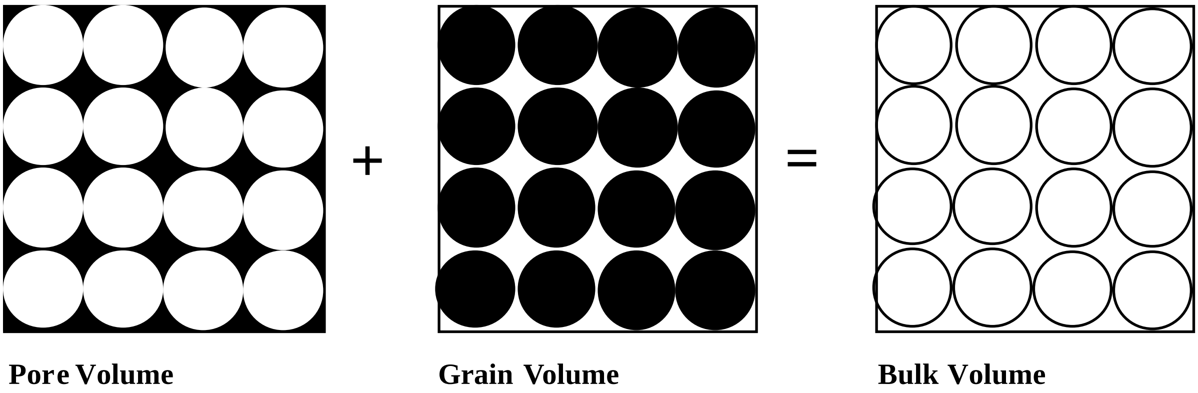
Grain Density	Mineral	Composition	CEC
2.00 – 2.80	Zeolites		**100 - >500**
	Laumontite	$Ca_4(Al_8,Si_{16},O_{48}).16H_2O$	
	Heulandite	$(Ca,Na_2,K_2)_4\ [Al_8,Si_{28},O_{72}].24H_2O$	

The zeolites occur as natural authigenic minerals in volcanic rocks and sediments. They may even grow in the deep marine environment at 4°C in the sediment water interface. They also form from the alteration of volcanic glass, tuff and feldspar in high pH conditions. They contain large volumes of water and have the highest cation ion exchange capacity in nature. When present they suppress resistivity tools through excess conductivity. They can easily liberate their water upon heating, and reabsorb it upon cooling in a humid atmosphere. There are sodium rich varieties and even barium rich zeolites, which have densities approaching 2.80.

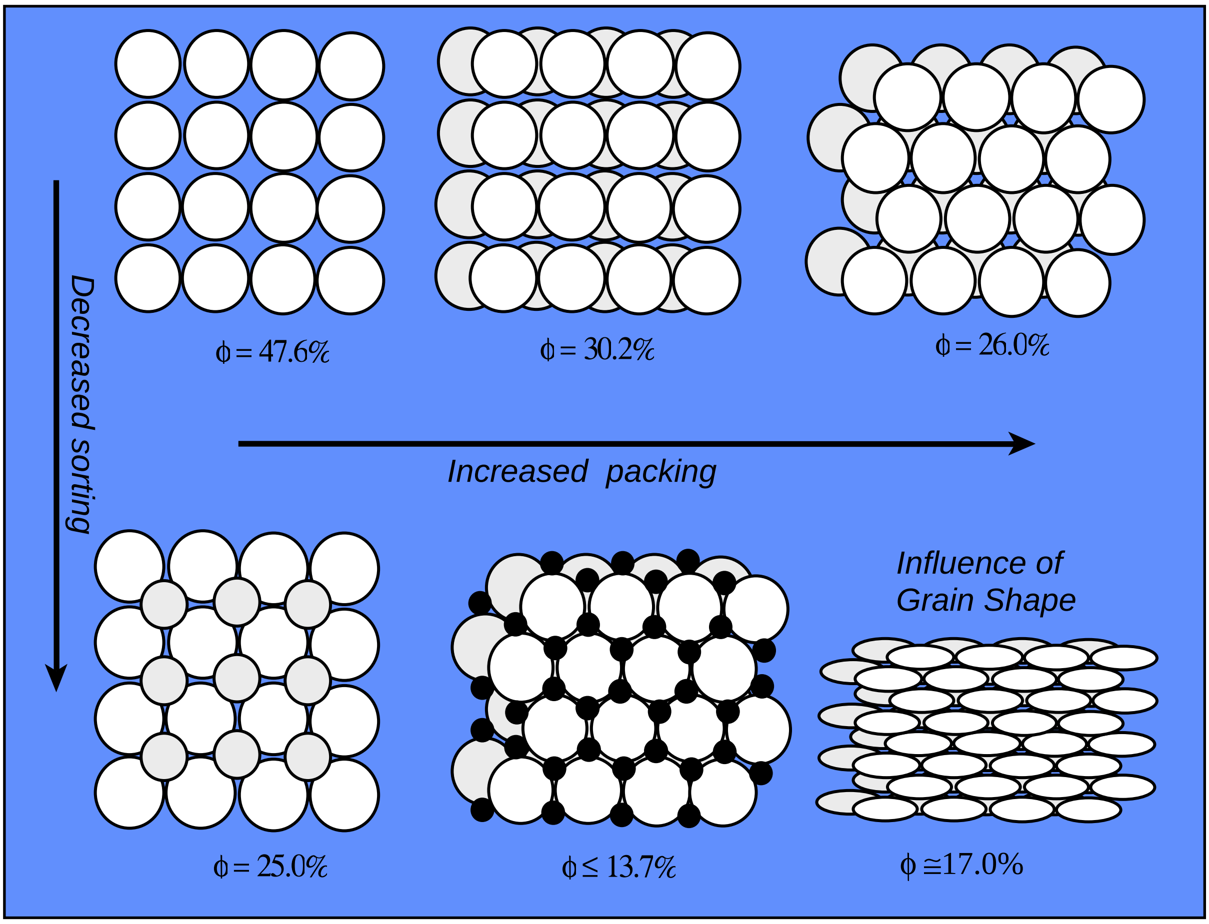
From the chemical point of view there are rocks that contain mineral mixes that have properties that are quite different to those we commonly associate with sandstones and limestone. We need to understand these properties, but also the rock fabric, or way that the rock grains are put together. After all, it is the rock fabric that will control the physical properties of porosity and permeability.

POROSITY AND STORAGE CAPACITY

Porosity Definition



Intergranular Porosity



POROSITY AND STORAGE CAPACITY

Definition

Porosity is defined as the ratio of the pore volume to the bulk volume of a substance. In oil and gas reservoirs, the pore volume is the space available for the storage of the hydrocarbons and water. Porosity is normally expressed as a percentage of bulk volume and is symbolised by ϕ.

$$\text{Porosity, } \phi = \frac{\text{Pore Volume}}{\text{Bulk Volume}} \text{ x } 100$$

$$\text{Porosity, } \phi = \frac{\text{Bulk Volume - Grain Volume}}{\text{Bulk Volume}} \text{ x } 100$$

$$\text{Porosity, } \phi = \frac{\text{Pore Volume}}{\text{Pore Volume + Grain Volume}} \text{ x } 100$$

Total Porosity

Total porosity is defined as the ratio of the volume of all the pores to the bulk volume of a material, regardless of whether or not all of the pores are interconnected.

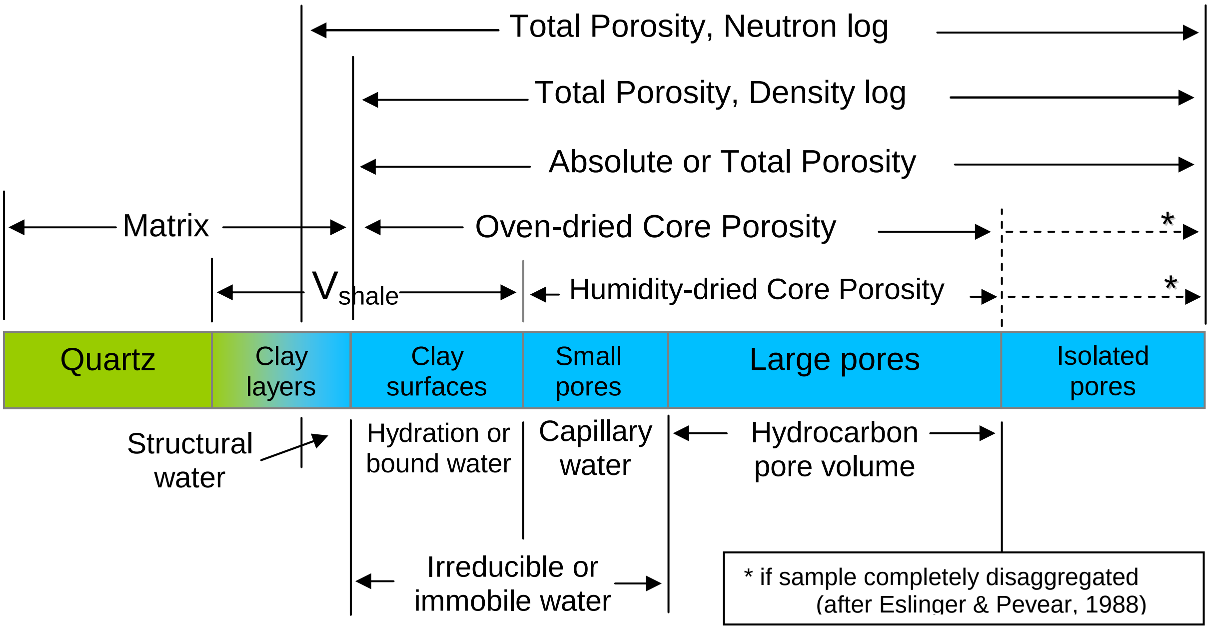
Effective Porosity

Effective porosity is defined as the ratio of the interconnected pore volume to the bulk volume of a material, i.e. it does not include dead-end pore-space.

Water of Hydration

The water of hydration of crystallisation of the constituent minerals of a reservoir rock is defined as a portion of the grain volume. It is not a portion of the pore volume. This can pose problems when comparing certain log porosities with core-derived data and in the derivation of fluid saturations on these rocks.

Porosity Concepts in Formation Evaluation

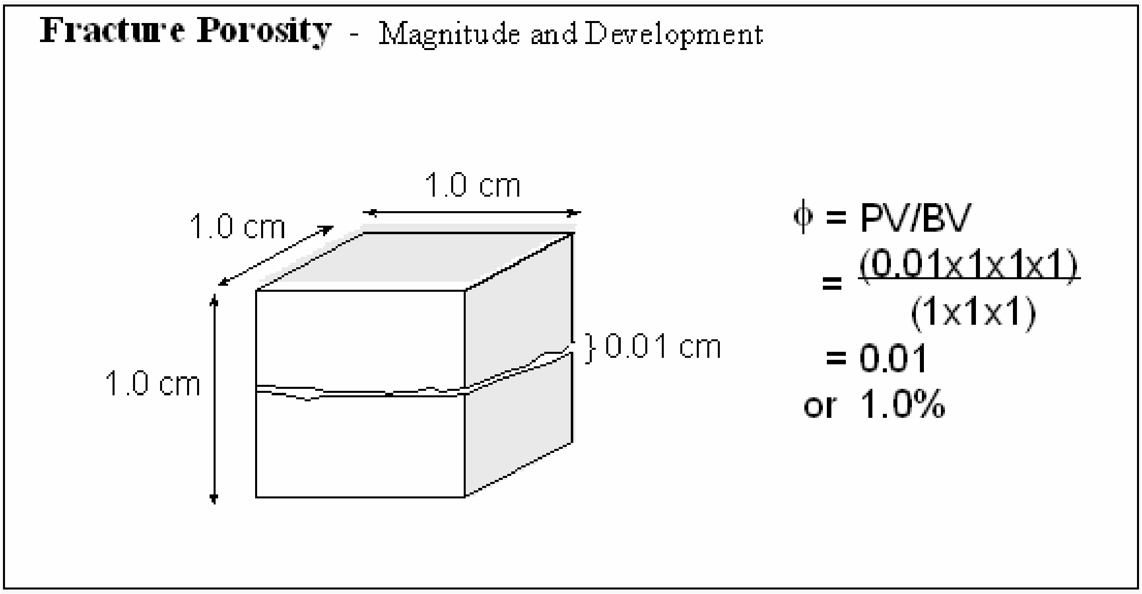


POROSITY-TEXTURE AND PETROPHYSICAL RELATIONSHIPS

Porosity in sands and sandstones varies primarily with grain size distribution, grain shape, packing arrangement, cementation, and clay content. These parameters control the overall pore geometry as well as the porosity value. The porosity of typical hydrocarbon productive sandstones ranges between 3 and 38 percent in gas reservoirs and 10 to 38 percent in oil reservoirs.

Porosity in carbonate rocks can be much more variable in magnitude than it is in sandstones. In some carbonates, such as reef build-ups and chalks, it is very high, in a few cases exceeding 50 percent. However, the fractures commonly encountered in carbonate rocks contribute little to the porosity. The development of vugs and fractures as found in carbonate reservoir rocks is termed ***Secondary Porosity*** and is a function of the depositional history and diagenesis of the rocks. Diagenetic overprints in carbonates can be much more radical than those in sandstone (siliciclastic) reservoirs as both complete mineral replacement and complete dissolution can occur a number of times as a function of burial history. Often, carbonate reservoir rock's porosity can be correlated with the degree of dolomitisation, as the dolomitisation of limestone can generate up to 12% additional porosity due to shrinkage of the crystalline lattice.

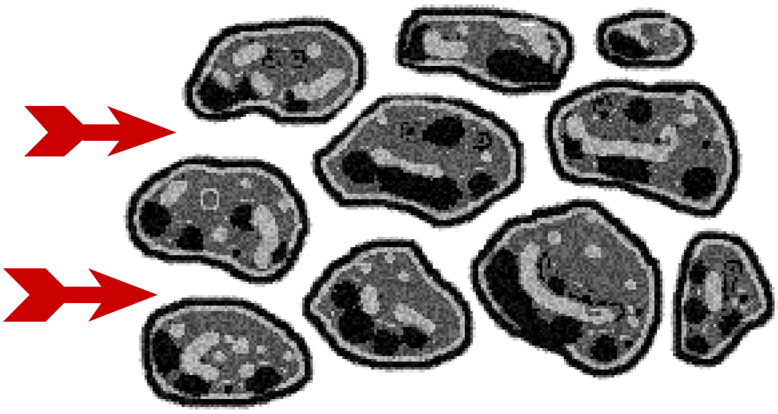
While vugular porosity can be large, caverns of some tens of metres size having been encountered in some rare cases, fractures, which make up the other major component of secondary porosity tend to be of a smaller aperture. This is because fractures are a response to reservoir stress history and there are always forces attempting to close them. A common misconception is how much they contribute to overall reservoir porosity.



PERMEABILITY

Definition and Theory

Permeability is a measure of the ability of a porous material to transmit fluid. The unit of measurement is the Darcy, named after a French hydrologist who investigated flow of water through filter beds in order to design the public drinking fountains of the city of Dijon in the year 1856.



$$Q \propto A \text{ and } Q \propto \Delta P\text{ ,}$$

$$\text{but } Q \propto \frac{1}{l}\text{ ,}$$

$$\text{so } Q \propto \frac{A \cdot \Delta P}{l}$$

$$\Rightarrow Q = \frac{k \cdot A \cdot \Delta P}{l}.$$

However, Henri d'Arcy was using clean water in his experiments. Subsequently, it was Henri Poiseceuilles, who noted that viscosity was also inversely proportional to the flow-rate. Hence it was essential to include a term for viscosity, μ, in centipoise, in the Darcy equation.

$$Q = \frac{k \cdot A \cdot \Delta P}{l \cdot \mu}$$

One Darcy is defined as that permeability that will permit a fluid of one centipoise viscosity to flow at a rate of one cubic centimetre per second through a cross-sectional area of 1 square centimetre when the pressure gradient is one atmosphere per centimetre.

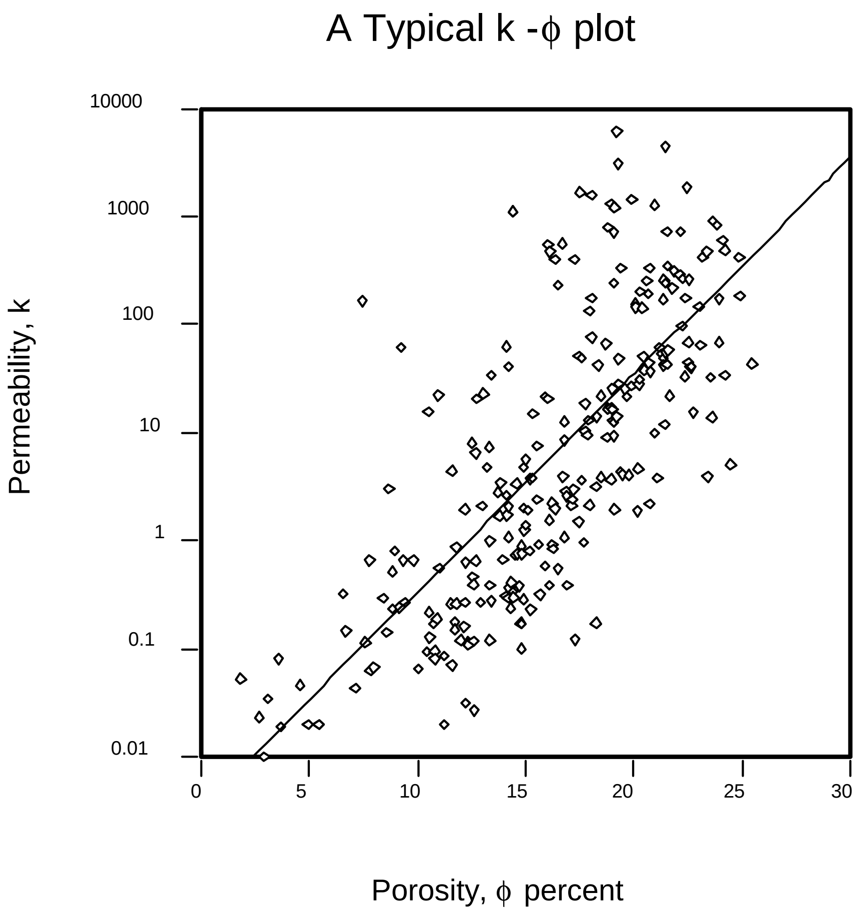
In practical units, one Darcy permeability will yield a flow of approximately one barrel/day of one centipoise oil through one foot of formation thickness in a well bore when the pressure differential is about one psi.

Darcy's Law is used to determine permeability, which is a constant when the following boundary conditions are met:

1. Linear-laminar flow
2. No reaction between fluid and rock
3. One phase present at 100 percent pore-space saturation
4. Incompressible fluid

Because of the relatively high value of the base-unit, the millidarcy, (one thousandth, 1/1000, of a Darcy) is commonly in use in reservoir description. The Darcy has a SI equivalent in the μm^2. Formation permeabilities typically vary from a fraction to more than 10,000 millidarcies.

Permeability and Porosity Relationships



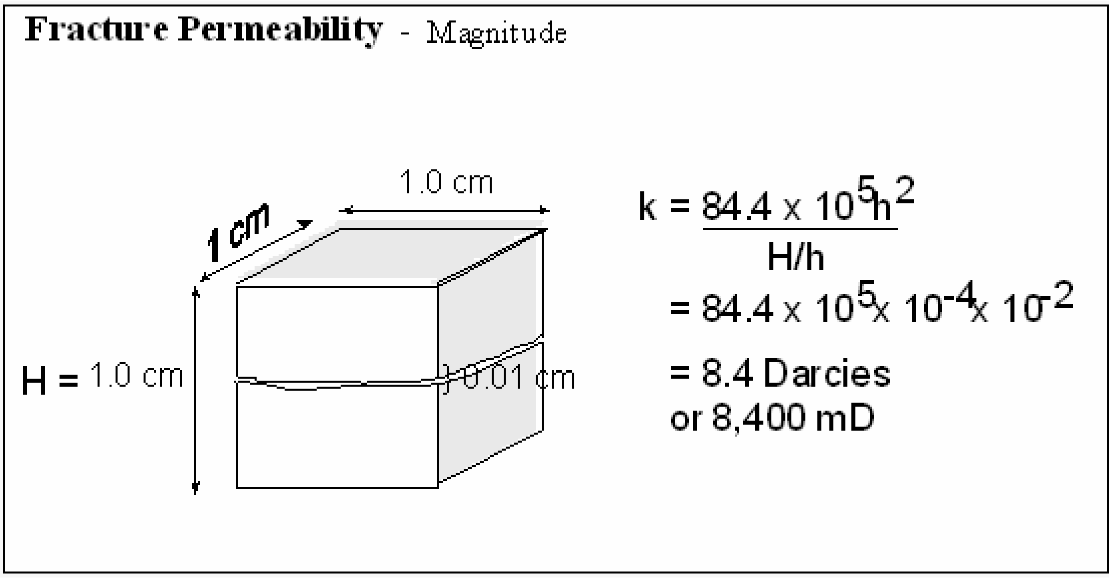
The Geological environment and depositional factors influencing porosity also influence permeability, and often there can be an obvious relationship between the two. The relationship varies with formation and rock type, and reflects the variety of pore geometry present. Typically, in sandstone reservoirs, increased permeability is accompanied by increased porosity. Constant permeability accompanied by increased porosity indicates the presence of more numerous but smaller pores.

Post depositional processes in sands including compaction and cementation result in a shift to the left of the permeability-porosity trend line, while dolomitisation of limestone tends to shift the permeability-porosity trend lines to the right.

Directional Permeability

Permeability is a directional quantity and should be truly considered a tensor property. Water-borne deposition of sand occurs with alignment of the long axis of the grains parallel to the current. In Aeolian sands the long axis may be at right angles to the paleo-wind direction. The greatest cross-sectional area of the grains lies in a horizontal plane. Permeability is highest parallel to the long axis of the grains.

Vertical permeability (perpendicular to bedding planes) is usually less than horizontal permeability, due to platy minerals lying flat along bedding planes. This vertical permeability may be further reduced by shale laminations in sands, or stylolites in carbonates. In reservoir description the ratio between kv and kh is an important factor in understanding sweep efficiency and recovery.



Fracture Permeability - Magnitude

$$k = \frac{84.4 \times 10^5 h^2}{H/h}$$

$$= 84.4 \times 10^5 \times 10^{-4} \times 10^{-2}$$

= 8.4 Darcies
or 8,400 mD

Fractures or joint trends existing in carbonates and hard, low porosity sands, result in widely varying directional permeability. This anisotropy is important in understanding reservoir behaviour.

Spatially oriented cores coupled with detailed core descriptions, listing strike and dip of major and minor fractures, core-goniometry, and directional permeability measurements, assist in defining fracture trends and permeability variation.

Supplementary Notes

NATURAL GAMMA RADIATION CHARACTERISTICS

The natural gamma radiation of sedimentary rocks is generally attributed to the presence of uranium group trace elements in certain heavy minerals and/or the potassium isotope, K_{40}. Potassium exists in Feldspars, Micas, KCl salt evaporites and Illite clays, while Uranium and Thorium are concentrated in Phosphatic minerals, such as Monazite, typical of low sedimentation environments. The Uranyl (U^{6+}) ion tends to be very soluble in water, but precipitates readily in reduced environments, such as organically rich, or pyritic facies.

Typically, shales have high gamma activity, carbonate rocks have low activity, and sandstones vary in activity between the former two types.

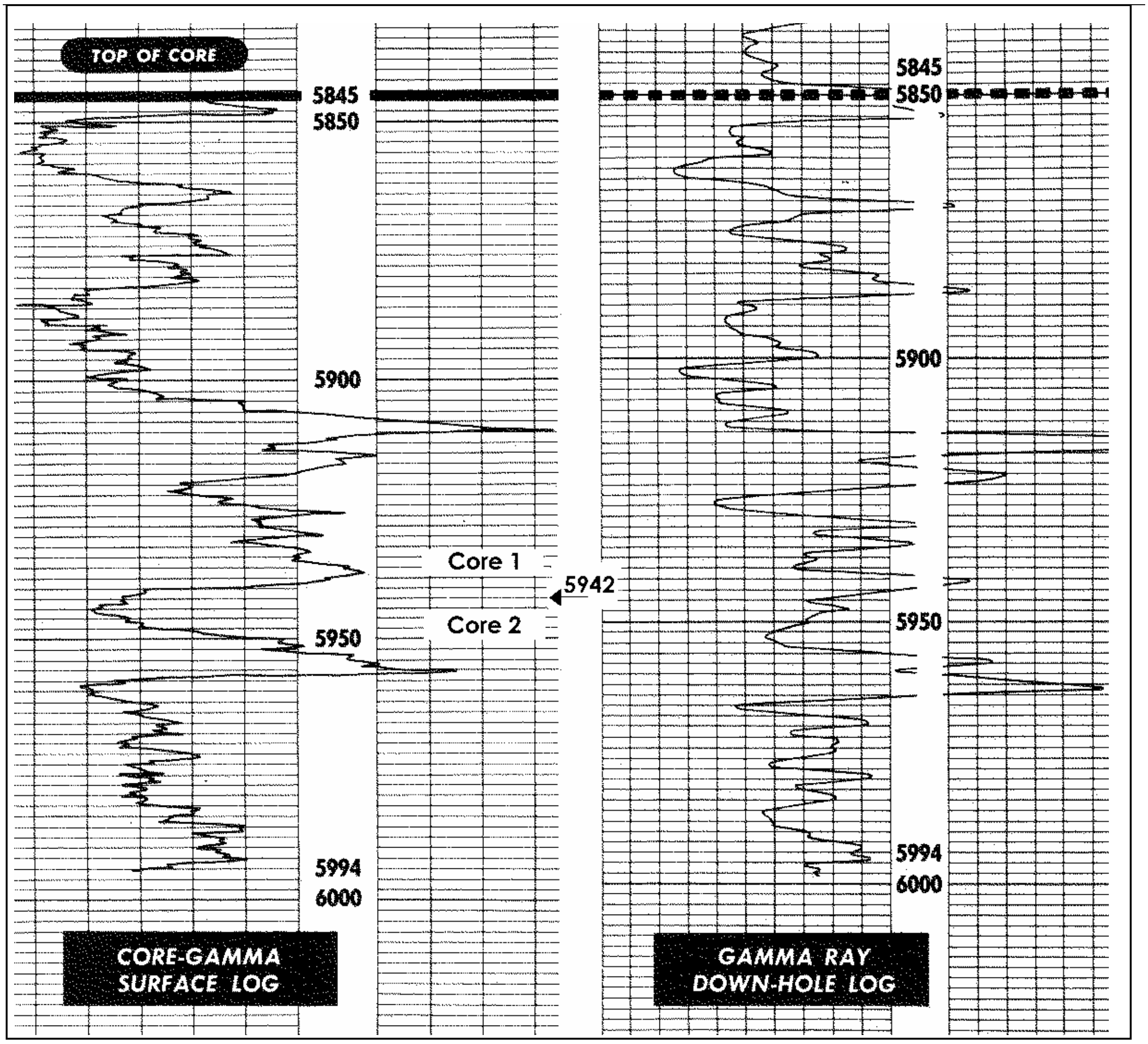
The natural gamma ray logs are utilised for discerning lithology and for correlation purposes.

Core-Gamma Surface Log

The natural gamma radiation of a core is monitored and recorded as a function of depth for the purpose of correlation with the down hole gamma logs of the same well or nearby wells. A scintillometer utilising a Sodium Iodide crystal and photo-multiplier similar to the down hole logging instruments, is used for detecting the gamma radiation. The Core-Gamma Surface Log scales are the same as those of the down hole logs.

A first-hand inspection of the cores that are being logged and the Core-Gamma Surface Log are combined to make a very useful tool. When correlated with down hole logs, Core-Gamma Surface Logs help to discern unusual gamma activity conditions, afford accurate perforating in thin productive intervals, locate anticipated pay zones, orient cores in a section, identify lost core intervals, and eliminate unnecessary coring.

Typically depth discrepancy between core depths and actual hole depths are found from a correlation of the core-gamma surface Log with the down hole gamma log of the well. This Allows for the core to be correctly assigned to the portions of the contiguous wellbore, by matching peak-to-peak and trough-to-trough. Depth discrepancies result from differential stretch between the wireline and drilling string, depth recorder clutch errors and miss/unrecorded drill pipe in the string. Errors in multiples of 30 feet (9.14 metres) can be common



The First Ever Surface Gamma-Ray Log,

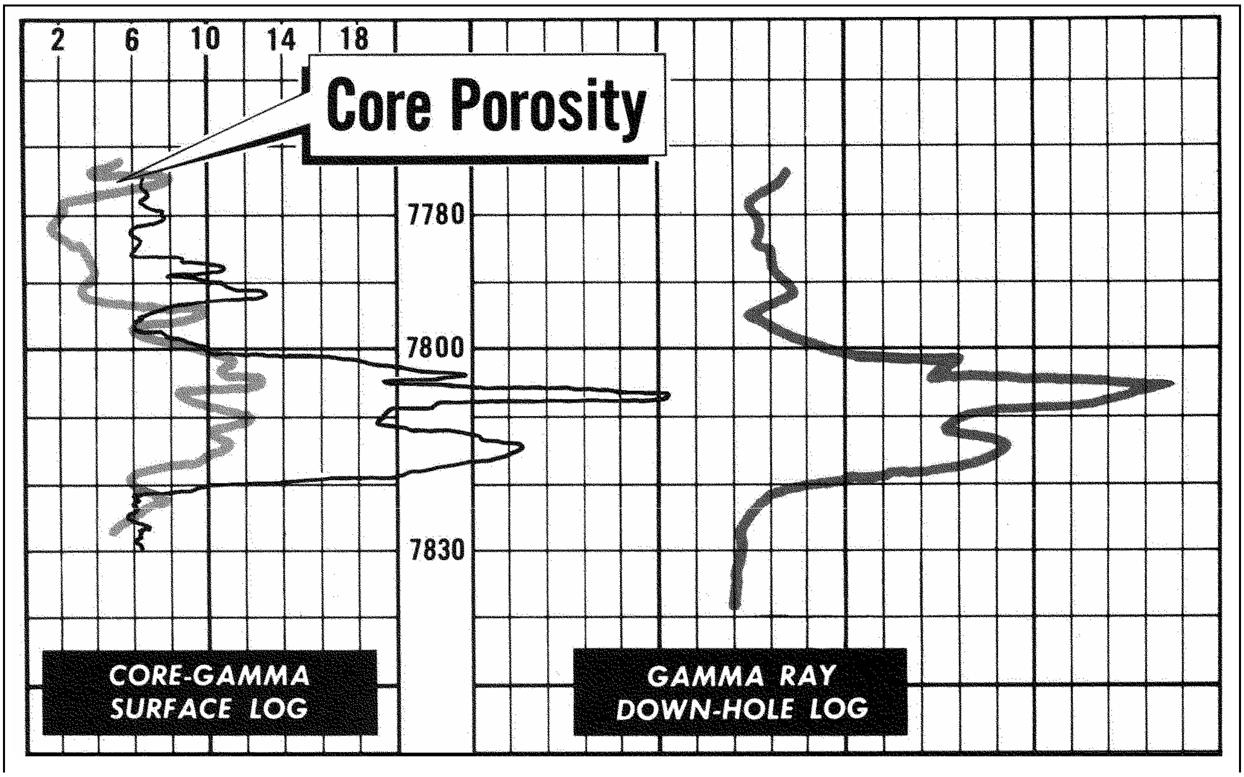
Glorieta formation, Andrews County, Texas

In this case a comparison of the core data with an adjacent well clearly indicated that the main pay zone had not been reached. A second core barrel was picked-up and the anticipated zone cored in the subsequent run. Note that a cross-plot of core properties , such as porosity, versus the down hole values from the logs will display considerable scatter unless proper depth matching is performed beforehand.

Devonian, Alberta, Canada

The gamma activity response is sometimes the reverse of the anticipated response. The Core-Gamma Log of a well in Alberta shows a case wherein the porous section between

7804 and 7820 feet was accompanied by an increase of gamma activity. Subsequent mineral analysis of the core showed the gamma activity in the porous interval to be due to the deposition of uranium salts on the walls of the pores.



Spectral Gamma Ray Logs

With the invention of scintillometers containing windows covering specific energy levels of the gamma rays detected by the tool, it became possible to quantify a proportion of the radionuclides in the formation. Because of the clear identity their spectra and their relative abundance, Potassium (K^{40}), Thorium^{232} and Uranium^{238} are the species detected.

K^{40} abundance coincide with the presence of K feldspars, Muscovite - Sericite micas and illitic clays and shales. In many cases it is a good shale indicator, but not when the shales are rich in Kaolinite and other non-potassic clay species.

Thorium^{232} Is quite rare and is only abundant when concentrated by periods of low sediment input. It is a component of Phosphatic heavy minerals, such as Monazite, which are either detrital or may be complexed in times of phosphoritic formation. Early authors attempted to relate Thorium content to clay chemistry. In particular it was related to Kaolinite content.

(Schlumberger Chart CP-19) This approach has been discredited by Hurst and Milodowski (1994). Thorium has been successfully related to maximum flooding surfaces in a sequence stratigraphic interpretation.

Uranium^{238}, like Thorium is also present in detrital heavy minerals such as Zircon and as Uranium salt precipitates. The Uranyl ion is very mobile, being readily soluble in most formation waters. It tends to precipitate when there is a drop in the pH of the environment. In percolating waters this may occur where there has been the most deposition of organic materials. This often is when there is the least input of sediment and also corresponds to a maximum flooding surface. In the Devonian example above, the presence of H_2S and reduced sulphides as pore-linings, was the cause of the Uranium deposition in the formation.

Supplementary Notes

ACOUSTIC PROPERTIES OF ROCKS

Elastic Wave Velocities in Solids

The velocity of elastic waves in solids is a function of the density and elastic properties of a material.

$$V_b = \sqrt{\frac{E}{\rho} \cdot \frac{(1 - \mu)}{(1 + \mu)(1 - 2\mu)}}$$

$$V_s = \sqrt{\frac{E}{\rho} \cdot \frac{1}{2\,(1 + \mu)}}$$

WHERE: V_b = Velocity of bulk compressional waves

V_S = Velocity of shear wave

ρ = Density

E = Young's Modulus

μ = Poisson's Ratio

Elastic Wave Velocities in Porous Media

The velocity of elastic waves in a porous medium is a complex function of many of the other characteristics of the medium, including:

1. Rock composition
2. Porosity
3. Grain size, type and distribution
4. Type and degree of cementation and lithification
5. Pore sizes and distribution
6. Pore fluid densities, viscosity, and saturations
7. Rock skeletal (matrix) pressure and pore pressure
8. Bulk compressibility and other elastic properties

Relationship of Porosity and Acoustic Velocity

A good correlation often exists between porosity and acoustic velocity values. The Wyllie "time-average equation" for compressional waves, has been very popular in the industry for many years.

$$\Delta t = \Delta t_f .\ \phi + \Delta t_m (1 - \phi)$$

or,

$$\phi = \frac{\Delta t - \Delta tm}{\Delta t_f - \Delta tm}$$

Stated another way, the total travel time is equal to the sum of the travel time of the signal through the pore fluid fraction plus the travel time through the rock solid fraction. The idealised models required by the "time-average equation" to rigorously relate porosity and velocity are shown below. The two left-hand models will yield a valid relationship, whereas the model on the right-hand side will not allow the porosity to be sensed.

Some Mineral P wave Velocities, at Room Temperature and Pressure

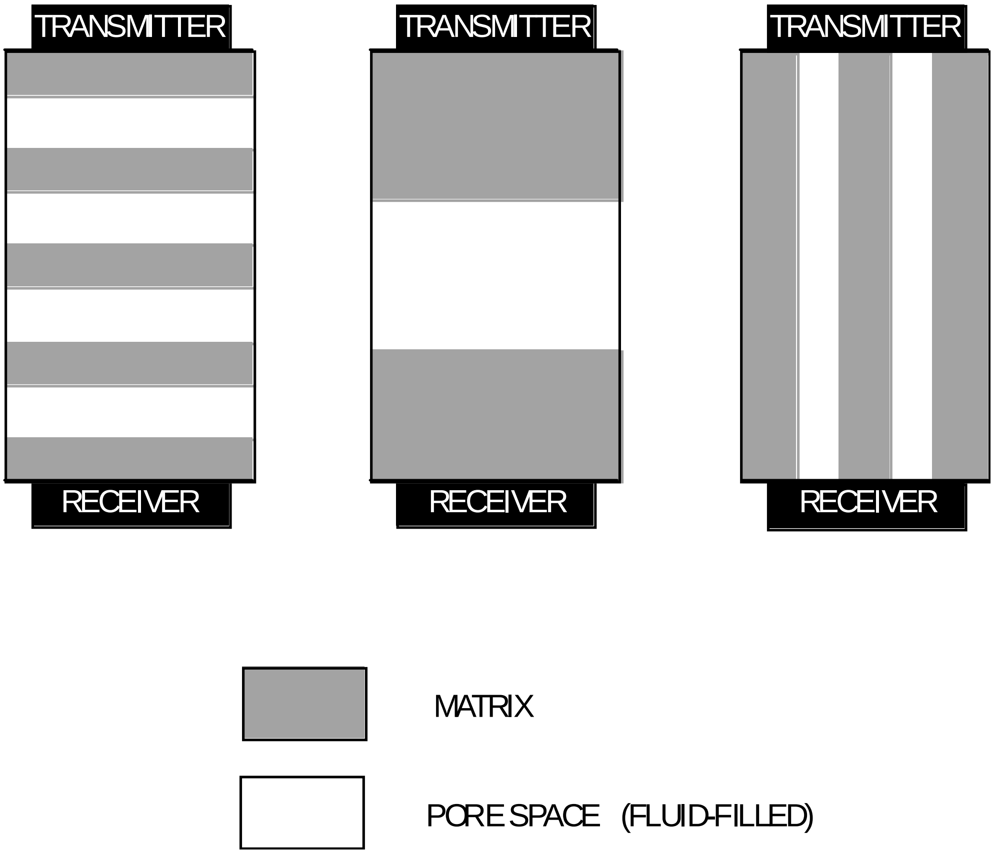
Mineral	Observed Directional Velocity (ft. / sec.)		
	X	Y	Z
Anhydrite ($CaSO_4$)	20,340	20,790	20,360
Calcite ($CaCO_3$)	23,060	21,570	15,740
Dolomite ($CaCO_3 \bullet MgCO_3$)	24,960	-	-
Feldspar ($K_2O \bullet A1_2O_3 \bullet 6SiO_2$)	12,150	18,760	12,460
Feldspar ($Na_2O \bullet A1_2O_3 \bullet 6SiO_2$)	14,370	21,920	-
Gypsum ($CaSO_4 \bullet 2H_2O$)	18,970	17,460	21,300
Halite (Rock Salt)	15,350	-	-
Mica Schist	5,000	16,650	12,860
Opal ($SiO_2 \bullet H_2O$)	17,250	-	–
Quartz	17,650	17,750	21,400

Quartz and Calcite measured on crystal axes.

Velocities (ft. / sec.) of Fluids

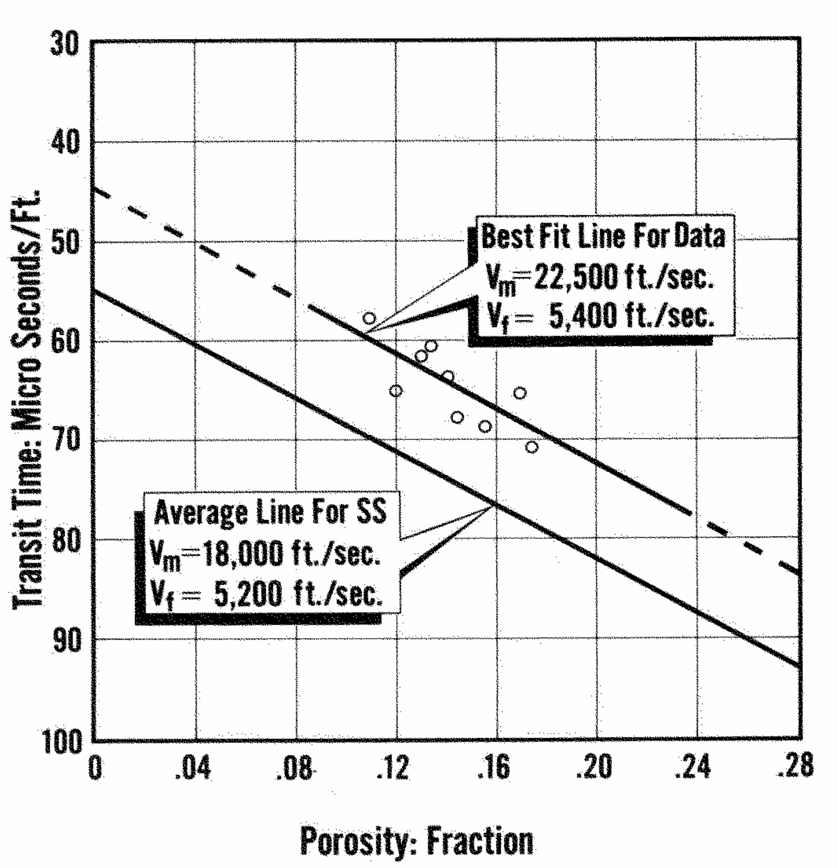
Drilling Mud (26° C.)	4,870
Drilling Mud Cake	4,980
Distilled Water (25° C.)	4,912
Glycerol 100 (25° C.)	6,380
n-Hexane (26.2° C.)	3,511
n-Pentane (26.2° C.)	3,303
Iso-Octane (26° C.)	3,622

From: Wylie, M.R.J. et al: "Elastic Wave Velocities in Heterogeneous and Porous Media" GEOPHYSICS, Vol. XXI, No. 1 (January, 1956) pp 41-70



Theoretical Models Relating Porosity and Transit Time

Transit Time Versus Porosity - Siliceous Sandstone

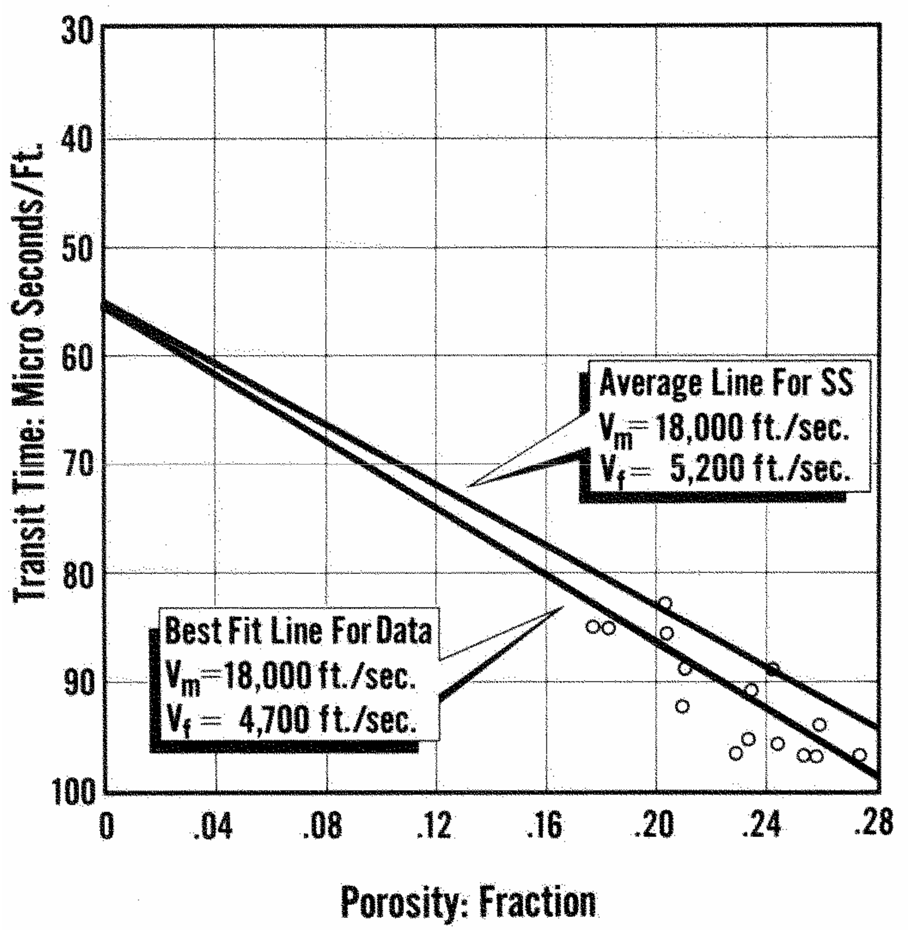


Example of Porosity-Velocity Correlation in Siliceous Sandstone

The upper figure on this page shows a suite of data from a deep Miocene sand from South Louisiana. The rock material was very clean and very well cemented with siliceous cement. The transit times were much lower and consequently velocities much higher than normally expected in sandstone. Note that for a Δt of 70 µs per foot, a porosity of about 18% is found, where the average velocity line would yield a value of about 11%. It is also worth noting that in the North Sea typical porosity cut-offs in the deeper well-cemented rocks would be close to 12%. Use of sonic porosities alone with these cut-offs, would suggest the entire zone was non-net pay.

In the last thirty years of well logging, the sonic, or acoustic tools fell from favour because of the non-unique nature of solutions to the Wyllie equation. However, in the 1980's, for the first time, new sensors using the piezo-electric properties of quartz and ceramics were introduced. The Array sonic devices marked a leap forward in precision and accuracy in sonic tools.

Transit Time Versus Porosity For Delaware sandstone

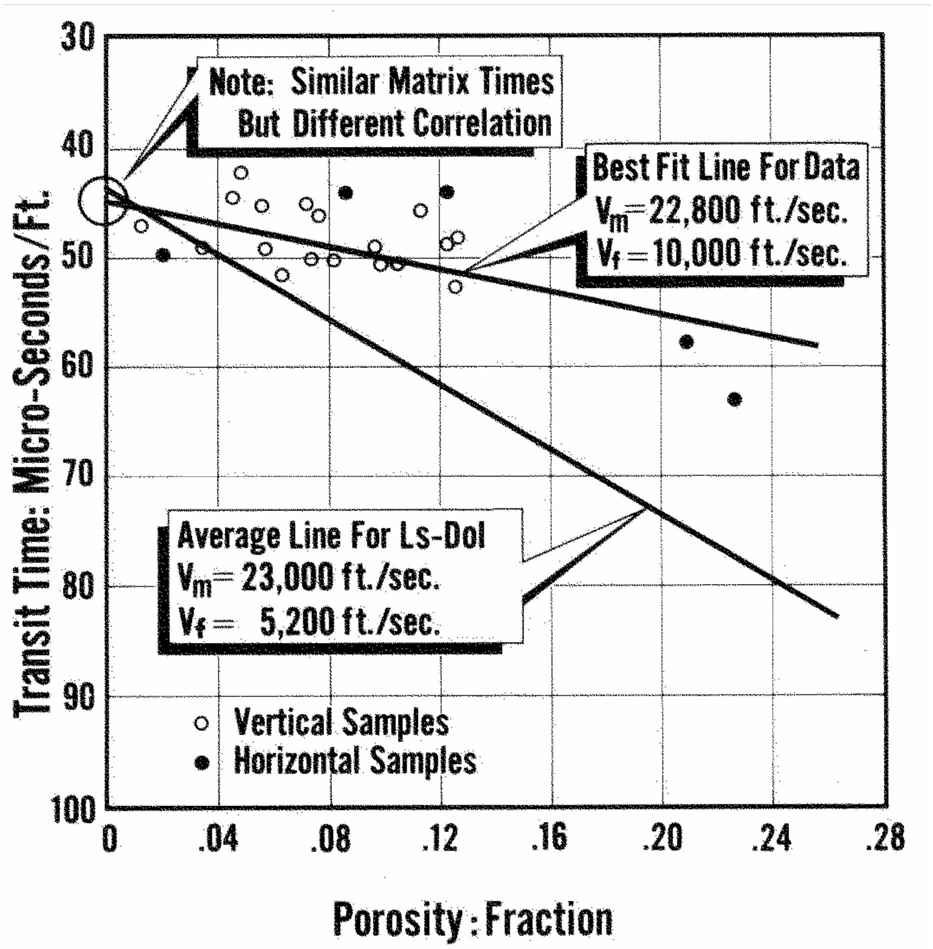


Example of Porosity-Velocity Correlation in Poorly Cemented Sand

The figure above shows a suite of data from the Delaware sand. Much of the productive Delaware formation is friable, very fine-grained sand with little cementing materials. Observed transit times are greater than normally expected for sands in the productive interval although the "matrix velocity" is very close to the average value for sandstones.

Fluid velocities are derived from the above plots from the intercept of the data slope with 100% porosity. It is obvious that this is an "apparent" fluid velocity, as modifications to the pore geometry as a function of reducing porosity can have non-linear effects on the data set, and therefore give a different intercept value. The Delaware sand data shows what can occur, with a result that 90 µs per foot transit times yield 25% porosity, when the true value is closer to 22%. In fields such as Prudoe Bay, 0.1% porosity equals $100,000,000 in producible oil. In unitisation disputes, we obviously need accurate porosity information.

Transit Time vs. Porosity For Smackover Oolitic Limestone

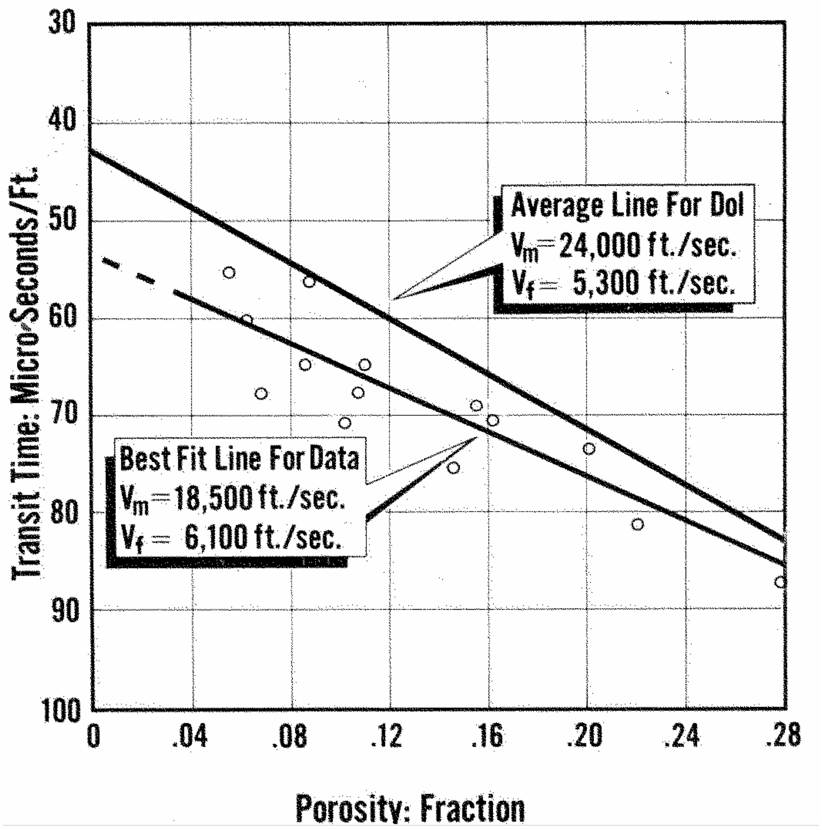


Example of Porosity-Velocity Correlation in Oolitic Limestone

The above figure on this page shows a suite of data from the Smackover formation. The samples tested were very firm, well cemented oolitic limestone. The observed transit times are much lower than normally expected from a limestone-dolomite in the high porosity interval, although the "matrix velocity" is normal. The Smackover is a prolific reservoir rock from Louisiana to Tennessee, so deriving accurate porosity is important. However, the data show very little variation in velocity/transit time with porosity. Values of 50 µs per foot yield porosities from 1 - 13%, strongly indicated the "bypassing" of pore space by the acoustic energy.

In cases like this, there is little point in using acoustic tools to attempt to derive porosity. Alternative porosity tools should be chosen.

Transit Time vs. Porosity
For Dolomite



Example of Porosity-Velocity Correlation in Dolomite

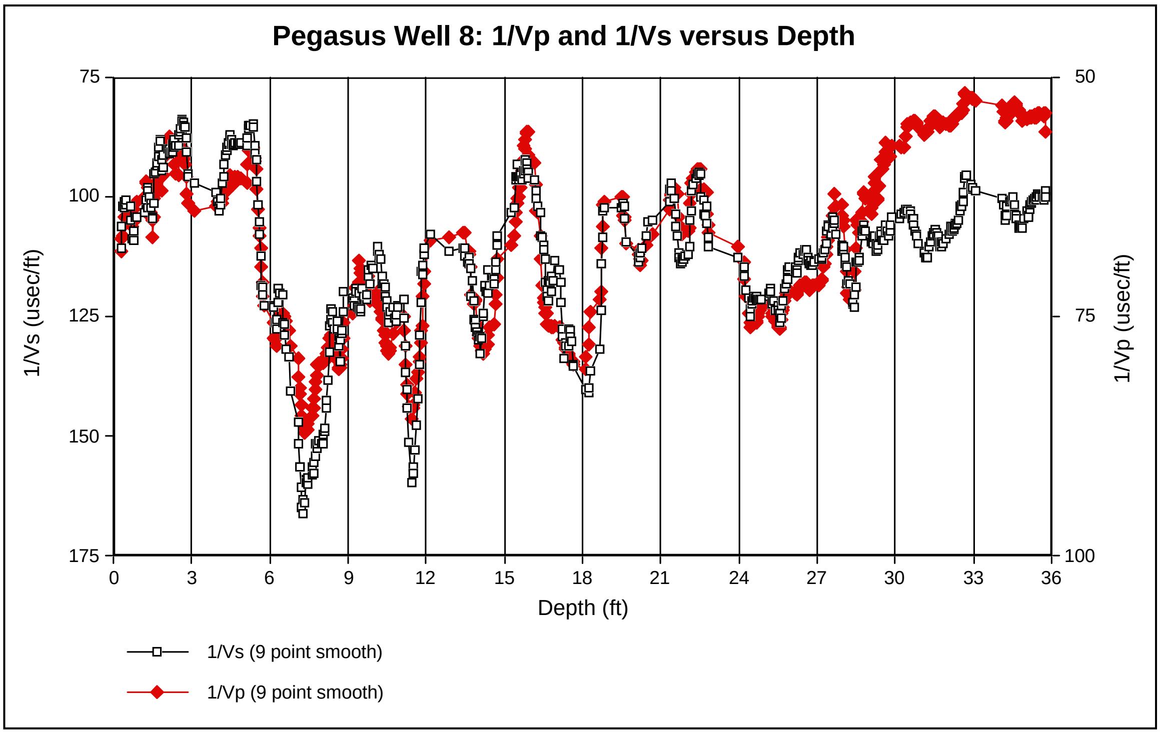
The figure on this page shows a suite of data from a dolomite formation. The samples tested were very hard. This example is unusual in that the transit times are consistently greater than predicted by the “time-average equation”, rather than less, which is the usual case for well-cemented, consolidated rock. In this case the sucrosic texture of the dolomite may well have contributed to the more sand-like matrix velocity.

Transit times may not fit with our conceived notions of porosity relationships. While it is always better to measure the formation velocity data, there still may be an unsatisfactory relationship. It is worth noting that all such measurements must be performed under net confining stress and with synthetic reservoir fluids in the pore space.

Shear Wave Properties

In addition to compressional, or P, wave velocities being measured in the wellbore and on the core, more modern tools allow for the determination of shear wave velocity as well. Shear, S waves cannot be sustained in fluid. Therefore shear waves transit around fluid filled porosity. Shear waves are slower than P waves and the ratio Vp/Vs is used to determine petrophysical properties. It is normally a ratio between 1.4 and 2.5, although examples exist of the ratio reaching values as high as 4.0 in unconsolidated sandstones.

In the example below, the velocities have been plotted on different scales to show the trend of the Vp/Vs ration throughout the section. At about 28.5 feet the Etive - Rannoch boundary is crossed and the P wave velocity diverges from its Etive trend, resulting in a different Vp/Vs ratio in the Rannoch and, of course, clearly implied differences in rock-mechanical properties.



Vp:Vs From the Etive-Rannoch boundary in the Brent Group

Vp and Vs data are combined in both petrophysical and rock-mechanical evaluations. Substitution of values into the pore-elastic equations given at the start of this section, allows for the computation of dynamic elastic moduli, young's modulus and Poisson's ratio. From these data the full mechanical properties, predicting borehole breakout or sand-face failure, can be calculated.

DENSITY CHARACTERISTICS

Grain density is a function of the mineral composition of a rock, and the state of hydration of the minerals.

The bulk density of an in-situ reservoir rock is the density of the overall bulk of the rock, with pore fluids in place and under reservoir environmental conditions. The gamma-gamma density logging tools are designed to sense this characteristic of rocks.

Bulk density, grain density, pore fluid density, and porosity are related in the following manner:

$$\phi = \frac{\rho ma - \rho b}{\rho ma - \rho f}$$

WHERE: ρma = Grain density

ρb = Bulk density

ρf = Fluid density

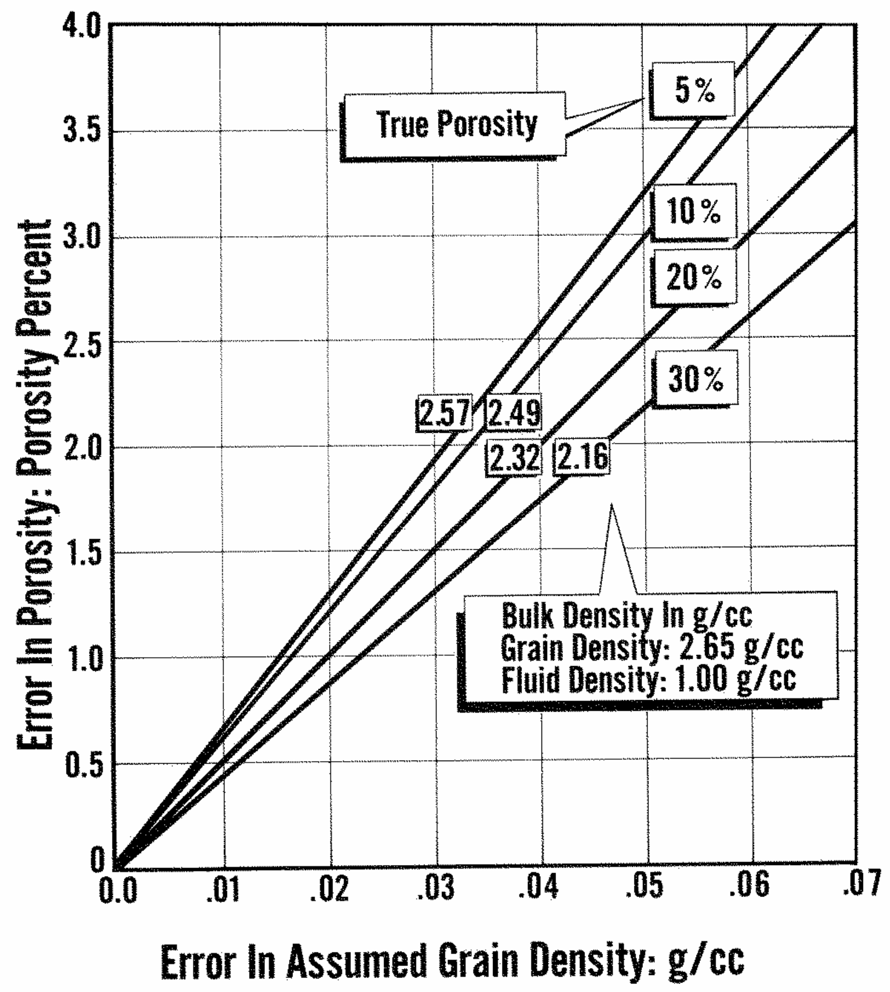
Typical Grain Density Values

Rock Type and Area	Grain Density, gm/cc
Tertiary Sandstones	2.55 - 2.69
Most N. Sea, US Mid-Continent, Calcareous, Dolomitic and Sideritic Sandstones	2.65 - 2.72
Limestone	2.70 - 2.76
Dolomite	2.75 - 2.90
Gypsum	2.32 - 2.40
Anhydrite	2.96

Effect Of Errors In Grain Density On Porosity Calculation

The technique of calculating porosity from a density logging tool response requires an assumption of the grain density of the rock and the pore fluid density. The logging tool responds to bulk density.

The assumed value for grain density is an important value, since an inaccurate estimate can cause a significant error in porosity. The figure on this page demonstrates the errors in calculated porosity values induced by errors in assumed grain density.



Porosity Error vs Error In Assumed Grain Density

A few cases are worthy of specific mention. Well-compacted and older shales commonly have grain density values of 2.70 gm/cc and greater; young and uncompacted shales often have very low grain densities, occasionally less than 2.55 gm/cc. Certain heavy minerals, such as pyrite and nontronite, present in sufficient quantity to be observable in drill cuttings and cores, must be taken into account for an accurate porosity evaluation. Typically, core derived density data are used to provide ρ_{ma} values for the density log interpretation.

SATURATIONS

The saturating fluid content of a porous rock may be quantitatively described in one of two ways. The saturation may be expressed as a fractional proportion, or percentage of the porosity that is occupied by the specific fluid phase, or the fractional proportion, or percentage of the bulk volume that is occupied by the fluid phase.

In formation evaluation we are most often concerned with the water saturation (Sw) as this is the phase that carries electrical current from the logging tools. By necessity 1-Sw is the hydrocarbon saturation of the pore-space. The Sw commonly derived is the portion of the porosity that is water and

$$Sw = \frac{Bulkwater}{\phi},$$

It should be clear that this means that the bulk water content is the product of porosity and Sw.

The Sw of the rock is dependent upon the balance between the gravity forces and the adhesive forces of the water–rock system. The adhesive forces are described by capillary pressure theory and the ***Young-Laplace*** equation:

$$Pc = \frac{2\sigma \cdot Cos\theta}{r} = h \cdot (\rho_w - \rho_h) \cdot g$$

Note that the expression $\sigma \cdot Cos\theta$ refers to the IFT of the two immiscible fluid phases, multiplied by the cosine of the contact angle measured through the denser phase of their fluid interface with a solid surface.

$$\sigma_{fluid_1 - fluid_2} \cdot Cos\theta = \sigma_{solid - fluid_2} - \sigma_{solid - fluid_1}$$

The water saturation of a reservoir rock is therefore a function of Capillary Pressure (Pc), which in turn is controlled by pore-geometry, wettability and the height of the hydrocarbon column. A major goal of Formation Evaluation is to define and use reservoir saturation - height relationships. These are determined through developing relationships between porosity, permeability, lithology and saturation, as a function of height above Free Water Level. Most water saturations are determined from the formation’s electrical properties.

Note: When averaging saturation data, the bulk water should be summed and divided by the sum of the porosity thickness products.

$$\overline{Sw} = \frac{\sum Sw \cdot \phi \cdot h}{\sum \phi \cdot h}$$

ELECTRICAL PROPERTIES

The electrical conductivity of any material is an index of its ability to conduct an electric current. It is independent of the dimensions of the element of the material, and it is the electrical analogue of permeability. The reciprocal of conductivity is resistivity. Resistivity and the electrical resistance are related as follows:

$$r \propto \frac{L}{A},$$

$$r = R \cdot \frac{L}{A},$$

$$R = r \cdot \frac{A}{L}.$$

Where:

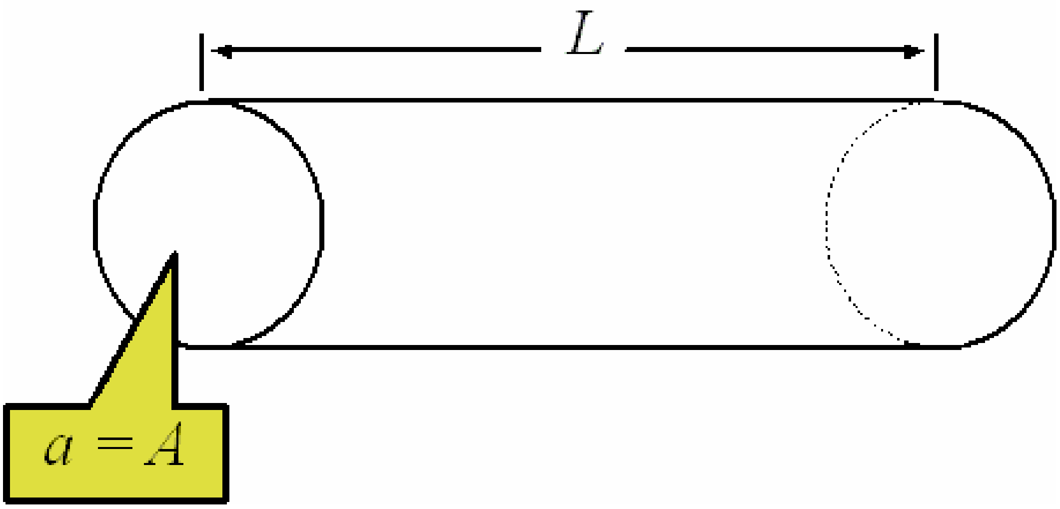
r = Resistance of element of any material of dimension A and L, ohm

R = Resistivity of any element, ohm-length

Rw = Resistivity of brine, ohm-length

ro = Resistance of brine saturated capillary or porous media model, ohm

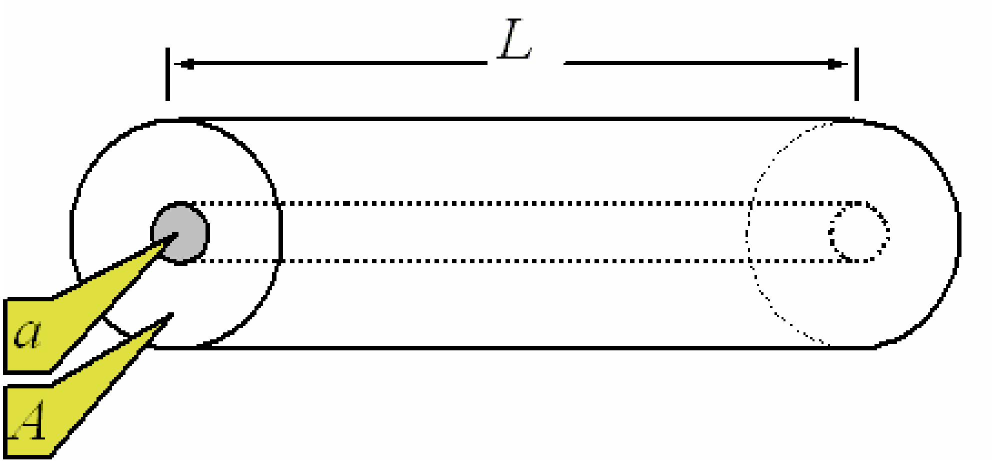
Ro = Resistivity of brine saturated capillary or porous media model, ohm-length



In a capillary tube model the equations are:

$$ro = Rw \cdot \frac{L}{a},$$

$$Ro = ro \cdot \frac{A}{L} = \frac{Rw \cdot \frac{L}{a} \cdot A}{L} = \frac{Rw}{\frac{a}{A}} = \frac{Rw}{\phi}$$

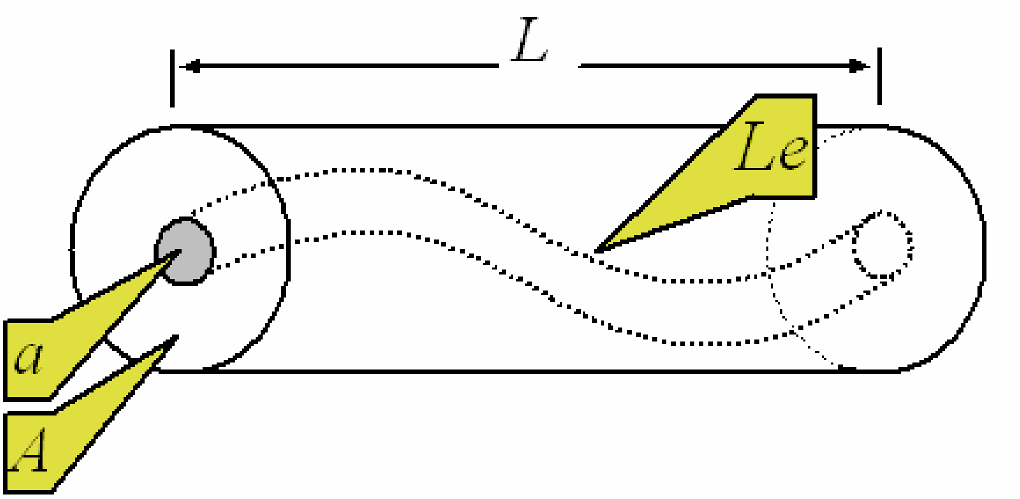


In a porous media model the equations become:

$$ro = Rw \cdot \frac{Le}{a}$$

$$Ro = ro \cdot \frac{A}{L} = \frac{Rw \cdot \frac{Le}{a} \cdot A}{L},$$

$$Ro = \frac{Rw \cdot \frac{Le}{L}}{\frac{a}{A}} \cdot \frac{\frac{Le}{L}}{\frac{Le}{L}} = \frac{Rw\left(\frac{Le}{L}\right)^2}{\phi}$$



Electrical Conductivity in Porous Media

The conduction of an electric current in porous rock is due primarily to the movement of dissolved ions in the brine that fills the pores of the rock. The conductivity varies directly with ion concentration. In formation evaluation this is usually defined as in NaCl equivalents. Schlumberger charts **Gen-8**, **Gen-9** and Baker Atlas **1-4** and **1-5**

Similarly, conductivity varies directly with temperature. This is due to the increased activity of the ions in solution as temperature increases. An estimate of formation temperature can be achieved from bottom hole temperature (BHT) measurements and Schlumberger chart **Gen-6**, or Baker Atlas **1-3**.

