Baker Hughes INTEQ

Advanced Wireline & MWD Procedures Manual

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Chapter **1**

Review Of Wireline Basics

Introduction

The “first” log generated from borehole information was recorded in 1869, when Lord Kelvin recorded the temperature of a shallow hole. In 1927, Marcel and Conrad Schlumberger, with Henri Doll, recorded the first electrical resistivity log at Pechelbron, France. Since then, more than fifty geophysical-type well logs have been introduced to record the various electrical, nuclear, acoustical, thermal, chemical and mechanical properties of the earth.

Without interpretation, the measurements provided by the various logs are not particularly useful. It takes time, knowledge, and experience to convert the raw data into meaningful and practical information. Many of these formation evaluation methods are now used in sophisticated, computerized programs, the input data consisting of raw well log data, and the output being porosity, hydrocarbon type, fluid saturations, and lithology.

Exploration with Wireline Logs

The information from wireline logs is used to enhance two principle objectives in the exploration program:

Rock & Reservoir Properties	Hydrocarbon Evaluation
a. Environment of Deposition	a. Correlation
b. Lithology & Mineralogy	b. Structure
c. Radioactivity	c. Permeability Traps
d. Porosity Type	d. Porosity Type
e. Fluid Properties & Distribution	e. Salinity Traps
f. Formation Pressure	
g. Temperature	
h. Rock Strength & Elastic Properties	

There are several complicating factors which must be dealt with in order to arrive at acceptable values for those formation and hydrocarbon variables. The three most common factors are:

- The borehole is a dynamic system. The mud system will penetrate the rocks surrounding borehole, and the borehole wall is affected by the drilling process and time (time difference between drilling and the wireline logging runs).

- Matrix and Pore Fluids affect certain tools differently.
- Tool Depth of Investigation is relatively shallow.

Classification of Wireline Logging Tools

1. Lithology Logs - These logs are designed to:
    a. Identify permeable formations
    b. Determine boundaries between permeable and non-permeable formations
    c. Provide lithology data for correlation with other wells
    d. Provide a degree of certainty for quantifying the formation lithology.

Examples of lithology logs are:
Spontaneous Potential
Gamma Ray

2. Porosity Logs - These logs are designed to:
    a. Provide accurate lithologic and porosity determination
    b. Provide data to distinguish between oil and gas
    c. Provide porosity data for water saturation determination.

Examples of porosity logs are:
Sonic/Acoustic
Neutron
Formation Density

3. Saturation (Resistivity) Logs - These logs are designed to:
    a. Determine the thickness of a formation
    b. Provide an accurate value for true formation resistivity
    c. Provide information for correlation purposes
    d. Provide a quick indication of formation pressure, hydrocarbon content and producibility.

Examples of saturation logs are:
Normal and Lateral Devices
Laterologs
Induction Logs

There are a number of auxiliary wireline services which can provide additional information to augment the interpretation of formation characteristics. These include: 1) caliper logs, 2) directional logs, 3) dipmeter logs, 4) sidewall coring, and 4) formation testers.

Recording Formats

Wireline logs are a graphic representation of various tool responses with regards to depth. In order to interpret the responses accurately, the individual must be able to read the graphic numeric response.

The petroleum industry has a standard format which is used in recording logging measurements (Figure 1-1). This API log grid has a width of 8.25 inches and is divided into three tracks and a depth column. The log has one track on the left side of the depth column and two on the right. Each track is 2.5 inches wide, while the depth column is 0.75 inches wide. Each track is scaled, referred to as the grid scale, and there are three types: linear, logarithmic and split grid.

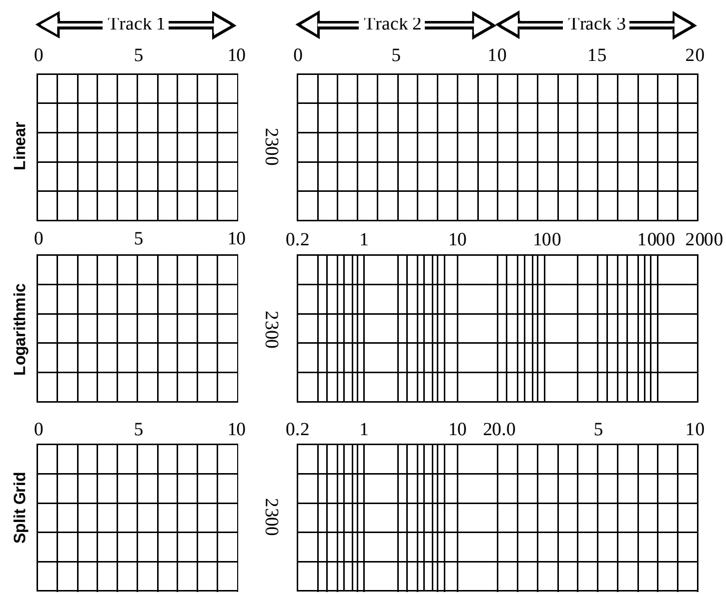


Figure 1-1: API Recording Formats

Depth Scales

The depths recorded in the depth column represent measured depth. The most common scales begin:

1 inch	-	100 feet	(1:1200)
2 inches	-	100 feet	(1:600)
5 inches	-	100 feet	(1:240)

The 1 inch and 2 inch scales are usually used for correlation purpose, while the 5 inch scale is usually available for scrutiny of sections.

On the 1 and 2 inch depth scales, each major division represent 100 feet of hole. Each subdivision indicates 10 feet of hole.

On the 5 inches scale, each subdivision indicates 2 feet of hole.

Grid Scales

The linear grid is usually the easiest to read. Track #1 is always linear. A linear grid represent functions that have a straight line or corresponding relationships of constant value.

The logarithmic scale, in Track 2 and 3, is usually a 4-cycle logarithmic scale. It is used for resistivity curves since it provides a greater range of values. A common scale is 0.2 ohms to 2000 ohms.

The split grid is a two-cycle logarithmic scale and linear grid. Track 2 is usually the logarithmic grid with a common scale of 0.2 ohms to 20 ohms. This allows more accurate reading of low resistivity values. Track 3 would be the linear grid.

Reservoir Characteristics

Before any well log analysis can take place, a thorough understanding of several reservoir parameters is necessary. The evaluation of a reservoir, or potential reservoir rocks, requires three basic data requirements: 1) porosity, 2) permeability and 3) fluid saturation.

This first step makes it possible to understand how the many types of logging devices react to various formation characteristics. Only then can the well logs be accurately interpreted.

Porosity

Porosity is a measure of the void space within a rock, expressed as a fraction (or percentage) of the bulk volume of that rock. To be commercially productive, a reservoir must have sufficient pore space to contain a appreciable volume of hydrocarbons. Porosity defines the storage capacity of a sedimentary formation for oil, gas and water. The general expression for porosity is:

$$\phi = \frac{Vb - Vs}{Vb} = \frac{Vp}{Vb}$$

Where:

	ϕ	=	Porosity
	Vb	=	Bulk Volume of the Rock
	Vs	=	Net Volume occupied by solid (grain volume)
	Vp	=	Pore volume

In reservoir rocks porosity is classified as Absolute Porosity (total porosity of a rock) and Effective Porosity (the porosity of void spaces which are interconnected).

It is the effective porosity which is of interest to the oil industry and reservoir engineers. Effective Porosity is the amount of porosity able to transmit fluid.

In unconsolidated and moderately cemented formations, the absolute porosity is approached by the effective porosity. However, in highly cemented sandstones and carbonates, the absolute porosity is much larger than the effective porosity.

$$\text{Absolute Porosity} = \frac{\text{Pore Volume}}{\text{Total Rock Volume}}$$

NB: When used in calculations, porosity is expressed as a number between zero and one. For example, 20% = 0.2, 8% = 0.08

Geologically, porosity has been classified in two types, according to the time of formation.

Primary Porosity

Porosity formed at the time the sediment was deposited. The voids contributing to this type are the spaces between individual grains of the sediment. Primary porosity is a function of the packing, sorting, rounding, compaction and cementation effects. It is intergranular porosity of sandstones and the oolitic or intercrystalline porosity of carbonates.

Secondary Porosity

Porosity formed after the sediment was deposited. The magnitude, shape, size and interconnection of the voids bear no relation to the form of the original sedimentary particles. Secondary porosity has been divided into three classes based on the mechanism of formation.

Solution Porosity
Voids formed by the solution of the more soluble portions of the rock by percolating surface and subsurface waters. Inconformities in sedimentary rocks are excellent targets for zones of solution porosity.

Fractures, Fissures and Joints
Voids formed by the structural failure of the rock under loads caused by various forms of diastrophism, such as folding and faulting. This type of porosity is extremely hard to evaluate due to its irregularity.

Dolomitization
Voids formed when limestone is transformed into dolomite. Porosity formed by dolomitization is due to the solution effects enhanced by a previous chemical change in limestone.

It is wrong to assume that there is a unique minimum porosity cut off which defines all reservoir rocks. A typical value for a clean, consolidated and reasonably uniform sand is 20%. A rough average for carbonate rocks is 6 to 8%. Remember though, these values are approximate and will not fit all situations.

Permeability

Permeability is a measure of a rocks ability to transmit fluids. In addition to being porous, a reservoir rock must allow fluids to flow through its pore network at practical rates under reasonable pressure differentials.

Controls on permeability include:

- The size of the available pores.
- The connecting passages between the pores.

Absolute Permeability

The ability to transmit a fluid when 100% saturated with one fluid

Effective Permeability

The ability to transmit a fluid in the presence of another fluid when the two are immiscible

Relative Permeability

Ratio of effective to absolute.

Permeability, as a darcy, is defined as:

$$k = \frac{q \times \mu \times L}{A \times \Delta p}$$

where:	q	=	1 cc/s (volumetric rate of fluid flow)
	A	=	1 cm^2 (cross-sectional area)
	μ	=	1 centipoise (viscosity of flowing fluid)
	$\Delta p/L$	=	1 atmosphere/cm (pressure gradient)

A permeability of one darcy is usually much higher than that commonly found; consequently, a more common unit is the millidarcy, where:

1 darcy = 1000 millidarcy's

A practical oil field rule of thumb for classifying permeability is:

poor to fair	= 1.0 to 15 md
moderate	= 15 to 50 md
good	= 50 to 250 md
very good	= 250 to 1000 md
excellent	= 1 darcy

Besides the typical matrix permeability, some reservoir rocks may have solution channels, vugs, or fracture systems which will increase permeability.

Permeability of solution channels is directly related to the size of the channels;

$$k = (.02) \times (10^8) \times (d^2)$$

where: d = diameter of the channel, (in.)

Permeability of fractures is a direct function of the fracture width:

$$k = (0.544) \times (10^8) \times (w^2)$$

where: w = width of fraction, (in.)

Reservoir permeability is a directional property. Horizontal permeability (k_H) is measured parallel to bedding planes. Vertical permeability (k_V) across bedding planes is usually lower than horizontal. The ratio k_H/k_V normally ranges from 1.5 to 3.

When only a single fluid flows through the rock, the term absolute permeability is used. However, since petroleum reservoirs contain gas and/or oil and water, the effective permeability for given fluids in the presence of others must be considered. It should be noted that the sum of effective permeabilities will always be less than the absolute permeability. This is due to the mutual interference of the several flowing fluids.

Reservoir Permeability from Log Data

Timur Equation:

$$k(md) = \frac{0.136\phi^{4.4}}{Swirr^2}$$

where: ϕ and Swirr are in percent

Morris and Biggs:

$$k(md) = \frac{C\phi^3}{Swirr}$$

where: C = 80 for gas and C = 250 for oil

ϕ and Swirr are in decimal fractions

Fluid Saturation

Porosity can be stated as the capacity to hold fluid; fluid saturation is the fraction (or percentage) of the storage capacity (porosity) of a rock occupied by a specific fluid. Sw is the fraction of pore volume occupied by formation water; 1-Sw is the fraction of the pore volume occupied by hydrocarbons (Sh).

A water saturation of 50% means that half the pore space is filled with water when:

Sw = 1.0 = 100% (water zone or aquifer)

Sw + So = 1.0 = 100% (water + oil system)

So = 1.0 - Sw

Some of the fluid in reservoir cannot be produced. This portion of fluid is referred to as residual or irreducible saturation (Swirr).

Basic Resistivity Concepts

Resistivity is a property of a material and can be defined as the electrical resistance of a cube of material. By definition it is:

$$R = \frac{rA}{L}$$

where:

where:	R	=	resistivity, (ohm-meters)
	r	=	resistance, (ohms)
	A	=	cross sectional area (meters^2)
	L	=	length, (meters)

In wireline logging, this is one of the principal parameters measured. Resistivity can also be stated in terms of conductivity where:

$$\text{Resistivity} = \frac{1000}{\text{conductivity}}$$

Conductivity is measured in millimhos/meter.

Invasion Profiles

Invasion of mud filtrate into the formation has a significant affect on the resistivity readings. Depending on whether the formation is water or oil bearing, changes in resistivity occur as you move through the flushed zone into virgin formation. In a water zone, there is no change in water saturation, only a change in water resistivity as mud filtrate dilutes the formation water.

In a hydrocarbon-bearing zone the hydrocarbon saturation is reduced in the flushed zone and increases in the transition zone until the original saturation in the undisturbed formation is reached. These changes in water saturation, combined with changes in the resistivity of the fluids filling the pores, create resistivity profiles.

Typical invasion profiles for three idealized versions of fluid distribution in the vicinity of the borehole are:

- The step profile is the simplest of the three and shows a distinct junction between the invaded and uninvaded zones.
- The transition profile is the most realistic model of true borehole conditions, showing invasion diminishing gradually, rather than abruptly, as you move out toward the uninvaded zone.
- The annulus profile reflects a temporary fluid distribution which should disappear with time. It represents a fluid distribution which exists between the uninvaded and invaded zone and indicates the presence of hydrocarbons. Beyond the outer boundary of the invaded zone is an annulus zone whose pores are filled with residual hydrocarbons and formation water. The abrupt resistivity drop reflects a high concentration of formation water in the annulus zone, due to the fact that formation water has been pushed ahead of invading mud filtrate into the annulus zone, causing a temporary absence of hydrocarbons which in turn have been pushed ahead of the formation water. Thus the decrease in resistivity in the annulus zone.

In fresh water drilling muds, the mud resistivity is normally higher than the formation water. In a water bearing zone, the formation resistivity is higher in the flushed zone due to Rmf > Rw, and decreases with movement out into the undisturbed formation. In a hydrocarbon bearing zone, drilled with fresh a mud (Rmf > Rw), the resistivity behind the flushed zone may be higher or lower, depending on Sw and Rw.

With a salt water-based mud (Rmf < Rw) the flushed zone normally has a lower resistivity, while the undisturbed zone either has the same or higher, depending upon if the formation contains equivalent or higher resistivity water.

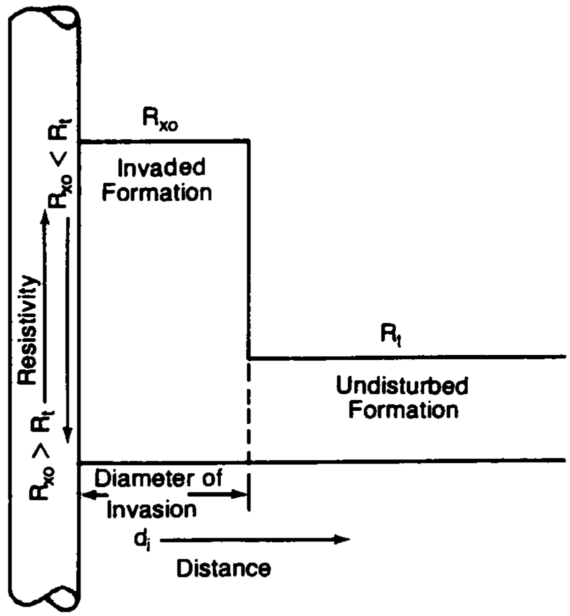


Figure 1-2: Step Profile

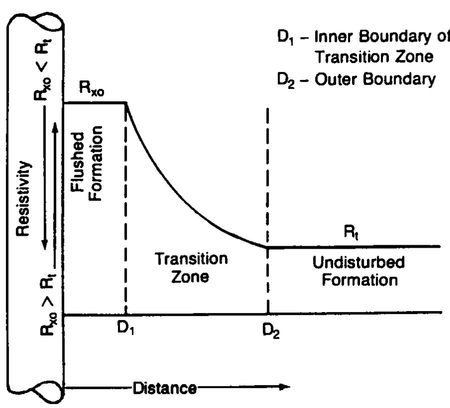


Figure 1-3: Transition Profile

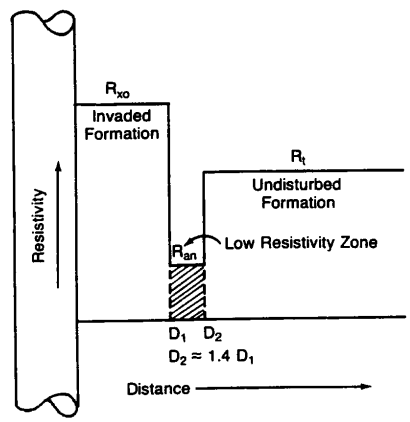


Figure 1-4: Annulus Profile

* Ro = resistivity of the zone with pores 100% filled with formation water (Rw).

Subsurface Temperature

Formation temperature (Tf) is important in log analysis because the resistivities of the mud, mud filtrate and formation water change with temperature. The following are needed to determine formation temperature:

- Formation depth
- Bottom hole temperature (BHT)
- Total depth of the well
- Surface temperature

Formation temperature can be obtained by graphical means (assuming a linear geothermal gradient) or by calculation using the linear regression equation.

$$y = mx + c$$

where:

x = depth
y = temperature
m = slope (geothermal gradient)
c = constant (surface temperature)

For example,

y = BHT of 250°F
x = TD of 15000 ft
c = surface temperature of 70°F

$$m = \frac{y - c}{x} = \frac{250 - 70}{15000} = 0.012°/\text{ft or } 1.2°/100 \text{ ft}$$

Therefore, for a bed at 8000 ft,

m = 0.012°/ft
x = 8000 ft
c = 70°F

$$y = (0.012) \times (8000) + 70 = 166\ °\text{F at 8000 ft}$$

After a formations' temperature is determined either by chart or calculation, the resistivities of the different fluids (Rm, Rmf or Rw) can be corrected to formation temperature.

Resistivity values of the drilling mud (Rm), mud filtrate (Rmf) and mudcake (Rmc), and the temperature at which they are measured, are recorded on the log's header. Formation water resistivity (Rw) is determined from the SP log or can be calculated in water zones by the apparent water resistivity method (Rwa).

Chapter 2

Review Of MWD Basics

Historical Developments

Measurement While Drilling (MWD) theories and practices have been around as long as wireline logging. It has been in the recent past that modern technology has caught up with the theories. The 1980's saw the development of tools and sensors that rival the wireline industry.

Pre World War II Developments

In 1927 the first wireline log was run in France by Conrad and Marcel Schlumberger. Two years later a patent was filed on the concept of mud pulse telemetry. The first “hardwire” system was used in the early 1930's by J.C. Karcher of G.S.I. when he attempted MWD by using an insulated sub above the bit and transmitting a continuous resistivity log by means of conducting rods fastened inside the drillpipe. As few years later, D.G. Hawthorne and J.E. Owen of Amerada used an electrical conductor inside the drill string to transmit formation resistivity data to the surface. The early 1940's saw D. Silverman of Stanslind Oil and Gas Company use an electrical cable inside the drill pipe, thus eliminating the need for special drill pipe. However, he had to pull the entire cable out at each connection.

The mechanical weakness of the insulating subs used, plus the difficulties in maintaining insulating material on the outside of the collars and the need for special drill pipe resulted in disadvantages which were too great to be overcome with the technology of the times. Because of this, further efforts along these lines were suspended.

Meanwhile, mud logging and wireline logging became the accepted methods of formation evaluation.

Post World War II Developments (1950's to 1970's)

In the 1950's, J.J. Arp, with assistance from Lane Wells, invented the positive pressure mud pulse system. Continued development led to a number of successful gamma ray and resistivity log runs in the early 1960's. A few years later, S.H. Redwine and W.F. Osborn invented the “While Drilling Focused Mono-Electrode Resistivity Log.” Around the same time the Varney Teledrift Tool was developed. It measured hole inclination mechanically and telemetered the data by positive pressure pulses to the surface.

In 1964, John Godbey at Mobil developed the Mud Siren System, and in 1965, SNEA (French) began research with Raymond Engineering joining SNEA in 1969.

By 1970, problems in designing delicate electronic packages to withstand the hostile downhole environment (temperature, pressure, and vibrations), together with the softening economic environment for the oil industry resulted in declining interest in MWD.

Recent Developments - 1970 to 1990

The rise in oil prices, due to OPEC, resulted in a better financial environment for the oil industry, and together with improved technology (microchips), led to a resurgence of interest in MWD.

1971 saw the first successful field test of the mud siren technique by Mobil R&D. Schlumberger/Mobil joint development projects began soon after. Teleco was formed in 1972, and between 1972 and 1977, Gearhart, Gentrex/Eastman, Exlog, and NL started research and development into MWD.

Commercial services began in September 1978, when Teleco started directional data services. Schlumberger/Analysts went commercial with their mud siren system in 1980, quickly followed by Gearhart. Exlog's first successful pilot demonstration of MWD service was in 1981 for Canmar (Beaufort Sea) with commercial services starting in 1982 (Chevron, North Slope Alaska and Pennzoil, Gulf of Mexico).

Eastman Christensen followed in 1983, and NL’s RLL commercial service began in 1985.

Benefits of MWD

The benefits of MWD services fall into three distinct areas: directional drilling, real-time or near real-time formation evaluation, and the resulting safety aspects and drilling optimization.

Directional Control

Using multiple accelerometers and magnetometers, MWD surveys provide much more accurate location of the drill bit in the borehole. These surveys take place during a connection, so there is much less survey downtime, reducing the risk of differentially sticking the drillstring. Taking surveys more often results in reduced dogleg severity, reduced time and costs of motor correction runs, and savings due to not running multishots prior to setting casing

Formation Evaluation

Real time logging results in quick evaluation of formation data resulting in fast, accurate correlation decisions. Information can be gained before significant hole deterioration takes place, prior to significant filtrate invasion, and the hole is logged and information gained before the possible loss of the hole.

There will usually be better bed resolution due to slower logging speeds, logging speed being based upon drill rate.

This real time information can eliminate top hole wireline log runs, and with the real time pore pressure information can eliminate planned casing strings. Both are tremendous cost saving measures.

Drilling Safety and Optimization

The information provide by MWD allows for improved drilling efficiency and improved bit performance by indicating formation changes. The information allows for improved pore pressure evaluation, highlighting the safety aspects of MWD.

Wireline/MWD Comparison

The main disadvantages of wireline logging systems include: 1) increased rig time costs while wireline operations are underway, 2) wireline logs are run several days to several weeks after drilling resulting in increased filtrate invasion and hole washouts, 3) the logging speeds are very fast, from 1800 to 6000 feet/hour, resulting in poor vertical resolution, and 4) large environmental corrections are required to compensate for 2 and 3.

Wireline logging is expensive, generally running in the $100,000+ range. In addition, the information provided by wireline logging is post-drilling and, therefore, cannot be used to assist in the present drilling operations.

MWD logging also has its disadvantages. Compared to wireline logging it has low data acquisition and transmission rates and few measuring systems, although this is improving. Because of its newness, environmental corrections and interpretation abilities are lagging (most of the research and development has been for improving the reliability of the tools). Rig site tool calibration is difficult, causing concern among petrophysicists, and there are few test facilities for the instrument subs.

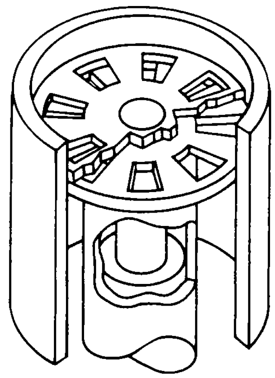
Appendix C provides a more detailed comparison of the tools and sensors.

MWD Transmission or Telemetry Systems

Once the information has been gathered by the downhole sensors, it must be transmitted to the surface. The previous section outlining the historical developments, briefly mentioned the more successful versions.

Design and patent considerations have resulted in a few telemetry systems being used at present. They include the continuous wave, positive mud pressure, and negative mud pressure systems.

Continuous Wave (Mud Siren) System



“Mud Siren”

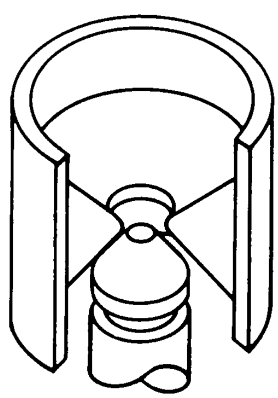
This system uses a slotted disk and creates a frequency modulation of the carrier wave. The speed of transmission is between 4000-5000 ft/sec in the drilling fluid.

This type of pulsing system requires no major modification to the rig and is a lower cost system compared to hardwire systems. This siren system has a higher data rate compared to the positive and negative pulsers, and because of this more sensors are possible.

The main drawbacks of the mud siren are the slotted disk is prone to plugging by LCM, there is no transmission with the pumps off, and the system has a low signal to noise ratio.

This system is used by Schlumberger/Anadrill.

Positive Mud Pulse System



“Positive”

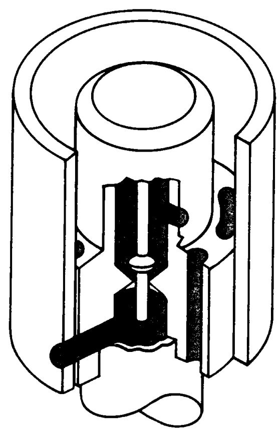
This system causes a periodic, partial restriction of the drilling fluid inside the MWD collar. The speed of transmission is between 4000 - 5000 ft/sec in the drilling fluid.

The positive pulse system is low cost when compared to hardwire systems, and no special rig modifications are necessary. It has the added advantage because it is not affected by LCM.

The system does have a slow data rate and is limited to a digital encoding scheme. Other disadvantages include one way communication, a low signal to noise ratio, no transmission with the pumps off, and downhole power generation must be increased in order to restrict the mud flow.

This type of system is used by Eastman-Teleco, Smith Datadril, Speery-Sun and Western Atlas.

Negative Mud Pulse System



"Negative"

This pulsing system uses periodic venting of drilling fluid from inside MWD collar to the annulus for pulse telemetry. The speed of transmission is between 4000-5000 ft/sec in the drilling fluid.

Negative pulse systems use less power than positive and siren systems, create sharper pulses for easier detecting/encoding, and can use either time analog or digital encoding schemes.

This system has a relatively slow data rate, the valve can be eroded by mud, and the pulser valve is susceptible to failure due to LCM.

This system is used by Halliburton Geodata.

Hardwire System

This was the first system developed using a special conducting drillpipe or cable for data transmission. It is advantageous for several reasons: 1) it can be powered from surface, 2) using a conducting medium, it will have a high data rate, and 3) there can be two way communication.

With a hardwire transmission system, data can be sent without mud circulation and there is no interference with mud additives. As long as there is cable, there is no depth limitation, and with the cabling system there are no noise problems due to bits, pumps, motors, etc.

The high cost of the special equipment, the wear and tear on the equipment, and the special handling procedures at every connection have precluded hardwire systems from being used in today’s MWD systems.

Electromagnetic System

This system allows data transmission through electromagnetic waves, with either the electrical or magnetic component being received at the surface. As with the hardwire system, electromagnetic transmission allows for two way communication, high data rates, transmission when the mud is not circulating, and few problems with mud additives. In addition there is a low cost of equipment because regular drillpipe can be used, and no erosion or wear problems.

Electromagnetic transmission does require high signal attenuations and a very low signal to noise ratio to be effective. With depth, there will be a need for signal repeaters, and some sort of downhole power generation. Receivers have to be placed over a wide area, and this limits their use offshore.

This system is used by Geoservices

Acoustic Systems

This system transmits data using an acoustic signal generated near the bit. It also has a high data rate, can include two way communication, and is relatively inexpensive.

As with the electromagnetic system, it will require a downhole power generator and signal repeaters as depth increases.

There are several problems with the acoustic signal: 1) there is a high background noise being generated by the drilling rig, 2) there will be reflective and refractive interference from the formations, and 3) the signal being generated downhole is of such low intensity it will have to be amplified several times to be effective.

MWD Sensor Types

MWD has been seen as the replacement for wireline logs, since much of their information is “real-time.”Real time is based on how far the sensors are behind the bit. MWD tools also have the ability to re-log sections of the borehole during tripping or reaming. These Measurement After Drilling (MAD) runs are used to verify the readings taken by the first pass (akin to a wireline repeat run) and have been used to illustrate how much flushing is taking place over a period of time.

Many of the MWD sensors have wireline equivalents. Though they have equivalents, they are not the same.

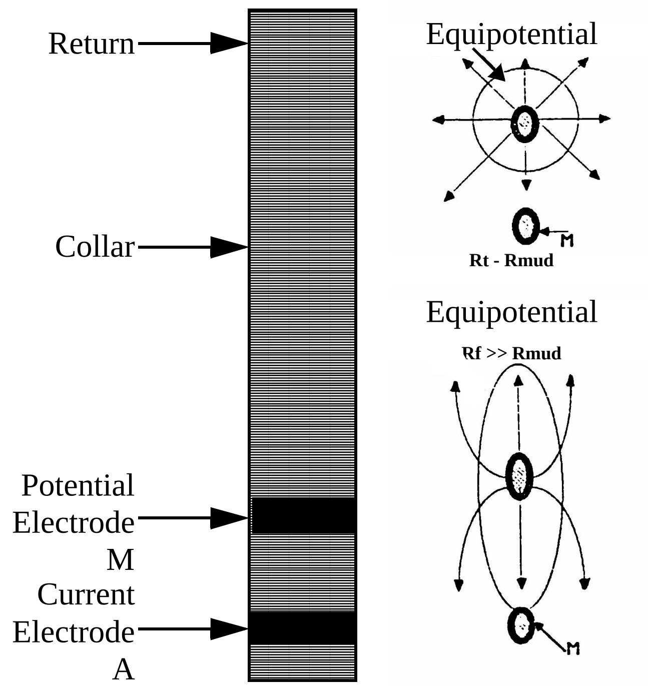
Gamma Ray Sensors

The Gamma Ray sensor is usually located nearest the bit. As with wireline logging, it is used as a lithology identifier and a correlation tool. The types of detectors used are the Geiger-Mueller and the Scintillation Counter. The main differences between the two will be covered in Chapter 3.

Resistivity Measurements

Resistivity sensors have their wireline counterparts. Many times the resistivity measured by the MWD resistivity devices is considered to be Rt or close to Rt, so they are relatively few conversion or “correction charts.” Most of the correction is for hole size.

Short Normal Device

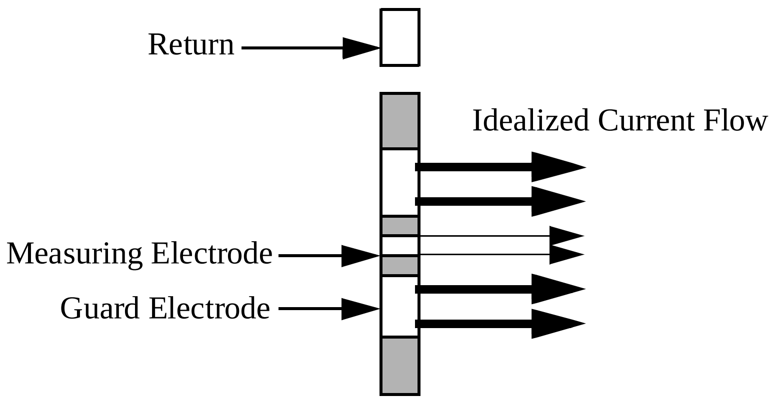


The Short Normal was the first MWD resistivity sensor produced; its design permits good measurements in fresh water muds when mud and formation resistivity are about the same and borehole effects are minimal.

The sensor has good response to formation resistivities between 0.2 and 30 ohm-m.

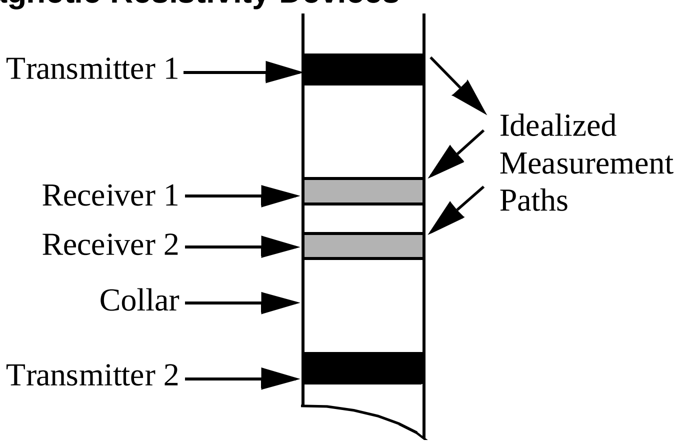
The Short Normal's correctable vertical response is limited to beds thicker than the tool spacing (16 inches). The sensor is calibrated prior to the run and is borehole corrected for downhole mud resistivity and downhole temperature.

Focused Current Devices



The focused design permits good resistivity measurements in conductive muds. The device has excellent response to formation resistivities between 0.1 and 1,000 ohm-m. Correctable vertical response is limited to beds greater than 4 inches (100 mm). The sensor is calibrated prior to the run and is borehole corrected for downhole mud resistivity and downhole temperature.

