CHAPTER SEVEN

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SCHLUMBERGER OPEN HOLE MEASUREMENTS

INTRODUCTION

As I indicated in chapter 6, this particular chapter will concentrate on geophysical measurements in uncased or so called open-hole. You were introduced to the general equipment associated with all logging in that chapter as well as the concept of depth control and the logs and records that are made. This chapter will deal with evaluation of the formations the well has penetrated so a decision can be made whether to run casing or not. The decision can't be made lightly because the cost of such an operation nearly doubles in most cases. I would like to leave you with an overview of that evaluation process as we consider the various measurements that can be made to help the oil operator make such a decision.

Although most, if not all, of the terms I will include in this chapter were covered to one degree or another in chapter five, it would seem a review is in order. Such terms will be sprinkled liberally throughout the following discussion of the various geophysical measurements, which Schlumberger is involved in. I won't make this laborious but only thorough enough for you to become conversant with the terms that will come up later. Maybe then, you won't get hung up on them as the operational theory of various geophysical measuring devices is explained. We'll classify these geologic terms in groups to make them easier to understand and remember. We'll even try to relate them to some everyday items with which you are already familiar. You know, kind of like the Lord did in his parables of the New Testament. Of course, one may come away from such an explanation as confused, if not more so, than many of the people were with the previously mentioned parables. Let's hope not, however. Besides, nothing ventured, nothing gained as the old adage goes.

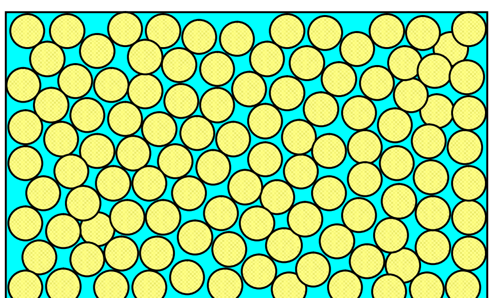


Figure 7-1 An illustration of porosity in a water filled sandstone.

COMMON OIL FIELD SEDIMENTS

By and large, oil field rocks are sedimentary in nature; meaning the particles of which they are composed were transported to the depositional site by rivers, currents, wind, etc. They are of three basic types, i.e. clastics, precipitates and evaporites. Sand - shale sequences are clastics and are the most common type of oil field rocks in my experience. In many areas, however, limestone-dolomite sequences are also prevalent and can be either clastic or precipitate in nature, though the latter is most common. Evaporites are often interleaved with precipitates and it would seem they mostly just complicate geophysical measurements, at least in the oil field. Of course, they also have economic value in many cases, if and when found at the proper depth. Where such evaporites have to be mined in solid form, like coal is, obviously depth is an important economic parameter to consider.

ROCK PARAMETERS

Rock composition is an important geologic parameter and must be known or otherwise determined when deciphering the various measurements made with a well log. The mineral composition of rocks affects the response of many logging devices and has to be accounted for when determining the value of other important rock parameters associated with common oil field sediments. So, I'm going to take time to briefly review the composition of the more common oil field sediments, as groundwork to simplify future discussions.

SANDSTONES

Sandstones are obviously composed of sand grains transported to the site by streams and ocean currents. They are composed primarily of quartz (SiO_2) and as they are laid down in layers or so called beds and buried they become compacted. There is void space separating the grains of sand, which is termed porosity. It is measured as a percent of the total rock volume and may reach as much as 40%. With depth of burial and time much of the pore space can be filled in by compaction and/or precipitation from percolating ground waters. Commonly the precipitates are calcareous ($CACo_3$) or Siliceous (SiO_2) in nature. They fill in the void space and destroy permeability. Consequently, such sandstones often have very low porosities in the order of 2-4 %. Void space is also referred to as the interstices from which the term interstitial water is derived. Such water is that which is laid down with the sand as it is deposited and/or altered with time.

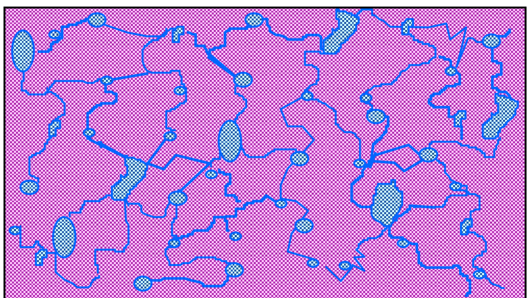


Figure 7-2 A simplified illustration of water filled vugular porosity.