Variables That Influence Resistivity of Natural Porous Media

Salinity of water
Temperature
Porosity
Pore geometry
Formation stress
Composition of rock

Supplementary Notes

THE ARCHIE RELATIONSHIP

The Archie relationship simply states that the true resistivity, Rt, is equal to the product of a factor of the formation, F, the resistivity of the saturating brine, Rw and a resistivity index of saturation, RI, or

$$Rt = F \cdot Rw \cdot RI\,.$$

Formation Factor

Formation factor is defined as the ratio of the resistivity of completely brine saturated rock to the resistivity of the saturating brine.

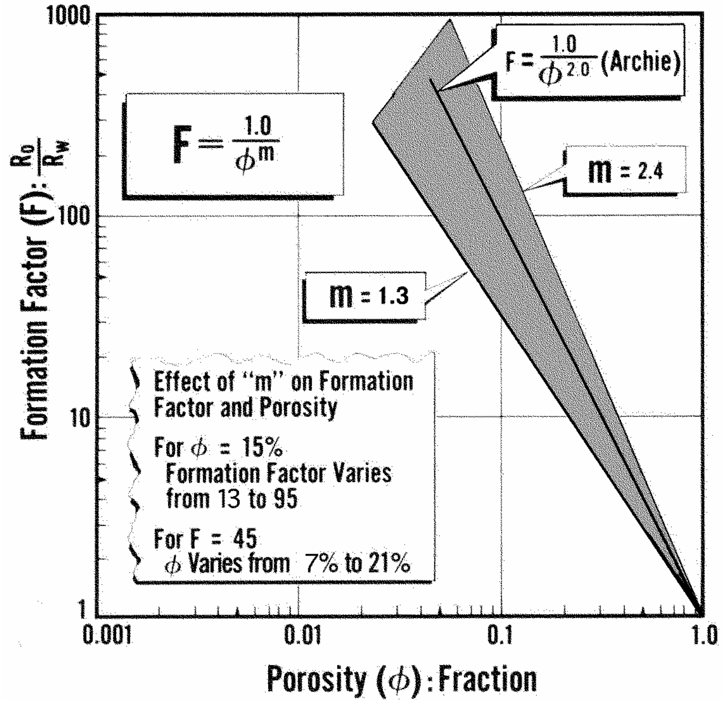
$$F = \frac{Ro}{Rw} = \frac{\dfrac{Rw\left(\dfrac{Le}{L}\right)^2}{\phi}}{Rw} = \frac{\left(\dfrac{Le}{L}\right)^2}{\phi}$$

The ratio Le/L is the ratio of the length of the tortuous path through the rock to the length of the rock element. It is commonly termed "tortuosity", and in clean, uniform sandstones the square of this value is approximately equal to the reciprocal of porosity.

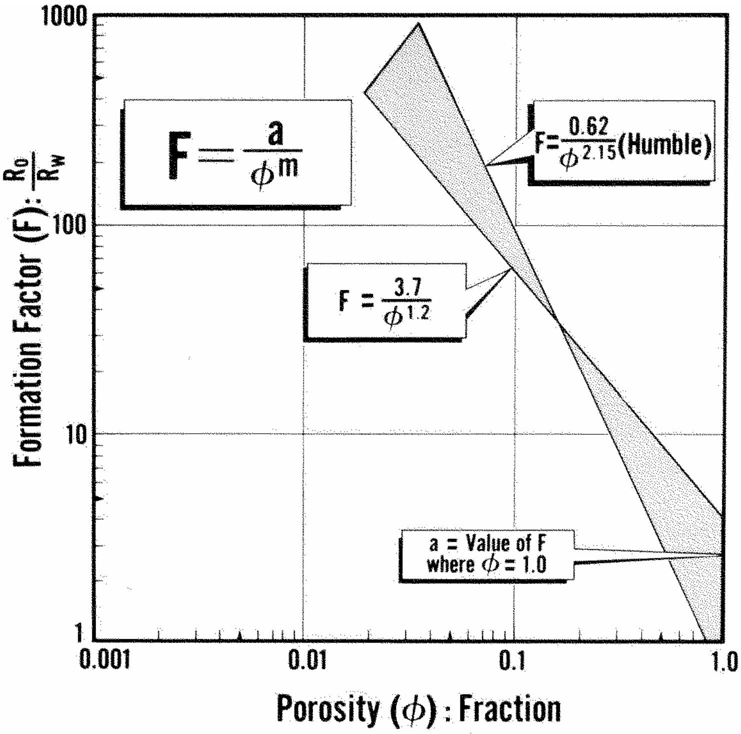
Resistivity and formation factor vary with porosity in somewhat the manner described by the previous equation. Rarely do natural formations have such uniform pore geometry. It is more common to express formation factor as:

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

where a and m are unique properties of the rock.



Formation Factor vs. Porosity
Illustrating Variation in slope "m"



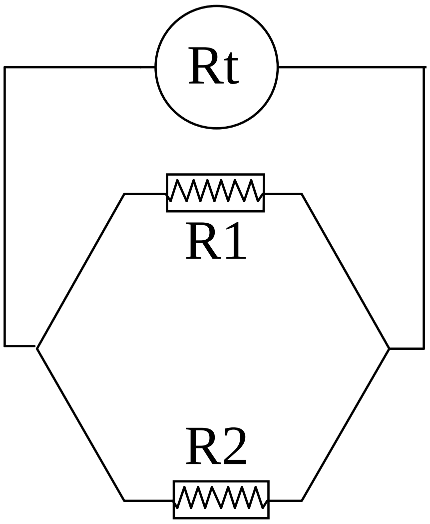
Formation Factor vs. Porosity
Illustrating Variation in Intercept "a"

Conductive Solids

The clay minerals present in a natural rock can act as a separate conductor and are sometimes referred to as "conductive solids". Actually, the water in the clay and the ions in the clay water act as the conducting materials. The effect of the clay on the resistivity of the rock is dependent upon the amount, type, and manner of distribution of the clay in the rock. This water may be present as bound water and be dependent upon the surface activity or Cation Exchange Capacity of the clay, or be due to capillary entrapment in the fine micro-porosity created by the clay morphology.

A few minerals are also conductive in their own right, pyrite for example is sufficient of a semi-conductor to affect resistivity readings, but only when present in appreciable quantities. Most minerals other than clays do not constitute a significant resistivity problem in formation evaluation.

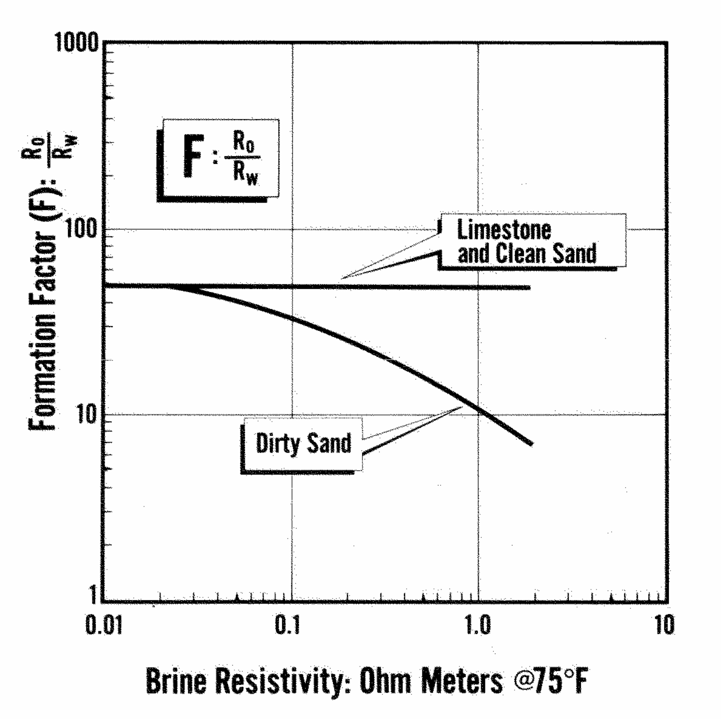
Clay conductivity effects in the suppression of Rt. This can be conceptualised through a parallel flow model:



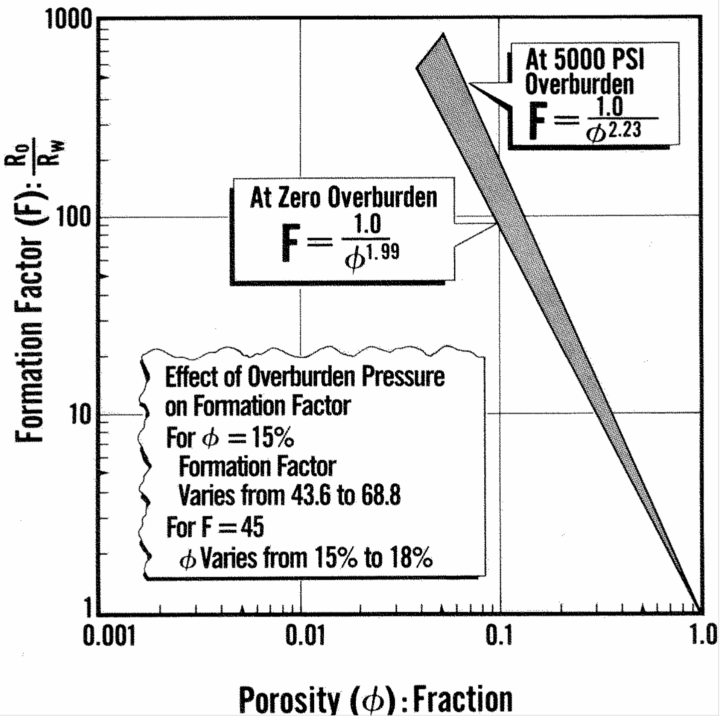
$$Rt = \frac{1}{\left(\frac{1}{R1} + \frac{1}{R2}\right)},$$

For example, for values of R1 = 1Ωm, and R2 = 10Ωm, then it follows that Rt = 0.9Ωm.

The situation is made worse when Rw becomes larger. This is the case when formation water becomes fresher. In SE Asia on the Baram Delta or in the Malay Basin it is not unusual for oil producing horizons to have less resistivity than the adjacent water zones.



Effect of Brine Resistivity On Formation Factor



Effect of Overburden Pressure On Formation Factor

Effect of Overburden Pressure on Resistivity

Confinement or overburden pressure may cause a significant increase in resistivity. This usually occurs in rocks that are not well cemented and in lower porosity rocks. In the past, most resistivity measurements and formation factors have been determined on unconfined core samples, and nearly all of the porosity formation factor correlations in widespread use today were derived from such data. Resistivity measurements and formation factors determined under confining pressures that represent the in-situ formation conditions are essential for accurate log analysis.

The figure above demonstrates the effect of overburden pressure on formation factor values observed on samples from a reef-limestone from Canada. Note the increasing difference between the overburden and non-overburden values as the porosity decreases.

Resistivity Index

Oil and gas are not electrical conductors. Their presence in an element of reservoir or in a core sample will reduce the mean cross-sectional area of the flow path for an electric current and increase the length of the flow path, thus increasing the resistivity.

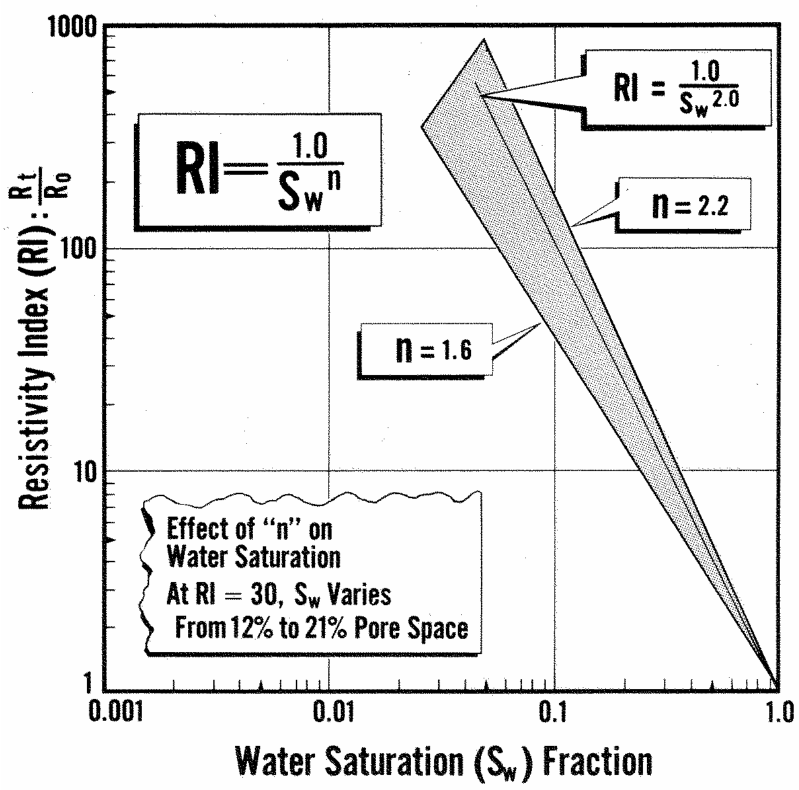
Resistivity Index is defined as the ratio of rock at any condition of gas, oil and water saturation to its resistivity when completely saturated with water:

$$RI = \frac{\mathrm{R_t}}{\mathrm{R_o}} = \mathrm{S_w}^{-n}, \quad \text{or} \quad \frac{1}{Sw^n}$$

Thus, the Resistivity Index is a function of water saturation. It is also a function of the pore geometry. The presence of cation-exchangeable clays (smectites, or mixed layer clays), cause apparently low Resistivity Index values to be observed.

The Saturation exponent, n, is also influenced by confining or overburden pressures, and should be determined under overburden conditions where the rock is significantly susceptible to the effect.

The main factor influencing the Saturation exponent, not covered above, is the formation wettability. Oil wetting tends to result in some of the water-phase being present in discrete, or discontinuous globules. Discontinuous water-phase cannot contribute to electrical flow, hence, there will be higher resistivity for a given saturation. The resultant increase in RI, gives a steeper slope and higher values of the saturation exponent, n. Typically values can approach 4 in strongly oil-wet reservoirs



Resistivity Index vs. Water Saturation
For Range of Measured Saturation Exponents

Resistivity Index (R_t/R_o) is a ratio of the resistivity of a zone containing hydrocarbons to the resistivity of the zone if it were 100 percent water saturated. The following data indicate the maximum error in calculated water saturation if all variables except "n" were correct when used in the equation to calculate water saturation.

Sensitivity of Calculated Water Saturation to Saturation Exponent "n"

	Calculated Water Saturation (S_W) %		
RI (R_t/R_o)	**n = 1.6**	**n = 2.2**	**ΔS_W**
100	6	12	6
30	12	21	9
10	24	35	11
4	40	53	13
3	50	61	11
2	65	73	8
1	100	100	0

To recap then, it is obvious that certain rock properties influence calculated water saturation, when using the Archie equation or its derivatives. The following is a summary of the relationships;

Where: **a** is the intercept of the F versus ϕ plot and is related to tortuosity,

m is the Cementation exponent and is also tortuosity dependent,

n is the saturation exponent and is saturation history, wettability and pore geometry dependent,

ϕ is the measured porosity

$$Rt = F \cdot Rw \cdot RI,$$

$$F = a\phi^{-m}, \text{ or } \frac{1}{\phi^m},$$

$$RI = \frac{\mathrm{R_t}}{\mathrm{R_o}} = \mathrm{S_w}^{-n}, \text{ or } \frac{1}{Sw^n},$$

so,

$$Sw = \sqrt[n]{\frac{F \cdot Rw}{Rt}}, \quad \text{and} \quad \sqrt[n]{\frac{Ro}{Rt}},$$

Hence,

$$Sw = \sqrt[n]{\frac{a}{\phi^m} \cdot Rw \cdot \frac{1}{Rt}}\ ,$$

The General Form of the Archie Equation.

Sensitivity of Calculated Water Saturation to Both "n" and "m"

Both saturation exponent "n" and cementation factor "m" vary with pore geometry and influence calculated water saturation. In any formation, either may be higher or lower than the value of 2.0 often assumed to be representative. The influence and importance of the cementation factor is maximised in low porosity rock. For example, if saturation exponent "n" equalled 2.0 and cementation exponent "m" equalled 1.7 in a formation with 10 percent porosity, the calculated water saturation would be 45 percent pore space. If the cementation factor equalled 2.4, calculated water saturation would be 100 percent pore space. This is a significant difference.

Sensitivity of Calculated Water Saturation to Saturation Exponent "n" and to Cementation Exponent "m"

Given: R_t = True resistivity from log = 25 ohm-meters

R_w = Down hole water resistivity = 0.1 ohm-meters

Effect of Cementation Exponent "m" (n = 1.6)

Calculated Water Saturation (S_W) %

	m = 1.7		m = 2.4		
Porosity	**F**	**Sw**	**F**	**Sw**	**ΔSw**
30	7.7	11	18	19	8
20	15	17	48	36	19
10	50	37	250	100	63

Effect of Cementation Exponent "m" (n = 2.0)

Calculated Water Saturation (S_W) %

	m = 1.7		m = 2.4		
Porosity	**F**	**Sw**	**F**	**Sw**	**ΔSw**
30	7.7	18	18	27	9
20	15	24	48	44	20
10	50	45	250	100	55

Effect of Cementation Exponent "m" (n = 2.2)

Calculated Water Saturation (S_W) %

	m = 1.7		m = 2.4		
Porosity	**F**	**Sw**	**F**	**Sw**	**ΔSw**
30	7.7	21	18	30	9
20	15	28	48	47	19
10	50	48	250	100	52

Supplementary Notes

CHAPTER 2.

DOWN-HOLE LOGS

Log Properties and Environments That Influence Formation Evaluation

Section 1

Wellbore Environment

BOREHOLE - WELLBORE ENVIRONMENT

Once a drill-bit has penetrated through a formation, the local environment has been altered from the conditions that existed before drilling. The longer the hole remains open, the more change to the environment occurs. The actual drilling process involves removing material that is part of the mechanical fabric of the system. The hole could not remain open unless it was supported by a column of fluid which is about as dense, or denser, than the equivalent pore fluid column. However, in maintaining an open hole, where permeability exists some of the fluid invades the formation. Drilling muds are designed to form a low permeability membrane against the hole side. This is called the filter-cake. In order to form this, there must be a spurt fluid loss to the formation. This is followed by a much slower continuous filtering of fluid (filtrate) over the period of time the hole remains open. The type of filtrate and filter-cake is dependent on the type of drilling fluid utilised.

There are basically four types of drilling fluid that we can consider. In each of these the filtrate is different:

Fresh-water muds

Salt-water muds

Oil based muds

KCl or CaCl - Polymer based muds

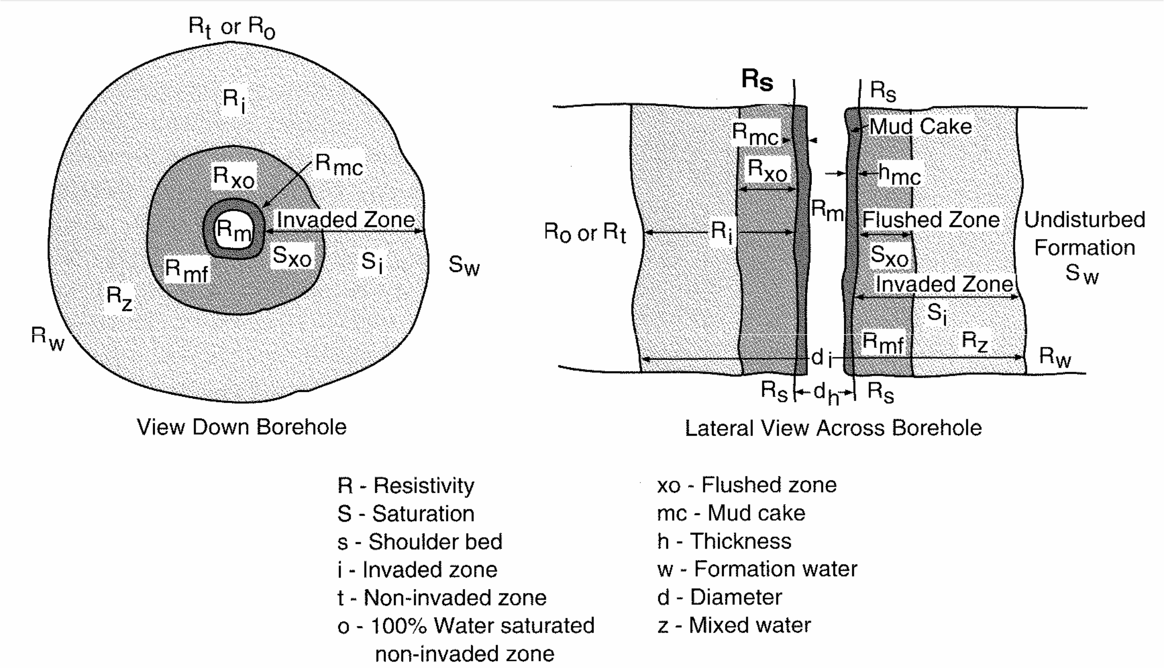
Fresh-water systems are usually used when the formation water is brackish-fresh and are not very common these days, except in onshore drilling. The filtrate is fresh water.

Salt-water systems are used in salty formation waters and the mud filtrate may be saltier or less salty than the formation water. Because of poor hole problems these became less popular in the 1970's. However, because of their more environmentally friendly properties they have made a comeback since the 1990's.

KCl or CaCl Polymer based systems are really hyper-saline salt water systems. However, there are some additional properties of the filter cake to take into account. Well-maintained systems have virtually zero permeability filter-cakes, resulting in less invasion. Both CaCl and KCl also act as clay stabilising agents, inhibiting swelling.

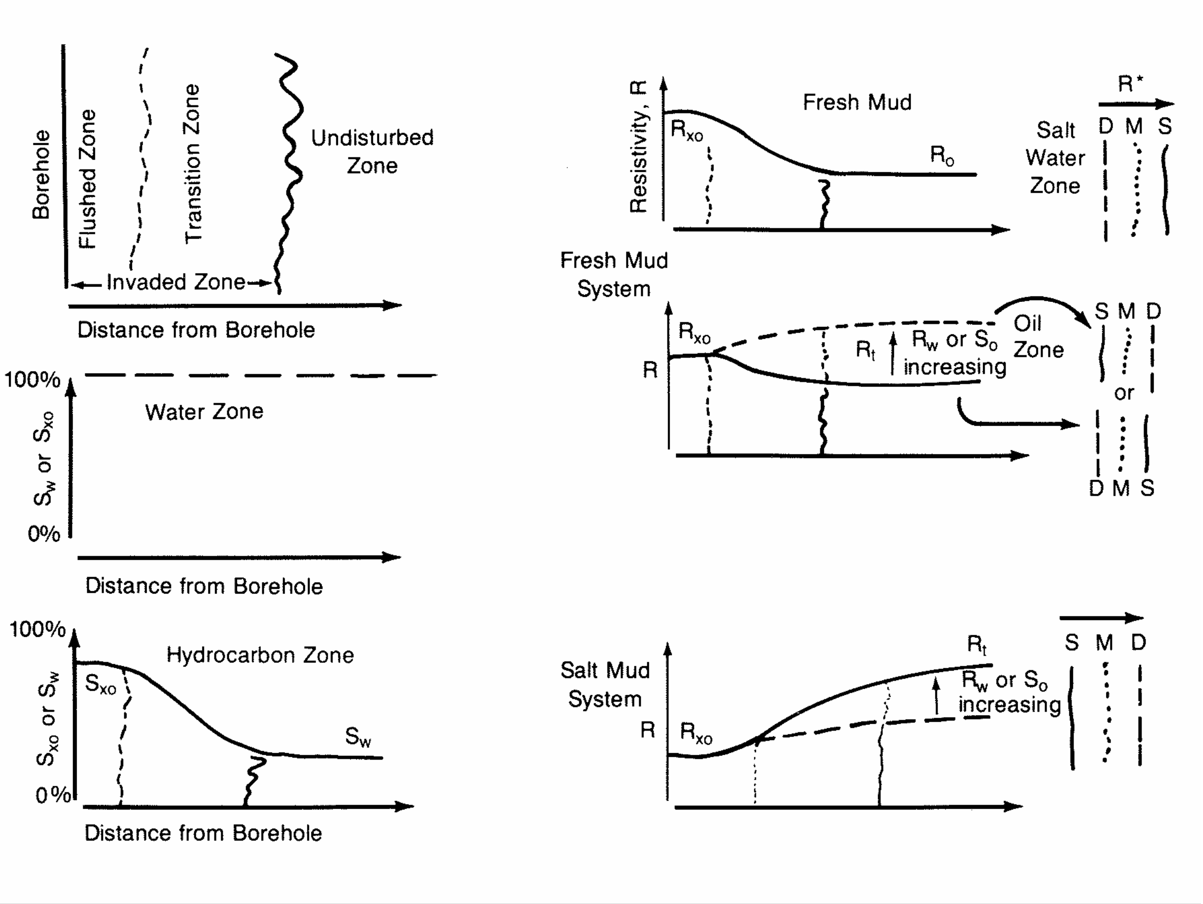
Oil-based systems carry their water, which may be as much as 40% of the system, as an emulsion phase. In addition, they are often hyper-saline systems containing as much as 350,000 ppm CaCl in solution. The filtrate *should* be oil only. The hyper salinity is used to de-hydrate the near wellbore by osmotic force. In order to maintain the water in an emulsion they contain appreciable quantities of surfactants. These can alter saturations and wettability in the near wellbore. Because of their negative environmental impact, alternatives are now being sought. These include bio-degradable base oils and the polymer systems outlined above.

Note that some water-based drilling fluids also contain emulsified oil as a clay stabiliser. This can be lost to the formation.



The Invasion Profile and Petrophysical Parameters

In measuring across invasion profiles of the sort generated by the various differing drilling fluids we might see the following profiles.

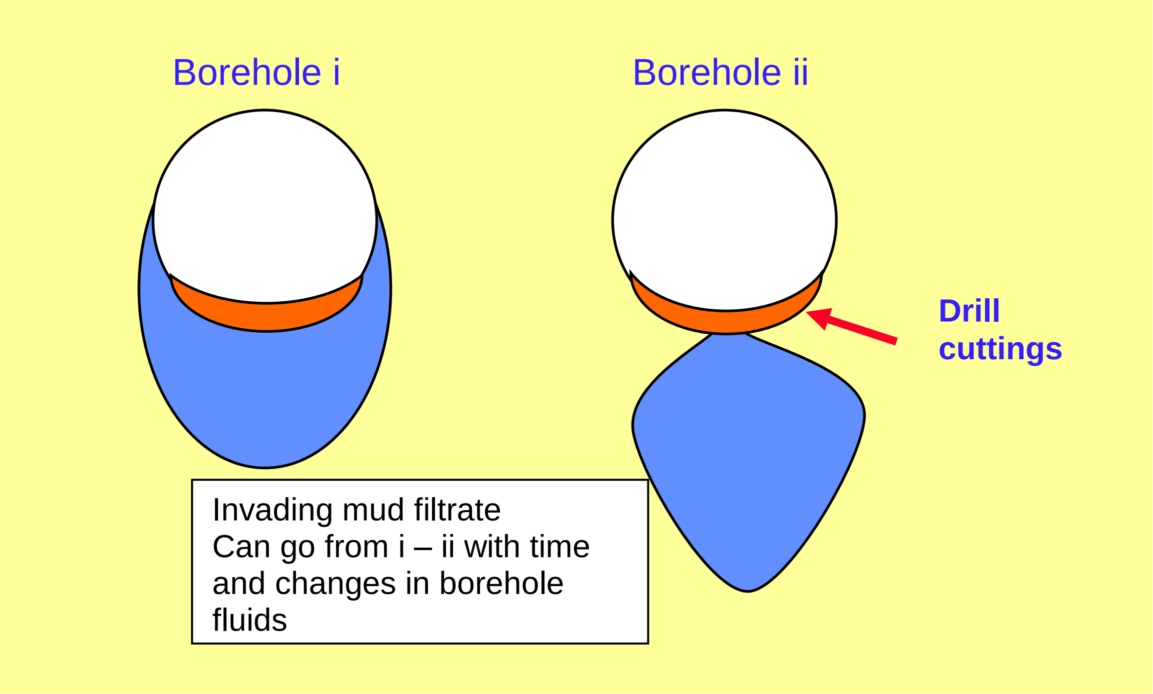


Where S = Shallow, M = Medium and D = Deep-reading device responses

The effects of the borehole invasion on various tool responses will be considered in each section covering the specific tools.

Hole Quality

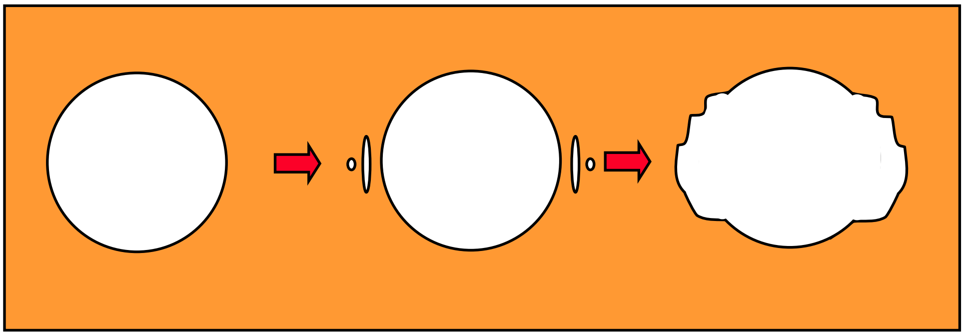
In addition to fluid invasion the drilling process may result in a hole that is far from cylindrical in aspect. Borehole washouts and key-seats can affect the quality of log responses. If the tool is not centralised, or pressed against the wellbore side, depending on its mode of operation, we can expect to have to make corrections to the response function. In some cases the hole is so bad, it is no longer possible to record usable data.



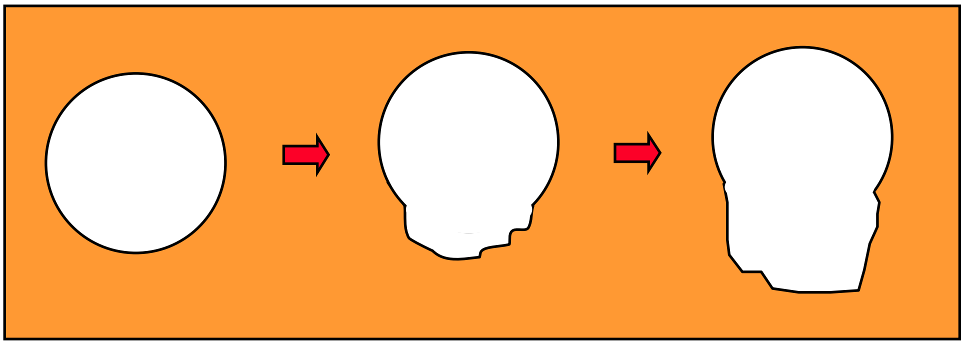
Horizontal Wellbores and Borehole Anisotropy

In Horizontal and high-angle wells the fluid loss from the borehole can sink under gravity such that the environment is strongly anisotropic and tool response depends upon the direction the sensor array is pointing to. This concept is known as tool-facing and has resulted in all the LWD tools used in these environments having azimuthal sensor arrays and "way-up" facing of the tool being routinely measured and often controlled.

When s1 is vertical, borehole breakout can occur horizontally



Erosion of the low side of the hole causes Key-seating



The nature of the borehole is investigated by a tool called the calliper log. Callipers are usually two sprung opposed arms with LVDT sensors. Some tools come with their own built in callipers by design. In most cases of anticipated borehole problems two callipers are run at 90º to each other so that there is full coverage of the bore-hole ovality.

Washouts in the borehole are the principal environmental source of bad log measurements in formation evaluation.

Chapter 2

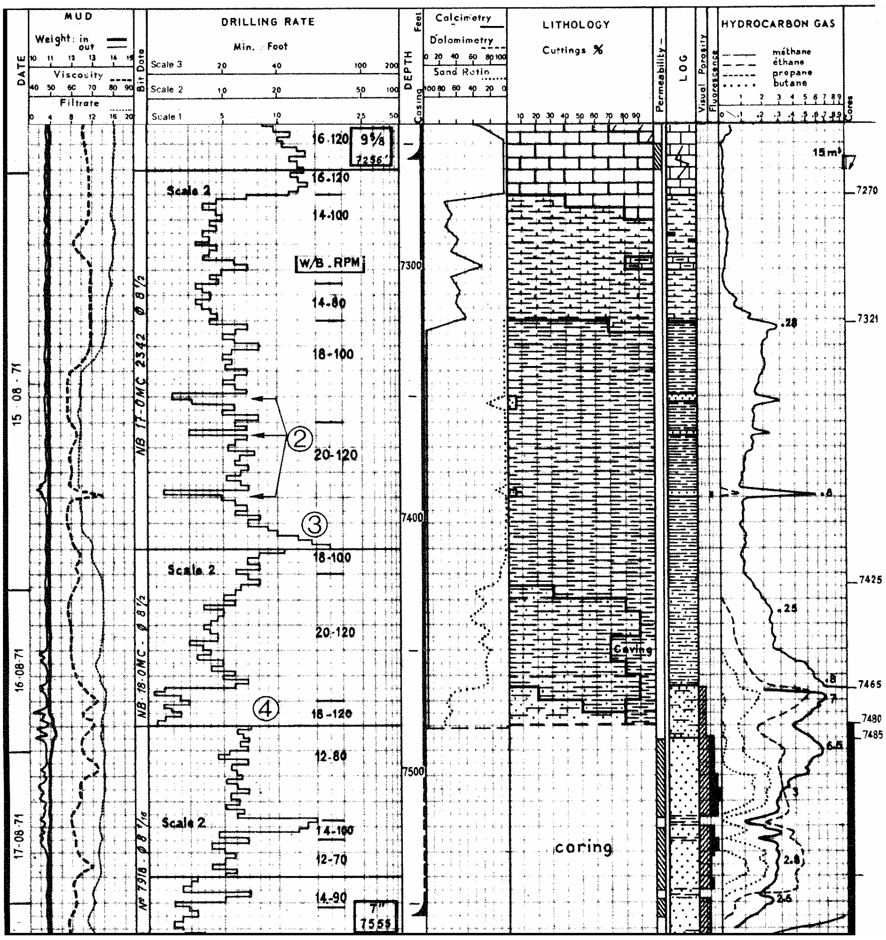
Section 2

Lithology Logs

LITHOLOGY IDENTIFICATION

The first goal of Formation Evaluation is to attempt to identify the lithology down hole and its depth of occurrence. The best way of doing this has little to do with down hole logging tools and more to do with surface mud-return logging, or Mud-logging.

The returning drilling fluid is designed to carry the rock cutting debris back to the surface where it can be removed from the system using a sieve, or 'shale-shaker', as it is known. By determining the length of time it takes to recirculate this material from the bottom of the hole, it is possible to reassign depths to the cuttings acquired over any time interval. Geological inspection of the washed cuttings can determine the lithology and often the presence or absence of hydrocarbons. An interpretation of the cuttings percentage log coupled with Rate of Penetration (ROP) gives a basis to assigning formation tops.

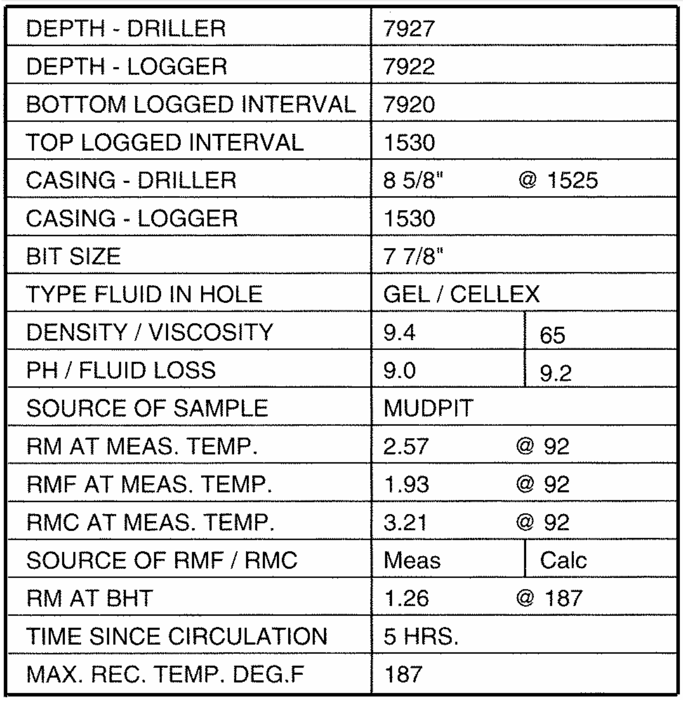


An Example Mud log

DOWN-HOLE LOG FORMATS

Before looking at the various tools and their analysis, it is necessary to look at the format of the presentation of data at the surface. The down-hole tool response is transmitted to the surface utilising multiplexing along the logging cable. Data are recorded at various sampling rates, depending on the type of tool in use and the logging speed. All wireline logs are recorded upwards, i.e. the tool is retrieved out of the hole while recording data. This is done to maintain depth control, through monitoring a steady pulling force and retrieving at a set speed. Modern logs have flags on them when an overpull condition is encountered. Data acquired in these intervals is considered suspect, if not useless. MWD data is acquired while drilling and is therefore recorded downwards.

The output of data tends to be on a half-foot, or decimetre basis. The log will consist of a heading, which contains most of the pertinent data relating to the well location, drilling fluid and borehole conditions encountered. In log analysis it is essential that the log heading be reviewed first.

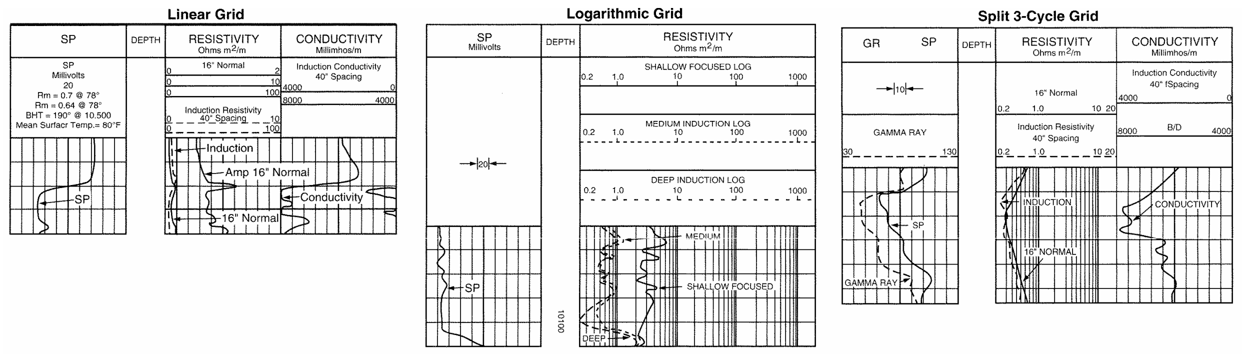


DEPTH - DRILLER	7927	
DEPTH - LOGGER	7922	
BOTTOM LOGGED INTERVAL	7920	
TOP LOGGED INTERVAL	1530	
CASING - DRILLER	8 5/8" @ 1525	
CASING - LOGGER	1530	
BIT SIZE	7 7/8"	
TYPE FLUID IN HOLE	GEL / CELLEX	
DENSITY / VISCOSITY	9.4	65
PH / FLUID LOSS	9.0	9.2
SOURCE OF SAMPLE	MUDPIT	
RM AT MEAS. TEMP.	2.57 @ 92	
RMF AT MEAS. TEMP.	1.93 @ 92	
RMC AT MEAS. TEMP.	3.21 @ 92	
SOURCE OF RMF / RMC	Meas	Calc
RM AT BHT	1.26 @ 187	
TIME SINCE CIRCULATION	5 HRS.	
MAX. REC. TEMP. DEG.F	187	

Typical Header Data

While the Header contains the well, mud and borehole properties, the Footer contains information about the tool string, such as its length, the generation and model of tool employed. This is valuable information when making environmental corrections and depth adjustments. However, the actual distance between the depth reference and the individual tools in the string is automatically compensated for in modern logs. Depth control should be to better than 1 / 10,000 ft (0.3 / 300 metres) accuracy.

Log data is recorded in ‘Tracks’, originally these were recorded on photographic film by a combination galvanometer-camera. Modern data are acquired directly by computer and recorded on magnetic tape. There are a number of conventions when displaying data in tracks, some of these are shown below.



Some Log Track Formats

When viewing a log, careful attention should be paid to the scales used and the number of units per division. In modern computer based analysis, this becomes less of a problem as the scale parameters are part of the data file.

The downhole log responses to be considered in lithology identification should be the Gamma ray, the Spontaneous Potential, the Caliper and the Photo-electric Effect. There are more modern Geochemical logs, but these require careful calibration with core-derived data.

STUDY GUIDE QUESTIONS ON THE GAMMA-RAY LOGS

1) What three (3) major radioactive elements does the gamma ray tool respond to?

2) What type of activity (high, medium, or low) do carbonates, sands, and shales typically exhibit?

3) How does an increase in clay content affect the gamma ray response?

4) What are the units on the gamma ray log and how is it calibrated?

5) Is the tool zeroed?

6) Where is the gamma ray tool an advantage over the SP tool?

7) Name three uses of the gamma ray log.

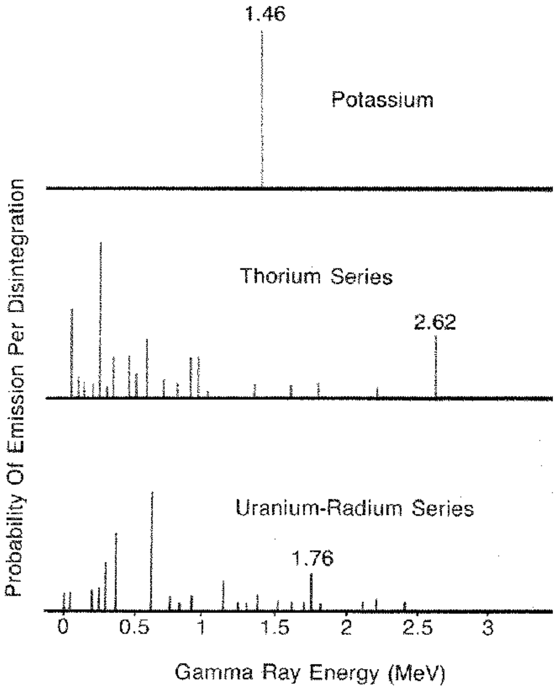
8) How is the gamma ray log used to estimate volume of shale?

GAMMA RAY LOG

INTRODUCTION

Sixty-five unstable radionuclides exist in nature. The ones in significant abundance are the Uranium-Radium series, the Thorium series and Potassium, K^{40}. These isotopes emit Alpha, beta, and gamma rays. The gamma ray has the ability to travel through rock material for some distance and is the easiest one to detect and measure. Detection is accomplished with a photosensitive crystal, such as NaI. Scintillation in the visible light spectrum occurs each time a photon of gamma-ray energy collides with the crystal. A photo-multiplier amplifies the signal.

All open-hole Gamma-ray tools are ‘spectral’ today. They have energy windows that sample the energy derived from the emissions from U^{238}, Th^{232} and K^{40} . However, the data are not always recorded as spectral values, but summed to provide the equivalent of the old total gamma-ray tool response.

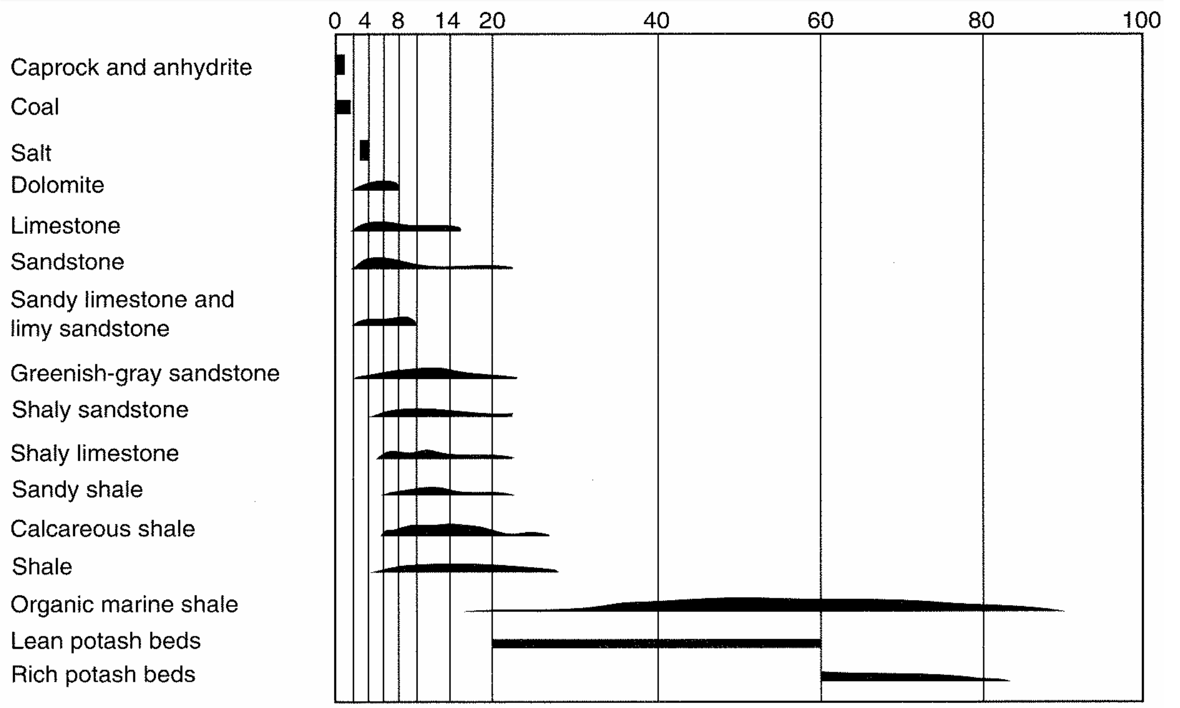


Spectral data can be very useful in correlating geology in shales, but have proved to have limited application in uniquely determining lithology and mineralogy. Bristow and Williamson (1998), and Hurst and Milodowski (1994), have demonstrated the basis for these problems. Many other works have demonstrated the value of spectral data, however and these tools should not be run in total response mode only. Often it is the spectral data that provide the best correlations for core - log depth matching.

GAMMA RAY LOG RESPONSE

As already discussed K^{40} exists in the feldspars and micas which weather easily into clay minerals. These clays, due to their ion-exchange capacity, can adsorb heavy radioactive elements from the formation water. Consequently, when there is an abundance of clay material as in shale, there generally is a high level of radioactivity observed.

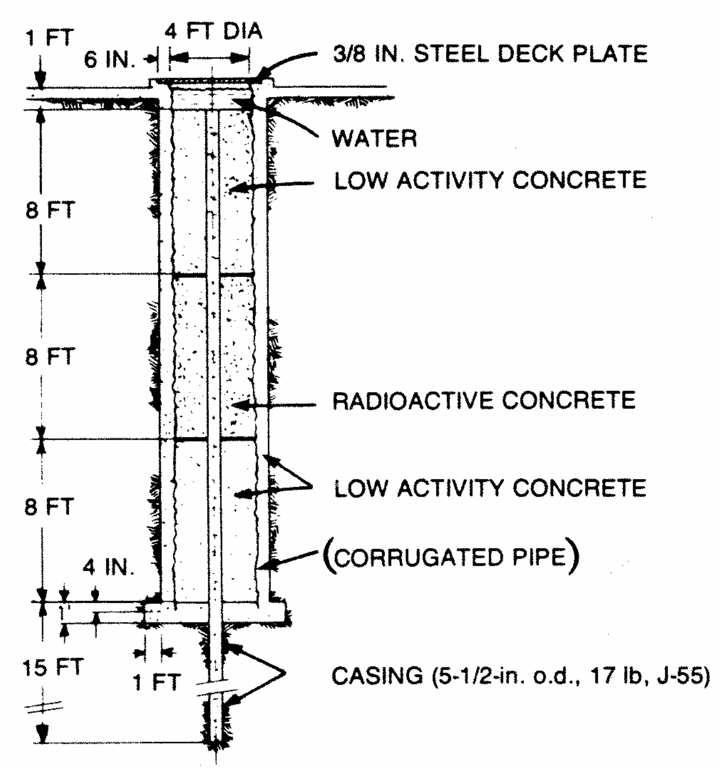
Carbonates are often deposited in areas with low concentrations of terrestrially derived sediments and hence, low concentrations of radioactive elements. Dolomites sometimes exhibit slightly higher radioactive levels. This is probably due to ground water (involved in the dolomitisation) carrying in additional traces of radioactive isotopes in solution.



(After Russell, 1941)

Gamma Ray Responses of Sedimentary Rocks

Approximately ninety percent (90%)of the gamma rays detected at the tool are emitted from the first six inches of the formation. Gamma rays can be detected through cement and casing, so the tool works in cased holes; the total counts however, will be low. The mud also absorbs gamma rays (the denser the mud, the greater the effect), so environmental corrections need to be made to obtain a true value for the formation radioactivity. Corrections need to be made for the borehole diameter and mud density. Baker Atlas charts **3-1** - **3-12** and Schlumberger **GR-1**, and **GR-2**

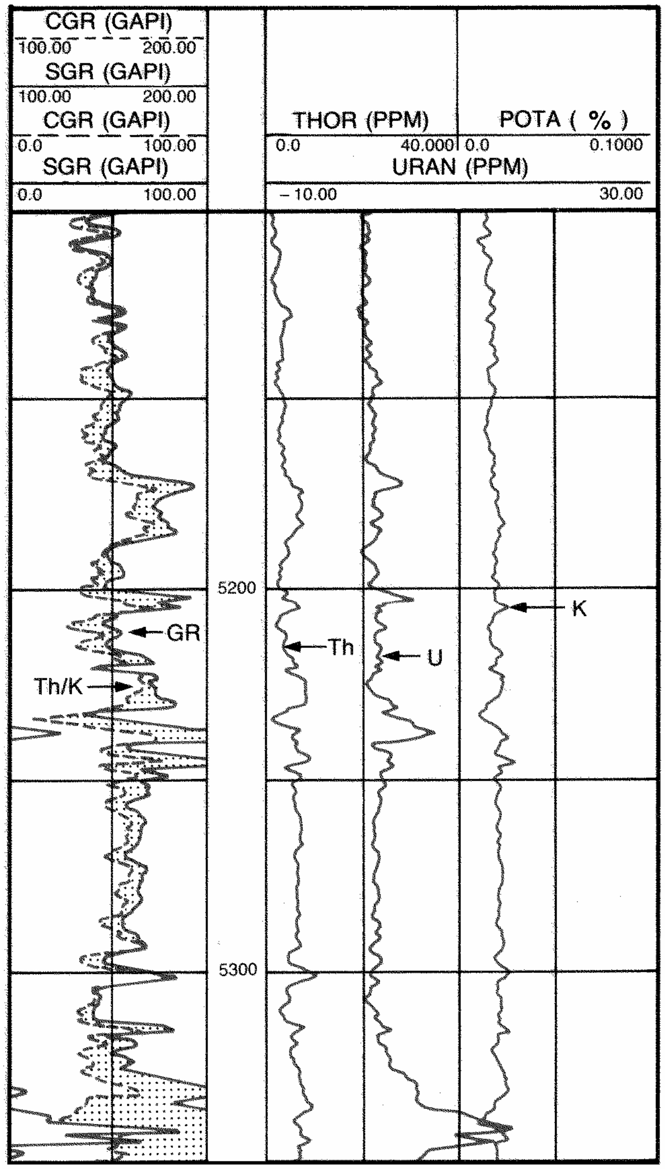


The API Calibration Pit

THE GAMMA RAY TOOL

The tool is normalised in an API test pit at the University of Houston. The test pit has a middle section of high-activity cement surrounded by two sections of low activity cement. The difference in radioactivity between the centre and outside sections is defined as 200 API units. The tool is then recalibrated at the well site and a zero reference picked. The tool is pulled up from the bottom of the hole and the time constant (which averages count rates over a period of time to give a smoother curve), and the logging speed regulates the vertical bed resolution.

The gamma ray response is recorded on the left-hand grid on a linear scale. It is plotted as API Gamma Ray Units ranging from a low of zero (0) to as high as two hundred (200) or more. One should always check the scale being used. In common use today is a scale of zero (0) to 150 API Units.



A Typical NGT - NGS Log Showing the Tracks Utilised

USES OF THE GAMMA-RAY LOG

Lithology determination is the main application of the gamma ray log. If used as a lithology tool, one must use it cautiously. The presence of uranium or potassium salts or anomalously low radioactive shales can create misinterpretations of the zone.

The gamma ray is also useful in areas where the SP log cannot function well, i.e. cased holes, oil or oil-base muds, or air filled holes. In a cased hole, the gamma ray log is used to help accurately place perforating guns.

The gamma tool is occasionally used as a shale indicator and has been used to empirically derive the volume of shale. The gamma ray shale index can be calculated as follows:

$$I_{GR} = \frac{\mathrm{GR} - \mathrm{GR}_{\mathrm{cl}}}{\mathrm{GR}_{\mathrm{sh}} - GR_{cl}}$$

GR = Log response in zone of interest

$\mathrm{GR}_{\mathrm{cl}}$ = Log response in clean beds

$\mathrm{GR}_{\mathrm{sh}}$ = Log response in shale beds

This value (I_{GR}) can be inserted into a chart such as Baker Atlas **3-19** and the volume of shale can be determined. Remember, this is used for known shaly formations and assumes that shale is the only radioactive source.

Finally, the gamma ray log can be used to correlate responses between wells. Sometimes these can be made quite accurately especially if there are thin beds of high radioactivity (i.e. volcanic ash or bentonite) or very low radioactivity (i.e. anhydrite, salt or coal).

Supplementary Notes

SUMMARY SHEET OF THE GAMMA RAY LOG

- The tool detects gamma rays primarily emitted from Potassium, Thorium, and Uranium.
- Limestone exhibits low gamma activity and dolomites sometimes exhibit slightly higher levels than limestone. Sandstone is usually somewhat higher than the carbonates, and increases in activity as clay (shaliness) content increases. Shale has high gamma ray activity.
- The log is reported on the left-hand track linear grid in API Gamma Ray Units. Spectral data fill tracks 2 and 3
- The tool is calibrated in an API test pit and later zeroed at the well site. The scales used vary and can start at zero (0) or any value higher, i.e. 30.
- An advantage over the SP is the gamma ray tool can be used in oil base mud, gas or other non-conductive borehole fluids. It is also used in cased holes.
- The gamma ray log is used primarily for lithology determination, and well-to-well correlation. It can also be used to pick perforation points in a cased hole.
- Using a calculated shale index, I_{GR}, one can estimate the volume of shale by applying it to a published logging company chart.

$$I_{GR} = \frac{\mathrm{GR} - \mathrm{GR}_{\mathrm{cl}}}{\mathrm{GR}_{\mathrm{sh}} - GR_{cl}}$$

STUDY GUIDE QUESTIONS ON THE SP LOG

1) How is a spontaneous potential generated:

2) a. How is the SP measured?
   b. Does it require a particular type of mud?

3) How is the SP zeroed?

4) Can the SP be used in defining bed thickness? If so, how?

5) What three (3) major factors control the SP's magnitude and direction?

6) What are three (3) minor factors?

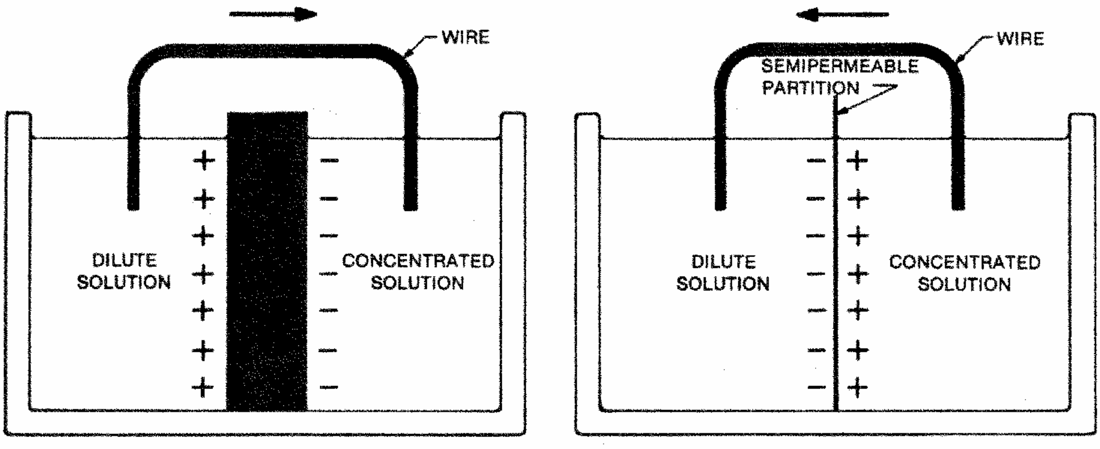
7) When will a static spontaneous potential (SSP) be developed?

8) When is the borehole not the dominant resistance?

9) What causes the deflection on the SP to the left, right, or no deflection at all?

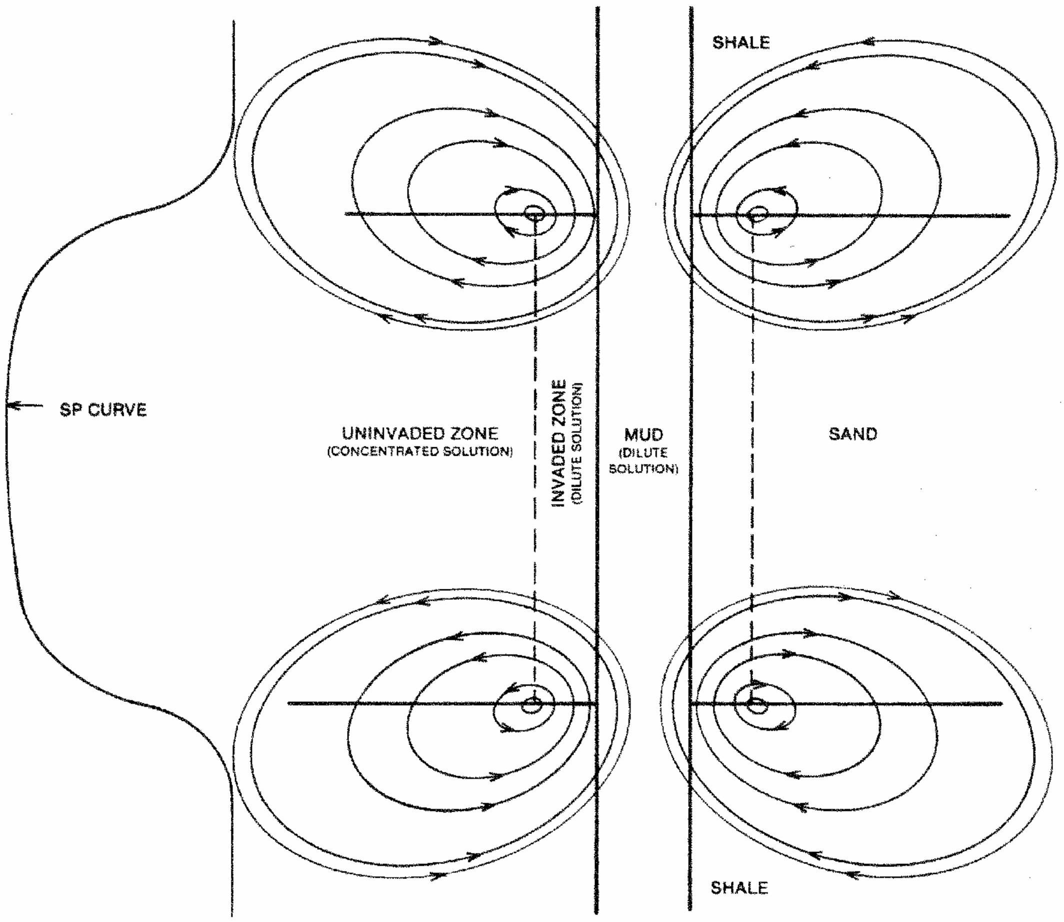
10) How can the shaliness of the bed be determined?

11) Name four (4) uses of the SP.



SHALE POTENTIAL

LIQUID-JUNCTION POTENTIAL



The Generation of the Spontaneous Potential and Current Flow

SPONTANEOUS POTENTIAL

INTRODUCTION

The spontaneous potential curve is a recording of the potential difference between a movable electrode situated in the tool and a fixed surface electrode. Spontaneous potential is not technically a property of rocks and is not induced by the tool. A water-filled borehole upsets ionic equilibrium conditions, established over geologic time, in the vicinity of the penetrated formation. Natural physical processes occur to restore the equilibrium and to equalise salt concentration. These constitute a small, but measurable current.

THEORY

Shale Potential

When shale separates two sodium chloride solutions of different concentrations, sodium will diffuse through the shale from the higher concentration to the lower, due to the ion exchange capacity of the clays present. The chlorine ions, due to their size and net negative charge cannot flow across the shale. So the dilute solution builds up more of a positive charge than the concentrated one. This electromotive force, built up across the shale, is known as the shale or membrane potential (E_S). If the two solutions were to be connected by an electrical wire, a current would flow from the dilute (positively charged) side, to the concentrated solution, then through the shale, and back into the dilute solution. This membrane potential is created near the boundaries of shale beds and permeable beds. In the permeable bed, there is the invaded zone, which contains the mud and mud filtrate (in this case the dilute solution), and the uninvaded zone, containing the formation water (here the concentrated solution). So, a current will be created moving from the mud or filtrate to the uninvaded zone through the shale and back to the mud or mud filtrate.

Liquid-Junction Potential

When two sodium chloride solutions differing in concentration are in direct contact with each other, a semi-permeable barrier is created. This allows ions to migrate from one solution to another, but keeps the solutions from mixing. Negative ions move much easier than the positive ions; therefore, a build-up of negative charges is created in the less a concentrated solution as they pass from the more concentrated (which becomes more positive). This flow is equivalent to a conventional current flow in the reverse direction. This current is thus created by an electromotive force known as the liquid-junction potential (E_1), which is about one-fifth of the membrane potential. In the borehole this scenario occurs at the interface of the uninvaded zone and the flushed zone.

The current created flows in the same direction as the one created by the shale potential.

Electrochemical Component

The sum of the two potentials is known as the total electrochemical emf (E_c) of the SP. Mathematically, it can be written as:

$$E_c = E_s + E_1 \quad = \quad -K \log (a_w / a_{mf}) \qquad (1)$$

where a_w and a_{mf} refer to the chemical activities at formation temperature of the formation water and mud filtrate, respectively. The factor K is a variable dependent upon the formation temperature and can be calculated using the following equation:

$$K = -(61 + 0.133 \ T\{^{\circ}F\}) \qquad (2a)$$

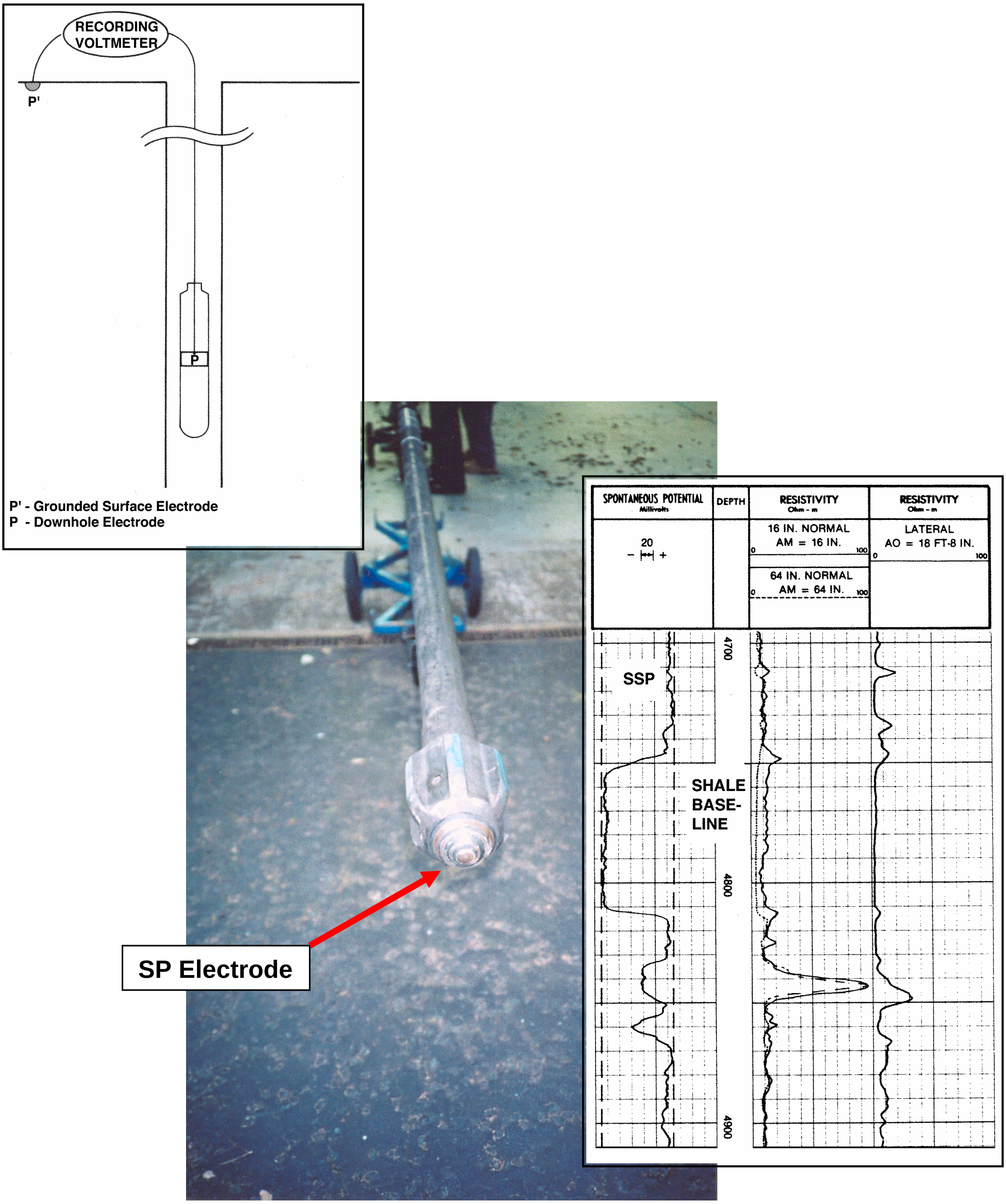
$$K = -(65 + 0.24 \ T\{^{\circ}C\}) \qquad (2b)$$

The chemical activities, a_w and a_{mf} , are inversely proportional to the resistivities of the formation water and mud filtrate, respectively. Equation (1) can, therefore, be rewritten as follows:

$$Ec = -K \log \frac{\mathrm{R_{mfeq}}}{\mathrm{R_{weq}}} \qquad (3)$$

This equation represents a system where there is only one type of salt present. In the event that there is more than one salt type present, which is usually the case, corrections must be made. The equation is still a good estimate, especially when sodium chloride is the primary salt in the mud and formation water.