Electromagnetic Resistivity Devices



In 1983, N.L. Baroid (now Sperry Sun Drilling Services) introduced the 2-MHz resistivity device. Over the years, it has become the most common MWD resistivity run, overshadowing the short, normal and focused devices, and most of the MWD companies now have their own version of it.

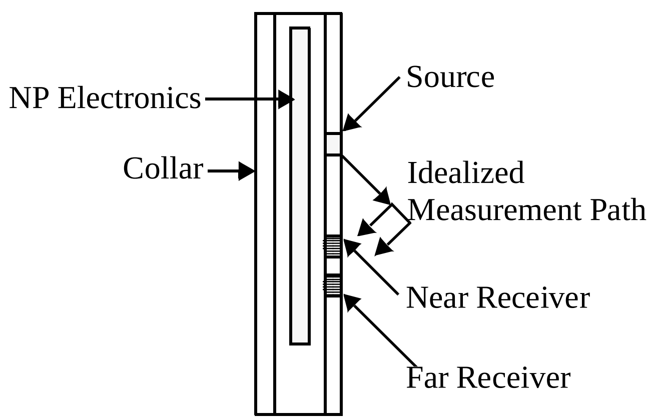
The 2-MHz frequency was determined to have the best operating conditions for depth of investigation (about 50 inches diameter), thin bed resolution (about 6 inches), drilling fluid applicability (water-based and oil-based), and a compromise between accuracy and the formation's dielectric effects. The device also offers two curves (phase and amplitude).

The electromagnetic device consists of transmitter coils (one or more) and receiver coils (two or more), with both phase and amplitude being measured and both placed on the logs.

The main differences between MWD tool designs are in the spacing lengths and number of transmitters. The greater the transmitter-to-receiver spacing, the greater the depth of investigation, but signal strength is reduced. The larger the spacing between receiver coils, the better the phase and amplitude resolution, but thin-bed resolution is reduced. Bore hole compensation is provided when using two transmitters (one above and one below the receiver pair).

The operating range of the 2-MHz device is between 0.2 and 200 ohm-m.

Porosity Measurements



Porosity measurements have made MWD tools equivalent to wireline logging in many respects.Proosoity devices are the newest tools available, with research and development continuing on source efficiency, source retrievability and interpretation methods. Three basic MWD porosity devices exist, the natural gamma-ray, gamma-ray scattering (density), and neutron-scattering (porosity).

Their design means that MWD tools do not respond like wireline porosity tools. Detector location, detector spacing, detector type, and the MWD collar means that techniques for correcting wireline measurements do not apply for MWD tools.

The MWD gamma-ray tools generally place the detector inside the collar. The two to three inches of steel between the detector and formation tend to act as an energy filter, allowing the high energy gamma ray to pass through better than the low energy ones.

Two companies, Schlumberger and Eastman Teleco, place their gamma-ray density sensor in stabilizer blades. The reason for this is simple; if the detector was inside the collar, the mud in the annulus would have to be taken into account (wireline tools do this by using pad devices). Sperry-Sun places four detectors equally around the collar and averages out the drilling fluid effects using sophisticated algorithms.

Because neutron-scattering (porosity) measurements are the most difficult to perform, tool variation is different for each of the MWD companies. They generally conform to the basic wireline configuration of a neutron source and two spaced detectors, but after that much changes. Eastman Teleco uses a Li-6 scinillator and its detector, which has a high counting efficiency. Sperry-Sun uses multiple Geiger-Mueller tubes placed around the circumference of the collar to detect gamma rays from neutron capture. Schlumberger takes a more “wireline” approach. It uses two sets (three detectors per set) of the wireline standard He-3 detectors placed around the collar, equally spaced from the centrally located source.

Special Hydraulic Considerations

MWD tools operate over a wide range of conditions and drilling fluid types. Due to the complexity of the internal components, some considerations must be made to ensure the components continue to function during all types of drilling activities and not be destroyed. Several cautions include:

Sand Content

The sand content should be kept at an absolute minimum, preferably below 1%. Significant amounts of abrasive sand can erode pulser components resulting in the loss of telemetry.

Lost Circulation Material

LCM can be used if pumped slowly, it should never be slugged. Large amounts, pumped rapidly can plug up a pulser. If pulser fails, it should not affect downhole memory.

Oil-Based Muds

Oil-based mud systems attenuates the pulse size at the surface much more than water based muds. Some software corrections need to be made by the operators.

Mud Turbines

Turbines have a very high pressure drop which pulsers have to work against. Turbines are more prone to high frequency pump pressure noise, which can cause distortion of the surface signal.

Positive Displacement Motors

These motors will also produce a high frequency pump pressure noise depending on the type of motor. The MWD tool is placed above PDM's, which means they have to work against the pressure drop of the motor and the drop at the bit.

•Notes•

Chapter 3

SP & Gamma Ray Logs

Spontaneous Potential

The Spontaneous Potential (SP) is a record of the natural occurring (DC) potentials in the borehole as a function of depth. This information is plotted in Track #1 of the wireline log. Scale deflections are in millivolts

The system includes a sonde (single moving electrode in the borehole), and a reference electrode (fish) on the surface. The information recorded is the relative measurement of DC voltage as the sonde moves through the borehole.

Shales will normally give constant readings, thus providing a “shale baseline” for reference. This reference line is usually set two chart divisions into Track #1. Sands or permeable beds will show movement either to the right (+) or left (-), depending on the salinity of the drilling fluid and formation waters. The sensitivity of the deflections is set so that all readings stay within the limits of the track.

The Electrochemical Components of the S.P.

When two fluids of differing salinities are separated by a semi-permeable membrane (i.e., shale), the two fluids will create a current flow. The current will flow from the fresh fluid to the more saline fluid, through the shale. If the shale is removed, the current would stop (the fluids would mix and create a fluid with one salinity). Interchanging the fluid positions would REVERSE the current flow (drilling fluid salinity is considered “fresh” when compared to the saline formation water).

Shales are permeable to cations (Na^+), due to the high negative charge on the clay lattice. The cations will move through the shale, from the high concentration of the salt water to the lower concentration of the fresh water, giving rise to a shale potential.

In sands, at the salt water and fresh water (filtrate) contact, the Na^+ and Cl^- ions migrate from the higher to the lower concentrated solution. The Cl^- ions have greater mobility and thus give rise to a negative potential across the liquid junction.

In the mud column opposite the shale a positive potential is created, while at the junction of formation water and filtrate a negative potential is created. The magnitude of the current is based on the resistivity of the solutions and the temperature. Any corrections are made through the use of empirical charts.

Formations containing saline water must be permeable for an SP to develop, also the mud must be conductive. The amount of permeability does not influence the SP, but it must allow the ion flow. Therefore, an SP will not develop in impermeable beds. The porosity of the formations has no influence on the SP.

Since the permeability of formations will not change too much after being drilled, the SP will usually duplicate itself on repeat runs. Because it will differentiate between beds, every small variation in curve movement is important.

The SP Curve

The curve, located in Track #1, is useful in determining bed boundaries. Bed boundaries are determined to be at the inflection points (maximum slope) on the curve. The best SP trace is obtained when borehole resistance is large, for example:

- When a fresh water mud is used.
- When there is a small diameter borehole.
- When there are thick sand and shale beds.

With this in mind, the shape of the SP curve will be influenced by the:

- The thickness (h) and resistivity (Rt) of the permeable bed.
- The resistivity (Ri) and diameter (di) of invaded zone.
- The resistivity (Rs) of surrounding formations.
- The resistivity (Rm) of the mud and diameter (d) of the borehole.

With formation water being a major component in SP development, the SP will have less amplitude in hydrocarbon-bearing zones.

In reference to the shale baseline:

- If the Rmf is greater than Rw, the SP curve will deflect to the left (-) opposite non-shales.
- If the Rms is less than Rw, the SP curve will deflects to the right (+) opposite non-shales.
- If the Rmf is equal to Rw, the SP curve will be a straight line, no reflection opposite non-shales.

Static Spontaneous Potential (SSP)

From the previous paragraph, it can be seen that the SP currents will flow through four different media: the borehole, the invaded zone, the non-invaded part of the formation, and the surrounding shales. In each medium there will be a current drop in proportion to the resistance encountered. If the SP curve was allowed to fully develop through those mediums, the total deflection drop would be equal to the total electromotive force (emf).

Because the SP seldom fully develops, the deflections on an SP curve represent only a fraction of the total emfs.

To compensate for this effect, the Static Spontaneous Potential (SSP), total emf, or the SP deflection that would occur opposite a thick clean formation is determined. Where a thin bed is encountered (less than 10 ft.), a SP correction factor is used to find the SSP.

A theoretical value for the SSP is:

$$SSP = -k \times \log(Rmf/Rw).$$

where: $k = (.133 \times Tf) + 60$

The SSP is can then be used to find Rw.

Limitations of the SP

The SP cannot be recorded in oil-based muds, air or gas-filled boreholes, or cased holes. In salt muds the SP curve data is unreliable.

Common problems encountered in recording SP are:

1. Spurious Spikes - Caused by lightening, arc welding, or short wave transmission.
2. Small Amplitude Sine Wave superimposed upon S.P. Curve - Caused by some mobile part of the winch (drum, chain, etc.) that becomes magnetized.
3. Abnormal anomaly in a highly resistive formation - Caused by bimetallism or an unbalanced survey current.
4. Noisy Curve - Caused by a poor, improper ground.

Shale Volume Calculation

The SP log can be used to the calculate the volume of shale in a permeable zone by the following formula:

$$Vsh(\%) = 1.0 - \frac{PSP}{SSP}$$

where:
- Vsh = Volume of shale
- PSP = Pseudo static SP (SP of a shaley formation)
- SSP = Static SP

Gamma Ray Log

There are two types of Gamma Ray logs in use today: the natural gamma ray and the natural gamma ray spectral log. The Gamma Ray curve is located in Track #1, with scale deflections in standard API units.

The natural gamma radiation measurement is used primarily for identification of lithology and correlation.

Low Radioactivity	**High Radioactivity**
Halite	Shale
Gypsum	Potassium Minerals
Anhydrite	Igneous Rocks
Limestone	
Dolomite	
Sandstone	

Where the SP cannot be run (i.e., non-conductive fluids, air drilled and cased holes), the Gamma Ray is substituted.

The Gamma Ray sonde is compact (5 to 6 feet long), which allows good formation definition.

Natural Gamma Ray

This log measures and records the natural radioactivity within a formation. Some rocks are naturally radioactive because of the unstable elements contained in the formation. Generally, three elements contribute the major portion of the radiation observed in sedimentary rocks: the uranium series, the thorium series and the potassium-40 isotope.

The Gamma Ray log usually reflects the clay content of sedimentary formations. Clean sands and carbonates normally exhibit a low level of natural radioactivity, while shales show higher radioactivity.

Natural Gamma Ray Spectral Log

The spectral log breaks the natural radioactivity of the formation into the different types of radioactive material: thorium, potassium or uranium. This can be used for stratigraphic correlation, facies identification, reservoir shaliness determination and sometimes for fracture identification.

Advantages of the Gamma Ray Log

- It is useful as a correlation tool
- It is used for depth control
- The major tool used for shale content calculations
- It may be run in casing, empty holes and in all kinds of drilling fluids.

Limitations

- The GR tool must be logged at relatively low speeds (1800 to 3600 ft/hr) to give accurate bed definitions.

Uses of the Gamma Ray Log

- Identifying lithologies
- Correlating
- Calculating shale volume

Shale volume (Vsh) calculations begin with determining the Gamma Ray Index (IGR).

$$IGR = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}}$$

where:
- IGR = Gamma Ray Index (dimensionless)
- GR_{log} = Gamma Ray Reading of Formation
- GR_{min} = Minimum Gamma Ray (clean sand or carbonate)
- GR_{max} = Maximum Gamma Ray (shale)

The calculated IGR is then used on the appropriate chart or determined mathematically using:

Consolidated - Older rocks

$$Vsh = 0.33 \times [2^{(2 \times IGR)} - 1.0]$$

Unconsolidated - Tertiary Rocks

$$Vsh = 0.083 [2^{(3.7 \times IGR)} - 1.0]$$

Lithology Determination

The heavy radioactive elements tend to concentrate in clays and shales. Gamma rays (bursts of high energy, electromagnetic waves) are statistical in nature. This means that the number of gamma rays received by the detector will fluctuate, even when the instrument is stationary in the hole. These statistical variations are average out through the use of “Time Constants.”

Logging Speed (ft/hr)	**Time Constant** (seconds)
3600	1
1800	2
1200	3
900	4

Radius of Investigation

Ninety percent of the measured gamma rays originate with the first six inches of the formation being investigated. The addition of another medium (i.e., cement or casing) reduces the total quantity of gamma rays, but does not detract from the usable information. With the proper speed and time constants, adequate resolution can be achieved in formations as little as three feet thick.

Formation boundaries are located at the mid-point of the recorded curve.

Radiation Detectors

Detection is accomplished by the ability of gamma rays to produce tiny flashes of light in certain crystals, which are then converted into electrical pulses. The pulse size is dependent on amount of energy absorbed from the gamma ray.

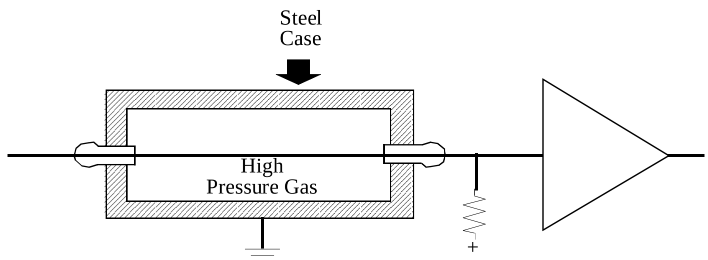


Figure 3-1: Ionization Chamber

The Gamma Ray Tool, which was introduced into the oil field in 1939, measures natural radioactivity of formations penetrated by the wellbore. Since gamma rays cannot be detected directly; some type detector is required which can measure gamma ray interaction with other matter. For gamma ray logging there are three such detectors: ionization chambers, Geiger-Mueller counters, and the scintillation counter.

The figure above shows an ionization chamber. It is a gas filled chamber with an anode maintained at approximately 100 volts positive with respect to the housing. The case is filled with high pressured gas. An incoming gamma ray interacts with the detector wall material and/or gas which releases an electron. The freed electron moves toward the anode through the dense gas. Electron interactions with gas atoms release additional electrons (the ionization process). As the free electrons are drawn to the anode, a minute current is produced, making the gamma ray influx into the borehole proportional to the amount and magnitude of current pulses produced at the anode.

Advantages	**Disadvantages**
Simple construction, low cost	Very low detector currents
Low voltages	Low detection efficiency (5 to 10%)
Output directly related to gamma ray energy	Drifts in counting rate due to current leakage.

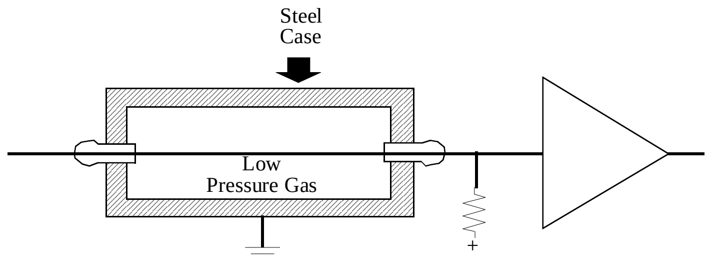


Figure 3-2: Geiger-Mueller Counter

The Geiger-Mueller counter is similar to the ionization chamber, but has much higher voltages and a lower gas pressure. The initial reaction is much the same as that of the ionization chamber; however, the high positive voltage (1,000 volts) at the anode causes the free electron to be fast moving as it collides with a gas atom, discharging additional electrons. The secondary electrons are drawn rapidly toward the positive wire which causes additional collisions resulting in many more electrons reaching the anode in pulses which are more easily detected. This ionization must be stopped or quenched because the cumulative electron showers can damage the detector. Quenching is achieved by lowering the anode voltage.

Advantages	**Disadvantages**
Simplicity	Low efficiency - 5 to 10%
Large pulse output	Relatively long counter-3ft
	Quenching problems

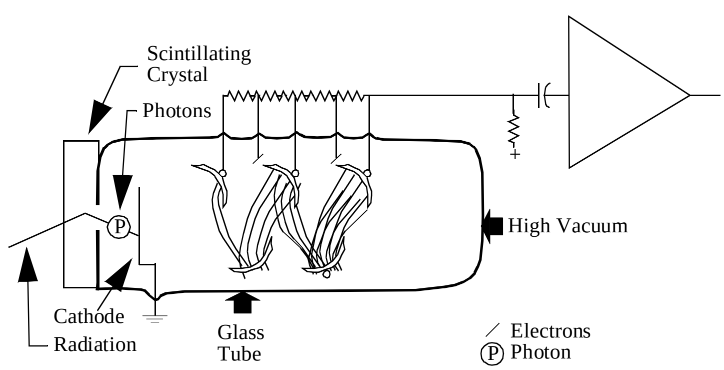


Figure 3-3: Scintillation Counter

The most modern logging detector is the scintillation counter. It has two basic components, a scintillating crystal and a photo multiplier tube. The transparent sodium-iodide crystal (NaI) will give off a minute burst of light when struck by a gamma ray. The light energy strikes a photo sensitive cell or cathode which causes electron emission. The electrons so produced are drawn to an anode which, upon impact, releases additional electrons which are directed to another anode. There are several stages of such amplification which finally give a sufficient flow of electrons to be easily measured and recorded as an indication of the gamma radiation penetrating the detector.

Advantages	**Disadvantages**
High efficiency - 50 to 60% of gamma rays are detected.	Temperature of tube must be closely controlled. High temperature causes random counts.
Short detector, length about 4 inches which gives good formation delineation.	Complex construction and more expensive than other detectors.
Selectivity - narrow ranges of gamma ray energy can be measured.	

Occurrence of Radioactive Elements

Uranium			
	Origin	Acid Igneous Rocks	
	Sediments	Direct Precipitation Reducing Conditions Black Shales (Jurassic) Uneven Distribution (erratic peaks)	
Thorium			
	Origin	Acid/Intermediate Igneous Rocks	
	Sediments	Detrital grains:	Zircon Thorite Epidote
		Clay minerals:	Bauxite Kaolinite Illite Smectite
Potassium			
	Clay Minerals:	Illite	5.2%
	Glauconite	4.5%	
		Kaolinite	0.63%
		Smectite	0.225%
		Chlorite	0.00%
	Evaporites:	Sylvite	52.5%
		Carnallite	14.1%
		Polyhalite	12.9%

•Notes•

Chapter 4

Resistivity Logs
Introduction

Resistivity logs are primarily used to differentiate between hydrocarbon and water-bearing zones. Because a rock's matrix is non-conductive, the ability of the rock to transmit a current is almost entirely a function of water in the pore spaces. Hydrocarbons, like the rock matrix, are non-conductive; therefore, as hydrocarbon saturation increases, the rock's resistivity increases.

There are two basic types of resistivity logs used in the oilfield, induction logs and electrode logs.

An induction tool consists of one or more transmitting coils that emits a high frequency, alternating current of constant intensity. The alternating magnetic field which is created induces secondary currents in the formation, and these create magnetic fields that induce signals to receiver coils. The received signals are essentially proportional to conductivity, which is the reciprocal of resistivity (conductivity = 1000/resistivity).

The second type of resistivity measuring device is the electrode log. Electrodes in the tool are connected to a power source (generator) and a current will flow from the electrodes through the borehole fluids into the formation and back to another electrode at the other end of the tool.

Induction logs and electrode logs are combined in many of the resistivity logging tools.

Depth of Resistivity Log Investigation

Flushed Zone (Rxo)	Invaded Zone (Ri)	Uninvaded Zone (Rt)
Microlog	Short Normal	Long Normal
Minilog	Spherically Focused Log	Deep Induction Log
Microlaterolog	Medium Induction Log	Deep Laterolog
Microspherically Focused Log	Shallow Laterolog	
Proximity Log		

Tools Measuring the Uninvaded Zone (Rt)

These tools (deep induction and deep laterolog) essentially measure Rt, and the log value is normally quite close to true Rt, providing the tool is used in the correct environment.

To obtain a more precise value for Rt, certain corrections must be applied to the raw values.

Tools Measuring the Invaded zone (Ri)

The actual quantitative value of these readings is not as important as how these readings relate to Rt and Rxo. By comparing them, we can obtain:

- Corrected Rt values
- Depth of invasion of the mud filtrate
- An idea of the formation's permeability
- An estimate of movable oil

Tools Measuring the Flushed Zone (Rxo)

Four different Rxo tools are available, the ML, MLL, PL and MSFL. They are intended for different conditions of salinity, mud cake thickness and diameters of invasion.

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Conventional Resistivity Logs

Normal Logs

The Short Normal (SN) measures the resistivity of the invaded zone (Ri). This curve has the ability to detect invasion by comparing the separation between the deep induction and the short normal. Invasion will indicate permeability. The SN curve is recorded in Track #2.

Electrical spacing of the electrode is sixteen inches (short normal) or sixty-four inches (long normal). Normal logs provide reliable resistivity values for beds greater than four feet in thickness. The curve will be symmetrical around center of bed. Using this parameter, bed boundaries will be at the inflection points on the curve.

Normal logs work best in conductive, high resistive muds.

The principle behind normal devices was briefly mentioned in the introduction. There are two electrodes in the sonde, a current electrode and a pick-up electrode, with two other electrodes located “an infinite distance” away (one is the cable armor, the other one is on the surface). A current of constant intensity is passed between two electrodes, one in the sonde and the one on the cable. The resultant potential difference is measured between the second electrode in the sonde and the one on the surface.

There are several factors affecting normal log measurements:

- The resistivity of the borehole (Rm, Rmc, Rmf).
- The depth of invasion (di).
- Formation thickness - the greater the spacing of electrodes, the thicker the formation must be to get accurate readings.
- Resistivity of surrounding beds - when there is a high resistivity contrast, distortion of the curve results.

Lateral Logs

The lateral curve is produced by three effective electrodes (one current and two pick-up) in the sonde. A constant current is passed between two electrodes, one on surface, and one in the sonde. The potential difference between the two electrodes, located on two concentric spherical equipotential surfaces, centered around the current electrode, is measured. The voltage measured is proportional to the potential gradient between the two pick-up electrodes. Point of measurement is halfway between pick-up electrodes (18 feet, 8 inches), making the radius of investigation approximately equal to the electrode spacing.

Lateral curves are asymmetrical, and only apparent resistivity (Ra) is measured. The resistivity values must be corrected for Rt. For thick beds, the lateral curve will define a bed boundary, depending on type of electrode arrangement.

Several factors affecting lateral measurements are:

- Borehole influences (Rm, Rmc, Rmf) are relatively small.
- Measurements in thin beds are difficult, if not impossible.

Induction Resistivity Logs

Induction

These logs are used to measure formation conductivity (Ct = 1000/Rt). The logs are most effective in formations with medium to high porosities. Induction logs enhance thin bed responses, with little adjacent bed effect.

Responses in thin beds are determined by the thickness of the bed and the conductivity contrast between the thin bed and adjacent beds. Bed boundaries are located halfway between the high and low readings.

Some corrections are necessary in thin beds (i.e., the reading is adjusted to the resistivity that would have been observed in a thick bed).

Induction logs can be used in any borehole fluid (gas, air, oil or water muds), but work best when used in a fresh water mud. They are generally used for determination of formation resistivities and correlation purposes.

A constant high intensity alternating current is made to flow through an insulated transmitter coil. The alternating current induces a secondary current in the formation and the resulting secondary field induces a current in the receiver coil. The induced flow is proportional to the conductivity of the formation.

The conductivity is measured in millimhos per meter and presented on a linear scale.

The spacing between the receiver and transmitter is a compromise between depth of investigation and thin bed resolution. Additional coils can be placed above and below the transmitter and receiver to “focus” the current flow. This focusing is used so that the materials in the borehole, the invaded zone and nearby formations do not influence the measurements. This focusing creates a very deep measuring device which does a good job of measuring conductivity in the virgin formation.

Induction values are used for Rt determination. When Rxo is greater than Rt, induction gives the best values. Charts are provided to make corrections for thin beds, large hole diameter and deep invasions. In formations that are shallow to moderately invaded, Rt can be taken directly from log and can be used in the Archie equation.

There are two types of Induction Logs:

Induction Log:

Logging Speed - 1000 to 4000 ft/hr
Gamma Ray on track #1
Resistivity curve in track #2
Conductivity curve in tracks #2 & #3

Induction-Electrical Log:

Logging Speed - 6000 to 8000 ft/hr
SP in track #1 - millivolts
SN and resistivity in track #2 - ohm meters
Conductivity in track #3 - millimhos

Factors affecting Induction Logs include:

1. Zones of high conductivity lying between the invaded zone and the undisturbed formation.
2. The response of the instrument is dependent upon 1) the depth of filtrate invasion, 2) the resistivity ratio between the filtrate and formation water, and 3) hydrocarbon mobility
3. Propagation of the signal in a thick formation with cylindrical boundaries of contrasting conductivity. Signal changes are due to the changes in conductivity and thickness, and also a function of the distance between transmitter and receiver coils.
4. Coil Spacing - Each pair is affected differently by the conductive zones encountered. The longer the coil spacing, the greater the loss of signal due to the propagation effects.
5. The borehole response to the induction log increases with the increase in mud conductivity.

When formation conductivities are low, borehole response is significant. To compensate for the borehole, the tool is fitted with rubber sleeves to keep it from coming in contact with the borehole wall.

Dual Induction Log

The Dual Induction Log (DIL) is one of the most advanced resistivity logging devices in use today, especially where invasions are large. The DIL is used to determine true formation resistivity, invasion diameter and for correlation purposes. It can be run in any fluid (air, gas, oil or water mud) and is generally used in formations that are deeply invaded by filtrate.

The DIL provides four measurement simultaneously, three resistivity curves, and either a Gamma Ray or Spontaneous Potential.

The three resistivity curves measure resistivity at different points in the formation. Shallow investigation, to measure the flushed zone resistivity (Rxo), uses either a focused device or a guard system which is positioned at the bottom of the tool. The medium induction measures the flushed and invaded zone (Ri), while the deep induction measures the uncontaminated zone (Rt).

Interpretation is accomplished using a “tornado chart,” where the ratios of the curves are plotted. To plot the shallow to deep ratio, go horizontally on the chart, (Rxo/RILD). The medium to deep ratio is plotted by going vertically on the chart (RILM/RILD). At the intersection of the two values there is a ratio of Rxo/Rt (between the solid curve, moving from right to left) and a ratio of Rt/RILD (from the dashed curve, moving from bottom to top). To find Rt, simply multiply Rt/RILD by the RILD value. To find Rxo, multiply the Rt value by Rxo/Rt. The diameter of invasion can be found from an additional curve.

DIL curves are plotted on a split cycle logarithmic scale, on Tracks 2 and 3. The scale covers 0.2 to 2000 ohm meters. This allows for a greater range of resistivities which makes ratio determination easier (the difference of two logarithms is equal to their ratio).

Visual inspection of the log can provide information regarding invasion, porosity and hydrocarbon content. The separation between curves and their relative positions can be used to estimate invasion. Variations in resistivity are due to changes in either water saturation or porosity.

When the resistivity of the filtrate is greater than formation water, with increasing invasion, the ratio between the medium and deep curves increases and the ratio between shallow and deep curves decreases.

With shallow invasion, the effect on the focused curve is large and there will be a large separation between the focused and induction curves. The separation between induction curves will be small and the resistivity of deep induction will be close to Rt.

An increase porosity is noted when a change resistivity occurs and the separation remains the same. When a change of resistivity is accompanied by a decrease in separation between the shallow and deep curves, hydrocarbons or deep invasion is indicated. Hydrocarbons will cause the shallow and medium curves to read lower than the deep curve.

For dense, impermeable formations, the three curves read approximately the same.

Focused Resistivity Logs

Focused resistivity devices were developed to overcome the inherent problems associated with the non-focused resistivity measurements. With the non-focused resistivity methods the current flows into the formations following the path of least resistance. The non-focused system can, therefore, be seriously affected by the borehole and by the formations above and below the bed being measured. Salt mud systems tend to short circuit the system, while surrounding beds of low resistivity distort the current.

The focused resistivity method uses electrode arrangements and an automatic control system to force the surveying current through formations as a sheet of predetermined thickness. The resulting resistivity measurement thus involves only a portion of the formation, of limited vertical extent, and is practically unaffected by the borehole mud. Its primary advantages over a conventional electrical log are sharper discrimination between different beds, more accurate definition of bed boundaries, and closer approximation of the true resistivity for thin beds, especially where salt mud is used. Principal applications are in hardrock areas, all areas where salt muds are used, and in areas where highly resistive formations exist even when fresh muds are used.

In any water-based mud, fresh or salt, the focused electrical method provides dependable logs for correlation purposes. It will, in every case, equal or excel the short normal curve in bed definition.

Two types of focused resistivity devices have been developed: the guarded-electrode system and the point-electrode system. The resistivity response of each of these systems is directed towards the measurement of Rt.

Guard/Laterolog 3 Type Logs

This type of tool has elongated focusing electrodes which are placed above and below the current electrode. A current of constant intensity is supplied to the center electrode and a controlled supply of current, of the same polarity, is applied to the guard electrodes (both guard electrodes are kept at the same potential). The potentials of the current electrode and guard electrode are monitored.

The intensity of the current applied to the guard electrodes is continuously adjusted to maintain zero potential difference between the guard electrodes and center electrode. This keeps the current in the center electrode from flowing into borehole fluids.

The current is forced to flow perpendicular to the logging tool. Voltage drops will occur in the mud, mud cake, flushed zone, invaded zone and undisturbed zone, with the greatest drops occurring in zones of highest resistance.

The radius of investigation is approximately three times the length of the guard electrodes, and the tool is intended for use in conductive muds, thin beds and high resistivity formations.

Point/LL7, LL8 Type Logs

Point tools operate by focusing the current beam using a number of point electrodes. The tool consists of a center electrode and three pairs of point electrodes. Each pair are symmetrically located with respect to the center electrode and connected to each other by a short-circuiting wire.

A constant current is sent through the center electrode, and an adjustable current is sent through the top and bottom pair (bucking electrodes). This current is adjusted so that the two pair of monitoring electrodes are brought to the same potential.

The potential drop is measured between one of the monitoring electrodes and an electrode at the surface. With a constant current, this potential varies directly with formation resistivity.

Since the monitoring electrodes are maintained at zero potential, the current from the center electrode must flow horizontally.

The difference between the LL 7 and LL8 is the electrode spacing. The Dual Laterolog uses longer bucking electrodes and a longer spacing (LLd) to give deep investigation.

Factors Affecting Focused logs

Focused logs cannot be run in non-conductive fluids (air, gas or oil-based muds).

There will be some effect from the invaded zone and surrounding beds. Focused logs however, have greater adaptability for the investigation of thin, resistive beds than do the other resistivity logs.

Micro - Resistivity Logs

Micro-Resistivity devices are used to measure Rxo and may be used to determine permeable beds by detecting the presence of mud cake. All are used on sidewall pads to remove the short circuiting effect of the drilling fluids, but the currents must pass through mud cake to reach the invaded zone and are, therefore, affected by its resistivity and thickness.

Measurements of Rxo are important for several reasons:

1. When invasion is deep, Rxo makes it possible to determine Rt and fluid saturations.
2. The ratio Rxo/Rt is water saturation.
3. In clean formations, F can be computed from Rxo and Rmf if Sxo is estimated.

The nonfocused, microtype tool consists of button (point) electrodes embedded in a fluid-filled rubber pad. There are usually three point electrodes, set one inch apart, to make the measurements. The electrodes are either flush or slightly recessed with respect to the surface of the pad. This pad is mounted on an arm. A second pad, similar to the first but containing no electrodes, is mounted on another arm. These arms are opened and closed by an electric motor. When opened, the hydraulic pads will ride the wall due to spring tension on the arms. These tools are usually five feet long.

There are several limitations on these devices, which can result in errors when interpreting the readings. They are:

1. Shallow invasion which usually occurs in very porous and permeable beds can affect the resistivity such that use of Rmf to determine F is not justified.
2. Very thick mud cake decreases the effect of the flushed zone on measurements such that the tool has very poor resolution. Mud cakes of 3/8 inch or more are detrimental to micro-resistivity interpretation.
3. High values of Rxo as compared to Rmf cause the current to leak around the pad through the filter cake resulting in poor log resolution. This will usually occur in low porosity formations.
4. Pads not in close contact with the formation face allows current leakage and poor log resolution, and spurious separation.
5. An incorrect value of Rmf will lead to erroneous values of Rxo. This is a common error.

6. Shaly sands will lead to lower measured resistivities and, therefore, a lower value of Rxo. Porosity will then be calculated higher than the actual porosity.

Contact/Mini or Microlog

These tools utilize a system of three small electrodes in a vertical line, spaced one inch apart, embedded in an insulated fluid filled pad that is forced against the side of the wall.

The current electrode is maintained at a constant current, resulting in two curves being generated, a 1” to 1-1/2” lateral curve (R1 x 1) and a 2” normal curve (R2). The radius of investigation is 1-1/2 inch to 2 inches for the lateral (micro-inverse) curve and 4” for the normal (micronormal) curve.

These curves are used to determine the resistivity of the flushed zone (Rxo) and to detect mud cake associated with the presence of permeability.

Resistivity values will be the same in an uninvaded zone, but will separate when invasion occurs. The normal curve reads higher where invasion of fresh drilling fluid has occurred. Mud cake is identified by the lateral curve. Resistivity of the mud cake is about equal to or greater than the resistivity of the mud and usually is smaller than the resistivity of the invaded zone.