CARBONATES

Carbonates can be either limestone (CA_2CO_3) or dolomite ($CAMgCO_3$). The latter usually is derived from limestone through the action of ground water. Both are normally precipitates but may be of clastic origin if the source beds were carbonates. Similarly, carbonates normally have vugular porosity to supplement any natural porosity established in the depositional process. Vugular porosity is that void space carved out through solution by those pesky percolating ground waters, once again. Such voids may be small and scattered through the rock or, in the extreme, big caves such as Carlsbad Caverns.

Quite simply that means, "There are some mighty big vugs hidden deep beneath the surface".

Experiences have been described by drilling crews wherein a drill string has dropped several feet instantaneously while cutting a carbonate section with accompanying lost circulation and a damaged drill string. Quite simply that means, "There are some mighty big vugs hidden deep beneath the surface". Such stories should give hope to the avid spelunker that many frontiers still await to be crossed in searching out the bowels of old mother earth. In fact, I dare say such frontiers lie below and beyond anything a man of reason would want to explore. I suspect, however, there are some spelunkers, individuals with little or no reason for probing the earth except for the thrill of it, who would like to probe any cavern they find.

POROSITY

Porosity is another parameter critical to the evaluation of geophysical measurements. It has already been defined clearly but I might emphasize that it occurs in the two forms mentioned, i.e. inter-granular (between grains) and vugular. An example of inter-granular porosity is illustrated in figure 7-1 while figure 7-2 illustrates vugular porosity. The light blue, of course, represents water while the yellow indicates sand grains. Similarly, the magenta represents carbonate rock matrix, with little or no porosity. One can see the more erratic nature of the vugular porosity with its associated permeability.

As a matter of perspective, consider the oil field that has a 10-foot thick sand spread over 1 square mile with 15% average porosity. Within that porosity lies 10,000,000 barrels of space of which maybe 6,000,000 would typically be full of oil and the remaining 4,000,000 barrels would be interstitial water or so called irreducible water. That is, water that can't be moved because it is held tight by molecular forces. Now, double that porosity to 30% and the field holds 12,000,000 barrels of oil. With a good water drive, 70% of the oil would be recoverable or 4,200,000 barrels in reservoir of 15% and 8,400,000 barrels in that with 30% porosity. If the price of oil were $20 per barrel, a little low in today's market, the value would be $84,000,000 and $168,000,000 respectively. No wonder those Arabs are so rich. Little field, brings big money. A big field brings "mucho grande dinero, senor". Our Arabic friends definitely fall into the latter category. For some reason the Lord smiles upon their sub-surface regions, maybe because He seems to frowns on the surface regions. Yep, that's where their big bucks are found; down there with that black liquid gold.

PERMEABILITY

Another important parameter mentioned in chapter five was "permeability" whose unit of measurement is the millidarcy. It is derived from the name of the man who suggested its need, Lord Darcy, a Frenchman. Of course, his wife, Lady Darcy was named Millie, hence the term millidarcy. He accomplished the work while she acquired fame for her name.

Actually, that's not quite right and such a statement falls somewhere in the category of "a little baloney", which I promised. In fact, I'm just a little embarrassed for imagining I could snooker you, who come from such fine stock. Being the technocrats that I feel sure my posterity must be, you know the term milli means "one thousandth" in the metric system or the millidarcy is simply one thousandth of a Darcy. The latter term did come from a scientist whose name was Darcy, however, and in all sincerity, I believe he was French. Permeability is expressed in millidarcies as mentioned earlier because typical values measured in rocks range from one or less to maybe a couple of thousand millidarcies. Thus, it provides a convenient unit of measurement for that parameter.

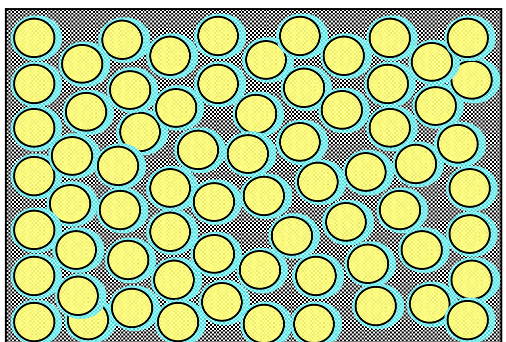


Figure 7-3 A simplified drawing of sandstone inter-granular porosity filled with oil and irreducible water.

This parameter (permeability) is next to impossible to determine in situ or in place and has proved to be very illusive to measurement in quantitative terms. Several devices have inferred its presence to one degree or another and reasonable values have been established through back door approaches from the values of other related parameters.