There is another potential worth mentioning although its effects are negligible. As the filtrate passes through the mud cake or through the shale, a small emf is created. This is known as an electrokinetic or streaming potential, E_k , but it usually has very little effect on the overall potential created electrochemically.



SP Tool Principles Schematic

A Typical SP Log

MEASURING SP

To measure the spontaneous potential created in the borehole a potential measuring device containing one electrode is lowered to the bottom of the hole. As the device is raised, the changes in potential with respect to a ground electrode at the surface are recorded. So, the SP curve represents changes in potential with respect to depth. Consequently, there is no zero line, only what is known as a shale base line.

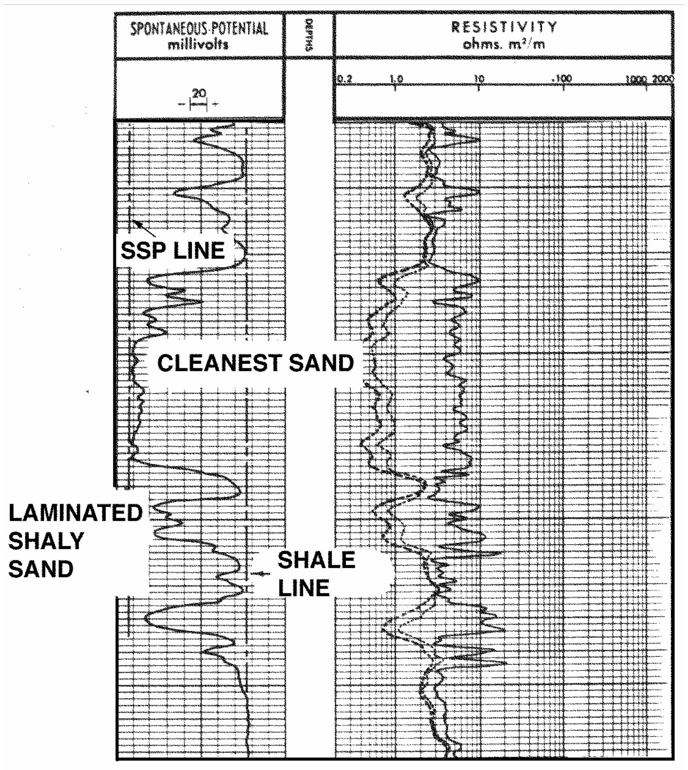
Shales of uniform age and the same salinity pore water, seem to create a uniform potential, hence the shale base line can be easily determined. It is from this line that the SP deflections are measured whether they are excursions to the right (+mv) or the left (-mv).

THE SP CURVE

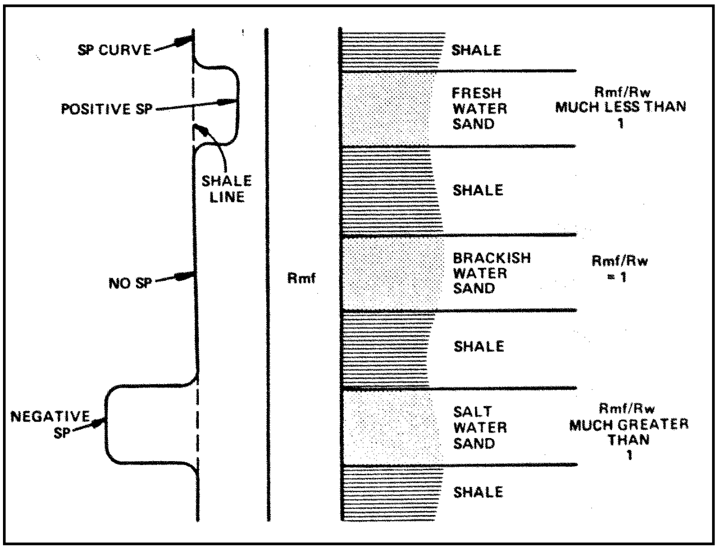
In the case where the formation water is saltier than the mud or mud filtrate ($R_w < R_{mf}$); the resulting SP is negative with an excursion to the left. This is typical of older formations where the salinity of the formation water may reach saturation values. The curve is symmetrical about the bed centre and the bed boundaries are picked at the inflection points. Across from a clean, thick, sand formation where the borehole fluid is the dominant resistance, the electrochemical potential is fully developed and the deflection is known as the static spontaneous potential, SSP

The SSP can range from +50 millivolts (mv), when the formation water is fresher than the mud filtrate ($R_w > R_{mf}$), to a zero value, when the filtrate and formation water have the same salinity ($R_w = R_{mf}$), to a value of -200 mv, when the formation water is very salty compared to the mud filtrate ($R_w < R_{mf}$).

The spontaneous potential will not be created unless there is conductive fluid in the hole. In other words, it will not work in air, gas, or oil-filled holes. Also, there must be at least a small amount of permeability present to allow the potentials to be created. There is, however, no direct relationship between permeability (or porosity) and the size of the SP deflection. Low permeability adjacent beds can suppress the development of a SSP.
The SP is measured from the shale base line. The shale base line can shift when the shale is not a perfect cationic membrane and is separating two formations of differing salinities. This can occur in zones of over-pressure development or at geological unconformities. In determining the value of the SP, the proper shale base line must be used.



Sand - Shale Sequences on a SP Log



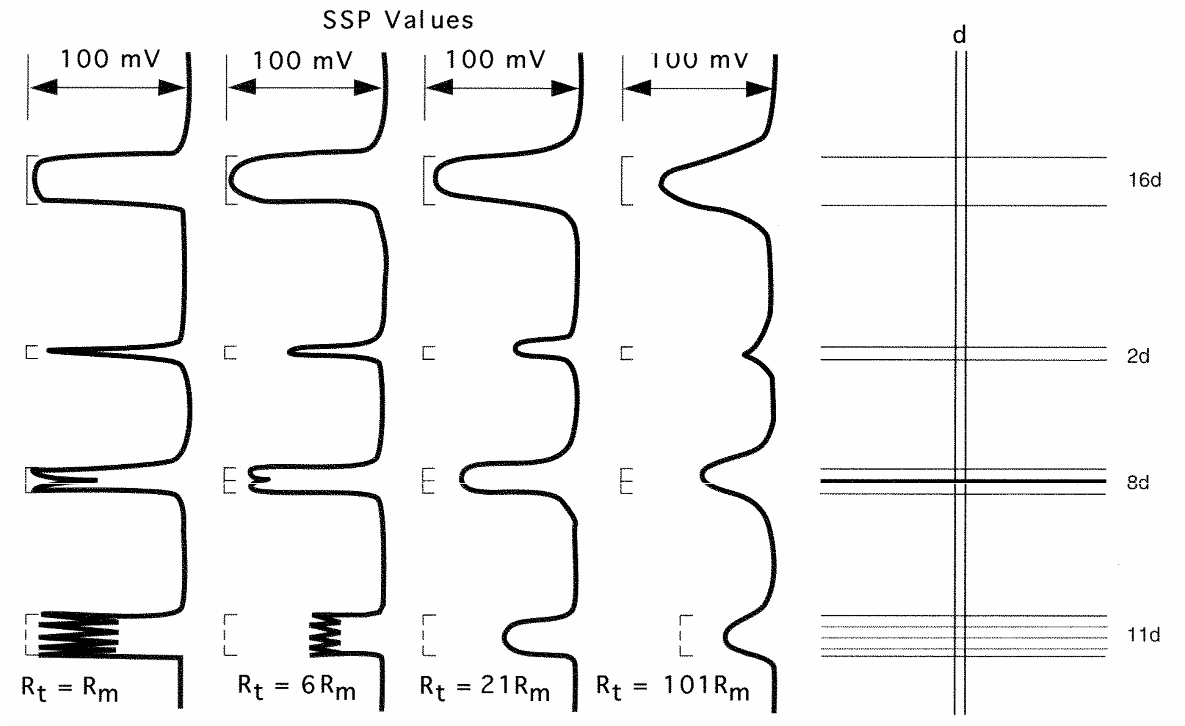
The Effect of Rw and Rmf on SP Response

Other Factors Affecting the SP

The SP is also influenced by the shaliness of the formation. The shale reduces the potential change for the bed; hence a lower SP value is observed than if it were clean. This is known as an ASP or PSP (actual or pseudo spontaneous potential). A qualitative indicator of the bed's shaliness is:

$$1-\alpha, \quad \text{where } \alpha = \frac{ASP}{SSP}$$

The shape of the curve is influenced by many other factors. For instance, the thickness and resistivity of the permeable bed. In low resistivity beds, like a salt-water sand, the SP is almost fully developed even in the thin beds. In the highly resistive beds, like a highly oil saturated sand, or in very low porosity carbonate the SP curve may be more rounded and become more suppressed, the thinner the beds. Other influences are the resistivity and diameter of the flushed zone, resistivity of the adjacent formation and resistivity of the mud and diameter of the borehole. The curves are also affected by extraneous artificial and natural electrical disturbances, by the presence of metallic junk, or by high concentrations of pyrite.



The Effect of R_t/R_m on The SP

USES OF THE SP

The SP curve is used as a correlating tool, to help identify lithology, and, in some areas, to help determine depositional environment. The inflection points define the bed boundaries; therefore, the bed thickness can also be determined. Beds having the slightest permeability are detected by a build-up of the SP when there is a salinity contrast. If a bed is shaly, the shaliness can be qualitatively determined.

If the resistivity of the formation water is unknown, the SP curve can often be used to calculate R_w . The R_w can only be determined from a clean, thick permeable bed, although corrections can be made for thickness and other factors. The equation for a thick, non-shaly bed is:

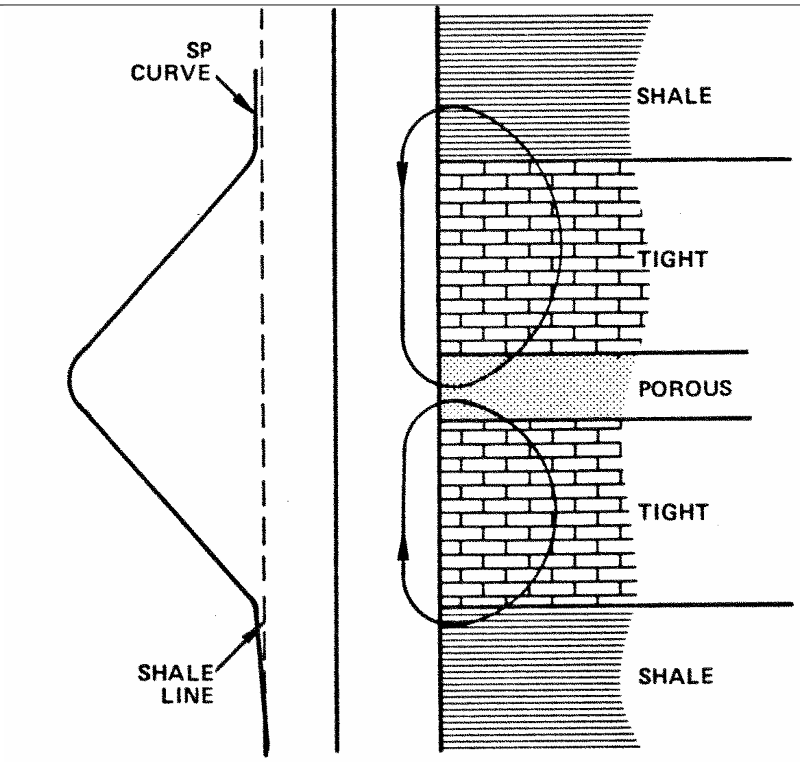
$$SSP = -(61 + .133\,T_{0\,(F)})\ \log \frac{R_{mfeq}}{R_{weq}}$$

If the formation temperature and the resistivity of the mud filtrate at formation temperature are known, the SSP can be determined from the log, and the R_w can then be calculated.

Environmental Corrections

The calculation of SP values requires that corrections are made for the borehole size, bed thickness, invasion and resistivity contrasts. Charts (Schlumberger) **SP-3** and **SP-4**, for example, are for this purpose. However, these charts do not correct for shaliness. In tight zones the electrokinetic potential may suppress the development of a SSP.

The equations are for mud and water containing sodium chloride as the dominant primary salt. In most instances, there are other salts present; therefore, an equivalent R_w, R_{weq}, is calculated. There are equations and charts available to correct R_{mf} to R_{mfeq} to a final R_w for both fresher and calcium/magnesium rich systems. Again, an erroneous R_w may be calculated if corrections are not applied to this formula.



Tight Zone Effect on SP Development

The SP log fell into disuse in the last 20 years due to the increasing popularity of oil-based muds and drilling fluids containing appreciable quantities of Potassium, Calcium and Magnesium chlorides. Within the last few years more interest is being expressed in it and it has been successfully reapplied in a number of wells.

Supplementary Notes

SUMMARY SHEET OF THE SP LOG

- SP is generated by the diffusion of ions through two solutions of different salinities separated by a shale membrane and a liquid-junction membrane.

- SP is measured by recording the change in potential between an electrode being pulled up hole in a sonde, and a grounded electrode at the surface. A conductive mud is required.

- There is no set zero line; however, there is a shale base line from which the SSP or ASP is measured.

- The inflection points of the SP curve represent the bed boundaries.

- The magnitude and direction of the SP curve is controlled by three major factors:

  1) Salinity of the mud filtrate, R_{mf}

  2) Salinity of the formation water, R_w

  3) Shaliness of the formation

- Other minor factors include:

  1) Streaming potential (E_K)

  2) Low salinity formation water

  3) High Hydrocarbon saturation

  4) Pyrite or metallic junk

  5) Extraneous artificial and natural electrical disturbance

- Maximum deflection (SSP) is achieved when the borehole is the dominant resistance and bed thickness is > 10 feet.

SUMMARY SHEET OF THE SP LOG (Continued)

- Conditions under which the borehole is not the dominant resistance:
  1) Very thin sand or shale beds
  2) Highly resistive beds
  3) Very deep filtrate invasion or excessively enlarged borehole
  4) Low resistivity muds

- Direction of Deflection

	Condition
Negative (to left)	$R_{mf} > R_w$ (Salty Formation Water)
Positive (to right)	$R_{mf} < R_w$ (Fresh Formation Water)
No deflection	$R_{mf} = R_w$

- Bed Shaliness (Qualitative) = $1 - \alpha$

$$\alpha = \frac{ASP}{SSP}$$

- Uses of the SP
  1) Correlation
  2) Detect beds having permeability and porosity
  3) Locate bed boundaries and thickness
  4) Indicate bed shaliness (qualitative)
  5) Determine depositional environment (only with much experience)
  6) Calculate R_w via the equation $SSP = -(61 + .133T)\log\frac{R_{mfeq}}{R_{weq}}$

Chapter 2

Section 3

Porosity Logs

STUDY GUIDE QUESTIONS ON THE ACOUSTIC LOGS

1. What two types of waves are generated by the acoustic tool?

2. Which wave is used in porosity calculation?

3. Does it matter what is filling the borehole, i.e., gas or water-base mud?

4. What is cycle skipping? Where can it happen?

5. How far in does the tool read? What is the spacing between the transmitter and the receiver in a typical BHC mode?

6. How does velocity relate to transit time?

7. What is the equation for porosity?

8. How do gas and oil affect the calculated porosity?

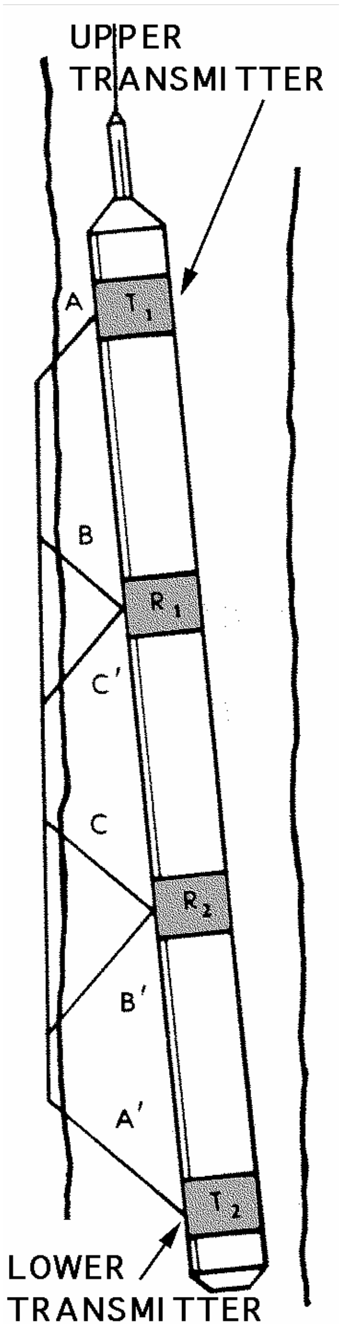
9. How important is the transit time of the matrix?

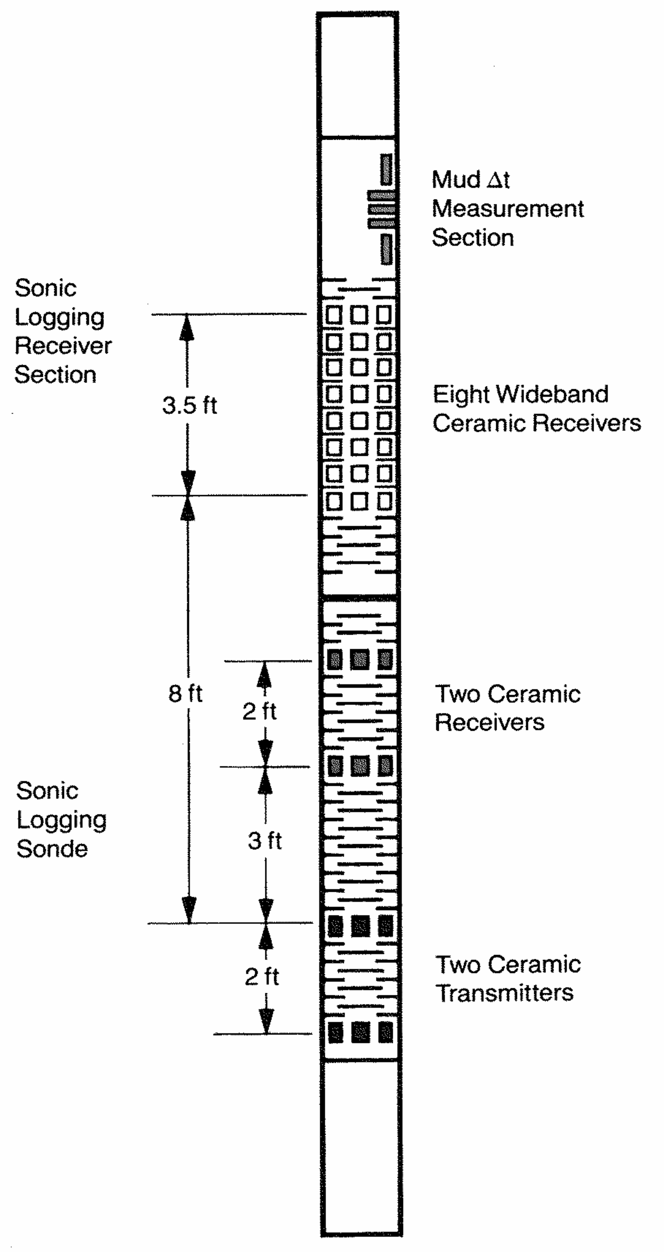
10. Does the tool detect secondary porosity, i.e., vugs and fractures?

11. Does the tool work well in both consolidated and unconsolidated sands?

12. Generally how does shale (clay) affect the porosity calculated?

13. The main purpose of the acoustic log is to calculate porosity. What is another?





The BHC Sonic Tool vs. The Array Sonic Tool

ACOUSTIC LOGS

INTRODUCTION

The passing of acoustic waves through the subsurface has been used for a long time to help detect subsurface structures. This idea was then applied to reading acoustic velocities versus depth in a borehole. The acoustic readings were extended to include calculation of primary and secondary porosity as well as lithology determination.

BASIC ACOUSTIC TOOL PRINCIPLES

Two waves are set off when an acoustic wave is generated. These are a compressional (P-wave) and the shear (S-wave). The P-wave runs parallel to the direction of propagation and travels faster than any other wave type. This compressional wave is referred to as a first arrival wave. The shear-wave moves perpendicular to the direction of propagation. Shear waves can be transmitted through solids, but not liquids or gases. A transducer in the downhole tool, produces acoustic wave pulses at a rate of 10 to 20 times per second. The pulses travel through the borehole fluid, and are reflected and transmitted into the formation at the borehole formation interface. They travel along the formation parallel to the borehole, creating secondary waves, Stoneley Waves, which emit energy back into the borehole. A receiver spaced some distance (i.e. 1-3 feet) below the transmitter detects the waves being reflected back into the borehole.

The time the P-wave takes to travel through the formation can be calculated by subtracting, from the total travel time, the time it takes the compressional wave to get from the transmitter to the formation plus the time from the formation to the receiver.

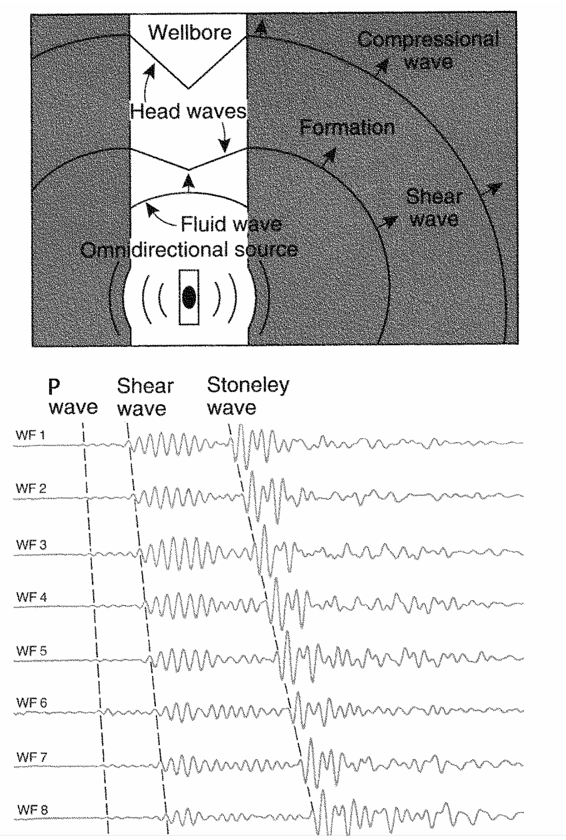
All acoustic logs must be run in a liquid-filled hole. Problems arise, however, due to differing mud and filtrate travel times, washed-out zones, or tool tilting. Consequently, tools have been developed to compensate for these borehole problems. The borehole compensated tools (BHC) use two transmitters and two receivers (or two pairs of receivers). These pulse alternately and the two sets of travel times are then averaged at the surface.

Sometimes a P wave signal reaches the first receiver, but is not strong enough to trigger the second receiver. The second receiver may be triggered by a later wave arrival and therefore the transit time measured is too long. This is known as “cycle skipping” and can occur in an unconsolidated formation, formations with gas saturation, fractured formations, or rugose boreholes.

The Array Sonic was developed in the mid 1980s, when new piezo-electric transponders made it possible to detect both P waves and the shear (S) waves. The Array tool has a number of modes in which it can acquire data. The entire acoustic wave-form can be captured. In a fast formation the toll can detect P, S and Stoneley waves. In a slow formation the Stoneley waves can help derive the equivalent S wave velocity.

The Array can be run as a short spaced, 3 - 5 foot and a long-spaced 5 - 7, 8 - 10 & 10 - 12 foot depth-derived borehole compensated sonic log in open hole, and as a 3 foot CBL and 5 foot VDL in cased hole. The log is capable of providing 6 inch vertical resolution of thin bed transit times. It automatically compensates for cycle skipping and deletes all skipped values.

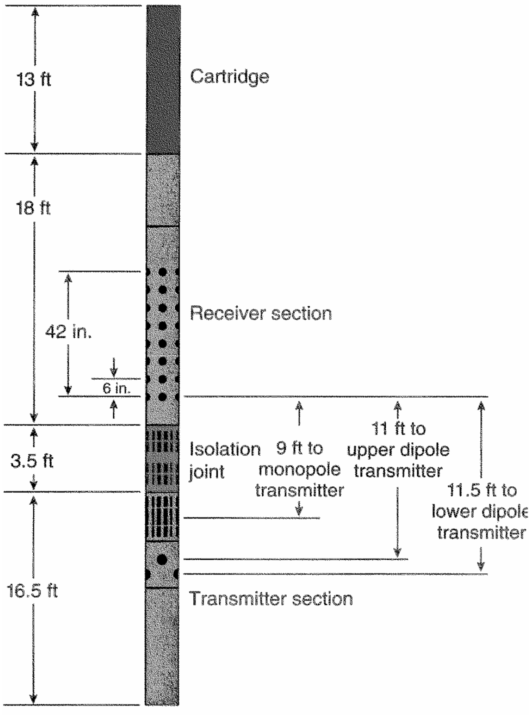
From the wave-train analysis, using slowness-time coherence and a semblance algorithm, arrivals that are coherent across all 8 detectors provide the basis of transit times for each waveform, P, S, and Stoneley. This data can be used in rock mechanical evaluations of the borehole stress regime and to create synthetic seismograms.



Wave-train Propagation in A Hard Formation and Typical Waveforms

THE DIPOLE SONIC IMAGER

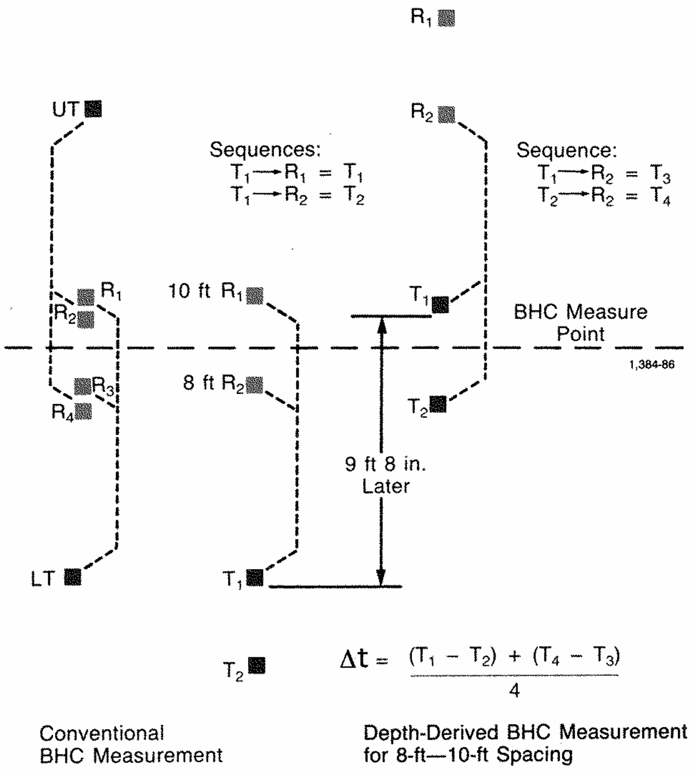
The DSI tool represents an improvement on some of the qualities of the Array Sonic. Introduced in 1995. In using dipole and monopole measurements the tool is capable of resolving shearwave velocity in slow, soft formations. The tool generates a Flexural wave in the borehole which displaces up and down the wellbore. The leading edge of the flexural wave is coincident with the shear body wave.



DSI Tool Array

THE LONG SPACED SONIC (LSS)

A deeper investigating device which is designed to generate a BHC velocity profile by deriving data at the same depth point. Depth Derived compensation was developed to allow for shorter tools than would be necessary in the traditional BHC device array. Data are stored at a depth and matching pairs of data acquired when the tool has moved up to this depth. The Array Sonic can be run in this mode but the LSS is a special device with two lower transmitters and two upper receivers 8 - 10 feet and 10 -12 feet apart. Depth of investigation is considered to be beyond the zone of borehole damage and anelastic strain relaxation.



LSS Versus Conventional BHC Sonic Modes of Operation

THE ACOUSTIC LOG

The acoustic logs are presented on the far right-hand tracks on a linear scale. The scale represents specific acoustic time measured in micro-seconds per foot (Δt); this is known as transit time and is a measure of slowness. To convert velocity (ft/sec) into transit time, the following equation is used:

$$\Delta t = \frac{1 \text{ x } 10^6}{V} \qquad (1)$$

Δt = Transit time, μ sec/ft

V = Velocity, ft/sec

CALCULATING POROSITY

The time it takes a pulse to get from the transmitter to the receiver is the time it takes to travel through the matrix of the formation plus the fluid in the formation. Wyllie in 1956 represented this relationship through a "time-average" equation:

$$\Delta t = \Delta t_f \bullet \phi + \Delta t_m \ (1-\phi) \qquad (2)$$

Δt = Total transit time (slowness), μ sec/ft

Δt_f = Transit time of the fluid, μ sec/ft

Δt_m = Transit time of the matrix, μ sec/ft

$(1-\phi)$ = Matrix

This equation, which is not mathematically rigorous, can be re-written to express porosity in terms of transit time:

$$\phi = \frac{\Delta t - \Delta t_m}{\Delta t_f - \Delta t_m} \qquad (3)$$

The log reads Δt; to properly calculate porosity, the transit time, or slowness, of the formation's matrix (Δt_m) and of the fluid (Δt_f) must be known.

THE EFFECT OF FLUID TRANSIT TIME

To calculate a correct porosity, the fluid's transit time must be known. The log reads only an inch or two into the formation; so it reads only in the flushed zone. The fluid to be concerned with would then be filtrate plus any residual hydrocarbon that is present. A typical average value used for Δt_f is 189 μ sec/ft. This, however, varies with salinity as can be seen in Table 1. Consequently, the porosity value calculated will be dependent upon the Δt_f used.

In the flushed zones containing residual oil, porosity that is too high will be calculated as the Δt_f of oil is higher than that of water. The error is even greater in gas zones for gas does not transmit sonic waves very well. Average correction factors to reduce the high porosities calculated in these zones are:

for oil $\phi_T = \phi_A \bullet 0.9$ ϕ_A = Original acoustic porosity

for gas $\phi_T = \phi_A \bullet 0.7$ ϕ_T = Corrected porosity

EFFECT OF MATRIX TRANSIT TIME

The type of matrix which the sonic wave travels through is very important. Sandstones, limestones, and dolomites all have different matrix transit times (Δt_m). Average Δt_m values are available in logging company manuals to be used in Wyllie's "time-average" equation, however, it is rare a formation is composed of one mineral or rock type. Often impurities such as calcite in sandstone, anhydrite in dolomite, etc. are found; these alter the matrix transit time. If the actual lithology is known, perhaps a transit time could be estimated. However, the best way to determine the formation's matrix travel time is to measure Δt_m in a laboratory on a representative core sample. Remember, the average times in the logging manuals are just that, averages. They do not take into account the variability introduced by changes in pore geometry, cementation, compaction, or complex lithologies.

EFFECT OF VUGS AND FRACTURES

When a sonic P wave is transmitted, it will take the quickest path to the receiver. It therefore never sees secondary isolated vuggy or fracture porosity. The acoustic logs generally do not detect secondary porosity. As a rule of thumb, the amount of secondary porosity can be estimated by subtracting the sonic porosity from a total porosity (neutron or density).

EFFECTS OF SHALE

Sands containing appreciable amounts of shale or clay will have longer transit times, because of the differences in the velocities of the clay particles and the matrix. Consequently, the calculated porosity in shaly sands is too high. A correction must be introduced to give a more reasonable value. There is no set correction because the transit time of shale (Δt_{sh}) can vary greatly. Logging companies have different equations to take into account the effect of shale and whether the formation is compacted or uncompacted. Shale corrections include a Vsh percentage (shale volume) which can be determined from the gamma, SP, or neutron log. Often the correction for shale is not used, especially in some areas of the world, where, for financial reasons they like to see the optimistically high porosities.

ACOUSTIC LOGS AS A LITHOLOGY TOOL

Several cross-plots of Δt versus bulk density or neutron log porosity are available. Corrections for the effects of hydrocarbons can also be incorporated. The cross-plots effectively average the two logs' responses; a percentage of the two rock types present (if the matrix pair known, i.e., limestone, sandstone) plus porosity can be read. Some types of formation or lithologies can be identified by the magnitude of the Δt reading. For example, an acoustic log being run through salt or anhydrite will show high transit times. This can be a tip-off that these minerals are present. Because of the varied effects of lithologies on the acoustic log, another empirical porosity equation has been proposed.

EMPIRICAL RAYMER-HUNT-GARDNER EQUATION

Because of the non-rigorous nature of the Wyllie time average equation and errors introduced by the selection of improper matrix, or fluid, velocities, this empirical equation has gained favour,

$$\phi_{sonic} = C \cdot \frac{\left(\Delta t_{\log} - \Delta t_{ma}\right)}{\Delta t_{\log}},$$

where the empirical constant, C, has a range from 0.624 to 0.7. Currently the value 0.67 has the highest appropriateness. When gas is encountered the value of C should be 0.6. The equation has the most applicability in fairly good porosity sandstones

EFFECTS OF UNCONSOLIDATED SANDS

Unconsolidated sands cause the signal to take a longer time to reach the detector. Consequently, the log reads higher transit times (Δt) and greater than true porosities are calculated. Unconsolidated sands are found in many areas including Oman, SE Asia, California, Canada, and the US Gulf Coast.

A rule of thumb exists that if the adjacent shale beds exhibit transit times greater than 100 μ sec/ft, a compaction correction is needed. The empirical equation for an unconsolidated sand is:

$$\phi = \frac{\Delta t - \Delta t_m}{\Delta t_f - \Delta t_m} \bullet \frac{1}{C_p} \qquad (4)$$

C_p = Compaction correction factor

$$Cp = \frac{\Delta t_{sh} \bullet c}{100} \qquad (5)$$

Δt_{sh} = adjacent shale bed's transit time, μ sec/ft

c = Shale compaction coefficient

100 = transit time in compacted shale, μ sec/ft

The compaction coefficient varies from a value of 0.8 which is used for Mesozoic shales to a high of 1.2 in the US Gulf Coast and SE Asia. If c or Cp is unknown, Cp can be determined using Shlumberger chart **Por-3** via cross-plots of density and acoustic logs in adjacent clean, water sands or with a neutron-acoustic log cross-plot in shaly water sands.

SHEAR-WAVE INTERPRETATION

The entire forgoing discussion deals with P , or compressional waves. The new tools allow for the recording and interpretation of shear-waves. Strange as it may seem, the time average equation seams to work relatively well with shear-waves. The analogy is that although the shear waves do not travel in fluid filled porosity, they do have to travel round it. The higher the porosity the more tortuous this path, the slower the transit time. Of course the values of matrix and fluid velocity must be different from those used with P waves.

Sandstone	Δtma	≈	86 µs/ft
Limestone	Δtma	≈	90 µs/ft
Dolomite	Δtma	≈	76 µs/ft
Anhydrite	Δtma	≈	100 µs/ft
Water	Δtma	≈	350 µs/ft

It should be noted that there is only a small difference between shear slowness in these lithologies. These values however, are only approximate and should be treated carefully. Obviously a value for water is purely imaginary, as water does not support shear wave propagation.

- The three waves of importance produced downhole are the compressional (P-wave) which arrives first, the Shear (S-wave) and the Stoneley Wave .

- The acoustic log records the first arrival wave, P-wave as the porosity signal.

- For the tools to work, there must be a liquid in the borehole. This transmits the wave from the tool to the formation.

- Cycle skip occurs in the BHC when the second receiver does not receive the initial wave and is tripped by arrival of a later wave. Consequently, an erroneously long transit time is measured. This can occur in gas saturated formations, fractured formations, unconsolidated formations or rugose boreholes.

- The tool "sees" into the formation only an inch or two and the spacings are between one and 12 feet.

- Transit time $(\Delta t) = \dfrac{1\text{x } 10^6}{\text{Velocity}}$

- Porosity $(\phi) = \dfrac{\Delta t - \Delta t_{ma}}{\Delta t_f - \Delta t_{ma}}$

- Oil and especially gas have higher transit times. Often this is not taken into account and porosities that are too high are calculated. Quickie corrections for gas and oil zones are:

for oil $\phi_T = \phi_A \bullet 0.9$

for gas $\phi_T = \phi_A \bullet 0.7$

SUMMARY SHEET (continued)

Since lithologies and mineralogy vary from formation to formation (and even well to well), so will the matrix transit time (Δt_m). Logging companies have published average values for sandstone, limestone and dolomite; but to calculate a more correct porosity, the Δt_m should be determined in the laboratory.

- Since the sonic P-wave takes the quickest route, it will by pass fractures and vugs. Consequently the tool does not ‘see’ secondary porosity.

- Wyllie’s “time-average” equation was developed on consolidated, clean sands. In unconsolidated sands the equation needs a compaction factor, Cp. to decide whether to apply it or not, the surrounding shale bed Δt should be read. If it is greater than 100µ sec/ft, apply the correction.

$$\phi_T = \phi_A \bullet \frac{1}{Cp}$$

- In shaly sands, a porosity that is too high is calculated unless a shale correction factor is applied.

- Using cross plots of the sonic and other porosity logs, estimates of the formation lithology can be made.

STUDY GUIDE QUESTIONS ON THE DENSITY LOG

1) What does the density log measure?

2) Is it a pad device?

3) What is the equation for porosity using the density log?

4) If a grain density too high is used, will a porosity that is too high, or too low be calculated?

5) If the fluid density is not corrected in a gas zone, will a porosity too high or too low be calculated?

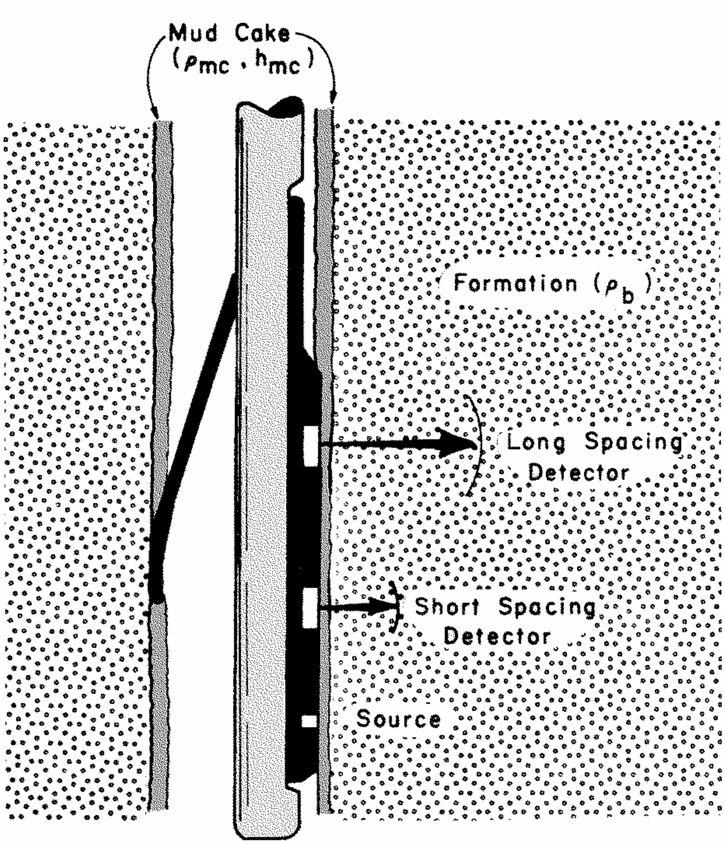
6) What are the "quickie" corrections for porosity in oil and in gas zones?

7) How can shale affect the porosity calculated from the density log?

8) What is the "q factor"?

9) How does pressure affect the bulk density?

THE DENSITY LOG



THEORY

A section of formation is subjected to a stream of medium energy gamma rays from a source mounted on sidewall skid. The energy levels are between 2 and 72 keV in the FDC tool. As the gamma rays enter the formation, some are absorbed, some pass through and others are slowed down and scattered. The last type of collision is known as Compton Scattering and is the basic signal mode of the density tools. Two detectors at fixed distances on the skid record the intensity of the scattered gamma ray. The scattered gamma radiation occurs because of collisions with electrons of the atoms making up the bulk formation. The signal is therefore proportional to the electron density of the formation. Since the number of electrons is balanced by a similar number of protons (the Atomic Number, Z) and the number of protons can be related to the Atomic Weight, A, by Avogadro's Number (6.02×10^{23}) the electron density is in turn, proportional to the bulk density of the formation. Where N_e is the number of electrons, we can express this as,

$$N_e = N \cdot \frac{Z}{A} \cdot \rho_b,$$

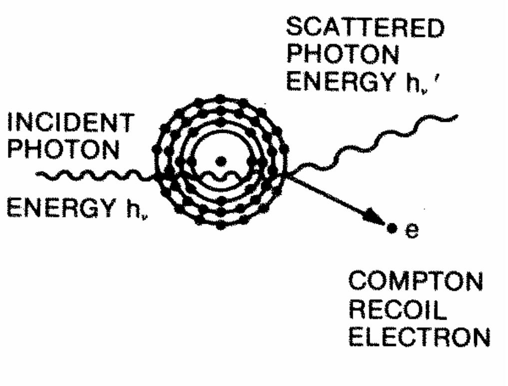
ρ_b being the bulk density of the formation in g/cm^3.

Solving for ρ_e, or electron density gives,

$$\rho_e = \frac{2Ne}{N} \quad \text{and} \quad Ne = N \cdot \rho_b \cdot \frac{Z}{A}$$

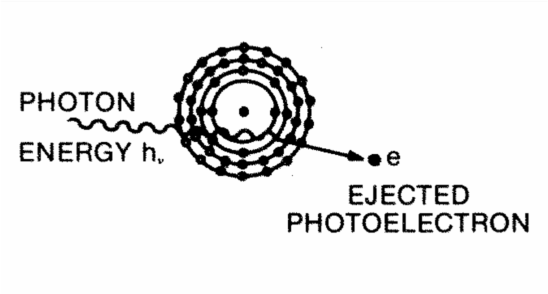
This follows from the definitions for ρ_e,

$$\rho_e = \rho_b \cdot \frac{2Z}{A}.$$



It turns out that the ratio 2Z/A is close to 1 for most minerals found in wellbores. Hence, the tool gives a close approximation of the true bulk density, RHOB.

More recently the energy level of density tools has been raised to take advantage of another nuclear phenomenon, the photoelectric effect. The photoelectric effect is described by absorbtion of the incident photon of gamma energy and the emission of a photoelectron. This is the principle behind the detector on the passive gamma ray tool. The photoelectric effect (P_e) is a *low* energy effect and the raising of the tool output was made to differentiate this energy spectrum from the higher zone of Compton Scattering. In the Lithodensity Log (LDL) the gamma-rays are emitted at 662 keV.



For a single atom $P_e = \left(\frac{Z^{3.6}}{10}\right)$,

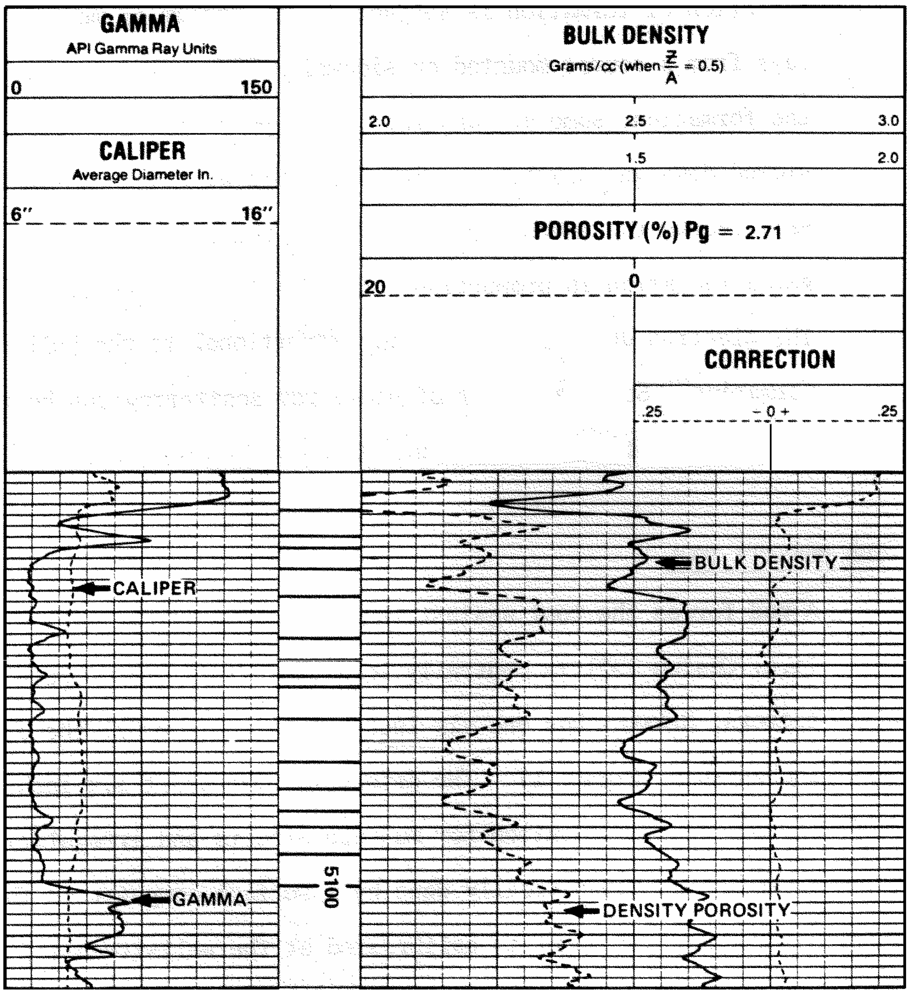
In a mixture of atoms making up a molecule, then, $P_e = \frac{\sum A_i, Z_i P_i}{\sum A_i, Z_i}$,

Obviously, each mineral, as a mix of molecules will have its own P_e value.

The P_e values for some minerals are;

<u>Mineral</u>	<u>P_e</u>
Anhydrite	5.055
Barite	266.800
Calcite	5.084
Dolomite	3.142
Quartz	1.806
Magnetite	22.080

A Sample FDC, Density Log



DENSITY TOOLS

A pad forces the tool against the borehole wall. A source of gamma rays (Caesium 137 in the FDC, chemical in later tools) is centrally located in the tool. There are two detectors; Baker Atlas has one six inches from the source, the other 11.5 inches away. The detectors read about six inches into the formation.

Compensation for mudcake effects and irregularities in the borehole are automatically done by a surface computer in the logging unit. The instrument is calibrated at the wellsite using calibration blocks of known low, medium, and high bulk density.

THE DENSITY LOG

The bulk density is reported on the far right-hand grid on a linear scale. If the grain density and fluid density are known, porosity can be plotted. The corrections made for mudcake and borehole effects are also printed along side the density log, but use a different scale.

When a LDL tool is used there is and additional Pe curve on the log (PEF). This is calibrated in Pe units , or Barns/ electron and is usually on scale of 1 - 10.

CALCULATING POROSITY

Bulk density is a function of the amount of matrix and the amount of fluid in the formation, as well as their respective densities.

$$\rho_b = (\phi)\,(\rho_f) + (1-\phi)\,(\rho_{ma})$$

ρ_b = Formation's Bulk Density

ρ_f = Fluid Density

ϕ = Porosity

$(1-\phi)$ = Matrix

ρ_{ma} = Grain (Matrix) Density

Rewriting equation (1), porosity can be solved for as follows:

$$\phi = \frac{\rho_{ma} - \rho_b.}{\rho_{ma}. - \rho_f.} \qquad (2)$$

The density log reads the bulk density fairly well. Errors in calculated porosity appear, however, because the grain density and fluid density are often not measured and erroneous values of their magnitude are assumed.

EFFECT OF GRAIN DENSITY

Logging manuals report average grain density values for sandstone, limestone, dolomite, etc. However, many formation grain densities are not equal to the average. For example, if one has a dolomitised limestone with matrix density of 2.77 gm/cm^3 and does not realise it, a grain density of 2.71 gm/cm^3 may be erroneously used. A porosity that is to low will be calculated.

MATERIAL	FORMULA	ACTUAL DENSITY g/cm^3
Quartz	SiO_2	2.65
Calcite	$CaCo_3$	2.71
Dolomite	$CaCo_3 . MgCo_3$	2.87
Anhydrite	$CaSO_4$	2.96
Gypsum	$CaSO_4 . 2H_2O$	2.32
Halite	NaCl	2.165
Sylvite	KCl	1.98
Anthracitic Coal		1.40 - 1.80
Bituminous Coal		1.20 - 1.50
Lignite		0.70 - 1.50
Water	H_2O	1.00
Saltwater	(100,000 PPM)	1.07
Saltwater	(200,000 PPM)	1.146
Oil	$C_n (CH_2)$	0.80
Gas	$C_n H_{2n+2}$	0.20

TABLE 1. Densities of Typical Minerals and Fluids.

	(g/cm^3)	
Chlorite	2.60 - 2.96	Low water absorptive properties
Halloysite	2.55 - 2.56	Completely evacuated
	2.76 - 3.00	Muscovite
	2.70 - 3.10	Biotite
	2.642 - 2.688	No absorbed water
Kaolinite	2.609	Theoretical density
	2.60 - 2.68	Extensive literature
	2.63	Most frequently quoted
Palygorskite	2.29 - 2.36	Limited data
Sepiolite	2.08	Limited data
Smectite	2.20 - 2.70	Nontronite essentially
	2.24 - 2.30	Saponite dehydrated
	2.348	
	2.20 - 2.70	Montmorillonite
	2.53	Low-iron smectite
	2.74	3.6% iron content

TABLE 2. Densities of Clay Minerals

In shaly sands, the type, amount, and hydration of clay present is important so that one knows whether to use a higher or lower grain density than 2.65 (Table 2). Also, other secondary minerals like gypsum (2.32 gm/cm^3) or anhydrite (2.96 gm/cm^3) can alter the average grain density. The best procedure is not to guess, but to measure the grain density. These measurements can be made on cuttings, sidewall plugs or whole core samples.

EFFECT OF FLUID DENSITY

In equation (2), fluid density is often assumed. Many wells are still drilled using fresh water mud systems. The filtrate, therefore, is fresh water with a fluid density of 1.0 gm/cm^3. The tool reads only six inches into the formation so it will read the flushed zone containing the filtrate. Consequently, 1.0 gm/cm^3 is the assumed average fluid density.

Errors arise when oil based or salty muds are used, or when hydrocarbon bearing zones are contacted. Highly saline muds can have fluid densities as high as 1.15 gm/cm^3. Since oil typically has a lower fluid density than water (i.e. 0.80 gm/cm^3), its presence as a residual saturation with the very salty filtrate in the flushed zone will usually result in an average fluid density close to 1.0 gm/cm^3. However, in zones containing no hydrocarbons, a porosity that is too low will be calculated if 1.0 gm/cm^3 is used instead of the correct value for the very salty mud.

Errors arise in hydrocarbon bearing zones flushed to residual amounts by a fresh water filtrate. In flushed oil zones, the effect is minor compared to that in flushed gas or very light oil. In the latter case, if the proper fluid density is not used, a porosity too high is calculated. Somewhat elaborate calculations are available to correct the calculated porosity both in oil and gas zones. Quickie corrections, if specific fluid densities are unavailable, are:

for oil $\phi_T = 0.9\ \phi_D$

for gas $\phi_T = 0.7\ \phi_D$

ϕ_T = true or corrected ϕ

ϕ_D = ϕ calculated originally from density log

If the neutron porosity is available, Baker Atlas presents the following equation to get a true porosity in a gas zone:

$$\phi = \frac{GD - BD + \phi_N}{GD}$$

EFFECT OF SHALE

The presence of shale can affect the calculated porosity. The density of shale can vary from a low of 2.20 gm/cm^3 to as high as 2.85 gm/cm^3. However, when the density of the shale is close to 2.65 gm/cm^3, the tool works well. Consequently, in that case, porosity calculated in shaly sands would be reliable. Quite often, though, the shale densities are lower-especially at shallower depths. If this is not accounted for, a porosity that is too high will be calculated. The effect of the shale also depends on whether it is dispersed or exists as laminations. Dispersed shale typically has lower densities than the surrounding shale beds. To correct for the effect of shale, two somewhat elaborate equations have been developed to represent dispersed shale and laminated shale. These will not be discussed at this time; however, there is a q factor used that is derived using sonic and density porosity.

$$q = \frac{\phi_S - \phi_D}{\phi_S}$$

ϕ_S = Sonic log porosity

ϕ_D = Density log porosity

q = Fraction of the total porosity occupied by clays.

This factor is used in different shaly sand water saturation equations and is used by some as a shaliness indicator. Schlumberger uses q as an indicator of how permeability is affected by dispersed shale. For example, in the US Gulf Coast, if 1 >0.40, it indicates a non-productive zone.

In summary, the density of shale affects the porosity calculations made from the density log in dirty formations. How the shale exists in the formation determines which equation to use in calculating the correct porosity. In general, the density of the shale is assumed to be the same as the matrix, which then allows the use of the original equation (2).

EFFECT OF PRESSURE

Increase in depth usually means increase in compaction which causes increase in the bulk density of shales. This trend, however, is reversed in overpressured zones.

Abnormally high formation pressures are sometimes created due to a sealing off of the formation and excess water is prevented from escaping. This results in high fluid pressure which can exceed normal formation pressure. Shales in contact with over pressured formations contain excess water, are under-compacted, and their bulk densities are lower than normal. Consequently, the density log can be helpful in predicting the approach to overpressured zones.

Supplementary Notes

SUMMARY SHEET OF THE DENSITY LOG

- A source centrally located on the tool emits gamma rays into the formation. As the gamma rays enter, they are slowed down and scattered or absorbed. The intensity of the gamma rays near the detector is recorded.

- As porosity decreases, which means the denser the formation, an increase in gamma rays scattering and absorption occurs; therefore fewer gamma rays are detected. So the amount of scattering or absorption relates to the formation density which relates to porosity.

- The tool is pressed up against the formation by a pad.

- $$\phi = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f}$$

- The rule of thumb is: If a grain density that is too high is used, a porosity that is too high will be calculated.

- Another rule of thumb is: If a fluid density that is too high is assumed, as in a gas zone (1.0 gm/cm^3 instead of perhaps 0.70 gm/cm^3), a porosity that is too high will be calculate.

- Quickie corrections of oil and gas zones are:

for oil	$\phi_T = 0.9\phi_D$
for gas	$\phi_T = 0.7\phi_D$

- When using the density log in shaly sands, the shale is assumed to have a matrix density close to 2.65 gm/cm^3 and that there is no error. How the shale or clay exists in the formation, however, does make a difference. Also the type, amount and hydration of the clay affects the average grain density of the formation.

- In a sand containing sodium montmorillonite the average grain density probably should be lowered. Otherwise, a porosity that is too high will be calculated.

- The q factor is used in different shaly sand water saturation equations and also is used as a permeability indicator:

$$q = \frac{\phi_S - \phi_D}{\phi_S}$$

- Typically as depth increases so will bulk density. In the overpressured zones, however, the bulk density of the shales are much lower than expected due to excess water trapped in the minute pores. This reversal in the trend, if recorded and noticed earlier enough, can be used to predict abnormally high pressured zones.

STUDY GUIDE QUESTIONS ON THE NEUTRON LOGS

1. Generally, how does the neutron log sense porosity?

2. Name the three basic types of neutron logs?

3. Which logs require liquid? Which logs can be run in cased holes?

4. How are the neutron tools calibrated?

5. How are the neutron logs presented?

6. How do hydrocarbons affect the log response? How can gas be detected?

7. How do clays and other hydrous minerals affect the log response?

8. What elements are resolved by neutron activated geochemical logging?

NEUTRON LOG

INTRODUCTION

Neutrons emitted from a radioactive source are categorised into three general groups according to their energy:

1. High energy neutrons, which are fast neutrons
2. Medium energy neutrons, which are epithermal neutrons
3. Low energy neutrons, which are thermal neutrons

The logging industry has different tools which respond to different types of these neutrons.

PRINCIPLE

Neutrons are continuously emitted from a source mounted on a down hole tool or device, often known as a 'sonde'. These neutrons collide in the formation and lose energy. They lose the most energy when a nucleus of equal mass is struck. Neutrons have almost equal mass to protons and only one nucleus consists of a single proton, hydrogen. Consequently, the amount of neutrons slowed down depends mostly upon the amount of hydrogen present. This is referred to as the Hydrogen Index (HI) of the formation

Within microseconds of being emitted, the neutrons are slowed down to thermal velocity. As the neutrons are captured, gamma rays are emitted. Some detectors sense the amount of gamma rays emitted while others record the density of neutrons in the vicinity of the tool. If the hydrogen concentration is low in the material surrounding the tool, then the neutron count rate at the detector will be high; likewise, the opposite is also true. The neutron count, therefore, reflects the amount of liquid-filled porosity in a clean formation whose pores are filled with oil and/or water.

TYPES OF TOOLS

The old Conventional Neutron Log (GNT) emitted neutrons from a source in the sonde and senses the gamma ray intensity around a detector which was spaced 15.5 or 19.5 inches away. This intensity is roughly proportional to the thermal neutron density and can be related to porosity. Many factors including the borehole fluid and the tool itself can affect the reading. Generally, the more gamma rays detected, the less thermal neutrons present; therefore, more hydrogen is present meaning a higher porosity. This tool is not used anymore.

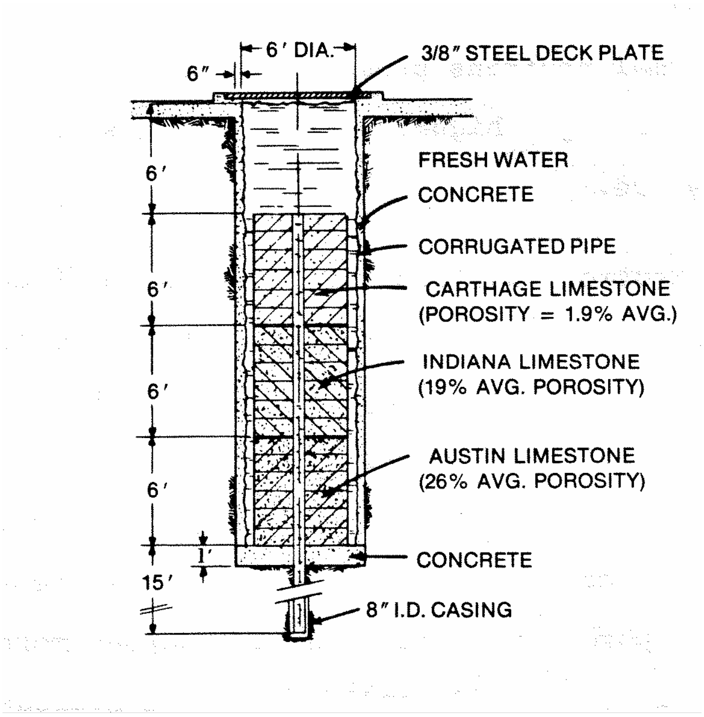
The Sidewall Neutron (SNP) is a pad device which detects epithermal neutrons. It has a detector 16 inches from the source on a pad, which is pressed up against the borehole wall. The tool can be run in liquid or air-filled uncased holes. The SNP takes the API count rates, automatically corrects for any borehole irregularities, and then prints the reading in limestone porosity units. The log senses more than one foot into the formation (depending upon the hydrogen content) and vertically averages about every 11/2 feet. This tool works well in complex lithologies. The advantages of the SNP over the GNT are: 1) borehole effects are minimised, 2) most corrections required are automatically performed, 3) sensing epithermal neutrons avoids effects of strong thermal neutron absorbers, such as chlorine and Boron. However, this tool is only rarely used these days.

The Compensated Neutron Log (CNL) has a strong (16 Curie) neutron source and will detect the amount of thermal neutrons not yet captured by the formation. Two detectors sufficiently spaced apart (1-2 feet) sense the thermal neutron concentration. The readings are ratioed, corrections automatically applied, and a compensated porosity curve is derived. The CNL reads at least 12 inches into the formation. The depth of investigation will vary according to lithology, porosity, and hydrogen content. This log gives better resolution in low porosity zones than does the SNP. This tool can be run in either cased or non-cased liquid-filled holes. The two detectors compensate for borehole irregularities but will not work well in washed-out zones. The CNL reads deeper than the SNP so it is good for detecting gas beyond the flushed zone. The CNL is often run in combination with a density porosity tool.

Modern tools include the DNL, which includes two epi-thermal neutron detectors as well as the two thermal ones, and the MWD tool, the CDN, which combines a density device within it. The DNL addresses some of the problems associated with thermal neutron detectors. The presence of shales and borehole problems may be quantified.

CALIBRATION

The Sidewall and Compensated Neutron Logs are directly calibrated in limestone porosity units. A test pit standard at the University of Houston is used where the reading from a 19% porosity, water-filled, six feet thick limestone is given as 1000 API units. There are two other six feet limestone standards of higher (26%) and lower (1.9%) porosities. An empirical sandstone calibration is available.



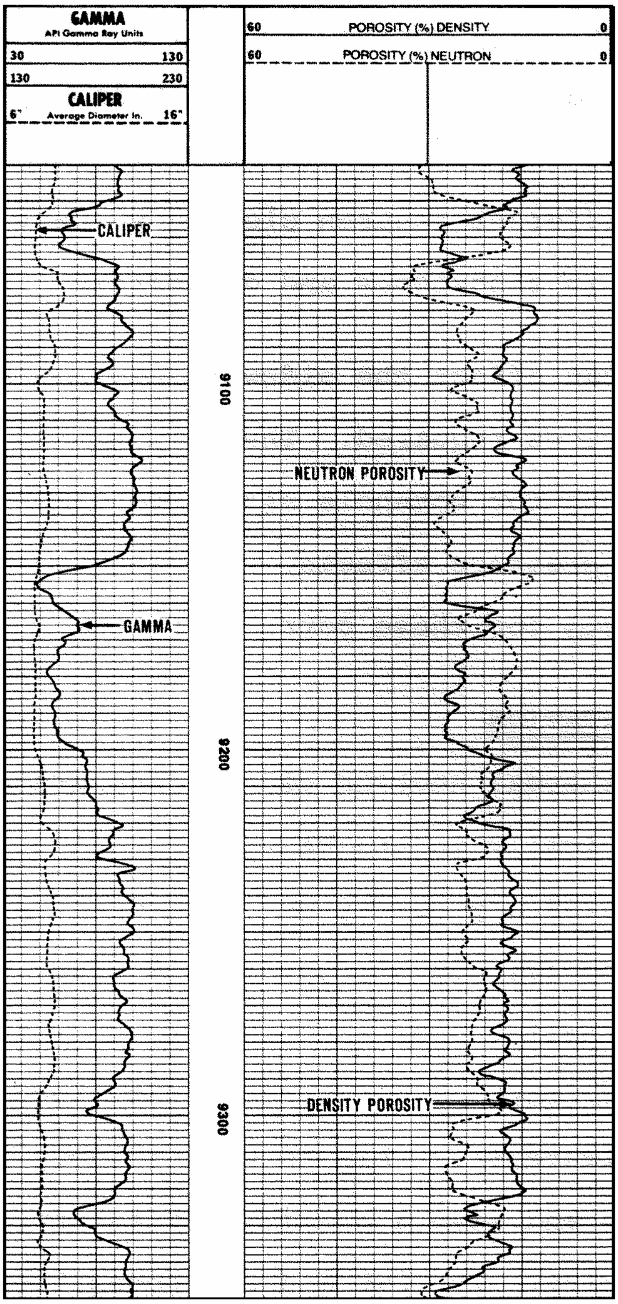
The API Calibration Pit For Neutron Porosity

If the matrix is not a limestone, a correction must be made either by built in software, or by using a porosity correction chart. The correction is developed by using comparisons of responses in a non-limestone test pit to that in the limestone test pit. This is necessary because of the different neutron slowing properties of the constitute elements in sandstones and dolomites. This conversion is now done automatically by the logging unit and presented with the proper lithology units. However, in mixed lithologies, the calibration can only be for one component.

Mudcake can affect the sidewall neutron response so corrections are sometimes required. The compensated neutron log often needs corrections for borehole size, mud weight, salinity, and temperature-pressure effects. The logging companies, of course, have charts for these corrections.

THE LOG PRESENTATION

The GNT thermal neutron count rates are plotted on a linear scale typically in tracks three and four. The SNP computes a porosity and records it directly onto a linearly scaled log, the CNL is also recorded in linear porosity units. When the CNL is run with another porosity log, such as the FDC, or LDL, both porosity curves are recorded using the same scale. This is used to help find gas productive intervals and give a qualitative interpretation of lithology and porosity. Both the CNL and SNP porosities are presented in limestone porosity units.



A Neutron Density Log Example

INTERPRETATION

The neutron log is used to identify porous formations and determine their porosity, distinguish gas from oil or water zones, and when used with other logs, help identify the lithology. The log works well in carbonates because the clay content is usually low and it has very good resolution in the lower rang of porosities typically encountered in a carbonate.

Effects of Hydrocarbons

The tool response depends upon how much hydrogen is present; this is known as the hydrogen index. The hydrogen index of fresh water is 1.0. Most oils have a hydrogen index close to one, except light oils and gas; they have lower values due to a lower hydrogen content. Consequently, the log estimates too low of a porosity in zones containing gas or light oil. As will be mentioned next, this can be masked by the presence of adsorbed water in clays.

If the porosity of a zone is fairly constant, a gas liquid contact can be picked using the neutron log. Gas zones are more easily picked when the neutron and density porosities are plotted on the same scale. The computed density porosity will read high in gas zones (a fluid density assumption that is too high would be used) and the neutron log will read low, therefore, a cross-over will occur. In other words, the density porosity will track to the left and the neutron porosity will shift to the right. Where they reverse this trend and return to a more normal response in a porous permeable zone, is an indication of the gas-liquid contact.

Effect of Shale and Other Hydrous Minerals

It must be remembered that neutron logs sense all of the hydrogen in the formation. That includes the hydrogen in the oil, the gas, the water, and the crystalline water. This means it will sense the 48 percent water of crystalinity bound in gypsum crystals and, thus, will calculate out a porosity too high. This is also true for other hydrous minerals such as opal, shale or clays in general.

Because gas is not very dense, it has a low hydrogen count which yields too low of a porosity. In clay-bearing gas productive zones, however, the presence of crystalline water causes porosities too high and will mask the presence of the gas. How high a neutron porosity calculates depends upon how much clay is present (and actually what type too). This concept can be represented mathematically by the equation:

$\phi_N = \phi_T + V_{SH} \cdot \phi_{NSH}$

ϕ_N = Observed neutron porosity in a shaly formation

ϕ_T = True formation porosity

V_{SH} = Volume of the shale

ϕ_{NSH} = Neutron porosity of a nearby shale

If a V_{SH} can be determined (the logging manuals cover several ways to estimate it), the "true" formation porosity without the effect of bound water can be determined. Cross-plots (i.e., neutron-density) are often used which have the V_{SH} factor incorporated.

Supplementary Notes

GEOCHEMICAL TOOLS, (GLT)

By combining Neutron sources of different energy and the spectral gamma response, it has become possible to derive the elemental contribution to the activated gamma ray energy emitted from the formation. At present 12 elements can be derived from their spectra, these are; aluminium, calcium, chlorine, gadolinium, hydrogen, iron, potassium, silicon, sulphur, thorium , titanium ,and uranium.