Contact tools are useful in locating porous and permeable zones. They will show up as positive separation between the curves. Shale zones show up showing no separation. In enlarged holes, shale zones exhibit a minor separation, so a microcaliper is run and included in Track #1.

Contact tools work well in salt-based or gypsum-based drilling fluids because the filter cake is not strong enough to keep the pad away from formation.

FoRxo/Proximity Log and Microlaterolog

These tools use pad mounted electrodes which have additional guards (shields) for focusing the current. This gives a deeper radius of investigation (usually 6 to 10 inches), because it is generally considered that complete flushing occurs 1 to 3 inches into the formation. The greater depth also reduces the filter cake effect and gives a better resistivity of the flushed formation (Rxo).

There are several other applications for these logs:

- They can be used as porosity indicators.
- They help in the estimation of movable hydrocarbons by determining the flushed zone depth.

The Microlaterolog is primarily run in salt mud or where the mud cake is thin. The Proximity Log is the fresh water equivalent of the MLL, because the electrode configuration is designed to offset the effects of thick mud cake and the effects of deeper invasion of fresh water drilling fluids.

Chapter 5

Porosity Logs

Introduction

Three main types of logging systems are used for porosity determination. They are:

- Acoustic/Sonic Logs
- Density Logs
- Neutron Logs

Each system responds to different formation and fluid characteristics. When used independently, additional information about the formation other than the sonde reading is required before porosity can be determined.

This additional information includes a knowledge of the formation's lithology and the type of fluid contained in the pore spaces of the formation being investigated.

Because the different porosity devices respond to different formation and fluid characteristics, combination's of two or all three of the devices can be used to solve for porosity and lithology, to differentiate between intragranular porosity and vuggy or fracture porosity, to locate gas caps, and to identify some minerals.

Porosity determination from an acoustic log is based upon the measurement of the travel time of an acoustic wave in the formation. When the travel time for the formation of interest is known, porosity can be calculated. The variations in acoustic travel time (Δt) are measured in μsec/ft and referenced to the value in limestone.

The neutron log measures porosity (ϕ) directly. Using limestone as the reference, porosity varies as a function of lithology and is shown either in percent or with respect to limestone.

On the density log, gas appears as an apparent increase in porosity (decrease in bulk density, (φb). The effects of changes in fluid saturation are predictable on the density log due to the relationship between porosity, formation density and fluid densities. The variation of φb as a function of lithology is shown with respect to the limestone value.

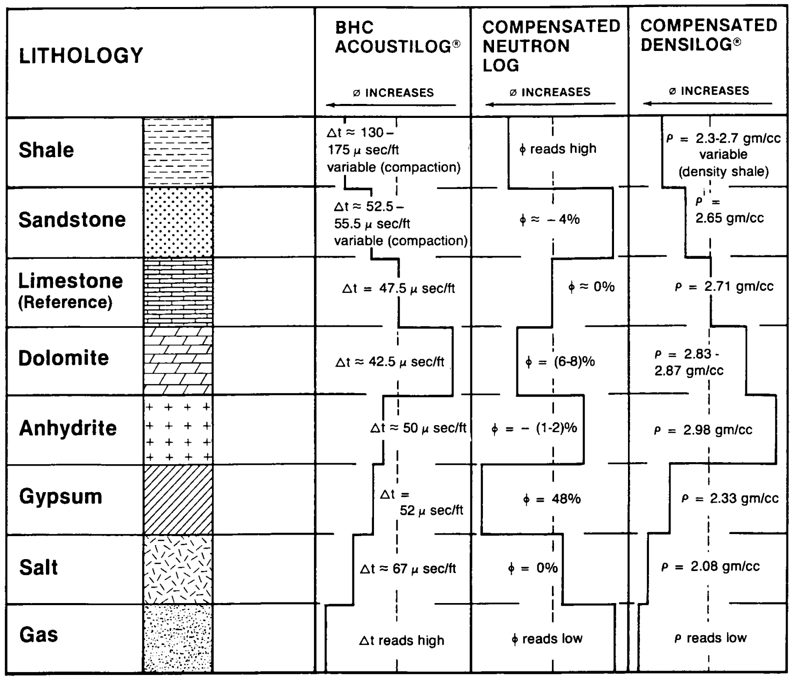

Figure 4-1: Variation of Instrument Response to Porosity

Acoustic or Sonic Log

The acoustic or sonic log is a continuous record versus depth of the specific time required for a compressed wave to traverse a given distance of formation adjacent to the borehole.

The acoustic tool contains a transmitter and two receivers. When the transmitter is energized, at a rate of 10 to 20 pulses per second, the sound wave enters the formation from the mud column, travels through the formation and back to the receivers through the mud column. Formation velocity (travel time or Δt) is determined using the difference in arrival times at the two receivers. The system has circuits to compensate for hole size changes or any tilting of the tool.

The basic measurement recorded on the log is interval travel time, which is the reciprocal of interval velocity. This parameter is recorded on the log in microseconds/foot.

To convert velocity to acoustic travel time*

$$\Delta t = \frac{10^6}{v}$$

where: v = velocity (ft/s)

* Acoustic travel time will normally fall between 40 and 200, which corresponds to velocity readings of 25,000 to 5,000 ft/s.

Acoustic/Sonic Porosity

The acoustic travel time in a formation depends upon lithology (formation type) and porosity. In general terms, the more dense or consolidated a formation, the lower the travel time (Δt). An increase in travel time indicates an increase in porosity.

$$\text{Porosity}(\phi) = \frac{\Delta tlog - \Delta tma}{\Delta tf - \Delta tma}$$

where:
- $\Delta tlog$ = Reading from sonic log in μs/ft
- Δtma = Transit time of matrix material (from table)
- Δtf = About 189 s/ft (corresponding to a fluid velocity of about 5,300 ft/s)

The depth of investigation of the acoustic/sonic log is only a few inches (12 - 100 cm) from the borehole wall. Bed resolution is around 2 feet.

Formation Effects

If shale exists within sandstone, the apparent porosity values are increased by an amount proportional to the bulk-volume fraction of the shale. The Δt readings are increased because Δt shale generally exceeds Δt sandstone.

In carbonates with intergranular porosity, the same formula applies. In vuggy formations, the porosity tends to be too low since a continuous path exists through the matrix.

The porosity formula gives readings too high in unconsolidated sands. To compensate for these uncompacted sands, a compaction coefficient is added to the porosity formula:

$$\phi = \frac{\Delta t_{log} - \Delta t_{ma}}{\Delta t_f - \Delta t_{ma}} \times \frac{1}{B_{cp}}$$

where: $B_{cp} = \frac{\Delta t_{sh}}{100}$

(Δt_{sh} is the average travel time in the shale as seen on the log)

In hydrocarbon bearing, uncompacted formations, the compaction coefficient will not account for the effect of hydrocarbons. If the hydrocarbon type is known, use the following corrections:

- In gas-bearing formations: ϕ x 0.7
- In oil-bearing formations: ϕ x 0.9

Log Traces

The acoustic curve is recorded in Tracks 2 and 3 on a linear scale. The acoustic log is usually run with Caliper and Gamma Ray curves, which are recorded in Track 1.

Quality Control

1. 1. Run 200' of repeat log and compare the two logs; they should repeat.
2. 2. Check travel times in known lithology.
3. 3. Check with resistivity log for correct depth.
4. 4. Recommended logging speed is 1,000 to 4,000 ft/hr.

Porosity determinations are normally finalized through the use of charts, because additional corrections are sometimes needed.

Formation Density Log

There are four main uses of the density log: porosity determination, identification of minerals in evaporate deposits, detection of gas, and the determination of hydrocarbon density.

The density tool measures the electron density of the formation, using a pad mounted chemical source of gamma radiation (Cesium 137 or Cobalt 60), which emits medium energy gamma rays (in the energy range of 66MeV). At each collision with formation electrons some energy is lost (Compton Scattering), affecting the amount of gamma rays being detected at the receivers. Density will be based on rock matrix, porosity and pore fluids.

The receivers are two shielded gamma ray detectors (Geiger Counters) which automatically compensate for mud cake and small borehole irregularities. The correction ($\Delta\varphi$) is plotted.

There are time constants for density tool speed, based on:

- Low density formations 2 seconds
- High density formations 4 seconds

The tool travels no more than one foot per time constant, making the maximum speed 1800 ft/hr.

Density and Porosity Determination

The petroleum industry assumes that electron density is equal to bulk density; therefore, the number of gamma rays counted at the detectors can be directly related to formation density.

Bulk density is the ratio of mass (weight) to volume, with units in grams per cubic centimeter (gm/cc).

In low density (high porosity) formation most gamma rays are counted. As formation density increases (porosity decreases), fewer gamma rays are counted. Since most mineral densities are known and the pore fluids densities are known, porosity can be determined.

$$\text{Porosity}(\phi) = \frac{\varphi ma - \varphi b}{\varphi ma - \varphi f}$$

The depth of investigation is shallow; therefore, in most permeable formations the pore fluid will be drilling mud filtrate.

Density Log Trace

The density log is recorded in Tracks 2 and 3,on a linear scale in gm/cc.

Adverse Effects

The effects of small amounts of hydrocarbons are not noticeable since the fluid density (filtrate) is close to oil density. If large amounts of oil or gas exist, the effect will be a large porosity reading.

Shale densities will show up on the log, with typical densities of around 2.2 to 2.6 gm/cc. With depth these densities will increase.

When gas or air drilling, the pore fluid is no longer one, and a nomograph is used to determine φf. If the gas being used is dry, the density is zero.

Abnormal pressure will affect the density readings. Normally, there is an increase of density with depth; however, in over-pressured zones there is a reversal of density trends. To contain abnormal pressures, an impermeable barrier is necessary, and in many cases there will be a high density shale barrier on top of the abnormally pressured formations.

Neutron Log

The neutron log is a measurement of induced formation radiation produced by fast moving neutrons bombarding the formation.

The source used to produce neutrons is usually a mixture of Beryllium and Radium. As Radium decays, it emits alpha particles. The Beryllium responds to those alpha particles by emitting neutrons. Other sources include:

- Plutonium - Beryllium: large volume needed to produce neutrons
- Americium - Beryllium: good source

Neutrons are electrically neutral, having approximately the same mass as hydrogen. They can penetrate dense matter (sands or limestones) with little loss of energy or velocity. Energy loss is a function of:

- Angle of collision
- Relative mass of the struck nucleus

When a neutron collides with a hydrogen nucleus, it will lose about half its energy. After about 20 collision with hydrogen, the neutron will be captured by one of the various elements in the formation (e.g., chloride, silicon, hydrogen). Those neutrons which are captured (thermal neutrons) emit a secondary gamma ray.

Types of Neutron Detectors

One type of detector measures neutrons just about thermal speed (epithermal). It shows maximum sensitivity to neutrons having energies above the thermal level and minimal sensitivity to gamma rays and thermal neutrons. This reduces those errors which arise from variations in formation chemistry and resolves porosity in areas where lithologies and liquids are mixed or uncertain.

There is a neutron detector which measures the neutron population at thermal energy. It responds to all formation and well parameters that affects neutron density.

- In salt water the count rate is lowered.
- It is influenced by formation chemistry.

Another detector responds to the gamma rays that are emitted upon neutron capture. Gamma ray emission can occur (1) in the formation, (2) in the wellbore, (3) in the materials that make up the detector, and (4) in the detector crystals. Also the densities of materials will affect the quality of gamma ray transmission.

Neutron Log Response

Neutron logs are basically a measure of the amount of hydrogen contained in the formation. High neutron count rate indicates low porosity, while low neutron count rate indicates high porosity. While there is very little difference between oil and water, the neutron tool will distinguish between gas and oil saturations. When gas is measured, the porosity will appear very low.

The neutron log is a very good porosity indicator in limestones.

The standard measurement is the “API Neutron Unit,” where one API unit is defined as 1/1000 of the difference between instrument zero and the log deflection opposite the 19% porosity of Indiana limestone.

Borehole Effects on the Neutron Log

1. Hole Diameter - Many neutron are captured in large liquid-filled boreholes causing low count rates. The neutron log loses its resolution ability in well bores greater than ten inches.
2. Mud Resistivity - Salt muds are a medium of high capture.
3. Mud Density - Weight material displaces some water and induces increased count rates. Gas or air drilled wells are difficult to interpret due to unpredictable scattering.
4. Mud Cake Thickness - Being very porous, thick mud cake can lend to optimistic porosity indications.
5. Casing - Iron is an efficient neutron absorber, so is cement which will mask out porosity.
6. Tool Eccentricity - Neutron count rate increases as the tool contacts the borehole wall. It is assumed that the tool is always along the wall.

Factors Dealing with Neutron Log Interpretation

1. Shales show high porosity due to bound water.
2. Because of low concentrations of hydrogen in gas, gas zones will indicate low neutron porosity.
3. Normally run with the Gamma Ray log in Track 1, the neutron curve is recorded on Track 2 and 3 on a linear scale for lithology and porosity determination.
4. Radius of investigation varies with the porosity.
    a. Several feet with low porosity formation.
    b. Few inches in 30% liquid filled porosity.

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Applications of the Neutron Log

As mentioned above, the main use of the neutron log is to assist in the determination of porosity. It has the added application in that it can be run in cased or open hole with any type of drilling fluid. The log response is greatly affected by gas, so it may assist in the detection of gas intervals. It is also used for the correlation of lithologic units from well to well.

Sidewall Neutron Log - SNP

The sidewall neutron tool is similar to the other neutron devices in its operation. The main difference is that the source is mounted on a skid which is expanded against the borehole wall. This allows the neutrons to be focused into formation, eliminating the environmental effects.

Porosity can be read directly from the log. It has the ability to detect gas and can assist in determining lithology. The tool can be run in open hole with any fluid and has the added benefit of responding to primary and secondary porosity.

The sidewall neutron device cannot be used in cased holes, and, for correct porosity determination, the lithology must be known.

Compensated Neutron Log - CNL

The CNL is a dual spaced thermal - neutron detection instrument. It contains a 16 - curie source which is designed to reduce statistical variation. Many borehole effects are reduced by taking the ratio of two count rates.

Porosity may be read directly from the log if the lithology is known. The response will help detect gas and with vendor charts can assist in the determination of lithology. For most consistent evaluation, the CNL should be used with other open hole logs.

When used in cased hole logging, the diameter of the open hole before running casing must be known for effective interpretation.

Quality Control of Neutron Logs

1. Check the calibration located on the bottom of the log.
2. Run 200 feet of repeat log and compare logs. The two should repeat.
3. Check depth with the resistivity log.
4. Check porosity values in a known lithology.
5. Curves should show good detail and be smooth.
6. Curves should be identified on the log.

•Notes•

Log Selection

Introduction

This chapter deals with the types of logs run over reservoir sections of a well and discusses the good and bad points of each tool in the various logging environments.

A “normal” logging suite involves:

Run #1: *Induction - Acoustic - Gamma Ray - SP*

This should always be the first tool suite run in the open hole because it does not contain radioactive sources or pad devices and has the minimum risk of sticking. This string will give a good indication of hole conditions, which should be the basis of decisions concerning other tool runs. In addition, resistivity and porosity tools on this first run will allow a quick evaluation of suspected pay zones, so that RFT and sidewall core points can be picked, and other tools cancelled, if they are not necessary.

Run #2: *Density - Neutron - Spectral Gamma Ray*

This should be the second tool suite run because, assuming hole conditions are good, it is best to run the logs with radioactive sources as soon as possible before hole conditions deteriorate. These tools will also give improved porosity and lithology information for evaluation.

Run #3: *Dual Laterolog - Micro-Resistivity Log - SP*

This suite is usually optional, depending on the presence of hydrocarbons. The micro-resistivity will be necessary to compute the hydrocarbon corrections to the neutron and density logs. The laterolog will give a better estimate of Rt in hydrocarbon (high resistivity) zones.

Run #4: *Dipmeter*

This should be run after the other open hole logs and before the RFT. It will give time for the other logs to be analyzed and identify depths for the RFT to be set.

Run #5: *Formation Tester*

If hole conditions are deteriorating, a wiper trip should be considered to condition the hole. The formation tester allows the formation pressures to be measured in the open hole and a sample of the formation fluids to be taken.

Run #6: Well Seismic Tool

This tool is either run as “check shots” to calibrate the sonic log or as a “Vertical Seismic Profile (VSP)” to give improved seismic control ahead of the bit.

Run #7: Side Wall Core Guns

These guns obtain small diameter formation samples. They must be the last tools run on the logging job because lost bullets and their connecting wires can easily stick other logging tools.

The remainder of this chapter provides information on the types of tools to be run for specific applications or if special information is required from a formation.

Selection of Tools

For Resistivity of the Uninvaded Zone

The induction log usually gives the best value for Rt. In some cases these other logs may be as good or better.

- In thick uniform formation a standard IES may be best Rt tool.
- The responses of the 6FF40 and LL7 indicates the LL7 reads closer to Rt only when invasion is greater than 0" and Ri/Rt is less than 1/5.
- In very thin formations with shallow invasion a Laterolog or Guard Log may be used to give bed definition and Rt.

For Porosity

1. If cores are available, a plot of core porosity versus log porosity will aid in selecting the best tools in future wells in a field.
2. If information related to lithology is desired, more than one porosity tool should be run.
3. If two porosity tools are to be run, the density and the neutron may be the best combination in most wells, but local experience is the best guide.
    a. The neutron along with the density or sonic can be used to detect gas.
    b. The neutron log and sonic log are influenced by shale and give porosities that are too high when shale is present. The density is normally influenced less by shale than the sonic or neutron.
4. In areas where the Movable Oil Plot is useful, a Microlaterolog may be run along with the density, neutron or sonic. This may be the only logging technique available in deeply invaded formations where Rt cannot be obtained.
5. In low porosity, regular formations, the neutron is probably the best, the density second and the sonic third. The Microlaterolog is not recommended for porosities less than 5%.

Additional Logs

1. Always run an SP if possible
2. Gamma Ray logs may help in identify shales
3. A caliper should be run to aid log interpretation

Logs in Cased Hole

1. Porosity is determined from the neutron or the newer sonic. Both are sensitive to hole and cement conditions.
2. Gamma Ray can be used to indicate shale.
3. Life time log for oil or gas in salty water.

Types of Logs for Various Borehole Conditions

Fresh Muds (Salinity less than 20,000 ppm Cl or Rmf/Rw >4)

Data Desired	Soft Formations	Hard Formations
Resistivity and Lithology	Induction IES Gamma Ray	Induction Laterolog IES Gamma Ray
Porosity	Formation Density Sonic/Acoustic Neutron	Formation Density Sonic/Acoustic Neutron Microlaterolog
Permeability Indication	Microlog Caliper	Microlog Microlaterolog Caliper

Salt Muds (Salinity greater than 20,000 ppm Cl or Rmf/Rw <4)

Data Desired	Soft Formations	Hard Formations
Resistivity and Lithology	Induction IES Laterolog Gamma Ray	Induction Laterolog Gamma Ray
Porosity	Formation Density Sonic/Acoustic Microlaterolog Microlog Neutron Caliper	Formation Density Sonic/Acoustic Neutron Microlaterolog Caliper
Permeability Indication	Microlog Microlaterolog Caliper	Microlog Microlaterolog Caliper

Oil-Base Muds (Non-Conducting)

Data Desired	Soft Formations	Hard Formations
Resistivity	Induction	Induction
Lithology	Gamma Ray Formation Density Neutron Sonic/Acoustic	Formation Density Neutron Gamma Ray
Porosity	Formation Density Sonic/Acoustic Neutron	Formation Density Sonic/Acoustic Neutron
Permeability Indication	Formation Tester	Formation Tester

Air or Gas Drilled Holes

Data Desired	Soft Formations	Hard Formations
Resistivity and Lithology	As with oil-based, no sonic	As with oil-based, no sonic

Data Desired	Soft Formations	Hard Formations
Porosity	Formation Density Neutron	Formation Density Neutron
Permeability Indication	Temperature	Temperature

Cased Hole

Data Desired	Soft Formations	Hard Formations
Resistivity	None	None
Lithology	Gamma Ray Neutron	Gamma Ray Neutron
Porosity	Neutron	Neutron
Permeability Indication	Formation Tester	Formation Tester

Determination of Basic Reservoir Characteristics from Logs

Porosity Determination

1. Density Logs measure effective porosity and are less affected by shale. Porosity values will be high with gas in pore spaces and with shallow invasion. Corrections will be necessary.
2. Acoustic Logs show good porosity in intergranular and intercrystalline porosity.They do not indicate all secondary porosity (vugs and fractures). Porosity values will be high in shaly zones.
3. Neutron Logs are frequently recorded with density or acoustic logs. Porosity values are high in shaly zones and low in gas zones.
4. Positive separation on Contact or Micro logs indicate porosity values which are dependent on knowledge of residual hydrocarbon saturation and are more accurate in moderate to low resistivity formations.

Permeable Bed Location

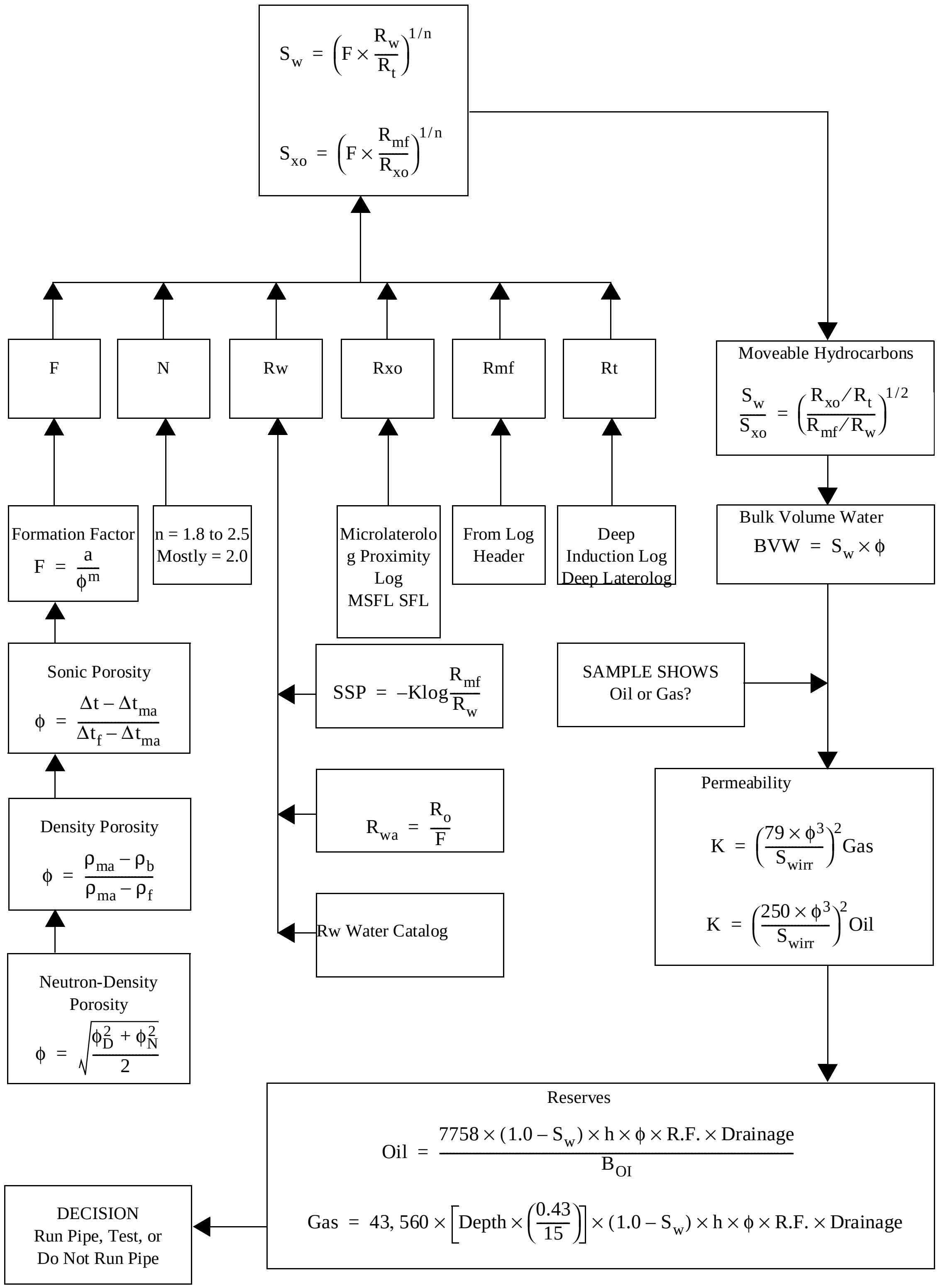
1. SP Curve Deflection: The SP current depends primarily on formation water being in contact with mud filtrate, so there must be some permeability. There is, however, no direct relationship for a qualitative evaluation. Shaliness or hydrocarbon saturation will reduce the magnitude of the deflection.
2. Resistivity Separation: For a formation to be invaded by a drilling filtrate, it must be permeable. The resistivity differences between shallow and deep investigation curves will indicate this invasion when Rmf is greater than Rw. In hydrocarbon zones the resistivity difference will be less depending on the amount of flushing (Residual Hydrocarbon Saturations), but will usually still be evident. Contact logs are useful for this purpose.
3. Caliper logs show the presence of filter cake, thus a hole diameter less than the bit size is an excellent indicator of permeability.

Hydrocarbon Saturation Indications

1. Where porosity values are assumed to be fairly constant, permeable zones having higher resistivity than adjacent sands indicate hydrocarbon saturation. The resistivity index may be estimated by the ratio (Rt/Ro).
2. When the deep reading resistivity curves have higher values than the shallow resistivity curves (Rt greater than Rxo), hydrocarbons are indicated.
3. A comparison of the deep investigation resistivity curve and a porosity log indicates hydrocarbons where resistivity values and porosities increase in the same zone.
4. Gas is indicated by lower porosity values on the neutron log. It is better than either the density or acoustic logs.

Bed Boundary Determination

1. The SP curve is very good for picking bed boundaries in fresh drilling muds and sand-shale sequences. Much of the SP character is lost in salt muds or in highly resistive and carbonate rocks.
2. The shallow investigation resistivity curves may be used for bed boundary determination. Normal curves will be distorted by one-half the spacing distance at each boundary. Focused current logs are excellent for this purpose. Induction logs have poor vertical resolution in thin beds.
3. The Gamma Ray log is very useful for determination bed boundaries both in open hole and cased holes. With normal logging speeds and correct time constants the vertical resolution is very good.



Flow Chart For Quick Look Log Interpretation

Other Information Required from Logs

1. Data to establish a lithology column
2. The ability to correlate with other wells
3. Variables to determine reserve characteristics
4. Data to aid in the solution of production problems
5. Data to evaluate secondary or tertiary recovery projects

Effects of Circulating Fluid on Logs

1. Water-base fluids, including oil emulsions, serve as an electrical bridge to a formation. Filtrate will usually displace all formation water from the invaded zone. In zones containing hydrocarbons, a residual oil or gas saturation will remain in the invaded zone. The depth of invasion is usually deeper in low porosity, low permeability zones.
2. In a few wells drilled with an oil emulsion mud, the filter cake resistivity has been very high.
3. Traces of oil may invade the formation when oil emulsion fluid is used.
4. Any of the logs can be run in water-base muds.
5. In oil-base fluids the induction, radioactivity, and acoustic logs may be used. The SP is not used.
6. If oil is the continuous phase and invades the formation displacing formation, it will leave a residual saturation of formation water and gas if present.
7. Oil-based “Black Magic” has blown asphalt, surfactants, ground oyster shells and little water. Bariod's “Invermul” and other inverted emulsion muds contain about fifty percent water, but oil is the continuous phase.
8. In wells drilled with air or gas, the induction and radioactivity logs may be used.

Basic Log Interpretation

Introduction

Having reviewed some basic concepts, the tools, the parameters measured, and the restraints under varied borehole conditions, it is now time to review wireline log interpretation.

Two primary parameters are determined from well log measurements: porosity and water saturation. In addition, logs help to define physical characteristics, such as lithology and permeability, as well as to identify productive zones. They also help in determining the depth and thickness of zones and in distinguishing oil from gas.

The Archie Equation

In 1942, Gus Archie demonstrated that the resistivity of a water-filled formation (Ro) having a water resistivity of Rw are related by means of a formation resistivity factor (F).

$$Ro = F \times Rw \quad \text{or} \quad F = Ro/Rw$$

Archie's experiments also revealed that this formation factor can be related to porosity, using:

$$F = \frac{1.0}{\phi^m}$$

Where m is a cementation exponent. As the term implies, m is determined by the type and degree of cementation holding the rock grains together. Its value will vary with grain size, grain size distribution, and the complexity of the paths between the pores (tortuosity). The higher the tortuosity factor, the higher the m value. Values range from about 1.3 to as high as 3.0. The values of m most commonly applied to log interpretation problems range from 1.8 to 2.2.

A more common form of Archie's equation relating formation factor to porosity is:

$$F = a/\phi^m$$

Where “a” is the tortuosity factor. A value other than 1 is sometimes appropriate to compensate for compaction, pore structure and grain size distribution in the relationship between F and porosity. The numerical value for “a” generally falls between 0.6 and 1.0. Some different relationships between F and ϕ are:

$F = 1/\phi^2$	For carbonates and highly cemented sands
$F = 0.81/\phi^2$	Tixier formula for unconsolidated sands
$F = 0.62/\phi^{2.15}$	Humble formula for unconsolidated sands

Other relationships exist for specific areas or formations, and still other relationships for F versus ϕ may be established from the formation factor chart in the wireline company's chart book.

Water saturation (Sw) can determined using the water filled resistivity (Ro) and the formation resistivity (Rw) using the following relationship:

$$Sw = \left(\frac{Ro}{Rt}\right)^{1/n}$$

Where n is the saturation exponent, whose value varies from 1.8 to 2.5, but normally assumed to be 2.

By combining the formula Ro = F x Rw, and $Sw = (Ro/Rt)^{1/n}$, the Water Saturation equation can be rewritten as:

$$Sw = \left(\frac{F \times Rw}{Rt}\right)^{1/n} \quad \text{or} \quad Sw = \left(\frac{a \times Rw}{\phi^m \times Rt}\right)^{1/n}$$

This formula is commonly referred to as the Archie Equation for water saturation. All present methods of interpretation involving resistivity curves are derived from this equation.

To best illustrate how Archie's fundamental relationships are applied in practice, two problems are solved below:

1. ϕ = 18% (sand)
   Rt = 22 ohm
   Rw = 0.025 at formation temperature
   a = 0.81
   m = 2
   n = 2

$$Sw = \left(\frac{a \times Rw}{\phi^m \times Rt}\right)^{1/n} \quad \text{or} \quad Sw = \left(\frac{0.81 \times 0.025}{0.18^2 \times 22}\right)^{1/n}$$

Therefore, Sw = 0.17 or 17%

2. ϕ = 27% (sand)
   Ro = 0.35 ohm (in a clean, water-filled sand)

$$Rw = \frac{Ro}{F} = \frac{Ro \times \phi^2}{0.81} = \frac{0.35 \times 0.27^2}{0.81}$$

Therefore Rw = 0.03 ohm

True Effective Porosity

The porosity formulas stated in Chapter 5 will normally give “pretty good” values for porosity. Accurate porosity determination is a little more difficult. Several “unknowns” can cause problems with the empirical formulas. These include:

- If the matrix lithology is unknown or consists of different minerals in unknown proportions
- If the pore fluid in the formation being measured is not water
- The nature of the porosity - primary or secondary

The determination of porosity using a single porosity log when one or more of the above factors are present is extremely difficult and inaccurate.

Using two or more logs tends to minimize the effects because each log responds to the various factors differently.

Crossplots

Crossplots are charts based on the slope and intercept of two porosity log responses (dependent on matrix lithology and pore fluid). Therefore, if one assumes “average” rock and fluid properties, an “average” lithology affecting the porosity measurements can be determined.

Crossplots were designed for sandstone, limestone and dolomite lithologies. When data points from either lithology are plotted, they will fall on the charts lithology lines. When a combination of those lithologies are present, the points should fall between the lines. Porosity is then determined by joining the data points and constructing a porosity scale between the major lithologies.

When using Crossplots, two items are very important to ensure that the correct chart is being used.

- The fluid forming the filtrate must be known (i.e., fresh water or salt water)
- The type of tool making the measurements must be known (i.e., SNP or CNL)

It should also be realized that the neutron porosity is recorded in limestone units; if other lithologies are recorded, corrections must be made.

Neutron-Density Crossplots

After many years of trial and error, the neutron-density charts appear to be less affected by lithology than the others. Because of this, formulas have been defined to calculate porosity. The root mean square formula provides the best calculation:

$$\phi = \sqrt{\frac{\phi N^2 + \phi D^2}{2}}$$

where: ϕN = Neutron porosity (limestone units)
ϕD = Density porosity (limestone units)

Many analysts use this formula in gas bearing zones and use:

$$\phi = \frac{\phi N + \phi D}{2}$$

in oil- and water-bearing formations. The above formula also has applicability in anhydritic dolomite formations.

Sonic-Density Crossplots

Crossplots of sonic logs and density logs have very poor porosity resolution and should not be used.

Sonic-Neutron Crossplots

Porosity values for the crossplots between the sonic log and neutron are as good as the density-neutron crossplots. However, if evaporites are present, porosities will be erroneous

Crossplot Review

All three porosity tools have about the same vertical resolution, two feet. If secondary porosity is present, it will have a large affect on the sonic values and sonic crossplots.

When shales are present, it is best to plot several shale porosity values and determine a “shale point” on the crossplot graphs. When porosity values start to move towards that shale point, they indicate the shales influence on the tools’ readings.