FRACTURES

I should mention the fracture here. They are nothing more than a giant crack in the sub-surface rock. Fractures do occur in nature and produce tremendous permeabilities. They are the equivalent of a pipeline leading from deep within the formation to the well, when open and encountered. As you saw in chapter five, they are also induced artificially through hydraulic pressure and held open with propping agents. Good permeability is essential to a good well. Ten million barrels of oil in reserve are of little value if they can't be produced.

FORMATION WATERS

Connate water and interstitial water are additional terms well loggers must contend with. Connate water refers to the original water laid down when the sand was deposited and reflects the salinity of such seawater. Interstitial water is the water, which is present within the void or pore space at any given moment of time. It may be connate or original in nature or it may be altered with time by fluid movement. The two terms are often used interchangeably though not strictly correct. Thus, we might say, interstitial water is the formation water typically found in porous rocks, which, though present during deposition of the rock, may have been altered through fluid movement later. Connate water typically becomes saltier with depth of burial but mineral content in solution varies widely. The most common mineral found in such water is $NaCl$ or Sodium Chloride, common table salt. The $NaCl$ content establishes the water's conductivity or its ability to conduct electric current. Geophysicists utilizing well logs are very interested in a rock's conductivity, or its reciprocal resistivity, in any zone of interest because they influence the final interpretation of well log measurements.

IRREDUCIBLE WATER SATURATION

In chapter five we explained how hydrocarbons migrated through porous permeable formations until finally trapped by some structure or sediment change, which prevented further movement. Because of the lesser density of oil and gas, they move up dip or up slope in the rock and continuously displace the water in their path as they progress. When a trap is encountered, all water that will move is eventually displaced until hydrocarbon entry ceases. In the trap, the total fluid is then composed of irreducible water (that which won't move) and hydrocarbon (either oil or gas or both). Typical values of irreducible water found as a percent of porosity ranges from 25% to about 70% and are related to permeability. This is illustrated in figure 7-3. The yellow spheres represent sand grains, the blue halos irreducible water and the remaining part of the black interstices, the oil saturation. The water saturation, S_w, under these conditions was shown in chapter five to be

1) $S_w = 1 - S_h$

In other words, the percent of volume (porosity) not filled with hydrocarbon. This is interesting but of little value unless it can be related to something we can measure. Well, it so happens, that resistivity can be measured in a number of ways and can be related to water saturation, so let's see just how the two might be brought together.

THE FORMATION FACTOR

It was found through various studies that the ratio of the resistivity of a porous rock saturated with salt water when compared to the resistivity of the water itself was always constant. This ratio was given the name "Formation Factor" and was designated by F. That is;

2) $F = \rho_o / \rho_w$ or $\rho_o = F\rho_w$

Where ρ_o was the resistivity of the salt water saturated rock and ρ_w the resistivity of the salt water. Since both ρ_o and ρ_w could be measured, F could now be calculated. The next challenge was to relate F to porosity, which was accomplished by Archie, a Shell Oil Co. research geologist, as well as by scientists of Humble Oil Co. now known as EXXON. Archie found in many cases that porosity, symbolized by the ancient Greek letter Φ (PHI), pronounced fee and F were related as follows:

3) $F = 1 / \Phi^2$

Whereas Humble Oil Co. derived the equation:

4) $F = 0.62 / \Phi^{2.15}$

as it applies to certain gulf coast sandstones. The general form of both equations 2 and 3 can be written as shown in equation 5.

5) $F = a / \Phi^n$

Where the letter a may be assigned a value of 1 or 0.62 and the letter n assigned values of 2 or 2.15. Small variations of the constants in these equations have been made and utilized since for special cases. Now you understand why, when referring to the more complex statements, many people say; "It's nothing but Greek to me".

WATER SATURATION

Archie pursued resistivity measurements of rock samples when oil was introduced into the pore space with the water and came up with a mathematical relationship, which can be expressed in a variety of ways, i.e.;

6) $S_w^2 = \rho_o / \rho_t = F\rho_w / \rho_t = \rho_w / \rho_t \Phi^2]$

Where ρ_t is the resistivity of a rock containing hydrocarbon and the other symbols (S_w, ρ_w, ρ_o, Φ and F) are defined as described earlier. This work opened a couple of avenues by which one could determine S_w in situ (in place) around the well bore which we'll see more of later.

IS GRANDPA NUTS?