A chemical ‘cook-book’ is applied, assuming that the elements are present as their oxides and that the oxides concentrations in weight percent sum to unity. Aluminium is derived from delayed neutron activation analysis, using a californium - 252 source, potassium , thorium and uranium are inferred from the relative abundance of their radio-isotopes, detected by the passive NGS/NGT. The other elements are spectrally derived from the gamma decay after a burst of 14 MeV neutrons. Magnesium concentrations can be inferred from the measured P_e, when compared to a derived P_e from the elemental analysis. Carbon concentrations can also be derived from the carbon-oxygen ratios measured by gamma-ray spectroscopy by inelastic collisions, utilising the RST, reservoir saturation tool.

Nuclear logging represents a fantastic opportunity to derive a great deal of fundamental information on the formations of interest. However, there are draw-backs. For accurate reconstitution of the spectra, it is necessary to develop a training set of mineral responses within any particular formation. This is usually done by geochemical assay of the constituent elements making up the rock and requires core samples. These are analysed by X-ray diffraction, FTIR and mass spectrometry. Once established the mineral set precision of the approach is very good.

A further draw-back is in the environmental aspects of having portable energetic neutron sources in a working environment. Tools have to be transported and stored under stringent regulations. The very latest devices use a new source, which is only activated when under power.

SUMMARY ON THE NEUTRON LOG

- The neutron tool emits neutrons which are slowed down and captured. Different tools sense wither the amount of neutrons present or the gamma rays emitted after collision. The quantity detected is dependent upon the amount of hydrogen present. The amount of hydrogen is dependent upon how much liquid-filled porosity is in the formation.

- The four main tools are:

  GNT - The old conventional neutron log which senses thermal neutrons

  SNP - The Sidewall Neutron Log, which is a pad device, can be run in either liquid or air-filled holes, but it can only be run in uncased holes.

  CNL - The Compensated Neutron Log has two detectors that average the responses which corrects for borehole irregularities. It has a deep investigation capability and is often run with the density tool to help detect gas zones. It must be run in liquid-filled holes; however, it works in cased or uncased holes.

  GLT The geo-chemical logging tool has two emitters and three detectors. It is designed to obtain excitation spectra from individual elements. One detector is a passive NGS device, the others look at the gamma-rays from the decay of high energy neutrons.

- These tools are calibrated in the University of Houston's API test pit which contains carbonates of known porosities. The porosities are given in limestone porosity units. If the matrix is not limestone, empirical corrections are made to correlate the porosity to the proper lithology.

- The GNT log presents the API Neutron count rates on a linear scale. Using different methods of calculation, a porosity can be determined. The SNP and CNL have the equivalent porosity calculated in the logging unit's computer and then plotted on a linear scale.

SUMMARY ON THE NEUTRON LOG (continued)

- The neutron log senses porosity fairly well in totally liquid-filled (i.e., not gas or light oil) formations. Due to less hydrogen present in gas zones, the neutron logs read low.

- This anomalous behaviour can be easily detected when a density-neutron log tool is run and the data is plotted on the same scale. The neutron log will skirt to the right and the density log will skirt to the left. When they meet again marks the gas-liquid contact.

- There are different methods, to obtain a porosity corrected for the gas effect. Two popular methods are:

$$\phi_{corr} = \sqrt{\frac{\phi_D^2 + \phi_N^2}{2}} \qquad \phi_{corr} = \frac{\rho_{ma} - \rho_b + \phi_N}{\rho_{ma}}$$

(ϕ_N as a fraction)

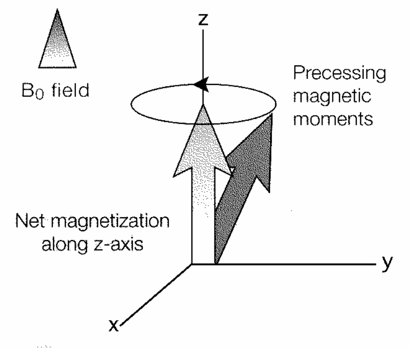
- Since the neutron log senses hydrogen, it will also detect the water bound in clay and other hydratable minerals. Consequently, porosities too high are calculated in formations containing these types of minerals.

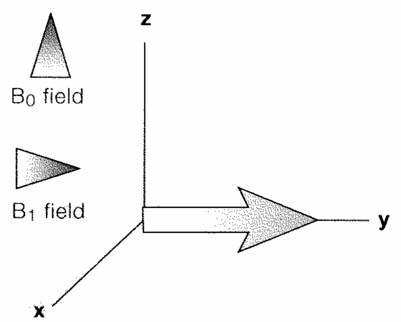
NUCLEAR MAGNETIC RESONANCE, NMR

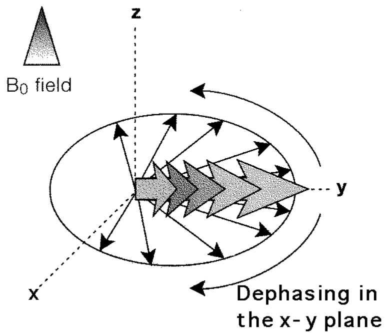
NMR, or Nuclear Magnetic Resonance was first investigated as a petrophysics tool by ‘Turk’ Timur, at Chevron research, in 1954. However, despite good bench-top apparatus, which enclosed the sample in a magnetic field, the inverse problem of the field being enclosed by the sample proved much more difficult to deal with. The earliest down-hole tools were introduced in 1960 and were not really a success, being phased out of service in the 1980’s. However, recent advances in the quality of signal generators and detectors and the use pulse sequences have resulted in a new generation of tools that are, in the 1990s, the most popular in the business.

The NMR Principle

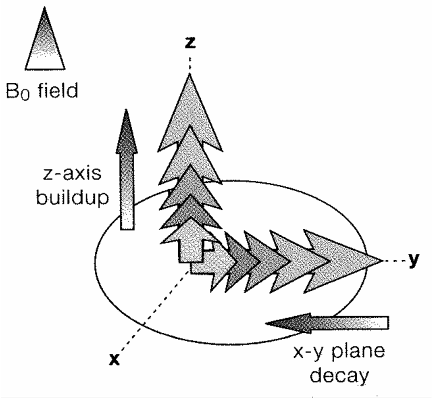
Many nuclei of atoms have a magnetic moment and they behave like miniature spinning magnets in the earth’s magnetic field. Hydrogen, with simply one proton as a nucleus has a relatively large magnetic moment when compared to the other elemental nuclei. Fortunately, hydrogen is abundant in water and hydrocarbon, both fluids. This is important because the atoms in fluids are free to move in comparison with those bonded in solid substances. So, we have these spinning protons all aligned in the earth’s magnetic field. We then create a magnetic field, which is not coincident with that of the earth. The frequency of this signal is the same as the resonant frequency of hydrogen, maximising the response. This field is called B_0 and is perpendicular to the borehole axis. A signal is then applied to tilt the nuclei by 90° into the B_1 direction. The nuclei then precess in this field, acting like gyroscopes in a gravitational field. This is the basis of the NMR measurement as this magnetic moment is detected by the tool antennae. Due to small instabilities in the field, the precessing nuclei begin to dephase, i.e. precess at slightly different frequencies. As they lose their synchronisation the signal generated decays. The decay time is called T_2 and is petrophysically very important

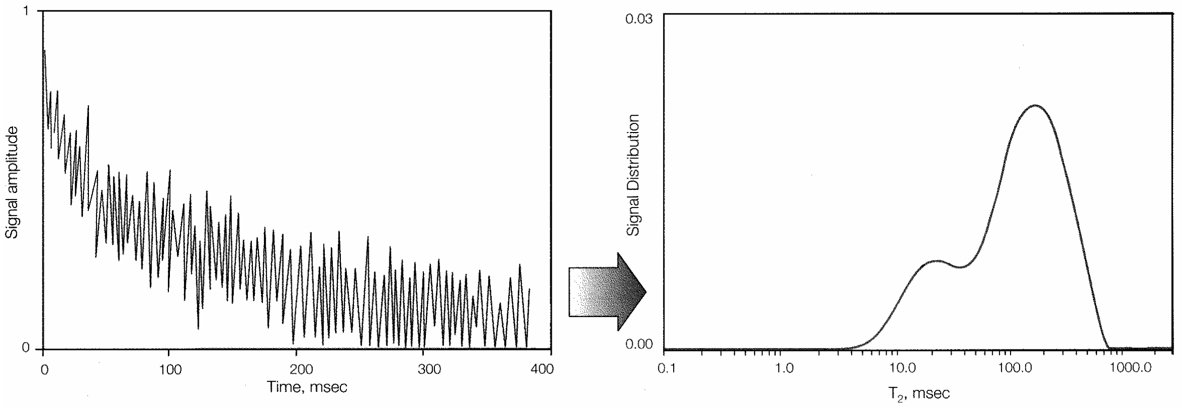




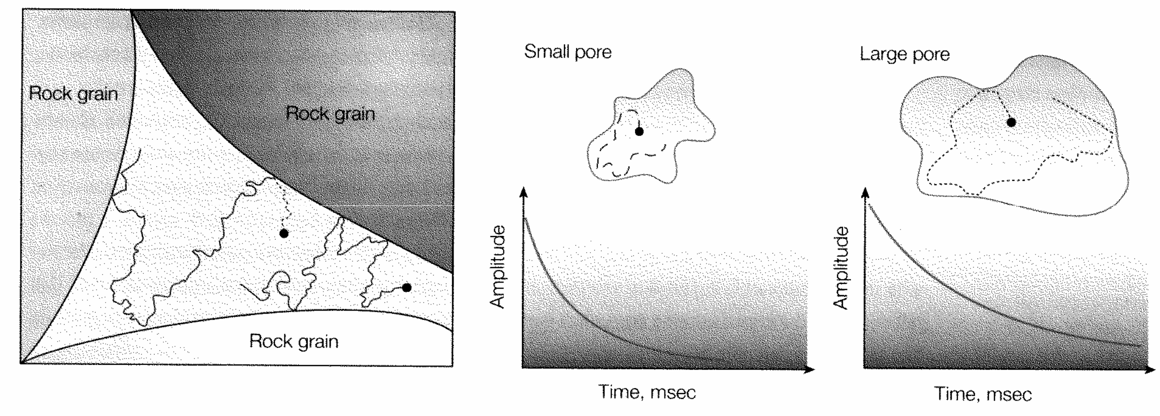


The decay time T_2 actually is dependent on the molecular interactions taking place in the fluid. The precessing protons have a random flight path and, as they move about, they collide with other protons and the grain surfaces within the rock. Individual mineral surfaces have different relaxation properties, but in essence two reactions may occur. Either the spin energy is lost in the collision and the proton realigns with B_0, contributing to the T_1 signal, or the proton is dephased, contributing to the transverse relaxation, T_2 signal. For our work, grain surface relaxation is the primary source of the NMR signal T_1 and T_2.





Signal Amplitude Processed to Give the T_2 Distribution



Grain Surface Relaxation and Pore Size Distribution

As a clear relationship exists between the T2 distribution and the pore-size distribution there are some corollaries with other petrophysical properties.

NMR Permeability

The relationship between pore size distributions and permeability was investigated by Burdine in 1953. Following from his work Purcell and others also related capillary held water saturation to permeability. Kenyon (1988) and Prammer (1994) have proposed models. The latter of these is called the Timur/Coates formula. The formulae are;

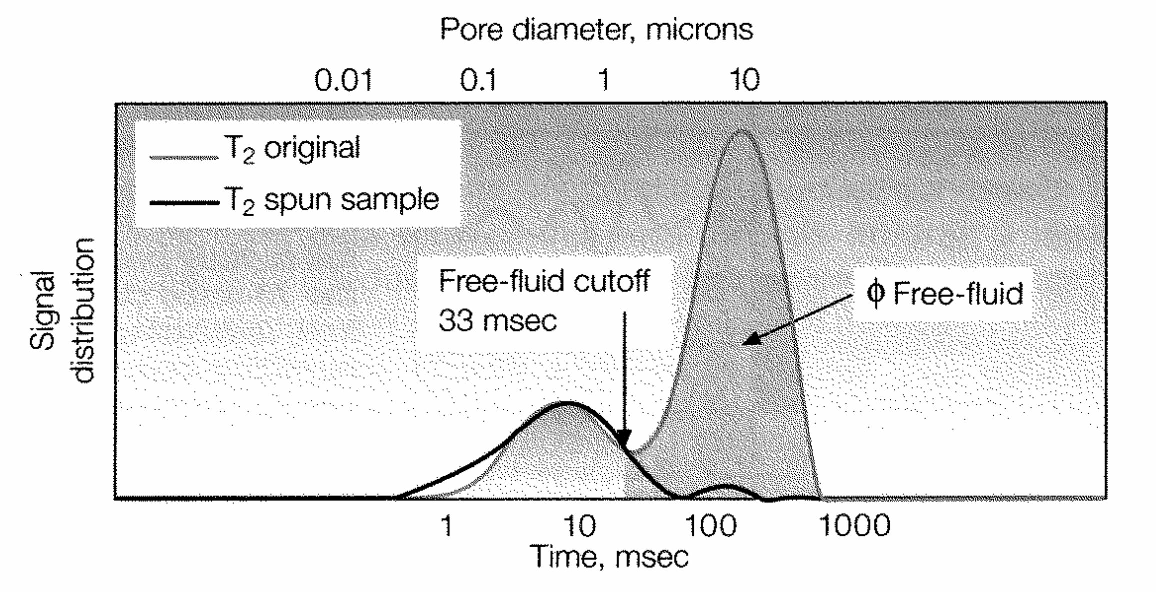
$$k = a\phi^4 (\overline{T}_{2,\log})^2 ,$$ (Kenyon),

where k is the permeability in millidarcies, ϕ is the fractional porosity, a is a formation dependent constant, typically 4 mD/(ms)^2 for Sandstone and 0.4 mD/(ms)^2 for carbonates, and

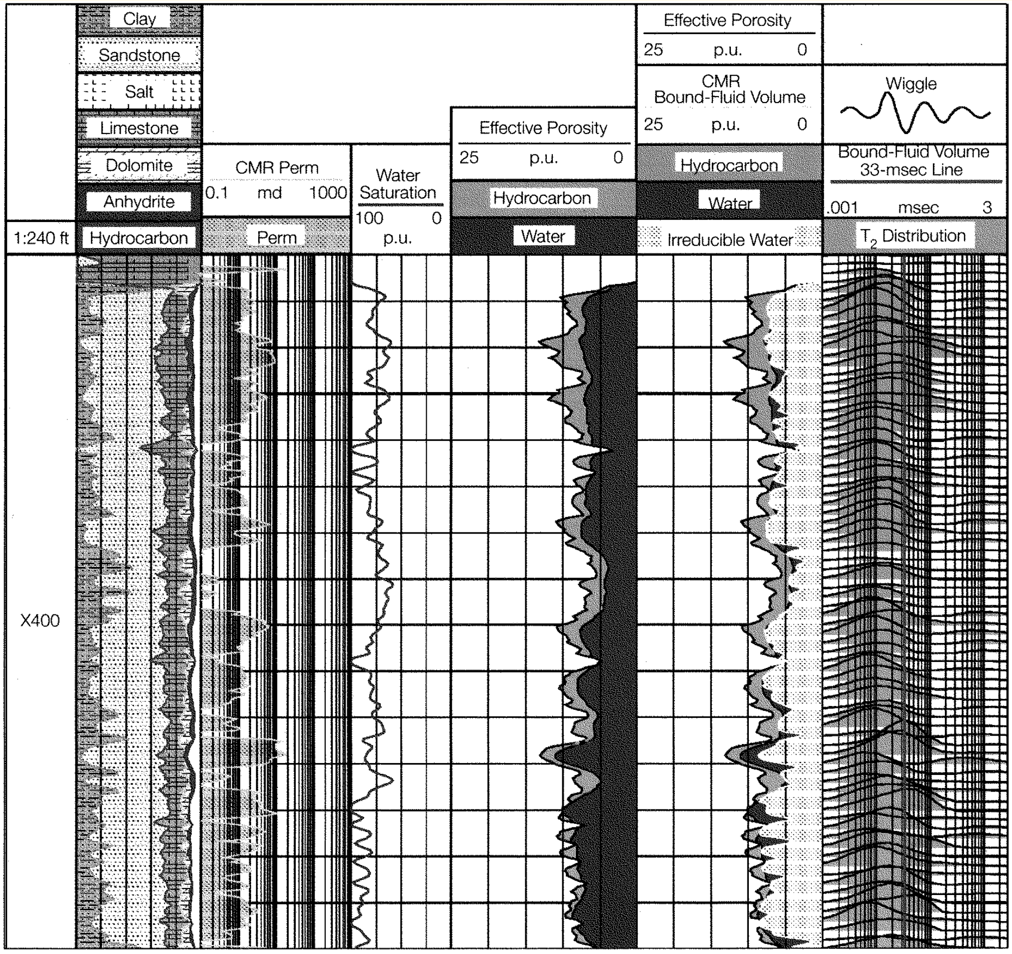
$$k = a'\phi^4 \left(\frac{FFI}{BFV} \right)^2 ,$$ (Timur/Coates')

where FFI is the free fluid index, or moveable fluid volume, and BFV is the bound fluid volume. The term a' is a formation dependent constant about 1 x 10^4 mD for sandstone.

The 'constants' above need to be validated by laboratory measurement. However, once established they can be used within a particular formation with high degrees of confidence.



A Comparison of Core and Log Derived Bound Water T_2 Spectra



An Example NMR Log (Schlumberger) Showing High Sw, Mostly Bound-water

Logging Services

Both Baker Atlas and Schlumberger have NMR tools. With the acquisition of Numar by Haliburton, HLS now also offer the Numar tools. The Numar - Baker Atlas logs are known as MRIL and the Schlumberger the CMR. MRIL looks out to 18 inches or so, with a vertical resolution of 24 inches. The CMR resolves down to 6 inch beds, but depth of investigation is only about 1 inch.

Precautions

- In order to be absolutely confident in the response another porosity log must be run.
- Medium to high viscosity oil appears as bound fluid.
- Wait-times must be increased in fine, poorly-sorted and tight rocks.
- Low Density shales, coals and tar-mats cause erroneously high free-fluid and permeability.

Chapter 2

Section 4

Resistivity and Saturation Logs

STUDY GUIDE QUESTIONS ON
CONVENTIONAL ELECTRIC (ES) LOGS

1) What is the principle of the conventional electric log?

2) Can this tool be run with any fluid in the borehole?

3) What are the typical spacings for the two normal devices? And for the lateral device?

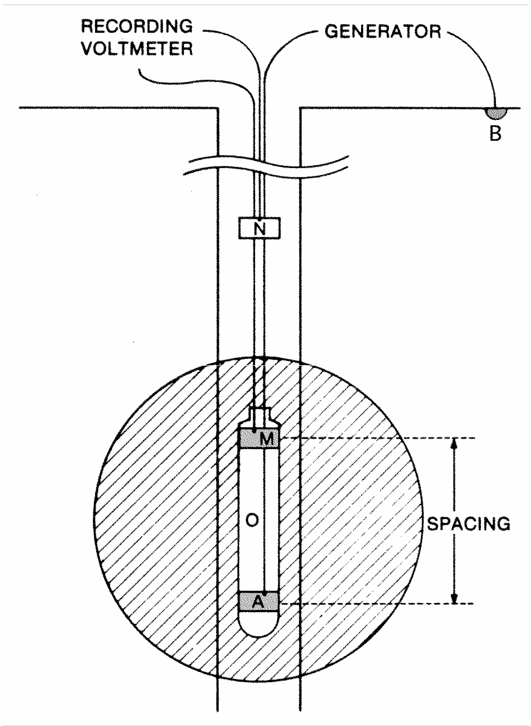
4) What is the depth of investigation for each tool?

5) Are both curves symmetrical about the bed's centre?

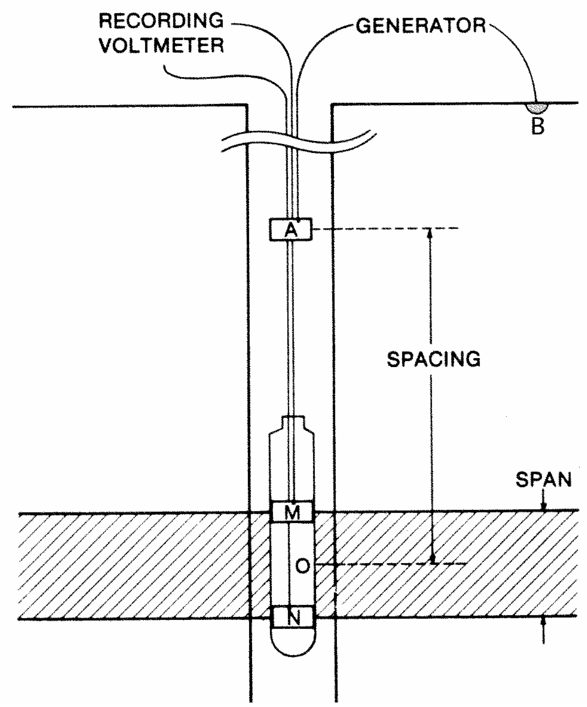
6) For a normal log, what is the true bed's thickness in a thick resistive zone? Thin resistive zone? Conductive zone?

7) Where is maximum resistivity to be read on a normal curve? Lateral curve?

8) What are three uses of the normal curve?



The Normal Electric Tool Schematic



The Lateral Electric Tool Schematic

OLD CONVENTIONAL ELECTRIC LOGS

INTRODUCTION

In 1927, two French brothers introduced a new logging method called "electric coring". Their three-electrode device, which measure resistivity at closely spaced intervals in the well, was tested the next four years in Venezuela, Russia, Rumania, and Oklahoma. During this time, the natural spontaneous potential was discovered and the SP tool created. Electric logging boomed and made its entrance into California in 1932 and the Gulf Coast in 1933.

In the 1950's, these electric survey (ES) logs started to become obsolete in the West, however, there are thousands of these electric logs still in old files and they were used successfully in the former Soviet Block. Accurate interpretation from these logs is often difficult, but relatively good estimates of resistivity can be made. Newer logs are easier to read and can detect thin beds more easily. The induction log, introduced in the 50's, utilised one or more of these conventional electric logs as a shallow investigation device. For these reasons, a short discussion on conventional electric logs is warranted.

RESISTIVITY LOGGING DEVICES

The basic principle of a conventional electric log is that a current is passed through a formation via some electrodes and the voltage between other electrodes is measured. From this reading, resistivity is determined. The conventional electric log can only be run in a conductive mud (i.e. not oil or air-filled holes).

Normal Device

A surface electrode (B) passes a constant current to an electrode (A), downhole on the tool (Figure 1). The potential difference is measured between another electrode (M) on the tool and one at the surface (N). The spacing of a short normal is usually 16 inches and the long normal is 64 inches. The normal log works best in soft sediments and can sense about twice its spacing into the formation. The short normal typically senses only the flushed zone.

Lateral Device

A constant current is passed from a surface electrode (B) to one on the cable (A) (Figure 2). On the tool are two potential electrodes (M and N). Here the spacing is defined as the distance between the electrode on the cable (A) and the midpoint between the two potential electrodes (0). This distance is usually 18' 8". The best interpretation using this tool is in thick, homogeneous sediments. It runs approximately a three foot average on the resistivity and has a depth of investigation around 19'.

FACTORS AFFECTING MEASUREMENT

Many factors affect the reading of a conventional electric log. The equation and relationships are most correct in homogeneous, uniform material. Since the material surrounding the electrode system is not uniform, the logs read only an apparent resistivity. Other factors which affect the log readings are:

1) Hole diameter - d
2) Mud resistivity - R_m
3) Bed thickness
4) Resistivity of surrounding bed - R_s
5) Resistivity of invaded zone - R_i
6) True resistivity of zone - R_t
7) Diameter of invaded zone - d_i

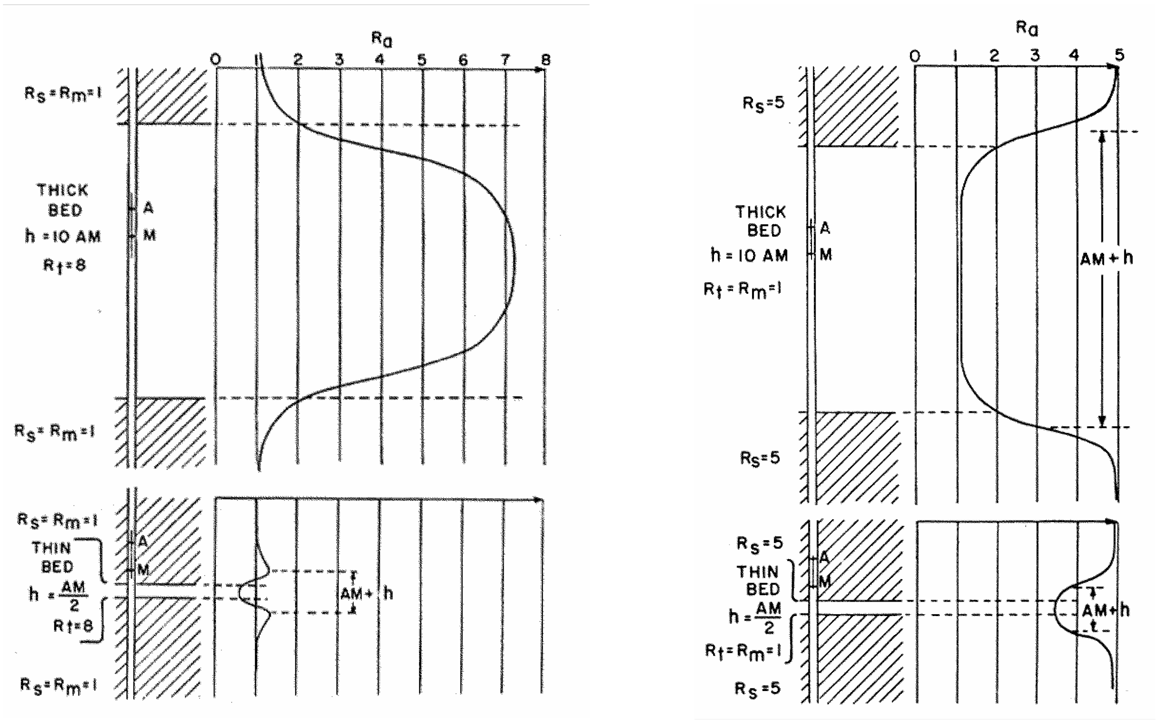
Conventional Electric Log Presentation

The log is presented starting with the third track. The scale is linear and often goes from 0-10 and then 0-100. The units for resistivity are Ω - m^2/m or ohm-meter (Ω - m). Typically speaking, the deep dashed line, if present, is the deepest reading curve. Sometimes there is an expanded scale for the short normal. This is used to help pick bed boundaries.

Normal Device Responses

Since the short normal was often used in conjunction with the induction log, a short discussion on its responses is needed. The short normal is used for correlation, defining bed boundaries, and recording resistivity at a shallow depth of investigation, near a borehole.

In a resistive bed thicker than the spacing, the curve is symmetrical with the maximum resistivity at the centre of the bed (upper-left Figure, below). The actual bed thickness is equal to the apparent thickness plus the spacing distance. If the resistive beds are thinner, then the symmetrical curve reverses forming peaks at each end of the bed (lower-left Figure, below). The bed's thickness is the distance between the peaks minus the spacing length.

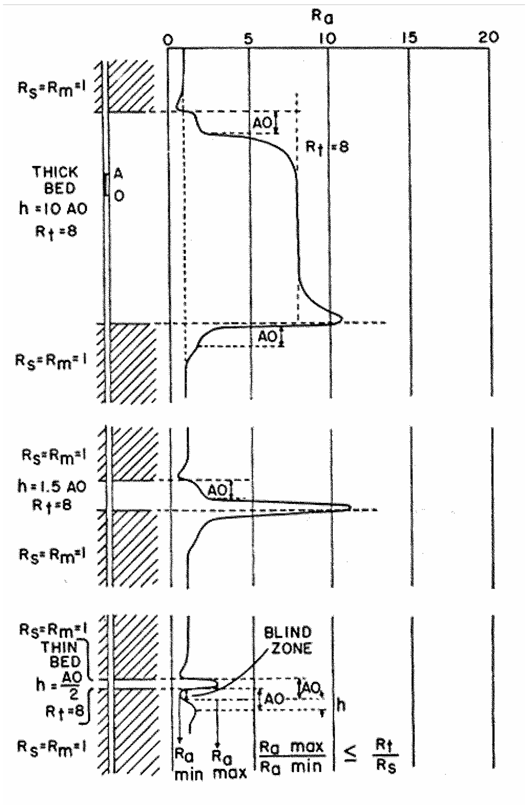


Normal Log Responses in Both Resistive (Left) and Conductive (Right) Beds

In a conductive (thick or thin) zone, the curves are symmetrical with no reversals. The bed thickness is equal to the apparent bed thickness minus the spacing.

Supplementary Notes

Lateral Device Responses



Reading the lateral curve takes experience. Since the log has become completely obsolete, a discussion on the lateral log responses will not be presented. By viewing the Figure opposite, one can see how the curve is not symmetrical about the bed centre and no sharp changes at bed boundaries. The curve is distorted by adjacent beds and thin beds. To read the apparent resistivity (R_a) the reading should be taken near the bottom of the curve. The truest reading of resistivity is achieved if the formation is at least forty feet thick.

Lateral Log responses in Resistive Beds

If quantitative work is to be done using the readings from any of these conventional electric logs, corrections for borehole and bed thickness effects must be made. These corrections can be made on charts available in the logging company manuals.

Supplementary Notes

SUMMARY OF CONVENTIONAL ELECTRIC LOGS

- Basically, the principle of the conventional electric log is: A current is generated between two electrodes and the potential difference between two others is measured. This potential difference can be related to the resistivity of the surrounding material. The change in the potential difference, (resistivity), is plotted versus depth. A well is logged starting from the deepest point first.

- There must be conductive fluid in the borehole for the tool to function properly. So this tool does not work in oil or air-filled holes.

- The spacings for the two normal devices typically are 16" and 64". The lateral device typically has an 18' 8" spacing.

- The normal device can see about twice its spacing into the formation. The lateral device has a depth of investigation close to 19'. It averages about 3' of formation resistivity.

- The normal curves are symmetrical about the bed centre, but the lateral curves are asymmetrical.

- Reading from normal log, a thick, resistive bed's thickness is the apparent thickness plus the spacing. In a thin, resistive bed, the curve is reversed and two horns or peaks appear. Subtract the spacing length from the distance between the two peaks and the result will be the true bed thickness. In a conductive zone with thin or thick beds, subtracting the spacing length from the apparent bed thickness summary of conventional Electric Logs will yield the true bed thickness.

- The maximum resistivity is located at the bed centre of a normal curve and near the bottom of a lateral curve.

- The normal curve is used in correlations from well to well, locating bed boundaries, and for measuring the resistivity near the borehole.

STUDY GUIDE QUESTIONS ON THE FOCUSED CURRENT ELECTRIC LOGS

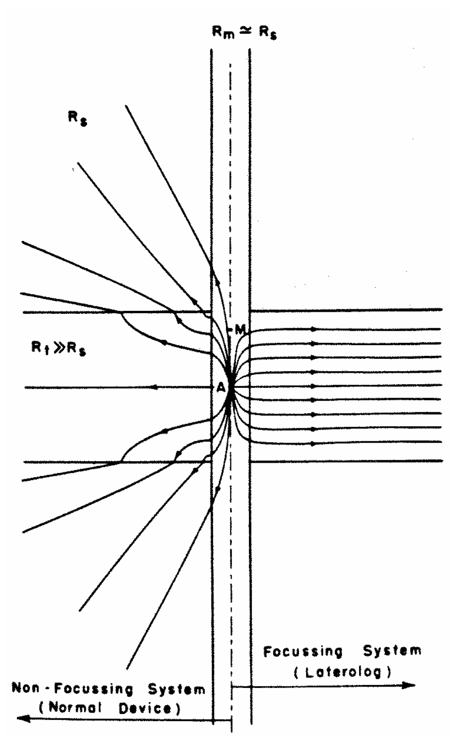
1) Different companies have different names for the logs they develop. Name five major focused logs and how far into the formation they see (i.e. shallow, medium, deep?).

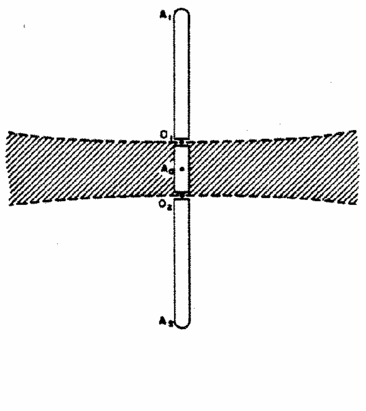
2) What is the advantage of the DLL over LL7 or LL3?

3) What type of scale are the logs now typically plotted upon? Why is this advantageous?

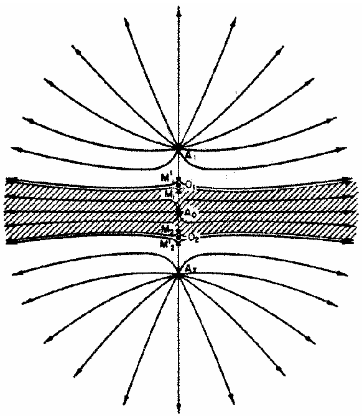
4) What are the optimum conditions for a focused current log to give the best resistivity reading?

Focused and Non-focused Current Flow Compared

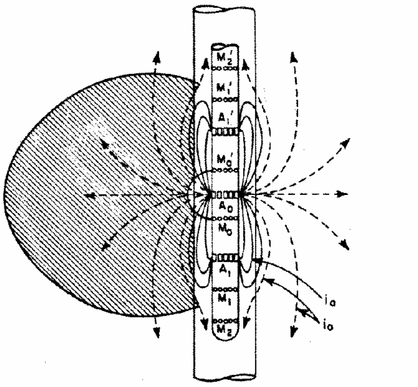




Laterolog 3



Laterolog 7



Spherically Focused Log

FOCUSED CURRENT ELECTRIC LOGS

INTRODUCTION

The conventional electric log allows the current to seek the paths of least resistance. The tool works best in conductive formations for it will lose current into the mud column in the presence of resistive formations. Consequently, conventional electric logs do not work well in salty muds or in highly resistive formations such as tight carbonates.

Focused current electric logs, developed in the early 1950's, focus the emitted current into a thin lateral sheet which minimises adjacent bed and borehole effects. This allows a truer resistivity to be measured in thin beds, when a conductive mud is present, and in highly resistive formations.

TYPES OF DEVICES

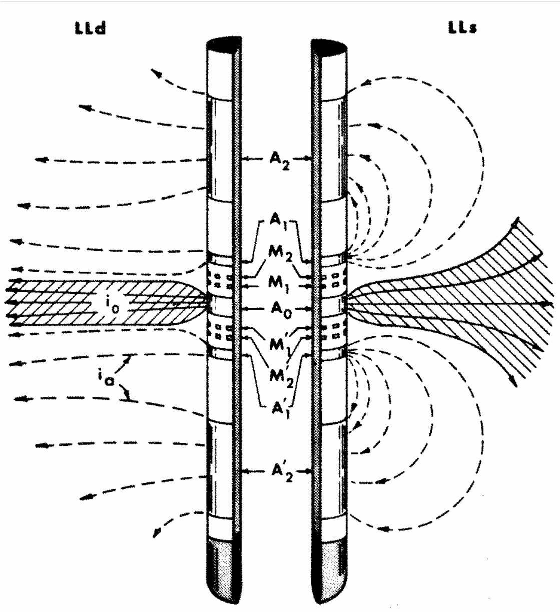
Schlumberger developed two deep reading logs, the Laterolog 7 (LL7) and the Laterolog 3 (LL3). (HLS had a Guard Log similar to LL3 and Atlas had a Laterolog with two designs, multi-electrode and guard.) In the design of the LL7, a constant current is passed through a central electrode. Three pairs of electrodes prevent the current from flowing up or down the mud column and focus a 32 inch sheet of current into the formation. As the tool is pulled up the borehole, a change in potential is measured between the electrode on the tool and one at the surface; the measured resistivity is proportional to this change in potential.

LL3 design is slightly different, but it's principal is the same. It too uses bucking electrodes to focus the current into the formation; it focuses a 12 inch sheet. Consequently, it gives better vertical resolution than the LL7 and is less influenced by the borehole or adjacent beds.

Other logs include the Laterolog 8 (LL8), the Spherically Focused Log (SFLU) and the Dual Laterolog (DLL). The LL8 is designed like LL7, but it only measures a short distance into the formation. It focuses a 14 inch sheet which gives very sharp detail, but the readings are more influenced by the borehole and flushed zone. This tool is typically run with the Dual Induction Log.

Another tool typically run with the Dual Induction Log is the Spherically Focused Log (SFL). It is found most often on the ISF/Sonic combination. It too reads only into the flushed zone. The SFL focuses the current into a spherical shape. Because of this design, it is unaffected vertically by the borehole.

The Dual Laterolog (DLL) was originally developed to give two resistivity readings, one deep (LLd) and one shallow (LLs). These two readings help indicate the invasion profile and allow a more accurate resistivity to be determined. The LLd is designed to read deeper than the LL7 and the LLs reads in between the LL7 and LL8. The current beam for both the LLd and LLs is 24 inches. Often accompanying the Dual Laterolog is the MSFL, SFL or LL8 which provides a better picture of the invasion profile.



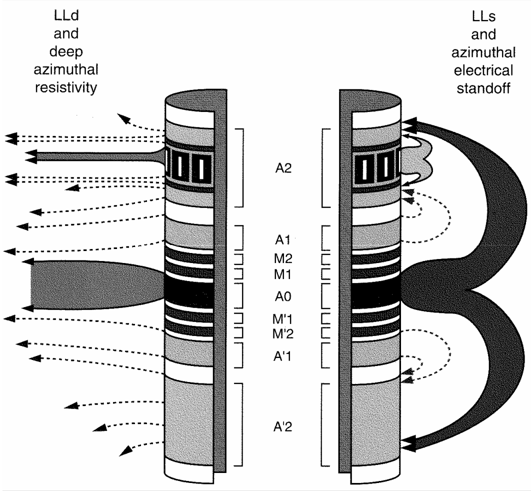
The DLL, Dual Laterolog

ARI

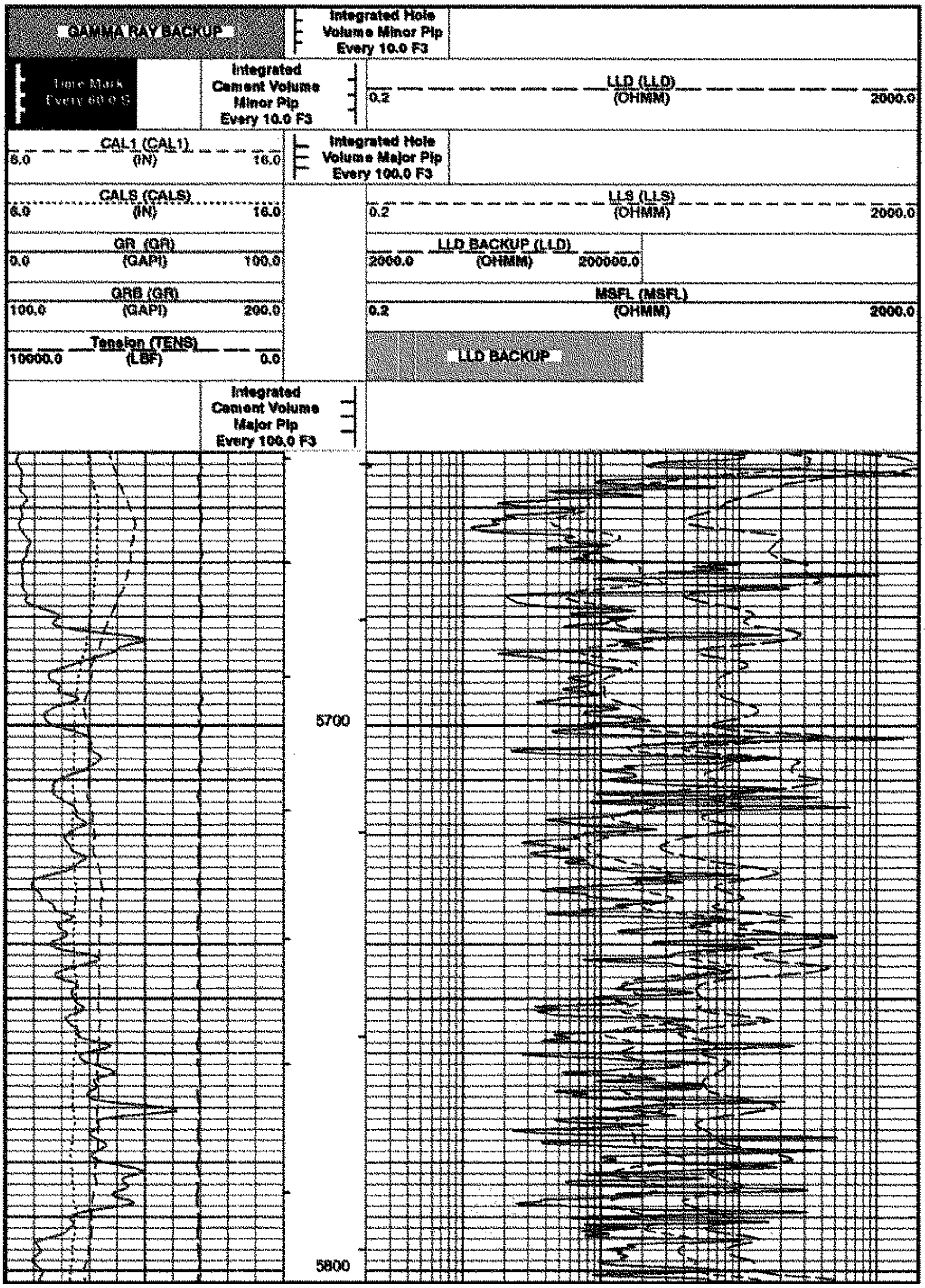
The Azimuthal Resistivity Imager is a new tool (1992) which was developed to accomplish two main goals:

In horizontal wellbores the tool was designed to achieve oriented estimates of Rt in Pseudo-LL3 mode, with an 8 inch vertical resolution.

In Delta-R mode the tool can image resistivity contrasts in the near-wellbore and bore-hole environment.



The device consists of twelve. lateral electrodes arrayed azimuthally around the tool and the relevant focusing electrodes. Borehole effects are compensated for using the shallow investigation readings to determine the stand-off of the device in a horizontal wellbore. Tool eccentricity can be seen in the results. Some data show that the depth of investigation of the ARI can be as deep as the LLd. Thin beds and fractures may also be analysed using output from the ARI.

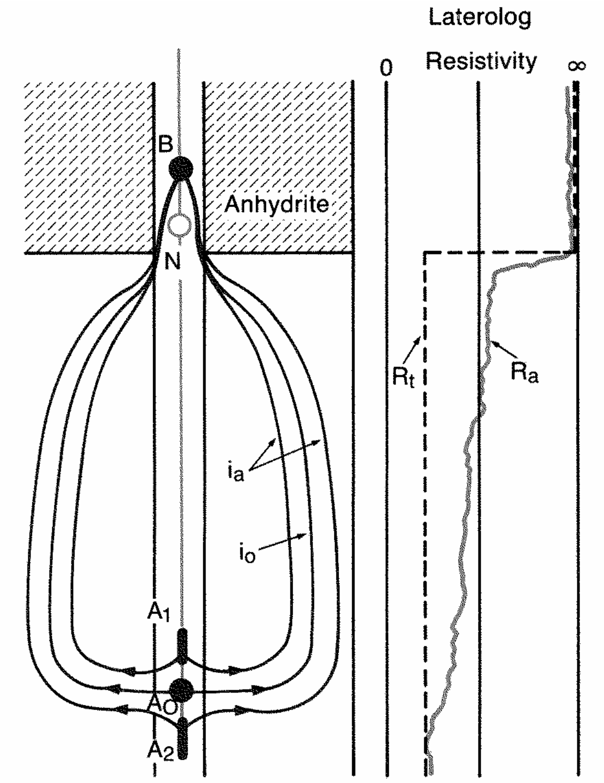


DLL-MSFL In a Salty Mud, Showing Clear Invasion Profile

SCALES

Originally linear scales were used for the laterologs. With the advent of the Dual Induction tool, a logarithmic scale was used and this has now been adopted for the laterologs and SFLU. The logarithmic scale allows for more detailed quantitative work in the low resistivity range plus it allows a quick-look evaluation of a zone.

ENVIRONMENTAL FACTORS AFFECTING THE LATEROLOGS



Each laterolog is affected differently by the borehole mud, the invaded zone, and adjacent beds. Consequently, there are correction charts for these effects depending upon what tool is used. There is a “Delaware Effect” seen in laterologs when a zone is overlain by a thick non-conductive bed, i.e., anhydrite or salt. This is similar to the “Groningen Effect” In the “Delaware Effect”, if the B and N electrodes are carried on a bridle down hole the current is forced into the borehole by a thick highly resistive/non-conductive bed, such as salt or anhydrite. The result is a gradual increase in apparent resistivity as the N electrode cannot remain at zero, but becomes more negative. In the Groningen effect this occurs even with the electrodes at the surface as the current returning in the mud is also shorted to surface in the casing string set above the zones of interest. This results in an even larger negative potential in the N electrode.

OPTIMUM CONDITIONS

The laterologs work best in muds of low resistivity (i.e., salty). It gives its truest resistivity (Ra ≈ Rt) when the invasion is shallow. Highly resistive muds adversely affect the laterolog. When the bed is thicker than the current sheet, the adjacent beds do not affect the reading. For instance, a minimum of one foot of thickness is required for the LL3. The LL7 requires approximately five feet to be unaffected by the adjacent beds.

The LL3 gives better vertical resolution than the LL7, but is more greatly affected by the invaded zone. For deeper investigation (i.e., truer Rt), but not as sharp vertical resolution, the LL7 can be utilised. For a clear invasion profile and to determine an accurate Rt, the Dual Laterolog should be used. It is useful in high resistivity contrasts, and in low resistivity drilling muds. Vertical resolution is about two feet.

So, focusing electrodes confine the current into a sheet which allows good vertical resolution of the beds. It also minimises the effects of conductive borehole fluids and adjacent beds. The truest resistivity is read in the uninvaded zone (LL7, LL3, LLd) when Rmf < Rw, invasion is not deep, the borehole not severely washed out, and the bed is thicker than the sheet of current. The laterologs should be considered when the following conditions exist:

1) Rmf / Rw < 4
2) Rxo < Rt
3) Rt / Rxo < 50

Supplementary Notes

SUMMARY SHEET ON FOCUSED CURRENT ELECTRIC LOGS

The Five Major tools were:

1)	Laterolog 7 (LL7)	-	3 pairs of guard electrodes (and one central electrode) focus a 32 inch sheet of current looking deep into the formation (Ra ≈ Rt)
2) better the	Laterolog 3 (LL3)	-	1 pair of guard electrodes focuses the current into a 12 inch sheet and reads deep into the formation. It gives better vertical resolution than LL7 and is less influenced by borehole or adjacent beds. However, the invaded zone does affect the resistivity reading more than it does with the LL7.
3)	Laterolog 8 (LL8)	-	Similar design to LL7, but instead focuses a 14 inch sheet of currents which allows for very sharp detail and good vertical resolution of beds. It has only a shallow depth of investigation.
4)	Spherically Focused Log (SFL)	-	A current focused into a spherical shape that is virtually unaffected by the borehole conditions. It has a shallow depth of investigation.
5)	The Dual Laterolog (DLL)	-	Gives two resistivity readings: LLd, which reads deeper than LL7, and LLs, which reads between LL7 and LL8. Often it is accompanied by LL8 or SFL. It then can give a profile of the invasion and allow a quick estimate on how badly flushed the formation is. A better Rt can then be derived.

The logs now use a logarithmic scale. This helps in accurately reading zones of high resistivity contrasts and also helps more in accurately quantifying low resistivity pay zones. The laterologs where basically designed for salty muds because the older tools would lose part of the current up and down the borehole. The laterologs work best when the mud filtrate is saltier than the formation water (Rmf < Rw), invasion is not deep, the bed is thicker than the sheet of current, and the borehole is not severely washed out.

STUDY GUIDE QUESTIONS ON
CONTACT LOGS

1) Name the two basic types of contact logs.

2) Where are the electrodes found?

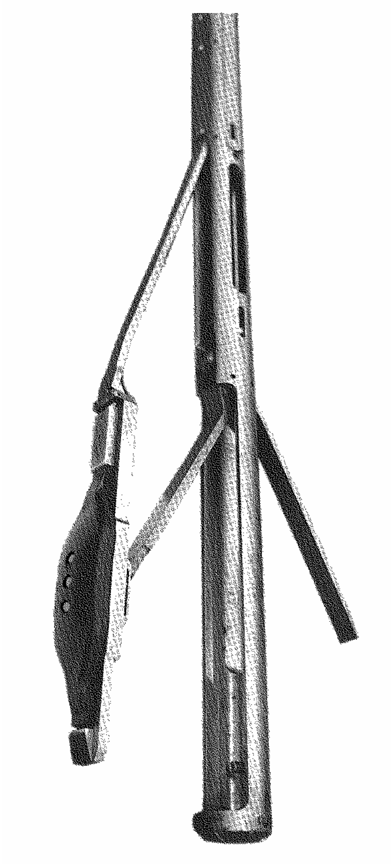
3) What is the depth of investigation for the contact logs (shallow, medium, deep)?

4) Does the microlog work well in conductive mud and hard formations?

5) How does the microlaterolog differ from the microlog? What is its mudcake limitation?

6) What is the advantage of the proximity log over the microlaterolog?

7) What is the advantage of the MSFL over the other types of contact logs?

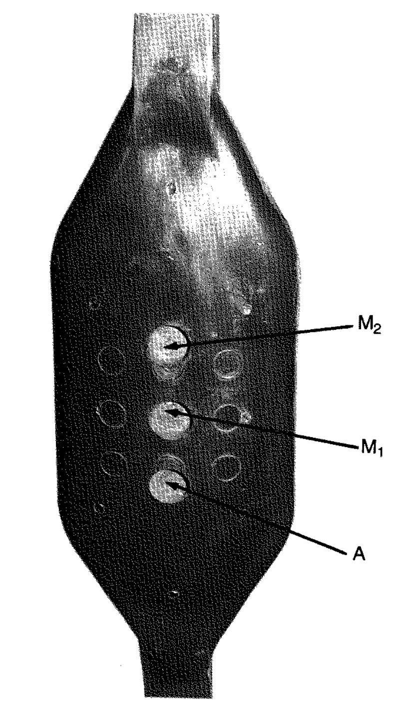


A Typical Contact Logging Tool:

Atlas' Minilog

Minilog Pad Electrode

Arrangement



CONTACT LOGS

Contact Logs are pad devices which have very short spaced electrodes in a pad which is pressed up against the borehole wall. Just as with the ES logs, there are two types of contact logs, non-focused and focused. The non-focused contact log was first developed to establish porosity data in the flushed zone, but because it was not focused, the accuracy of the measurement was questionable. The focused contact log gives a better determination of porosity, more detailed bed definition, and a more reliable Rxo reading than the non-focused. Some of the non-focused logs are still run, therefore, a discussion on both types follows.

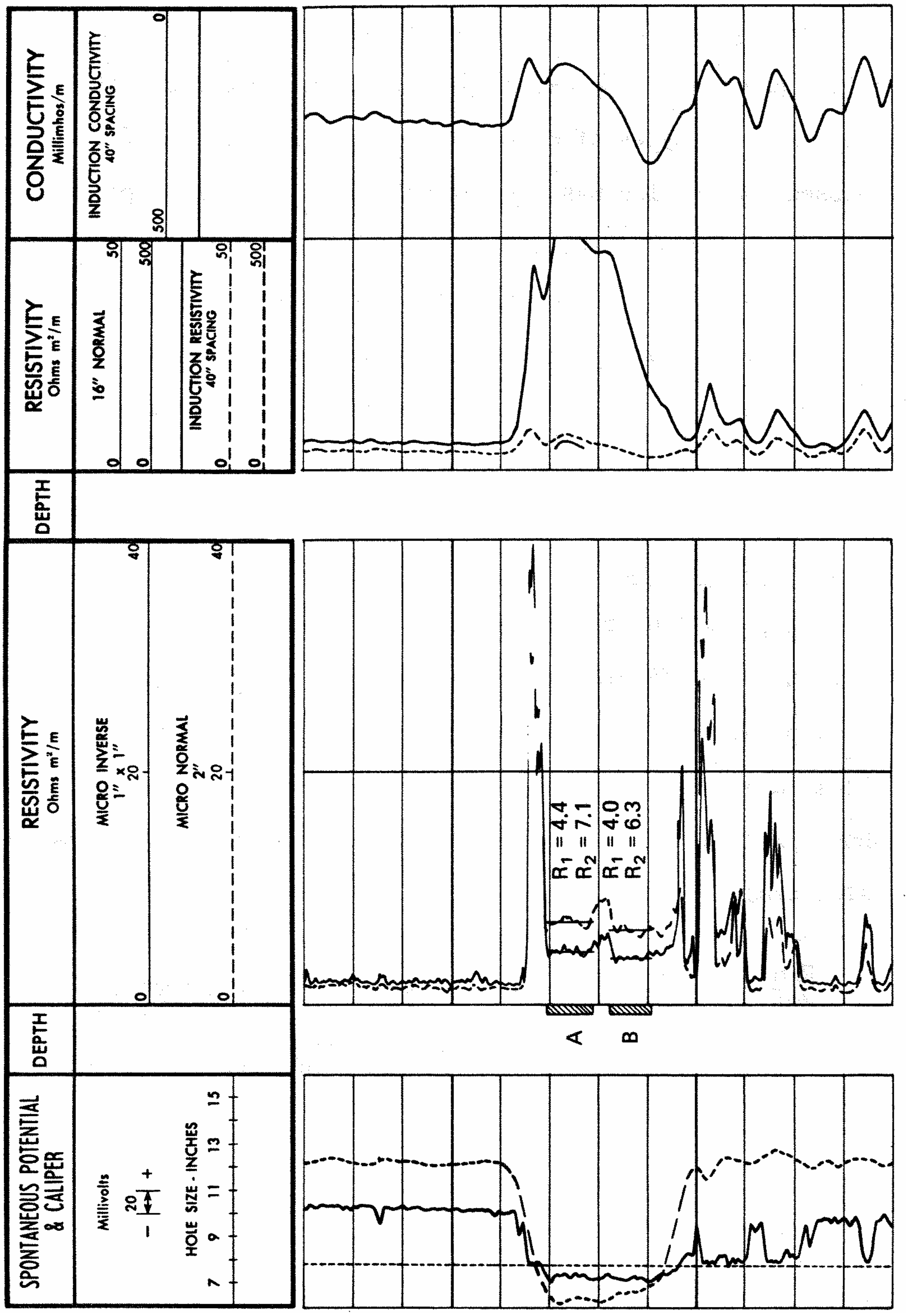
NON-FOCUSED CONTACT LOGS

These logs fall under different names depending upon the logging company, i.e., microlog (Schlumberger), minilog (Atlas) and contact log (Haliburton, HLS). Their purpose is to read the resistivity in the flushed zone (Rxo), obtain a detailed bed definition and show where zones of permeability exist from mud-cake build-up. If Rxo could be determined, Rmf was known, and the Archie or Humble relationship assumed, porosity could be calculated.

$$\frac{Rxo}{Rmf} = F = \frac{a}{\phi^m} \qquad (1)$$

F = Formation Factor
Rxo = Resistivity of the flushed zone
Rmf = Resistivity of the mud filtrate
ϕ = Porosity, fraction

This can only work, however, if Rxo represents a zone saturated with 100% mud filtrate. In a hydrocarbon bearing zone, residual saturations result in an error in computed porosity. Under these circumstances a full inversion of the Archie equation with Sor or Sgr accounted for can be used.



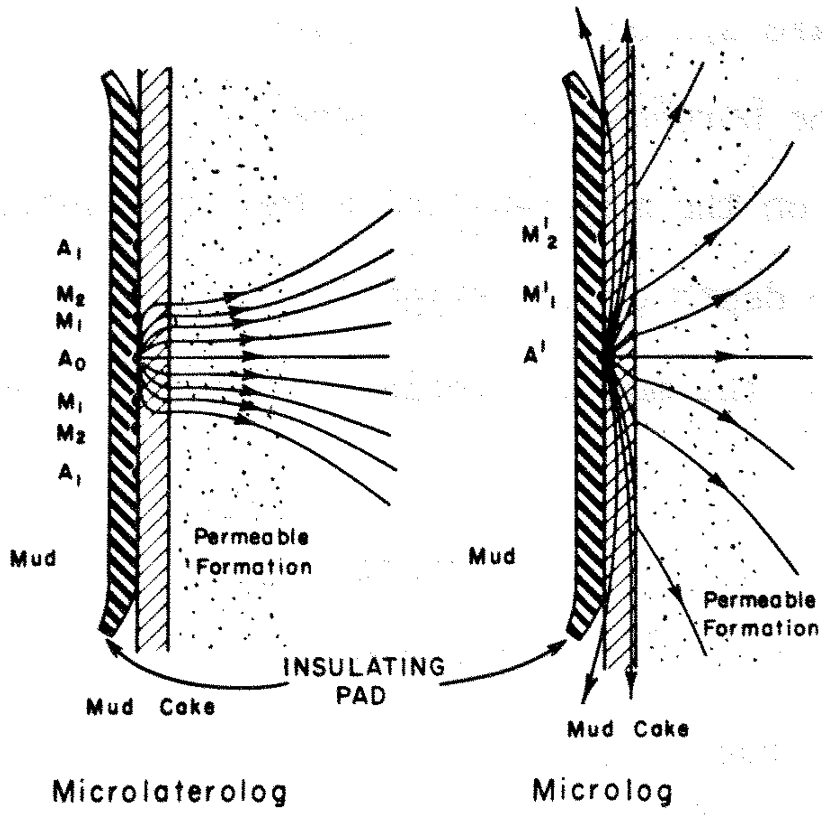
Minilog Example

MICROLOG (MINILOG, ETC.)

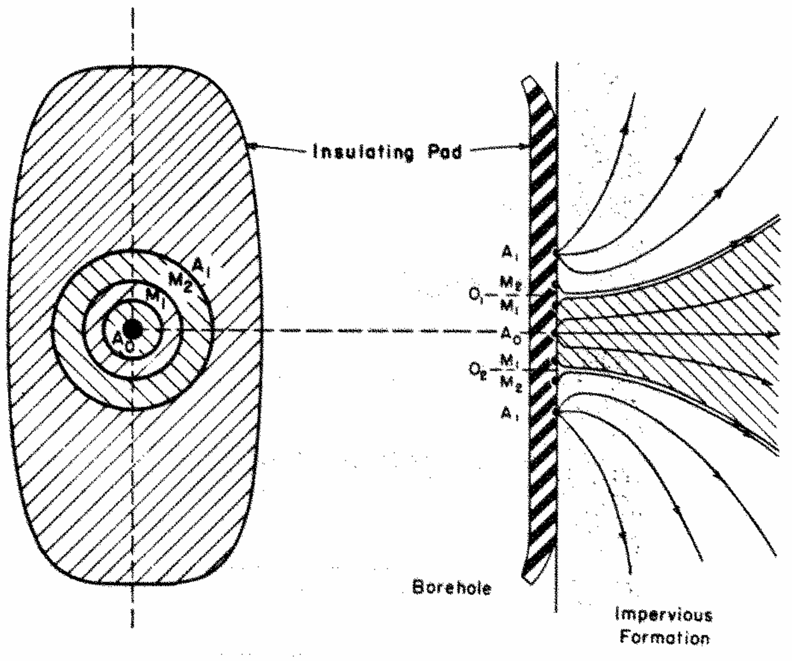
Three electrodes are spaced one inch apart in a rubber pad which is pressed against the borehole wall. A one inch spaced micro-inverse (11/2 inch on the minilog) and a two-inch spaced micro-normal are recorded. The depth of investigation is shallow (4 inches) and is greatly affected by the mudcake resistivity and flushed zone resistivity.

Other factors which affect the resistivity are: not enough or excessive mudcake thickness, too shallow invasion, presence of residual oil in the flushed zone, or a rugose borehole which does not allow the pad to conform to the wall of the borehole. Charts are available to correct these conditions to yield an approximate Rxo. The non-focused contact logs work best if porosity is greater than 15%, mudcake thickness is 1/2 inch or less, and fresh mud is in the borehole.

The log is presented on a linear scale. The one-inch spaced log (micro-inverse) is represented by a solid line and the two-inch spaced log (micro-normal) is recorded as a dotted line. The two-inch spaced log reads deeper than the one-inch so it is less influenced by the mudcake. When the two readings separate, it indicates a mudcake has built-up and therefore a permeable formation is present.



Current Paths in Focused and Non-focused Contact Logs



Microlaterolog Electrode Array and Current Sheet

FOCUSED CONTACT LOGS

Focused contact logs were developed to overcome many of the borehole or formation conditions which affected the non-focused contact logs. The focusing allows the log to be used effectively in conductive muds and hare (low porosity) formations. It yields better bed resolution, a more reliable Rxo, and therefore better porosity. The trade names vary with the company, Microlaterolog, and Proximity Log (Schlumberger, Atlas), FoRxo (HLS), and MSFL (Schlumberger).

MICROLATEROLOG

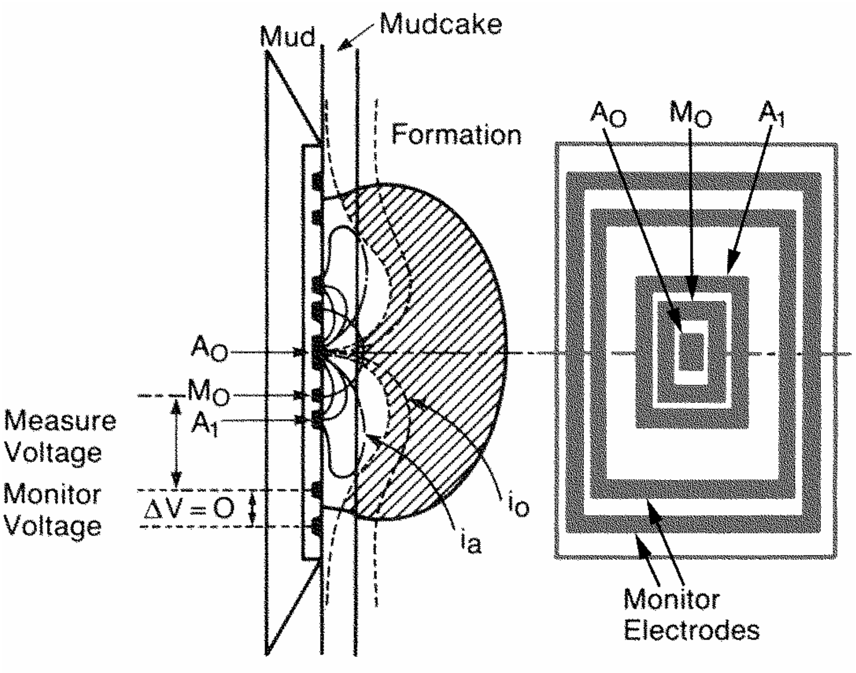
The design and principle is like a laterolog but miniaturised. Guard electrodes focus the current into a narrow beam. The spacing is similar to the microlog; consequently, the depth of investigation is only about three inches. The focusing, however, keeps the current from flowing up the mudcake in areas where the resistivity of the flushed zone is greater than the resistivity of the mudcake (Rxo > Rmc). The microlaterolog is typically used when the resistivity of the flushed zone is very high (Rxo / Rmc > 15)) and the mudcake is less than 3/8 inches thick. The microlaterolog is printed on a logarithmic scale.

PROXIMITY LOG

The tool design is slightly different, but the principle is similar to that of the microlaterolog. It looks a little deeper into the formation (4-6 inches) and is less affected by the mudcake. A mudcake thickness of 3/8 inch or greater affects the microlaterolog: however, a mudcake thickness up to 3/4 inch has very little affect on the proximity log. The one drawback is that to determine Rxo from the proximity log, adequate invasion (40") is required. If di is less than 40", corrections via charts must be made. The proximity log is printed on a logarithmic scale.

MICRO-SFL (MSFL)

The Microspherically Focused Log is a miniaturised version of the SFL. The MSFL reads shallower than the SFL, but does not require the depth of invasion that the proximity log does. Also, due to the type of focusing, the response is not greatly affected by the mudcake thickness. It can tolerate a mudcake thickness of 3/4 inch with little effect. An advantage over all contact logs is that a separate logging run is not required. This tool, the MSFL, can be attached to the Compensated Formation Density Log or the Dual Laterolog.



MSFL, Microspherically Focused Log Electrode Array and Current Sheet

SUMMARY SHEET ON THE CONTACT LOGS

- The two basic types of contact logs are focused and non-focused.

- It is a pad device with the electrodes found in the pad. Their spacing is very short.

- The contact logs see only a few inches into the formation so they read an Rxo.

- The microlaterolog has a similar design as the laterolog, but the spacing is very short. Consequently its depth of investigation is only a few inches. The current is focused into the formation and therefore overcomes the effects of conductive muds and resistive formations if the mudcake stays less than 3/8 inch thick.

- The proximity log looks deeper into the formation than does the microlaterolog. The proximity log is not influenced if the mudcake is less than 3/4 inch thick.

- The MICROSFL is a miniaturised version of the SFL. It does not require the depth of invasion that the proximity log requires in order to allow a good resistivity reading in the flushed zone. It can, however, tolerate a mudcake up to 3/4 inch thick. Its main advantage over the other contact logs is that the MSFL can be attached to the Density tool or Dual Laterolog. The other contact logs require a separate run.

STUDY GUIDE QUESTIONS ON THE INDUCTION LOG

1) Why was the induction log invented? Is it a focusing tool?

2) Name three types of induction logs and on what type of scale they are printed.

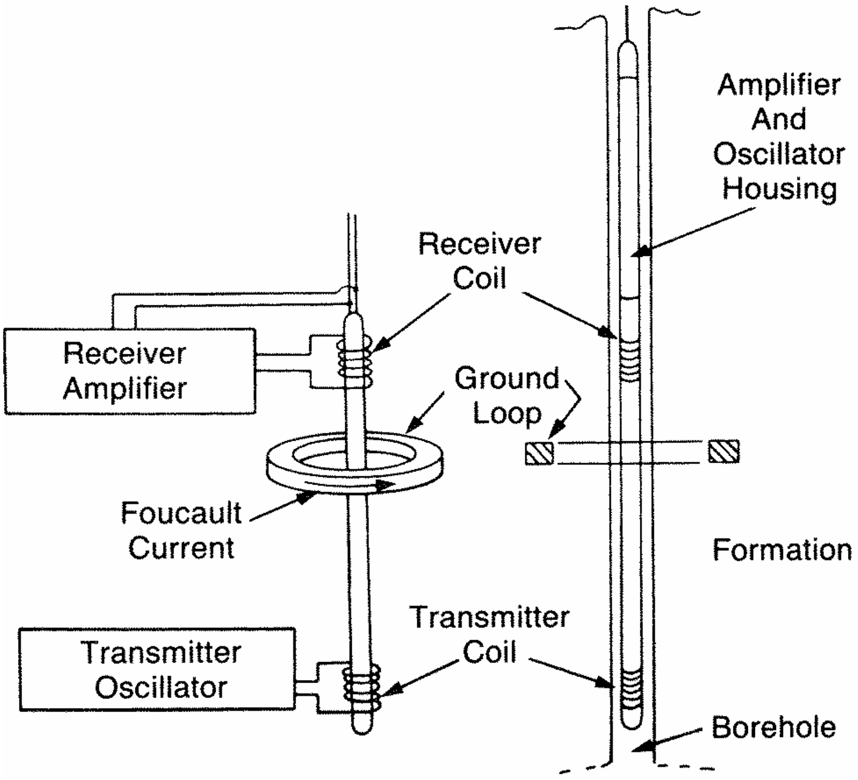
3) Does bed thickness affect the log response? Explain.

4) In terms of effects from invasion, what condition limits best apply to the induction log?

5) A more accurate resistivity value is determined how when reading below what resistivity value?

6) Identify the upper ohm-m limit in which the induction log should operate. Why?

7) Does the induction log work well in all types of fluid? Where does it work best? Explain.



Induction Log Principles of Operation -

Simple Two Coil System

INTRODUCTION

In the early years of electric logging, an electrically conductive fluid in the borehole was needed to transmit the electrical currents to and from the formation. As the use of non-conductive drilling fluid (oil-based mud, air, etc.) increased, a new logging technique to measure resistivity was required. In 1946, induction logging was introduced.