When gas is present in the pore spaces, its effects will appear on all porosity tool readings.

- The apparent porosity will increase in the density log
- The apparent porosity will decrease in the neutron log
- In uncompacted formations, the apparent porosity will be higher in the sonic log, showing:

  Sonic-Neutron Plots - decreases in porosity
  Sonic-Density Plots - increases in porosity

As a final note, the neutron-density crossplot is the one most likely to produce the best results, and the neutron-density equations perform as good as the crossplots in determining true effective porosity. If time permits, the calculation method is preferred because the correct charts may not be present at the wellsite.

Sxo and Movable Hydrocarbon Determination

If the water resistivity in the saturation equation is replaced with filtrate resistivity and the formation resistivity replaced with Rxo, the fluid saturation calculated would be the filtrate saturation in the flushed zone, Sxo.

$$Sxo = \left(\frac{F \times Rmf}{Rxo}\right)^{1/n}$$

When a microresistivity curve or shallow focused curve is recorded to provide Rxo, solving for Sxo is beneficial for determining residual hydrocarbon saturation.

$$ROS = (1 - Sxo)$$

The significance of knowing Sxo through a porous interval, as well as Sw, is that it allows the determination of the degree of hydrocarbon flushing by the invading filtrate. As long as Sxo is numerically greater than Sw, it can be inferred that there are movable hydrocarbons present. If Sxo = Sw it can be inferred there were no movable hydrocarbons present.

Shaly Sand Analysis

Introduction

The presence of shale (i.e., clay minerals) in a reservoir can cause erroneous water saturation and porosity values derived from logs. These erroneous values are not limited to sandstones, but also occur in limestones and dolomites.

Whenever shale is present in a formation, all porosity tools (Sonic, Neutron, Density) will record a porosity which will be too high. Two extraordinary exceptions to this rule are density, if the density of the shale is equal to or greater than the matrix, and the neutron through a gas-bearing shaly sand, depending on the volume of shale present.

As well as affecting porosity, the presence of shale in a formation will cause the resistivity log to read a resistivity that is too low. This has the effect of reducing the contrast between oil or gas and water; hence, if shale is present in a reservoir, Sw may be difficult to calculate. It is usually accepted that for shale to significantly affect log derived water saturations, the shale content must exceed 10% to 15%.

All shaly sand formulae reduce the water saturation value which would be calculated if the shale effect was ignored. However, lowering water saturation can be a problem in log evaluation. If the shale content is overestimated, a water-bearing zone may calculate like a hydrocarbon zone.

The first step in shaly sand analysis is to determine the volume of shale (Vcl or Vsh). There are a number of ways to do this and some are summarized below. If more than one method is used and all values are reasonably close, the lowest value should be taken to represent shale volume (Vcl).

Vcl may be calculated from single curves or from crossplots using the following logs:

- Gamma Ray
- Spectra Log
- Spontaneous Potential
- Resistivity
- Neutron

- Neutron - Density Crossplot
- Neutron - Sonic Crossplot
- Density - Sonic Crossplot

Gamma Ray

The Gamma Ray responds to the natural radioactivity of the formation. In derivation of shale content, the assumption is made that the only radioactive component is shale, hence the presence of other radioactive minerals will cause Vsh to be too high. There are two methods used to calculate clay volume from the Gamma Ray; one assumes a linear response and the other a curved response.

The basic equation common to both linear & curved response is the Gamma Ray Index:

$$\text{IGR} = \frac{\text{GR log} - \text{GR min}}{\text{GR max} - \text{GR min}}$$

where: GR min = GR minimum (in clean sand)
GR max = GR maximum (shale zone)

linear response: VclGR = IGR

curved response:

(i) if IGR $\geq$ 0.55

$$\text{VclGR} = \frac{0.06078 \times 100X^{1.58527}}{100}$$

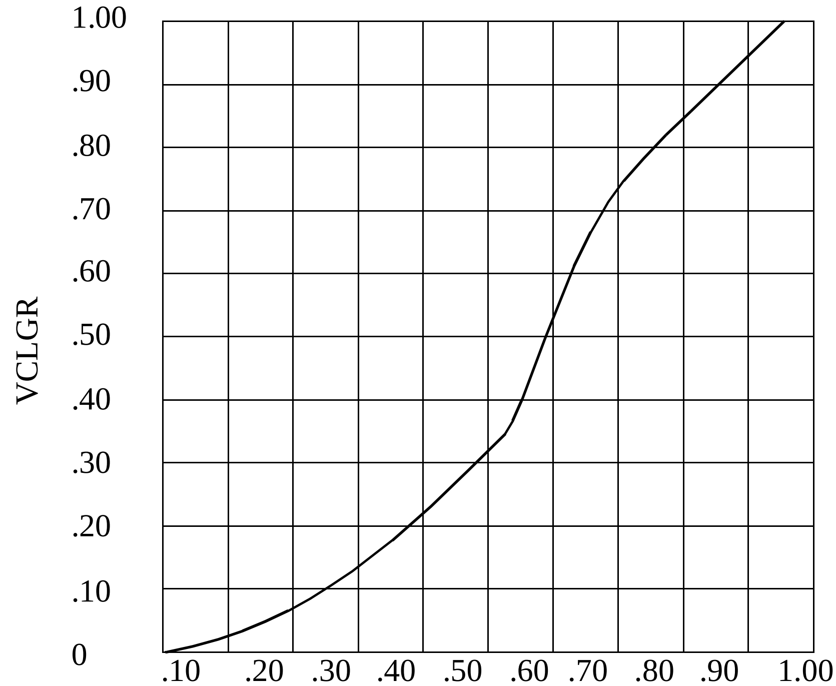
(ii) if 0.55 < IGR $\leq$ 0.73

$$\text{VclGR} = \frac{2.1212 \times 100 \times (X - 81.667)}{100}$$

(iii) if 0.73 < IGR

$$\text{VclGR} = \text{IGR}$$

The curved GR response is illustrated on the following page.



Curved GR Response

Spectra Log

The Spectra Log (Western Atlas term) may be used in one of three ways to calculate Vcl.

1. *Spectralog Total Counts*: The total counts curve on a Spectralog is a sensitive gamma ray measurement and may be used subject to the same constraints as mentioned for the Gamma Ray. It is a linear response:

$$Vcl = \frac{CTS - CTS\ min}{CTS\ max - CTS\ min}$$

2. *Spectralog Potassium*: The spectralog-derived determination of potassium may be used to calculate Vcl because, with the exception of potassium deficient shale, potassium content can be correlated directly to the formation shale content.

   The presence of other potassium rich minerals will cause too high a value of Vsh; however, with the exception of potash deposits, feldspar rich granite washes and zones rich in mica, the clean formation contribution to potassium content is generally small. The greatest advantage of this method is that it is not affected by uranium salts.

3. *Spectralog Thorium*: Thorium can also be correlated to the amount of shale in the formation. Unlike the GR or K40 curve, the Thorium curve may be used for Vsh calculations in a granite wash. The presence of thorium in formation other than shale is rare in sedimentary environments.

$$\text{Vcl} = \frac{\text{TH log} - \text{TH min}}{\text{TH max} - \text{TH min}}$$

Spontaneous Potential

The SP curve may be used to calculate Vsh; however, factors such as SP noise, lack of Rw to Rmf contrast, and hydrocarbon content can complicate the derivation of Vcl from the SP. The use of high salinity drilling fluids restricts the development of a good SP and a valid Vcl.

$$\text{Vcl} = \frac{\text{SP log} - \text{SP min}}{\text{SP max} - \text{SP min}}$$

where: SP min = SP in clean water sand
SP max = SP in shale

Another way of calculating Vcl from the SP is as follows:

$$\text{Vcl} = 1.0 - \frac{\text{PSP}}{\text{SSP}}$$

where: PSP = SP of shaly formation
SSP = SP of thick, clean sand or carbonate

SSP can also be calculated rather than read from the SP curve:

$$\text{SSP} = -k \times \log\left(\frac{\text{Rmf}}{\text{Rw}}\right)$$

where: k = 60 + (0.133 x Tf)

Resistivity

The use of a resistivity device as a clay indicator is dependant on the contrast of the resistivity response in shale and a clean pay zone. The basic equation is:

$$X = \frac{Rclay}{Rt} \times \frac{Rlimit - Rt}{Rlimit - Rclay}$$

where: Rlimit is the maximum resistivity where clay volume is zero.

If $Rt \le 2Rclay$, then $Vcl = X$
If $Rt > 2Rclay$, then $Vcl = 0.5 \times (2X)^{\{0.67(X+1)\}}$

The resistivity method for Vcl calculations is not always accurate and should be used with discretion.

Neutron

The Neutron response in a formation is primarily a function of the formation hydrogen content. Since shale contains various amounts of water, the neutron porosity in a shaly interval is a function of both shale content and liquid filled effective porosity. Vcl calculations in low porosity zones will be accurate while calculations in higher porosity zones will cause Vcl to be too high. Zones which contain light hydrocarbons will show a volume of shale which is too low.

$$Vcl = \frac{\phi Nlog}{\phi Nclay} \times \frac{\phi Nlog - \phi Nmin}{\phi Nclay - \phi Nmin}$$

where: $\phi Nmin$ = Neutron value where clay volume is zero

Neutron-Density Crossplot

This crossplot relies on the neutron and density response in shale to calculate a Vcl. Calculated shale volumes will be too low in gas-bearing intervals. The clean matrix characteristics (neutron and density values in sand) must be known or assumed. Typically, the density of clean matrix is taken as 2.65 gm/cc and the neutron is about 4% when recorded in limestone porosity units, or 0% when recorded in sandstone units.

Examples of this crossplot are on page 7. The shale and gas effects on the porosity logs are shown on page 7.

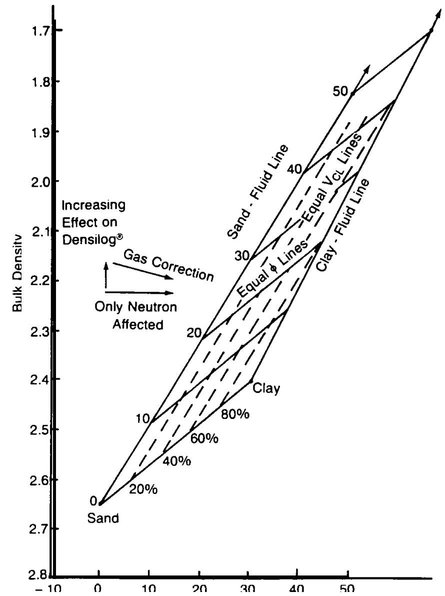
Neutron-Sonic Crossplot

This is not widely used to calculate porosity or clay content in shaly sands because both the sonic and neutron tools are highly affected by clay. When crossplotted, there is very little resolution for either porosity or clay content.

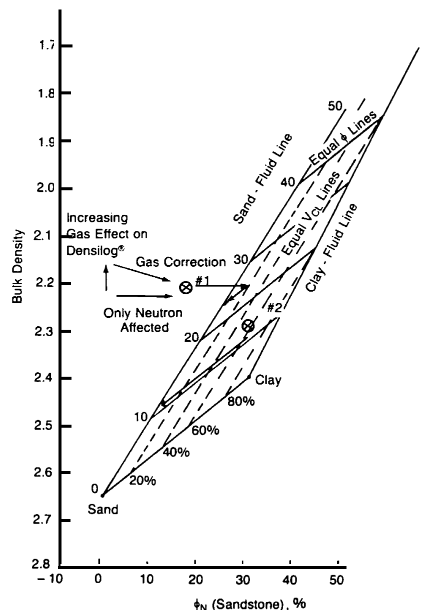
While this crossplot has little use in determining porosity or clay content, it can be used effectively in selecting potential gas zones. Since the sand-fluid and clay-fluid lines are very close points those which are gas bearing will normally fall to the left of the matrix-fluid triangle. See page 8 for examples.

Density-Sonic Crossplot

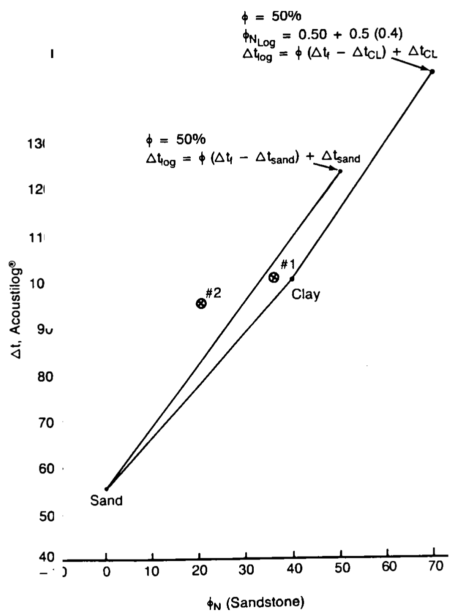
The density-sonic crossplot has the advantage that the lithology lines are close together and a changing lithology will only slightly change calculated shale volumes. Caution should be used in applying this technique to unconsolidated formations



Neutron Density Crossplot



Neutron Density Crossplot: Shale and Gas



Neutron-Sonic Crossplot

Table of Clay Indicators

Clay Indicator	Most Favorable Environment	Unfavorable Environment
Resistivity	Zones having low free water content as in hydrocarbon-bearing zones or low porosity zones.	Porous, water-bearing zones or when clay resistivity is very high.
Spontaneous Potential	Water bearing zones where Rmf and Rw are not similar	Hydrocarbon zones thin beds; high resistivity zones Rmf ≈ Rw
Gamma Ray	When clay is the only radioactive mineral present	When other radioactive minerals not associated with clay are present.
Neutron	Low porosity or very high gas saturation	Medium to high porosity; non gas-bearing zones.
Neutron-Density Crossplot	Simple lithology + clay systems (gas, oil or water-filled if paper zone discrimination is maintained).	Unpredictable changing of lithology and/or gas saturation.
Sonic-Density Crossplot	Low sensitivity to lithology changes makes this a good indicator in most conditions.	Extremely non-compacted formation.
Neutron-Sonic Crossplot	Gas bearing formations with low water saturation	Non-gas bearing formations

After Vcl has been determined, it can then be used to correct the porosity logs for the shale effect. This can either be done graphically with the density, neutron and sonic crossplots (see previous page) or by using the following formulas:

Sonic

$$\phi\text{Sonic} = \left(\frac{\Delta\text{tlog} - \Delta\text{tma}}{\Delta\text{tf} - \Delta\text{tma}} \times \frac{100}{\Delta\text{tsh}}\right) - \text{Vsh}\left(\frac{\Delta\text{tsh} - \Delta\text{tma}}{\Delta\text{tf} - \Delta\text{tma}}\right)$$

where:

ϕSonic	=	Sonic derived porosity corrected for shale
Δtlog	=	Interval transit time of formation
Δtma	=	Interval transit time of matrix
Δtf	=	Interval transit time of fluid (189 for fresh mud and 185 for salt mud)
Δtsh	=	Interval transit time of adjacent shale
Vsh	=	Volume of shale

Density

$$\phi\text{Density} = \left(\frac{\varphi\text{ma} - \varphi\text{b}}{\varphi\text{ma} - \varphi\text{f}}\right) - \text{Vsh}\left(\frac{\varphi\text{ma} - \varphi\text{sh}}{\varphi\text{ma} - \varphi\text{f}}\right)$$

Combination Neutron-Density

$$\phi\text{Ncorr} = \phi\text{N} - \left(\frac{\phi\text{Nclay}}{0.45} \times 0.30 + \text{Vcl}\right)$$

$$\phi\text{Dcorr} = \left(\frac{\phi\text{Dclay}}{0.45} \times 0.13 \times \text{Vcl}\right)$$

$$\phi\text{N-D} = \sqrt{\left(\frac{\phi\text{Ncorr}^2 + \phi\text{Dcorr}^2}{2.0}\right)}$$

Next, after the volume of shale has been calculated and the porosity corrected for Vcl, the water saturation can be calculated. Many shaly sand equations have been proposed, and the selection of a particular equation for a wildcat area is often difficult. Three of the better equations to use are:

- Simandoux
- Modified Simandoux
- Schlumberger Indonesian (Poupon-Leveaux)

Simandoux

$$Sw = \left(\frac{0.4 \times Rw}{\phi^2}\right) \times \left\{-\frac{Vcl}{Rcl} + \left[\left(\frac{Vcl}{Rcl}\right)^2 + 5\left(\frac{\phi^2}{Rt \times Rw}\right)\right]^{0.5}\right\}$$

Modified Simandoux

$$\frac{1}{Rt} = \frac{\phi^m \times Sw^n}{a \times Rw(1 - Vcl)} + \frac{Vcl \times Sw}{Rcl}$$

Schlumberger Indonesian (Poupon-Leveaux)

$$Sw = \left(\frac{1}{A + B}\right)^{2/n} \qquad A = Vcl \times \left(\frac{1 - Vcl}{2}\right) \times \left(\frac{Rt}{Rcl}\right)^{0.5}$$

$$B = \frac{\phi^{m/2}}{a} \times \frac{Rt}{Rw}$$

These three Vcl equations are modifications of the Archie equation. In each case, they require a resistivity value to be chosen as representative of the resistivity of a 100% clay (Rcl), having the same properties as the clay in the zone of interest. With these methods the geologist must make the assumption that the resistivity of an adjacent shale is the same as the resistivity of the shale in the formation, and this assumption is not always correct.

As these are complicated formulae, it is recommended that they be used with a programmable calculator or programmed into a computer.

Two more equations are in general use, the Waxman-Smits and Dual Water Model. The Waxman-Smits model tries to divorce the log analyst from errors associated with the Rcl from adjacent shales; however, it requires extensive coring and core analysis.

The Dual Water Model attempts to incorporate the basic concepts of the Waxman-Smits approach into a general model that does not require core data.

Both of these methods are complex and are best handled by computer analysis.

Comparison of Shaly Sand Equations

Recommending a particular shaly sand equation, especially in wildcat areas, is difficult. If time permits it is advisable to run as many methods as possible and compare results. One obvious way to rate the various methods is to compare Sw values in 100% water zones - the equation that gives Sw's closest to 1.0 is probably best suited to the area.

•Notes•

Quality Control

General Notes On Wireline Logging Procedures

1. When rigged-up, ensure there are suitable signs placed so that no cranes, forklifts, or other vehicles cross any cables.
2. Combination tools are to be made up in the mousehole and not in the well if they are too long to be made up above the closed rams unless the Company Representative gives permission.
3. Downhole “before surveys” to be made where applicable.
4. Make the “repeat section.”
5. Make a sight survey, specifically checking:
   - logging speed
   - tension so not exceed 3000lbs overpull without consulting base. It is preferred to fish by the “strip and cut” method.
6. Check log overlaps with the GR of the previous logs and all GR's are correctly on depth.
7. Check “repeat section” repeats.
8. Record down-hole “after survey” calibration and check that both calibrations are good.

Log Presentations

All scales should have "back-up" scales

Gamma Ray/SP/Induction/Sonic

Track 1:	Gamma Ray/SP (Linear) preferably	On suitable scales SP 15 mV or 10 mV per division GR 0-100 API or 0-150 API
Track 2:	Induction (Logarithmic)	0.2 to 20 Ohms m^2/m with 20 to 2000 Ohms m^2/m Back-up
Track 3:	Sonic (Linear)	140 to 40 MicroSecs Per Foot (single spaced transit times should be presented in the depth track)

Gamma Ray/Density/Neutron

Track 1:	GR/Caliper (Linear)	GR 0-100 API or 0-150 API CAL 6 - 16 inches (or suitable)
Track 2+3:	FDC/CNL (Linear)	CNL: +45 to -15 p.u. FDC: 1.95 to 2.95 g/cc
Track 3:	DELTA RHO/Pe (Linear)	DELTA RHO: -.25 to +.25 Pe: -4.0 to +6.0

Gamma Ray/Dual Laterolog

Track 1:	GR/Caliper	As Above (Linear)
Track 2+3:	DLL/MSFL (Logarithmic)	0.2 TO 2000 Ohm m^2/m

Gamma Ray/Dipmeter

A "tadpole" quicklook print is required. No further wellsite interpretation is necessary.

Tension

Tension only on the1:200, away from data curves.

Calibration

The wireline engineer must have a record of all tools' last calibrations readily accessible and available.

Density and Neutron logs are to be "shop" recalibrated every month.

Rig-up and Survey Checks

1. On bottom
   a. Check depth.
   b. Make repeat section.
   c. Check scales, look for obvious anomalies, check light intensity of film. Check memorization and applied corrections.
   d. Run survey.
2. Surveying
   a. Check lift-off point. Restart if footage is missed.
   b. Check readings to ensure they make sense.
   c. Watch that film canisters are turning.
   d. Make sure Bell remains on depth.
   e. Cable Tension. When using standard weak point on normal cable, this must not exceed 3000 lbs overpull without permission from authority. The weak point is designed to break at about 5000 lbs overpull. Monocable heads (monocables are used when perforating) use weak points with considerably reduced breaking strength.
   f. Logging Speed. See individual tools for maximum speed.
   g. Correlate with previous logs.
   h. Record 100 ft past casing shoe, or overlap with previous logs.
3. After Survey
   a. Check that repeat section "repeats."
   b. Record down-hole calibration after survey, and check that both calibrations are good.
   c. Check that logging speed is correct. Note that the speed is indicated on the film by breaks in the left hand margin of track one. The distance between two breaks is the distance recorded in one minute.
   d. Be satisfied with the log before laying down tools.
   e. Check head, bridle, torpedo, tool for damage as soon as the tool is out of the hole.
   f. Make surface "after survey" calibration.

Induction - Spherically Focused

1. Spontaneous Potential (S.P.)

   a. Scale 10 mV or 15 mV per division

   b. Speed 1800 - 6000 ft/hr (limited by GR requirements).

   c. Calibration - recording not required

   d. Common Faults

      i) Noise. This is frequently caused by welding on the rig, storms, rig generator faults.

      ii) Oscillation. Cause by magnetization of drum, winch chain or spooler.

      iii) Galvo drifts off track. With the above scale, there is no reason why the galvo should be re-set and the log re-run. This problem be spotted during the survey.

   e. Notes
   The SP is rarely used for quantitative analysis. Do not waste too much rig time trying to get it perfect.

2. Spherically Focused Resistivity

   a. Scale Normally Logarithmic 0.2 to 2000 Ohm m^2/m

   b. Speed 3600 to 6000 ft/hr (limited by GR requirements)

   c. Calibration

      i) Standard Logging Unit
      Steps required as noted on calibration tail. Recording before and after survey should match exactly. No shop calibration.

      ii) Computer Service Unit

Zero	*Plus*	*Units*
Before survey 0	500	mmho/m
After survey Tolerance + 2	+ 20	mmho/m

   d. Notes
   Look out for noise “spikes” caused by poor contacts in tool or electrodes, or wear on commutator.

   e. Resistivity Values
   Shale resistivities are variable, and formation water resistivities also vary. In general, as a result of anisotropy, resistivity recorded by the SFL in shales tends to be equal to or slightly higher (x 1.4) than the induction resistivity.

f. Note that SFL cannot be run in oil-base muds

3. Induction Resistivity

a. Scale Logarithmic normally 0.2 to 2000 Ohm-m^2/m.

b. Speed 3600 to 6000 ft/hr (limited by GR requirements)

c. Calibration

i) Standard Logging Unit
Steps required as noted on calibration tail. Calibration before and after survey should match exactly, and the appropriate signals should match the shop calibration.

ii) Computer Service Unit

Zero	*Plus*	*Units*
Before survey 0	500	mmho/m
After survey Tolerance+ 2	+ 20	mmho/m

d. Notes

i) Resistivity Values
Shale resistivities are very variable, but rarely less than 1 ohm-m. Induction will usually read slightly less than SFL or SN as a result of anisotropy.

ii) Ensure that Induction has been correctly memorized.

iii) Induction survey should repeat exactly.

iv) Ensure that 1-1/2” standoffs are used.

4. 4. Gamma Ray

a. Scales
0-100 API (Open and Cased Hole). If recorded value is around 100 API for long intervals the scale may be changed to 0-150 API.

b. Speed 1800 ft/hr Time Constant 2.
3600 ft/hr Time Constant 1.
(Cased hole, for correlation only)

c. Calibration

i) Standard Logging Unit
Before survey calibration only required. This includes zeros, memorizer sensitivity check, background and calibration.

ii) Computer Service Unit
Zero: O Plus: 165 API units

d. Notes

i) Check that GR is correctly memorized, to be on depth with main simultaneous survey.

ii) Check for cross-talk with other pulsed tools.

iii) Reject a survey with spurious, random peaks or zero readings.

iv) Clean, porous sections have a GR background reading around 10 API. Shales exhibit values around 80 API

v) Repeat will not be exact, as a result of statistical variations,

e. Depth Control for Perforating
When surveying with Casing Collar Log (CCL) for perforating depth control, 200 ft repeat run should include 100 ft CCL depth corrections, 100 ft without.

Log heading must include tool type and CCL and radioactivity tool measure points. State clearly whether CCL or the correlation log is on depth. If memorization or optical correction is applied so that both the CCL and the recorded log are on depth, this should be stated, along with the amount of correction applied. Ensure that panel settings relevant to tool response are noted on the heading.

Spooler adjustment is permissible during depth control logging, but must be limited to 0.5 ft/100 ft per survey.

Microtools

1. 1.Micro-SFL (MSFL)
   a. Scale Logarithmic 0.2 to 2000 ohm-m^2/m.
   b. Speed 2000 to 3000 (max) ft/hr
   c. Calibration
      i) Standard Logging Unit
      Calibration before and after survey should match exactly. Check low reading (2 ohm-m) and high reading (1000 ohm-m).
      ii) Computer Service Unit

Zero	*Plus*	*Units*
Before Survey: 0	100	mmho-m
After Survey Tolerance: + 2	+ 20	mmho-m

2. Proximity Log
   a. Scale Logarithmic 0.2 to 2000 ohm-m^2/m.
   b. Speed 2000 to 3000(max) ft/hr
   c. Calibration
   Calibration before and after survey should match exactly, except 1000 ohm-m signals may not be very stable and may drift between 750 and 1050. This need not cause concern.
   d. Notes
   The survey can be run with cartridge in “Microlaterolog” position. This results in survey with resistivities too low (x 1.65 to get true reading). In water-bearing zones a good rule of thumb is that Rprox is approximately ten times R at Bottom Hole Temperature. Rprox may increase significantly in hydrocarbon bearing zones to over 10 ohm-m.

3. Microlaterolog
   As for Proximity, except the most common fault is running this log with the cartridge in “Proximity” position. This results in a survey with resistivities too high (x 0.6 to get true reading).
4. Microlog
   a. Scale 0 to 10 ohm-m^2/m
   b. Speed 2000 to 3000(max) ft/hr
   c. Calibration
   Calibration before and after survey should match exactly.

d. Notes

i) Reject a survey with negative readings.

ii) One or both resistivity curves may read incorrectly - often caused by faulty pad wiring.

General Comments

i) Pad tools will rarely repeat exactly but any discrepancy between runs should be minor. If in doubt, ask for extra repeats. In any case, check condition of pads before and after the survey.

ii) Always make a short piece of film into the foot of the casing, and check the resistivity readings and caliper.

iii) Always run caliper with Microtools as it is essential for interpretation.

Dual Laterolog

1. Scale Normally 0.2 to 2000 ohm-m^2/m (logarithmic)

2. Speed 3600 to 5000 (max) ft/hr (limited by speed of MSFL or GR when run in combination)

3. Calibration

a. Standard Logging Unit
Calibration recorded downhole before and after survey should match exactly. Crucial reading is 31.6 ohm-m (last step).

b. Computer Service Unit

	Zero	*Plus*	*Units*
Before Survey			
LLD/LLS	0	31.6	ohm-m
After Survey Tolerance			
LLD/LLS	+ 0.1	+ 2%	ohm-m

c. Notes

i) Ensure that memorization depth is correct (curves on depth).

ii) In water-bearing zones, laterologs are affected by invasion, particularly if Rmf > Rw. In oil zones, RLLD may increase to 500 or 1000 ohm-m.

Dual Induction Laterolog

1. Scales normally 0.2 to 2000 ohm-m^2/m (logarithmic)
2. Speed 3600 to 6000 ft/hr (limited by GR requirements).
3. Calibration
   a. Standard Logging Unit
   Recording before and after survey should correspond exactly, and the appropriate signals should match the shop calibration.

   b. Computer Service Unit

	Zero	*Plus*	*Units*
Before Survey			
Induction	0	500	mmho
Laterolog	0	2	ohm-m
After Survey			
Induction	+ 2	+ 20	mmho
Laterolog	+ 0.1	+ 2%	ohm-m

   c. Notes
      i) Resistivity Values
      Shale resistivities are very variable, but rarely less than 1 ohm-m. Induction will usually read slightly less than laterolog in shales as a result of anisotropy. Water-bearing sands have a resistivity around 1.2 to 2.0 ohm-m.
      ii) Ensure that induction curves have been correctly memorized.
      iii) Check that resistivity readings are in the order Deep Induction/Shallow Induction/Laterolog (either increasing or decreasing).
      iv) Repeat should be exact.
      v) Ensure that 1-1/2” standoffs are used.

Density (Compensated)

1. Scales Bulk Density: 1.95 to 2.95 g/cc (or as requested).
   Correction: -0.25 to + 0.25 g/cc (Track 3)

2. Speed 1800 ft/hr (Time Constant 2)

3. Calibration

   a. Standard Logging Unit
   Before and after survey calibration checks of response of long and short spacing detectors should be as closely identical as statistical variations on calibrate time constant will allow. Shop (master) calibration should be less than one month old. Checks include panel computation. Calibration film readings should correspond with legend on calibration tail, and observed count rates during calibration should match shop-recorded counts within 5%.

   b. Computer Service Unit
   Before survey calibration format is as follows:

	JIG		
Block Calibrated	*Measured*	*Calibrated*	*Units*
FFDC	336	336 (+)	CPS
NFDC	527	527 (+)	CPS

The numbers in the 'Block Calibrated' column are constant and an integral part of the calibration software.

The “Jig Measured” values are the actual count rates measured by the tool with the calibration jig in place and should match the count rates noted on the master (shop) calibration when the block is in place.

The 'Jig Calibration' numbers are normalized count rates after the computer has applied appropriate calibration factors, and they should be close to the numbers in the first column (Block Calibrated).

	JIG		
Before	*After*	*Units*	*(Tolerance)*
FFDC 336 (+)	(336)	CPS	+ 14
NFDC527 (+)	(527)	CPS	+ 22

“Jig Before” values are precisely those recorded during the before survey calibration as “Jig Calibration.”

“Jig After” are the count rates from the jig corrected by the same factor as used by the computer thought the survey:

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they should be very close to the "Jig Before" readings, with a tolerance as noted in the last column.

4. Notes

   a. Correction
   Unless the mud weight is excessive, correction magnitude is close to zero. Treat any survey with significant (0.05 g/cc) and fairly constant correction in porous intervals with suspicion.

   b. Repeat
   Repeat Section will not match main survey exactly, but differences should be within statistical variation.

   c. Check survey against logs from nearby wells, if possible. Cross-plot density and neutron readings on appropriate company charts. In clean, water-bearing sands the cross-plotted points should lie along or close to the standard sandstone line. Hydrocarbon bearing points will plot to the North-West of the standard line, gas-bearing intervals even further away. Shales tend to throw the cross-plotted points to the South East of the standard sandstones line: in general, any intervals which plot to the SE of the standard limestone line are probably too shaly and impermeable to be classified as reservoir rock.

   d. Recording of caliper is essential for interpretation

   e. Record tension on 1:200 throughout survey.

   f. Observe all safety precautions relating to handling and use of radioactive sources.

Neutron (Compensated)

1. Scale -15 to +15 (-15 to +45 porosity when run with density) or as requested.
2. Speed 1800 ft/hr, Time Constant = 2
3. Calibration
   a. Standard Logging Unit
   Before and after response should be as closely identical as statistical variation on calibration time constant will allow. Shop (Master) calibration should be less than 1 month old. Count rate deflection should match master calibration with jig. Porosity should be 18%. Ratio should match within + 0.04. Checks also include panel computation. After survey calibration should be left attached to main survey. Ensure that the memorizer sensitivity adjustment is recorded during panel test.
   b. Computer Service Unit

		Zero	*Plus*
Before survey	NRAT	0	2.16 (+ .01)
After survey		2.16	+ 0.04

   During calibration the calibrating box must be at least two feet away from any solid object.

4. Notes
   a. Check that hole size correction switch is properly set.
   b. Check that correct time constant (2) is being used.
   c. Check that memorization depth is accurate.
   d. Check for cross-talk.
   e. Erroneous readings. Ensure that repeat section and main survey are basically identical. Then check against logs in nearby wells.

   Cross plot neutron against density. In clean water-bearing sands the cross-plotted points should lie along or close to the standard sandstone line. The neutron reads too low porosity in hydrocarbon-bearing intervals, very low in gas-bearing intervals: points from hydrocarbon zones plot to the North-West of the standard sandstone line. Shales tend to throw points to the South-East of the standard line, as the neutron responds to bound water in the shales, whose density is almost the same as sandstone and, therefore, does not affect the density tool. In general, any cross-plotted points which fall to the South East of the standard limestone line are probably too shaly and impermeable to be classified as reservoir rock.

f. Recording of caliper is essential to interpretation of CNL when surveyed in open hole. The CNL normally makes use of the FDC caliper. When CNL is recorded alone, a specially modified FDC caliper is run for this purpose.

g. Record tension on 1:200 scale.

h. Observe all safety precautions relating to handling and use of radioactive sources.