By now, many of you who aren't mathematically inclined may be shaking your head at this basic algebra and muttering, "What's grandpa up to anyway. The old geezer has gone bonkers if he thinks I'm going to read this stuff." Well, it's not as though I expect everyone to enjoy "this stuff" but there might be one or two as weird as I am out there and besides, you gotta have an idea, of sorts, about Schlumberger technique if you want to enjoy chapters nine through sixteen. Remember, they are the ones that contain my Indiana Jones type adventures including teeth rattling, stress laden, even death-defying experiences, which you simply won't want to miss. So, learn the basics and shape up. Also, so as not to worry you more sensitive souls, there's no test over the technical part until you all arrive at my quarters beyond the veil where my interrogation facilities will be established.

Remember, they are the ones that contain my Indiana Jones type adventures including teeth rattling, stress laden, even death-defying experiences, which you simply won't want to miss.

MORE FORMATION CONCERNS

There are some other variables affecting logging measurements, which we should review with the reader too, before getting into the actual logging. These are the effects of invasion, bed thickness in the zones of interest and borehole considerations. We'll generalize here for simplicity and get more specific later as those items become a factor in the accuracy of the device we happen to be considering. As you will see, it's not simple.

THE MECHANICS OF INVASION

By now the real astute reader should have some appreciation for the mechanics of invasion. Don't worry, however, **"if you are not astute or simply don't give a hoot"** because old grandpa will drag those principles by you one more time. Remember, in rotary drilling, well control is maintained by keeping the hydrostatic pressure within the well bore some two to three hundred pounds higher than formation pressure. Hydrostatic pressure is, of course, the pressure applied to the rock surface around the perimeter of the borehole by the mud or fluid within the borehole at any given depth. Formation pressure is determined by the overburden or depth to which it is buried and increases with depth, as does the hydrostatic pressure. This allows a given mud weight (in pounds per gallon) to control fluid flow from all permeable formations encountered.

MUD CAKE FORMATION

The borehole fluid (mud) tries to flow into formations, which are permeable (sands primarily), because of the positive differential pressure, i.e. the hydrostatic pressure is higher than formation pressure. In so doing the mud solids (clay, barite, etc.) are stopped by the sand (like a coffee filter) where they build up a mud cake. The mud cake eventually forms an impermeable wall and prevents further fluid flow or so called water loss, i.e. that of the filtrate into the rock. Some mud types allow a good deal of filtrate to move into the formation before the cake seals off the sand (high water loss mud) and others allow very little (low water loss mud). The former allows thick mud cakes to build up and the latter thin tough mud cakes.

CHANGING WATER RESISTIVITY

Near the borehole, i.e. just behind the mud cake, all formation water is normally flushed back into the formation and replaced with filtrate. Beyond that lies a transition zone composed of a mixture of filtrate and formation water. It is called the invaded zone whose resistivity is designated by term ρ_i. With distance from the borehole, this mixture finally gives way to pure formation water and that undisturbed area has a resistivity designated by ρ_t. Figure 7-4 provides an illustration of this effect. For convenience I have chosen to designate the latter two zones by their resistivity designations, i.e. ρ_i and ρ_t. Now, why go to so much trouble of explaining the details of invasion? Well, unfortunately, it affects many of our measurements and must be compensated for in various ways. Additionally, Schlumberger turned this problem around and utilized it to provide a means of indicating permeability (qualitatively) as well as a method to determine porosity, as you'll see later. So, it's a problem but not all bad because it also produces some favorable attributes.

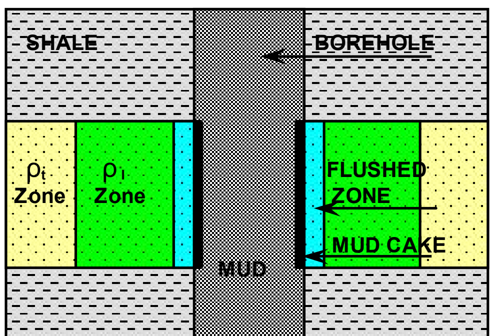


Figure 7-4 An illustration of the various zones of an invaded sandstone with their designations.

BED THICKNESS

Bed thickness could make it difficult to determine the true resistivity of a bed because of the influence of surrounding formations. At that time, as late as the early sixties, deep reading devices (those that could reach beyond the influence of the invaded zone) were more adversely affected by surrounding beds than were shallow reading devices. Also deep reading devices also had a tendency to ignore thin beds or register very small anomalies. Thus, logging devices had to be compromised (like many things in life) such that their responses were optimum under normal conditions.