As stated, it was developed to measure formation resistivity. A conductive fluid is not required in the borehole because the current is induced, not forced to flow from the tool. The current is also focused which minimises the effects that the borehole, the invaded zone, and surrounding formation may have on the log's response.

INDUCTION LOG PRINCIPLES

The induction tool has several transmitter and receiver coils which are wound coaxially on a supporting insulated sonde. The distance between coils (the spacing) is typically from 28-40 inches. The transmitter creates an alternating current of constant intensity and high frequency which induces eddy currents into the formation. These currents create their own magnetic field which induces a current back in the receiver that is proportional to the formation conductivity.

The tool performs well in oil-base mud or air-filled holes; i.e., non-conductive fluids. It will work in moderately conductive mud, as long as the fluid does not become too salty, the formation too resistive, or the borehole too large.

TYPES OF INDUCTION LOGS

Logging companies have trade names for their different types of tools. The particular type used will be given on the log heading. Below are summaries of a few of the log types now in use:

1) Induction Log
   - 6FF40, Schlumberger's 6 fully focused coils with a 40" spacing. Can be run with a 16" normal and SP. it will read a true resistivity if di < 35"-40" and give a good approximation if di < 100" . Atlas label their tool Numbers 805, 809, 811, 814, 815 & 818; HLS called theirs 5C40.
   - Averages about every 5 feet, so vertical resolution in resistive beds is 5 feet; however, in conductive beds vertical resolution is good for beds no thinner than 3 feet.

2) Dual Induction (DIL)
   - Has a deep reading device, ILd, or LD
   - Has a medium reading device; i.e., ILm, LM
   - Has a shallow reading device; i.e., LL8 or SFL, or MSFL

- Has an SP (or Gamma Ray in non-conductive fluids)
- This log gives the most precise knowledge of the invasion profile, therefore, better Rt values in zones of deep invasion.

3) ISF/SONIC

- Schlumberger's old combination log, all-in-one tool

- A deep induction log, like the 6FF40 which will give an Rt, and a Spherically Focused Log which gives an Rxo, both in track 3.
- A Sonic log detailing the porosity in track 4
- Plus an SP curve with a calculated Rwa curve

  (Rwa = $\phi^2 \cdot Rt$) in track 1

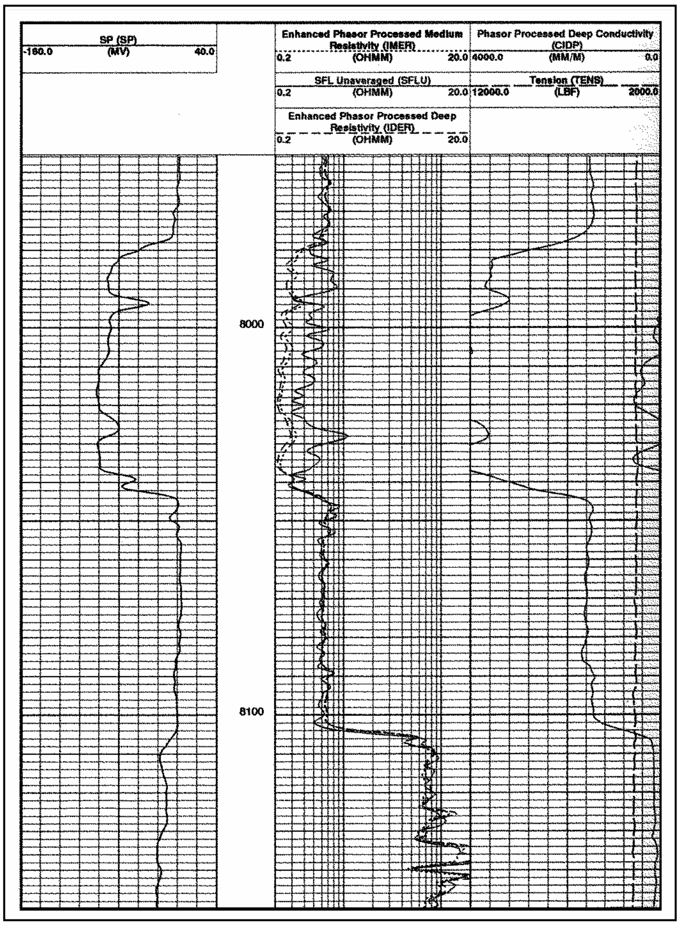
- This was a popular tool, i.e., in the US Gulf Coast, because all of the measurements are taken during one logging run
- Atlas had an Induction-Acoustilog combination and HLS had an Induction-Acoustic Velocity log combination

4) The Phasor Induction SFL

- This new tool (1987) replaces the older devices and consists of a deep induction , IDPH, a medium induction, IMPH and a SFL tool. A SP electrode is also included. Its main advantage over the older tools is in signal processing. It can operate at 10, 20 and 40 KHz and the signal is analysed for the in phase and quadrature components. This allows vertical resolution to be much better than its predecessors and it can resolve 2 ft beds with full bed shoulder correction. 3 Vertical resolutions are available; 8 foot and 6 foot IDPH and IMPH, 3 foot resolution IDER and IMER, and finally, 2 foot IDVR and IMVR.

5) The Array Induction Imager Tool (AIT)/ High Definition Induction Log HDIL

- These two new tools from Schlumberger and Atlas respectively are designed to resolve down to 1 foot beds with multiple arrays of receiver coils. The spacing ranges from 6 inches to 90+ inches and has coils at 3 inch intervals. The device operates simultaneously at three frequencies, which allows both the in phase radial, and quadrature (X) components to be analysed for each of 8 coils. The signal is processed into 5 logs giving 10, 20, 30, 60 and 90 inch investigation depth from the centre of the borehole. Obviously invasion profiles are easily assessed, however, because of the increased data, volumes of filtrate loss can also be computed.



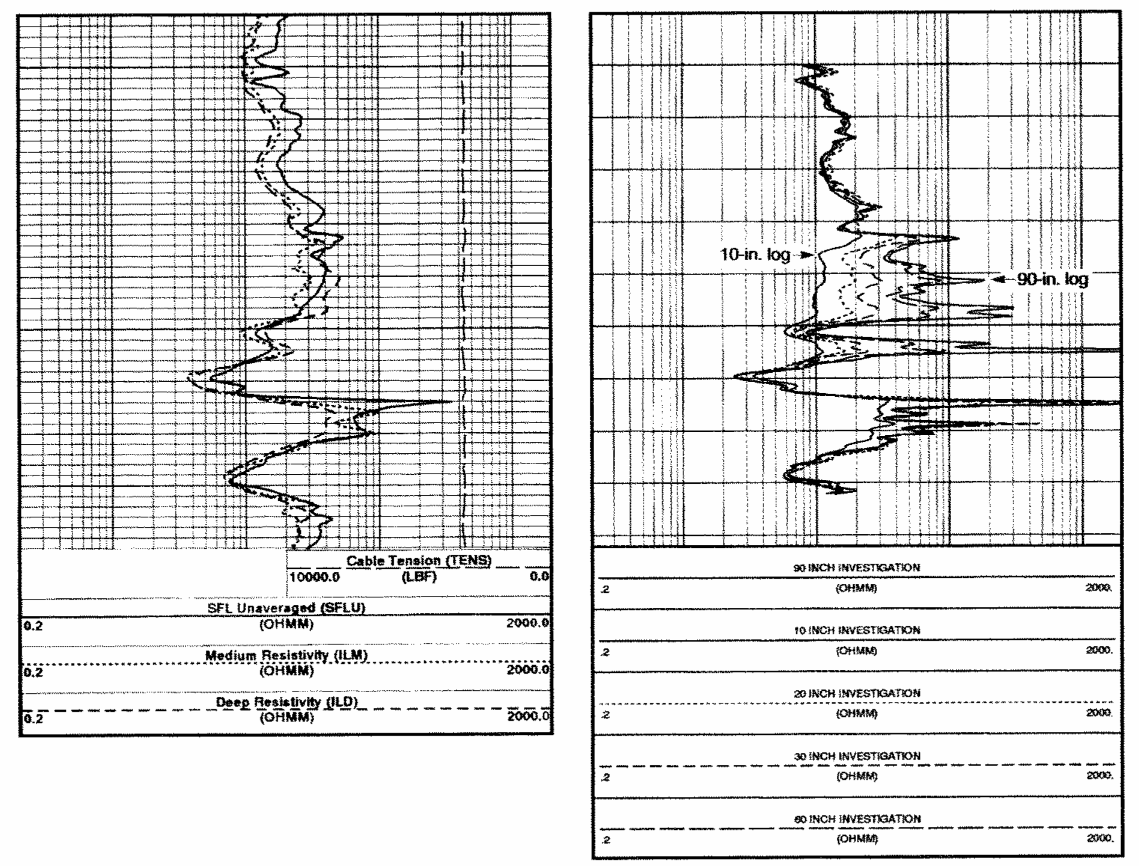
Phasor Induction Log

LOG PRESENTATION

Since the induction log measures conductivity, its respective curve is printed on the far right-hand scale, track 4. The conductivity measurements are automatically reciprocated and a plot of the processed equivalent resistivity is found on track 3, $\left(R = \frac{1000}{C}\right)$. When the resistivity becomes less than 2 ohm.m, it is more accurate to read the conductivity curve and calculate the equivalent resistivity.

The Dual Induction Log (DIL) is presented above, covering tracks 3 and 4. Its four decade logarithmic scale allows a more precise reading in zones of low resistivity. The conductivity curve is not given. This type of scale also allows a wider range of resistivities without crossing over onto a new scale. Also resistivity ratios can be easily read and then used to help understand the invasion profile and its effects.

The logarithmic scale for the induction log from the ISF/SONIC tool in track 3 is only two decades because track 4 is occupied by the sonic log. The scale for transit time is linear as it is for the Rwa and SP in track 1.



DIL Versus AIT, Hidden Zone Identification

ENVIRONMENTAL FACTORS AFFECTING LOG RESPONSE

The induction log, if calibrated correctly, can accurately read the formation conductivity in resistive beds from two to five feet or more in thickness and in two to three, or more, feet thick conductive beds. The resistivity is automatically reciprocated from the conductivity curve. On the linear scale, the reciprocation should be checked for accuracy. When values become less than two ohm–m, the resistivity value used should be calculated from the conductivity curve.

Under certain conditions, the log requires other corrections due to environmental factors which affect its response. These factors are skin effect, borehole size, adjacent bed boundary (shoulders), geometrical factor and depth of invasion. Each correction must be made in a sequence that preserves precision.

The order of correction is: Borehole, then bed-thickness, then invasion. The following is a brief highlight of each of these factors.

Skin Effect

In conductive formations, the induction log induces strong secondary currents. The magnetic field generated by these induces additional emf's which interfere and reduce the conductivity reading recorded at the receiver. This is known as skin effect; however, modern logs automatically correct for this. In resistive beds, the effect is negligible.

Borehole Size

The size of the borehole can affect the induction log's response. The borehole effect increases as the hole diameter increases. This is typically corrected through use of the geometric factor. There still may be some uncertainty in this factor, which may cause a significant error in highly resistive zones. Use Chart **Rcor-4** for Schlumberger and **6-1 - 6-5** for Atlas to make corrections

Adjacent Beds

The resistivity of adjacent beds affect the measured value in beds thinner than the vertical tool resolution. The vertical resolution of the ID is about 8 feet and the IM about 6 feet. In resistive beds thicker than five feet, the shoulder effect is minimal; however, the thinner they become (for the ID less than five feet) the greater the effect. For the ILd the same effect applies to conductive beds less than three feet thick. More modern tools have less problems, but the IDVR still exhibits some minor bed shoulder effects below the 2 foot vertical resolution. Phasor deconvolution processing of ID and IM data reduces the shoulder effect to minimal and it is corrected automatically, by the acquisition software.

Dipping Beds

If the Borehole encounters formations with variable resistivities and dips, then there are corrections that apply to the Induction logs. The higher the angle of dip, with respect to the borehole trajectory, the larger the correction. Thin beds are more affected than thick ones. Highly resistive beds are more effected than conductive ones.

Geometrical Factor

This is a concept which implies that different zones, moving horizontally away from the borehole, contribute differently to the over all resistivity measurement. So a fractional geometric factor is assigned to each zone and, thus, will indicate what portion of the total signal is contributed by each zone. Knowing this, a more accurate resistivity can be determined which takes into account the responses in the borehole, adjacent beds, and the invaded zone.

Invasion Effects

The effect of invasion increases as the invasion diameter increases and as resistivity contrast increases. The invasion effect also becomes greater as the resistivity of the formation becomes greater than that of the invaded zone. For the best results, formation resistivity (Rt) should be less than 2.5 times that of the flushed zone (Rxo) and the diameter of invasion be less than 100 inches for the ILd and 200 inches for the IDPH. So, the induction log works better in a fresh-water, resistive mud than a salty, conductive mud.

In a system where the filtrate is more resistive than the Rw, an annulus of formation water may be flushed ahead of the filtrate. This results in a ring of more conductivity around the invaded zone and before the virgin formation. Annulus effects the Induction logs, mostly the IM but some times the ID and can suppress Rt. The Annulus will dissipate with time.

Though very resistive beds do not require corrections other than just mentioned, it should be noted that the ID log does not accurately read resistivities over 100 ohm-m. This is due to an uncertainty of about ±2 mS/m on the zeroing of the sondes. That means the error becomes greater than 20% as the conductivity becomes less than 10 mS/m (or greater than 100 ohm-m). So to insure a less than 20% error, the tool's accuracy is best in less than 100 ohm-m formations. The IDPH is better calibrated and the uncertainty is down to 0.75 mS/m in zeroing. This means that the tools are only 7.5% in error at 100 ohm-m. In more resistive formations the Laterologs are more accurate.

Depth of Invasion can be determined from inspection of the Tornado charts applicable from any chart book.

SUMMARY SHEET ON THE INDUCTION LOGS

- The induction log was developed to run in non-conductive muds such as oil because the electric logs could not work in them. It focuses its current in a 28-40" spacing that allows it to measure the formation's conductivity with minimal effects from secondary media.

- Five types of tools are:
  1. The Induction Log which is run with a short normal and SP; it has conductivity on a linear scale in track 4 and a reciprocated resistivity linear scale on track 3.
  2. The Dual Induction Log which has a deep, medium, and short focused tool plus an SP; the resistivity curves are printed on a four decade logarithmic scale starting at 0.2 ohm-m finishing at 2000 ohm-m.
  3. The ISF/SONIC Log which has a short normal and deep induction log curve printed on a two decade logarithmic scale in track 3. Track 4 has the transit time printed on a linear scale.
  4. The Phasor Induction Log, which has better resolution due to X and R signals being used in deconvolution. It has a deep and medium device and 8/6, 3/3 or 2/2 feet vertical resolutions. Bed shoulders are automatically corrected for.
  5. The Array Induction Imager Tool, which has 28 coils at 3 inch spacing and 1 foot bed resolution. It is excellent at profiling invasion.

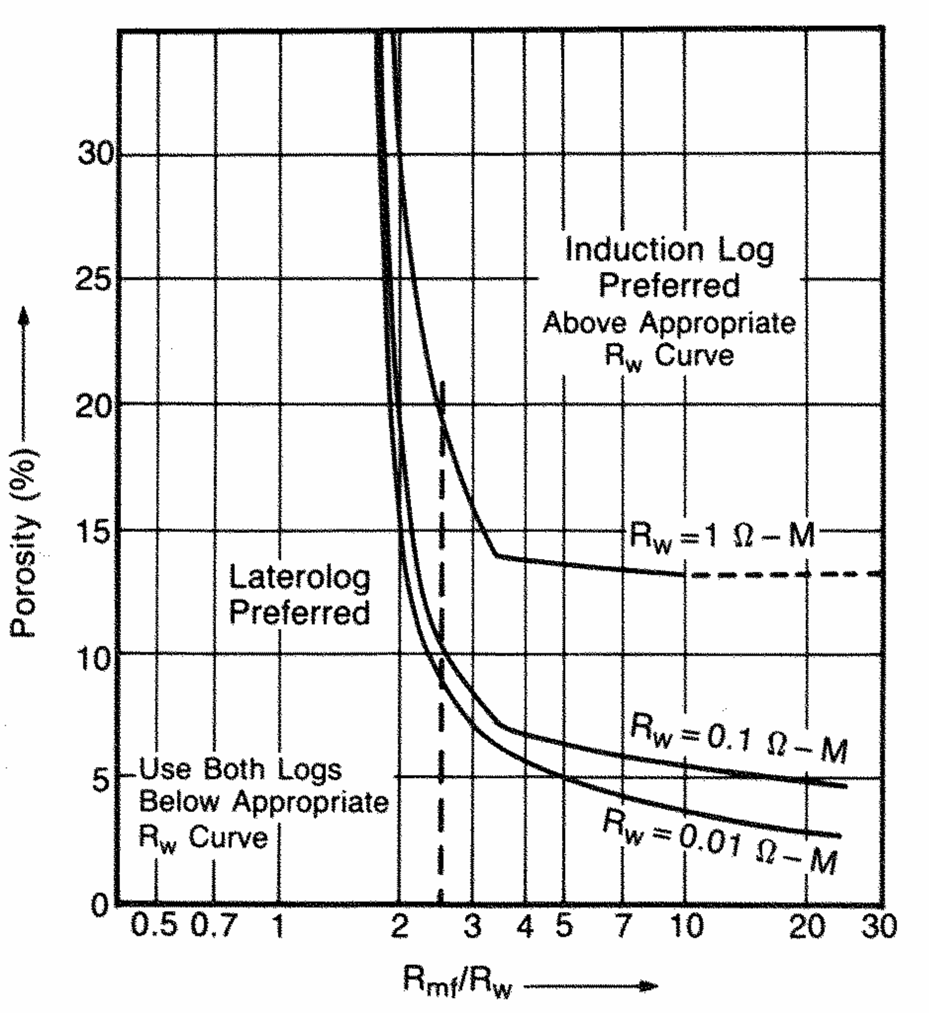
- For the ID, if a resistive bed thickness becomes less than 5 feet, corrections must be applied because the adjacent beds begin affecting the response, The same holds true for conductive beds less than three feet thick. Phasor logs are automatically corrected.

- To avoid correcting for invasion effects, the log responds best when Rt < 2.5 Rxo and di < 100".

- When the ID resistivity dips below 2 ohm-m (500 mS/m), it is more accurate to calculate the resistivity from the conductivity curve than just trying to read it. The Phasor is better than the ID

- The ID log best operates in zones of resistivity from very low to a high of 100 ohm–m. This is due to a 2 mS/m uncertainty in zeroing the tool. Using the tool in this range keeps the error less than 20%. The Phasor only has 0.75% uncertainty in zeroing and can be read to 7.5 % accuracy in the same range.

- The induction log was designed and works best in non-conductive fluids. This covers fresh water mud, oil-base mud, or gas filled holes. It will work in moderately conductive fluids as long as the borehole does not become too large, the formation too resistive, or the fluid too salty.



Selection Criteria for Induction or Laterolog Tools

THE ELECTROMAGNETIC PROPAGATION TOOL, EPT

The Electrical impedance of the formation considered so far has always been based upon the assumption that conduction follows Ohm's Law.

$$V = IR$$

Where V is the voltage, I the current in amps and R the resistance in ohms.

In a strictly direct current (DC) we might be able to make that assumption, however, all the electrical measurements we have studied so far are alternating current (AC). There is a contribution to impedance that is non-ohmic. Impedance losses may be due to heating, capacitance and phase-angle. Hence, measurements of electrical resistance and computed resistivity will all be frequency dependent. This means different resistivities measured in the same zone can both be "right".

The non-ohmic portion of the impedance of a medium is dependent on its dielectric permitivity. As we increase the frequency of emitted electromagnetic energy, more and more materials permit the energy to flow through them. So a glass object insulates against 50 Hz AC electrical current, but allows microwaves to pass through it. Every medium has an impedance that is dependent upon its dielectric constant. The relationships are described by Maxwell's equations.

$$\gamma = \alpha + j\beta$$

$$\omega^2 \mu\varepsilon = \beta^2 - \alpha^2$$

and

$$\omega\mu C = 2\alpha\beta,$$

where γ is the electromagnetic wave propagation,

α is the attenuation of the wave,

β is the phase shift,

ω is the angular velocity,

μ is the magnetic permeability,

ε is the dielectric constant

and C is the conductivity.

Therefore, a measurement of α and β can yield the dielectric constant and conductivity in the medium in which the waves are propagating.

There are a number of ways of computing the desired parameters. The complex Refractive Index Method, Complex Time Average Method, Loss-less Propagation Time Method and the currently most popular Weight-Average Effective Medium equation. These are described in the logging company manuals and the reader is directed to them for a fuller treatment of the subject.

The EPT tools are used in resistive formations where Rw is moderately high and the mud is fresh or oil-based. Because of the good contrast between the dielectric constants of oil and water, it is a good hydrocarbon discriminator. In water sands the porosity can be computed from a weighted time average equation;

$$\phi_{EPT} = \frac{t_{po} - t_{pma}}{t_{pwo} - t_{pma}}$$

where t_{po} is the loss-less propagation time, t_{pl} the measured propagation time, t_{pwo} is the loss-less propagation time of the water and t_{pma} is the propagation time in the matrix.

$$t_{po}{}^2 = t_{pl}{}^2 - \frac{A_c^2}{3604} \text{ and } t_{pwo} = 20 \cdot \left(\frac{710 - T_{{}^0F}/3}{444 + T_{{}^0F}/3} \right),$$

where A_c is the attenuation corrected for spreading loss.

Conversely the flushed zone saturation, Sxo can be determined, when hydrocarbons are present, (Schlumberger chart **Sxo - 1**)

$$Sxo = \frac{\phi_{EPT}}{\phi}$$

The main drawback of the current EPT type tools is their signal loss. The EPT requires a spreading loss correction, which is a very big number, of the order of the desired measurement.

They are affected by mudcake build-up and rugose boreholes. The higher the frequency of the tool the larger the effect. Tools are available in a range of frequencies from 20 MHz to 1.1 GHz. The higher the frequency the less the depth of investigation. The ADEPT 1,1 GHz specifies 1-2 inch vertical resolution with a depth of penetration of about an inch. The DPT, deep 25 MHz tool investigates up to 45 inches into the formation over a vertical spacing of 8 feet.

The main use of the tool was to provide sufficient data to solve the Archie equation for m, the saturation exponent, to determine Rw in fresher formation waters and in oil based mud, and as a backup water-filled porosity tool. In recent years, because of the many corrections and boundary assumptions of the tools they have fallen into less use. The tools were particularly affected in shaly sand environments, by the complex conductivity of the clays. Recently, their role has been usurped by the NMR tools, however, under the right borehole conditions, they are an useful, if expensive, logging tool.

Supplementary Notes

Chapter 3

Section 1

Log Analysis

GUIDE TO LOG ANALYSIS PROBLEM SOLUTIONS

1. What is purpose of the analysis; i.e., what is required to be known?

2. What data are available or given?
   - A. Logs - what type?
   - B. Formation water - R_w, salinity, compute from SP/EPT/Rwa
   - C. Mud data.
   - D. Temperature - surface and bottom hole.
   - E. Cementation factor (m) - saturation exponent (n).
   - F. Log calibration data - Δt_{ma}; ρ_f; ρ_{ma}; Δt_f.

3. Determine temperature of zone of interest and convert all temperature sensitive data to the formation temperature (R_w, R_m, R_{mc}).

4. Set up a table showing the data needed as a function of depth (or interval), such that all log readings or calculations can be kept in logical order.

5. Depth match all the logs to one primary log, normally a gamma-ray.

6. Take zone or bed average value readings from the logs from the intervals specified.

7. Make necessary environmental corrections (use charts) to determine the correct, or 'true' values. Remember: Borehole, Bed shoulder/thickness/dip and Invasion, in that order.

8. Make the necessary calculations for the desired parameters.

9. Check calculations for accuracy, and be sure answers are reasonable (porosity less than, ≈ 40% and water saturation no more than 100%, or just slightly over 100% in a water zone). Interpret results of calculations and determine if item No. 1 has been answered.

HOW TO START

We want to work in an ordered approach, realising each parameter as we go. We need lithology, porosity, water saturation (Sw) and some estimate of permeability. The first step is to realise the data we will need for each interpretation.

LITHOLOGY AND POROSITY

We cannot calculate a correct porosity, nor Sw, without a good interpretation of lithology. Throughout this course we have looked at various forms of evidence for the lithology. Prima-facie evidence comes in the form of cores, sidewall-cores, and mud-logs, all of which ground-truth any interpretation of down-hole logs. No log analyst worth having will ignore this evidence. However, we don't always have this evidence and even if we do, lithological analysis of down-hole logs extends our knowledge to the uncored sections of the well.

We need to get estimates of lithology to determine the **matrix** characteristics essential to calculating a valid porosity. These are

$$\rho_{ma},\ \phi N_{ma},\ \Delta t_{ma},\ tpl_{ma}$$

For example if log readings were $\rho b = 2.51$ g/cm3, Rt = 21 Ωm and Rw = 0.07 Ωm at FT, the following porosities and saturations could be calculated:

Matrix	Resultant Porosity	Sw
Sandstone	0.08	72%
Limestone	0.12	48%
Dolomite	0.19	30%

MONOMINERALIC FORMATIONS

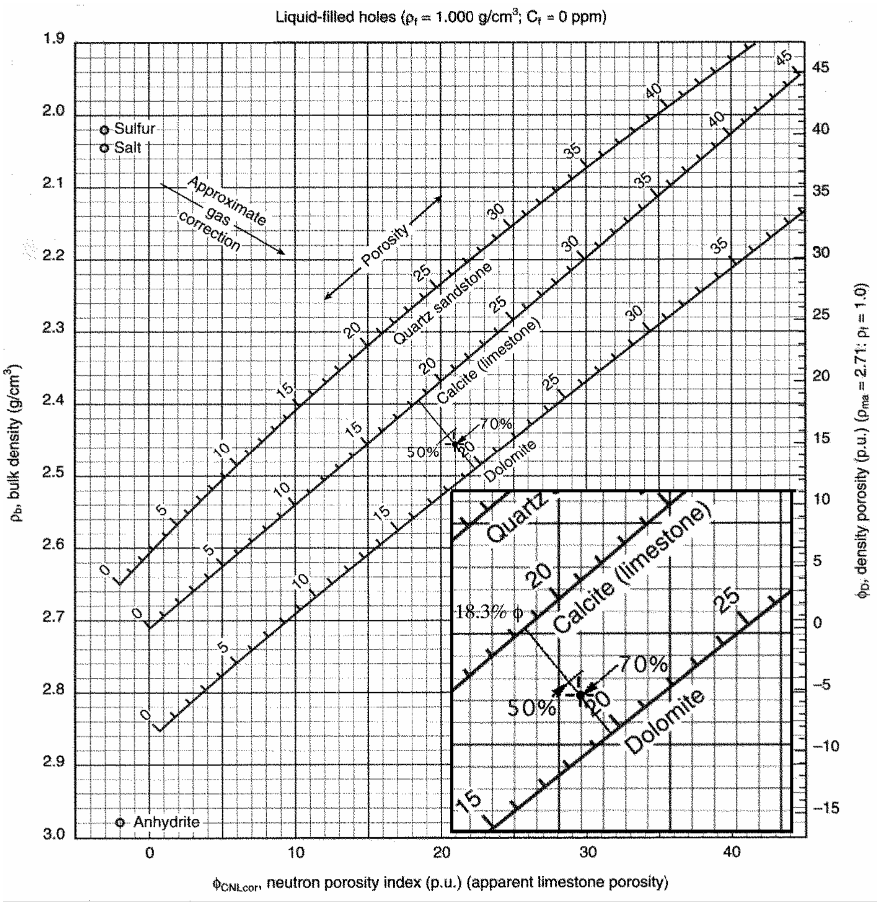
The matrix can be estimated with reasonable confidence from the LDL and P_e data. Schlumberger chart **CP-16** and **CP-17**. If the spectral Gamma log has been run, primary estimations of mineralogy can be verified through cross-plots on chart **CP-18** for P_e versus K^{40} and P_e versus Th/K ratio. Determination of the apparent matrix volumetric photoelectric factor U_{maa} from chart **CP-20** allows us to compare the apparent matrix density with U_{maa} to determine both lithology and the presence of gas.

MINERAL MIXTURES

More commonly, we are confronted with a formation that is a mixed mineral lithology. Fortunately, because the physical responses of the porosity logs are different to different mineral and fluid combinations in the formation. This means that cross-plots of the tool responses will be quite useful in identifying the presence of various component parts of the mixture. The most basic and fundamental cross-plots are the Neutron-Density, Density Sonic and the Neutron Sonic.

NEUTRON DENSITY

Charts **CP-1a-f** and **CP-22-24** deal with the various different tools responses for FDC, LDL and the SNP, CNL, CDN and ADN tools. Simply select the chart that represents the tool string run. The neutron device should always be on the 'X' axis and the bulk density, or density porosity on the 'Y' axis.



A Neutron Density Cross-Plot,

Showing a Solution For $\phi_N = 21$, $\phi_D = 15$

In an example case, given the response of the two logging devices we can determine a binary mixture of mineralogy. However more than a mixture of two components will pull the data in differing, or reinforcing directions. It then becomes difficult to determine the lithology. This is particularly true when clays, and/or shale are present, and also gypsum. For the components, sandstone, limestone, dolomite and anhydrite the plot works well at correcting porosity. However, in multi-component systems, anther plot is needed.

THE M - N PLOT

The 'm' - 'n' plot combines all three basic porosity tools' responses. The idea is to minimise the effect of porosity on the lithology determination by dividing one porosity response into another.

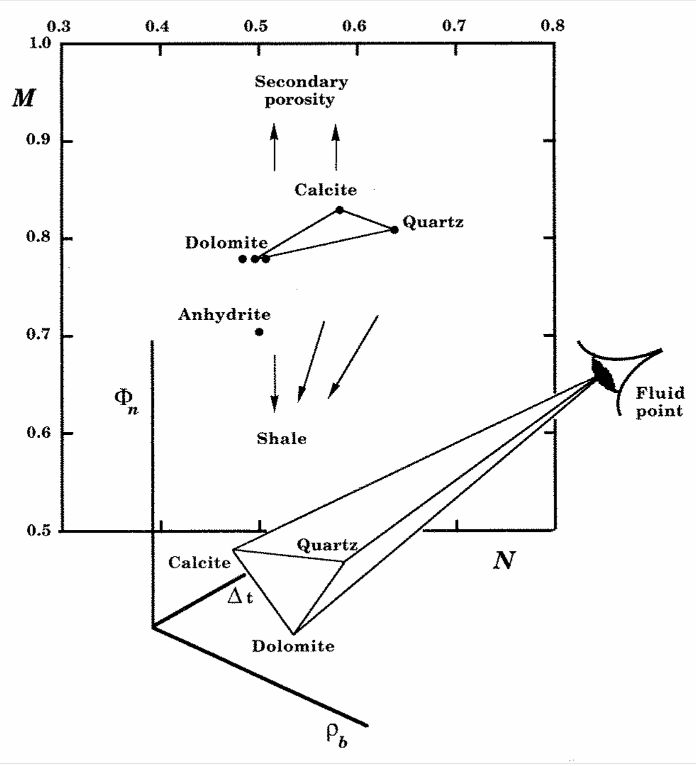
$$M = \frac{\Delta t_{fl} - \Delta t}{\rho_b - \rho_{fl}} \cdot 0.01 \text{ and } N = \frac{\phi_{Nfl} - \phi_N}{\rho_b - \rho_{fl}}.$$

The fluid characteristics can be approximated as

	Fresh Mud	**Salty Mud**
ρ_{fl}	1.0	1.1
ϕN_{fl}	1.0	1.0
Δt_{fl}	189	185

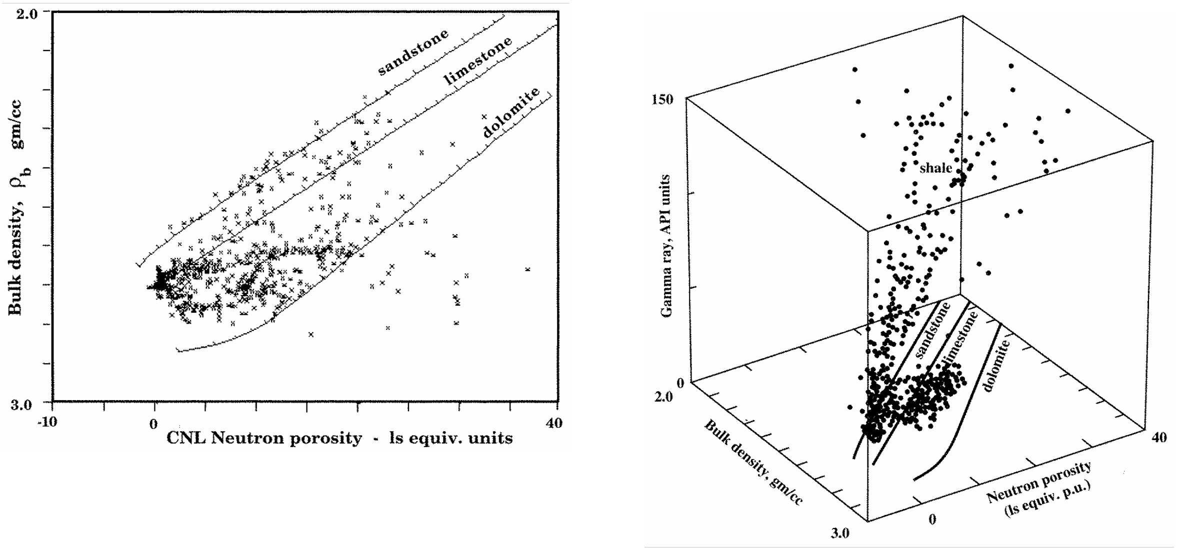
Chart **CP-8** in Schlumberger's chart book shows an example M - N plot, which can be used as a template.

Note that fluid such as gas and shale will shift the points away from the ideal triangle. The figure opposite shows the true 3D nature of the problem.



M-N Plot in 3D Showing the Visualisation From The Fluid Point

While the N - D and M - N plots are extremely useful, it is obvious that the data may array in 2D because of the influence of another parameter. For example the following 2D and 3D N -D plots show that coherent data in 3 D may look very scattered when viewed in 2D.



2D and 3D Representations of the Same Data From a Palaeozoic Carbonate-Shale-Sandstone Sequence

THE MID PLOT

The MID plot is an improved 'M' - 'N' plot. The apparent total porosity, ϕ_{ta}, is computed from both the Neutron - Density (N - D) and the Neutron - Sonic (N - S) cross-plots to derive input parameters for the following equations,

$$\rho_{maa} = \frac{\rho_b - \rho_{fl}\phi_{ta(N-D)}}{1-\phi_{ta}}$$. and

$$\Delta t_{maa} = \frac{\Delta t - \Delta t_{fl}\phi_{ta}}{1-\phi_{ta}}$$ for the Wyllie time-average relationship, or

$$\Delta t_{maa} = \Delta t - \frac{\phi_{ta}\Delta t}{C}$$ for the Raymer-Hunt-Gardner empirical relationship.

Data can be estimated from the chart **CP-14** and plotted on the chart **CP-15** to identify the matrix components.

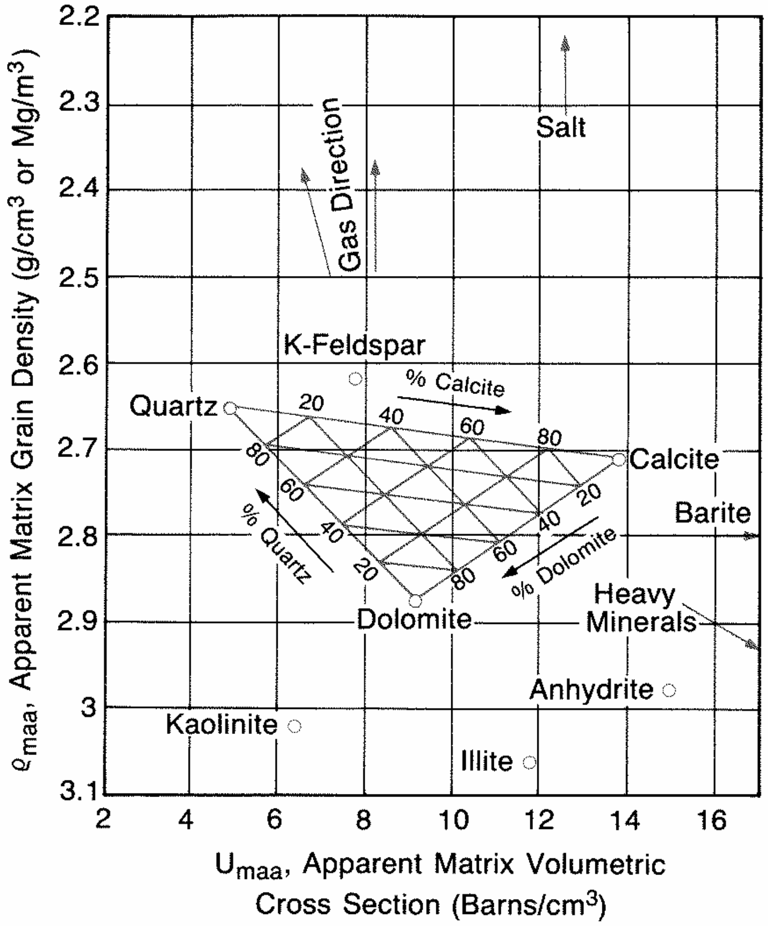
THE ρ_{maa} VERSUS U_{maa} PLOT

This triangular plot allows us to estimate the lithology in terms of percentages for an admixture of three minerals.

$$\rho_{maa} = \frac{\rho_b - \rho_{fl}\phi_{ta(N-D)}}{1-\phi_{ta}} \text{. and } U_{maa} = \frac{U - U_{fl}\phi_{ta(N-D)}}{1-\phi_{ta(N-D)}} .$$

We can approximate U from P_e, where U = P_e x ρ_e, or use chart **CP-20** and $\rho_e = \dfrac{\rho_b + 0.1883}{1.0704}$, or simplify this by making U = P_e x ρ_b.

The mud filtrate should provide the fluid values as the tools have shallow depths of investigation. Hence, for fresh mud ρ_{fl} = 1.0 g/cm^3 and U_{fl} = 0.40 B/cm^3, and for salty mud, ρ_{fl} = 1.1 g/cm^3 and U_{fl} = 1.36 B/cm^3.



A ρ_{Maa} Versus U_{maa} Plot

Rw AND Sw FROM LOGS

The purpose of the forgoing section was to provide us with accurate estimates of lithology and porosity in order that we may then proceed to make good estimates of the saturation and volume of hydrocarbons in our reservoir. This section will dwell upon the various methods to achieve this goal.

Rw

Most serious petrophysicists will smile wryly when you mention Rw. Of all the logging parameters it would appear to be the simplest to both understand and to characterise. Unfortunately this is often not the case. Geochemical studies of pore waters have shown that in many cases the Rw of formation water varies both horizontally and vertically. In the case of some hyper-saline fields in the US with postulated dynamic aquifers the Rw varies by as much as a factor of 3 across the field. In SE Asia it is quite common for the pore-water in the hydrocarbon leg of a reservoir to have widely different salinity to the underlying water, due to pervasive meteoric water invasion since the reservoirs received their charge.

There are a few simple aspects to bear in mind when considering the effect of Rw. In the Archie equation, or any one of its derivatives and variants, Rw is a direct multiplier in the numerator. Hence, any increase in Rw results in an increase in calculated Sw. However, Rw is not linearly related to Sw, nor to the salinity (ΔCl) of the water. The ionic constituents of the water each have a different effect on Rw. One solution is to use the Dunlap chart **Gen-8**, to derive multipliers for the calculation of an *equivalent* sodium chloride concentration. We tend to talk in terms of NaCl equivalents, when discussing the salinity of water.

The Resistivity of NaCl brines with respect to concentration and temperature may be derived from Atlas chart **1-5, which** is far clearer than the equivalent Schlumberger chart, **Gen-9**. Because of the logarithmic nature of the relationship, small changes in salinity at low concentrations have much more influence on Rw than similar changes at high concentrations. In short, an accurate Rw becomes more essential as the formation water freshens. As a rule of thumb, in waters saltier than 50,000 ppm NaCl equivalent Rw is relatively insensitive, while in fresher waters Rw is sensitive. For example a change from 50,000 ppm to 60,000 ppm results in Rw dropping by 0.02 from 0.135 - 0.115 Ωm at 75 ˚F, while going from 8,000 ppm to 10,000 ppm results in a change of 0.13 from 0.73 - 0.6 Ωm. This represents a six-fold increase in sensitivity of the multiplier.

Rw APPROACHES

The simplest way to establish Rw is from a book, or catalogue of previously measured values in a basin. This has a drawback in that the precision of your entire analysis is dependent upon this parameter. Rw is ***not*** a constant in nature

Commonly the Rw is measured on a recovered formation water sample. This is not always a good analysis. Because the water has been drawn to the wellbore it will have lost pressure and temperature which can change the solubility of some of the component salts and these may be lost through precipitation. Further, the water may be contaminated in the wellbore.

Nearly all formation water analyses show iron present in appreciable quantities. This is more often than not, a contaminant introduced by the casing and pipe in the wellbore. Formation pH may be quite low, however, most waters are oxygenated in recovery and display pH values closer to 7.0. This again can change the solubility of components. Hence, recovered formation water may not have the same composition as the formation water in the reservoir.

Rw FROM SP

In the section on the SP we saw how the Rw could be derived from a static spontaneous potential SSP,

SSP = Static spontaneous potential
K_c = Temperature coefficient = - (61 + 0.133 T ˚F)
T = Formation temperature, ˚F
R_{mfeq} = Resistivity of mud filtrate (When R_{mf} @ 75° F > 0.1, then $R_{mfeq} = R_{mf} \times 0.85$
When R_{mf} @ 75°F < 0.1, use Schlumberger Chart **SP-2** to find R_{mfeq}
R_w = Formation water resistivity

$$SSP = -K_C \log \frac{R_{mfe}}{R_{we}}$$

Use chart **SP-1** to derive R_{we}.

R_w is found by entering R_{we} into Schlumberger Chart **SP-2**

This approach only works in clean water sands, so must be performed on an adjacent formation to the hydrocarbon zone, with all the assumptions that entails. Beware of unconformities or faults juxtaposing completely dissimilar formations.

There are corrections available for beds thinner than 10 feet, and their Rt, adjacent shale Rs, Rxo and d_i, borehole diameter, d_h, and mud Rm, all from charts **SP-3** and **SP-4**.

Rw FROM Rwa

Rwa is the apparent Rw of a formation. The formation may contain filtrate and hydrocarbons, but we can assume an Archie relationship and solve the equation for Rw. Obviously in a water-sand Rwa would be the actual formation Rw. Rwa is defined as,

$$Rwa = \frac{Rt}{F},$$

We take a Rt value from a deep resistivity tool, make the requisite environmental corrections then either from known a and m, or from assumed Archie values, and a measured porosity we compute F from the general formula:

$$F = \frac{a}{\phi^m}$$

Commonly Used Relationships:

$$Sandstones: \quad \mathrm{F} = \frac{0.62}{\phi^{2.15}} \quad \mathrm{Or} \quad \mathrm{F} = \frac{0.81}{\phi^{2.0}}$$

$$Carbonates: \quad \mathrm{F} = \frac{1}{\phi^{2.0}}$$

The first pair of sandstone equations is based upon a relationship first reported for samples from the US Gulf Coast by researchers at Humble Oil and Refining Co., soon to be merged into Exxon Corporation. As such they are known as the Humble formulae. In clean water bearing formations, Rt = Ro = F·Rw and Rwa = Rw.

It should be apparent that when Rwa deviates to higher values in a zone of known constant Rw, there is a strong indication that hydrocarbons are present. This led to Schlumberger producing a Rwa log as a hydrocarbon indicator log.

THE RATIO METHOD

The forgoing estimates of Rw all rely on the formation properties remaining constant in the zones of interest. By this we mean the 'a' and 'm' values are constant even if porosity varies. In many formations there is a progressive change in diagenesis, which results in 'm' varying. In advanced petrophysics 'm' becomes a variable that is porosity and shaliness dependent, but that is outwith the current scope of this course. What we need is a Rw method that does not rely on F. The approach used is the Ratio Method.

In the invaded zone, which is measured by one of the medium investigation devices,

$$Ri = \frac{F \cdot Rmf}{Si^n} \cdot K,$$

where K is some constant of invasion. If invasion is deep in a fresh-water mud system, K is close to one. In shallow invasion it is less than one.

In the uninvaded zone $Rt = \dfrac{F \cdot Rw}{Sw^n}$,

If we divide the second equation into the first, we get,

$$\frac{Ri}{Rt} = \frac{Rmf \cdot K \cdot Sw^n}{Rw \cdot Si^n},$$

In a water bearing zone Si = Sw = 100%, and

$$\frac{Ri}{Rt} = \frac{Rmf \cdot K}{Rw} = \text{constant} = \left[\frac{Ri}{Rt}\right]_{Sw=100\%},$$

showing the ratio Ri/Rt is a constant if Rmf, Rw and K remain constant in the zone of interest. Hilchie (1989) reports that this is commonly the case. So we can solve the equation for Rw.

It should be obvious that once a water point is established, this method can be used to establish saturation in hydrocarbon bearing zones. Tixier (1949) described this as the "Rocky Mountain Technique"

$$Sw = \frac{\left(\frac{Ri}{Rt}\right)}{\left[\frac{Ri}{Rt}\right]_{Sw=100\%}}$$

This has been used with some success in variable pore-geometry. A later variant of this equation, introduced in the mid '50s uses Rxo instead of Ri,

$$Sw = \left(\frac{\left(\frac{Rxo}{Rt}\right)}{\left[\frac{Rxo}{Rt}\right]_{Sw=100\%}}\right)^{\frac{5}{8}}.$$

The key to successful analysis is to compare results from various approaches to see which information reinforces the others.

WATER SATURATION DETERMINATION

So far we have seen that some of the methods used to establish Rw can be extended to derive water saturation, Sw. To a disinterested observer it may seem peculiar that we devote a lot of time and effort to establishing water saturation , when what we want is the hydrocarbon saturation. This little anomaly stems from the fact that the main tools used to establish hydrocarbon saturation are the resistivity logs. Electrical current flows in the water not the oil, hence we work-out the water saturation, which when subtracted from unity gives us the hydrocarbon saturation.

Almost all water saturation equations are derivatives of the Archie equation,

$$Sw = \sqrt[n]{\frac{F \cdot R_w}{R_t}} \quad \text{and} \quad F = \frac{a}{\phi^m} \ ,$$

In order to calculate good data we need to know the values of the parameters for F. These may be available from core analysis data, suitably corrected for shaliness and net overburden. Conversely we can use graphical methods such as the Pickett Plot.

THE PICKETT PLOT (1966)

The basis for this plot is to assume ‘m’ is unknown and that we can use an Archie relationship.

$$Sw^n = \frac{F \cdot Rw}{Rt}$$

the base-ten logarithm of this equation is,

$$n \log Sw = \log F + \log Rw - \log Rt.$$

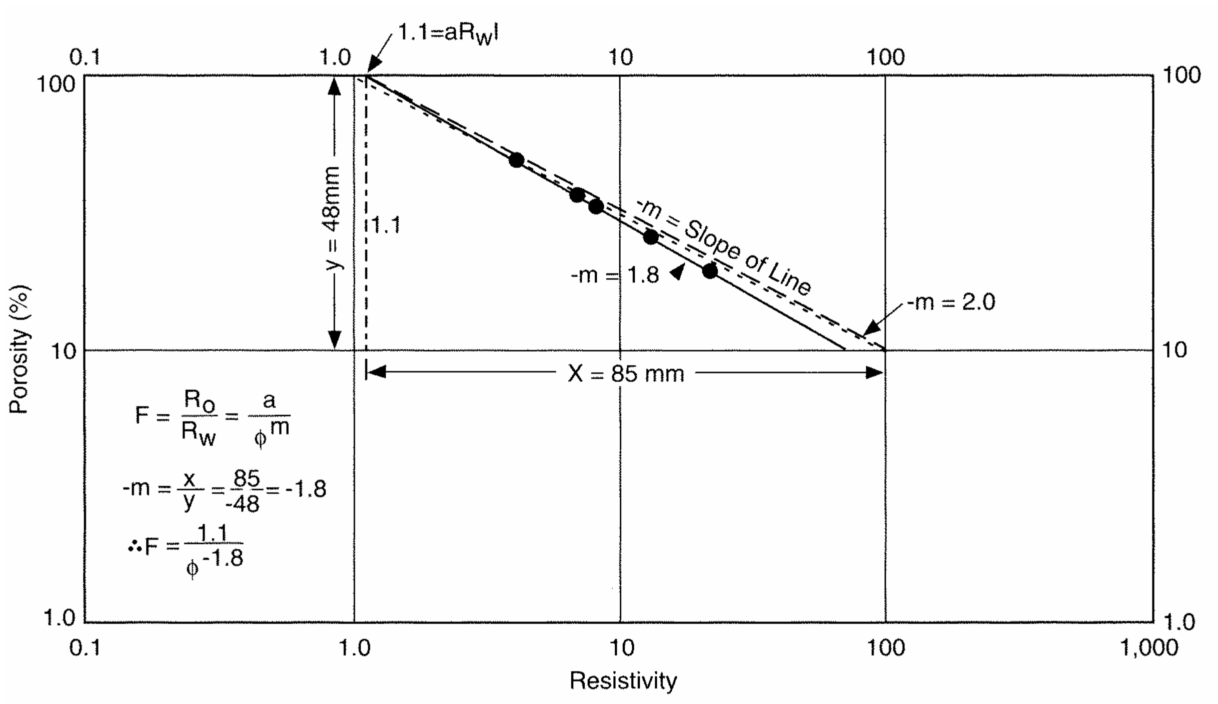
Reorganising this for $F = a/\phi^m$ and simplifying to solve for log Rt gives:

$$\log Rt = -m \log \phi + \log (a\ Rw) - \text{‘}n\text{’} \log Sw$$

and at 100% Sw this simplifies further to become,

$$\log Rt = -m \log \phi + \log (a\, Rw),$$

which is the equation of a straight line in log-log co-ordinates, of the form Y = mx + b. This means if we plot Rt versus ϕ on a log-log plot, we should get a straight line as long as 'm' is constant. The slope of this line will be 'm' and the intersection the product 'a x Rw'. Where 'a' equals unity, the intersection is Rw.



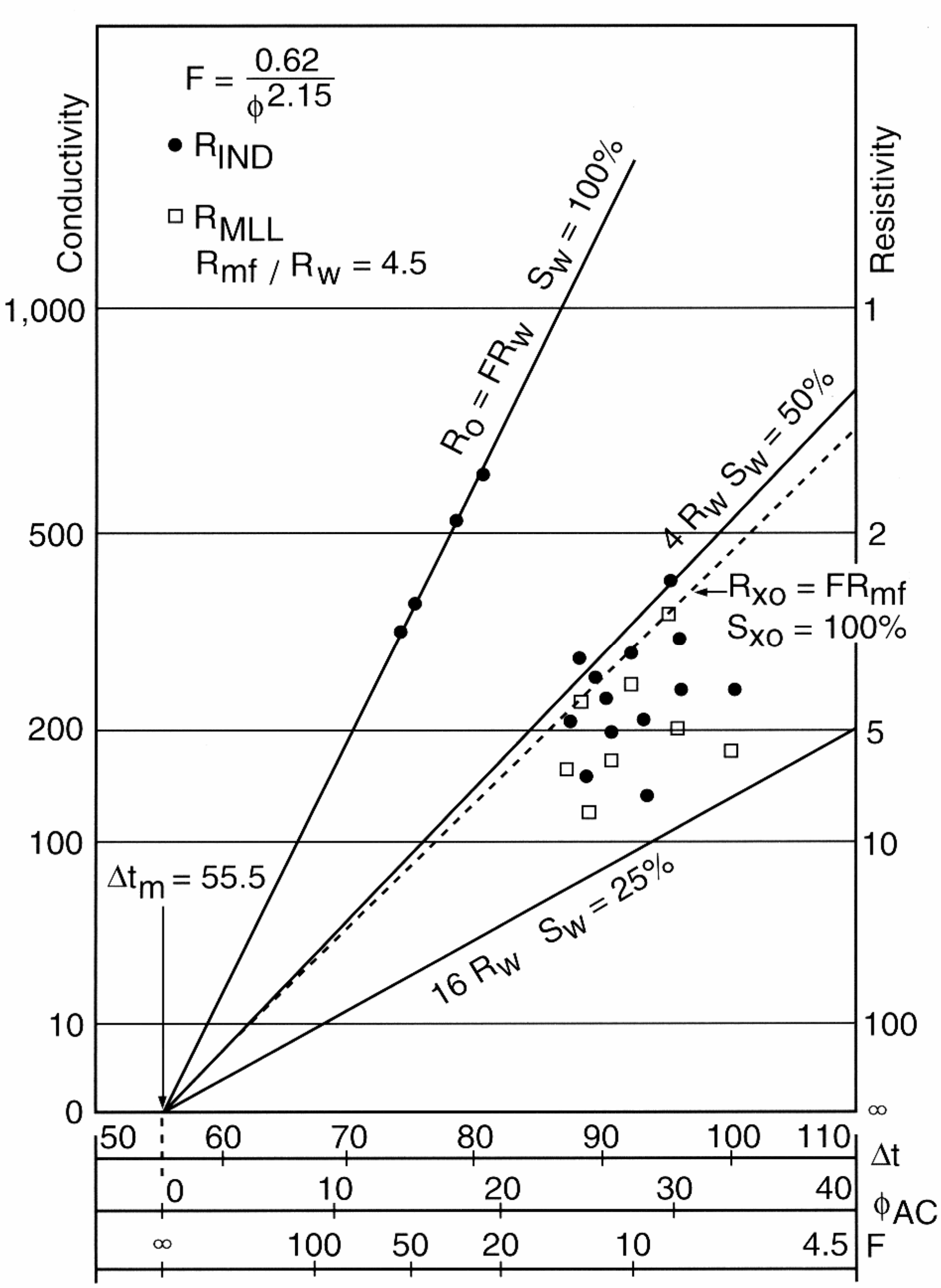
A Sample Pickett Plot Showing 'm' Derivation

The virtue and the vice of the Pickett plot, is that it allocates all uncertainties and errors to the value of m, which can only be verified with core analysis data. However once 'm' is determined we can also use an earlier form of the Rt - ϕ cross-plot, the Hingle plot

THE HINGLE PLOT (1959)

This was the first graphical attempt to solve the water saturation equations. To scale the plot correctly you need to know the value of m. In its earliest use this was assumed to be the Archie or Humble values. The virtue of this plot is that it also allows us to establish Rw from a Sw = 100% line.

Lines of various Sw can be plotted and the array of data about them inspected for its value and quality. The slope of each line is determined by the Archie parameters *and* the Sw. The 0 porosity value is the intercept of the Ro line at 100% Sw.



A Hingle Plot For The Humble Equation

BVWi AND BUCKLES NUMBERS

In 1965 Buckles first proposed that the relationship that Swi.ϕ product was constant and that this could be plotted as a hyperbolic function on a graph of ϕ versus Swi. The value of this constant, ‘c’, is actually the water saturation expressed as a volume fraction of the bulk volume of the rock, or BVWi. As a plotting device we can linearise this relationship with base-ten logarithms to provide,

$$\log Swi = \log c - \log \phi.$$

We can apply the Archie equation to this and rearrange, solving for log Rt;

$$\log Rt = \log (a \cdot Rw) - \text{‘}n\text{’} \log c - (n-m) \log \phi.$$

This equation describes a line on a Pickett plot with a slope (n-m) and an intersection with the water line at a value of ϕ where Swi = 100%. When ‘m’ = ‘n’ the line should be parallel to the porosity axis. When ‘n’ < ‘m’ it should slope to the left and when ‘n’ > ‘m’ it should slope to the right. This allows us to estimate ‘n’ where ‘m’ is determined from the Pickett plot.

ANALYTICAL Sw DETERMINATION.

So far we have only looked at the basic Archie relationship to describe analytically the Sw,ϕ relationship from Rt. There are a number of published equations that attempt to modify this relationship for differing equations in different parts of the world. For clean formations we tend to allocate all of the variability in formation behaviour to the parameters a, ‘m’ and n. However, most common reservoir sandstones are not clean. The reservoirs often contain shaly material in the form of laminations, drapes, or clasts. To top this, most sandstones also contain disseminated clay in the pore space. The presence of clay and shale can severely complicate Sw and porosity evaluation. This can be all the more problematic because small shale volumes can have extremely high surface areas upon which to exchange ions and conduct electricity. In Chapter 1 we discussed the various problems.

The late Walter Fertl listed 19 different equations that have been proposed to handle shale conductivity and its effect on the Archie relationship. All these have a few common elements. These are;

The volume of shale or clay, V_{sh} and V_{cl},
The Resistivity/Conductivity of the shale R_{sh}, or C_{sh}.

In addition to this some equations require the activity of the shale, CEC , or Qv and the activity of the associated water, B. It is outwith our scope to try all these models here. We will restrict ourselves to The following relationships,

The Poupon Model,
The Simandoux Equation,
The Indonesia Equation, or Poupon - Leveaux model,
The Waxman Smits (and Thomas) Equation.
The Dual Water Model, or Clavier, Coates and Dumanoir Equation.

We have already covered the Archie equation in some detail, so no more need be said at this time, except that it does not handle shaly-sands well as the effects of shale removes the linearity of the parameters ‘m’ and ‘n’ on a log-log transform. The rest need the volume of shale to get started.

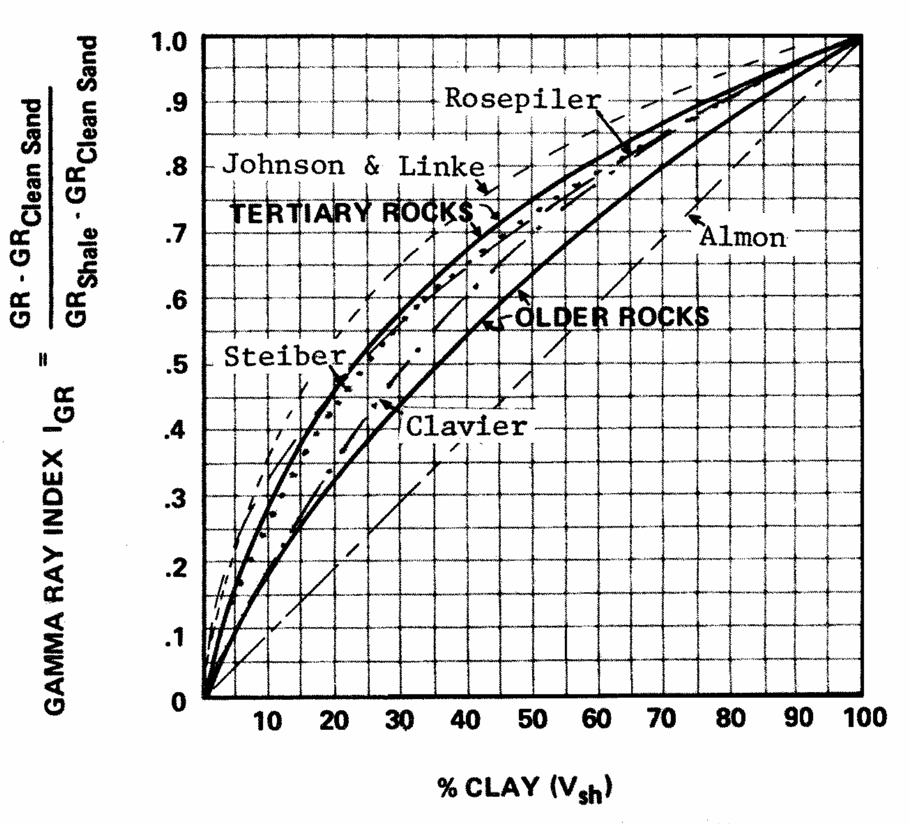
V_{sh} DETERMINATION

Gamma-Ray

In order to apply any of the above equations we need to know the quantity of shaly material present in the formation. Like everything else there are a number of ways we can do this. In Chapter 1 and 2 we looked at the response of the Gamma-ray log to shales. Given that there is no appreciable influence from non-clay gamma-ray sources, the following equation can be derived,

$$I_{GR} = \frac{GR - GR_{(Clean-Sandstone)}}{GR_{(Shale)} - GR_{(Clean-Sandstone)}},$$

where, I_{GR} is a Gamma-ray shale index. This is then plotted on a graph of I_{GR} versus V_{CL}, or V_{sh}.



Published Correlations Between Gamma-ray And V_{sh}

The NGT

An embellishment of the gamma-ray technique is to only use the Thorium and Potassium responses from the spectral gamma-ray log, or NGT. The Uranium response is subtracted from the tool response to achieve this. There is a certain logic to this approach, as Uranium concentrations often imply ground-water percolation has taken place, rather than the presence of shale. The equation becomes,

$$V_{sh} \le \frac{CGR - CGR_{(Clean-Sandstone)}}{CGR_{(Shale)} - CGR_{(Clean-Sandstone)}},$$

Where the term CGR represents the NGT - URAN responses.

SP

We saw earlier that the SP could be attenuated by the presence of shale. From this response a normalised SP V_{sh} has been developed,

$$V_{sh} \le \frac{SSP - ASP}{SSP} \text{ and also } V_{sh} \le 1 - \frac{ASP}{SSP}.$$

This value of V_{sh} is considered an upper limit of effective shale. This is useful because if the Gamma-ray, or other methods predict a higher V_{sh}, something else is affecting their response, not effective shale. Note that the usual bed thickness rules apply to the shaly bed as well as a clean one.

Density P_e Response

We saw how the LDL allows us to determine U_{maa} and U, the photoelectric absorbtion volumetric index. From an assumption of an effective medium response function, and since,

$$U \approx \rho_b \; x \; P_e,$$

We can express U as the sum of the products of each component in a mixture,

$$U = (1 - \phi - V_{sh}) \cdot U_{maa} + \phi \cdot Sxo \cdot U_f + \phi \cdot (1 - Sxo) \cdot U_h + V_{sh} \cdot U_{sh},$$

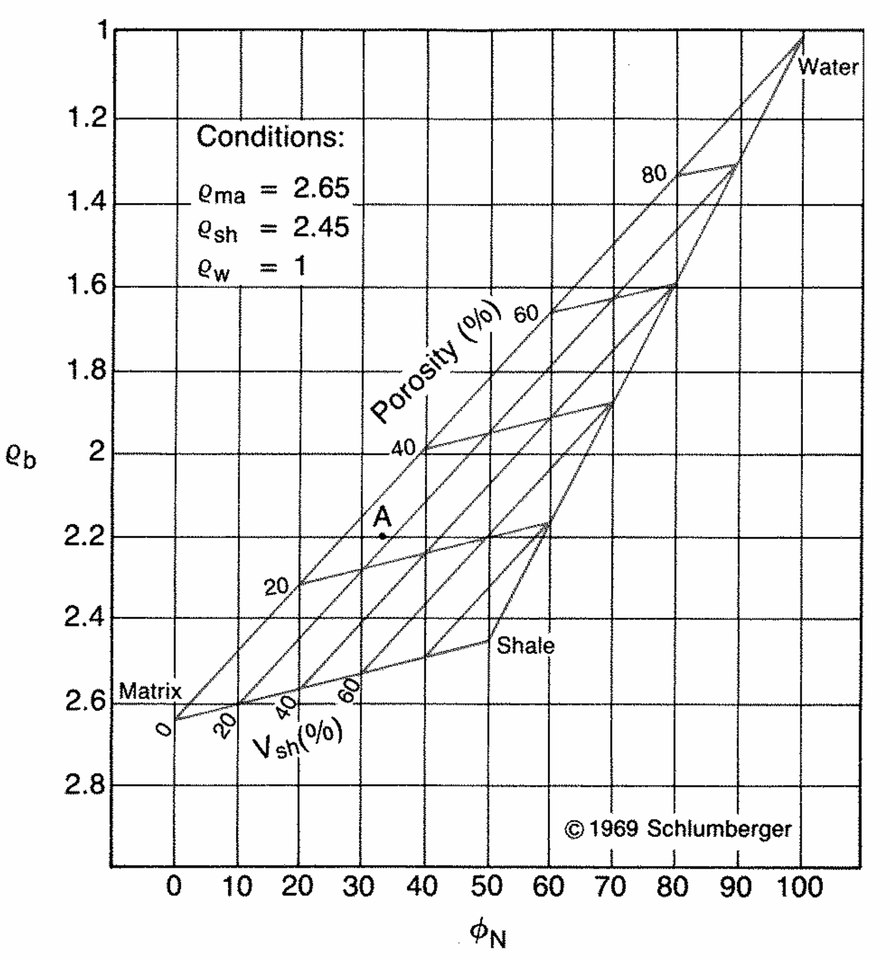
Since Uh is always smaller than 0.12 we can neglect the term $\phi \cdot (1 - Sxo) \cdot U_{h.}$ If the formation is invaded with fresh water filtrate we can also ignore the Uf term, $\phi \cdot Sxo \cdot U_{f.}$ However, in salty muds this term must be included. For fresh muds then,

$U = (1 - \phi - V_{sh}) \cdot U_{maa} + V_{sh} \cdot U_{sh},$ and

$$V_{sh} \le \frac{U - (1 - \phi_{DN}) U_{maa}}{U_{sh} - U_{maa}}.$$

Neutron - Density Cross-plot

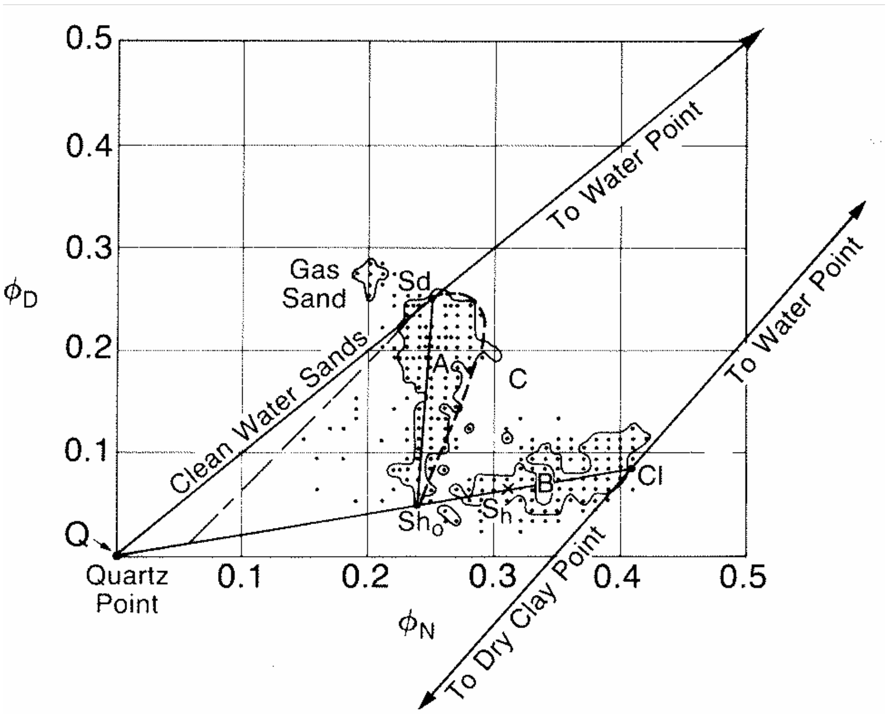
As well as using the N - D cross-plot to estimate lithology and porosity it has real value as a Vsh predictor. It cannot discriminate whether the shale is effective or not (i.e. has an active effect on the resistivity response). The shale effectiveness depends on its type and location in the formation. Disseminated shale (clays) have the strongest effect, followed by laminated shales.



A Neutron - Density Cross-plot with the Shale point Scaled

Not only does the scaling for the shale point give a volume of shale, it also gives the porosity value corrected for shale influences. The same procedure can be done on a Sonic - Density cross-plot. This plot may be better where the matrix lithology is not well constrained as the lithology lines are close together and therefore less uncertainty is introduced.