Acoustic (Borehole Compensated)

1. Scales: 40-90-140 microsecs (run alone)
   40-140 microsecs single track (in combination)
   or as requested.

2. Speed: 3000 to 4000(max) ft/hr
   (limited by GR when run in combination)

3. Calibration

a. Standard Logging Unit
Downhole calibration before and after survey should match exactly. Calibration signals are 40, 60, 80, 100 and 140 microsecs. If integrated time is recorded, a check must be made with 100 microsec and 50 microsec signals for at least 10 pulses/signal.

b. Computer Service Unit
No calibration recorded
N.B. Sonic equipment is not calibrated (in the accepted sense of the term) by feeding a known signal into the down-hole circuitry and adjusting the recording equipment to give a standard output. Sonic calibration involves normalization against time signals from a quartz - controlled clock, and can be effected with the down-hole equipment disconnected. Only check of correct operation of the sound velocity recording system is the travel time in steel casing which is 57 microsecs/ft.

c. Notes
Do not accept a survey with excessive cycle skips, which are long, thin “pips” caused by serve signal attenuation. The “pips” may be on either side of the correct reading. Occasional cycle skips are no great disadvantage, but since they can

normally be prevented by a slight surface adjustment they should be kept to a minimum, particularly in reservoir sections. If cycle skips cannot be manipulated by panel adjustment, two other courses are possible:

i) Re-polarize the sonde

ii) Ensure that centralizers are in good condition. Although cycle skipping it usually recognized in the form of “pips,” it must be remembered that under appropriate conditions several feet of survey can be recorded with the wrong Δt. This situation does not frequently arise but the possibility should be borne in mind.

d. Repeat will be exact, except for cycle skips.

e. Caliper is not normally required with BHC Acoustic

f. Sonic requires good centralization.

g. Integrated Travel Time should always be recorded.

h. A short section must be run in casing to check correct Δt which should be 57 microsecs/ft.

i. Ensure that trigger level is set manually by the Wireline Engineer, not automatically by the equipment.

Dipmeter/Diplog

1. Scales
   Resistivity scale selection is based on the principle that curves have sample variation, without saturation, Scales may be changed during the course of the operation.
   Caliper scales normally 6 - 16 inch, may be changed to suit hole size.

Deviation	0 - 9 (vertical wells) 9 divs. Track 1	
	0 - 36 (deviated wells)	
	0 - 72 (highly deviated wells)	
Azimuth	0 - 360	9 divs. Track 1
Relative Bearing	0 - 360	9 divs. Track 1

2. Speed 2400 ft/hr maximum
3. Calibration
   Before survey only. After panel calibration has been recorded, a check is made of:
   a. Caliper calibration
   b. Deviation
   c. Azimuth and Relative Bearing correct and tracking.
   d. Pads connected correctly, and no cross-talk.
4. Notes
   a. This is one of the easiest tools of all to ensure that the survey is good.
      Caliper
      Inside casing, both calipers should be virtually identical and equal to I.D. of casing. Over limestone/sandstone intervals calipers should be similar and about bit size. In shales the calipers may be considerably different, depending on the ovality of the hole. Calipers with stairsteps are not acceptable. The angle of dip will vary considerably depending on hole size. An accurate caliper is essential for accurate interpretation.

      If one caliper indicates very large hole, one or both resistivity curves associated with that caliper may appear “dead.” This is simply because the pad is not against the hole wall, and there is not much that can be done about it.
      Resistivity
      Resistivity curves will all indicate about the same deflection from zero at the same depth, and they should all be “lively”

without too much saturation. Scales can be changed while logging without affecting the value of the survey. A mechanical zero shift is unimportant. If one or more curves go “dead,” check the hole size from the corresponding caliper. If the hole is too big, the pads may not be touching the wall.

Angles

First check the deviation (solid trace). This should agree with the deviation recorded from surveys made while drilling. The curve is quite smooth, since it has a long time constant, but it will be affected by changes in resistivity scale. This need not cause concern, as rapid variations are discounted in interpretation. Note where deviation is less than 0.5^o, since this will affect the behavior of the Relation Bearing.

Next, check the Azimuth (solid trace). As a result of the cable characteristics, the tool rotates clockwise as it is pulled from the hole. When a low-angle dipmeter cartridge is used, the azimuth of #1 electrode moves from 1 division of track 1 to the right hand edge of track 1, then jumps back to repeat the movement as the tool rotates. In oval hole the tool may even rotate counter-clockwise a few degrees. Again look out for stair-steps (sudden changes of azimuth followed by constant readings, a series of “steps”) as the tool rotates. Reject a survey with “steps” in the Azimuth reading. However, in high-angle cartridges the tool registers the actual hole azimuth, which is relatively constant and changes only when the orientation of hole deviation changes. In this case long sections of constant azimuth, followed by a fairly rapid change, may be quite normal.

Finally, check the Relative Bearing (dotted trace).

If the deviation is less than 0.5^o, the relative bearing may wander indiscriminately over Track 1.

With deviation greater than 0.5^o, in the low-angle cartridge, the relative bearing behaves like the azimuth, with a separation which depends on the direction of the hole deviation. Consequently, the relative bearing and azimuth “track” together until the hole deviation changes direction (infrequently in most holes). Again, look out for “stair-steps” which indicate mechanical problems in the relative bearing mechanism.

The relative bearing when a high-angle cartridge is in use may rotate independently of the azimuth. Note that an oval hole may prevent rotation, making the relative bearing almost constant.

b. Avoid sudden changes in cable tension with dipmeter: torque induced in the cable may not be able to release, and a birdcage in the cable will result.

c. Dipmeter requires good centralization.

Caliper

1. Scale Bit size - 2 in. to Bit size +8 in.
2. Speed As for other logging tools.
3. Calibration
   Record settings for 8" and 12" rings before survey.
4. Notes
   a. Stairsteps.
      Caliper does not move smoothly, but jumps from one reading to the next. A log with this defect should be rejected.
   b. Erroneous readings.
      Checks: In production intervals hole diameter should be bit size minus up to 1" for filter cake. In tight intervals hole diameter should be bit size. Best check is the I.D. of casing.
   c. SFL, or Microlaterolog caliper, is a two-arm device with very low pad force and soft pads. This caliper will follow the largest diameter hole (in the case of oval hole), but reduce by twice the mud cake thickness.

      FDC Caliper is a two-arm caliper with high pad force and steel pad and back-up shoe. This caliper will also follow the greatest diameter, reduced by filter cake thickness since the backup shoe is assumed to cut through the filter cake and press against the formation.

      Sonic and CDM (three-arm dipmeter) caliper are both three-armed calipers with moderate arm force. This device reads the smallest diameter of all, since it averages the hole size reduced by twice the filter cake thickness. These calipers are no longer used.

      The four-arm dipmeter has a four-arm caliper which gives two independent orthogonal readings of hole diameter. Pad force is extremely high, and the reading will be affected very little by filter cake.

      BGT (Borehole Geometry Tool) is a four-arm caliper similar to Dipmeter Tool, giving two independent orthogonal readings of hole diameter, reduced by mud-cake. The BGT can also be used to determine the magnitude and direction of hole deviation.

Note: The BGT includes a Hole Volume Integrator, but remember that the integrated volume may be severely underestimated.

•Notes•

Special Logs

Dipmeter

The Dipmeter logging tool has been used since the 1930's. Used in exploration, the tool helps to locate and identify geologic structures that serve as traps. As techniques became more refined and interpretation more accurate, wireline companies are applying dipmeter information to describe internal lithological features that illustrate the sedimentological processes responsible for them. Several books are available (Schlumberger and Western Atlas) which illustrate how dipmeter information can help interpret depositional environments.

The high sampling density (60 readings per foot of borehole depth) makes the dipmeter invaluable in supplying detailed information on the sedimentary structures adjacent to the borehole.

The dipmeter's primary function is to obtain data on the inclination and azimuth of bedding planes. In addition, the tool provides measurements of borehole geometry and borehole shape.

The Dipmeter Tool

The arms of the dipmeter have pads containing several electrodes which measure the conductivity of the formation. Assuming geologic features are continuous across the space of the borehole, those features should show up in each record of measurement.

The dipmeter measures conductivity simultaneously at four points spaced 90^{o} apart around the borehole; the parallel tracks of the measurements to be correlated are, therefore, no more than a few inches apart. Vertically, measurements are taken sixty times per foot (0.2 inches apart).

There are usually five identical microconductivity electrodes mounted on four to eight equally spaced pads (two electrodes share one of the pads). Three electrodes would be enough to define a dipping plane. The fourth provides redundancy in the computation. The fifth electrode adds a correction term for variation in tool velocity.

These microconductivity electrodes are small enough to resolve structures with linear dimensions down to about 1-2 cm. Water-based muds give the best electrical contact for the pads. For non-conductive borehole fluids, special “knife-blade” electrodes must be used to provide the contact with the formations.

The tool's caliper arms are actuated hydraulically from the surface. They are collapsed when lowered into the hole and extended when the tool is drawn up for logging. A sufficient force maintains contact with the borehole under most conditions. Caliper geometry keeps the four electrode pads in a plane normal to the tool axis.

Dipmeter logs are not used as conductivity logs because dipmeter correlations depend on variations in conductivity (the circuitry is arranged to preserve all details at the expense of absolute calibration). As such, the log shows an output from each pad on a “floating zero” format with a nonlinear scale designed to accommodate large variations in conductivity. It is important that the instantaneous velocity of the tool be known throughout the logging run. The surface cable speed may not reflect the tool velocity accurately, because of variations in cable tension, and a correction is necessary. The fifth electrode (known as the “speed button”) provides this correction.

The curve recorded by the upper electrode on a pad should correlate with the curve recorded by the electrode mounted below it to yield a displacement equal to their separation. However, if the instantaneous tool velocity varies from the surface cable speed, this apparent displacement will also vary. The ratio of apparent displacement to the distance between electrodes is the speed correction factor for curve displacements. Corrections factors range from 1/2 to 2.

Without knowing the orientation of the tool in space, the only item that can be determined is the apparent dip (the slope of a geologic feature relative to the plane defined by the four conductivity pads). To measure this angle against true dip, three angles must be measured:

- Borehole inclination
- Azimuth from magnetic north.
- Hole-drift azimuth.

Borehole inclination and the first of the two azimuths can be measured directly. A “relative bearing” measurement is also made (the angular rotation, about the axis of the tool, of electrode No. 1 from the upper generatrix of the hole), and it is from this angle that the second azimuth is computed.

Dipmeter Calculations

Each movement on the output curves (neglecting noise) is considered to be the signature of a geologic event. Each event is usually recognized in each of the curves, but not necessarily at the same depth, because geologic features do not generally lie in a plane parallel to that of the four electrodes. By measuring the displacement of the event between each of the four curves and applying trigonometry, the dip angle for that feature relative to the plane of the electrodes can be obtained. Knowing the hole deviation and the azimuth of the #1 electrode, that dip angle can be converted to true dip relative to the horizontal and magnetic north.

Log Presentations

Wireline companies have their own processing system to produce various output presentations. However, similar to each is the “arrow” or “tadpole” plot. The arrows consisting of dots positioned horizontally to illustrate the angle of dip and vertically to show depth. A headless arrow indicates the direction of dip, with north at the top. A numerical printout of dip angles and measured and computed data usually accompany each log.

In addition to arrow plots, each company has a selection of other graphic presentations that assist interpretation of the data. Common names are azimuth frequency diagrams, stick plots, Modified Schmidt plots, SCAT plots (Western Atlas) and GEODIP (Schlumberger).

Problems with Dipmeter Interpretation

The most common parameter which interferes with dipmeter reading is collectively known “noise.” Borehole noise due to wall rougosity, fracturing or uneven filter cake thickness (the worst problem). Another problem is geologic noise, resulting from lack of integrity in the bedding planes across the few centimeters of borehole diameter (causing the plane not to be detected by all the electrodes). Electronic noise in the sensors, cable and recorder is never entirely eliminated, though this is usually less pronounced than the other two noises.

The validity of each reading is tested in several ways. If displacements are determined between each adjacent pair of curves taken cyclically (1-2,2-3,3-4,4-1) they should have an algebraic sum of zero. This condition is known as “perfect closure.” Lack of closure, or “closure error,” indicates a problems in the data.

Closure Closure error is defined as the ratio of the distance by which the traverse fails to close to the sum of all the displacements in the traverse.

Planarity Planarity is the condition where four points should define a plane. After four displacements have been calculated, the lines joining diametrically opposed electrodes will fail to intersect if there is an anomaly in the calculation or the bedding.

The geometry of the pads ensures that the distance between the four pads remains equal. Displacements computed from opposite pairs of curves must be equal, but opposite if the bedding surface is planar.

Likeness Likeness is the quality illustrating the similarity of the curves. A correlation function computes a coefficient of 1 when two curves are identical and 0 when completely dissimilar. (A coefficient of -1 would be computed if a curve were compared with its mirror image.) The highest correlation coefficient computed over the search interval is the “likeness” of the two curves.

Despite these tests, the dipmeter sometimes shows excessive scatter that is not of geologic origin, particularly when shorter correlation lengths are selected in order to gain resolution. An additional drawback is that by using a constant correlation interval, the program ignores natural variations in the density of geologic data.

Selecting Dipmeter Computation Parameters at the Wellsite

The primary tool used for geological interpretation is the computed dipmeter, obtained from the computing center of the wireline company after the well has been drilled. The computed results rely heavily on the wellsite geologist’s input to the wireline engineer at the wellsite, because the engineer must decide on three vital parameters which will be used in the dipmeter computation, namely:

- correlation interval
- step distance
- search angle

It is, therefore, important that the wellsite geologist be familiar with what these parameters are and how they affect the computed results.

The Schlumberger programs for dip computation are CLUSTER and GEODIP, the Dresser programs are DIPLOG and STRATADIP. CLUSTER and DIPLOG are the programs used over gross intervals and require the input of correlation interval, step distance and search angle; while GEODIP and STRATADIP are specialized processings used to define small sedimentary units and do not need the above inputs.

Correlation Interval
The correlation interval refers to the length of the reference curve used when matching each pair of resistivity curves from the 4 arm dipmeter. It can be varied from 1 to 20 feet and the wellsite geologist must choose this value. The choice depends in the application of the dipmeter results. Are they looking for structural or stratigraphic dip?

1. Structural Dip Applications
   If structural dip is of primary concern, a longer correlation interval is chosen, usually from 8 to 15 feet. It should be noted that using a longer interval does not produce the same results as averaging shorter intervals unless a very large number of shorter intervals are taken.

   This is due to the fact that a longer interval takes in a much larger number of resistivity features, which include both structural and stratigraphic features. If these two groups are at variance in dip, they will produce two or more peaks in the correlogram. As the correlation interval is increased, the structural features increase in number. With stratigraphic features their effect is to reinforce each other on the correlogram until the peak shifts to the structural correlation interval and tends to completely bypass the stratigraphic features. If, however, the interval chosen is too long, certain localized structural features such as faults can be lost.

2. Stratigraphic Dip Applications
   Stratigraphic features commonly cause major resistivity breaks which tend to control correlograms on short localized intervals (since we are looking for localized features and have to use short correlation intervals).

   The normal correlation interval used when looking for stratigraphic dips is three feet, but as little as one foot can be used. There is no lower limit at which a curve cannot contain enough identifiable characters to be matched with another curve of similar character, but it is unusual to use a correlation interval of less than one foot.

   The major drawback in using a small correlation interval is that it tends to find correlations on “borehole accidents” such as caliper changes, rugosity, etc., and interpretation can be difficult.

Step Distance

Step distance is the distance between the center points of consecutive correlation intervals. If two consecutive correlation intervals are taken, there will be no overlap on the reference curve. Overlap tends to smooth out the results, but it can cause some problems, namely:

1. A given resistivity feature may control two or more adjacent correlations, which can have the misleading effect of giving consistent consecutive dips.

2. In flat, wide correlograms too large an overlap may tend to shift the peak gradually, causing a slow change in dip angle or azimuth.

Overall, for structural dip, an overlap of up to 50% of the correlation interval should be used, and for stratigraphic interpretation, zero overlap is probably best.

Search Angle
This is the maximum value of shift between curve pairs, expressed as an angle, and is applied in both up and downhole directions. In other words, it expresses how far (an angle) one looks for a match between the two sets of resistivity curves.

Increasing the search angle vastly increases the search distance, and this can cause problems if the resistivity curves lack character or are dissimilar because the program will tend to find accidental correlations. At high search angles (over about 70 ^{o}), the extremity of the search distance approaches infinity; therefore, statistically there is a better chance of finding an accidental dip.

When logging deviated holes, the problems of finding accidental dips is aggravated since the search distances becomes very long in the drift direction. Also, curve similarity deteriorates due to:

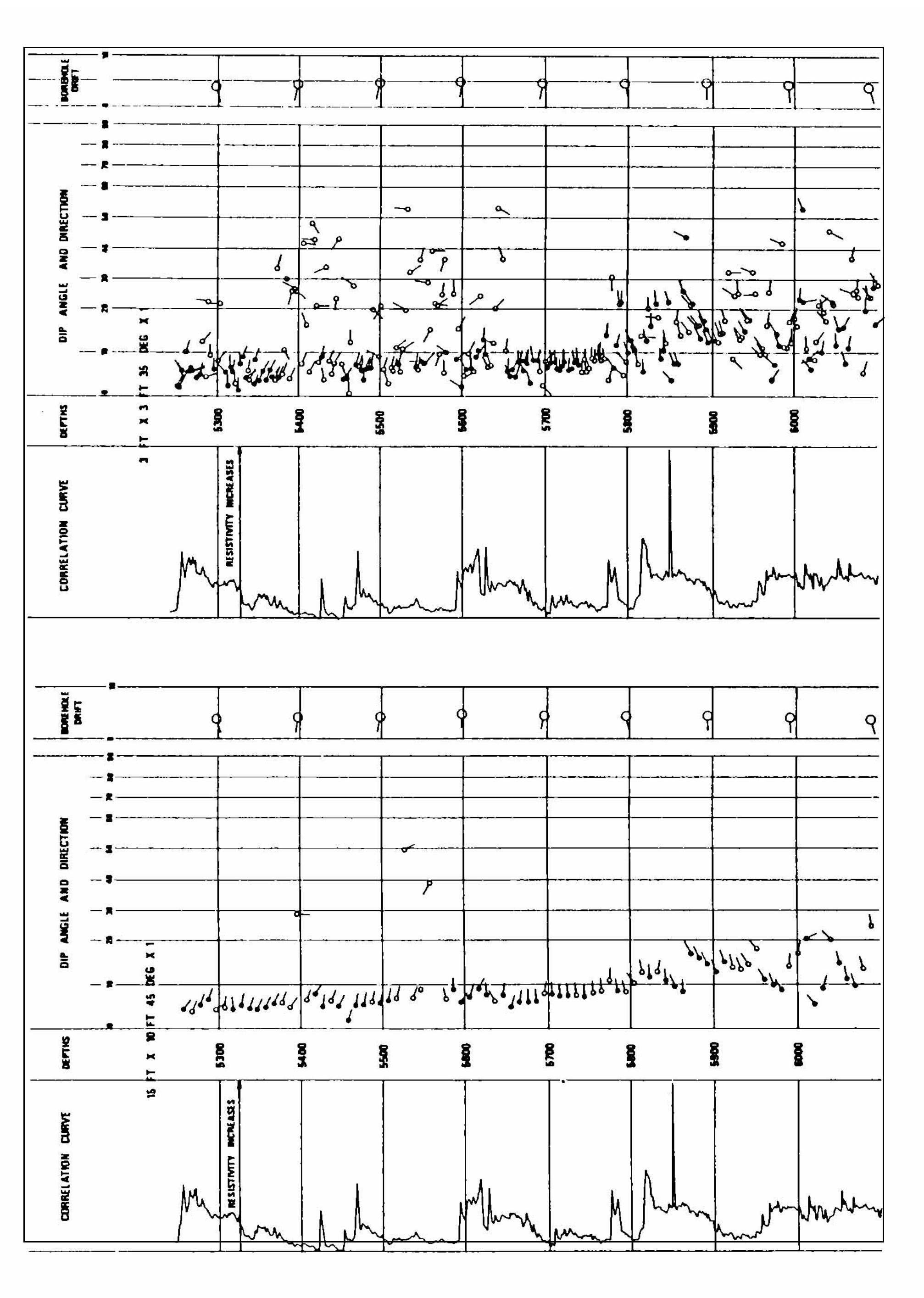
1. poor pad application
2. curve distortion due to current penetration
3. tendency towards rugosity in deviated holes
4. tool sticking

Search angle should be chosen to be about 15^{o} greater than expected dip when looking for structural dip and about 30^{o} greater than expected dip when looking for stratigraphic dip. Deviated holes will limit effective angle due to unreliability of results.

Dipmeter Tools - Summary

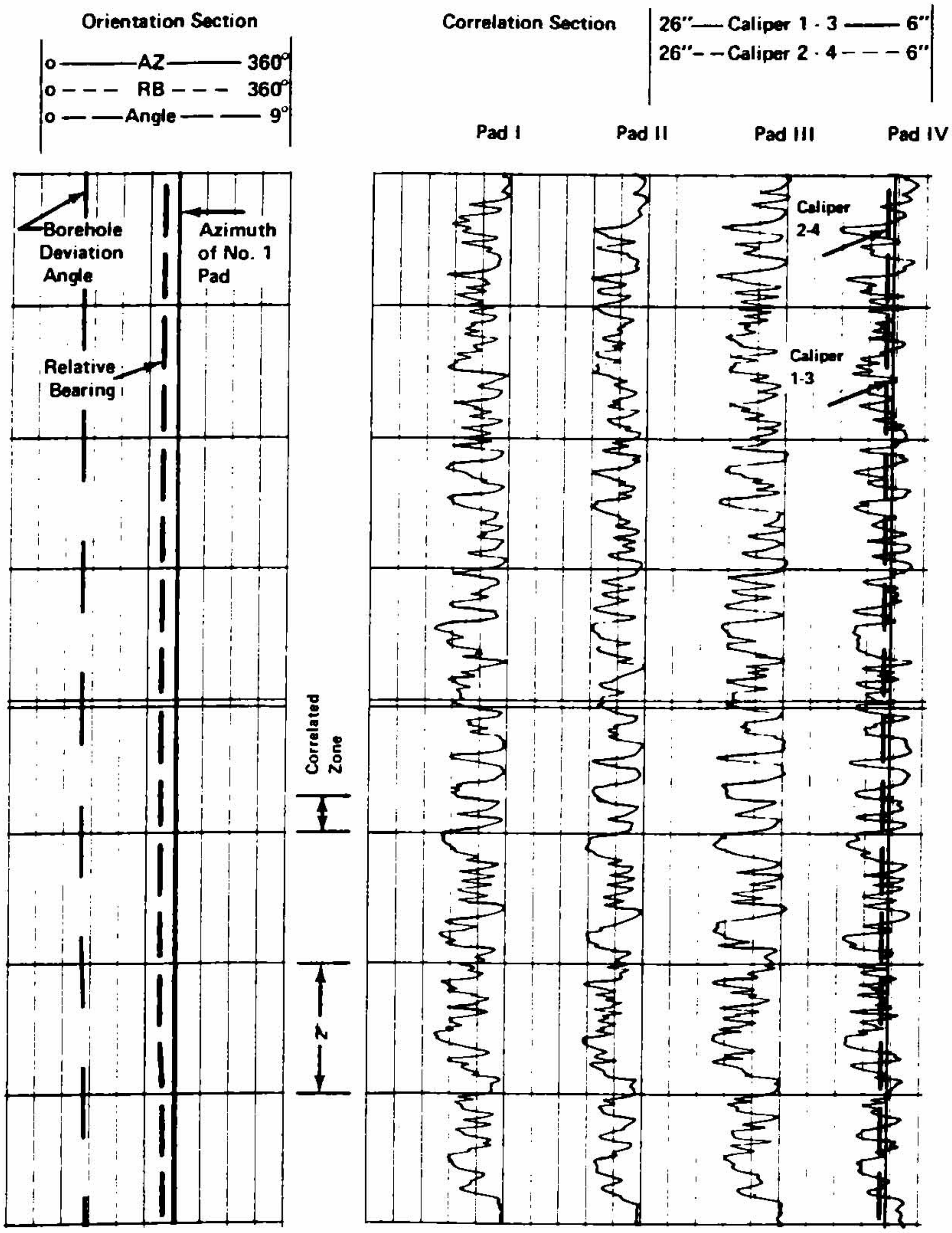
- *Schlumberger*: HDT (High Resolution Dipmeter)
- *Western Atlas*: HRDIP (High Resolution 4-Arm Diplog)

The dipmeter is 4-arm wall contact logging tool designed to detect changes in resistivity. Data is obtained from very short spaced focused electrodes in pads designed to maintain uniform contact with the borehole wall. The tool's orientation in space is recorded as well as the measurements from borehole wall. Similar electrical responses form all electrodes can be correlated and their relative position in space established in order to compute dips in the well. A large number of readings are competed over a given interval so that spurious values can be statistically eliminated.



Log #1

LOG # 2


Orientation Section
o AZ 360°
o RB 360°
o Angle 9°
Borehole Deviation Angle
Azimuth of No. 1 Pad
Relative Bearing
Correlated Zone
Correlation Section
26" Caliper 1 - 3 6"
26" Caliper 2 - 4 6"
Pad I
Pad II
Pad III
Pad IV
Caliper 2-4
Caliper 1-3

Wireline Formation Tester

- *Schlumberger*: FIT (Formation Interval Tester)
  RFT (Repeat Formation Tester)
- *Western Atlas*: FMT (Formation Tester)
  FMT (Formation Multi-Tester)

These tools are designed to recover fluid samples from formations and to measure hydrostatic pressures within those formations.

The FIT of Schlumberger and the Formation Tester of Western Atlas are used to take one pressure reading and a fluid sample on each trip into the hole. Sampling is by means of shaped-charge perforators; thus it can be used in open or cased holes.

Tool Description

The general configuration of the repeat formation tester (RFT) consists of control panels in the truck, a down-hole electronic cartridge, a mechanical unit and sample chambers.

The setting section of the mechanical unit is shown in Figure 10-1. The packer assembly and backup shoes are either in the extended (set) or retracted (running) positions. The small area-wall contact points minimize differential sticking that has troubled earlier tools. Actuation is by means of a hydraulic power system in the mechanical unit, which may be energized on command from the surface to control the setting and retracting of the packer assembly and backup shoe, as well as all valving functions.

The pretest function, incorporated in the mechanical unit, permits the operating engineer to ascertain that the packer is sealing properly and that fluid flow is adequate to obtain a sample in a reasonable period of time. Shown schematically in Figure 10-2, a small pretest chamber with a 15-cc volume is located between the packer and the valves leading to the sample chambers. When the packer is set, the equalizing valve closes and the chamber is opened, resulting in one of three possible pressure responses: an indication of mud pressure if the seal is lost (Figure 10-3a); a very low pressure if the packer is seated on an impermeable zone (Figure 10-3b); or a pressure decrease followed by a buildup to formation pressure if the tool is in a permeable zone (Figure 10-3c).

Since the volume of the pretest chamber is known, the rate of fillup provides and indication of the time that would be required to fill one of the

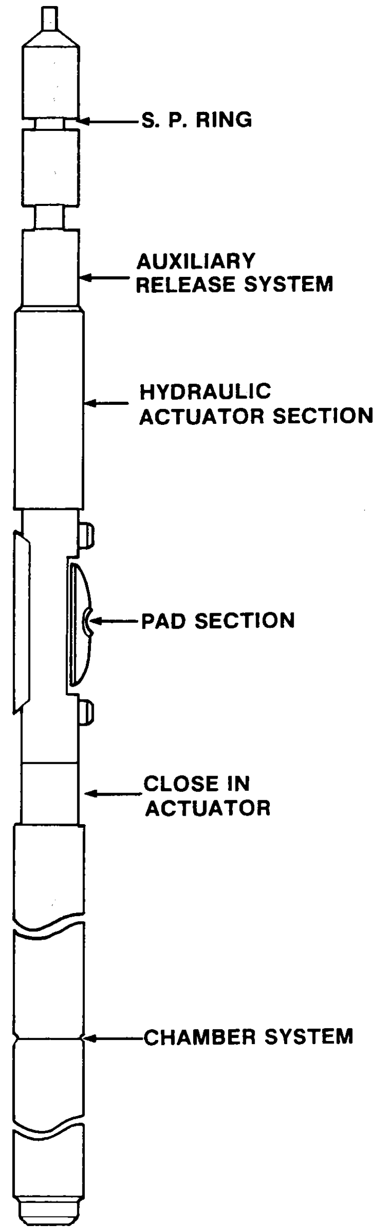


Figure 10-1: Figure 10-1: The RFT mechanical unit.

larger sample chambers located below the seal valves (Figure 10-2). If all pretest indications are satisfactory, one of the seal valves is opened to allow fluid to enter a sample chamber. These valves may be closed and reopened at any time during the test to obtain a pressure buildup measurement.

If the pretest indications are negative, the tool is simply retracted. In this event, the pretest chamber is emptied automatically, and the equalizing valve is opened as the tester is retracted.

A probe, which can be seen protruding from the center of the packer in Figure 10-1, improves testing across a broad range of formations. The probe is equipped with a filter to restrict flow of loose sand. Figure 10-4 illustrates the probe forced part way through the mud cake. A piston is then retracted, exposing the tubular filter to the formation fluids. If the formation is unconsolidated, sand flows into the probe, but further movement is restrained by the filter. Concurrently, the probe moves into the formation to occupy the void produced by the flowing sand to avoid undermining the packer seal and subsequent failure. If the formation is consolidated, the probe does not penetrate the formation and only mud cake and formation fluid flow into the hollow cavity of the probe.

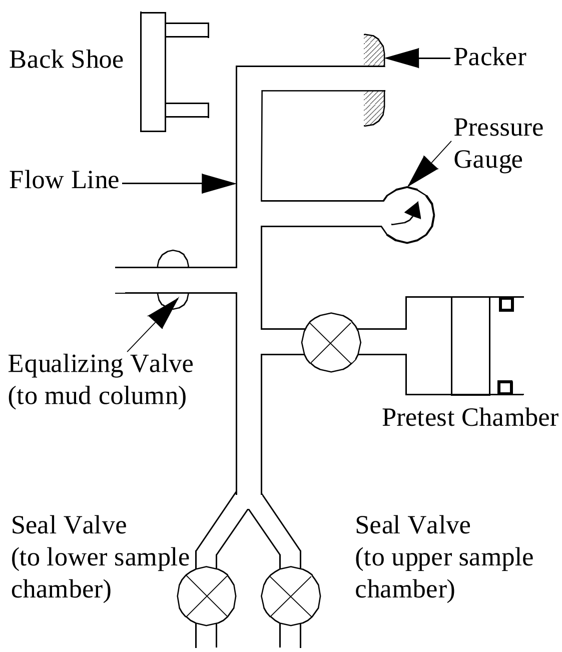
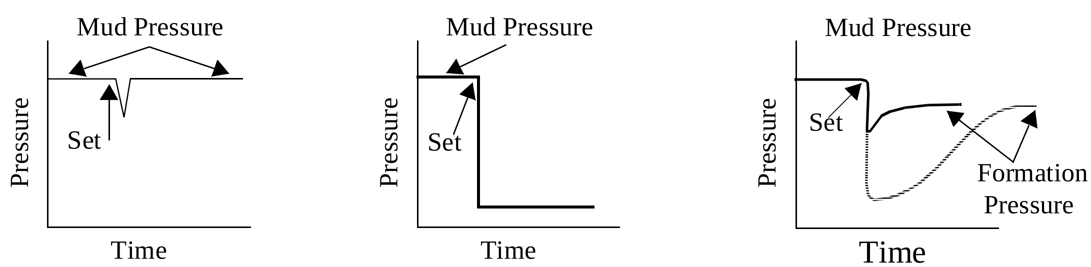


Figure 10-2: Figure 10-2: Functional schematic of RFT sampling system.



Mud pressure after set indicates packer seal failure.

Very low pressure after set indicates no flow from formation-impervious streak.

Good seal indicated. Solid line reflects good flow rate; dashed line, tight.

Figure 10-3: Figure 10-3: Pretest indications

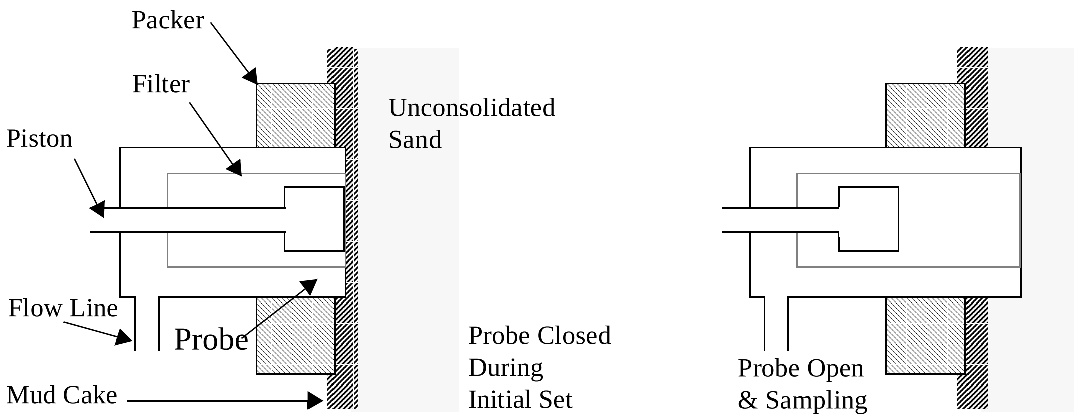


Figure 10-4: Figure 10-4: Packer Filter-Probe Assembly

When the tool is retracted, the piston within the probe moves back into closed position in preparation for another test, wiping the filter clean in the process. Cleaning the filter is important when there are multiple-set operations.