Two problems may arise with the N -D approach to V_{sh}. The most important of these is the distinction between effective and non-effective ones. Low CEC shales, not contributing to resistivity suppression will still affect the shale point. This may cause the over estimation of V_{sh} for use in shaly sand equations. The second important distinction is that the shale point is truly 100% shale and not a dirty silt. V_{sh}. Once again poor selection of the shale point will lead to the choice of a too high. Measurements of CEC and clay content on cores can help solve both these problems.



A N - D Cross-plot Showing The Concepts of Shaliness Versus Clay

In the figure above the line from Sd to Sh_o represents a formation ranging from clean sand (Sd) through laminar shales to shale at Sh_o. Points falling to the right of this line are more clay rich than the silty shales. So, group A on this plot are sands and shaly sands, to silts, and group B are shales with varying silt content. Since there is a shale point and a clay point on this plot it is scaled in terms of V_{cl}. A silt index (I_{sl}) can be defined in terms of V_{sh} and V_{cl}, $I_{sl} = ((V_{sh} - V_{cl}) / V_{sh})$.

SHALE CORRECTED POROSITY

For the various porosity tools we can now describe formulae which correct their responses for shaliness.

Neutron

$$\phi_{Nclean} = \frac{\phi_N - \phi_{Nsh} \cdot V_{sh}}{1 - V_{sh}}$$

Density

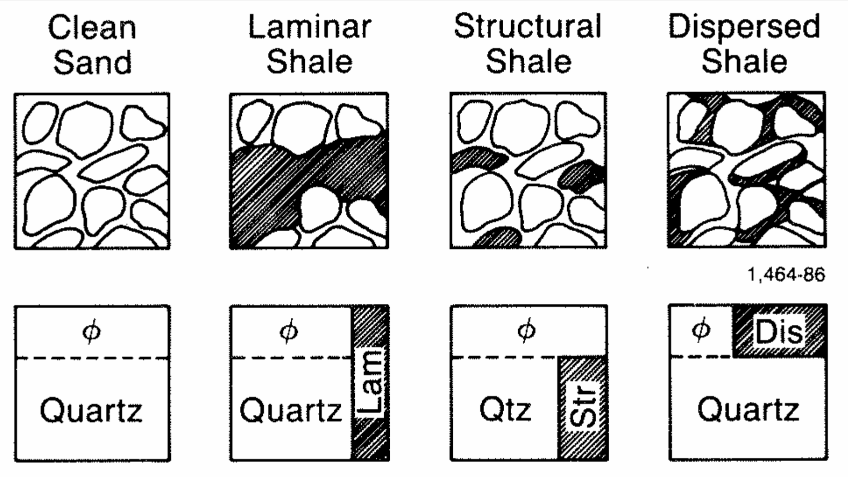
$$\rho_{bclean} = \frac{\rho_b - \rho_{sh} \cdot V_{sh}}{1 - V_{sh}}$$

Sonic

$$\Delta t_{clean} = \frac{\Delta t - \Delta t_{sh} \cdot V_{sh}}{1 - V_{sh}}$$

SHALE RESISTIVITY

This is one of the parameters upon which the approach to shaly sands can founder. Normal practise would be to take the Rsh of an adjacent shale. However this presupposes the porosity, mineralogy and Rw of the shale are the same as the shaly material in the shaly sand. While this may be appropriate in some laminated shale-sand sequences it cannot be said to be true of dispersed clays and some disseminated shale.



Mixing Models For Shales And Their Volume Cubes

Published values for clay resistivity are from 0.7 - 1.5 ohmm for montmorillonite and 1.0 - 3.0 ohmm for illite at 77 ˚F. These can be corrected to formation temperature , FT and used instead of adjacent bed values,

$$Rsh\ @\ T_f = \frac{77 \times (Rsh\ @\ 77^0\ F)}{T_f}$$

SHALY - SAND Sw EQUATIONS

As previously stated we will restrict ourselves to a few of these. The first of these is suitable for laminated sand shale sequences only. A rough rule of thumb from Hilchie suggests that to distinguish the shale, compare the V_{sh} from the Gamma-ray with the V_{sh} from the SP. In laminated shales they should be equal and in dispersed clays the SP value should be higher.

LAMINATED SHALES

The Poupon equation for laminated shales is a simple parallel flow model in which the resistivity, Rt should be,

$$\frac{1}{Rt} = \frac{1 - V_{sh}}{R_{sand}} + \frac{V_{sh}}{R_{sh}},$$

Solving this for Sw using an Archie model and substituting through,

$$Sw = \sqrt[n]{\frac{a}{\phi^m} \cdot \left(\frac{1}{Rt} - \frac{V_{sh}}{R_{sh}}\right) \cdot \left(\frac{Rw}{1 - V_{sh}}\right)}$$

This model works reasonably where the sand laminae are clean. If the sands are not clean then a dispersed clay model should be used.

DISPERSED SHALES

More often than not, the formation shaliness consists of dispersed clay, with or without laminations. A fundamental problem is shown in the work of Hoyer and Spann, Waxman and Smits and Brown in 1988. The excess conductivity introduced by the presence of clay with a CEC does not cover the entire problem. for independent of the CEC, the shale present will affect the cementation exponent, ‘m’ through it micro porosity. In fact the more shale there is the higher the true m. In our discussion in earlier chapters we did not investigate this problem in any depth. Before we consider it we must review the alternative dispersed clay models.

Simandoux

The Simandoux equation was an attempt to provide a solution that could be achieved graphically or by computer. It is a **Total Shale Equation** and has the form

$$aSw^2 + bSw = Rt^{-1},$$

Which is a quadratic equation that transforms as follows when ‘m’ and ‘n’ both equal 2,

$$Sw = \left(\left(-\frac{V_{sh}}{R_{sh}} \right) + \sqrt{\left(-\frac{V_{sh}}{R_{sh}} \right)^2 + \frac{5\phi^2}{Rt \cdot Rw}} \right) \frac{0.4Rw}{\phi^2},$$

and when a and ‘m’ are not 1 and 2:

$$Sw = \frac{aRw}{2\phi^m} \left(\left(-\frac{V_{sh}}{R_{sh}} \right) + \sqrt{\left(\frac{V_{sh}}{R_{sh}} \right)^2 + \frac{4\phi^m}{a \cdot Rt \cdot Rw}} \right)$$, or expanded to,

$$Sw = \left(\sqrt{\frac{Ro(1-V_{sh})}{R_t} + \left(\frac{RoV_{sh}(1-V_{sh})}{2R_{sh}} \right)^2} - \frac{RoV_{sh}(1-V_{sh})}{2R_{sh}} \right)^{\frac{2}{n}},$$

where $Ro = \frac{aRw}{\phi^m}$.

The Indonesian Equation

As its name implies, after the opening up of Indonesia to oil exploration after 1945, it became quickly apparent that the simple Archie relationships would not work in the shaly sands of the Mahakam Delta and Sumatra. If the Archie ‘m’ and ‘n’ equals 2 are appropriate then the following form can be applied,

$$Sw = \frac{1}{V_{sh}\sqrt{\frac{Rt}{R_{sh}}}+\sqrt{\frac{Rt}{F \cdot Rw}}},$$

However, this is a simplification and the correct form is as follows

$$\frac{1}{\sqrt{Rt}} = \frac{\phi^{\frac{m}{2}} \cdot Sw^{\frac{n}{2}}}{\sqrt{a \cdot Rw}} + \frac{V_{sh}^{\left(1-\frac{V_{sh}}{2}\right)}}{\sqrt{R_{sh}}}$$

and

$$Sw = \sqrt[\frac{n}{2}]{\frac{1}{\left(\left(\frac{\phi^{\frac{m}{2}}}{\sqrt{a \cdot Rw}}\right)+\left(\frac{V_{sh}^{(1-\frac{V_{sh}}{2})}}{\sqrt{R_{sh}}}\right)\right) \cdot \sqrt{Rt}}}$$

, or expanded to

$$Sw = \left(\frac{V_{sh}^{0.5(2-V_{sh})}}{\sqrt{\frac{R_{sh}}{Rt}}}+\sqrt{\frac{Rt}{Ro}}\right)^{-\frac{2}{n}}$$

Waxman Smits and Thomas

Although generally known as Waxman Smits equations, the current forms owe a lot to the work of E C Thomas. The concepts here were also investigated by Hoyer and Spann. The idea is to derive a shale conduction term that corrects for the suppression of resistivity. The equation was developed from observations of laboratory experiments and through measurements of the CEC of shale bearing samples.

The CEC was evaluated either by wet chemical titration with ammonia ions (NH^{3+}), Barium ions (Ba^{2+}), Membrane potential measurements or multiple Rw saturation and Ro determination. CEC measured by wet chemistry was determined in terms of 100g of material. This is related to pore space by the following equation,

$$Qv = \frac{CEC(1-\phi)\rho_{ma}}{100\phi} \ ,$$

Where Qv is the quantity of cation exchanging material per ml of pore-space.

The Waxman Smits equation is,

$$Sw = \sqrt[n*]{\frac{a^{*}}{\phi^{m*}} \cdot \frac{Rw}{Rt\left(1+\frac{RwBQv}{Sw}\right)}} \ ,$$

where the terms denoted with an asterix are the independent of clay conduction values of the formation factor. The term B is the “specific counter-ion conduction” and is effectively the electrical activity of the ions in solution in the formation water. The following are therefore definitions,

$$F* = Fa(1+Rw\cdot B\cdot Qv) \text{ and}$$

$$B = 4.6\left[1-\left(0.6\exp\left(\frac{-0.77}{Rw}\right)\right)\right] \text{, or}$$

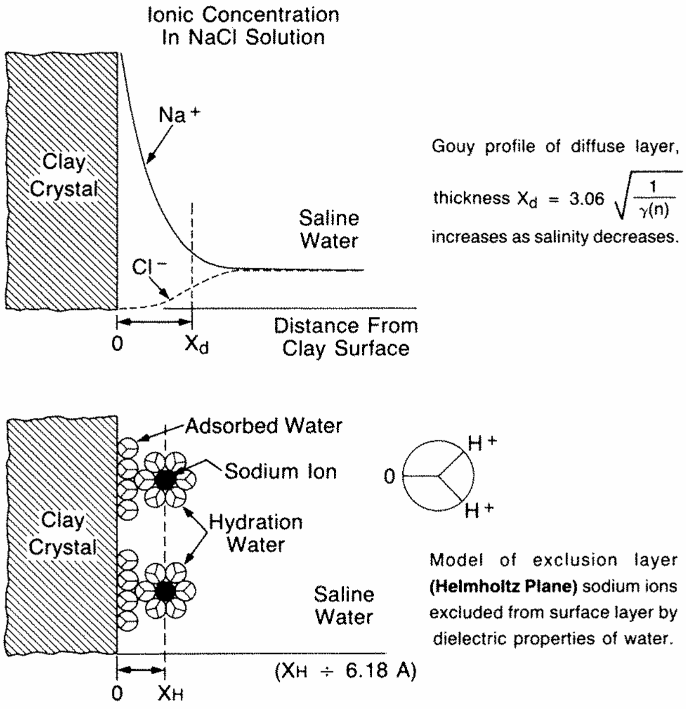
$$B = \left[1-\left(0.6\exp\left(-\frac{Cw_{@25C}}{0.013}\right)\right)\right]0.046 \text{, in terms of conductance}$$

$$n^* = \left(\frac{1}{\ln Sw}\right)\ln\left(\frac{1+RwBQv}{RI\left(1+\frac{RwBQV}{Sw}\right)}\right)$$

If there is an advantage of the Waxman Smits equation it is that when Qv is zero, the equation simplifies to the Archie equation. The principle disadvantage of the equation is that it relies upon a large database of measurements of CEC on core material. This has made it unattractive to the average user. It also can only be solved iteratively.

The Dual Water Model

This equation started off as an attempt to advance the Waxman Smits model. Clavier et al, noted that the Waxman Smits tended to over-predict the clay suppression in some cases. They theorised that this was due to the Helmholtz, or De Gouy - Stern boundary layer of water bound to the clays surfaces.

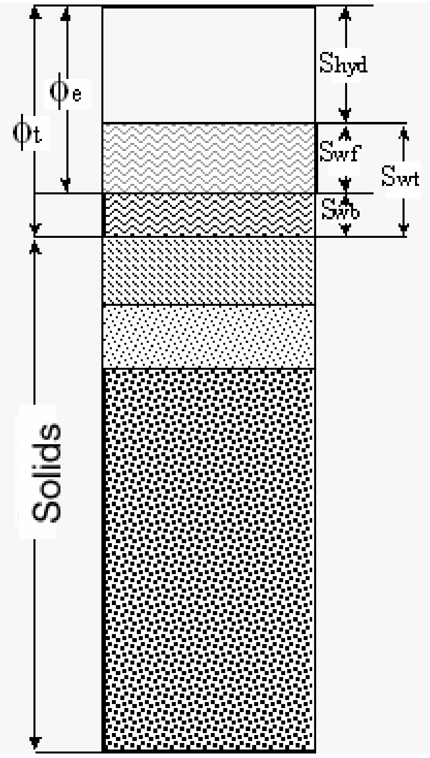


While no one is certain which of the alternative physical models is correct there is no doubt that the bound water layer can act like an electrolyte in a capacitor and increase the impedance between the pore-water ionic conduction and the clay-bound ionic conduction through dielectric effects.

This occurs as the anions are excluded from the bound water system. The cations become complexed in a zone of decreasing salinity. Some research also suggests that the bound water becomes more dense taking on a semi-crystalline structure. Whatever the case, we should adapt our shaly sand models accordingly

The Dual Water model then treats clays as a complex of clay and surface water. The rest of the pore water is the far-water. The amount of bound water actually depends on the surface area of the clay. Some research has shown that clay CEC is actually proportional to the surface area of the clay and less dependent upon its bulk chemistry. This is simply because any surface chemistry is bound to have yields dependent upon the amount of surface available to react upon. The surface area of 1g of montmorillonite is approximately 1 x 10^{12} the surface area of an equivalent mass of quartz.

There are a few new terms in these equations that need defining. By viewing the figure below as a conceptual model of the distribution of the various physical zones that make up the total rock model. we can see that; The total 'Solids' are made up from the sand, silt and dry clay volumes. Total porosity, ϕ_t, includes bound and far-water, and the hydrocarbon pore-space, while the effective porosity, ϕ_e, excludes the bound-water layer.



S_{wt} = The total water saturation,

S_{wb} = The bound water saturation,

S_{hyd} = **$(1-S_{wt})$**, The hydrocarbon saturation,

S_{wf} = **$(S_{wt}-S_{wb})$**, The far-water saturation,

$S_{wb}\cdot\phi_t$ = The bound-water volume,

$(1-S_{wt})\cdot\phi_t$ = Hydrocarbon volume,

$(S_{wt} - S_{wb})\cdot\phi_t$ = Far water volume.

$\phi_e = (1-S_{wb})\cdot\phi_t$ = Effective Porosity.

$$Sw = \frac{\text{Free water}}{\text{Effective Porosity}} = \frac{\left(S_{wt} - S_{wb}\right)\cdot \phi_t}{\left(1 - S_{wb}\right)\cdot \phi_t},$$

and therefore,

$$Sw = \frac{\left(S_{wt} - S_{wb}\right)}{\left(1 - S_{wb}\right)},$$

To solve the equations for a reservoir rock, we need to look at the equivalent of an Archie relationship,

$$Sw = \sqrt[n]{\frac{aRw_m}{\phi_t{}^m Rt}},$$

Where ϕ_t and Rw_m replace their corresponding values. Rw_m is defined as the equivalent Rw of the Dual Waters,

$$Rw_m = \frac{R_{wb}\cdot R_{wf}}{R_{wb}\left(1 - S_{wb}\right) + \left(R_{wf}\cdot S_{wb}\right)},$$

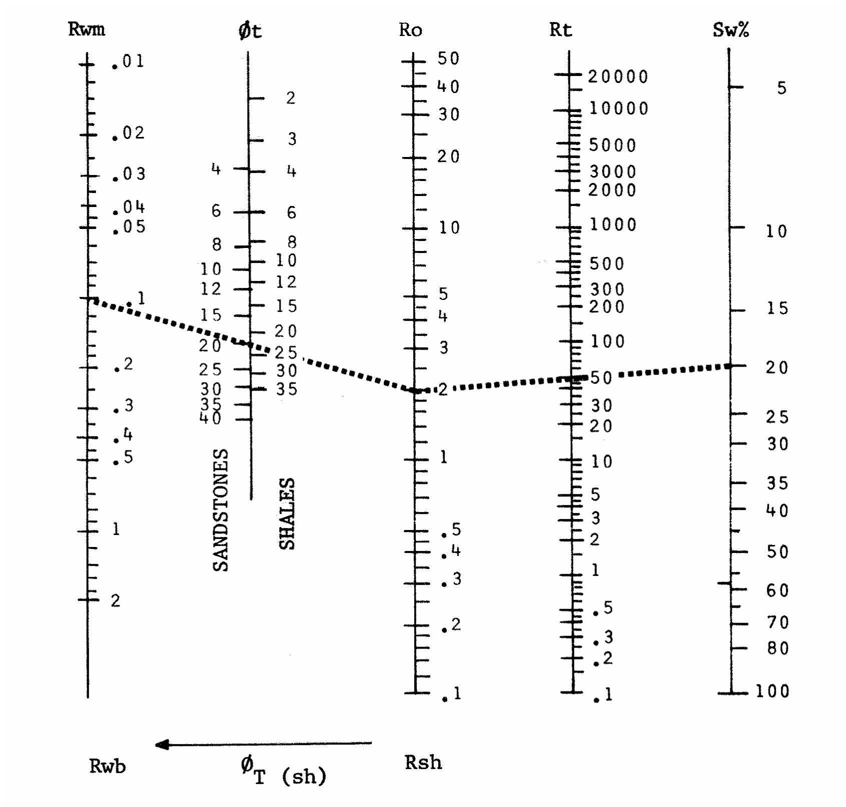
where;

R_{wb} is the bound water resistivity = $\phi_{sh}{}^2 \cdot R_{sh}$

Rwf is the free(far)-water resistivity = $\phi_{clean}{}^2 \cdot R_{clean}$

S_{wb} is a function of V_{cl}, dependent on and proportional to the wetness of the shale. Since this is the case we can estimate this from a nomogram.

Dual Water Model R_{wb} From R_{sh} and ϕ_t



By determining R_{wb} from the previous chart and entering it into this chart along with Rw and V_{sh} the value of R_{wm} can be arrived at.

We can now derive ϕ_t from either of the following;

When $\phi_N \geq \phi_D$,'

$$\phi_t = \frac{\phi_D + \phi_N}{2}$$

and when $\phi_N < \phi_D$,

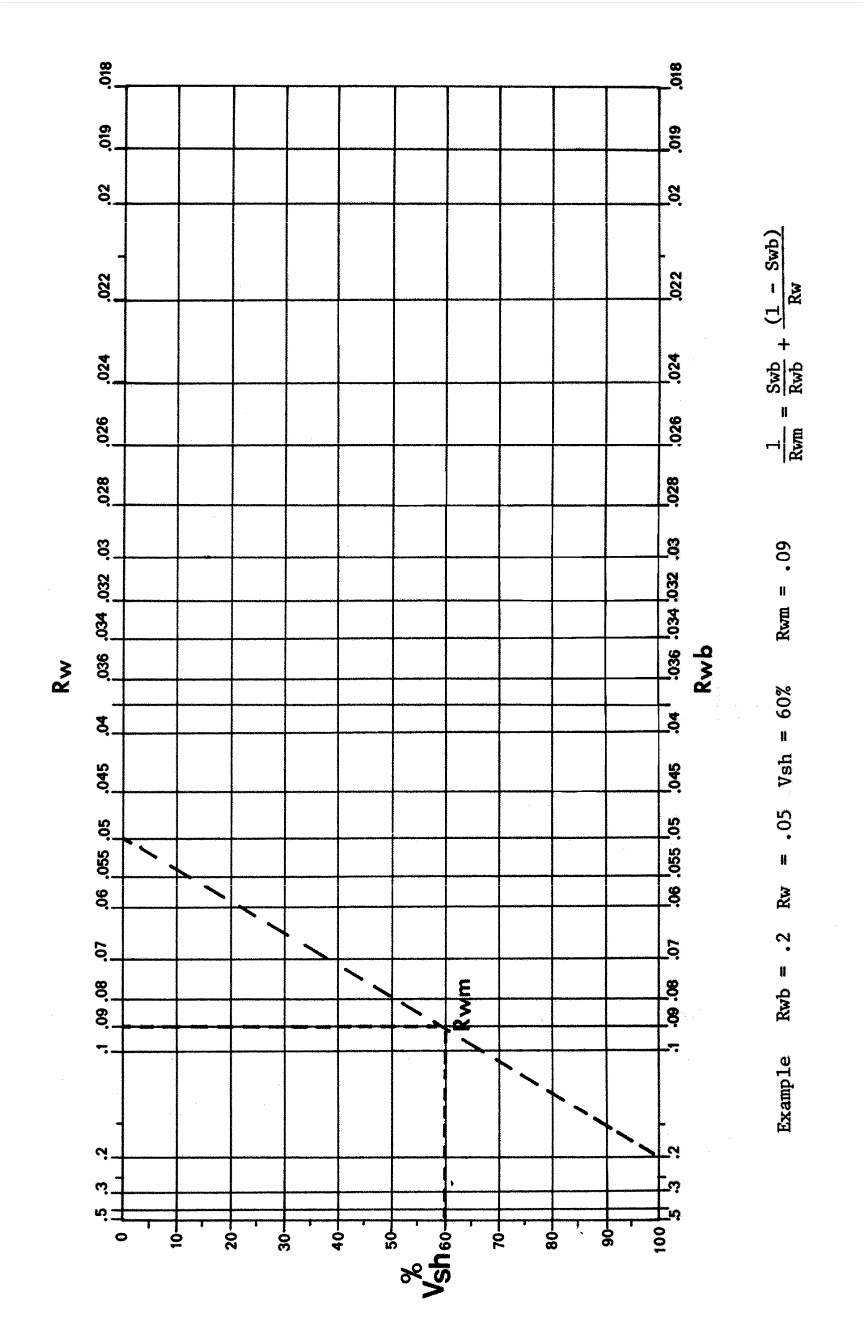
$$\phi_t = \sqrt{\frac{\phi_D{}^2 + \phi_N{}^2}{2}}$$

The wet resitivity of the formation under study is therefore related to the total porosity by,

$$Ro_{Dwm} = \frac{a \cdot R_{wm}}{\phi_t^{\,m}},$$

and the water saturation is,

$$Sw = \sqrt[n]{\frac{Ro_{Dwm}}{Rt}}$$



R_{wm} Determination in the Dual Water Model

STEP BY STEP APPROACH TO Sw

1) Select a valid and representative log reading.

2) Make all the appropriate environmental corrections - in the right order, borehole, bed, invasion.

3) Determine V_{sh} and make necessary corrections to porosity.

4) Correct for hydrocarbon density. Use chart **CP-9** to obtain ϕ_1 and $\Delta\phi$ to be summed to find ϕ. For this correction a S_{hyd} is needed from the near wellbore. Conversely you can use $\phi = \phi_1(1 - 0.10\rho_{hyd})$, with ρ_{hyd} determined from chart **CP-10.**

5) Solve for Sw using the appropriate choice of shaly-sand equation.

Modern computer programs have most of the common algorithms pre-programmed for use.

PERMEABILITY PREDICTION

If we accept that all the models we have encountered so far will give us a value for the amount of hydrocarbons in place, then the only remaining thing to determine is how fast will we be able to produce them. In other words, what will be the rate of return on this project, or well.

We saw in Chapter 1 that most core data will be plotted as porosity versus log permeability. Where this provides a good trend with little scatter and the core represents all of the range in permeability, and lithology in the reservoir, then a normal practise would be to build a core - log porosity transform, so that permeability values may be allocated to down-hole log data. While this is the simplest approach we could make, it is fraught with potential errors.

Core porosity and permeability data need to be under simulated net overburden. The data need to have sampled the range in variability of the properties of the reservoir. By this we mean that the specimen volume and sampling frequency must satisfy the requirements of support and stationarity within the bounding limits of statistical analysis. Often one foot sampling with core plugs does not meet that criteria. Core plug scale can be inappropriate with respect to the reservoir heterogeneity and the anisotropy that introduces. Likewise, although a well-test samples the reservoir, we may have no idea of how it is spatially volume averaging the effects of geological heterogeneities in the near and far field. So the dilemma is; which permeability am I predicting?

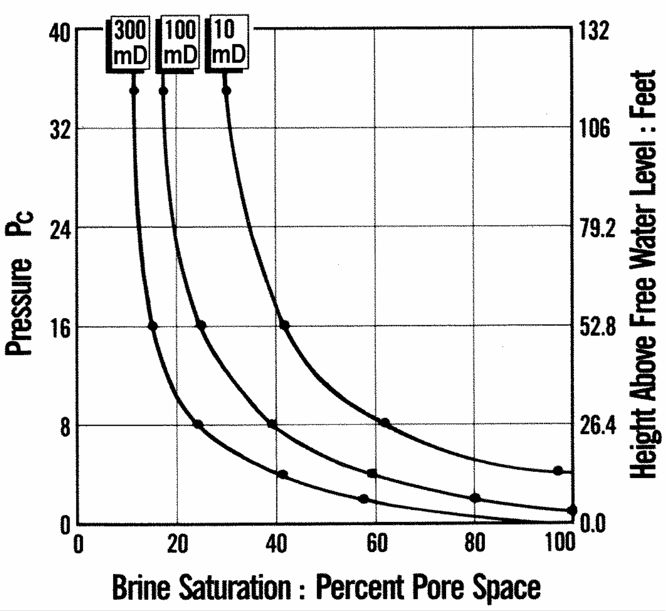
Early on in the history of petroleum engineering the Sw - height capillary pressure relationship was recognised in granular rocks, such as sandstones. Capillary pressure, Pc, is a measure of the ability of a rock to hold water against a displacing phase pressure. In nature the buoyancy difference under gravity, between oil, or gas, and water is what provides the displacing pressure. Obviously the higher you go in a hydrocarbon column the stronger the displacing pressure. The Young - Laplace equation quantifies Pc in terms of the wettability ($\cos\theta$), the interfacial tension between the fluids (σ) and the pore entry radius (r),

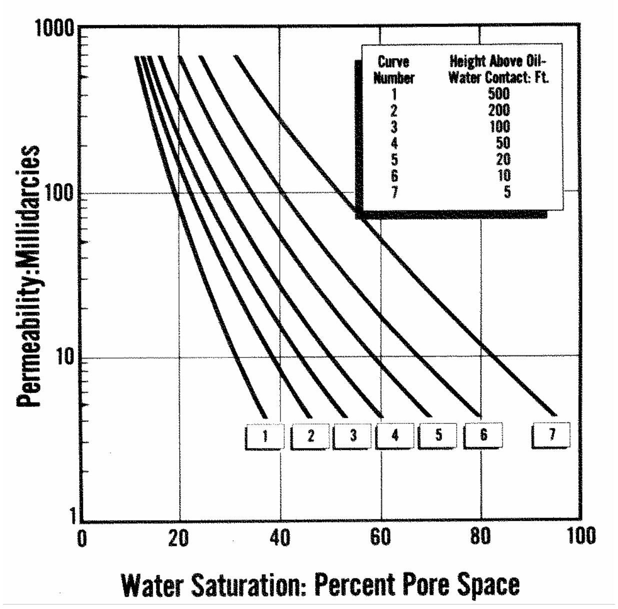
$$Pc = \frac{2\sigma \cdot \cos\theta}{r},$$

This equation was formulated for straight capillary tubes and it has become common to replace r with the Leverett (1941) mean-hydraulic radius $(k/\phi)^{0.5}$. It should not be surprising that this implies some inverse proportionality between k and Pc, and that Sw is some function of Pc.

From the above relationships we would expect to see Sw vary with height above a free water level, where buoyant forces = zero, and vary inversely with Pc. If the changes in pore geometry within the zone are systematic and proportional we should be able to see a family of Pc curves that represent the poorest to best quality rock.

An Array of Pc Curves Demonstrating Sw vs. Height





A Resultant Correlation of k With Sw and Height

It should be blatantly obvious that if we can correlate K with Sw we can turn the relationship round and use Sw to predict k. Petrophysicists have been doing this since the 1940s. From the Young Laplace equation and the above figures we can imply that,

$$k^a = \frac{C \cdot \phi^b}{Swi}$$

Which is the general form of the Wyllie and Rose expression first postulated in 1950, where a, b and C are parameters depending upon the grain-size, sorting fluid saturation and diagenesis in any particular sandstone reservoir. Reported values vary as follows: a = 0.5, b = 2.25 - 3.00 and C varies from 100 to 250. Oil with a ρ_{hyd} of 0.8 gives a value of 250 while gas gives 100.

We should be aware the permeability measured in the lab is a true darcy permeability. This is known a ‘specific permeability”. In the wellbore we have more than one fluid phase competing for pore space. The result is that the permeability we estimate is an “effective permeability”, i.e. the permeability of one fluid phase at less than 100% saturation of that phase.

$$k^{0.5} = \frac{250 \cdot \phi^3}{Swi},$$ Tixier,

$$k^{0.5} = \frac{100 \cdot \phi^{2.25}}{Swi},$$ Timur,

$$k^{0.5} = \frac{300}{w^4} \cdot \frac{\phi^w}{Swi^w},$$ Coates - Dumanoir, where w is ≈ ‘m’ ≈ n,

$$k^{0.5} = 100 \cdot \frac{(1 - Swi) \cdot \phi^2}{Swi},$$ Coates.

Each of these empirical equations has a different solution, so their use must be validated against measured data, with all the potential traps that this entails. There can be an order of magnitude or more difference in their predictions.

RESISTIVITY GRADIENTS

The capillary profile leads to a transition zone between 100% Sw and the Swi. This will create a gradient between Ro and Rt. If we express this per foot of depth then we can relate this to the overall permeability of the zone with,

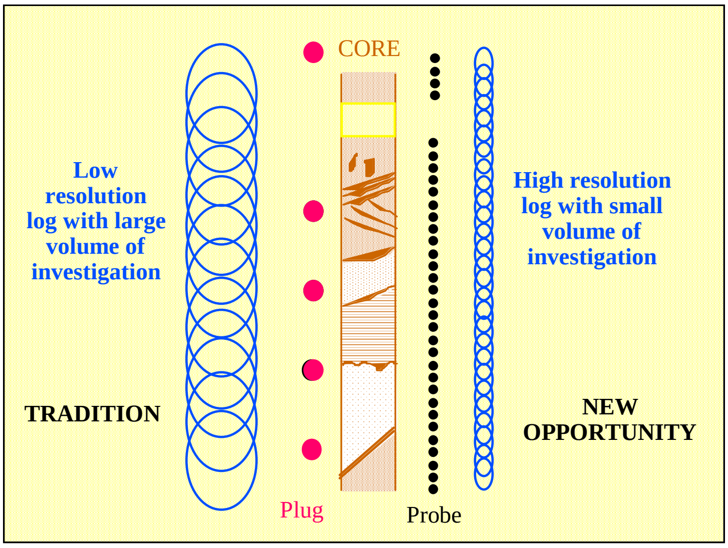
$$k = C\left(\left(\frac{\Delta R}{\Delta D}\cdot\frac{1}{Ro}\right)\cdot\frac{2.3}{\rho_w - \rho_h}\right)^2,$$

Where C is a constant around 20, and ΔR and ΔD are the change in resistivity and the change in corresponding depth.

MICRO - RESITIVITY CORRELATION

In recent years the relationship first presented by Gus Archie, between Formation Factor and permeability has been the focus of new investigation. The focus of this work has been on adequately describing the permeability variation so that it can be validly upscaled to compare with Rxo and F.

Jackson et al. Ball et al and Thomas et al, have all produced models for tools varying from a laboratory resistivity probe, the MSFL response and the FMI imaging tool. Each relationship needs to be derived on the individual formation of interest and backed-up with acquisition of fine scale probe permeametry.



A Graphical Illustration Of The Concepts

NMR

In the section dealing with NMR in chapter 2 we saw how the Timur equation could be used to predict permeability from NMR data.

$$k = a'\phi^4\left(\frac{FFI}{BFV}\right)^2,\ \text{(Timur/Coates')}$$

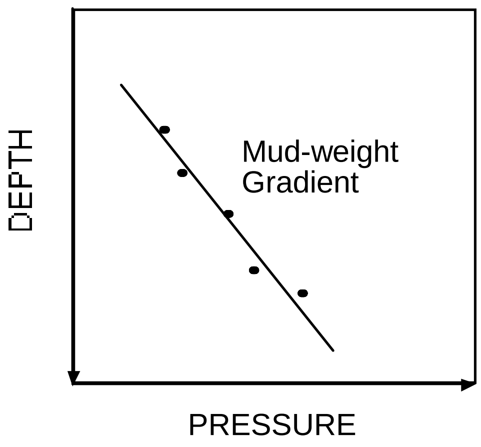
This is the most popular approach today, once calibrated against core data.

FORMATION TESTERS

Perhaps the most important current tool for validating permeability is the formation tester. The original tools were the FT and FIT, which simple pushed a probe, surrounded by a seal, against the well-bore and opened a valve to fluid flow. The acquired sample was brought to the surface to test it for the presence of hydrocarbons.

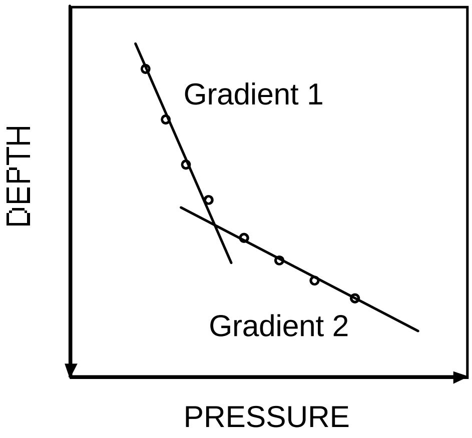
Each sample was in its self a miniature well test. In the original tools there was provision for two Amerada type pressure recorders. However, their poor resolution made decent analysis near impossible until the advent of modern quartz and digital strain -gauge pressure recorders. With modern equipment it is possible to resolve very small changes in pressure down to 0,001 psi and measure accurately to 0.01 psi. It is outwith the scope of this course to cover this analysis in detail, however, a simplified review follows.

The Modern sampling devices are the RFT and the MDT. The former of these has the ability to take multiple pressure tests and recover up to two samples of fluids. The MDT can be configured in a number of ways, but the main advantages are its ability to flow between probes and to recover multiple fluid samples as well as multiple pressure tests.



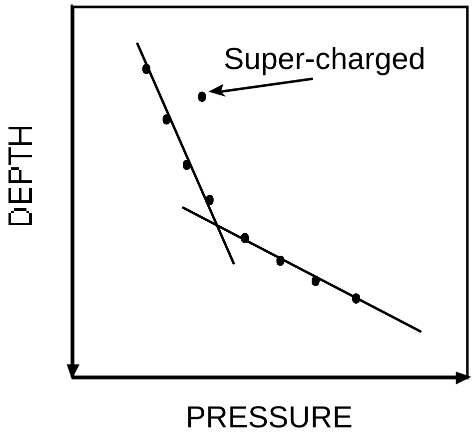
The first step in assuring good quality data is to plot the recorded formation and mud column pressures versus depth. These data show where the tool is making acceptable measurements and where it is not.

Once a decent hydrostatic column is established a degree of confidence can be applied to the formation pressure data. The plot of pressure may show that there is more than one fluid gradient down-hole. This is good news as the likelihood is that the lower gradient is hydrocarbon.



This technique of identifying the fluid contact is known as "Gradient Intercept" and is very valuable, particularly in gas reservoirs. Unfortunately, in oils the gradients may not be different enough to give any depth precision.

The fluid gradient may have spurious data points for a large variety of reasons, such as reservoir heterogeneity, over-pressure etc. One example is when the mud column supercharges a low permeability zone such that the hydrostatic pressure does not bleed away.



The actual tool uses pre-test chambers to perform mini-drawdowns on the isolated formation. The pre-test chambers are very small, only 20 cm^3 or so, but this is enough to investigate a volume out to 2 feet or so. One of the pre-test chambers has a small orifice and the other a larger one in order to change the filling rate characteristics. In essence, differentiation of the pressure drawdown with respect to time and some geometrical model gives permeability. The resultant equation for the pressure drop is,

$$\Delta P = \frac{C\mu q}{2\pi r_p k_d} \cdot \left(1 - \frac{r_p}{r_e}\right),$$

where;

ΔP is the drawdown pressure

C is the geometric shape factor for flow

q is the flow rate

μ is the viscosity of the fluid

r_p is the effective probe radius

r_e is the outer radius of investigation of the flowing field

k_d is the effective permeability.

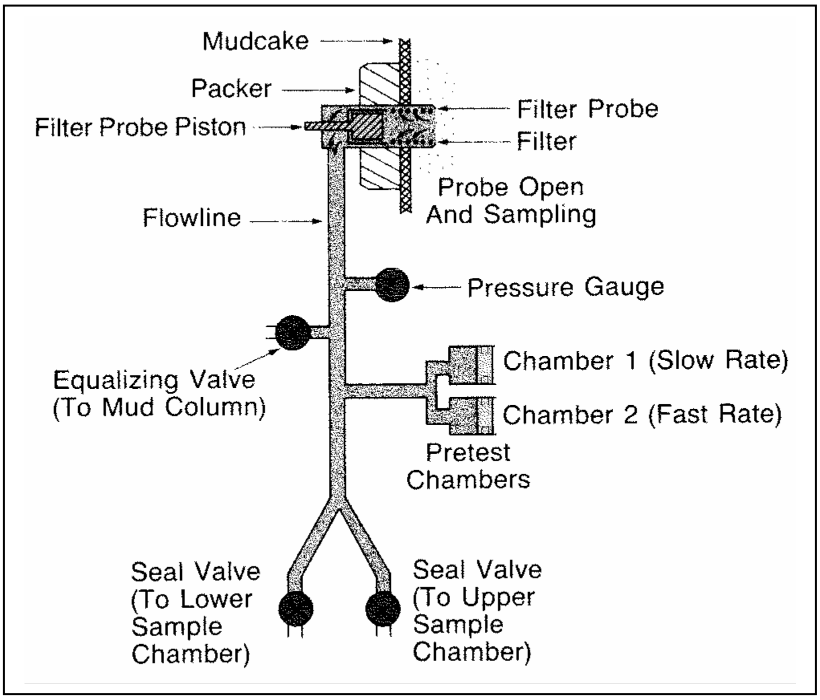
We can simplify the equation because r_p is very small with respect to r_e and solve it for permeability,

$$k_d = \frac{C\mu q}{2\pi r_p \Delta P},.$$

Because the geometrical terms are all to do with the probe and packer sizes under pseudo-hemispherical flow, they can be grouped as a probe constant and the equation simplifies to;

$$k_d = c \cdot \frac{\mu q}{\Delta P}.$$

Where c is the probe constant, 5660 when the standard probe is used.



RFT Schematic

Chapter 4

Reviews

FORMATION EVALUATION AND LOGGING - REVIEW

I. Review cross section of hole for thorough understanding of flush zones, terminology.

Note: Low porosity zones flush deeply and may be badly invaded. A given volume of H_2O is required to build the mud cake and stop filtrate loss. A given water volume in low porosity invades deeply, while high porosity zones often have shallow invasion.

II. Review numerous example logs.

A. Spontaneous Self Potential (SP) recorded in left track in millivolts per division: Note scale used.

1. SP is caused by natural electrical current flow from mud to porous bed to shale to mud, and requires conductive fluid

2. Used for correlation, bed thickness determination, calculation of R_w, and shale estimate in certain cases.

3. Influenced by shaliness (suppresses), R_w, bed thickness (thin beds suppress), laminations, high resistivity (suppresses), lack of invasion, mud chemicals.

4. Reverses when $R_{mf} < R_w$ (Indicates formation H_2O fresher than filtrate); zero when $R_{mf} = R_w$; Increases with ΔR_w of R_{mf} and R_w.

5. Cannot be used in oil base, non-conductive mud or gas filled hole.

6. Gamma ray should be run w/DIL for better Sand-Shale delineation.

7. Many times shows an increase at hydrocarbon/water contact.

B. Short normal;

1. 16” normal electrode spacing, reads approximately 10-12” deep in a spherical shape; normally reads within filtrate flushed zone; reverses in resistive beds of 16” or less thickness; good for delineating thin beds and for picking tops and bottoms (better than SP); reads low in salty mud, because the tool is not focused.

2. In shale or other low resistivity intervals the short normal curve is amplified to a much larger scale. This greater sensitivity permits better correlation of logs in thick shale sections.

3. The good vertical resolution and sensitivity to filtrate often permits qualitative porosity and permeability evaluation.

C. Conductivity (units are millimhos):

1. Review induction principle and sonde design in Schlumberger and Atlas documents.

2. The 6FF40 (6 = coils, FF = fully focused) signifies 4 focusing, 1 transmitting, and 1 receiving coil, with 40" spacing between transmitting and receiving coil.

3. The tool indicates horizontal conductance and reads approximately 8-10 feet deep. Most of signal comes from large "do-nut" area beyond normal zone of invasion.

4. It emphasizes conductive beds and tends to skip over resistive beds less than 2-4' thick.

5. Requires 6' thickness in a resistive bed to read R_t, but only about 3' in conductive bed.

6. Frequent scale changes are used and the curve often goes off scale, but scale is linear.

7. Usually shows erroneously low resistivity in bottom two feet of resistive zone. This makes log look wet (Low R_t in bottom two feet.

8. Needs drastic and impossible correction for resistive beds less than 4' thick, see p. 6-10, 6-11 Schlumberger Log Interpretation Charts and p. 7-12, 7-13 Atlas Log Interpretation Charts.

9. Good with oil or gas filled holes. Not good in salty muds when $R_m < 2.5 R_w$.

E. The Induction log indicates conductance, which is due to ionic conductance in electrolyte (salt water).

1. High resistivity is due to (1) low ion concentration or (2) low water content, and therefore it indicates either:

   a. Hard streak with low porosity and little or no water content

   b. Hydrocarbons and low S_w

   c. Fresh water

   d. Some combination of a, b, c

2. Sand, lime, dolomite, or any other normal mineral (as well as oil and gas) have infinitely high resistivity and it is only the presence of the water that gives conductance or lower resistivity.

3. Log calculations for % S_w from resistivity requires knowledge of R_w, R_t, porosity, formation factor, and saturation exponent.

F. Microlog - Rarely ever used now for porosity; employs two short spaced normal electrodes with 1" and 2" spacing.

1. Requires good wall contact. (See Atlas Log Review p. 5-1)

2. Cannot work without invasion.

3. Very erroneous if flushed zone (Rxo) disappears by gravity drainage in high permeability zones.

G. Caliper log - Indicates washouts and presence of mud cake in porous and permeable zones.

1. Sometimes used to count effecttive net thickness.

2. Necessary for proper use of porosity logging tools.

3. Difference in hole diameter and caliper reading must be divided by two to find mud cake thickness.

III Porosity Logs:

A. Sonic or Acoustic Log: Measures time in micro-seconds required for Acoustic Wave transmission vertically along bore hole wall.

$$\phi_s = \frac{\Delta t_{log} - \Delta t_{ma}}{\Delta t_f - \Delta t_{ma}}$$

1. Only reads approximately 1" deep and naturally follows <u>fastest</u> path.

2. Has no rigorous mathematical relationship with porosity. Is valid indicator only if pore space and solid rock are in series - which rarely happens. It does not see vugs or fracture porosity - only primary or intergranular - and reads low in vug or fracture systems.

3. Requires knowledge of both matrix and fluid travel time.

4. Does not require wall contact as does other pad type devices.

5. Assumes 100% liquid saturation in zone of investigation.

6. Hydration water associated with clay and shale included same as pore water and hence reads high (total) porosity.

7. Requires compaction correction when adjacent shales read > 100 micro - seconds/foot.

8. Instrument records first sound wave arrival and will "cycle skip" by missing first wave, if it is weak, such as commonly occurs with gas saturation, poor tool sensitivity selection, poorly compacted shales and sometimes with fractures.

9. Sonic porosity is high in shaley sands and this results in a low S_w calculated value; hence tool is optimistic in shaley sands.

10. In high porosity hydrocarbon bearing formations <u>with shallow invasion</u> the log porosity value will be too high and should be multiplied by 0.9 in oil and 0.7 in gas formations for approximate connection.

B. Density log:

$$\phi_D = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f}$$

(This relationship is mathematically rigorous: not so with sonic)

1. Formation bombarded with weak gamma rays and instrument receiver records the "scatter" of rays, which is a function of electron density, which in turn is function of Bulk Density, which in turn is function of porosity.

2. Reads approximately 4-6" deep; deeper than sonic and deeper in higher porosity zones than in low porosity zones.

3. Indicates "Effective" porosity. Excludes clay and shale from porosity if we assume the Bulk Density of the clay or shale is the same as Grain Density of the formation (rarely ever the case and not true in young shales where clays are hydrated).

4. Have to know lithology and density of both pore fluid and matrix; requires 100% liquid saturation or need large correction for Gas Saturation.

5. Requires wall contact. Bore-hole compensated tool "corrects" for hole irregularities and cake density. (Note amount of correction used, as this is frequently a source of tool error).

6. If obviously high porosity values are indicated, gas saturation is probably present within the zone of investigation and a very large correction is required where corrected porosity equals .6 or .7 of

non-corrected porosity. However, rather than make such large corrections, log analysts usually go to nearest "comparable" water sand to get porosity and assume both sands have same porosity.

7. Density log porosity is lower than sonic porosity in shaley sands, but re Calculated S_w will be higher than S_w value calculated from sonic. (Geologists therefore usually prefer the optimistic sonic with its lower S_w calculation).

8. Bulk density value read from Density log should be equal to our saturated sample density value.

9. Combination Sonic and Density porosity allows calculation for shaliness or Q factor:

$$Q = \frac{\phi_S - \phi_D}{\phi_S}$$

    a. Q factor is used in Schlumberger's calculation of empirical perm, but no allowance is made for sorting or grain size.

    b. Q values > .40 in the Gulf Coast are indicative of non-production due to shale and low k, according to Schlumberger.

C. Micro-log:

1. Discussed above - no longer in common useage.

2. Excellent for thin beds and counting net sand if invasion is sufficient. In zones of very high permeability (1000 md. or so) the invaded water in flush zone may drain away from well bore, allowing gas or oil to refill the flushed zone. Instances have occurred where an initial micro-log (with a good flushed zone) correctly indicated good porosity, but a few days later when the filtrate had drained from around the well bore, a second micro-log read very high resistivity, indicating a very low poroxity zone.

3. Requires good wall contact, a mud cake, some invasion, and knowledge of R_{mf} and R_{os}.

D. Neutron and sidewall neutron logs:

1. Indicates presence of hydrogen and hence indirectly indicates porosity in water or oil bearing zones.

2. Sidewall neutron used for detecting gas in shaley, low resistive sands. (Presence of gas makes SNP read porosity too low).

3. Used in conjunction with sonic and density to determine lithology, and with a computer programme to indicate hydrocarbon density.

4. Sidewall neutron is a pad devise and is dependent on good hole size.

Compensated neutron log (CNL) is not a pad device, but will not read correctly in washout zones. It reads much deeper than SNP and hence is good for gas detection beyond the invaded zone.

COMMONLY USED FORMULAS FOR ELECTRIC LOG ANALYSIS

ESTIMATION OF FORMATION TEMPERATURE - Sch Chart Gen - 6

TD = Total depth of log run or depth of known temperature

BHT = Temperature in °F at TD or at known depth

GG = Geothermal Gradient in °F per 1 ft.

FD = Depth of formation of interest

FT = Temperature in °F at FD

MST = Annual mean surface temperature in °F

$$\frac{BHT - MST}{TD} = GG \qquad BHT - \left[(TD - FD)GG\right] = FT$$

RESISTIVITY VS. TEMPERATURE - SCH Chart Gen - 9

R_1 = Known Resistivity

T_1 = Formation temperature in °F @ R_1

T_2 = Formation temperature in °F @ unknown resistivity

R_2 = Unknown resistivity

$$R_2 = R_1\left(\frac{T_1 + 6.77}{T_2 + 6.77}\right)$$

R_{we} DETERMINATION FROM THE SSP - Sch Chart SP-1

SSP = Static spontaneous potential

K_c = Temperature coefficient = 61 + .133T

T = Formation temperature, °F

R_{mfe} = Resistivity of mud filtrate (When R_{mf} @ 75° F > 0.1, then

$R_{mfe} = R_{mf} \times 0.85$

When R_{mf} @ 75°F < 0.1, use Sch Chart SP-2 to find R_{mfe}

R_w = Formation water resistivity

$$SSP = -K_C \log \frac{R_{mfe}}{R_{we}} \qquad R_{we} = \frac{R_{mfe}}{\left(\frac{R_{mfe}}{R_{we}}\right)}$$

R_w is found by entering R_{we} into Sch Chart SP-2

FORMATION FACTOR VS POROSITY - SCH CHART POR-1

a = Tortuosity

m = Cementation factor

ϕ = Porosity - fraction

F = Formation factor

General formula: $F = \frac{a}{\phi^m}$

Commonly Used Relationships:

$$\text{Sandstones}: \ F = \frac{0.62}{\phi^{2.15}} \quad \text{Or} \quad F = \frac{0.81}{\phi^{2.0}}$$

$$\text{Carbonates}: \ F = \frac{1}{\phi^{2.0}}$$

FORMATION DENSITY VS POROSITY - Sch Chart POR-5

ρ_{ma} = Grain Density

ρ_b = Bulk Density (From Density Log)

ρ_f = Fluid Density (1.0 fresh mud; 1.1 salt water mud)

ϕ = Porosity

$$\phi = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f}$$

COMMON GRAIN DENSITY VALUES:

Sandstone	-	2.65
Limestone	-	2.71
Dolomite	-	2.87

ACOUSTIC OR SONIC LOG VS POROSITY Sch Chart POR-3

Δt = Travel time reading from log

Δt_{ma} = Travel time of matrix

Δt_f = Travel time of borehole fluid.....typically 189 usec/ft

ϕ = Porosity

$$\phi = \frac{\Delta t - \Delta t_{ma}}{\Delta t_f - \Delta t_{ma}}$$

APPROXIMATE POROSITY CORRECTION FOR NEUTRON LOG VS DENSITY LOG FOR CLEAN,

FAIRLY DRY GAS BEARING FORMATIONS ONLY - Sch Chart CP-9

ϕ_N = Neutron Log Porosity corrected for lithology (Sch Chart POR-13)

ϕ_D = Density Log Porosity corrected for lithology (Sch Chart POR-5)

ϕ = Approximate true ϕ Porosity

$$\phi = \sqrt{\frac{\phi_N^2 + \phi_D^2}{2}}$$

Commonly Used Values

	Δt_{ma}	$\Delta t_f - \Delta t_{ma}$
Sandstone	51.0	138.0
	55.5	133.5
Limestone	47.6	141.4
Dolomite	43.5	145.5

WATER SATURATION (Ratio Method) (Clean Formations Only) Sch Chart SW-2

$\frac{R_{xo}}{R_t}$ = Resistivity of flushed zone over Resistivity of unflushed zone

(This ratio is usually derived from Sch Chart Rint-2 or D A Chart 4-4)

R_{mf} = Resistivity of mud filtrate at formation temperature

R_w = Resistivity of formation water at formation temperature

S_w = Water Saturation

.625 = Exponent (This value remains constant)

$$S_w = \left(\frac{R_{xo} / R_t}{R_{mf} / R_w} \right)^{.625}$$

WATER SATURATION (Archie Method) (Clean Formation) Sch Nomogram SW-1

F = Formation Factor

R_w = Resistivity formation water at formation temperature

R_t = Resistivity of uninvaded formation (true resistivity)

S_w = Water saturation of uninvaded formation

R_{mf} = Resistivity of mud filtrate at formation temperature

R_{xo} = Resistivity of invaded zone at formation temperature

S_{xo} = Water saturation of invaded zone

n = Saturation exponent (value is usually 2)

$$S_w = \sqrt[n]{\frac{F \bullet R_w}{R_t}} \qquad S_w = \sqrt[n]{\frac{F \bullet R_{mf}}{R_{xo}}}$$

Sch Nomogram S_w - 1, S_w - 9, R_{wa} (Archie Formula)

R_o = Resistivity of uninvaded formation when 100% saturated with water

R_t = Resistivity of uninvaded formation
F = Formation Factor
R_w = Resistivity of formation water at formation temperature
S_w = Water saturation of uninvaded formation
R_{wa} = Apparent resistivity of formation water

$$R_{wa} = \frac{R_t}{F} \qquad S_w = \sqrt[n]{\frac{R_w}{R_{wa}}}$$

When 100% water saturated then:

$$R_w = \frac{R_o}{F} \quad \text{or} \quad F = \frac{R_o}{R_w} \quad \text{or} \quad S_w = \sqrt[n]{\frac{R_o}{R_t}}$$

SUMMARY OF OFTEN USED FORMULAS

Formation Temperature: $\frac{BHT\ -\ MST}{TD} = GG \quad BHT\ -\ [(TD - FD)\ \ GG] = FT$

Resistivity vs Temperature: $R_2 = R_1\left(\frac{T_1 + 6.77}{T_2 + 6.77}\right)$

R_w & R_{we} vs SSP: $SSP = -K_c \quad \log\left(\frac{R_{mfe}}{R_{we}}\right) \qquad R_{we} = \frac{R_{mfe}}{\left(\frac{R_{mfe}}{R_{we}}\right)}$

Formation Factor vs Porosity: $F = \frac{a}{\phi^m}$

Density Porosity: $\phi = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f}$

Acoustic Porosity: $\phi = \frac{\Delta t - \Delta t_{ma}}{\Delta t_f - \Delta t_{ma}}$

Gas Porosity Correction - Neutron vs Density: $\phi = \sqrt{\frac{\phi_N^2 + \phi_D^2}{2}}$

Water Saturation (Ratio Method): $S_w = \left(\frac{R_{xo}/R_t}{R_{mf}/R_w}\right)^{.625}$

Water Saturation (Archie Method): $S_w = \sqrt[n]{\frac{F \bullet R_w}{R_t}} \qquad S_{xo} = \sqrt[n]{\frac{F \bullet R_{mf}}{R_{xo}}}$

Rwa (Archie):

$R_{wa} = \frac{R_t}{F} \qquad S_w = \sqrt[n]{\frac{R_w}{R_{wa}}} \qquad R_w = \frac{R_o}{F} \qquad F = \frac{R_o}{F} \qquad S_w = \sqrt{\frac{R_o}{R_t}}$

FORMATION EVALUATION - LOGGING TOOL SUMMARY

Logging Tool	Use	Basic Principles	Borehole Conditions (Most Favorable)	Major Factors Affecting Measurements
SP (pontaneous-Potential)	Lithology Correlation Bed Boundaries R_w	Measures potential difference between a shale-sand or shale-carbonate due to the difference in ion concentration of the borehole fluids and formation waters. (normally run with electric or induction log)	Open hole using fresh water mud. (mud must be conductive)	• Salt mud (low R_{mf}) • Fresh Formation Water (high R_w) • Shaliness • Thin beds • Deep invasion or enlarged borehole High R_t (high Hydrocarbon Saturation or dense zone)
CONVENTIONAL ELECTRIC (Normal and Lateral)	Correlation Bed Boundaries R_t	Measures potential difference between two points due to electric current introduced into borehole. Potential difference is proportional to the apparent formation resistivity (current allowed to seek path of least resistance)	Open hole using fresh water mud. (mud must be conductive)	• Mud resistivity (low R_m) • Hole diameter (large d) • Invaded zone resistivity (low R_i) • Invaded zone diameter (large D_i) • R_t (high) R_s (low)
FOCUSED CURRENT ELECTRIC (Laterolog)	Correlation Bed Boundaries R_t	Same as conventional electric log. Introduced current is focused into formation for better bed resolution and deeper investigation in high resistivity zones.	Open hole using salt based mud. ($R_{mf} < R_w$)	• Borehole washout (large d) • Depth of invasion (large D_i) • Fresh water mud (high R_{mf})
INDUCTION	R_t	A.C. current in transmitter coil induces eddy currents in formation. Eddy currents induce a potential in receiver coil which is proportional to formation conductivity.	Open hole using conductive or non-conductive muds (or gas filled boreholes)	• Borehole effects generally negligible • Adjacent bed effects negligible except for resistive beds less than 5' thick and conductive beds less than 3' thick D_i > 30" Fresh mud preferable ($R_i > R_t$)

LOGGING TOOL SUMMARY

Page 2

Logging Tool	Use	Basic Principles	Borehole Conditions (Most Favorable)	Major Factors Affecting Measurements
CONTACT TYPE (Microlog)	Bed Boundaries R_{xo} R_{xos}	Pad type device. Introduces electric current into formation and measures potential difference between two points. Potential difference is proportional to resistivity. (caliper usually run with tool)	Open hole using fresh water mud. (thickness of mud cakes $\leq$ 1/2")	• Mud cake thickness >1/2" • Salt based mud • Borehole washout • Quality control (logging speed, mud properties and BHT) • Porosity < 15%
FOCUSED CONTACT TYPE (Micro-Laterolog)	Bed Boundaries R_{xo} R_{xos}	Same as contact type log. Electric current is focused into formation	Open hole using fresh or salt mud	• Mud cake thickness >1/4" (use correction charts) • Borehole washout
ACOUSTIC (Sonic)	ϕ	Transmitter emits high frequency sound pulses. Travel time for pulse to reach two receivers is measured. Porosity is a function of difference in travel time between these two receivers. (BHC uses 2 transmitters and 4 receivers)	Open hole using conductive or non-conductive mud. (cannot use in gas filled borehole)	• Shaliness • Borehole irregularities • Gas in mud or formation (cycle skipping) • Vulgar porosity • Fractures (cycle skipping)
GAMMA RAY	Correlation Lithology Depth Control (cased hole)	Measures natural radioactivity of formations. Shales have high radioactivity.	Open or cased hole.	• Time constant • Logging speed • Borehole size and fluid (can reduce measurement) • Casing and cement (reduces measurement) •

LOGGING TOOL SUMMARY
Page 3

Logging Tool	Use	Basic Principles	Borehole Conditions (Most Favorable)	Major Factors Affecting Measurements
NEUTRON	ϕ Correlation Depth Control (cased holes) Gas Recognition	Formation is bombarded with neutrons. Neutrons are captured mainly by hydrogen. Neutron detector 1' to 2' from source measures neutron count rate. Count rate related to amount of hydrogen in formation and ideally to porosity. (includes pad type - SNP)	Open or cased hole (only cased hole porosity tool)	• Gas in borehole or formation • Casing and tubing (reduces count rate) • Logging speed - Time Constant • Source-Detector spacing • Borehole size
DENSITY	ϕ Correlation Gas Recognition	Gamma rays are directed into formation. Gamma rays are attenuated and scattered by formation elements. Detector measures gamma ray count. Formation density is a function of count rate and density is related to porosity. (pad type device and BHC)	Open hole using conductive or non-conductive mud (or gas filled boreholes)	• Borehole irregularities • Gas in formation
NEUTRON DECAY (TDT NLL)	OWC GWC GOC S_w	Neutron source emits high energy neutrons into formation. Neutrons are slowed primarily by hydrogen and captured mainly by chlorine. Capture causes gamma rays to be emitted which are a function of the slow neutrons present. Detector measures gamma ray count at 2 times and this is related to total formation capture cross section. Formation capture cross section is related to ϕ and S_w.	Cased hole	• Formation water salinity (> 20,000 ppm chlorid) • Perforated intervals (use low invasion mud) • Borehole size changes • Casing size and weight changes • Cement • Shaliness

PROBLEM #1

CALCULATION OF Sw FROM ACOUSTIC VELOCITY vs POROSITY USING MEASURED ABD STANDARD RELATIONSHIPS

Given:

Rw = 0.1 ohm-m @reservoir Temp
Rt = 65 ohm-m (From Zone of Interest)
Δt = 60 usec/ft (From Zone of Interest)

Find :

(1) Ø and Sw using average relationships:
Acoustic Log Ø - ____________________ (Assume Matrix Velocity = 18,000 ft/sec)
Calculate Sw - ____________________ (Assume Archie Relationship)

(2) Refine Ø and Sw calculations with laboratory measured data :
Acoustic Log Ø - _________________ (Use measured Δt vs Ø relationship)
Calculate Sw - _________________ (Use measured Resistivity Data)

Given:

Rw = 0.1 ohm-m @reservoir Temp
Rt = 10 ohm-meters
Δt = 70 sec/ft (from log in zone of interest)

Find:

(1) Ø and Sw using average relationships:
Acoustic Log Ø - ____________________ (Assume Matrix Velocity = 18,000 ft/sec)
Calculate Sw - ____________________ (Assume Archie Relationship)

(2) Refine Ø and Sw calculations with laboratory measured data :
Acoustic Log Ø - _________________ (Use measured Δt vs Ø relationship)
Calculate Sw - _________________ (Use measured Resistivity Data)

PROBLEM NO. 2

DETERMINATION OF CALCULATED LOG Ø SENSITIVITY TO ERRORS IN ASSUMED GRAIN DENSITY AND FLUID DENSITY

BD (From log) = 2.16 g/cc
FD = 1.0 g/cc

GD (g/cc)	Ø Calculated	ΔØ (From Ø Value When GD = 2.65)
2.70		
2.65		
2.60		

BD (From log) = 2.49 g/cc
FD = 1.0 g/cc

GD (g/cc)	Ø Calculated	ΔØ (From Ø Value When GD = 2.65)
2.70		
2.65		
2.60		

GD (g/cc)	BD	FD (g/cc)	Ø Calculated	Sgr	FD Avg(g/cc)	Ø Calculat
2.65	2.18	1.0		30%		
2.65	2.20	1.0		30%		
2.65	2.17	1.0		30%		
2.65	2.24	1.0		30%		

EQUATIONS:

(1) $$\phi = \frac{GD - BD}{GD - FD} = \frac{\rho\, ma - \rho\, b}{\rho\, ma - \rho\, f}$$

(2) $FD\ Avg = FD_1 \times (\text{Fractional Fluid Saturation})_1$
$FD_2 \times (\text{Fractional Fluid Saturation})_2$

PROBLEM NO. 3 & 5

CORE LABORATORIES INC
Petroleum Reservoir Engineering
Dallas, Texas

FORMATION FACTOR & RESISTIVITY INDEX DATA

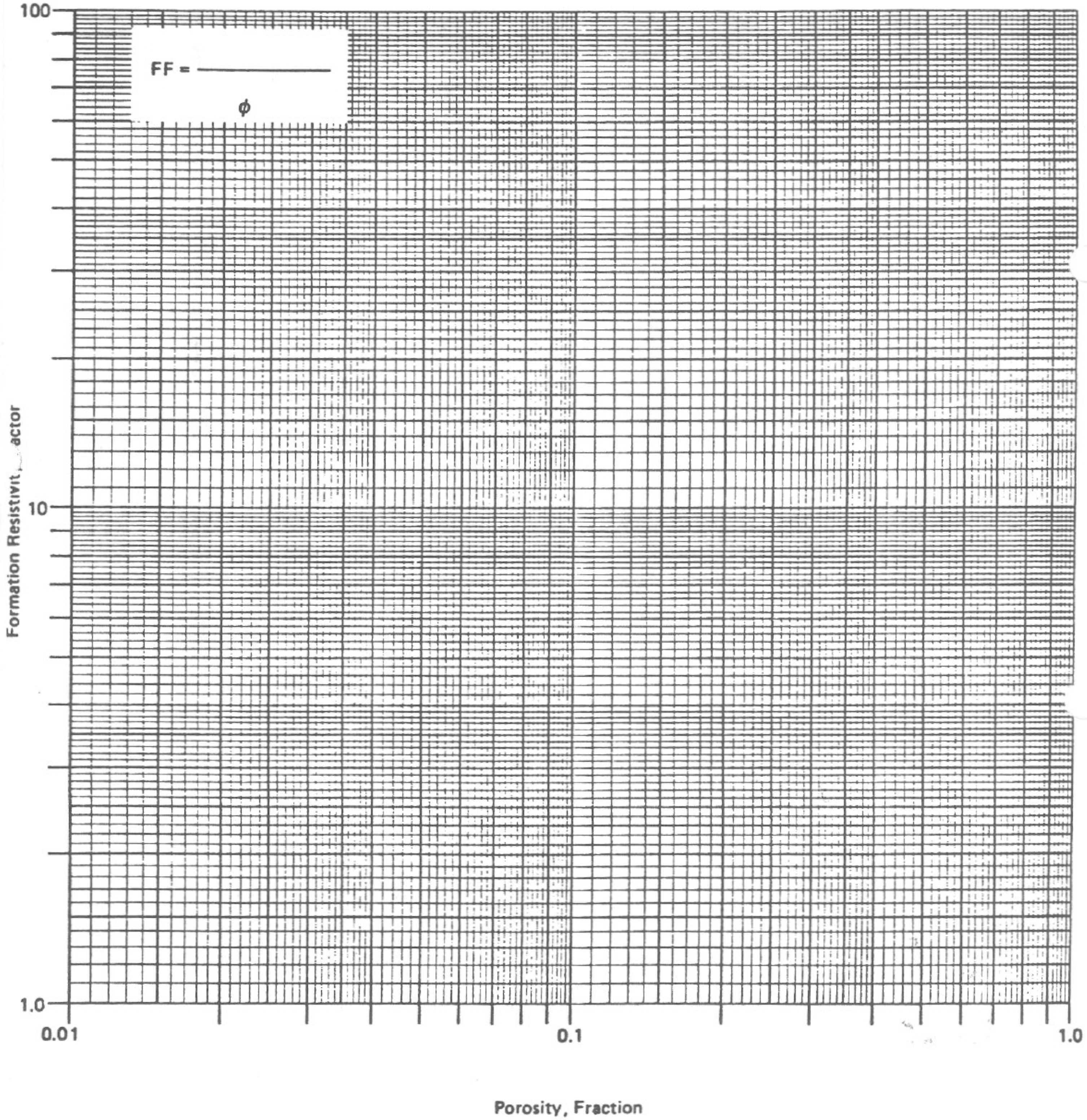
Resistivity of Saturing Brine, Ohm-Meters 0.21 @75° F

SAMPLE NUMBER	POROSITY PERCENT	FORMATION FACTOR	BRINE SATURATION PERCENT PORE SPACE	RESISTIVITY INDEX
	35.0	7.15	100	1.0
			85	1.27
			70	1.9
			60	2.4
			50	3.0
	26.9	11.1	100	1.0
			60	2.2
			46	3.5
			40	4.3
			35	5.2
	22.9	14.7	100	1.0
			70	1.9
			60	2.4
			45	4.0
			30	7.6
	20.0	18.5	100	1.0
			80	1.5
			60	2.4
			40	4.6
			20	14.5
	17.2	23.9	100	1.0
			85	1.3
			65	2.0
			50	3.2
			28	8.3

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

Page ________ of ________
File ________

Company Problem #3 & 4
Well ________
Field ________
Formation ________
County ________
State ________



PROBLEM NO. 4

CORE LABORATORIES INC
Petroleum Reservoir Engineering
Dallas, Texas

OVERBURDEN FORMATION FACTOR DATA

Saturant : Brine
Resistivity of Saturant, Ohm-Meters : 0.21 @ 75° F

Pressure, PSI : 0.0

EOB
Sleeve Pressure, PSI

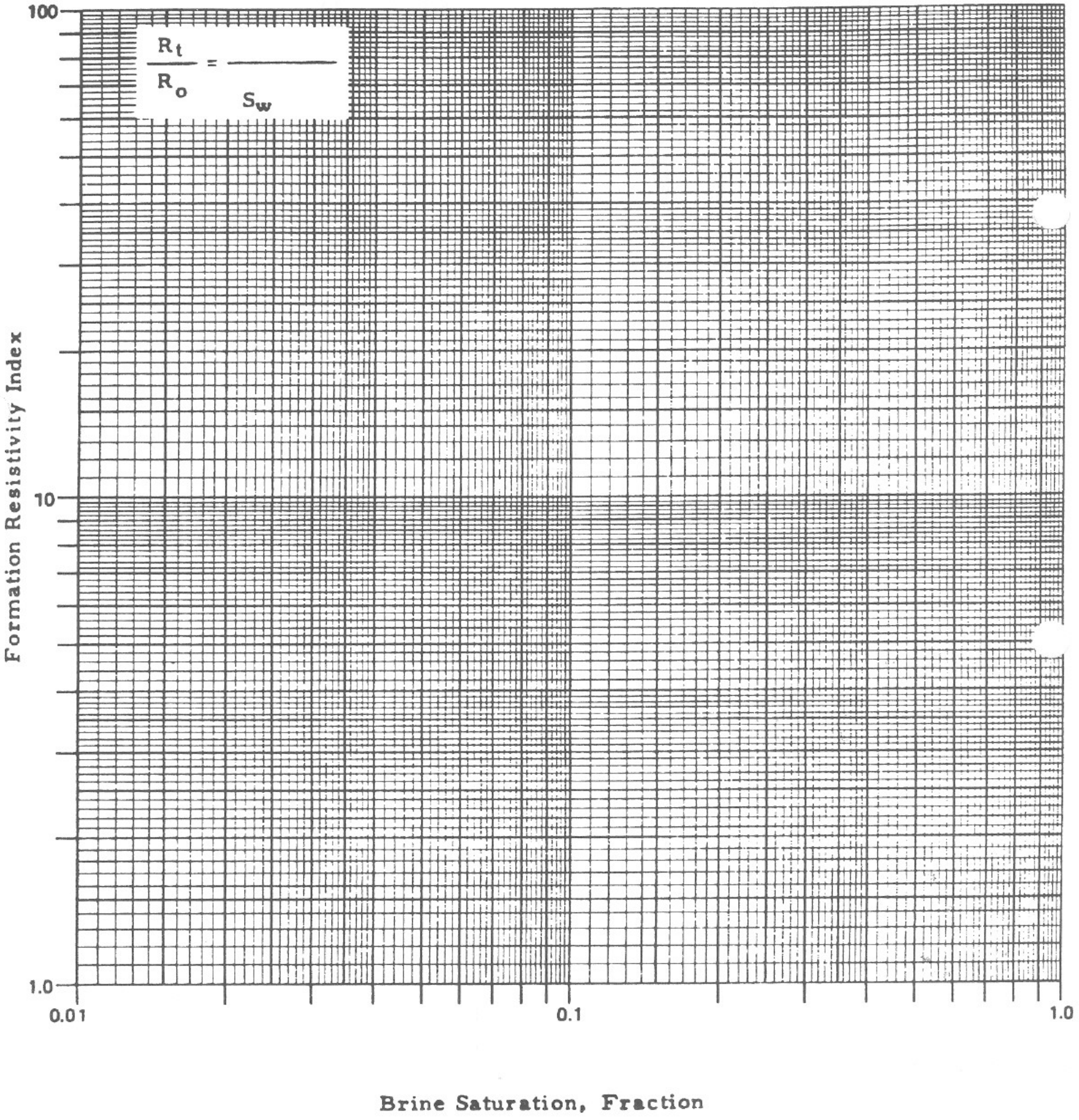
Sample Number	Porosity, Percent	Permeability, Millidarcys	Grain Density, gm/cc	200	2,000	3,000	4,000
				Formation Factor F			
7	35.0	--	--	7.15	9.0	9.1	9.2
8	26.9	--	--	11.1	14.5	14.7	14.8
9	22.9	--	--	14.7	19.8	19.9	19.9
10	20.0	--	--	18.5	25.3	25.4	25.5
11	17.2	--	--	23.9	33.4	33.7	33.8

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

Page ________ of ________
File ________________

Company Problem #5
Well ________________
Field ________________

Formation ________________
County ________________
State ________________



PROBLEM NO. 6

CALCULATION OF Sw FROM DOWN HOLE LOG Rt & MEASURED “m” & “n”
(Using Charts of F vs Ø & RI vs Sw0

Rw = 0.1 ohm-meters down hole

Ø	F	Ro	$\frac{Rt}{Ro}$	Rt	Sw
30			25		
30			20		
30			10		
20			25		
20			20		
20			10		
10			25		
10			20		
10			10		

Where “m” =
“n” =
“a” =

PROBLEM NO. 7

PROBLEM FOR SECTION

Rw-Rm-Rmf-Rmc-Temp

I. Given:

Rw = 0.2 ohm-m @ 78° F

Find :

(1) Rw @ 200° F = __________ ohm-m
(2) Equivalent NaCl Concentration _____________ ppm
Equivalent NaCl Concentration _____________grains/gal

II. Given:

Rm = 1.25 ohm-m @ BHT
BHT = 175° F @ 12,000 ft
Mud Weight = 12 lbs/gal
Annual Mean Surface Temperature = 60° F

Find:

(1) Formation Temperature @ 8,000 ft = ___________°F
(2) Rm @ 8,000 ft = ____________________ohm-m
(3) Rmf @ 8,000 ft = ____________________ohm-m
(4) Rmc @ 8,000 ft = ____________________ohm-m

III. Given:

The chemical analysis of water is as follows:

Na	23,000 ppm
K	1,000 ppm
Ca	2,000 ppm
Mg	1,000 ppm
Cl	30,000 ppm
SO_4	3,000 ppm
Total	60,000 ppm

Find:

(1) Equivalent NaCl __________ ppm (see conversion factors following page)
(2) Rw @ 150°F _____________ohm-m

Conversion Factors to Na Cl Equivalent Solutions When Salinity is Given in Ionic ppm

(According to Atlantic Richfield)

IONS	FACTOR
Na^+	1.00
K^+	1.00
Ca^{++}	0.95
mg^{++}	2.00
SO_4^{--}	0.50
Cl^-	1.00
HCO_3^-	0.27
CO_3^{--}	1.26

PROCEDURE: Multiply reported ions by above factors and then sum the results for a total NaCl equivalent solution in ppm.

CONTINUATION OF PROBLEM NO. 7

V. Given:

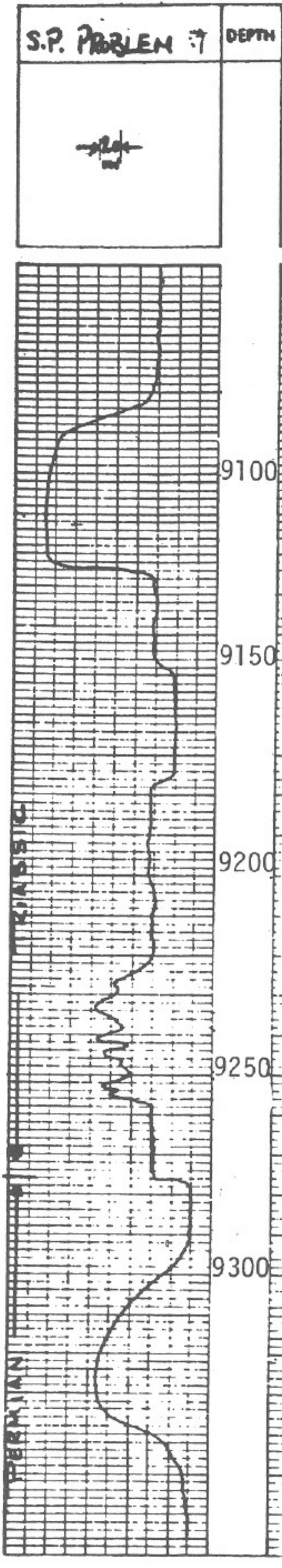
BHT = 200 °F @ 12,000’
Rm = 1.0 @ BHT
Mud Wt = 12 #/gal
Hole Size $\simeq$ 8”
Mean Surface Temperature = 60 °F
Average in Ø 9100 sand = 30%
a = 1 m = 2 n = 2

Calculate:

(1) Fill in formation tops
(2) Fill in lithology
(3) Draw SSP and shale base lines
(4) Calculate Rw for
    9100’ sand
    9150’ sand

(5) Calculate $\propto$ for 9250’ sand
(6) Estimate Rt for 9100’ sand
(7) What Rw would use for 9250’ sand
(8) Calculate Rw for Permian Reservoir (SSP= ASP)

S.P. PROBLEM 7



GIVEN:

BHT = 200°F AT 12,000'
R_m = 1.0 AT B.H.T.
MUD WT. = 12#/gal.
HOLE SIZE ≈ 8" (d)

CALCULATE:

1) FILL IN FORMATION TOPS
2) FILL IN LITHOLOGY
3) DRAW S.S.P & SHALE LINE
4) CALCULATE R_w FOR
9100' SAND
9150'
5) CALCULATE Ø FOR
9250' SAND
6) ESTIMATE R_t for 9100' SD.
7) WHAT R_w would you use for 9250' SD?
8) Calculate R_w for Permian Reservoir, assume S.P. = S.S.P.

PROBLEM NO. 8

INDUCTION LOGGING

The following log is an example of a fully focused induction electric log. Eight intervals have been selected for analysis. As a practice in reading the induction log, obtain the following data for each bed:

(1) Reading the induction conductivity curve in millimhos/meter, CIL

(2) Resistivity, as calculated from the conductivity reading, in ohm-meters.

$$R_{IL} = \frac{1000}{C_{IL}}$$

(3) For greatest accuracy of R_{IL} in zones less than 2 ohm-meters, calculate R_{IL} from the conductivity curve. In zones greater than 2 ohm-meters, directly read the resistivity curve; however, check to see that this conductivity has been correctly reciprocated.

Given:

GD = 2.65
SSP = - 105
R_w = .06
S_{CIW} = 50%
a = .5 m = 2 n = 2

(a) Calculate S_w from each zone (read peak) and if productive or not.

(Do not do Xone 2 in Part a)

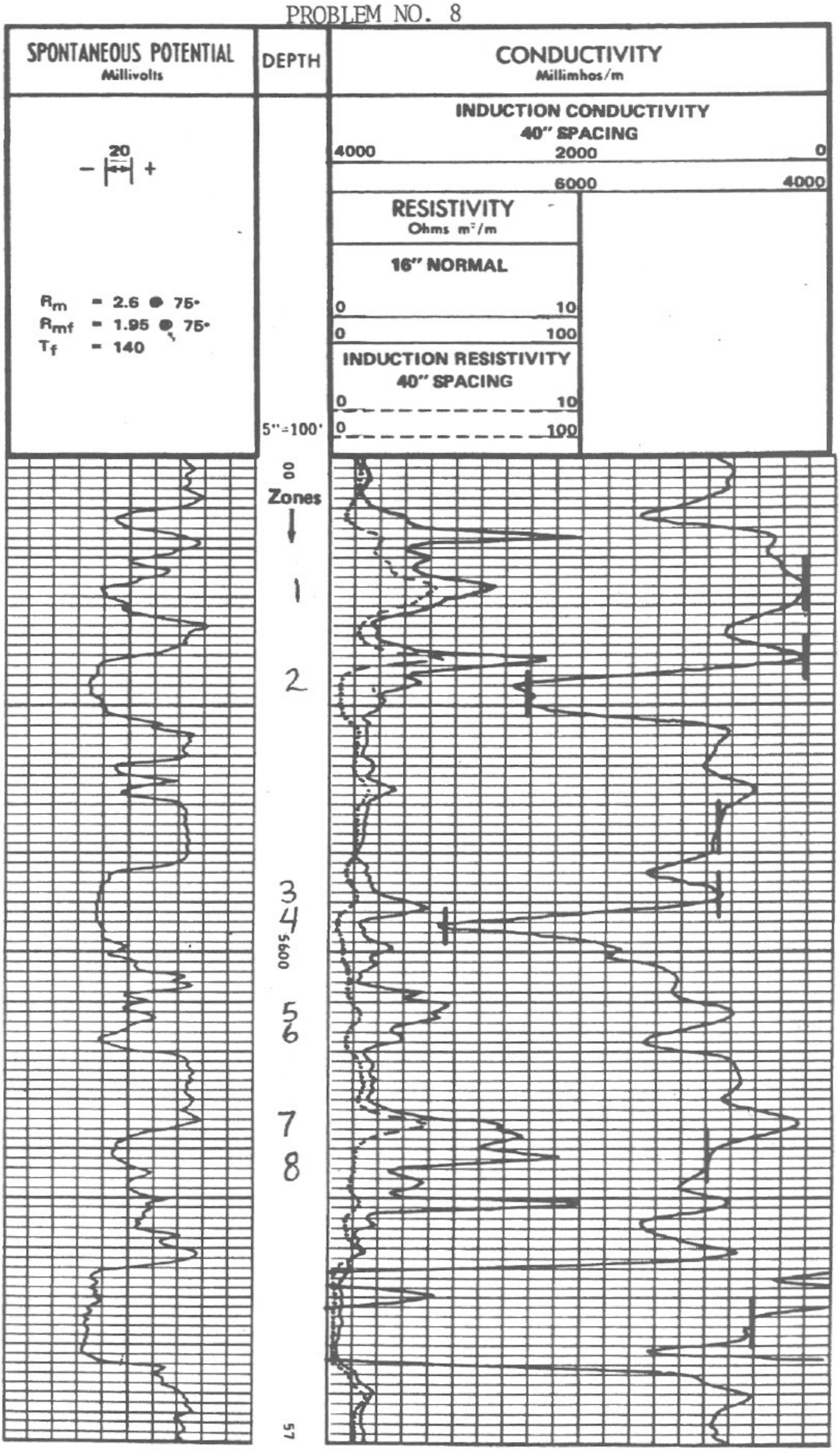
PROBLEM NO. 8

Zone	Cond. Reading mmhos/m	Resist. From Cond. Ohm-m	Resist. Reading Ohm-m	Ø	R_w	S_w	Productive (Y or N)
1				27.3			
3				28.5			
4				27.3			
5				20.1			
6				27.3			
7				27.8			
8				27.3			

(b) In zone 2, from 5540' thru 5550', calculate S_w every two feet and productivity (Y or N)……Use same parameters as in Part a.

Depth	Cond. Reading mmhos/m	Resist. From Cond. Ohm-m	Resist. Reading Ohm-m	Bulk Den.	Ø	R_w	S_w	Productive (Y or N)
5540				2.30				
5542				2.17				
5544				2.20				
5546				2.22				
5548				2.19				
5550				2.20				

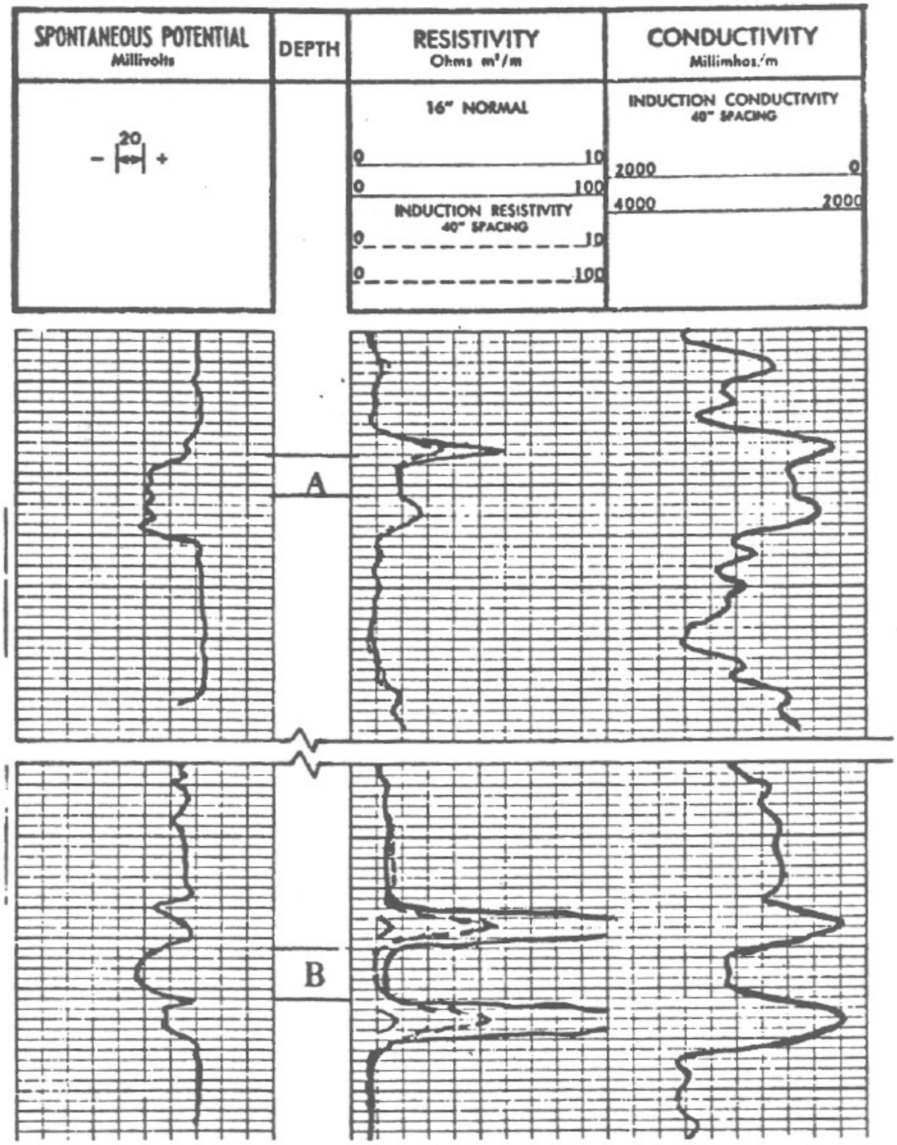
PROBLEM NO. 8



Example 181a

PROBLEM NO. 9

INDUCTION LOG



USE: Humble Formatio
Factor Formula

USE: n = 2.0

GIVEN:	ZONE A	ZONE B
ϕ	28.4%	25.2%
R_w	0.06 Ω m	0.06 Ω m
R_t	________ Ω m	________ Ω m

Calculate S_w

PROBLEM NO. 10

ACOUSTIC LOG

1) Using the SP (fom the induction log) in the water sand, B, calculate R_w.

2) a. Calculate an Rw using the resistivity and acoustic log at 9394’.
   b. How does it compare to the R_w in question 1.

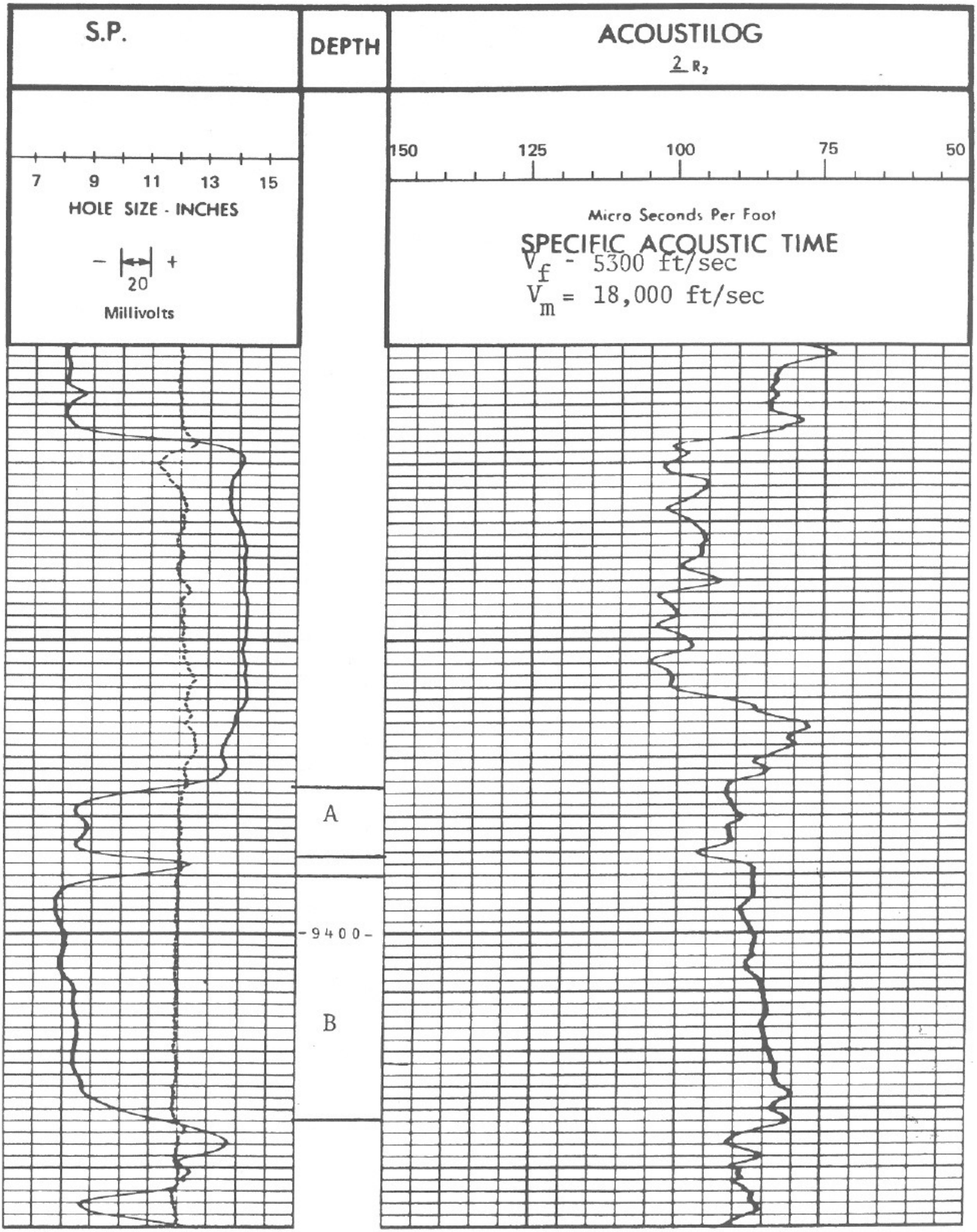
3) Calculate porosity and water saturations at the following depths.

Depths	Ø	S_w
9377		
9380		
9384		

PROBLEM No. 10

Dresser Atlas

BHC
Acoustilog®

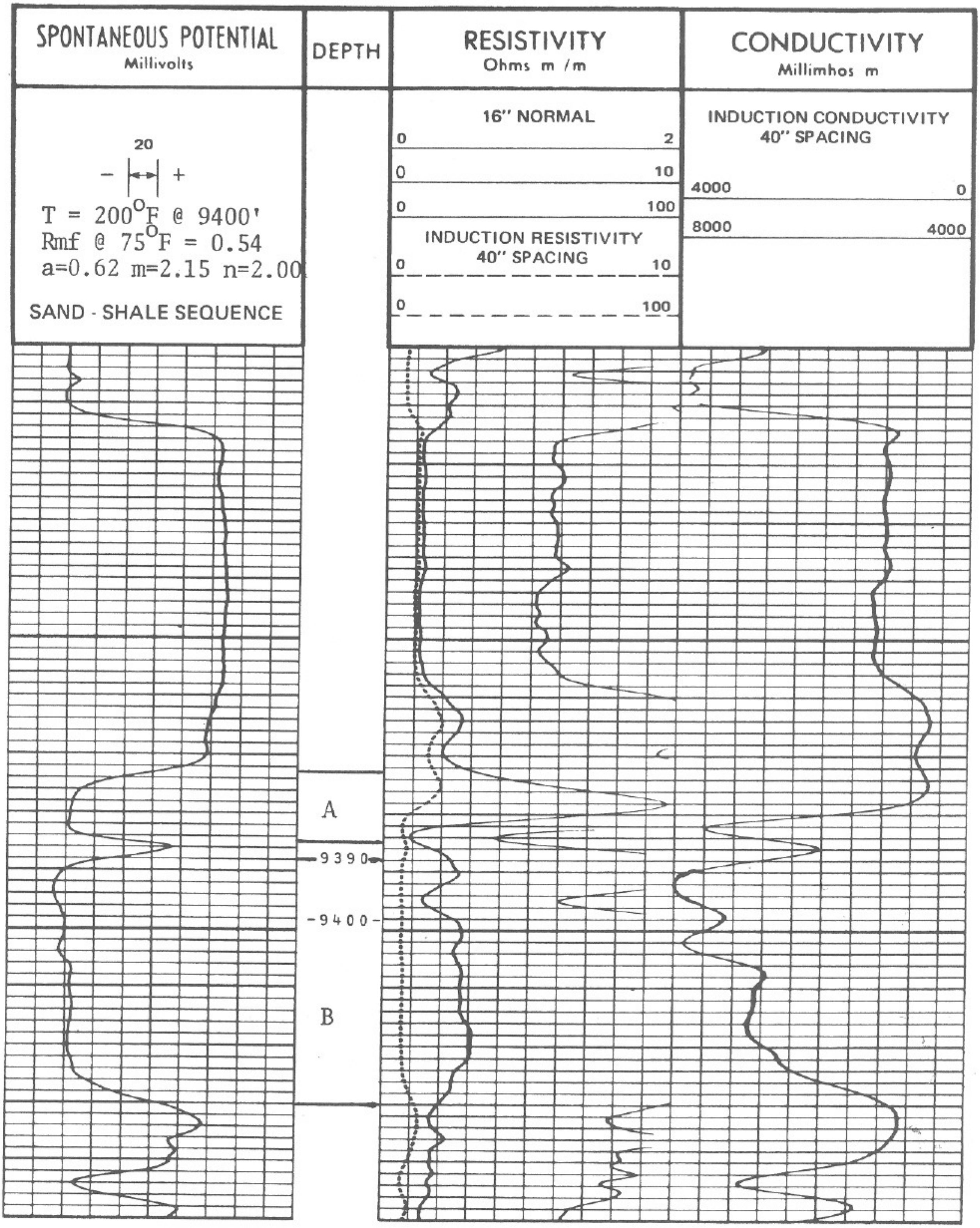


V_f - 5300 ft/sec

V_m = 18,000 ft/sec

PROBLEM NO. 10

Induction Electrolog®



T = 200°F @ 9400'

Rmf @ 75°F = 0.54

a=0.62 m=2.15 n=2.00

PROBLEM NO. 11

DENSITY LOG

Given : R_{mf} = .78 @93°F @ 2200'

GD = 2.67
FD = 1.0

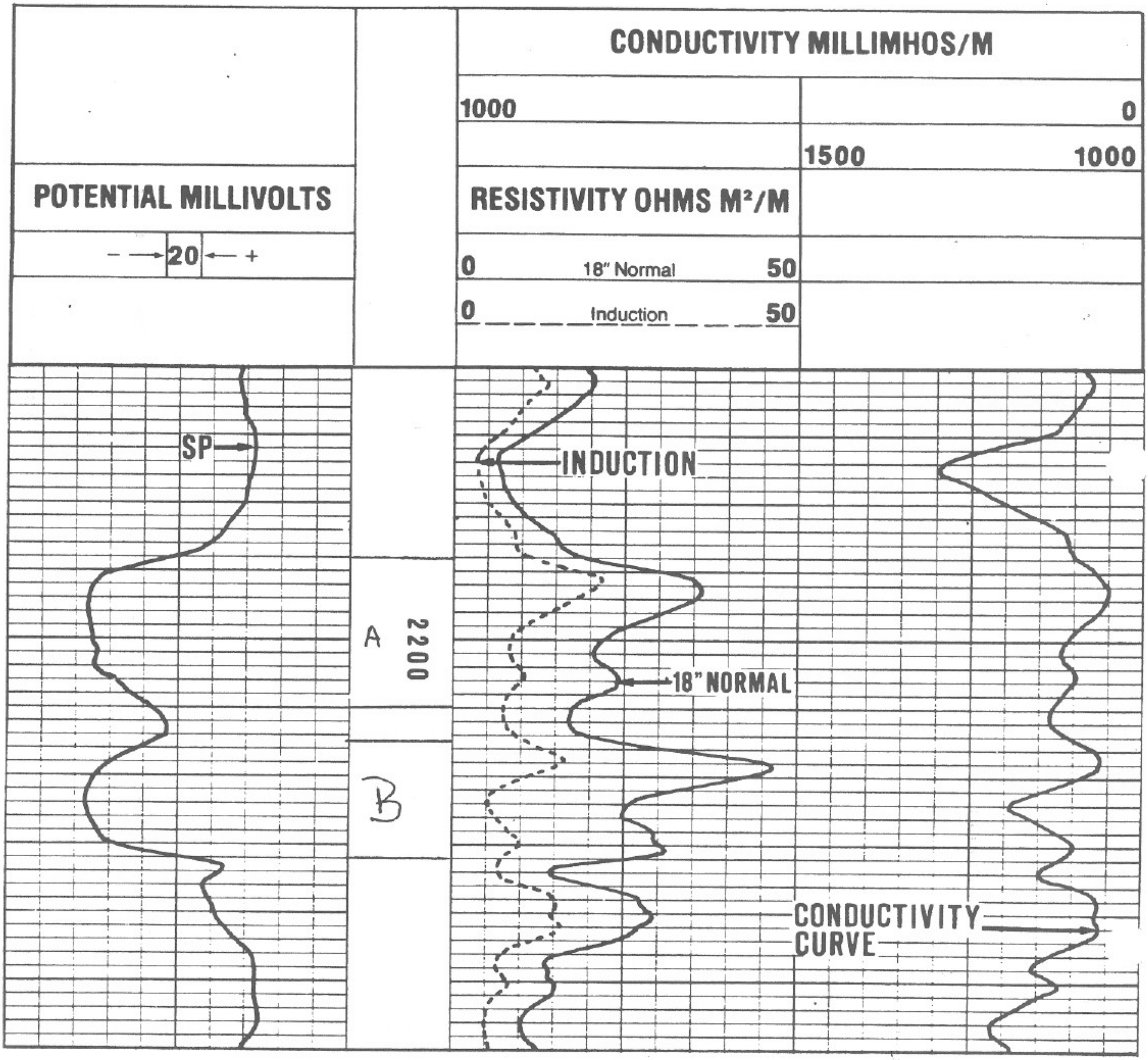
1. a) Calculate Rw from the SP curve

   b) Assume the sand in zone B at 2224' is 100% saturated with water. Calculate R_w using the Humble equation.

2. Using the Humble equation and the R_w from the SP curve, calculate S_w in zones A and B at the following depths.

Zone	Depth	BD	FD	Ø	R_w	R_t	S_w
A	2191						
	2205						
B	2218						

PROBLEM NO. 11
INDUCTION ELECTRIC LOG

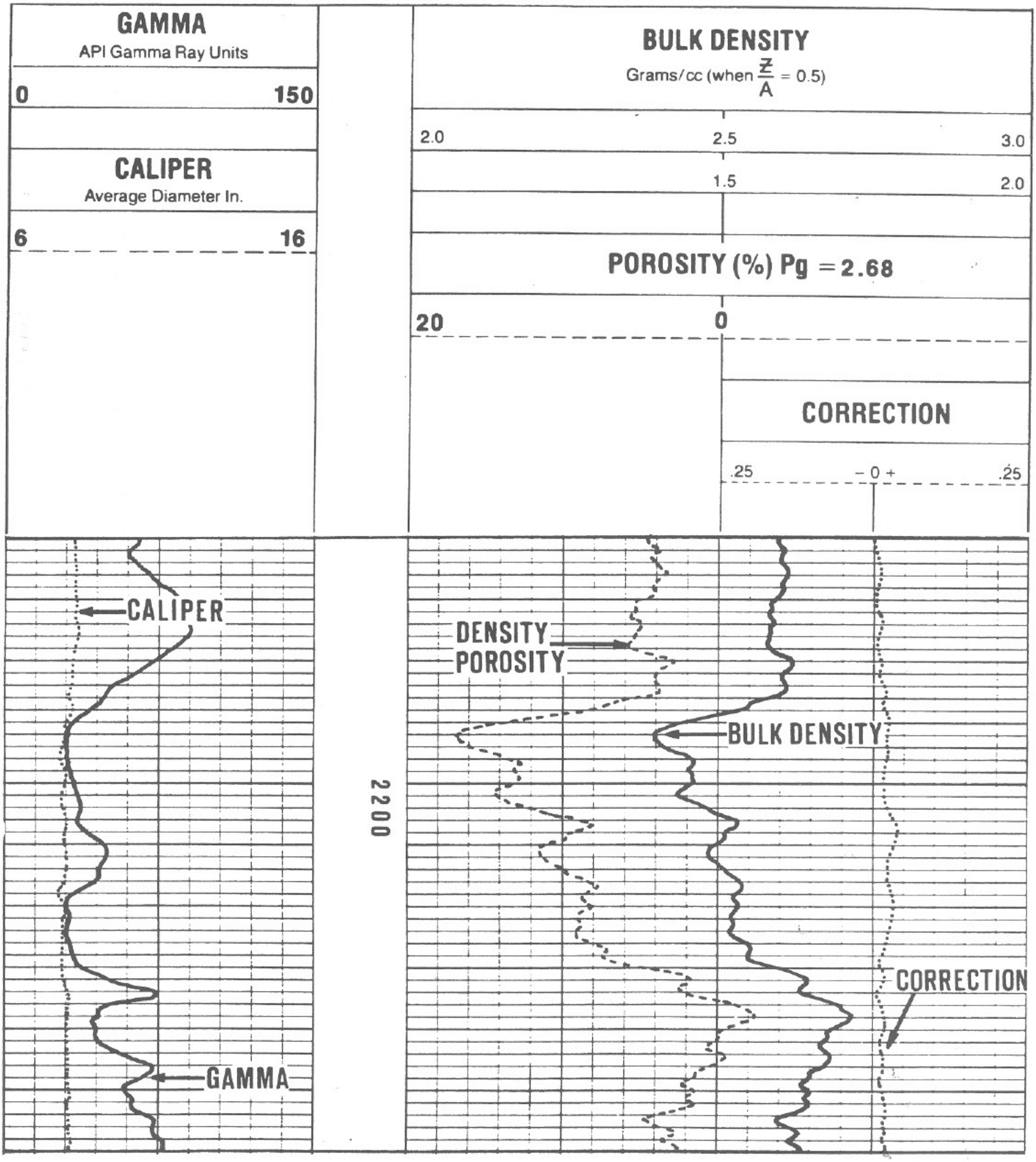


Formation: Cole Sand (Calcarious) – Terrebonne, La.

Data Given: $R_{mf} = .78$ @ 93°F @2200

PROBLEM NO. 11

COMPENSATED DENSITY LOG



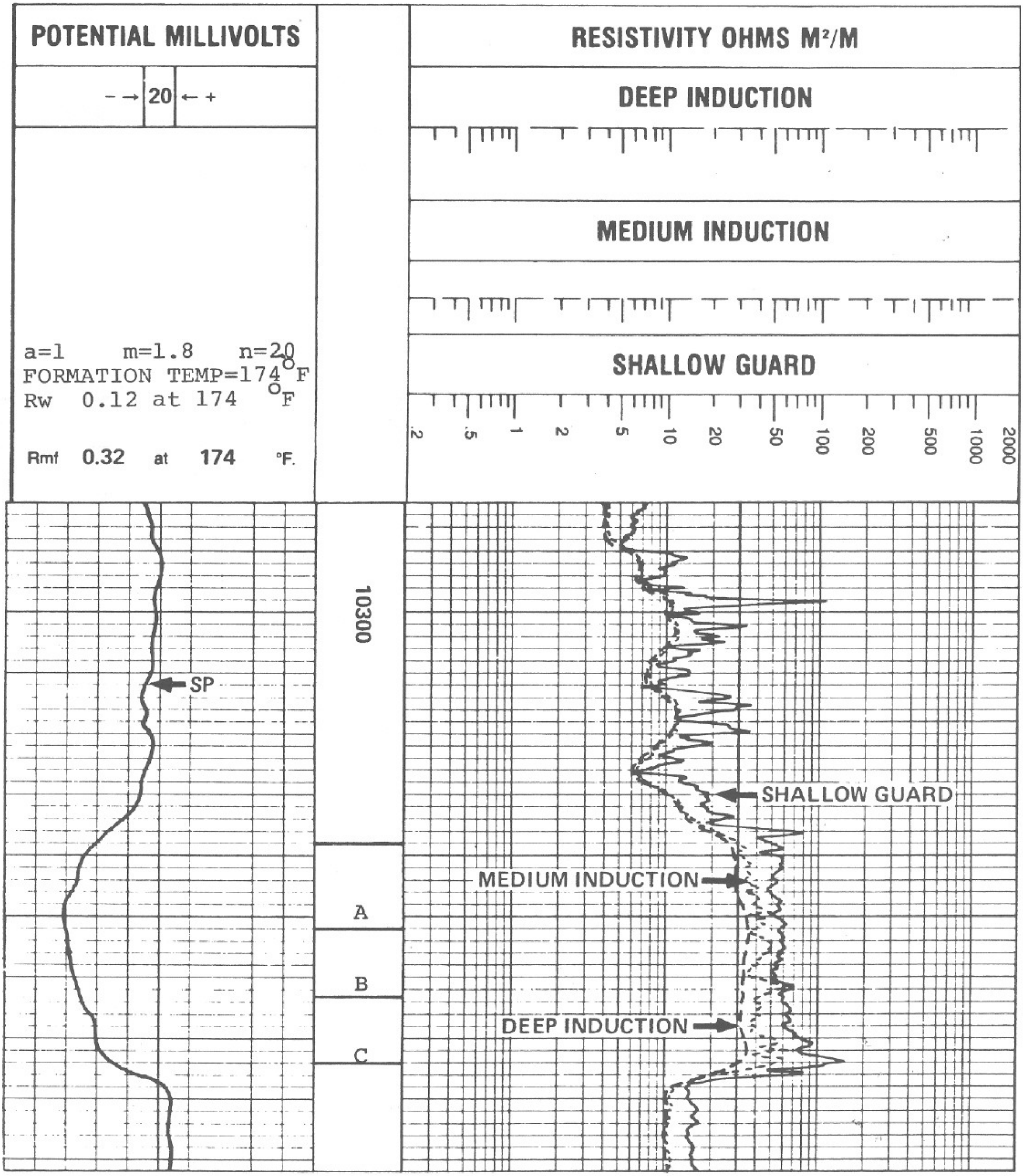
PROBLEM NO. 12

1) Determine the $Ø^{*}_{corr}$ in each zone. Also calculate out the average water saturation for each and indicate the probable production (S_{ciw} = 45%)

ZONE	$Ø_D$	$Ø_N$	$Ø^{*}_{corr}$	R_w	Rt	S_w	PROD
A							
B							
C							

$$* \text{ Use } Ø_{corr} = \sqrt{\frac{Ø^2_D + Ø^2_N}{2}}$$

PROBLEM NO. 12

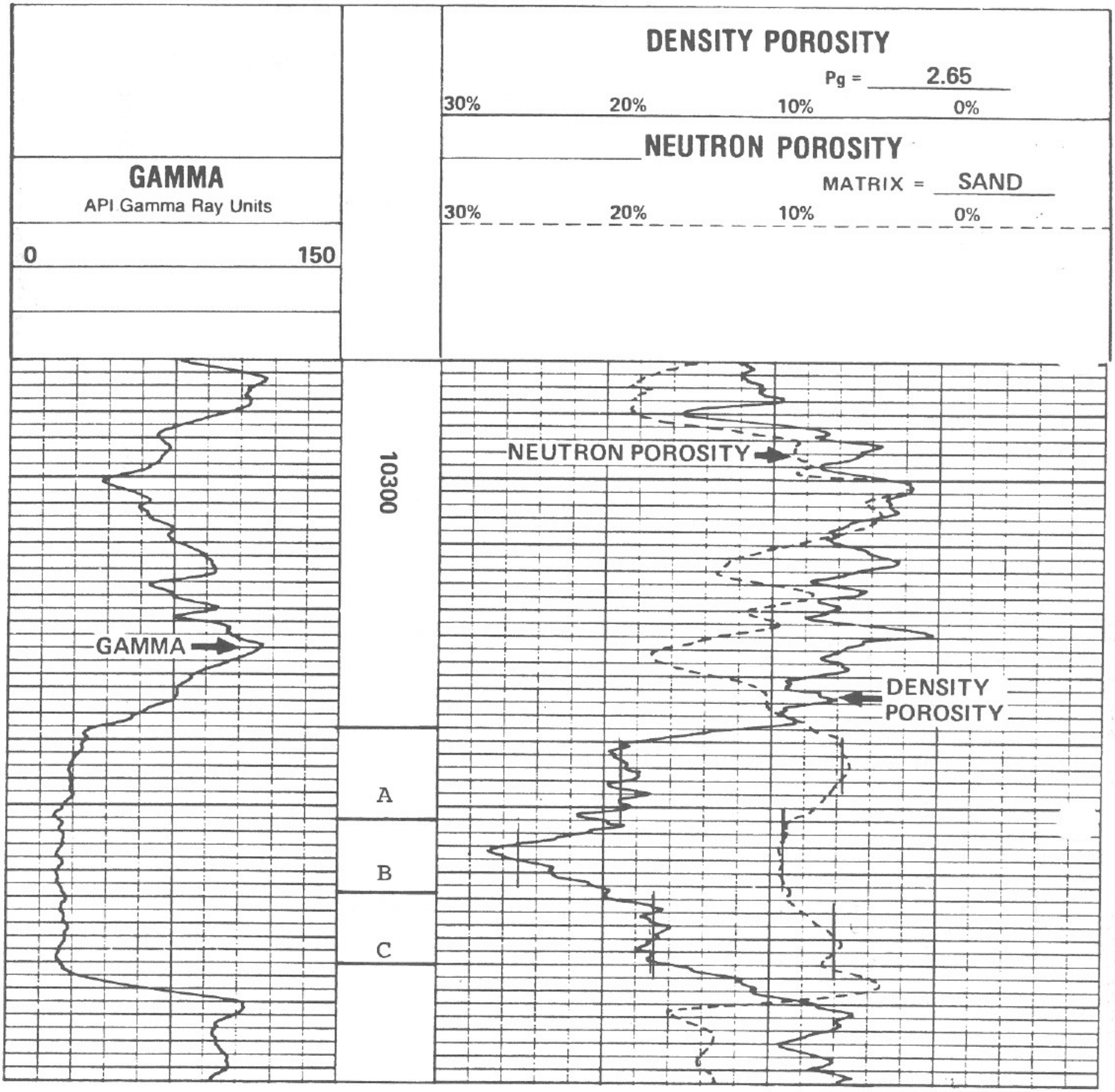


a=1 m=1.8 n=20
FORMATION TEMP=174 °F
Rw 0.12 at 174 °F

Rmf 0.32 at 174 °F.

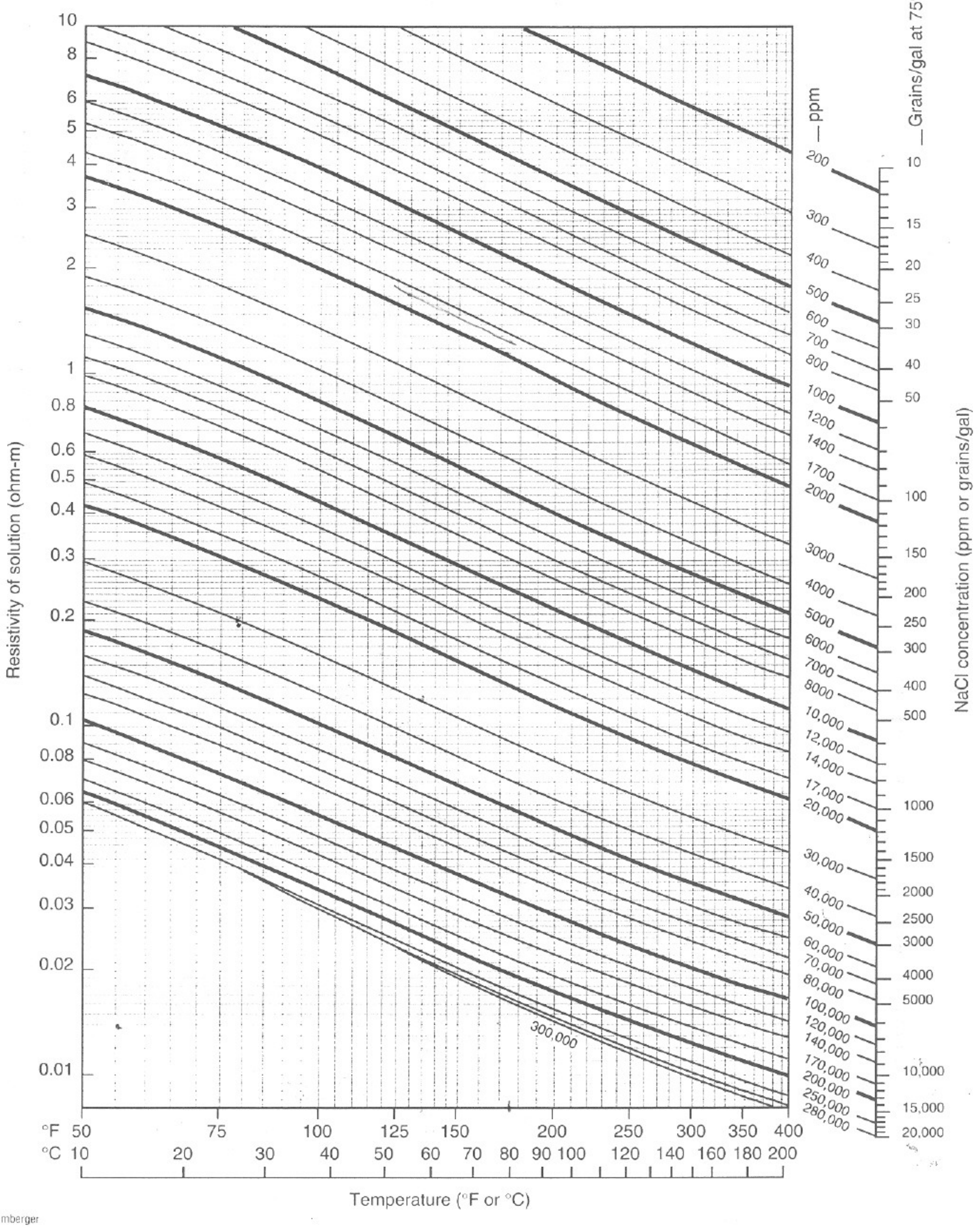
Formation: Morrow Sand
Custer County, Oklahoma

PROBLEM NO. 12



Resistivity of NaCl Solutions

Conversion **approximated** by $R_2 = R_1 [(T_1 + 6.77)/(T_2 + 6.77)]$°F or $R_2 = R_1 [(T_1 + 21.5)/(T_2 + 21.5)]$°C



R_{weq} Determination from E_{SSP}

Clean formations

This chart and nomograph calculate the equivalent formation water resistivity, R_{weq}, from the static spontaneous potential, E_{SSP}, measurement in clean formations.

Enter the nomograph with E_{SSP} in mV, turning through the reservoir temperature in °F or °C to define the R_{mfeq}/R_{weq} ratio. From this value, pass through the R_{mfeq} value to define R_{weq}.

For predominantly NaCl muds, determine R_{mfeq} as follows:

a. If R_{mf} at 75°F (24°C) is greater than 0.1 ohm-m, correct R_{mf} to formation temperature using Chart Gen-9, and use $R_{mfeq} = 0.85\ R_{mf}$.

b. If R_{mf} at 75°F (24°C) is less than 0.1 ohm-m, use Chart SP-2 to derive a value of R_{mfeq} at formation temperature.

Example: SSP = 100 mV at 250°F

$R_{mf} = 0.70$ ohm-m at 100°F
or 0.33 ohm-m at 250°F

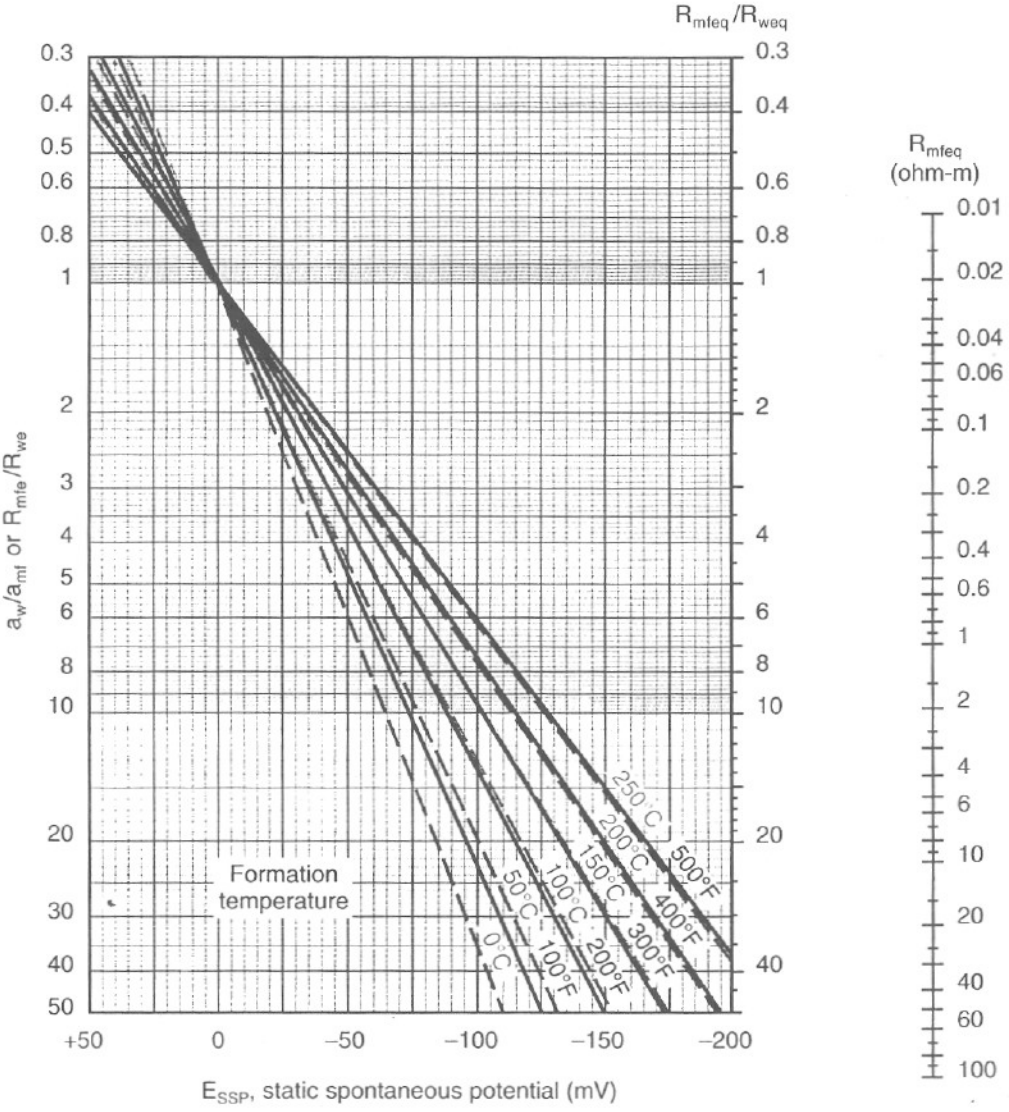
Therefore, $R_{mfeq} = 0.85 \times 0.33$
$= 0.28$ ohm-m at 250°F

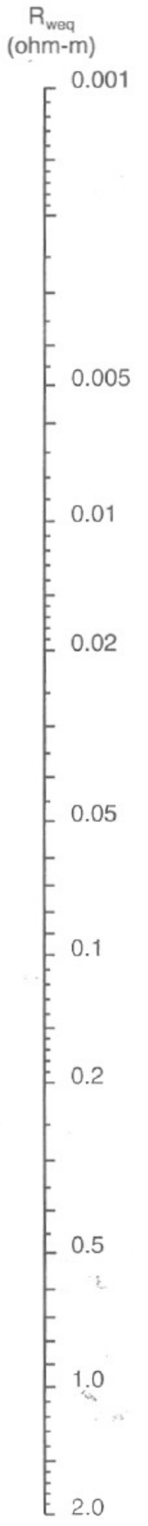
$R_{weq} = 0.025$ ohm-m at 250°F

$E_{SSP} = -K_c \log(R_{mfeq}/R_{weq})$

$K_C = 61 + 0.133\ T_{°F}$

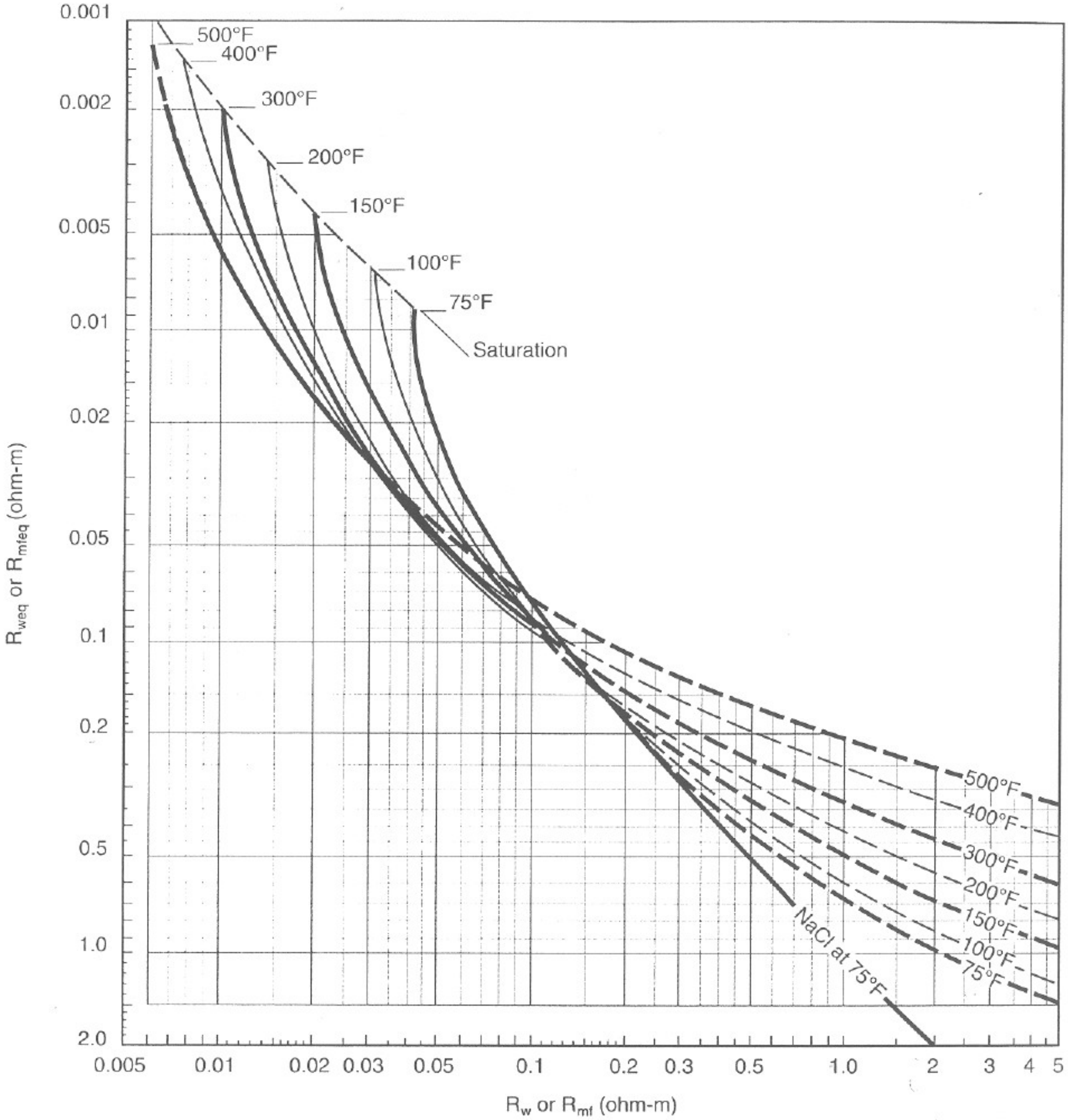
$K_C = 65 + 0.24\ T_{°C}$





R_w versus R_{weq} and Formation Temperature

SP-2
(English)



These charts convert equivalent water resistivity, R_{weq}, from Chart SP-1 to actual water resistivity, R_w. They may also be used to convert R_{mf} to R_{mfeq} in saline muds.

Use the solid lines for predominantly NaCl waters. The dashed lines are approximate for "average" fresh formation waters (where effects of salts other than NaCl become significant). The dashed portions may also be used for gyp-base mud filtrates.

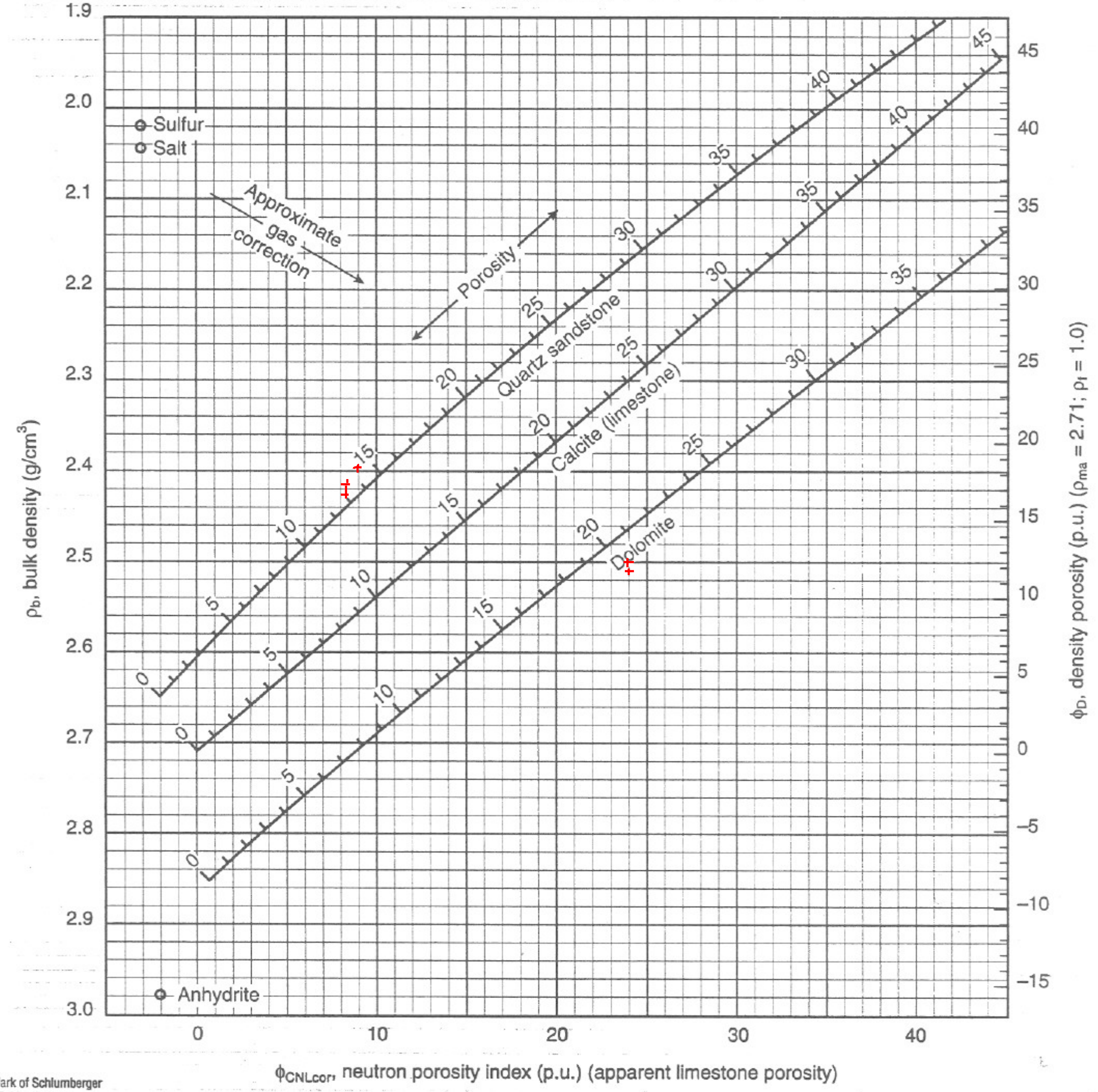
Example: R_{weq} = 0.025 ohm-m at 120°C
From chart, R_w = 0.031 ohm-m at 120°C

Special procedures for muds containing Ca or Mg in solution are discussed in Reference 3. Lime-base muds usually have a negligible amount of Ca in solution; they may be treated as regular mud types.

Porosity and Lithology Determination from Litho-Density* Log and CNL* Compensated Neutron Log

For CNL curves after 1986 labeled TNPH

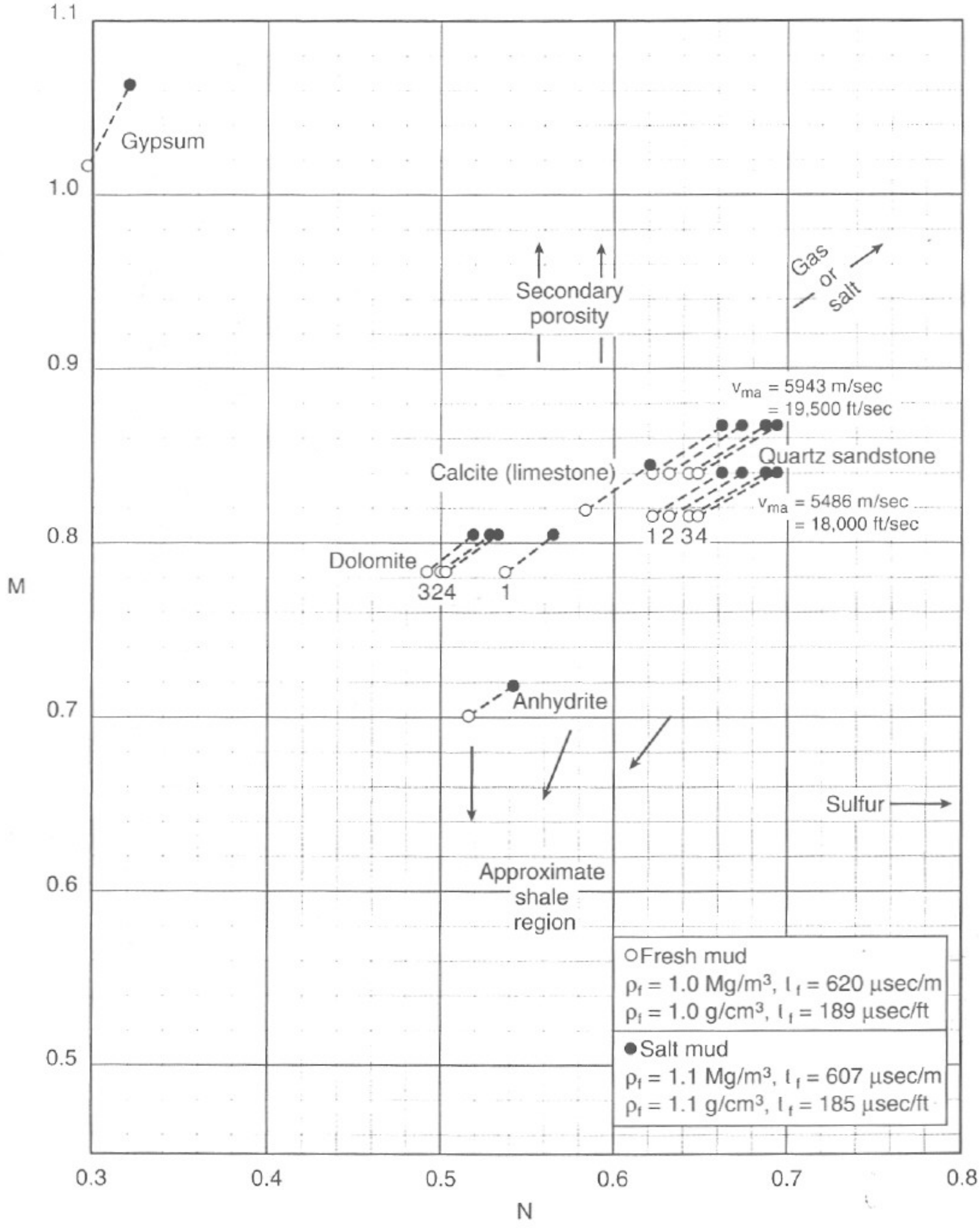
Liquid-filled holes ($\rho_f = 1.000$ g/cm^3; $C_f = 0$ ppm)



*Mark of Schlumberger

M-N Plot for Mineral Identification

For CNL* curves that have been environmentally corrected



This crossplot may be used to help identify mineral mixtures from sonic, density and neutron logs. (The CNL neutron log is used in the above chart; the time average sonic response is assumed.) Except in gas-bearing formations, M and N are practically independent of porosity. They are defined as:

$$M = \frac{t_f - t}{\rho_b - \rho_f} \times 0.01 \text{ (English)}$$

$$M = \frac{t_f - t}{\rho_b - \rho_f} \times 0.003 \text{ (metric)}$$

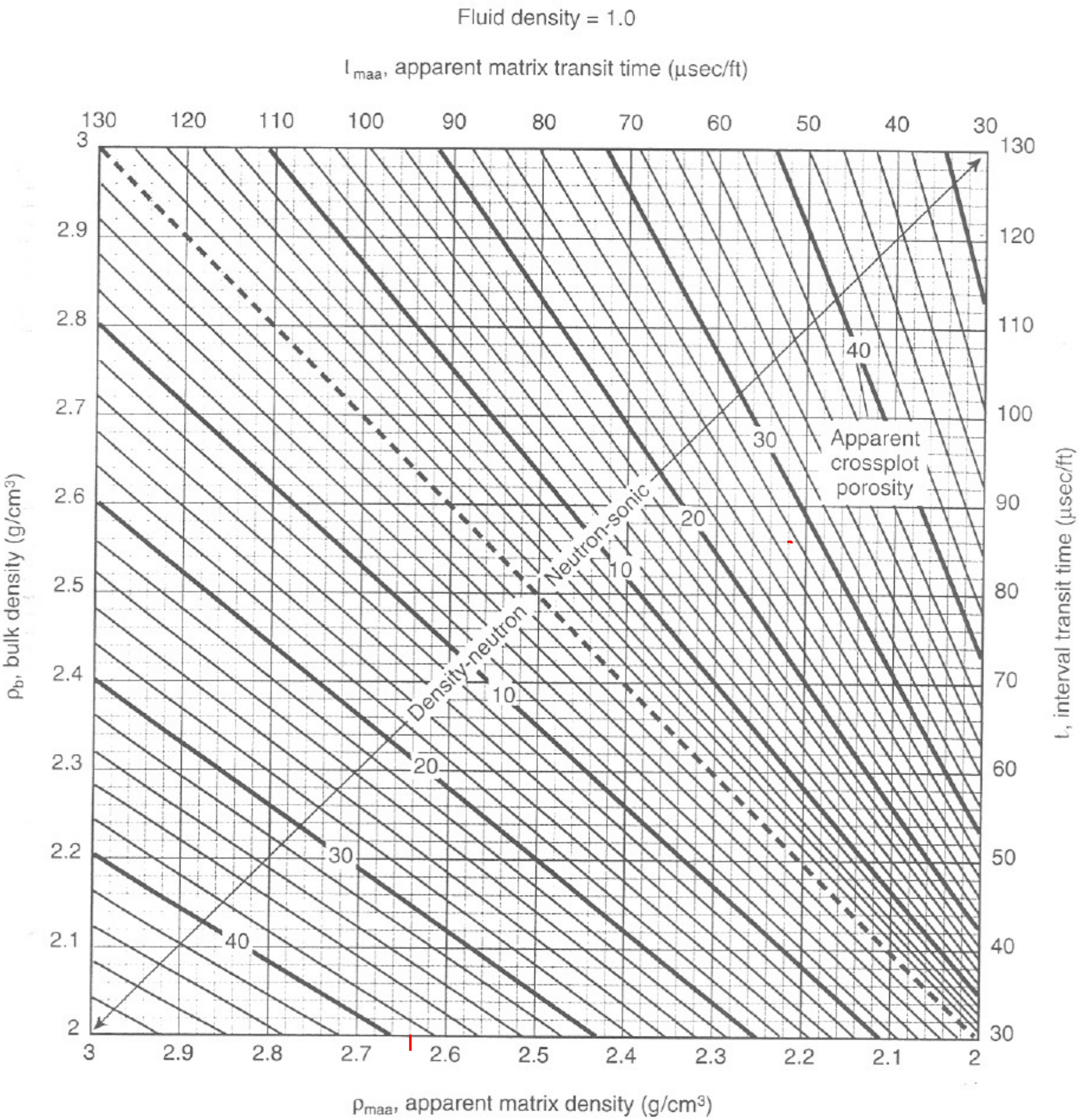
$$N = \frac{(\phi_N)_f - \phi_N}{\rho_b - \rho_f} \text{ (English or metric)}$$

Points for binary mixtures plot along a line connecting the two mineral points. Ternary mixtures plot within the triangle defined by the three constituent minerals. The effect of gas, shaliness, secondary porosity, etc., is to shift data points in the directions shown by the arrows.