A strain-gauge transducer is used to achieve accurate pressure measurements of high resolution and good repeatability. A direct digital pressure readout is provided on the control panel in the truck, with simultaneous analog and digital curve recordings on film.

A typical recording of a “pressure test only” and of a sampling operation are shown in figures 10-5 and 10-6. In these figures, the left-hand track shows the analog pressure recording vs. time. The right-hand four tracks display the equivalent digital information: the first of these tracks indicates thousands, the next hundreds, the next tens, and the last track units. Thus, in Figure 10-6, the total digital reading at the end of the test is 4,000 + 300 + 60 + 9, or 4,369 psi.

On the surface, the time required to empty the sample chambers and prepare the equipment for subsequent testing has been reduced significantly with the RFT. This tool is designed with clean-out ports that provide easy access to the sampling flowlines and chambers. A thorough backflush of the sampling system with both water and air is performed by field personnel. The result is a quick, effective surface preparation of the tool for additional tests.

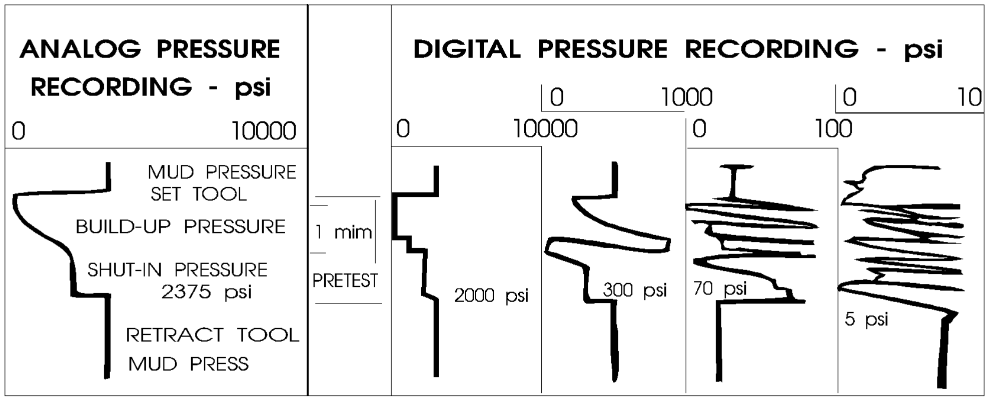


Figure 10-5: Figure 10-5: Pressure test recording, sample chamber is not open

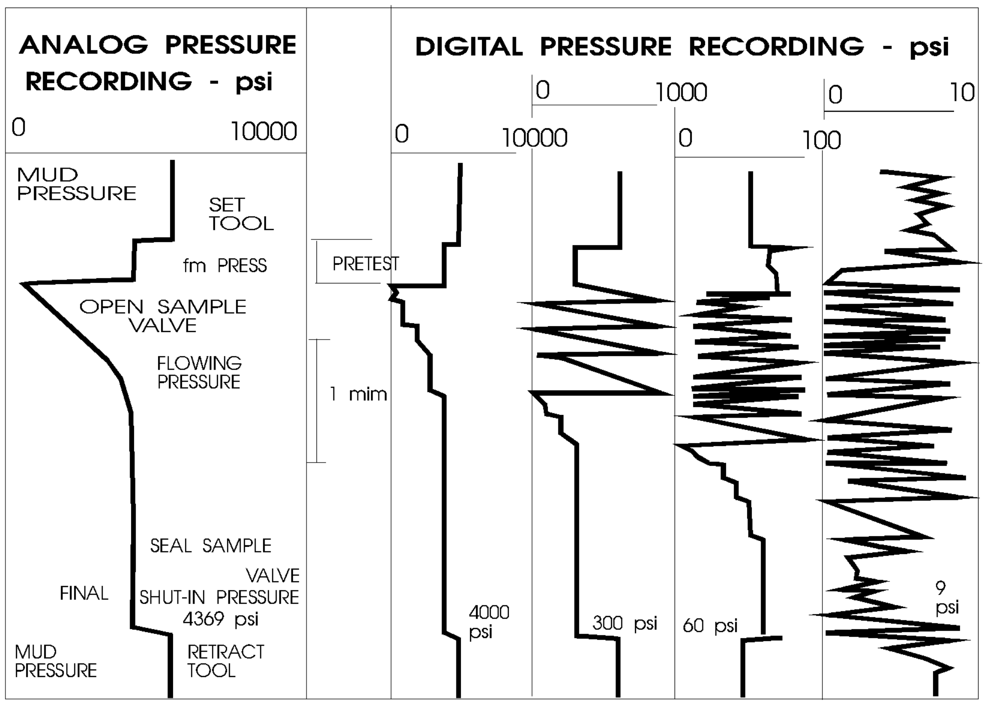


Figure 10-6: Figure 10-6: Recording of sample test.

A formation test is conducted in order to recover formation fluids, measure formation pressure and rate pressure build-up after draw-down, determine test rates and to assess possible formation damage caused by invasion during drilling. With this information it is generally possible to determine the type of fluid the formation will produce and the present and future production potential of the reservoir. These tests normally provide the “moment of truth” to the long and arduous process of planning and conducting an exploration program. Their importance cannot be over emphasized.

When significant shows of oil or gas are encountered, the well will be logged, cased and finally tested through casing. These tests will be supervised by the consultant/petroleum engineer with the co-ordination of the drilling superintendent and wellsite geologist. The reasons and objectives for testing, intervals to be tested, and methods and procedures to be conducted during the test should be discussed and clearly understood by all parties.

The testing program will need to remain flexible but would normally involve a production test, with formation fluids being produced and hydrocarbons flared. Typical equipment used would be downhole shut-in testing valve, subsea test tree, surface flowhead, choke manifold, separator and burners. The testing sequence will normally be as follows:

1. Initial Flow Period (short).
2. Initial Shut-In Period.
3. Main Flow Period.
4. Main Shut-In Period,
5. Downhole Sampling Period (if required)

Prior to testing the geologist should ensure that sufficient supplies of sample containers and gas bottles are at hand. He should liaise with the petroleum engineer to establish a thorough sampling program for hydrocarbon and formation water recovery. The sample containers should be air tight, clearly marked with the well, test and sample numbers and carefully packed to avoid damage in transit. In addition, the geologist should arrange for suitable sample analysis at the wellsite. If gas surfaces this should be analyzed through the gas chromatograph in the mud-logging unit, oil should be measured for A.P.I. gravity and formation water for salinity and other standard chemical tests.

The Repeat Formation Tester is operated by an electrically driven hydraulic system; so, it can be set and retracted as often as necessary to pressure test all zones of interest in only one trip. Two fluid tests, each at different depths, can also be taken during one trip.

Pretest pressure observation permits the engineer to determine if the packer has sealed properly and if the fluid flow is adequate to obtain a diagnostic sample. If either condition is questionable, the tool can be retracted and moved to a more suitable test depth.

At the surface, formation pressures are recorded on film and displayed in both digital and analog from.

RFT test data is played back with computation of the pressure data with the running time computed, starting from the beginning of the test. A plot of any of the digitized variables versus any other can be provided. This feature allows specific sections of the pressure profile to be enlarge for better interpretation.

Computations of Horner and spherical time functions for the test are interpreted, and these functions can be plotted versus pressure in order to determine final parameters such as formation pressure and permeability.

An interpretation summary will list computation of final buildup pressure, fluid buildup slope, drawn down permeability, and buildup permeability for future analysis.

Sidewall Core Gun

- *Schlumberger*: CST (Chronological Sample Taker)
- *Western Atlas*: Corgun

Sidewall cores are usually run at the end of each logging program. A side wall core gun provides the means for recovering small formation samples to confirm data displayed on the primary logs. Sidewalls cores are taken to confirm lithology, to check for hydrocarbon shows, and for paleontology and source rock studies. Up to fifty-one cores can be shot on any run.

Supervision of Sidewall Coring

A mud log or wireline log is used to define the zones of interest, then a list of depth, caliper reading and expected lithology is prepared prior to coring. This list should be made up as soon as possible so the wireline engineer can prepare his guns.

Prior to coring, the amount of shots per gun should be reviewed. To ensure complete coverage, at least two guns should be prepared before the logging job begins.

Positioning of the gun in the borehole is accomplished by using either the SP or Gamma Ray. The SP is usually supplied at no additional charge, but unless SP character is exceptionally good and the formations to be sampled are several feet thick, it is generally better to use the Gamma Ray log.

The distance between the point “seen” by the Gamma Ray and the first bullet is 8.5 feet. This distance will become progressively shorter with succeeding shots (due to the physical make-up of the sampling tool). The wireline engineer has a work sheet for compensating for this difference in shooting and sampling depths. Be sure to check his additions because small errors can (and do) appear on this list.

Supervision of taking sidewall coring is continuous. The geologist must know that each sample is from the depth requested.

The following is a guide to the operation of sidewall cores:

1. No radio transmissions or welding until the guns are 100 feet into the hole.
2. Run to the lowest area of required samples.
3. Make a Gamma Ray film and compare it to the Sonic.
4. Adjust depths to correspond to the Sonic.
5. Make depth correction of 8.5 feet deeper to correspond to shooting depth.

6. Make another Gamma Ray film if unsure that the correction was made in the proper direction.

7. Move into position for first the shot. Always come from at least ten feet below and be sure to stop at the exact depth.

8. If depth is not exact, go back down ten feet and try again. Small adjustments in depth are difficult due to cable stretch. Keep track of the free hanging weight.

9. Switch to the shooting position and arm the firing circuit - a deflection should be seen in the gauge.

10. Pull up carefully, watching cable tension. The wireline engineer knows the maximum allowable pull. Most cables have a 15000 lb test. Calculated weak point is: 1/2 of cable test times 75%, less tool weight plus cable weight, for maximum pull (i.e., weak point is about 6500 lbs). The two retaining wires on the bullet have a combined strength of 2-3000 lbs.

* From (3) above if there is little character on the Gamma Ray at the lowest point, find a zone with good Gamma Ray character and get 'on depth.'

When the sidewall core gun is returned to the surface:

1. Do not approach the gun until it is laid on the pipe rack, all misfires are disconnected, and it is OK’d by the wireline engineer

2. Then check the following;

- number of bullets fired
- number of bullets recovered
- number of bullets lost
- sample recovery (if poor, you may have to change bullet types or retaining wire lengths)
- lithology - was this what was expected?.

Sidewall Core Gun - Operation

The maximum running speed in the borehole is 12000 ft/hr. When the core gun is back on the surface, avoid washing the cores or the core gun. The use of partially fired guns on re-runs is not recommended.

Single Gun Firing System

A “chronology system” is used in shooting most core guns. An arming wire is associated with each igniter on the gun, except for the first three. This arming wire fits under the igniter finger, preventing premature electrical contact. While running in the hole the first three bullets are the only ones armed (Figure 10-7).

Running through the fastener wire of bullets #'s 2 and 3 is the arming wire for bullet # 4. Thus when 2 or 3 fires, this arming wire is pulled and bullet # 4 becomes armed.

Similarly, by shooting:

#'s 3 or 4 bullet, # 5 is armed
#'s 4 or 5 bullet, # 6 is armed
#'s 5 or 6 bullet, # 7 is armed

There are two bullets armed all the time and each is connected to a separate conductor. By selecting the cable wire at the surface (i.e., #'s 1,2,3) the bullet to be fired is chosen.

This type of arming mechanism employs an extreme current which makes the feeder lines polarity sensitive (i.e., sends positive current to the lower gun and negative to the upper gun).

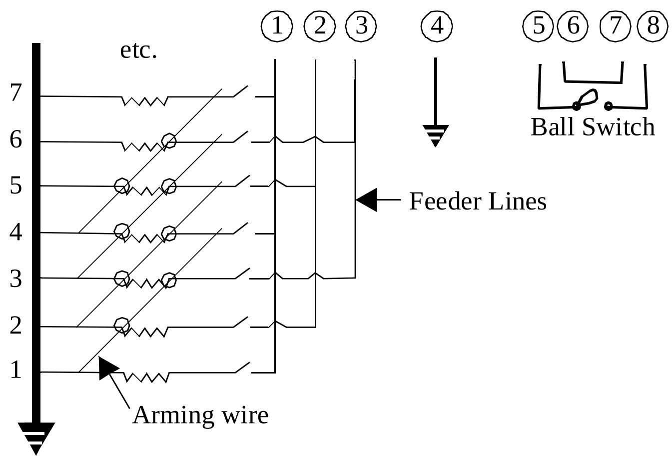


Figure 10-7: Figure 10-7: Sidewall Core Gun Firing System

Skipped Shots

If a shot is skipped, the bullet is WASTED. Under no circumstances can one switch back to that line (two other igniters are now armed). The best recourse is to continue shooting until you return to that feeder line to shoot the two bullets. A firing current greater than 1.4 amps is necessary for firing because the normal current through the lines is greater than 0.7 amps. After firing the two shots on that feeder line, the problem should be cleared. If not, discontinue shooting on that line.

For example, the following is observed:

No. 1 @ 0.6A
No. 2 @ 0.7A
No. 3 @ 0.9A
No. 4 @ 1.4A
No. 5 @ 0.7A
No. 6 @ 1.0A
No. 7 @ 0.7A
No. 8 @ 0.8A
No. 9 @ 1.0A

What is happening?

Clearly igniter # 1 did not fire with 0.6A, causing double arming. Increasing the current to 1.4A for # 4 fired both igniters and cleared the problem. The shooting of the gun can be continued normally but the depth of # 1 must be changed. The increasing current intensity on # 3 was probably caused by a leak.

Shooting in salt saturated muds creates another problem. The current may leak from feederline contact with the mud and through the mud to the gun body, which will increases from shot to shot.

Selection of sidewall coring points is discussed in Chapter 11.

•Notes•

Chapter **11**

Operations In The Field

This chapter is intended to familiarize a Wellsite Geologist with the Operational Requirements of Wireline Log Supervision. Oil companies differ in their specific requirements, but a general guide to supervision, tools and associated problems can be drawn up to assist in a successful operation.

Prior To Wireline Logging Operations

The Wellsite Consultant will normally have the following information available before arriving at the wellsite.

- Well name, depth, location etc.
- Number of anticipated logging runs
- Sequence of logs
- Name of wireline company and engineer

Although it may not be the direct responsibility of the Wellsite Geologist to “call out” the wireline company, it is a good idea to check with the Oil Company Representative at the rig, so that enough time is allowed for wireline tool checks and wellsite calibrations to be made prior to the job. Normal call out for the wireline company is twenty-four hours before a job. For the start of a drilling program, however, more time may be required, so check this requirement.

Before the logging job begins it is a good idea to be aware of the following, and to have discussed them with the personnel involved.

- Logs Required
- Log Scales
- Hole Problems
- Tool Combinations
- Casing Depths
- Mud Type/Parameters
- Rush Prints
- Log Copies/Dispatch
- Mud Log/Lithology

Logs Required

This information should be given to the geologist before arrival at the rig and should be obtained from the drilling prognosis. Do not assume all logging suites are correct in the drilling prognosis. These are often drawn up a considerable time before the well is actually drilled, and changes in the logging program may have been made in the meantime. ALWAYS CHECK WITH THE OPERATIONS GEOLOGIST BEFORE THE JOB.

Log Scales

As with the logs, check the log scales before the job. Normally, once scales have been set for a drilling program they will not be changed. However, it is the geologist's job to make sure the correct scales are used. This is especially important at the start of a drilling program.

The consultant should provide details of the following, so that an accurate log heading can be made.

- Well Name and Number
- Well Location
- Drill Floor (RKB) Elevation, Water Depth (if offshore)
- Hole Diameters and Depths
- Casing Information
- Mud Parameters
- Hole Conditions

Hole Problems

It is important to inform the wireline engineer if you think there may be any hole problems (i.e., swelling clays, dog legs, wash outs, tight spots, etc.). This will reduce the possibility of problems during the logging runs. Generally, deviated holes are more difficult. Stuck tools will be dealt with later in the chapter.

Tool Combinations

This is becoming particularly important as 'super combos' are often used. Some types of tool are ***Not*** compatible with others. For example, the DLL and Sonic can be run together, but not all types of sonic will combine with the DLL. It is really the wireline engineers problem, but it is useful to check that the correct tools are on the rig. If not, they can be made available so to not lose time.

Casing Depths

Make sure the logging engineer knows where casing shoes have been set. Shoe depths are important for several reasons.

- They are sometimes used as depth 'tie-ins.'
- They are easily identified and logs are generally run only as far as the shoe. The Gamma Ray may be run back to surface for correlation purposes.
- Calibrations - caliper checks are made in casing where exact I.D. is known.
- As the shoe is approached, the running speed will need to be reduced - logging tools should not enter the open hole at very fast speeds.

Mud Parameters

Mud parameters data is essential for accurate log analysis. As a general rule, prior to logging, the hole should be circulated clean. The geologist should have some input if this includes a full wiper trip. A wiper trip is probably not necessary where there is no gas, no tight hole, and reasonable mud viscosity, cake thickness, etc. If there have been hole problems, gases, etc. while circulating and pulling out as far as the shoe, then it is a good idea to run back to bottom and repeat a full circulation. This will be the decision of the oil company representative.

Just before circulation stops, the consultant should remind the mud engineer to collect a mud sample, normally a viscosity cup. This should be tested for filtrate and filter cake. The time when circulation stops should be noted, as should the flowline temperature. The mud sample will be given to the wireline engineer for resistivity measurements. In summary:

- Note time when circulation stopped
- Note flowline temperature
- Get mud sample taken
- Check filtrate and filter cake thickness
- Give samples to the wireline operator
- Maker sure resistivity measurements are made on the samples

Rush Prints

Most oil companies require rush field prints to be sent to town as fast as possible. These will normally be faxed. It is a good idea to find out prior to logging the following:

- Are rush prints required?
- What scale - one inch, five inch, or both?

A reasonably new development is that a thermal print of the log is run off at the same time as the actual logging. It is therefore not necessary to wait for film development for a rush print to be made. However, only one print can be made, so it is best to find out from the Operations Geologist what scale to make the thermal print.

If there are partners in the operations, do they require rush prints also? Get Fax numbers, etc. if they do.

Log Copies

Check what copies and the number of each (prints, films, play backs, etc.) are required of each log. Make certain that the wireline engineer has taken note of the number of copies required to be sent to town. Again, this may well be in the drilling prognosis, but check with the operations geologist, as numbers may change, especially when partners or government departments are involved.

Log dispatch: This is not such a priority as it used to be. Fax machines and data links to shore are often available. Nevertheless there may be situations when such a dispatch is important. If this is the case, then the wireline engineers and the oil company representatives should be advised, so that transportation can be arranged in advance.

Supervision of the Logging Job

It is an important part of the geologist's job to witness the logging runs. A "wake me when the first log is out of the hole," is unacceptable. At the same time there should be no need for the geologist to go without sleep for several days.

Wireline logging companies have very strict quality control standards of their own, but the wireline engineer cannot notice every detail, and it is here that the geologist can assist the wireline engineer. However, a bossy or arrogant attitude towards the wireline engineer can only be negative.

General information should be acquired throughout a logging job.

- Time out of hole
- Time of start up for rig-up of Log #1
- Time of start in hole with the Log #1
- Time on bottom with Log #1
- Time out of hole with Log #1
- Start up time for rig-down Log #1
- Start time for rig-up Log #2, etc.

Times are important - the Company Representative will need a breakdown in the morning. It is useful to give him one before he has to ask, include what types of logs were run.

Oil companies differs as to their quality control requirements. Some have Quality Control sheets, parts of which should be filled out by the geologist and parts by the wireline engineer. These are usually self explanatory.

Although logs produce very different information, the actual operational sequence of running logs in the field is identical. This section will deal with the logging operations, things to remember, simple Quality Control, and problems that may arise while logging. They include:

- Rig-Up
- Running In
- Logging
- Quality Control
- Repeating Sections
- Stuck Tools
- Fishing

Rigging-Up

The geologist is not directly involved with the rig-up or rig-down of tools. It is sufficient for the geologist to note the start up times of rig-ups and rigdowns. If there are delays between them, it is a good idea to ask the wireline engineer for reasons. If the geologist is not happy with the explanations, the oil company representative should be notified.

Surface Calibrations - The geologists should not concern themselves with surface calibrations unless they are very familiar with the various tool responses. However, the consultant should ensure that master calibrations are attached to the logs.

Temperature Readings - Bottom hole temperature is important. Two thermometers should be attached to the wireline suite during each run. The height of the thermometer above the tool head should be noted.

Running In

Casing - Sometimes calibrations are carried out in casing (especially tools such as calipers), as the I.D. and material characteristics of casing are accurately known. Log readings are seldom taken in casing as their responses are greatly reduced and generally of no value. Gamma Ray is often recorded to surface for correlation purposes, but again the response is greatly reduced.

Open Hole - This part of the operation should be witnessed by the geologist. It is often useful to “Log-In” with the first tool, but this will depend on the oil company. If a hole is suspected to cause problems, then logging-in is recommended, to at least see that information can be gathered.

Logging

Assuming T.D. is reached and logging proceeds, the correct speed and time constant should be used. A gap appears in the line at the margin of track one once per minute so that logging speed can be checked for consistency and correctness.

Maximum Logging Speeds

BHC Sonic	4,000 feet/hour
Induction	6,000 feet/hour
FDC, CNL	2,000 feet/hour

Going slower over zones of interest is recommended. While logging remember to be observant.

Logs should be on scale or a back-up should appear. Cyclic variations, zero values, and constant readings are suspicious. Be suspicious of logs that constantly peak or level out at less than Full-Scale deflection. Look for events that demonstrate the range of response of that tool (i.e., High and Low Porosity Beds, Shales, Salt, Anhydrites, Coals, Washouts, etc.).

Quality Control

Detailed Quality Control checks can be found in the Chapter 10. Here are some easy checks for the more common logs which should identify major problems while logging.

Gamma Ray
Near zero API readings are unlikely except in massive Halite, Gypsum, or Anhydrite.

- Most coals are less than 50 API units
- Some radioactive shales and will generate more than 500 API units.
- Uriniferous beds may give readings outside the range of the tool.
- API values may vary due to tool running speed and hole and mud variations.
- Static drift should be compared with the “before” and “after” calibration counts.
- Repeat sections may not agree in absolute values, but the curve character should be very similar.

S.P. - Spontaneous Potential

- Drift to the left due to temperature change is normal.
- If a baseline shift is required it should be done in a shale section.
- The SP log should be compared to nearby wells if possible.
- The SP log should be smooth, with no rapid or cyclic variations.

Caliper

- Repeatability is not a relevant check because a hole is rarely perfectly round.
- Hard dense zones should be in-gauge unless there is good reason not to be.
- Check the caliper log in casing if possible.

Resistivity Log (IES)

- Repeat runs should agree within 5% of the full scale value
- In water zones resistivity should be small, but a finite number, not zero.
- Amplified curves should be in relation with the regular curves

- In thick, in-gauge shale sections the short normal curves usually has a slightly higher value than the other curves. The ratio values of the long and short normal curves should be less than 2:1 in such sections.

Induction Logs

- Repeatability in zones of interest is very important.
- In thick compacted shales, the RIL medium and RIL deep measurements should nearly overlay.
- There should be no zero readings.

Laterolog Logs

- Resistivity in casing should near zero.
- In thick compacted, uninvaded shales the RIL deep and RIL shallow should overlay.

Microlaterlogs

- There should be no readings near zero (except in washouts using salt muds).
- Resistivity values should be greater than mud resistivity.
- Caliper should be checked in casing
- A 'mud' log may be recorded running in with the tool closed - this will verify Rm and tool operation.

Compensated Acoustic/sonic Logs

- Look for cycle skipping and spikes
- Values of less than 40 υs/ft, and greater than 190 υs/ft are unusual.
- Check the relationship of the sonic with the Gamma Ray.
- In clean porous water zones, without regular or fracture porosity, sonic should agree with other porosity values to within five units.
- Sonic reading should be 57 υs/ft in casing.

Compensated Density Logs

- In clean porous water zeros, density porosity should be compared with other porosity values
- In pure anhydrite, gypsum, salt or dense carbonate beds greater than 3 ft thick, the zero porosity value should be checked.
- The "$\Delta\rho$" should be mainly positive except in dense baritic muds or gas zones. Consistent drift above zero is suspicious.

- Repeatability should be within 0.05 g/cc except in washed out zones.

Compensated Neutron Logs

- Leap frogging is caused by tool sticking and is indicated by a saw-tooth appearance on the caliper over a short distance. If in doubt a tension curve should be requested.
- In gas zones neutron porosity < density porosity
- In tight, clean limestones, anhydrite and dolomite, neutron should be checked for zero porosity.
- Neutron porosity should be checked with other porosity measurements.

Dipmeter

- Individual traces should be identical and slightly out of register.
- Good detail should be shown on the curves.
- Rate of rotation of the tool, as detected by the azimuth electrode, should be less than one turn/minute/50 feet.

Providing most of the above checks appear valid, log quality should not be a problems.

Repeat Sections

Repeat sections must always be taken, this in itself is a good quality control measure. Unfortunately, repeat sections are often run late in the logging operation, making it expensive to re-run tools if discrepancies are found. Oil companies vary in the amount of repeat section. Normally 250 feet or 80 - 100 meters is enough. Generally, take repeat sections over sensible areas, either zones with good character if there are no hydrocarbon indications or hydrocarbon zones where these are obvious.

Repeating log runs is costly, unless the fault can be pinned directly on the wireline company. Sometimes, however, especially with some of the higher resolution tools, this may be worth-while where specific information is required. Porosity, dipmeter and some sonic tools are cases where either a slower speed, or a second pass over on an interval may produce a better log. It is always better, where possible, to consult with the operations base either before or during logging if you feel advantage can be gained by repeats or re-runs.

Beware of “washed-out” holes, this is the main cause of poor tool response and log quality, and there is really very little that can be done about this. Do not waste time trying to get improved log quality over highly washed out zones.

Stuck Tools

This is not a common occurrence when standard suites are run, but can be a problem when some of the special tools are used. More commonly, while running standard suite tools (Porosity, Resistivity, Gamma Ray, etc.), they may get “hung up” on the way into the hole and you may not be able to get to bottom. Sometimes you are sufficiently close to bottom to make it unnecessary to try and improve hole, conditions, but more often than not a “wiper trip” will be needed. In such cases always log out from the point of constriction to the casing shoe, as hole conditions may deteriorate and the repeat attempt at logging the hole might be even less successful. You will then have some information from the first run.

Differential Sticking

This is the most common form of tool sticking, and it occurs when the hydrostatic head of fluid in the borehole is considerably greater that of the formation. This is really only a problem where it is necessary to have a tool in a static position, such as a RFT. As long as the wireline sonde stays away from the wall, differential sticking should not be a big problem.

Ledges and Key Seats

Logging tools can occasionally be pulled into a key seat, which is sometimes cut into the high side of the hole, either while logging or due to “cable rubbing” from a long series of logging runs. Tools may also get “hung up” on a ledge or bridge. Limestones and dolomites can sometimes cause ledges, due to the hardness of the rocks compared with surrounding clays or sands.

Preventive Measures

To prevent differential sticking, the wireline cable should always be moving when in the open hole section of the well. The only permissible exceptions to this might be.

- For calibration purposes of certain tools, and if possible these should be carried out in the open hole section just below the shoe, and in the shortest possible time frame.
- Wireline Formation Testing. The cable, however, is to be slackened off so as to prevent a taught wireline sitting against the wall of the open hole.

Another precaution to prevent sticking is to limit the number of logging runs between bit trips into the hole. If the hole is in good condition and no drag is noticed during logging runs, then this limitation can be relaxed. If, however, a heavy mud is used and frequent drag is experienced, then it may be necessary to make a “wiper” trip. This should be decided upon by discussions with the engineer, the company representative, the wellsite geologist and operations base.

It is strongly suggested that the last tool to be run in any logging suite be the sidewall cores, as there can be situations where bullets may be left in the wall of the hole. These can cause problems to any subsequent logging tool run into the hole. If the hole is in poor condition during the sidewall core run, it is preferable to take shots “on the run” so that the wireline is seldom stationary.

Fishing

In the event that a tool becomes stuck, and all attempts to free the tool have failed, it becomes necessary to fish the tool. Providing the cable has not parted from the tool, stripping over the cable is possible. This system involves cutting the wireline and feeding it through the drillpipe.

While running into the hole, a quick fit latching system allows connections to the made. Often cable and tool may become free some distance before the drill pipe has reached the tool. This is especially true where differential sticking is the problem - the cable may be differently stick over a porous zone somewhere above the tool depth. Usually stripping in over a cable is successful, but occasionally tools do become irretrievably stick. Fishing for stuck tools is not the responsibility of the geologist and providing the correct precautions have been taken while logging to minimize the possibility, then they will not be held in any way responsible for such problems.

Special Tools

Sidewall Cores

Often sidewall core selection causes unnecessary concern and worry to the wellsite geologist. Sidewall cores are taken for any one or a combination of the following reasons:

- Lithology Identification
- Hydrocarbons Evaluation
- Biostratigraphy
- Geological Analysis

Deformation of rock structure, especially more fragile sandstones, means that they are of little petrophysical use. For core analysis to be accurate large cores are used, although there are now available coring tools that will take small cores that are structurally intact and suitable for accurate petrophysical study.

Selection of Coring Points

In general the operations base will discuss with the wellsite geologist prior to and during the logging job as to the specifics of the sidewell coring program. For biostratigraphy, geochemistry and source rock analysis, shales or clays are generally of much more use, although carbonates, if they are present should be considered. The geologist being observant during the drilling process will have a good idea from the lithology and depths where such things as fossils, coals, lignite, carbonaceous material or lithological anomalies are likely. It should be a fairly simple process to build up a list of sidewall shots that will yield the correct information.

Here are a few suggestion to help in picking sidewall coring points.

- Use in-gauge hole sections where possible
- Do not shoot in zones where cores have been taken during the drilling phase.
- Shoot either side of major events - e.g., unconformities/fault, especially for biostratigraphic information.
- In long shale sections do not shoot at too close an interval
- For hydrocarbon evaluation it may be necessary to shoot fairly close together. If you think you can identify on oil/water contact, then shoot on either side of this.

- If possible give the wireline engineer a list of core points in time so he can load the guns with the best wire lengths and ring sizes. This can often mean enhanced recovery.

It is common practice from the operations base to send a list of coring points to the rig, if you notice any anomalies with this list, bring it to the attention of the operations geologist.

Collection of Sidewall Coring Samples

It is important that there is no mixing of coring shots while they are being collected. Make sure of the following:

- Shots fired
- Shots recorded
- Shots misfired
- Shots lost

Bottles should be clearly marked with well numbers, depth and shot number. It is a good idea to scratch this on the top of the appropriate bottle as well as mark the bottle itself. Correct collection of the coring samples is the responsibility of the wellsite geologist - do not leave this to the wireline crew without supervision.

Description of Sidewall Core Samples

As this is the last job it is often more of a chore than an enjoyable experience. It is something that has to be done rapidly and accurately. Usually the oil company supplies a sidewall core description sheet which, although layouts will be different, will contain the following information.

Heading sheet
This is self explanatory, the following information will already have been collected.

- well
- date
- run no.
- shots fired
- shots recorded
- shots lost

Description sheet
Shot number and depth will already have been collected. Length recorded refers to the actual length if the rock sample and this should be measured with a ruler and noted either in metric or imperial.

- shot no.
- depths
- length recorded
- lithology description
- fluorescence

Beware of small fragments - these are often foreign or mud cake and should not be bought. Generally be suspicious of any core less than 1/2”, and reject anything 1/4” or less.

Logging Description

Take a small piece of sample using a tweezers or probe. Do not damage the core. Examine this piece and make a concise description - there is no need to be overly descriptive; color, hardness, grain size, accessories and overall lithology type is sufficient.

Fluorescence

Test every sample; occasionally there are surprises. These formation samples from a known depth help end any disputes. A decision to test or not can be made on a sidewall core.

Repeat Formation Tester (RFT)

These tools are run for one or more of the following reasons:

- Formation Pressure Evaluation
- Identification of Formation Fluid
- Pressure Gradients
- Hydrocarbon Analysis
- Fluid Contacts
- Permeability Estimates

Generally, the decision to run an RFT is made by the operations base, once resistivity and porosity logs have been run. Most commonly RFTs are necessary where there is dispute as to the nature of the formation fluid, and for accurate formation pressure information.

In order for the RFT to give useful information, zones of reasonable porosity must be identified (sands, vuggy or fractured limestone, for example). In the case of establishing a pressure gradient, the sand must be of reasonable thickness so that accurate pressure differences with depth can be measured.

The operation of the RFT may be said to consist of three stages.

- The Pretest
- Sampling
- Recovery

The Pretest

The RFT is run into a predetermined depth, identified from the Gamma Ray and porosity logs. The tool is then set; the pad is pushed against the borehole wall, isolating the formation from the hydrostatic column. The actual mechanics, with illustrations are described in Chapter 10, together with a graphic description of pretest and sampling curves.

Where pressure gradients are concerned, the distance between sampling points is important. The gradient is measured in psi/ft, and since oil, water, and gas have different gradients, the fluid type within formations can be identified.

Sampling

This has also been described in Chapter 10. The following information must, however, be recorded during sampling.

- Depth
- Hydrostatic pressure
- Formation pressure
- Start sampling pressure
- Start sampling time
- End sampling pressure
- End sampling time.

Recovery of the RFT

An important part of the RFT program is sample recovery.

Once the RFT is at the surface and samples are contained within the chambers, these have to be collected. For this a gas/fluid separator is used. Since the samples may be under high pressures, a X-mas tree of valves is needed to measure the pressure within the chamber, and a second and third tree of values are used as a safety precaution. The last valve tree is usually a 50 or 100 psi valve so that the sample can be transferred at a reasonable rate.

It is important to check all fittings within the sample transfer system before opening the release valves, as accurate measurements of fluid and gas are required.

Gas flows through gas meters, which can be read in cubic feet. Gas is not normally stored, although some oil companies will supply cylinders that can be filled for analysis at a later date.

The wireline or mudlogging company should have balloons available, which can be filled with gas for chromatographic analysis at the wellsite. The availability of the balloons should be checked beforehand.

Fluid Recovery

Gas, when present, is driven off first, followed by whatever fluid is present. This fluid is collected in the separator, and once the chamber is empty, the contents of the separators are emptied into a measuring bucket. If the fluid contents are of one fluid, it may be measured immediately. There may be mixture of oil and water, in which case the fluid must settle before it can be measured. The volume of both fluids should be measured.

Normally at least part of the RFT fluid is kept for further analysis, and it is the consultant's job to ensure an adequate supply of containers is available. The RFT sample should be labeled with RFT Number, Depth, and Well, then stored for shipment.

Where the fluid is water, this should be tested immediately by the mud engineer to check whether it is mud filtrate or formation water; usually a chlorides test is sufficient.

The following should be noted and reported for each RFT Run.

- Number and Depth
- Surface Pressure
- Gas Volume (when present)
- Liquid Volume
- Type of Fluid - Separate volumes when both oil and water are present.
- If water is present, determine if is it filtrate or formation fluid

Well Seismic Tools (WST)

These tools are frequently used and although they are not usually considered the direct responsibility of the consultant, there is sometime a need to witness such logs, so an idea of how they work is useful. Often oil companies send their own geophysicists to the wellsite for a WST run.

The property being measured is the velocity of the formation. Formation velocities are obtained by measuring the time required for wavelets generated by a surface energy source to reach the seismic tool which is positioned at various depths in the well.

The recorded travel times of the direct arrivals are used to adjust the sonic log in order to correct for drift, which is usually caused by borehole effects and dispersion. When sonic logs are calibrated in this way by check shots, they form the basic references required to scale a surface seismic section with depth.

Borehole seismic records can be made by recording several seconds of waveform data at one specific depth, and repeating the process at frequent down hole intervals. This system is called a VSP or vertical seismic profile.

Well Seismic Techniques

The well seismic tool equipment consists of seismic sources, a recording system and a down hole tool.

Normally the source is in the form of an air gun. An array of synchronized air guns can be used if a powerful depth of penetration is needed, as in very deep wells. The air gun firing chambers, incorporate a wave shaping kit which reduces the bubble effect and results in a cleaner signal.

Other types of guns such as water guns have been used with satisfactory results.

At each depth, the average velocity between the source and the borehole geophones is measured through the recording of two traces.

A surface detector trace is used to monitor the signature and timing of the hydrophone signal, and a downhole detector trace is used to record the direct arrival at the geophone of the wavelets generated by the surface energy source.

Transit times are measured from the first break of the hydrophone (surface) recording to the first break of the geophone (downhole) recording. Several shots are fired at the same level and stacked in order to increase the signal-to-noise ratio. Assuming that noise is random, the stacking of “n” shots will improve the signal- to-noise ratio.

If the hole is deviated or there is a large gun offset, the transit times obtained must be converted to vertical times.

When a VSP has been witnessed, the above information should be useful. The consultant will have been given the depths for the shot. If just check shots are required, the interval will be greater. A quiet rig is necessary throughout a seismic log run although stacking of shots will help outrun any surface noise.

Terms and Symbols Used in Wireline Logging

a	tortuosity factor
BHT	bottom hole temperature
BVW	bulk volume water
c	conductivity
Cp	compaction factor for sonic porosity
rj	radius of invaded zone
Δt	interval transit time of formation
Δtf	interval transit time of fluid in borehole
Δtma	interval transit time of formation matrix
dh	diameter of borehole
di	diameter of invaded zone (flushed zone)
dj	diameter of invaded zone
F	formation factor
GR log	gamma ray reading from formation
GR max	gamma ray reading from shale
hmc	thickness of mudcake
ka	absolute permeability
ke	effective permeability
krg	relative permeability to gas
kro	relative permeability to oil
krw	relative permeability to water
m	cementation exponent
MOS	movable oil saturation (Sxo - Sw)
ϕ	porosity
PSP	pseudostatic spontaneous potential
φb	bulk density of the formation
φf	density of fluid in borehole
φh	hydrocarbon density

φma	density of formation matrix
Rfl	resistivity of shallow focused log
Ri	resistivity of invaded zone
Rilm	resistivity of induction long medium
Rild	resistivity induction log deep
Rlld	resistivity laterolog deep
Rlls	resistivity laterolog shallow
Rm	resistivity of drilling mud
Rmc	resistivity of mud filtrate
Ro	resistivity of the formation 100% water saturated
ROS	residual oil saturation (1.0 - Sxo)
Rs	resistivity of adjacent shale
Rsfl	resistivity of spherically focused log
Rt	resistivity of uninvaded zone
Rw	resistivity of formation water
Rwa	apparent formation water resistivity
Rxo	resistivity of flushed zone
Sh	hydrocarbon saturation (1.0 - Sw)
SP	spontaneous potential
SPI	secondary porosity index
SSP	static spontaneous potential
Swirr	irreducible water saturation
Swa	water saturation of invaded zone (Archie Method)
Swr	water saturation of invaded zone (Ratio Method)
Sw/Sxo	movable hydrocarbon index
Sxo	water saturation of flushed zone
Tf	formation temperature
Vsh	volume of shale

Nomenclature For Wireline Services

Tool Type	Schlumberger	Atlas	Gearhart	BPB	Welex
Borehole Geometry	BGT	4CAL	X-Y		
Borehole Televiewer	BHTV				
Cement Bond Log	CBL	ACBL	CBL	CBL	CBL
Compensated Neutron	CNT-A/H	CN	CNS	CNS	DSN
Sidewall Core	CST-C/U/V	CG	SWC	SCG	SCG
Density	FDC	CDL	CDL	CDS	
Density (lithology)	LDT	ZDL	SLD		SDL
Dipmeter	HDT-D/F	DIP	FED	PSD	HDD
Dipmeter (stratigraphic)	SHDT		SED		
Dipmeter (oil-based)	OBDT-A		SED		
Dual Laterolog	DLT-D/E	DLL	DLL	DLS	DLL
Dielectric Tool (Deep)	DPT	47MHZ	DCL		LFD
Dielectric Tool (Shallow)	EPT-D/G	200MHZ			
Formation Microscanner	FMS				
Formation Tester	RFT-A	FMT	SFT	RFS	SFT
Free Point Indicator	SIT-D/E	FPI	FPL		
Gamma Ray	SGT-E/L/GR	GR	GR	GR	GR
Gamma Ray Natural Spectroscopy	NGT-C/D	SL	SGR	SGS	CSNG
Gamma Ray Spectroscopy	GST	COC			
Induction	IRT-R/M	IEL	IEL	DIS	DIFL
Induction (dual)	DIT-D/E	DIFL	DIL		
Nuclear Magnetism	NMT		NML		
Micro Resistivity	MSFL	MLL	MSFL	MLL	MGL
Sonic	SLT-N/M (BHC)	AC	BCS		CAV
Sonic (long spaced)	SLT-N/M (LSS)	ACL			
Sonic (digital)	SDT-C				FWS
Thermal Decay Time	TDT-K/M/P	PDK	DNLL		TMD
Well Site Seismic	WST-B/SAT-A	DSS		SR1	

Wireline Calibration Theory

Most major wireline logging companies perform nearly all their logging services using computers. Calibration records are attached to the end of the log to verify that the tool was operating properly and the tool's measurements are correct.

The calibration of wireline logging tools involves a two-point calibration technique, which assumes the tool's response is linear. This linearity of response states that any two points on the tool's response line can be compared to the calibration references to determine any gain or offset. These gain and offset values are used in the calibration equations, which converts the measured signal to a calibrated value.

Calibration Terminology

Some of the calibration terms are:

Measured Value

These values represent the raw or uncalibrated signals from the downhole logging sonde. These will be converted from signals to units of measurements, and expressed in the proper engineering units.

Zero Measurement (ZM)

This is the uncalibrated signal from the downhole logging sonde representing the low point for calibration purposes.

Plus Measurement (PM)

This is the uncalibrated signal from the downhole logging sonde representing the high point for calibration purposes.

Zero Reference (ZR)

This is the low point calibration standard. This is what the calibrated zero value should read.

Plus Reference (PR)

This is the high point calibration standard. This is what the calibrated plus value should read.

Gain Gain is equal to the Plus Reference minus the Zero Reference divided by the Plus Measurement minus the Zero Measurement
(PR - ZR ÷ PM - ZM).

Offset The Offset is equal to the Zero Reference minus the Gain times the Zero Measurement or equal to the Plus Reference minus the Gain times the Plus Measurement.
{ZR - (Gain x ZM)} or {PR - (Gain x PM)}

Calibrated Value

This value is equal to the Gain times the Measured Value plus any Offset.

Units These are the engineering or physical units used to express the data.

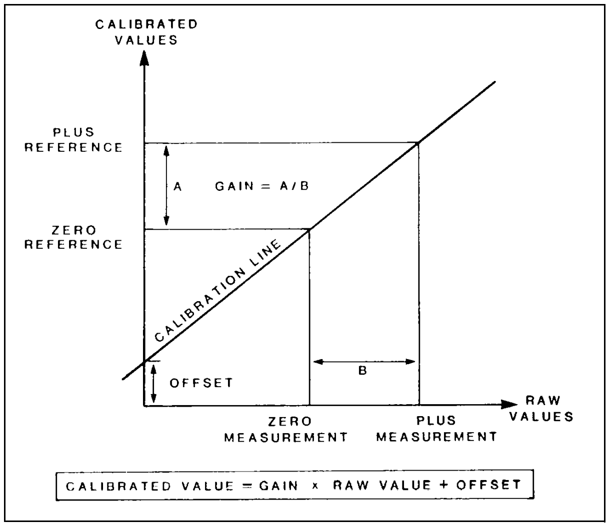


Figure A-1: Typical Wireline Calibration Nomenclature

Calibration Procedure

An example of this calibration procedure is as follows:

Logging Sonde: Caliper on the Formation Density

Surface Reference Rings:
Small Ring - 8 inches
Large Ring - 12 inches

Downhole Measurements:
Smallest Value - 7.5 inches
Largest Value - 13.5 inches

Gain: 0.67
(12 - 8 ÷ 13.5 - 7.5)

Offset: 2.965 (average value)
{8 - (0.67 x 7.5)} or {12 - (0.67 x 13.5)}

Measured Values: 8.2, 10.9, 12.1

Recorded Values Placed on Log: 8.459, 10.268, 11.072
(0.67 x 8.2 + 2.965)
(0.67 x 10.9 + 2.965)
(0.67 x 12.1 + 2.965)

Information Placed on Calibration Record (attached to log):

	Measured		*Calibrated*		
	Small	*Large*	*Small*	*Large*	*Units*
CALI	7.5	13.5	8.0	12.0	IN

If the response is linear and there is no drift in the electronics, the recorded values placed on the log should reflect the hole diameters.

The logging companies assure linearity through tool design and by periodic shop checks. Electronic drift is monitored by tool checks before and after logging runs.

Three types of calibration summaries should appear in the Calibration Record, attached to the log: the Shop Summary, the Before Survey Summary, and the After Survey Summary.

Shop Summary
This is used for tools which have calibrators that are too bulky, too heavy, or too involved to be used at the wellsite. Such tools include, the Dual Induction, Density and Neutron devices. Shop calibrations should be run once a month. The tool is calibrated to the shop standard, then compared to the secondary field standard which will be used at the wellsite to ensure there is no drift in the tool.

Before Survey Calibration
This is performed at the wellsite. This will also ensure that the computer system is calibrated for the tools being run.

If the tool has a Shop Summary, the computer system is calibrated to that summary. The secondary standard or “jig” is checked and those values compared to the Shop Summary. If the logging engineer notices significant changes, an alternative calibration can be used, which is based on the secondary or jig values, rather than the Shop values.

Some tools have no Shop Summary, because the field standard is used at the wellsite is the primary standard.

After Survey Summary
After a logging run, the tool is checked to confirm that any downhole drift has remained within tolerances. These tolerances are chosen to represent standards of tool performance under normal logging conditions:

1. downhole temperatures of 300°F or less
2. logging time of less than eight hours
3. no hard pulling, jerking or spudding of the tool

If the After Survey values are out of tolerance, a decision must be made as to how much error will be accepted by the client.

Chapter 9 should be reviewed for the tolerances expected from each tool.

Shop Calibrations

The previous section reviewed calibration techniques. Several tools require specialized equipment to ensure the are operating properly. Most of the equipment necessary to calibrate the tools cannot be transported to the wellsite, and therefore they are calibrated in the wireline companies field shop. This section will explain the shop calibration for the Density, Neutron, Dual Induction and Gamma Ray tools.

Density Calibration

The primary calibration standards for these tools are precision laboratory formations, with densities known to four significant figures. Several examples are:

Vermont Marble	φ = 2.675 g/cc
Bedford Limestone	φ = 2.420 g/cc
Austin Limestone	φ = 2.211 g/cc

These formation samples have an eight inch borehole cut into them, and the borehole filled with water. The tool is inserted into the borehole and the response adjusted to read the formations bulk density.

A secondary (environmental) calibration is necessary to ensure linearity. This is accomplished using 400 pound blocks of aluminum and sulfur, with a six inch hole cut into them. Using the tool's calibrated limestone tool response, the tool is inserted into the aluminum block and an equivalent limestone density of 2.59 g/cc is obtained. To verify the linearity, the tool is inserted into the sulfur block, and a reading of 1.90 g/cc is obtained.

A portable jig is used for wellsite calibration. Using two small gamma-ray sources, with adjustable shielding, the jig is set to make the count rate the same as if the tool was in the aluminum block. The typical count rates for the tools are:

long-spaced detector	400 cps
short-spaced detector	600 cps

Neutron Calibration

The neutron logging devices to not utilize count rates to determine a desired formation parameter. In these tools, the ratio of count rates from the two detectors is related to formation porosity. Rather than calibrating count rate versus porosity, it is calibrated using count-rate ratio versus porosity. Then calibrated directly into porosity units (p.u.).

Again, a series of laboratory formations, are used to provide the standards. Examples are:

Vermont Marble	ϕ = 1.7 p.u
Bedford Limestone	ϕ = 18 p.u.

Austin Limestone	ϕ = 25 p.u.
Crushed Marble	ϕ = 44 p.u.

(Similar standard formations are used for sandstone and dolomite calibrations.)

The tool is inserted into these formations and the ratio of the count rates between the two detectors is determined to be the porosity of the standard formation. There is a ± 0.5 p.u. uncertainty due to the tools statistical response.

A Neutron Calibration Tank (NCT) is used as the secondary (environmental) calibrator to verify calibration. The NCT is filled with water, stabilized at 75^{o}F, and designed so that the response from the tool is the same as an 18 percent water filled limestone formation.

A field jig is used at the wellsite, and designed to give the same count rate ratio as the NCT.

Dual Induction
Calibration of the Dual Induction involves three separate calibration routines:

1. The downhole electronics
2. The surface electronics associated with the tool
3. The surface electronics associated with the recorder

The transmitter within the sonde is designed to couple a signal into the receiver via the formation. In the absence of a conductive formation, there is still an unwanted signal due to coupling between the transmitter and receiver. This is known as Sonde Error. The signal from the receiver coils is passed to additional electronics, which prepares the signal for transmission to the surface (amplification and rectification). Even with no signal present, there is a small voltage output. This is known as Diode Error.

To calibrate the surface system, the recording mechanism is disconnected from the system, and the recorder mechanically and electrically zeroed.

To compensate for Diode Error, the receiver coils are then disconnected from the sonde, and the electronics adjusted until zero volts are recorded in the surface controls. This corresponds to infinite resistivity.

Because zero and infinity do not exist on logarithmic scales, a voltage offset is injected into the surface electronics making them read 500 ohm-m, when the voltage point is at zero.

To compensate for Sonde Error, the coils are reconnected to the sonde, and the tool is suspended in air (zero conductivity) and the voltage adjusted to read zero. Again, to allow logarithmic scaling, a precise offset is required, normally 500 ohm-m.

Once the Diode and Sonde errors have been compensated for, the tool is calibrated. An internal signal (usually 2 ohm-m) is generated and the recorder adjusted to read that signal.

To adjust the internal signal to the correct value, a test loop (54 inches in diameter, containing a precision resistor) is positioned around the tool, still hanging in air. The recorder trace is again adjusted to read the 2 ohm-m (500 mmho). The loop is removed and the internal signal reapplied, to ensure the signal and recorders are reading the same.

The Before and After Summaries, essentially verify the stability of the error compensations and scale normalization.

Gamma Ray

The API Test Facility in Houston, Texas serves as the primary standard for all Gamma Ray logging devices. The test pit consists of 17 feet of 5.5 inch ID casing set in cement. There are three sections of cement, the middle section containing enough radioactive material to give is the same spectrum of energy as in shales. The difference in radioactivity between the “hot” cement and the “normal” cement is, by definition, equal to 200 API Gamma Ray Units.

Each tool size, each source spacing, and each detector type (Geiger-Mueller, Scintillation Counter) must be calibrated the same way.

Secondary calibration sources are compared to the API Test Pit. After the tool is run in the test pit, the secondary source is placed a fixed distance from the tool, and the source strength is determined. Wellsite calibrations are based on this secondary source.

Gamma Ray tools cannot be zeroed due to background radiation, so circuitry accounts for this by making the secondary source deflection “full scale” and dividing the track into equal segments.

•Notes•

MWD Tables

MWD Operating Principles

	Schlumberger Anadrill	Eastman-Teleco	Geoservices	Halliburton Geodata	Smith Datadril	Sperry Sun	Western Atlas
Tool OD (inches)	6 1/2, 8, 9 1/2	6 3/4, 7 3/4, 8 1/4, 9 1/2	4 3/4, 6 3/4, 8	6 1/4, 7 1/4, 8, 9 1/2	4 3/4, 6 3/4, 7 3/4, 8, 9 1/2	6 1/2, 7 1/4, 8, 9 1/2	6 3/4, 8
Tool Length (feet)	22 (CDR) 31 (CDN)	39 (RGD) 72 (TC)	30 - 31	37	42	36	44 (GR) 56(+Res)
Maximum Operating Temperature	150^{o}C 302^{o}F	125^{o}C 250^{o}F	125^{o}C 257^{o}F	150^{o}C	150^{o}C 302^{o}F	125^{o}C 257^{o}F	150^{o}C 302^{o}F
Power Source	Turbine or Battery	Turbine generator	Lithium Battery	Turbine generator	Lithium Battery	Turbine generator	Turbine generator
Maximum Pressure (psi)	18,000	20,000	10,000	20,000	20,000	15,000	20,000
Flow Rate Range (gpm)	450 - 850	320 - 1,100	No Limit	250 - 1500	70 - 330 200 - 650 350 - 1200	225 - 1500	700 - 1300
LCM Size & Amount	Medium No limit	Medium No limit	No Restrictions	Fine-Medium 30 lb/bbl	No Restrictions	Medium 20 lb/bbl	No Restrictions
Surface Mud Screen	Yes	Yes	Not Required	Yes	Yes	Yes	Yes
Prs. Drop @ 250 gpm @ 500 gpm @1000 gpm	19 psi 77 psi 83 psi	17 psi 23 psi 70 psi	No Pressure Drop	30 psi 80 psi 280 psi	48 - 30 105 - 50 100	140 180 300	70 - 61 123 - 145 187 - 170
Pulsation Dampener	Yes to 75%	Yes to 60%	Not Applicable	Yes to 50-70%	Yes to 75%	Yes to 40%	Yes to 60%
Transmission Trigger	Not Applicable	Stop pumps, stop rotary, start pumps	Not Applicable	Low flow/ High flow	Stop pumps, stop rotary, wait 30 sec start pumps	Stop pumps, start pumps	Stop pumps, start pumps
Telemetry Type	Siren	Positive	Electro-magnetic	Negative	Positive	Positive	Positive
Wireline Retrieval	Nuclear Sources only	No	No	No	Yes (electronics)	No	No
Maximum Bit Pressure	no limitation	no limitation	no limitation	500 min 2500 max	no limitation	no limitation	no limitation
Logging while Steering	Yes	Yes	No	Yes	Yes	Yes	Yes

MWD Sensor Comparison - Directional

	Schlumberger Anadrill	Eastman-Teleco	Geoservices	Halliburton Geodata	Smith Datadril	Sperry Sun	Western Atlas
MTF/GTF inclination	Operator Selectable	3^o	Operator Selectable	Operator Selectable	Operator Selectable	5^o	Operator Selectable
Tool face update, sec	4.5 or 8.9 8.9 or 17.8	11.25	6	15	6.9 or 34.5	8.75 or 14	8
Survey time, seconds	82 or 132	55	96	84	78 to 271	96 to 332	136
Measurement Point	19 ft from bottom of collar	17 ft from bottom of collar	15 ft from bottom of collar	18 ft from bottom of collar	12 ft from bottom of collar	15 ft from bottom of collar	14 ft from bottom of collar
Tool face accuracy, Oo	1.5	3.0	2.0 MTF 1.0 GTF	2.0	1.5	2.8	0.75 MTF 2.0 GTF
Azimuth accuracy, Oo	1.5	1.5	2	2.0	1.0	1.5	1.2
Inclination accuracy, Oo	0.1	0.25	0.125	0.15	0.20	0.2	0.18

MWD Sensor Comparison - Gamma Ray

	Schlumberger Anadrill	Eastman-Teleco	Geoservices	Halliburton Geodata	Smith Datadril	Sperry Sun	Western Atlas
Detector Type	Scintillation	Geiger-Mueller	Scintillation	Scintillation	Scintillation	Geiger-Mueller	Geiger-Mueller
Measures	AAPI GR	AAPI GR	API GR	API GR	API GR	AAPI GR	AAPI GR
Real Time? Recorded?	Yes Yes	Yes Yes	Yes Yes	Yes Yes	Yes Yes	Yes Yes	Yes Yes
Spectral Gamma Ray	Yes	No	No	No	No	No No	

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MWD Sensor Comparison - Resistivity

	Schlumberger Anadrill	Eastman-Teleco	Geoservices	Halliburton Geodata	Smith Datadril	Sperry Sun	Western Atlas
Type	2 MHz Propagation	2MHz Propagation		Dual Resistivity	Guarded Current	2MHz Propagation	1MHz Propagation
Measures	Phase Shift Attenuation	Phase Shift Attenuation		Lateral Resistivity	Guarded Current	Phase Shift Attenuation	Phase Shift Attenuation
Real Time? Recorded?	Yes Yes	Yes Yes		Yes Yes		Phase Shift Yes	Yes Yes

MWD Sensor Comparison - Density

	Schlumberger Anadrill	Eastman-Teleco	Geoservices	Halliburton Geodata	Smith Datadril	Sperry Sun	Western Atlas
Detector Type	Scintillation	Scintillation (NaI)				Geiger-Mueller	
Measures	density, PEF	density, PEF				density	
Real Time? Recorded?	Yes Yes	Yes Yes				No Yes	
Source Retrievable?	Yes	No				No	

MWD Sensor Comparison - Neutron

	Schlumberger Anadrill	Eastman-Teleco	Geoservices	Halliburton Geodata	Smith Datadril	Sperry Sun	Western Atlas
Detector Type	Helium 3 Geiger-Mueller	Scintillation (Li6)				Geiger-Mueller	
Measures	Neutron Porosity	Neutron Porosity				Compensated Neutron	
Real Time? Recorded?	Yes Yes	Yes Yes				No Yes	
Source Retrievable?	Yes	No				No	

Quality Control Of MWD Services

Introduction

The quality control of MWD operations requires many of the safe guards as do wireline operations. Care and scrutiny must take place from the time the tools are on the rig, through their downhole operations, until the tool is returned to the service companies base.

The size, weight and expense of MWD tools necessitate that safety requirements be monitored to ensure there is no damage to the tools, or to the individuals moving the tools.

Bringing a MWD Tool On Board an Offshore Rig

When the MWD tool(s) arrive and need to be transported from the workboat to the rig, it is imperative that all personnel involved communicate throughout the operation. The personnel on the workboat, the crane operator, and the person on the rig deck must know the correct hand signals.

The area for storage of the tools should be selected beforehand to ensure there is no hurried cleaning or moving of tubulars. The crane operator must have specific instructions on how to lift the tool, carry the tool, and where to place the tool on the deck. Ensure that all applicable subs and crossovers are included in the shipment, and that they will connect to the drillstring.

When all tools are on board, review the paperwork with the service company's representative to verify that all the tools that were requested are present at the wellsite.

Initial Checkouts and Calibration

Before a MWD tool is attached to the drillstring, it should be checked out to ensure it is in working condition, and all the sensors, valves, generators, etc. are functional. The tool will have to be moved out of its carrying container and moved to an area close to the service company's logging unit (the cat walk is an ideal location). Box and pin thread protectors should be on the tool before it is moved.

The hydraulic parameters which will be used during the run should be rechecked to ensure the proper valves, screens, and nozzles are installed in the tool. The MWD crew should ensure that the relevant parameters are “initialized” into the tool and that communication between computer and tool are possible. Sensor calibration or verification of shop calibration can take place at this time.

Movement of the Tool to the Drill Floor

Any time a MWD tool is move, there should be constant communication between the MWD crew and the members of the drill crew performing the moving operations. Ensure that the thread protectors are on the box and pin threads before movement begins.

The tools have a standard carrying method, and it the MWD crew's responsibility to inform the drill crew members of that method and ensure that only that method is used. This will prevent damage to the threads and internal components.

Ensure that all subs and crossovers are on the drill floor prior to moving the tool. This will save time during tool make-up. Also ensure the pipe tally is correct before any make-up begins.

Make-up of the MWD Tool to the Drillstring

When the tool is ready to be connected to the drillstring, the thread protectors can be removed. The threads should be cleaned and inspected to ensure they are not damaged. The box and pin ends should be well lubricated with pipe dope. Some companies have a special dope for this purpose, Ensure it is used!

These tools should not be stabbed into position. Stabbing will damage the threads. Make-up torque specifications will be provide by the MWD company. Ensure these are followed! Tongs should not be placed on or near any sensors. The MWD crew should instruct the drill crew where to place the tongs.

When nuclear sources are being placed into the MWD tool, only those personnel with the proper training and certification should be allowed on the rig floor. If nuclear sources are used **All** certifications should be checked and **All** safety procedures reviewed and followed. Once the source is inserted into the tool, personnel can return to the rig floor.

If a float valve is used with the MWD tool, ensure it is fitted correctly and right-side up.

Pre-Drilling Checks of the MWD Tool

During the trip into the hole, the MWD tool can be checked to ensure that pulsing is taking place and the tool is functioning. Each tool has certain set points to tell the MWD tool's processor when to send data to the surface. Typical transmission triggers include:

- Stop pumps
- Wait fifteen seconds
- Start pumps

During fill-up, this procedure can be followed to see if the MWD tool will pulse data to the surface. Pulse traces can be observed in the MWD logging unit, and parameters such as pulse size, transmission speed, and data type can be monitored.

If the tool appears to have failed, a retest should be conducted. If the tool does respond to any retests, then a decision will have to be made whether to trip out and replace the defective tool or to continue to bottom and rely on the tool to record data while drilling and the memory “dumped” when the tool is on the surface.

Post Drilling Surface Checks

When the MWD tool is back on the surface, the tool should be observed for any damage which may have occurred during drilling. Particular areas to check are:

- The resistivity sleeve for wear and tear
- Any resistivity rings are loose
- Wires showing
- Erosion marks on the metal or outside bolts
- Erosion on the float valve or Totco ring
- Thread damage or galling
- Junk damage

Consideration can be made whether to rerun the tool or to lay it down and run another. Considerations include:

- Is this the only tool at the wellsite
- Are any of the sensors damaged
- Has pulsing stopped
- Is there still available memory
- Is it transmitting, but no memory
- Do the pulse sizes indicate significant wear on the pulser, which could mean failure on the next run

The MWD crew should be able to respond to these questions and provide their recommendations are to the ability of the tool to withstand another run. They should also be able to state the tool's “mean time between failure,” and these hours checked against the time on the present tool.

If there are any questions which remain unanswered and another tool is available and checked-out, it is best to run the newer tool. The old tool can then be laid down and a thorough inspection made of the components. If the tool passes these checks, it can be rerun.

If operating conditions have changed (flow rate, pressure drop, etc.) and the present tool cannot be modified, another tool will have to be run.

Shipment of MWD Tools Back to Base

Tools will have to be replaced if there is a failure, if the tool is close to failure hours, or if the MWD job is completed. The same carrying procedures should be followed. Box and Pin protectors should be placed on the threads, and the tool secured in its carrying container. Any special packing requirements are the responsibility of the MWD crew (these should be known and communicated in advance).

Conclusion of the MWD Service

MWD services can be conducted throughout the entire well or over certain sections (kick-off points, build sections, etc.). The service can be concluded due to excessive tool failure, or cost over-runs.

All logs, reports and plots should be received and reviewed as soon as possible. During the review process, the MWD crew should be available for questions, advice and recommendations. Points to note are:

- Do the log curves match up with the wireline curves? If not what are the reasons.
- Does the survey data match up other survey data? Is it acceptable for regulatory requirements?

All paperwork should be completed and reviewed. Any questions which arise should be answered before any reports or invoices are signed.

A written report concerning the service should be made and forwarded to the oil company. The report should include:

- Tool performance
- Crew performance
- Surface system performance
- Affect on drilling operations
- Any problems
- Recommendations on future use

The report should highlight the effects of the MWD information on the drilling operations. Was it cost-effective? Did the MWD operations save rig time? Was the MWD crew knowledgeable about their service, the tool, the surface system, and the log output? Did the crew provide recommendations concerning drilling efficiency, formation pressures and log interpretation? What else did the MWD service provide that proved useful?

Appendix **C**

Evaluating differences between wireline and MWD systems

Contrary to popular notions, sensor systems developed for MWD formation evaluation do have differences from their wireline equivalents in terms of design, construction, measurement, operational methods, interpretation and even environmental considerations

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IT HAS BEEN commonly, and erroneously, assumed that formation evaluation sensors run in measurement-while drilling (MWD) logging are identical to equivalent sensors used in wireline logging. Many systems, in fact, exhibit significant differences of various types. Because of these differences associated with sensors of a similar type, the system response of a particular MWD sensor may never be the same as the response of a wireline system of the same design, even when all environmental corrections have been applied. [1,2,3,4] This statement is occasionally true when comparing MWD systems of the same type but rarely true when comparing *wireline* systems of the same type [5,6,7,8,9,10]

Therefore, the unfortunate, but usual, expectation of exploration geologists, petroleum engineers and log analysts that a given MWD sensor response should be identical to an equivalent wireline sensor response has led to undeserved MWD sensor denegration by some otherwise very competent log analysts.[l1 12,13,14] Fig. 1 sketches generalized MWD and wireline multisensor sonde configuration; these systems are discussed in more detail below.[l5 16] Table I compares MWD and wireline formation evaluation sensor characteristics and Table 2 provides criteria for selecting wireline and MWD electrical systems on the basis of expected formation properties. [17]

These sensor differences can be described and tabulated as:

- Data Transmission, sampling and handling
- Operational
- Physical
- Design.

These differences, for appropriate sensors, are discussed in the following sections.

DATA TRANSMISSION, SAMPLING AND HANDLING

Currently, wireline sensor data, analog or digital, are transmitted to the surface via a multiconductor cable where the primary processing and recording (on film, tape, disk or all three) occurs. Power is supplied from the surface to the logging sonde and the measurements travel up the cable to the surface recording medium. Downhole power is limited by the number of conductors available in the cable, by cable diameter, insulation and condition and by logging depth. Data transmission is rapid; effectively, fiber optics cables have unlimited transmission rates. Digital data sampling for log presentation is usually at the rate of 2, 3 or 4 per ft. [18]

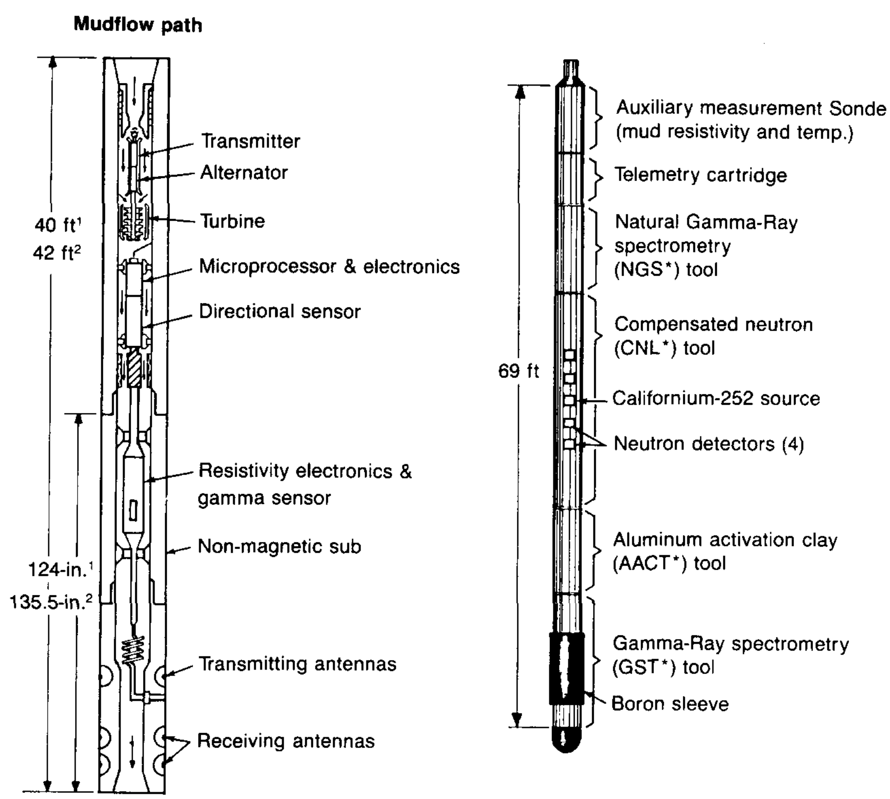

Figure 1 - An MWD Collar showing packaging of components (left), contrasted with a schematic of a wireline geochemical tool.