The dolomite and sandstone lines on Chart CP-8 are divided by porosity range as follows: 1) $\phi = 0$ (tight formation); 2) $\phi = 0$ to 12 p.u.; 3) $\phi = 12$ to 27 p.u.; and 4) $\phi = 27$ to 40 p.u.

Determination of Apparent Matrix Parameters from Bulk Density or Interval Transit Time and Apparent Total Porosity

CP-14
(Englis



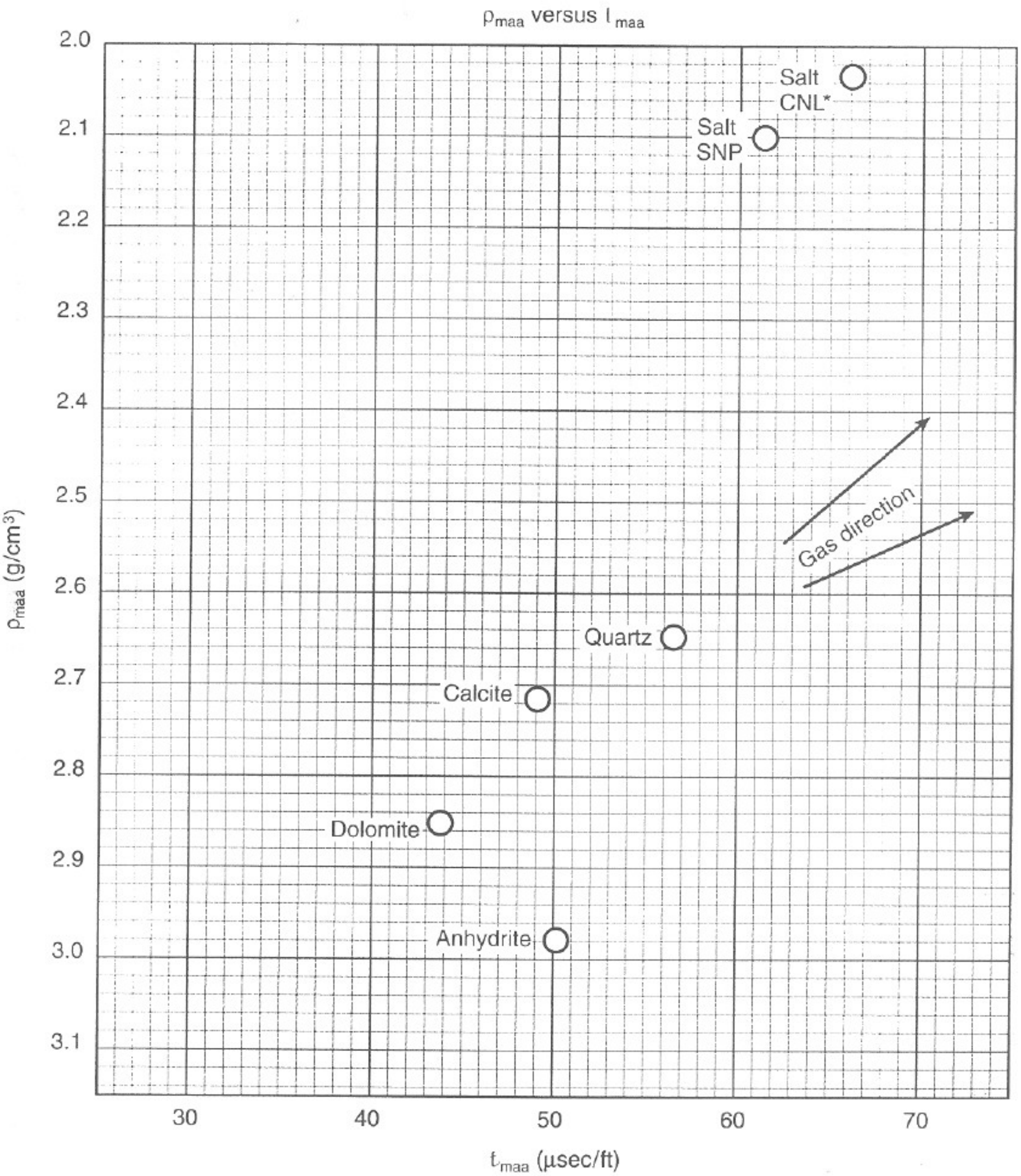
The MID plot permits the identification of rock mineralogy or lithology through a comparison of neutron, density and sonic measurements.

To use the MID plot, three steps are required. First, an apparent crossplot porosity must be determined using the appropriate neutron-density and empirical (red curves) neutron-sonic crossplot (Charts CP-1 through CP-7). For any data plotting above the sandstone curve on these charts, the apparent crossplot porosity is defined by a vertical projection to the sandstone curve.

Continued on next page

Matrix Identification (MID) Plot

CP-15
(English)



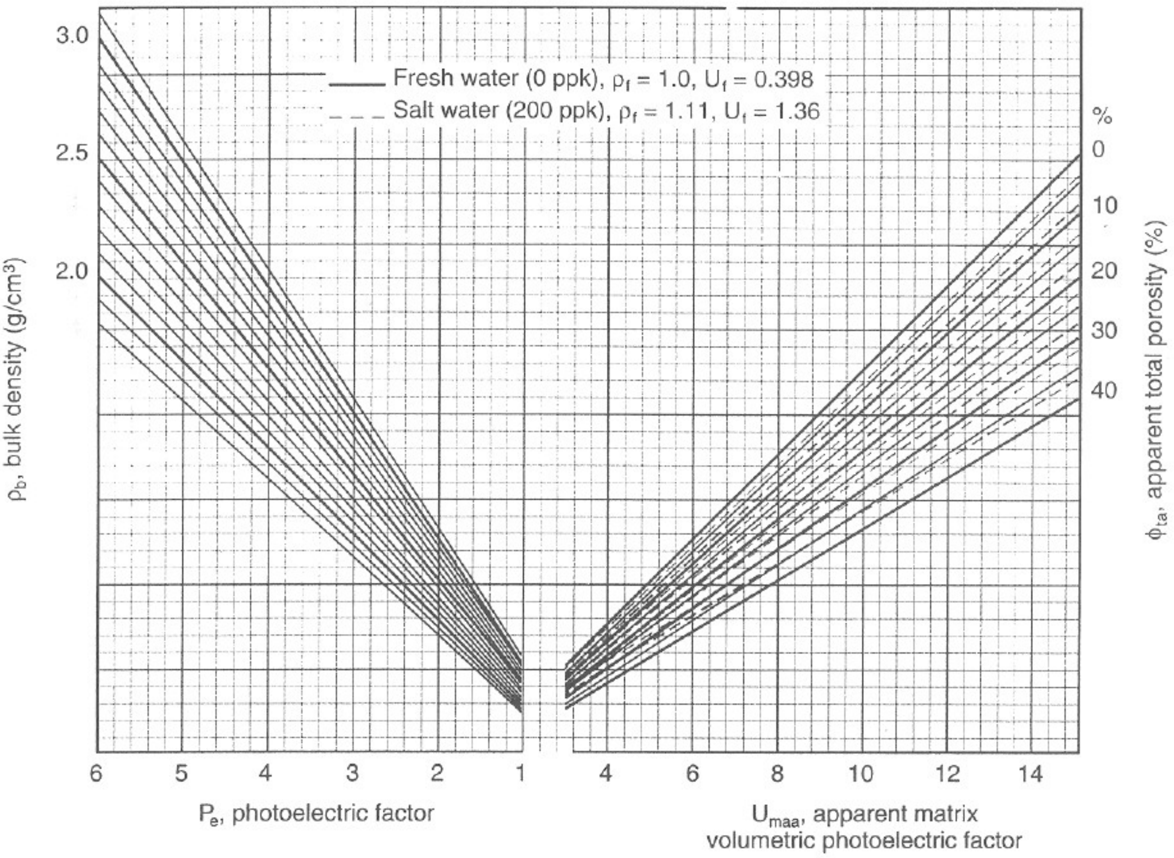
Examples:	*Level 1*	*Level 2*
	$t = 67$ μsec/ft	$t = 63$ μsec/ft
	$\rho_b = 2.04$ g/cm^3	$\rho_b = 2.46$ g/cm^3
	$\phi_{CNL} = -3$	$\phi_{CNL} = 24$ p.u.
	$\rho_f = 1.0$ g/cm^3	
giving	$\phi_{aND} = -1$	$\phi_{aND} = 21$
	$\phi_{aNS} = -1$	$\phi_{aNS} = 21$
and	$t_{maa} = 66$ μsec/ft	$t_{maa} = 43.5$ μsec/ft
	$\rho_{maa} = 2.03$ g/cm^3	$\rho_{maa} = 2.85$ g/cm^3

From the MID plot, Level 1 is identified as salt and Level 2 as dolomite.

Continued on next page

Determination of Apparent Matrix Volumetric Photoelectric Factor

CP-20



Lithology Identification Plot

Plot CP-21 identifies rock mineralogy through a comparison of apparent matrix grain density and apparent volumetric photo-electric factor.

To use, apparent matrix grain density ρ_{maa}, and apparent volumetric photoelectric factor, U_{maa}, are entered in ordinate and abscissa, respectively, on Plot CP-21. Rock mineralogy is identified by the proximity of the plotted data point to the labeled points on the plot.

To determine apparent matrix grain density, an apparent total porosity must first be determined (using, for example, a neutron-density crossplot). Then, Chart CP-14 may be used with bulk density, ρ_b to define the apparent matrix grain density, ρ_{maa}.

To find the apparent matrix volumetric photoelectric factor, U_{ma}a, enter Nomograph CP-20 with the photoelectric factor, P_e; go vertically to the bulk density , ρb; then, go horizontally across to the total porosity, $Ø_t$: and finally , go vertically downward to define the matrix volumetric photoelectric, U_{maa}.

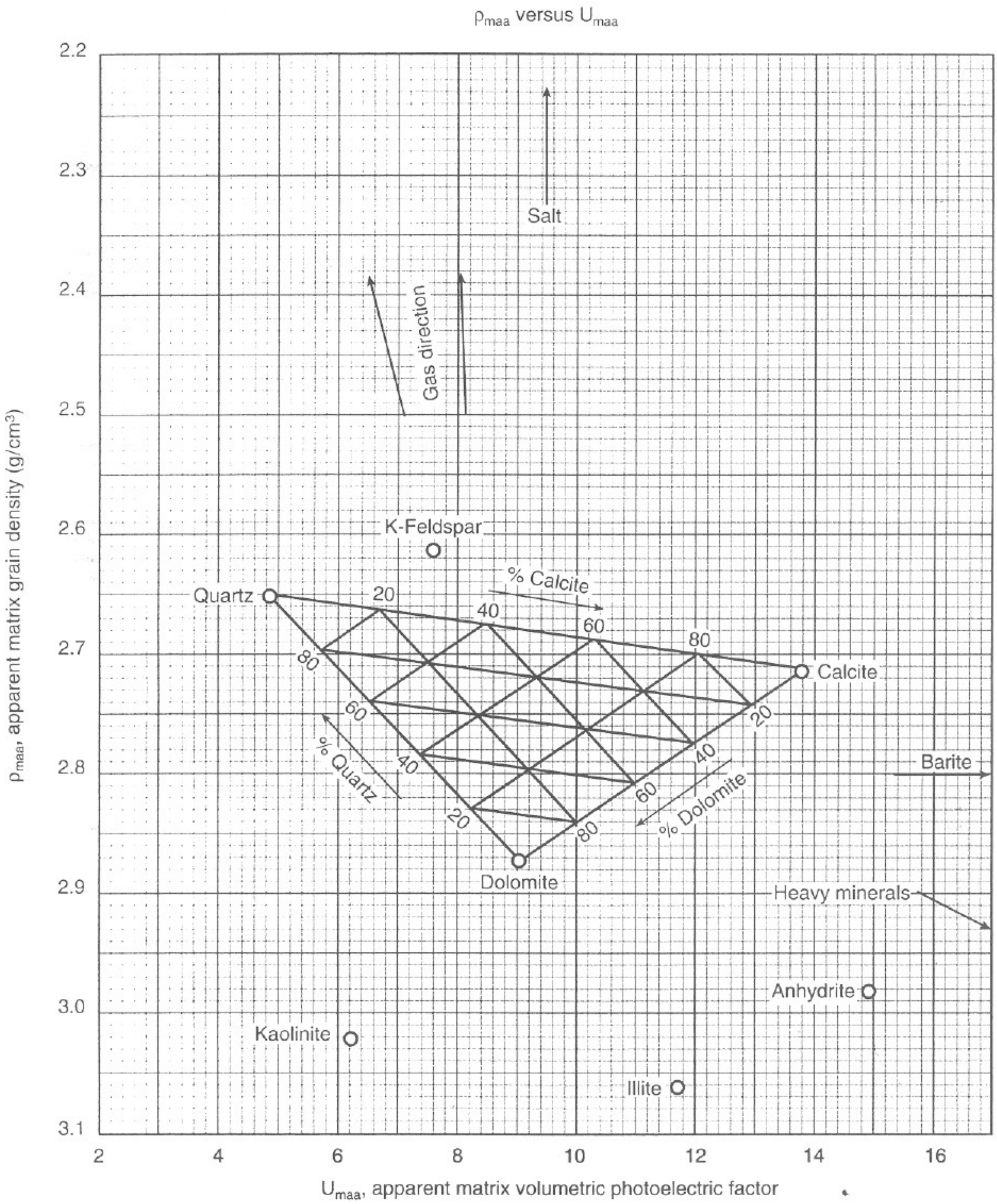
Example:

$Pe = 3.65$
$\rho_b = 2.52$ g/cm^3 ($\rho_f = 1.0$ g/cm^3)
$Ø_{ta} = 16\%$

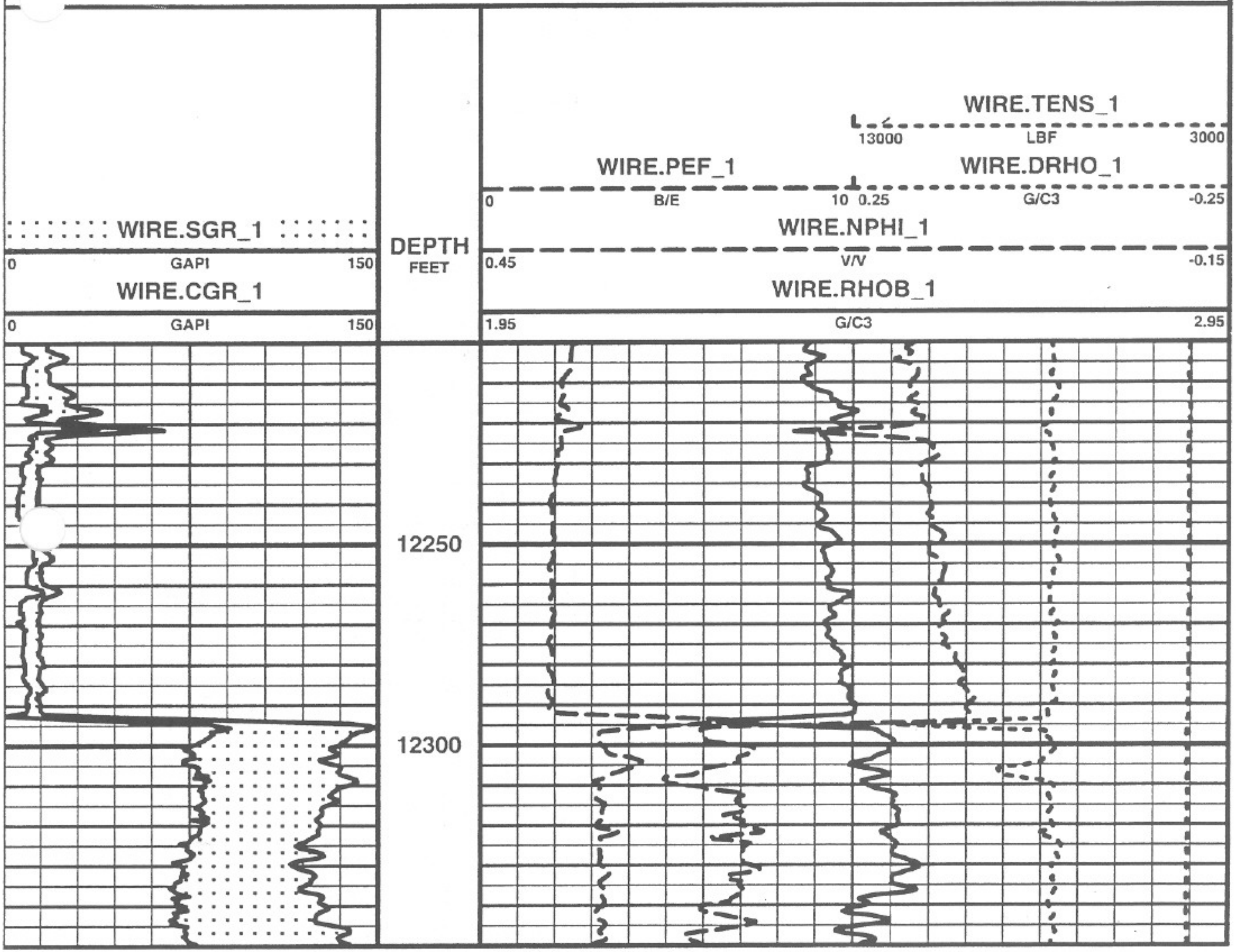
Giving $\rho_{maa} = 2.81$ g/cm^3 (from Chart CP-14)
And $U_{maa} = 10.9$

Plotting these values indicates the level to be a mixture of approximately 60% dolomite and 40% limestone.

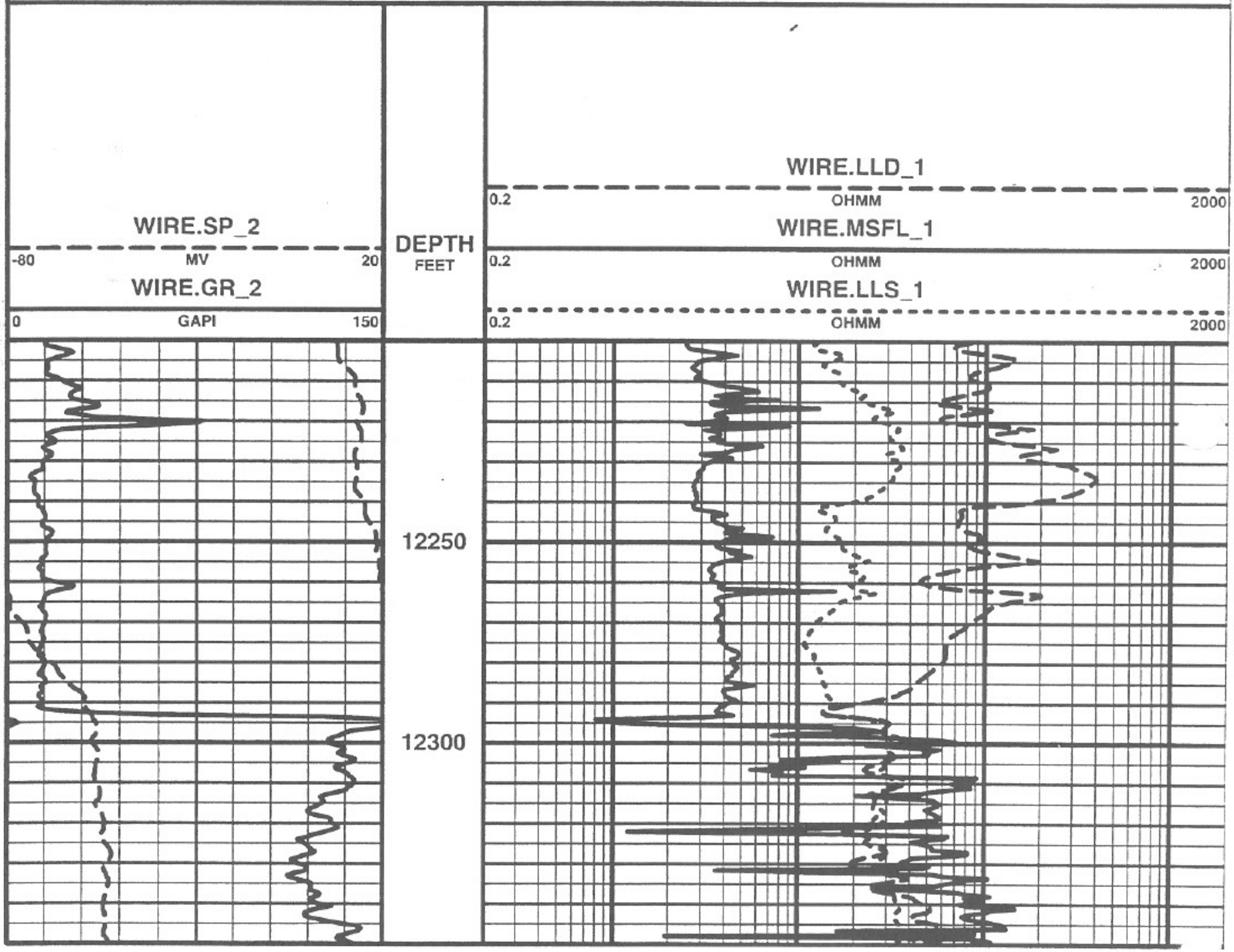
Lithology Identification Plot



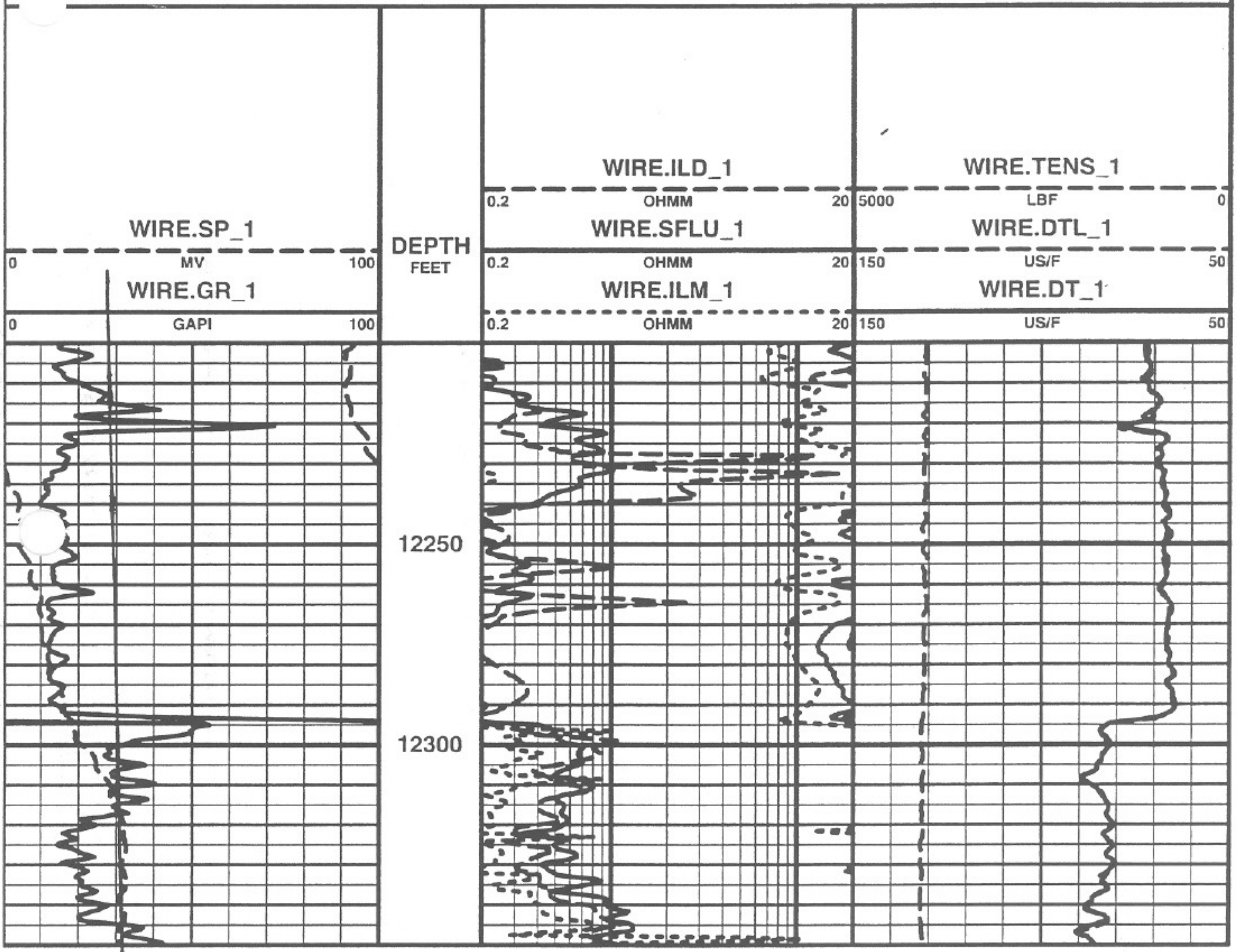
WELL: PROJECT 5.



WELL: PROJECT 5.

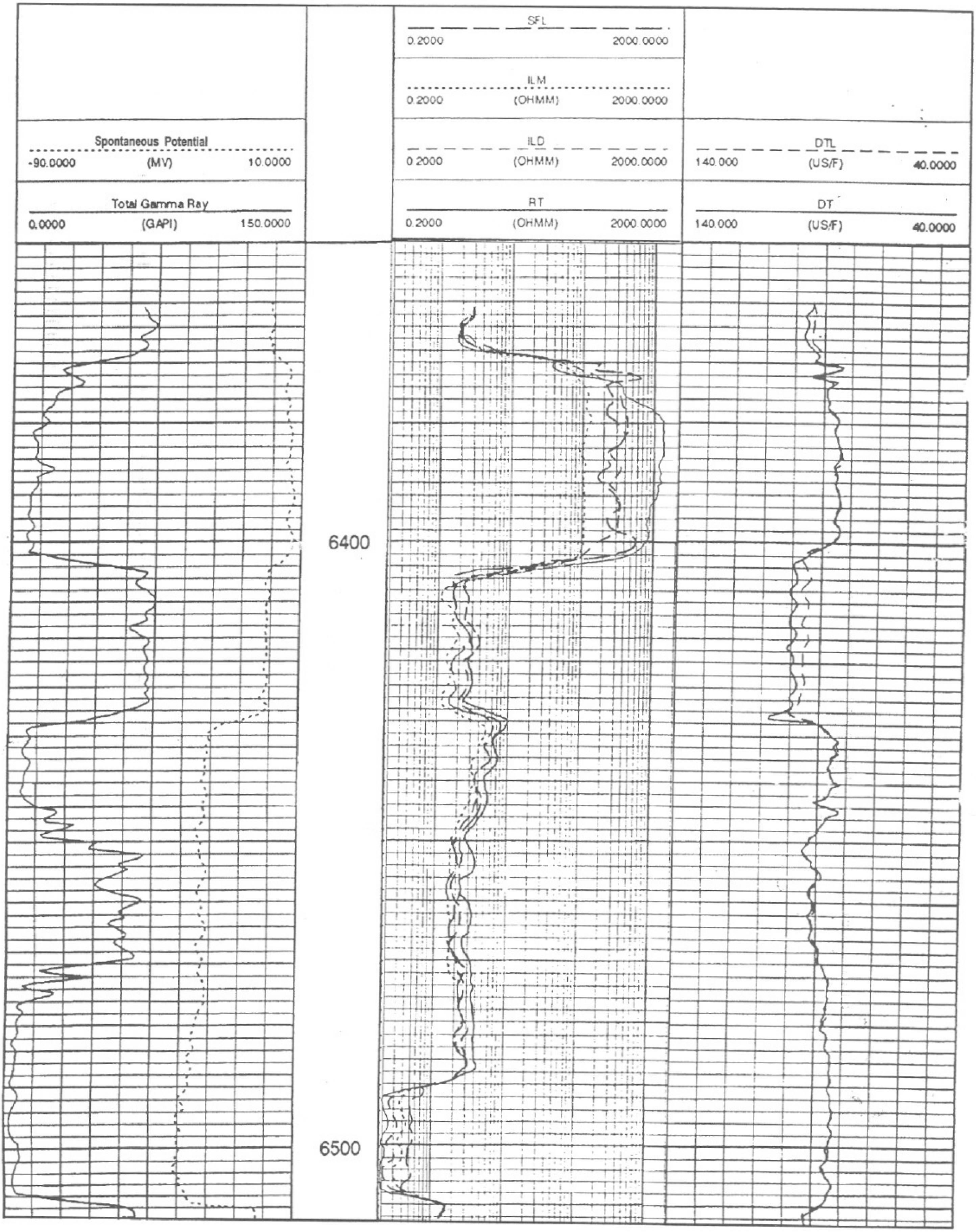


WELL: PROJECT 5.

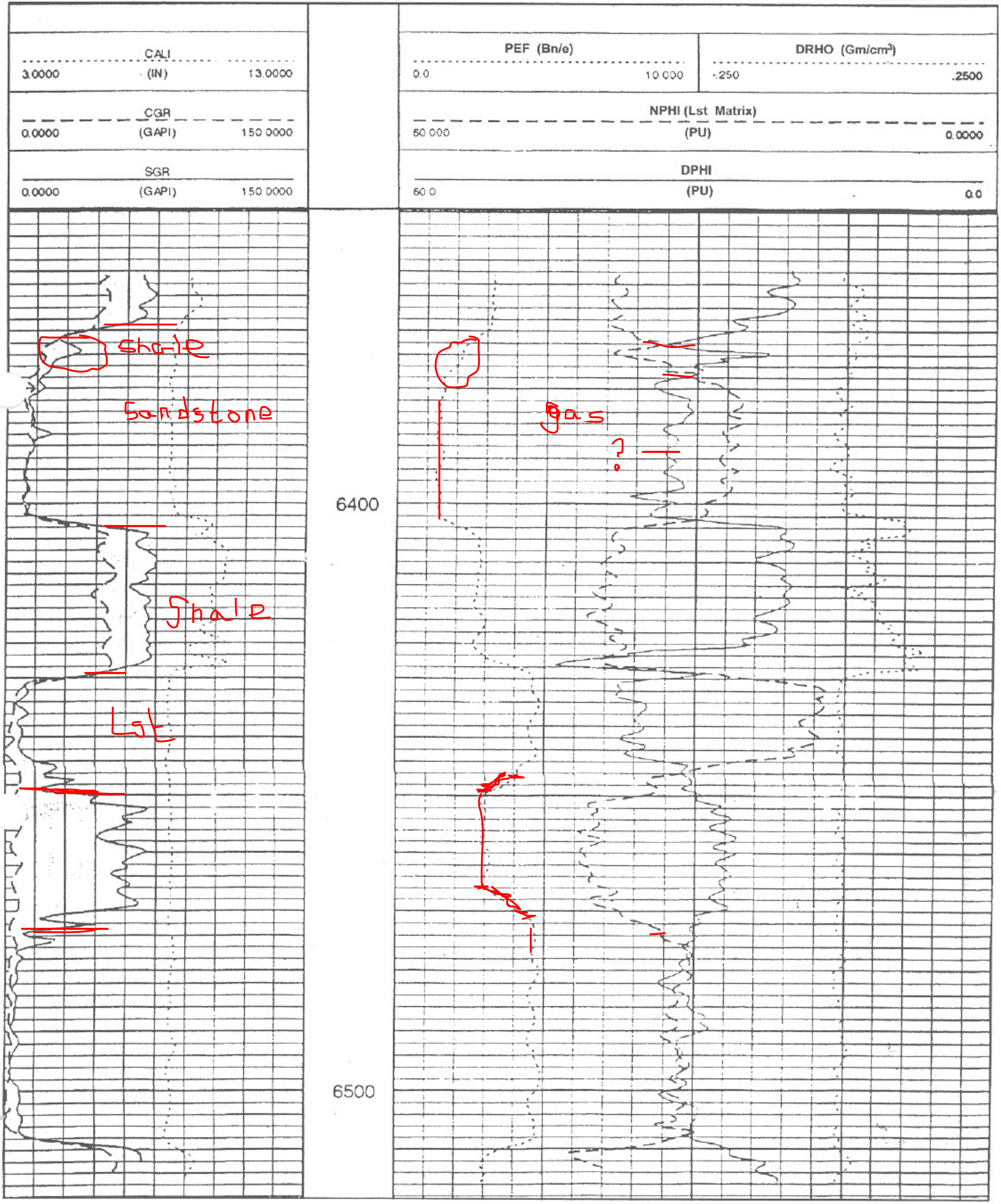


SP Base line drawn from Shales above and below.

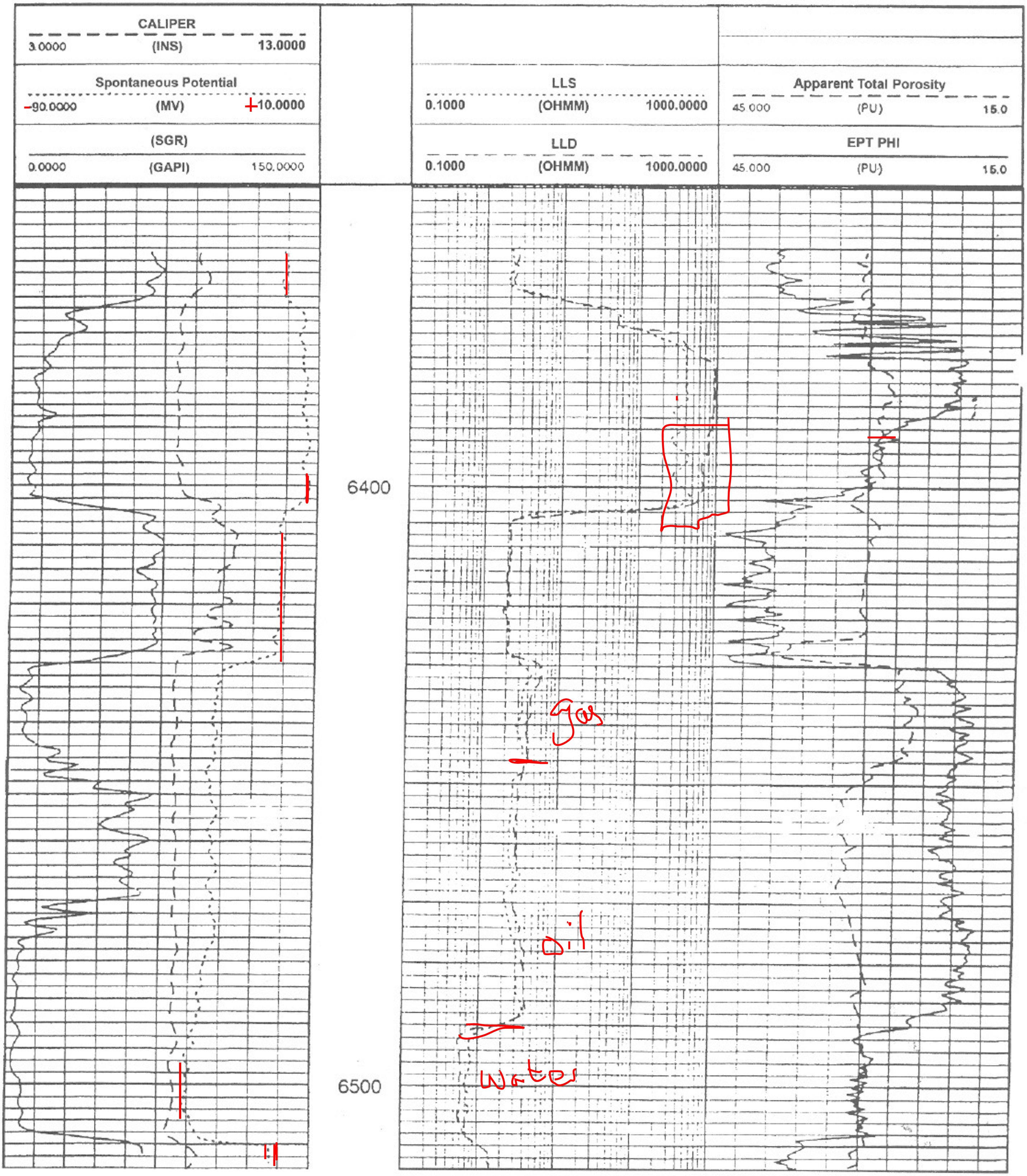
LOG 1


SFL
0.2000 2000.0000
ILM
0.2000 (OHMM) 2000.0000
Spontaneous Potential
-90.0000 (MV) 10.0000
ILD
0.2000 (OHMM) 2000.0000
DTL
140.000 (US/F) 40.0000
Total Gamma Ray
0.0000 (GAPI) 150.0000
RT
0.2000 (OHMM) 2000.0000
DT
140.000 (US/F) 40.0000
6400
6500

LOG 2


CALI
3.0000
(IN)
13.0000
CGR
0.0000
(GAPI)
150.0000
SGR
0.0000
(GAPI)
150.0000
PEF (Bn/e)
0.0
10.000
DRHO (Gm/cm³)
-.250
.2500
NPHI (Lst Matrix)
60.000
(PU)
0.0000
DPHI
60.0
(PU)
0.0
6400
6500
shale
sandstone
Shale
Lst
gas
?

LOG 3


CALIPER
3.0000
(INS)
13.0000
Spontaneous Potential
-90.0000
(MV)
+10.0000
(SGR)
0.0000
(GAPI)
150.0000
LLS
0.1000
(OHMM)
1000.0000
LLD
0.1000
(OHMM)
1000.0000
Apparent Total Porosity
45.000
(PU)
15.0
EPT PHI
45.000
(PU)
15.0
6400
Gas
Oil
Water
6500

SECTION B

This section deals with a suite of down-hole logs, attached. The information you require is as follows:

You have three suites of logs comprising, SP (Spontaneous Potential), GR (Gamma ray), DIL (Dual Induction), SFL (Spherically Focused Log), DT (Sonic/acoustic), DTL (Long-spaced sonic), CAL (Caliper), SGR (Total Spectral Gamma), CGR (Computed Th + K Gamma), PEF (Photoelectric Effect), DRHO (Bulk Density), NPHI (Neutron Porosity), DPHI (Density Porosity), LLS (Laterolog Shallow), LLD (Laterolog Deep), EPT (Electromagnetic Propogation tool) and a computed apparent total PHI.

The hole size is 8.5 inches and the mud is water-based. The section of interest is from 6390-6510 feet. The formation temperature at 6500 ft is 185°F. Mud properties are:

Rmf = 0.36 ohmm @ 75°F
Rm = 0.40 ohmm @ 75°F

B10 Zone the log, within section of interest, using the porosity log & gamma-ray.
Indicate:

(a) The possible/probable lithology and,
(b) Where permeable, the potential fluid contents.

Mark a maximum of 5 zones, including shales and hand this log back with your answer book.

B11 Determine the lithology of intervals 6390-6400; 6432-6440; 6460-6470 and 6490-6500 by plotting 1 data point per interval on both a Neutron density cross-plot and a M & N Plot.

Does the PEF (Pe) curve back up your analysis?
If any ambiquity is seen suggest potential causes and a solution.

B12 Determine the appropriate Rw at 6396 and 6500 feet using the SP and Rwa methods. Discuss possible causes of any discrepancies.

B13 Briefly discuss why the EPT data show distinct separations from the total porosity curve. Does this enhance your understanding of this log suite?

End of Paper

(Enclosures: 3 Logs, Pe values for various minerals, N-D X-plot template, M & N Plot template).

B12 Determine the appropriate Rw at 6396 and 6500 feet using the SP and Rwa methods. Discuss possible causes of any discrepancies.

[10]

B13 Briefly discuss why the EPT data show distinct separations from the total porosity curve. Does this enhance your understanding of this log suite?

[5]

End of Paper

(Enclosures: 3 Logs, Pe values for various minerals, N - D X-plot template, M & N Plot template)

Density and PE Data for Various Compounds

Mineral/Compounds	ρb, (RHOB)	Pe	ØN, (PHIN) (Lst matrix)	Δt, (DT)	ρmaa, (RHOMAA)
Quartz	2.65	1.8/2.0	-0.02	55.5	2.64
Limestone ($CaCO_3$)	2.71	5.1	0.0	49	2.71
Dolomite $(Ca,Mg)CO_3$	2.87	3.132	0.01	43.5	2.85
Barite ($BaSO_4$)	4.09	267	-.02		42.9
Hematite (Fe_2O_3)	5.18	21	0.11		39.2
Anhydrite ($CaSO_4$)	2.98	5.1	-0.02	50	2.98
Halite (NaCl)	2.03	4.65	-0.03	67	2.03
Water					
Fresh	1.0	1.1	0.358	189	
Salty	1.165	1.15	0.807	187	
Oil (mean)	0.985	0.9	0.12	189-220	
Illite	2.60-2.90	2.52	3.45		
Average Shale		3.42	0.45-0.60		
Coal - Anthracite	1.47	0.61	0.38	105	

ANSWER TO
PROBLEM #1

CALCULATION OF Sw FROM ACOUSTIC VELOCITY vs POROSITY USING MEASURED ABD STANDARD RELATIONSHIPS

Given:

Rw = 0.1 ohm-m @reservoir Temp
Rt = 65 ohm-m (From Zone of Interest)
Δt = 60 usec/ft (From Zone of Interest)

Find :

(1) Ø and Sw using average relationships:
Acoustic Log Ø - ____3.2%__________ (Assume Matrix Velocity = 18,000 ft/sec)
Calculate Sw - ____>100%__________ (Assume Archie Relationship)
a = 1, m=2, n=2

(2) Refine Ø and Sw calculations with laboratory measured data :
Acoustic Log Ø - ____11.1%________ (Use measured Δt vs Ø relationship)
Calculate Sw - ____26.3%________ (Use measured Resistivity Data)
a = 1.37, m=1.80, n=1.65

Given:

Rw = 0.1 ohm-m @reservoir Temp
Rt = 10 ohm-meters
Δt = 70 sec/ft (from log in zone of interest)

Find:

(1) Ø and Sw using average relationships:
Acoustic Log Ø - ____10.6%__________ (Assume Matrix Velocity = 18,000 ft/sec)
Calculate Sw - _____94.4%_________ (Assume Archie Relationship)

(2) Refine Ø and Sw calculations with laboratory measured data :
Acoustic Log Ø - ____18.2%_________ (Use measured Δt vs Ø relationship)
Calculate Sw - ______47.6%______ (Use measured Resistivity Data)

ANSWERS TO
PROBLEM NO. 2

DETERMINATION OF CALCULATED LOG ø SENSITIVITY TO ERRORS IN ASSUMED GRAIN DENSITY AND FLUID DENSITY

BD (From log) = 2.16 g/cc
FD = 1.0 g/cc

GD (g/cc)	ø Calculated	Δø (From ø Value When GD = 2.65)	
2.70	31.8	+2.1	7.1% error
2.65	29.7	-	
2.60	27.5	-2.2	7.4% error

BD (From log) = 2.49 g/cc
FD = 1.0 g/cc

GD (g/cc)	ø Calculated	Δø (From ø Value When GD = 2.65)	
2.70	12.4	+2.7	27.8% error
2.65	9.7	-	
2.60	6.8	+2.9	29.9% error

GD (g/cc)	BD	FD (g/cc)	ø Calculated	Sgr	FD Avg(g/cc)	ø Calculate
2.65	2.18	1.0	28.5	30%	0.70	24.1
2.65	2.20	1.0	27.3	30%	0.70	23.1
2.65	2.17	1.0	29.1	30%	0.70	24.6
2.65	2.24	1.0	24.8	30%	0.70	21.0

EQUATIONS:

(1) $$\phi = \frac{GD - BD}{GD - FD} = \frac{\rho\,ma - \rho\,b}{\rho\,ma - \rho\,f}$$

(2) $$\text{FD Avg} = FD_1 \times (\text{Fractional Fluid Saturation})_1 + FD_2 \times (\text{Fractional Fluid Saturation})_2$$

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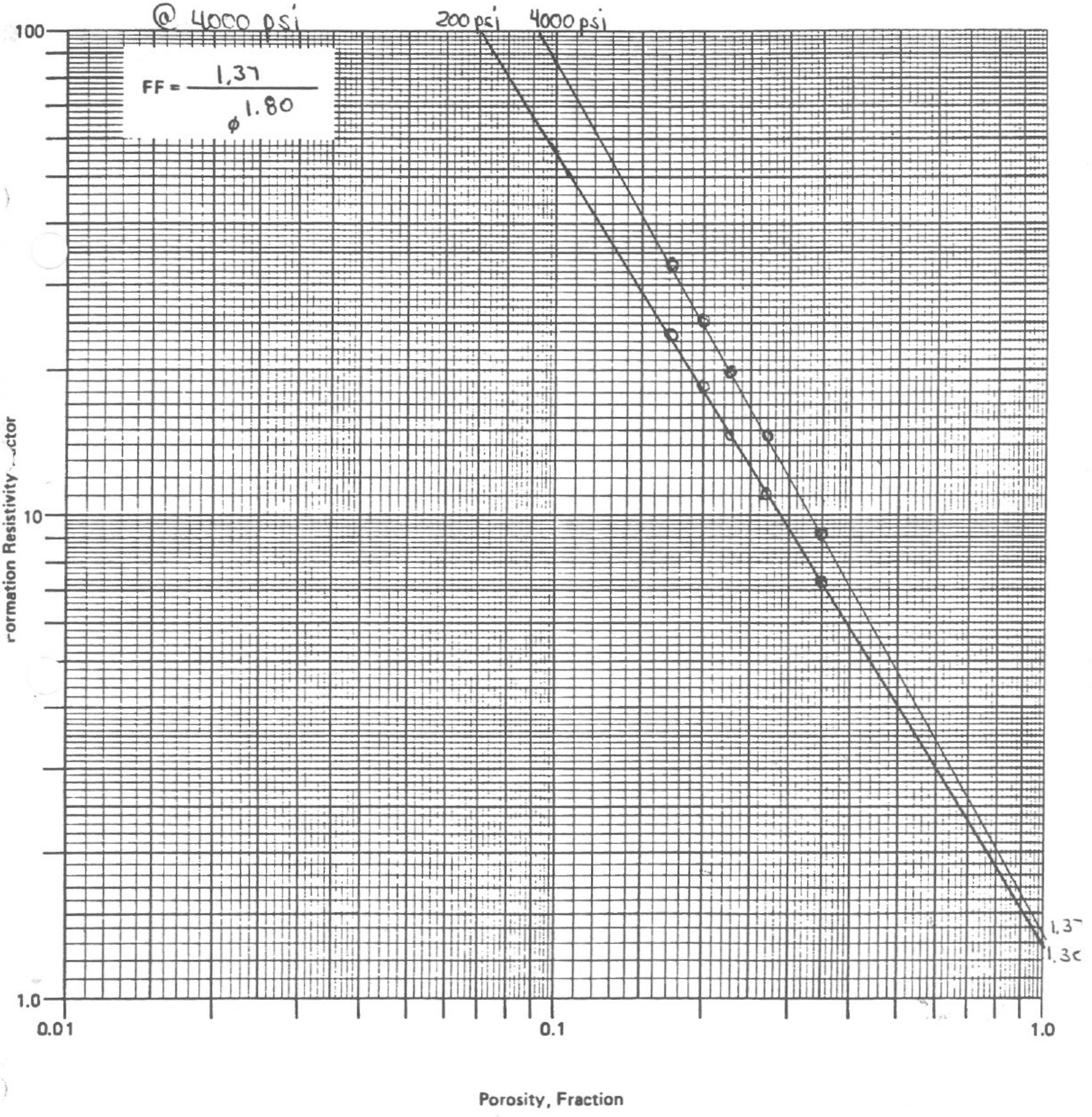
Petroleum Reservoir Engineering
DALLAS, TEXAS

Page ________ of ________
File ________________

Company Answers to 3 & 4
Well
Field
Formation
County
State



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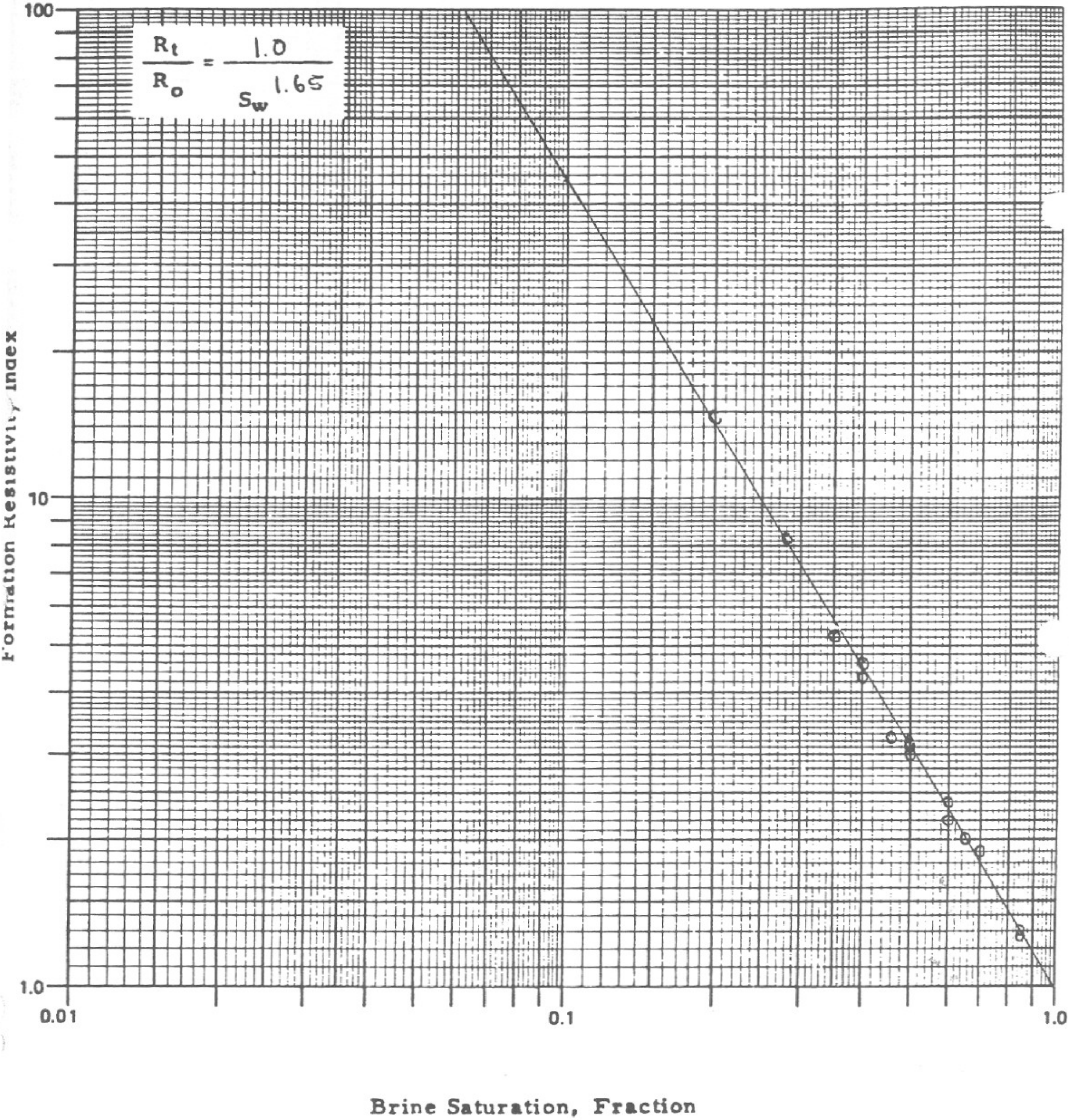
Petroleum Reservoir Engineering
DALLAS, TEXAS

Page ________ of ________
File ________

Company Answer to #5	Formation
Well	County
Field	State



ANSWER TO
PROBLEM NO. 6

CALCULATION OF Sw FROM DOWN HOLE LOG Rt & MEASURED “m” & “n”
(Using Charts of F vs Ø & RI vs Sw)

Rw=0.1 ohm-meters down hole

Ø	F	Ro	Rt	$\frac{Rt}{Ro}$	Sw
30	11.96	1.196	25	20.89	15.8
30	11.96	1.196	20	16.72	18.1
30	11.96	1.196	10	8.36	27.6
20	24.82	2.482	25	10.07	24.7
20	24.82	2.482	20	8.06	28.2
20	24.82	2.482	10	4.03	42.9
10	86.44	8.644	25	2.89	52.5
10	86.44	8.644	20	2.31	60.1
10	86.44	8.644	10	1.16	91.5

Where “m” = 1.80
“n” = 1.65
“a” = 1.37

PROBLEM SOLUTIONS TO PROBLEM NO. 7

I. FORMATION WATER & MUD RESISTIVITY

1. Use Chart Fig. 4-1, pg. 27 in Pirson or Chart A-6, pg. 9, Schlumberger Log Interpretation charts, 1969. Enter chart for resistivity of solution = 0.2 ohm-m to intersect temperature = 78°, follow constant salinity line to intersect with temperature of 200°F. Read R_w = 0.082.

2. Equivalent NaCl concentration = 30,000 ppm or 1800 grains/gallon at 75°F.

II.

From Schlumberger Gen-6, A-2, pg. 6 assuming a annual mean surface tremperature of 60°F. Then at 8,000 feet temperature of formation is 36°F. Using the Schlumberger charts, we can solve this problem as follows:

Assume a mean annual surface temperature of 60°F:

From Chart A-2, find $T_{8000\ ft}$ = 136°F
From Chart A-6, Rm @ 136 °F = 1.60 ohm-m
Assume mud weight of 12 lb/gal.
From Chart GEN-7, R_{mf} = 0.92 ohm-m
R_{mc} = 2.5 ohm-m

III. WATER RESISTIVITY

The chemical analysis of a formation water is as follows:

			NaCl Equiv, ppm @ 75°F	
		1968 Schlumberger Chart, Gen-8 Variable Dunlap Multiplier	By Dunlap Variable Multiplier	By Factors in this Manual II, C Page 6
Na	23,000 ppm	1.0	23,000	23,000
K	1,000	0.86	860	1,000
Ca	2,000	0.98	1,960	1,900
Mg	1,000	1.49	1,490	2,000
Cl	30,000	1.0	30,000	30,000
SO_4	3,000	0.55	1,650	1,500
Total	60,000 ppm		58,960	59,400

Resistivity at 150°F = 0.060 ohm-m

ANSWERS ON CONTINUATION OF PROBLEM NO. 7

#4a. 9100 SD BHT = 200°F @ 12,000'
SP = -110
T° @ 9100 = 167°F
Rmf @ 167°F = .71Ω-m
Rmfeq = (.71)(.85) = 0.60Ω-m @ 167°F

Rm = 1.0 @ BHT
$\text{Rmf @ }167^{\circ}\text{F} = (.584)(1.2)^{1.07}$
$= 0.71$

Chart: Rmfeq/Rweq = 20
Chart: Rweq = .029
Chart: Rw = .04

$$\text{Equation: } -110 = -(61+.133(167))\log\frac{.60}{\text{Rweq}}$$

$$-110 = -83.21\log\frac{.60}{\text{Rweq}}$$

$$\text{Antilog}\left[1.32 = \log\frac{.60}{\text{Rweq}}\right]$$

$$21.00 = \frac{.60}{\text{Rweq}}$$

Rweq = .03

Rw = .04

#4b. 9150 SD
SP = + 20
T° @ 9150 = 167 °
Rmeq @ 167 = 0.60

(can't accurately use chart)

Equation : $SP = -(61 + .133\ T°F) \log \frac{Rmfeq}{Rweq}$

$+20 = -(61 + .133\ (167)) \log \frac{(.60)}{Rweq}$

$+20 = -82.21 \log \frac{.60}{Rweq}$

Antilog $(-0.243 = \log \frac{.60)}{Rweq}$

$.57 = \frac{.60}{Rweq}$

Rweq = 1.05

Rw is off chart so deduce Rw = Rweq since so fresh,
i.e, no effect from multivalent cations.

#5. Calculate $\propto$ for 9250'

$$ASP = \propto = \frac{-40}{-110} = 0.36$$

#6. $\emptyset = 30\%$

Sw = 100%

$$F = \frac{Ro}{Rw} = \frac{1}{\emptyset^2}$$

Rt = Ro

Archie's equation

$$\frac{Ro}{.04} = \frac{1}{(.3)^2}$$

$$Ro = \frac{.04}{(.30)^2}$$

$$Ro = Rt = 0.44$$

#7. You'd have to use the Rw from 9100 sand since an SSP isn't developed.

#8. BHT = $200^{\circ}F$ @ 12,000' T° @ 9,300 = $169^{\circ}F$

Rm = 1.0 @ BHT Rm @ $169^{\circ}F$ = 1.19

Mud wt = 12 lbs/gal Rmf = .70Ω-m @ $169^{\circ}F$

Hole size = 8"

SSP = -90 mv

Rmfeq = (.70)(.85) = .595

Chart: Rmfeq/Rweq = 11.8

Chart: Rweq = .05

Chart: Rw = .054

Equation: $$SSP = -(61+.133\ T^{\circ}F)\ \log \frac{Rmfeq}{Rweq}$$

$$-90 = -(61+.133(169))\ \log \frac{.595}{Rweq}$$

$$-90 = -83.48\ \log \frac{.595}{Rweq}$$

$$\frac{-90}{-83.48} = \log \frac{.595}{Rweq}$$

$$\text{antilog} \left[1.08 = \log \frac{.595}{Rweq} \right]$$

$$12.02 = \frac{.595}{Rweq}$$

$$Rweq = .0495$$

From chart Rw = .054

ANSWERS TO

PROBLEM No. 4, ISF/SONIC LOG

1. Use Scaler for Humble F, m = 2.15, n = 2.00
2. Determine R_w from Water sand resistivity at 8500 feet where porosity is 31% R_w = 0.025
3. Plot R_o and R_{mp} points on log for samples 8654 - 8682 feet
4. What is depth of oil/water contact by R_{mp}? 8669
5. Calculate S_w from plotted R_o and recorded log resistivity for following depths

8658 = 34 %; 8666 = 37 %; 8676 = 100 %.

Side Wall Core Analysis Data

IN. REC.	DEPTH, FEET	PERM., Md. *	POR., %	% POR. SAT.		PROB. PROD.	% OIL VOL.	% GAS VOL.	S_{ciw} ↓	DESCRIPTION
				OIL	TOTAL WATER					
1.0	8654	37.	28.5	3.5	64.6	OIL	1.0	9.1	64	SD VFG SHY SLTY CALC LAM CD ODR STK
1.	656	320.	30.2	9.7	65.8	OIL	2.9	7.5	44	SD VFG SL SHY SLTY CALC GD ODR BLU W
1.0	8658	125.	27.5	8.7	55.4	OIL	2.4	9.9	52	SD VFG SL SHY SLTY FOSS GD ODR MIN/B
1.0	8660	1550.	31.6	11.7	58.6	OIL	3.7	9.4	32	SD VFG CLN GD ODR BLU WH FLU
1.0	8662	260.	30.2	12.2	52.9	OIL	3.7	10.5	46	SD VFG SLTY CALC GD ODR BLU WH FLU
1.0	8664	310.	29.6	13.8	51.0	OIL	4.1	10.4	43	SD VFG SLTY CALC GD ODR BLU WH FLU
1.0	8666	345.	29.7	12.1	50.2	OIL	3.6	11.3	42	SD VFG SL SHY SLTY CALC GD ODR BLU W
1.0	8668	315.	31.4	12.4	47.2	OIL	3.9	12.7	47	SD VFG SL SHY SLTY CALC GD ODR BLU W
1.3	8670	525.	29.0	11.8	63.0	WATER	3.4	7.4	36	SD VFG SL SHY CALC GD ODR BLU WH FLU
1.0	8672	600.	31.9	12.9	61.6	WATER	4.1	8.2	38	SD VFG SL SHY CALC GD ODR BLU WH FLU
.0	8674	350.	27.2	4.1	64.0	WATER	1.1	8.7	38	SD VFG SLTY SL CALC NO ODR MOT FT FL
1,	676	225.	27.4	0.0	76.6	WATER	0.0	6.4	45	SD VFG SL SHY SL CALC SLTY NO ODR NC
1.0	8678	180.	25.4	0.0	68.5	WATER	0.0	8.1	44	SD VFG SL SHY SL CALC SLTY NO ODR NC
1.0	8682	150.	25.1	0.0	71.8	WATER	0.0	7.1	45	SD VFG SLTY SL CALC NO ODR NO FLU

(*) PERMEABILITY VALUES FOR PERCUSSION TYPE SIDEWALL CC

SOLUTION
PROBLEM NO. 8

Zone	Cond. Reading mmhos/m	Resist. From Cond. Ohm-m	Resist. Reading Ohm-m	Ø	R_w	S_w	Productive (Y or N)
1	225	4.4	4.2	27.3	0.06	31	Y
3	900	1.1	1.1	28.5	0.06	58	N
4	3080	0.3	0.3	27.3	0.06	100	N
5	800	1.25	1.3	20.1	0.06	77	N
6	1500	0.7	0.7	27.3	0.06	77.5	N
7	270	3.7	3.8	27.8	0.06	32	Y
8	1000	1.0	1.0	27.3	0.06	63	N

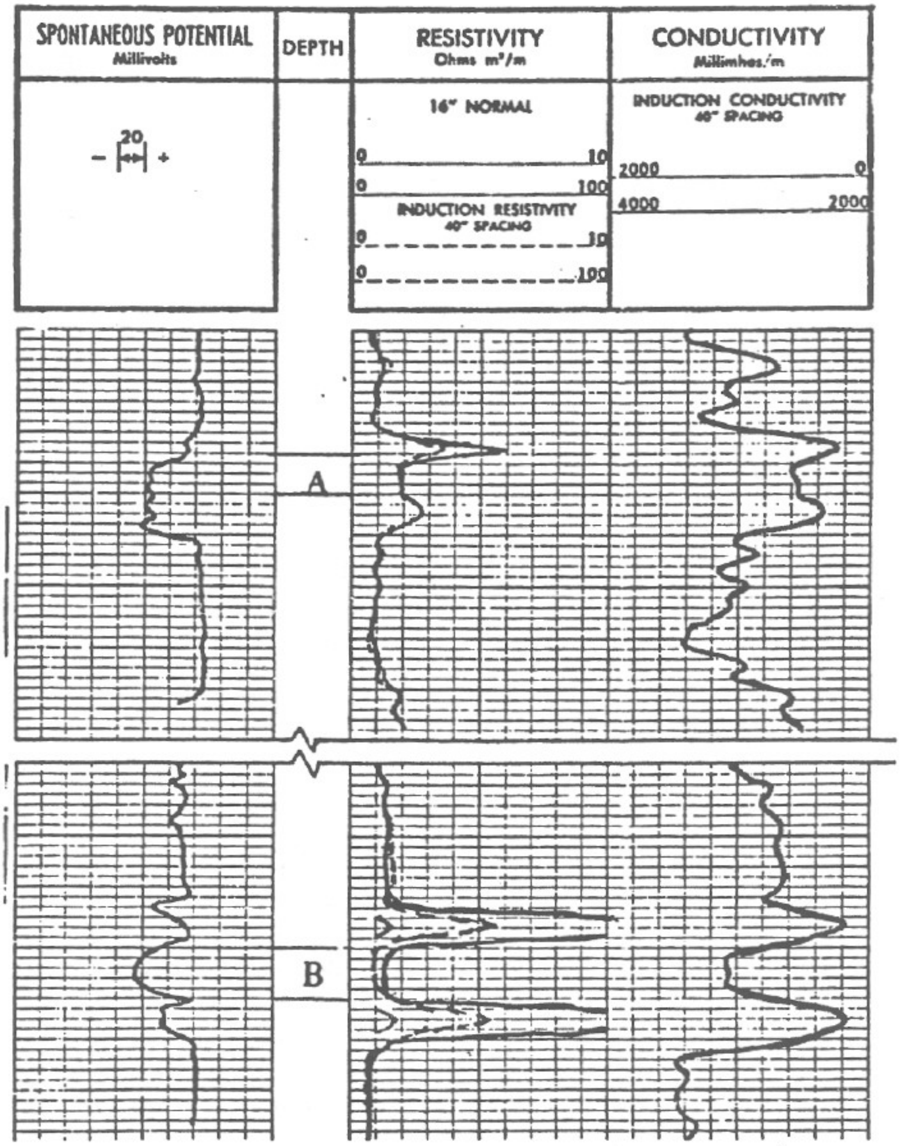
(c) In zone 2, from 5540' thru 5550', calculate S_w every two feet and productivity (Y or N)……Use same parameters as in Part a.

Depth	Cond. Reading mmhos/m	Resist. From Cond. Ohm-m	Resist. Reading Ohm-m	Bulk Den.	Ø	R_w	S_w	Productive (Y or N)
5540	270	3.7	3.8	2.30	21.2	.06	41	Y
5542	600	1.67	2.0	2.17	29.1	.06	42	Y
5544	1650	0.61	0.6	2.20	27.3	.06	82	N
5546	2500	0.40	0.4	2.22	26.1	.06	100	N
5548	2380	0.42	0.4	2.19	27.8	.06	98	N
5550	2400	0.42	0.4	2.20	27.3	.06	100	N

Solution to

PROBLEM NO. 9

INDUCTION LOG



USE: Humble Formati
Factor Formula

USE: n = 2.0

CONDUCTIVITY

590

1080

GIVEN:	ZONE A	ZONE B
Ø	28.4%	25.2%
R_w	0.06Ωm	0.06Ωm
R_t	1.7 Ωm	0.93 Ωm

Calculate S_w

57.2%	88%

ANSWER TO PROBLEM NO. 10
ACOUSTIC LOG

1) Using the SP (from the induction log) in the water sand, B, Calculate R_w.

R_{mf} @ 200°F = 0.21

R_{mfeq} @ 200°F = 0.18

$-120 = -(60 + .133(200°F)) \log (0.18 / R_{weq})$

antilog $1.386 = 0.18/R_{weq}$

R_{weq} @ 200°F = .0074

$R_w = .018$

2) a. Calculate an R_w using the resistivity and acoustic log at 9304'

b. How does it compare to the R_w in question 1.

$Ø = (87.0-55.56)/(188.7-55.56)$

$Ø = .236$

$Rw = Ø^{2.15} \cdot R_t \cdot S_w^{2.00}/.62$

$0.018 = (.236)^{2.15} \cdot 0.25 \cdot 1/.62$

(3) Calculate Porosity and water saturations at the following depths.

Depths	Δt	Ø	R_t	R_w	S_w
9377	92	0.274	1.7	.018	32.6
9380	89	0.251	1.1	.018	44.5
9384	91	0.266	0.28	.018	82.9

ANSWERS TO PROBLEM NO. 11

DENSITY LOG

Given : R_{mf} = .78 @93°F @ 2200’

GD = 2.67
FD = 1.0

1. a) Calculate Rw from the SP curve

   b) Assume the sand in zone B at 2224’ is 100% saturated with water. Calculate R_w using the Humble equation.

2. Using the Humble equation and the R_w from the SP curve, calculate S_w in zones A and B at the following depths.

Zone	Depth	BD	FD	Ø	R_w	R_t	S_w
A	2191	2.42	1.0	.150	.150	22	28
	2205	2.42	1.0	.102	.102	11	62
B	2218	2.52	1.0	.09	.09	17	57

ANSWER TO
PROBLEM NO. 12

1) Determine the Ø^*_{corr} in each zone. Also calculate out the average water saturation for each and indicate the probable production (S_{ciw} = 45%)

ZONE	Ø_D	Ø_N	Ø^*_{corr}	R_w	Rt	S_w	PROD
A	19.0	5.5	14.0	0.12	30	37	Gas
B	25.0	9.2	18.8	0.12	33	27	Gas
C	17.0	6.0	12.7	0.12	31	40	Gas

$$* \text{ Use } \text{Ø}_{corr} = \sqrt{\frac{\text{Ø}^2_D + \text{Ø}^2_N}{2}}$$