Many MWD collars contain a mud generator, so more power is available for operating sensors. However, transmission of measured or processed parameters is often via pressure pulses generated in the mud column by a mechanical valve, so the transmission rate is low and ultimately limited to a few parameters, and too infrequent sampling when several parameters are measured, or when there are several sensors collecting data.[19] Some MWD systems only record the data downhole and interrogate the collars at the surface during trips, or perhaps, with a wet-connect cable downhole. However, the latter approaches do not yield a near real-time log, the objective of MWD logging.

Table 1—A comparison between MWD & wireline measurements

Advantages MWD

- Drilling decisions
- Pre-invasion/washout formation measurements
- Completion decisions
- Fewer measurements required for analyses
- No additional rig time
- Inexpensive
- Slow logging speed

Advantages wireline

- Controlled speed
- High data rate acquisition/transmission
- Multiple measurements
- High system reliability
- Controlled measurements
- Accepted evaluation procedures & results
- Research well funded

Disadvantages MWD

- In developmental stages
- Low data acquisition & transmission rates
- Few measuring systems
- Environmental corrections & interpretation lagging
- Research funding lagging
- Reliability not acceptable
- Rig calibration difficult
- Few test facilities for instrument subs

Disadvantages wireline

- Increased rig time cost
- Run when invasion/hole washout predominate
- Fast logging speed
- Large environmental corrections required
- Expensive
- Questionable results
- Poor vertical resolution
- No drilling information/final completion data only

Table 2—Selecting MWD & wireline resistivity measurement devices

Wireline electromagnetic (deep induction)

- Applicable resistivity range for $\pm 10\%$ corrected readings: $0.2 \leq R_f < 100$ ohm-m; $0.02 < R_m \leq \infty$ ohm-m
- Best range of applicability: $R_f < 50$ and $R_m > 0.2$ ohm-m in hole diameters $< \approx 12.25$ in. & beds $> \approx 4$ ft.

MWD electromagnetic (2 Mhz systems)

- Applicable resistivity range for $\pm 10\%$ corrected readings: EWR $0.2 \leq 30$ ohm-m; $0.02 < R_m \leq \infty$ ohm-m EWR $0.2 \leq 50$ ohm-m; $0.02 < R_m \leq \infty$ ohm-m
- Best range of applicability: $R_f < 30$ and $R_m > 0.2$ ohm-m in annular spaces $< \approx 80\%$ of tool diameter & beds $> \approx 6$ in.

MWD or wireline 16-in. short normal

- Applicable resistivity range for $\pm 10\%$ corrected readings: $0.2 \leq R_f$ 50 ohm-m; $0.02 < R_m < 50$ ohm-m
- Best range of applicability: $R_f < 20$ and $0.2 < R_m < 5$ ohm-m in annular spaces $< \approx 80\%$ of tool diameter & beds $> \approx 4$ ft.

MWD or wireline focused current devices

- Applicable resistivity range for $\pm 10\%$ corrected reading: $0.1 \leq R_f \leq 1000$ ohm-m; $0.02 < R_m < 5000$ ohm-m
- Best range of applicability: $R_f > 20$ and $R_m < \approx 0.2$ ohm-m in annular spaces $< \approx 80\%$ of tool diameter & beds ≥ 6 in.

Logging speed has a large influence on all logging measurements, particularly those based on statistical yield like the radiation sensors. In wireline logging, radiation logs can be run at a controlled, slow speed (often 1,800 ft/hr or less), so enough events can be collected per unit time in the detector(s) to ensure statistical reliability and repeatability in the measurements. Wireline electrical devices can be run at speeds up to 6,000 ft/hr.

In general, it can be found that MWD logging speeds are governed by the drilling rate and may vary from 1 ft/ hr to several hundred ft/hr or more (in unconsolidated sands and shales of the U.S. Gulf Coast, drilling rates of 1,200 ft/hr or higher, are encountered). At a drilling rate of 60 ft/hr, and a transmission rate of one sample per minute (typically, one measurement from each of four sensors transmitted per minute, such as gamma-ray, resistivity and bit orientation and attitude) a reasonably detailed log can be obtained with only thin excursions being missed. However, at the same transmission rate and a high penetration (drilling) rate, there may not be enough samples per unit of vertical interval to define more than major changes in formation properties. At one sample per minute and a drilling rate of 600 ft/hr, each sample represents 10 ft of formation, and this log may miss the thinner beds. The data missed during mud pulse transmissions can be in-filled from the downhole memory, in which all data are stored, when the collar is interrogated.

This problem with transmission rate and logging (drilling) speed applies to all types of MWD measurements and is the primary drawback associated with mud pulse transmission systems. Fig. 2 is an example of the influence of logging speed, transmission rates and sampling rates on the resulting transmitted, focused, current resistivity MWD log. Three runs over the same interval are compared. All runs were made at nominal logging speeds of 300 ft/hr. During run A (left), data were averaged over a 2-sec acquisition interval and transmitted every 2 sec. This provides a high resolution log, which clearly demonstrates the excellent vertical resolution of the tool. During run B (middle), data were averaged over a 10-sec interval and transmitted every 10 sec. While obviously showing less detail, this run responds to all the major features of the interval. For run C (right), data were acquired and averaged for 2 sec during each 10-sec transmission period. Not unexpectedly, this log fails to delineate several of the beds in the section.

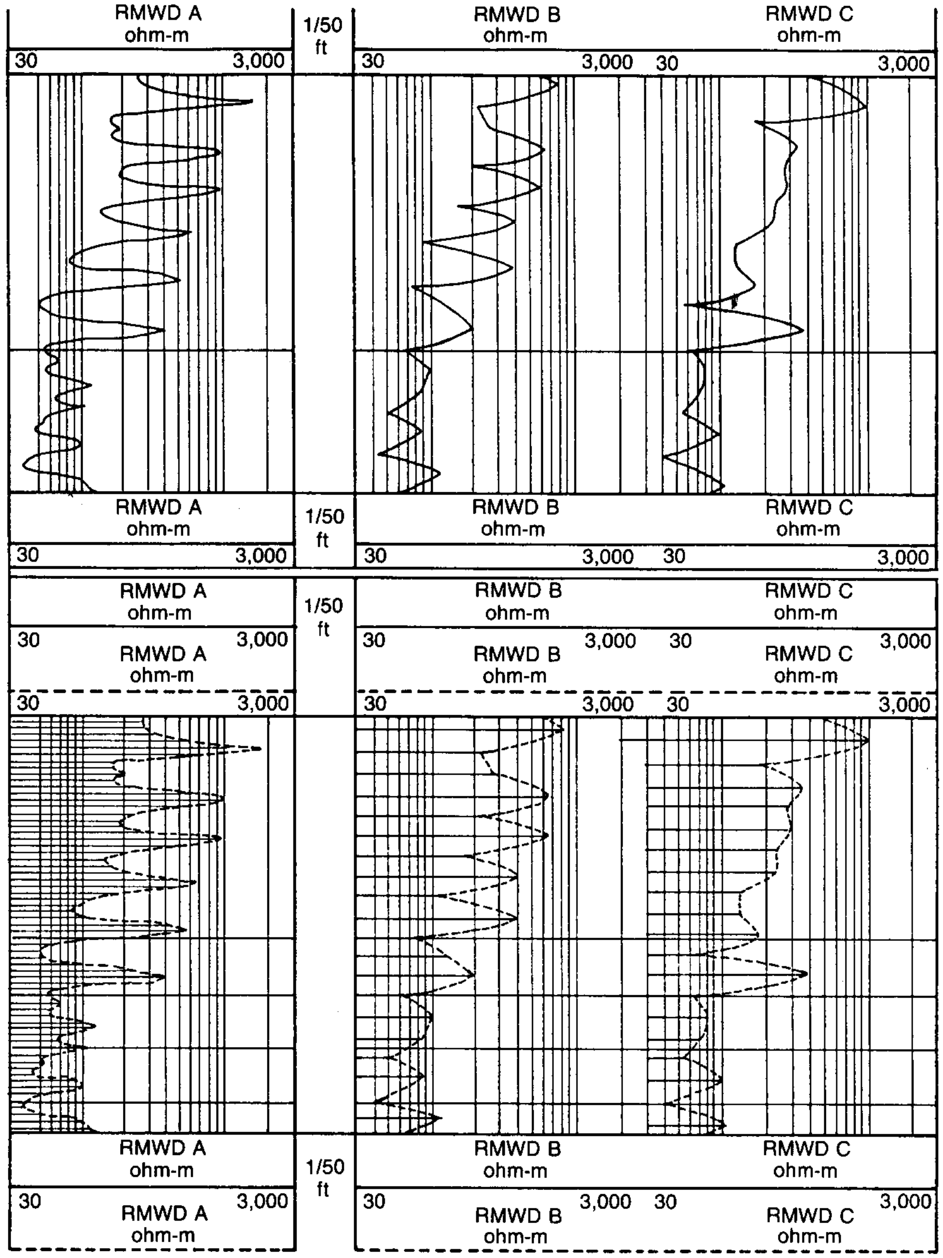

Figure 2 - Example of MWD focused current resistivity values obtained under diffferent sampling conditions: logs at the top; transmitted data at the bottom.

In the lower half of Fig. 2, the same data are plotted with the continuous logs shown as dashed lines and the transmitted data values shown as horizontal bars. This presentation confirms that the data transmission rate was comparable for runs B and C. However, the log derived from run B is more representative of the section than the spot-sampled run C. This example shows that data transmission rate controls the resolution achieved by the system but does not, by itself, ensure that data are representative.

The sample mode required to achieve this is a function of logging speed and the inherent vertical resolution of the sensor.[20]

PHYSICAL DIFFERENCES

Physical differences are those pertaining to logging sonde dimensions and construction, as shown by Fig. 3. In general, for example, MWD multisensor sondes are shorter and have larger diameters than wireline sondes. Specifically, several differences can be observed.

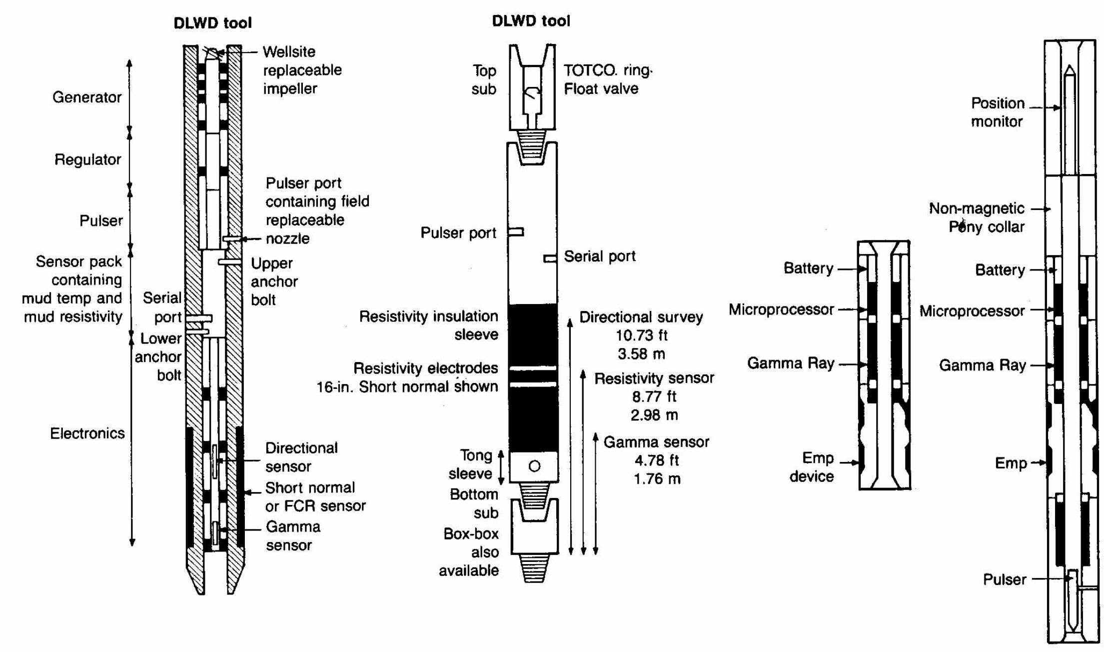

Figure 3 - Cutaway view of an MWD formation evaluation collar (left) contrased with an external view, with sensor locaitons. To the right is a battery-powered MWD pulse telemetry collar.

MWD sonde (the MWD collar or sub) lengths do not greatly exceed one standard drill string length, about 30 ft. and frequently can be less than 20 ft long, depending on the measurement being made.

Wireline sondes, on the other hand, can vary from less than 5 ft to over 100 ft in length, again depending on the various measurements carried out and their configurations.

Thus, a combination sonde can be configured to provide:

- Thermal neutron and epithermal neutron porosity measurements
- A neutron activation spectrum recording of formation hydrogen, chlorine, aluminum, iron and other selected elements
- Natural gamma-ray spectroscopy determination of K, U and Th
- A density, photoelectric absorption and gross natural gamma ray measurement plus caliper

- The Phasor dual induction conductivities plus Spherically Focused Log resistivity
- Downhole data processing, correction, correlation and transmission electronics packages can easily be 100 ft or longer when run in a single pass mode. Individual measurements such as natural gamma ray, caliper, etc., can be carried out in relatively short sondes, often 5 ft or less. Fig. 3 illustrates some physical aspects of both wireline and MWD gamma ray attenuation paths.

Standard openhole wireline devices have a diameter of 35/8 in., and standard production log sondes have 1-11/16 in. diameters. Specialized openhole devices may range up to about 6 in. in diameter, while specialized production sondes usually fall in the 3/4 in. to 2-1/2 in. diameter range. MWD sondes (collars), on the other hand, are always greater than 6 in. in diameter and, currently, do not exceed 9-3/4 in.; therefore, more “source strength” is required for MWD sensors to respond to a given formation than is required for wireline sensors of the same type. [21 22]

In standard wireline sonde design, probes usually are constructed to operate at downhole temperatures of 300° C or more and pressures of 20,000 psi, so sonde wall thicknesses of 1/8 to about l/2 in. are adequate, depending on the sonde diameter.

In the design of MWD sondes, the primary consideration is drillstring integrity in an environment where vibration, stretching, bending, acceleration and shock effects predominate, so structural strength of the collar as an entity within the drillstring is emphasized. MWD sonde wall thicknesses are between 5/8-in. and about 2-in. or more. Concerning response characteristics of radiation devices, this difference in wall thickness can significantly influence relationships between the MWD and wireline systems. Currently, MWD sondes operate slightly below 250°C and 20,000 psi, and most are in the 200°C and 15,000-psi range.

One example to be considered is the natural gamma ray sensor; in wireline devices, the relatively thin housing wall thickness attenuates gamma rays of a given energy much less than the thicker-walled MWD collars, so that the two systems, calibrated with the same source (the API test facilities, for example) do not yield same-response curves. Physically, the situation is clear, so one should not expect curves from the two systems to overlay; yet, many MWD gamma ray curves have been rejected by log analysts because they do not overlay wireline gamma ray curves run in the same intervals. [23,24,25,26]

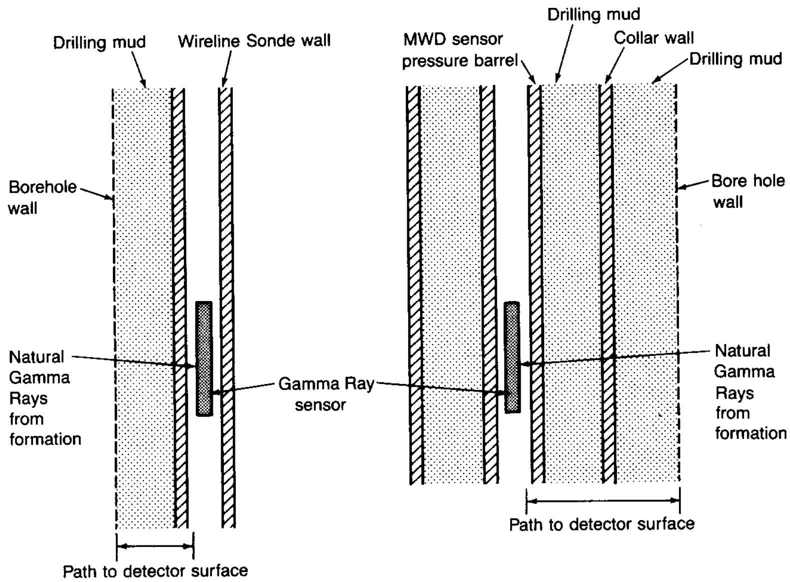

Figure 4 - Schematic drawing of the attenuation path encountered by gamma rays from the formation in a wireline sonde (left) and an MWD collar (right).

Coope, 1983, and Wilson, et al, 1985, have shown the attenuation in MWD systems to be several times greater than in wireline systems having the same size detector crystals, and the same gamma ray energy distribution (and mud density, of course), depending on the wall thickness. Wireline and MWD gamma ray systems are sketched in Fig. 4. For example, given a collimated point source of gamma rays of intensity I_o and average energy 1.5 MEV incident normal to the surface of steel housing of 5.7 gm/cc density and 3/8-in. thickness, as shown in Fig. 3, the gamma ray intensity of the inner surface of the detector is:

$$I = I|_o \exp-(\mu \times \rho_s \times d)$$

where y is the mass attenuation coefficient (cm^2/gm), which is gamma ray energy dependent, and ρ_s the density of steel (gm/cc), respectively, and d is the thickness of the steel wall (cm). If it is assumed that the gamma ray path through the mud in the borehole is identical for the wireline and MWD cases, one can ignore that contribution to the scattering in each and consider only the effects of the housing. Thus, for steel, $\mu = 0.055$ cm^2/gm, and $\mu_s = 5.7$ gm/cc. If d = 3/8-in., the result is:

$$I/\mathrm{I} = \exp-(0.055 \times 5.7 \times 0.935) = 0.746$$

A typical MWD steel collar can have a wall thickness of 3/4 in., an interior flow channel of annular thickness of 0.61 in. and a pressure barrel (detector and electronics) having a wall thickness of 1/8 in. If the mud density is 1.15 gm/cc, the result is:

$$I/\mathrm{I} = \exp -(0.055 \times 5.7 \times 2.23 + 0.06 \times 1.15 \times 1.55) = 0.447$$

(about twice the attenuation that is found in the wireline sonde), where the attenuation coefficient for mud is about 0.06 cm^2/gm.

If both the wireline and MWD systems are set to reject gamma ray energies above about 0.10 MEV (roughly the lower energy for compton scattering), the count rate in the wireline device must be greater than that in the MWD device for the same calibration, formation and operating parameters. Hence, one can expect the MWD system to record a higher count rate than the wireline device in a potassium rich environment, and a lower count rate than the wireline system in uranium/thorium- rich environments, [27, 28, 29, 30, 31] when both have been calibrated relative to the API gamma ray facility, for example.[32]

These same conclusions concerning physical characteristics apply to density and neutron systems, even though the principles of operation are different (see below).

OPERATIONAL DIFFERENCES

Operational differences are those related to environment, measurement mode, and corrections required. The density log is a good example: wireline systems are eccentered, so corrections are for mudcake thickness and density and, to some extent, borehole rugosity. The orientation of an MWD density system during measurement can vary from centered to eccentered while drilling. The correction is for the mud density and annulus through which the scattered gamma rays must penetrate (hence, for the amount of eccentering).

In both the wireline and MWD cases, a cross plot between the long and short-spaced detector count rates provides the basic compensation, once calibration for formation materials of known density have been established. In the wireline case, a combination of lab measurements and computer modeling provides the calibration of long and short-spaced detector count rates [33,34,35,36,37,38,39] However, the equations describing the MWD density log response at the two detectors requires that a measurement of mud density be available at each data acquisition point.

Perhaps the best way to provide these mud density data is to use a third, very short-spaced detector to continuously measure the mud density. Then, it is necessary to establish relationships between eccentering and formation density over a range of mud densities and borehole sizes.

That is, if CRls = Fls(ρm, Tm, ρf) and CRss = Fss (ρm, Tm, ρf) where Fls and Fss are functions of ρm, Tm and ρf, CRls and CRss are the count rates at the long and short-spaced detectors, respectively, ρm and ρf are the densities of the mud and formation, respectively, and Tm is the mud thickness (actually the effect due to eccentricity) of the scattered gamma ray path.

Then, if ρm is measured, Tm and ρf can be determined from the two count rates once the eccentering/mud density/ hole size calibration has been established for a range of formation densities. Lab and computer modeling are combined to determine this calibration.[40,41,42,43]

Some interesting design efforts have been carried out to attempt to compensate for the variable mud thickness that can be present during measurement. These include bundles of detectors on opposite sides of the collar as well as sources and detectors in stabilizer fins.[44,45,46,47] Very similar conclusions can be drawn concerning wireline and MWD neutron logging systems. [48, 49, 50, 51, 52, 53]

MWD gamma ray spectroscopy is operationally more difficult than wireline because of the greater attenuation caused by thicker collar walls and the mud flow channel within the collar, and because of collar diameter. Fig. 1, 3 and 4 illustrate the difference in attenuation paths. In the wireline devices, the natural gamma rays penetrate the mud column and a thin steel housing before striking the detector, usually centered within the tool. [54,55,56,57]

In the MWD case, however, the natural gamma rays penetrate a thick steel collar wall, then the mud flow channel and, finally, the pressure barrel having steel walls as thick as most wireline sonde housings. Each interface reduces the gamma ray energy resulting in more gamma rays scattered out of the path to the detector. The net result is that fewer gamma rays have energies high enough to be defined in terms of elemental source, so statistics are poorer, and the measurements are made with less accuracy in any given formation logged. Naturally, accuracy of the measurement can be improved by increasing the detector diameter or the number of detectors, but neither is easy to accomplish in the already crowded space available within a collar less than 30 ft long (see Fig. 1 and 4).

Thus, calibration in terms of centering or eccentering, mud density (and atomic number) and gamma ray source energy are much more critical in the MWD tool than in the wireline tool. [58, 59, 60] Again, MWD response in uranium/thorium-rich intervals results in lower count rates than that recorded by wireline sondes. Electromagnetic propagation (EMP) measurements also depend on coil size, number and spacing, source frequency and position within the borehole. In general, the non-sidewall wireline devices have higher source frequencies, more coils and larger spacings. The wireline tools are assumed to be pulled up the side of the borehole wall; invasion is a very large detriment to EMP wireline measurements. The MWD tools are considered to be centered. Neither assumption is always correct. There are no direct equivalent systems in EMP logging,[6l, 62, 63, 64,] but invasion is not usually a serious problem in EMP systems run in the MWD environment.

DESIGN

The differences between MWD and wireline sensors considered here are those for which it is necessary to modify a wireline equivalent method or instrumentation in order to carry out the measurement in the MWD environment with essentially the same response accuracy as is obtained with the wireline measurement. Often these differences are related to sonde geometry.

Concerning radiation devices, for example, wireline sources and detectors are centered. Detectors can be relatively large with scintillation crystals up to 3 in. by 12 in. for sensitivity enhancement. Furthermore, low-density (low atomic number) metals can be used for windows over the active detector area to increase count rates at all radiation energies. In the MWD radiation systems, however, sources and detectors may be eccentered or may exist as radial bundles of detectors to help to offset the effects of the collar mud flow channel attenuation. Detectors are smaller (a l/2-in. by 4-in. crystal is considered large) because of the limited space available for packaging.

Low-density inserts are avoided because of the resulting reduction in collar strength (or integrity). Furthermore, detection and compensation techniques must be modified to accommodate the normal MWD geometry. For example, some MWD density systems locate the source on one side of the collar or in a stabilizer, while detectors are often placed radially within the collar and/or the stabilizer.[65, 66, 67, 68] Because the possibility of losing radiation sources is somewhat higher in the MWD environment, elaborate source locking and retrieval methods have been devised. Wireline sources, when lost with the sonde, are retrieved, if possible, using wireline fishing tools. Retrieval of collars has never been such a straightforward procedure, so the chances of leaving a source in the borehole increase when using MWD systems. Again, similar differences exist for MWD and wireline neutron devices.

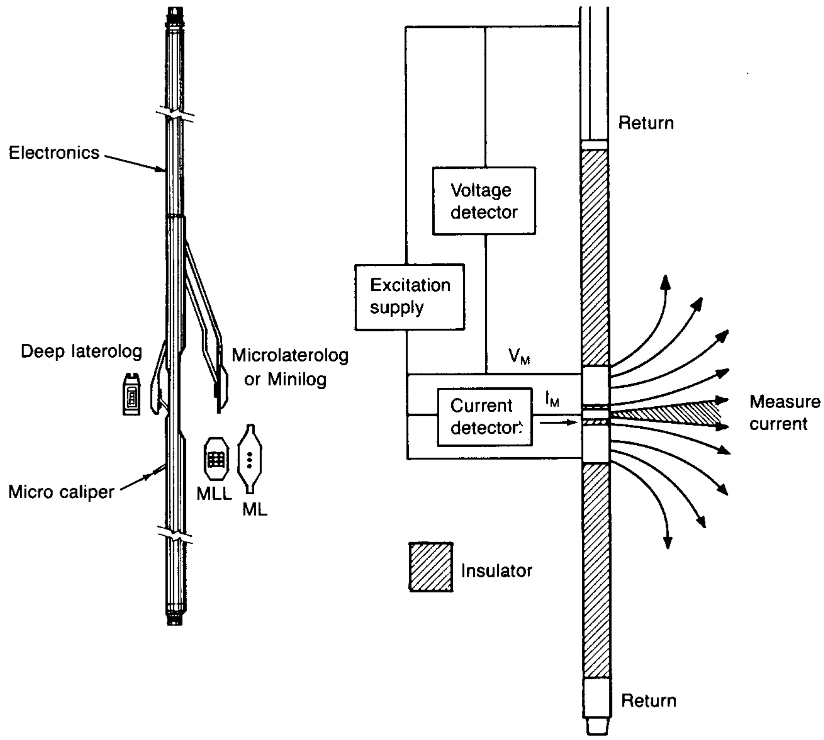

Figure 5 - Example of a wireline focused current resistivity device with focused current “R x O” reading sensor (left), versus an MWD focused current resistivity sensor (right).

Another example of a design difference is found in the focused current resistivity devices. Fig. 5 shows a sketch of a newer wireline device and a relatively recent MWD tool. For a given current strength, the current density of a wireline device is much higher than that of an equivalent MWD device, because the wireline surface area is smaller by a factor of about two to five. Thus, to obtain the same response specifications on an equivalent MWD system, the active current electrodes must be reduced in length and/or the current strength significantly increased.

Furthermore, because of the cable, wireline focused current system response can be referenced to a reasonably effective “electrical infinity” if the return electrode(s) is situated at the surface or at a point on the cable far removed from the sonde (perhaps 100 ft). Electrical infinity in the MWD system is, necessarily, the noninsulated end(s) of the collar (a distance of a few meters at most). As a result, extreme depth of investigation is not obtained (and in most cases, not needed) from MWD focused current devices, while vertical resolution for an equivalent geometrical and operational system is often much better.[69.70,7l,72,73]

Naturally, MWD electromagnetic propagation systems require larger diameter coils and operate at lower source frequencies than wireline systems, so the response characteristics are proportionately different. The non-sidewall wireline EMP devices have more coils and larger coil spacings than MWD systems. Responses of the wireline tools are significantly influenced by filtrate invasion into the formation, which has only minor effects on MWD systems run near the bit.[74, 75] Fig. 6 shows the environmental resistivity conditions under which specific wireline and MWD sensors operate effectively when constrained by environmental and operational errors not exceeding 20%.

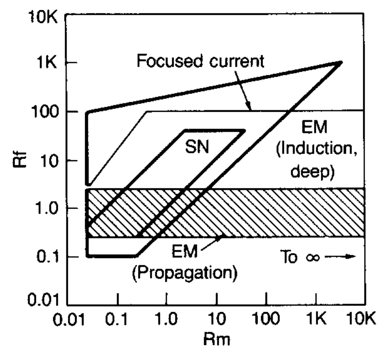

Figure 6 - Acceptable response under operating conditions specified (only 20% environmental and response corrections permitted).

RESEARCH SYSTEMS

Although nothing has been published to date, several research projects, representing the work of a number of companies, could add useful, new MWD formation evaluation sensors to the several now in various stages of development and application. Basically, these systems fall into three categories, but these do not represent more than a small portion of the efforts being expended in MWD research:

- Sonic logs and related acoustic measurements
- Nuclear resonance measurements
- Pulsed neutron applications.

The sonic studies range from sonic logs similar to those used in wireline logging to running VSP geophones in the MWD collar and the application of downhole noise generated while drilling as a seismic source. [76, 77, 78, 79] Design of an MWD sonic log could be very similar to that of current wireline devices, but small transducers located circumferentially on the collar would cause minimal reduction in collar strength. Since centering is important in obtaining good sonic logs, MWD provides a reasonable environment for these measurements, particularly if stabilizers are employed. At the source frequency of standard wireline sonic systems (10 Khz to 30 Khz), the drilling and vibration noise interference with sonic measurements is unlikely, because these sound sources are predominantly below I Khz.

Information available from an appropriately instrumented and recorded MWD sonic log include porosity and permeability estimates, lithology determinations, fracture detection, microgeological features, a sonic caliper, etc. Information available from studies concerning a possible MWD nuclear magnetic resonance (NMR) system suggest that in order to obtain the necessary response characteristics, high field strengths and very stable centralization would be required. There is enough power available from a mud generator to energize the coil, but standard stabilization methods may not be sufficient to permit acceptable NMR measurements to be carried out in the MWD environment.

Wireline NMR devices always have suffered from a shortage of power with which to energize the polarizing coil. The most successful wireline systems require sonde eccentering and sample signal stacking to obtain statistically significant NMR response. The NMR measurement is potentially extremely valuable in formation evaluation, because it can yield a free fluid porosity value essentially independent of the influence of clay in the formation. It can be interpreted in terms of irreducible water saturation and finally, when long-term proton signal decay curves are recorded, it can be used to determine the types of fluids in the pore spaces and their relative amounts. These data can make significant contributions to evaluating formation properties, particularly fresh water and heavy oil problems. A sketch of a wireline system representation is shown in Figure 7 [80, 81, 82, 83, 84, 85]

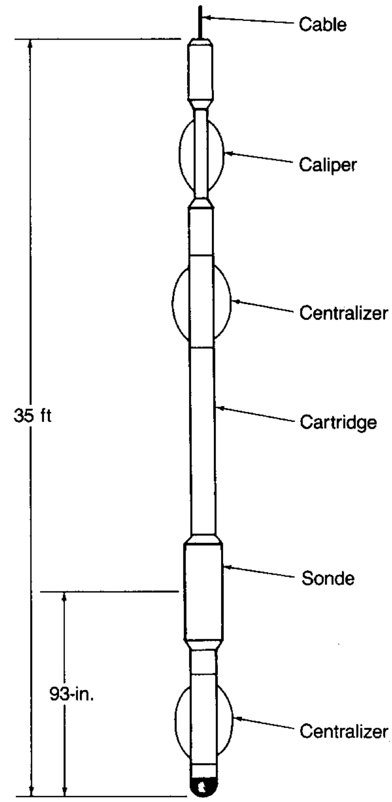

Figure 7 - Tool configuration for a wireline logging sonde utilizing nuclear resonance.

Wireline pulsed neutron devices can be extremely versatile in terms of measurements carried out and information obtained. They can be used to obtain:

- Epithermal, thermal or capture gamma ray-derived porosity
- Relative amounts of hydrogen, chlorine, iron, aluminum, magnesium, silica and other elements in the formation
- Density and photoelectric absorption value under certain conditions
- K, U and Th values from natural gamma ray spectroscopy when the source is off and other parameters. The largest difficulty anticipated in adapting the pulsed neutron system to the MWD environment is in sufficiently “ruggedizing” it to handle the high accelerations and shock associated with the drilling process [86, 87, 88, 89]

TERMINOLOGY

1. A log is the visual display of one or more downhole physical or chemical measurements or parameters as a function of depth in a drillhole or as a function of time.
2. The word log used with a descriptor like density refers to the type of measurement carried out.
3. Device, system, sensor, logging tool and sometimes sub all refer to the downhole measurement method and the detection arrangement by which it is carried out.
4. Sonde, probe, collar, and sub all refer to the physical hardware within which electronics, sources, detectors and support equipment reside.
5. Wireline systems are those logging systems that operate at the end of a cable having one or more conductors; wireline logging is usually carried out days or weeks after the well is drilled, so a significant part of the sensor response is due to borehole washout and the filtrate invaded part of the formation.
6. Measurement While Drilling (MWD) refers to logging measurements carried out from a collar or sub above the drill bit. Measurements near the bit are little influenced by washout or invasion and can provide more realistic values of the formation properties than multiple measurements carried out later.

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