BORE HOLE INFLUENCE

Boreholes, though essential for access to formations of interest, also affect the logging measurements, which are made. For those devices requiring it, the mud provides an electrical connection through its conductivity to the formations. However, the mud can also influence measurements in an adverse way because of its salinity and the size of the borehole. Thus, tools had to be designed to minimize that effect, in so far as possible, so the devices would respond to the surrounding rock. Remember, our goal is to determine the properties of a specific bed of interest. Many areas of the world contain salt beds among the sediments, which must be penetrated to reach oil-producing horizons. The resulting salt saturated mud produced adverse effects on the measurements of various resistivity devices. That problem resulted in the development of a parallel battery of tools, which provided data in a salt mud environment similar to that acquired in a fresh mud environment. These and other points will be clarified in the discussion of specific devices. The point is, Schlumberger had to design systems to acquire data desired by oil companies regardless of the drilling environment, which in turn was controlled by old Mother Nature. As you will see, this resulted in many different types of devices.

OPEN HOLE LOGGING

When it comes to wire line work, logs are run in the open hole (uncased) as well as inside casing for somewhat different purposes. There are several types for each application, hence the term "Open Hole Logging". Logs, I might explain, are simply records of all the various measurements made in a drill hole much like a supervisor's log of a shift's production or other such activity for a given time frame. In the case of the well log, the basic data was recorded as a continuous measurement of some formation or bore hole parameter, i.e. resistivity, radioactivity, temperature, etc. versus depth in the hole and presented in graphical form. The geologist can then make various decisions regarding the zones of interest much like the shift supervisor.

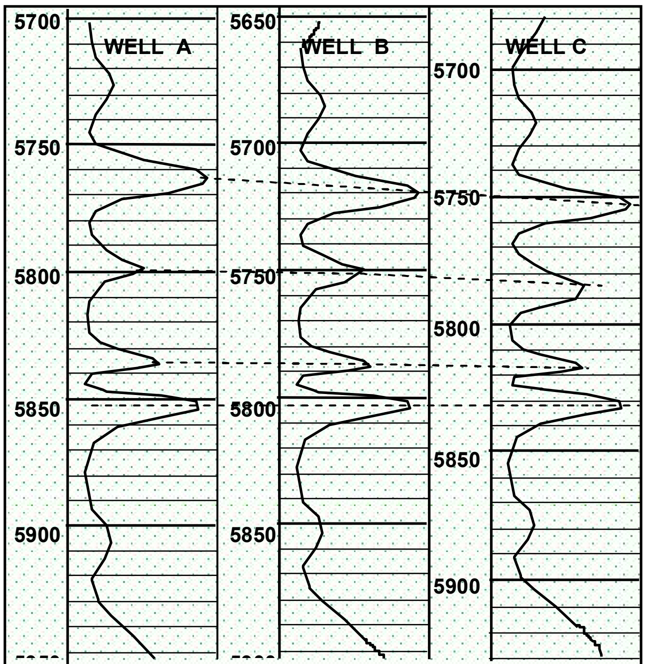


Figure 7-5 A drawing illustrating the correlation of resistivity logs between wells.

THE RECORDING OF DATA

From chapter six you will remember that the medium on which it (the data collected) was recorded, when I began work, was photographic film only. From such film any number of prints could be made once it was developed and dried. The product looked a bit like an electrocardiogram, which is used so commonly today. The film came in roles 9" wide and 150 feet in length. The film could be cut to length with each operation. In the case of an electrocardiogram, the heartbeat was recorded versus time on paper whereas here, the well parameter of interest is recorded versus depth on transparent film. Figure 7-5 illustrates the recording once again which was described in more detail in chapter six. In Schlumberger's case, you will recall, a light beam from a galvanometer mirror produced the trace on the film and recorded the measured value rather than a needle. It was extremely accurate in terms of printing the trace on the film grid (horizontal and vertical lines expressing depth and measured signal value) but it was necessary to calibrate the signal involved with the galvanometer so as to include all the variables involved in the measurement.

In later years the records were also made on tape for processing by computer. The film and prints are necessary for well site computations and decisions as well as quick decisions in the office. More detailed computations take place later via the computer. When I retired from Schlumberger, computer technology and associated processing was in full use including many computed products in the field. With changes as rapid as they have been, I don't know what's available for field decisions these days. I probably wouldn't recognize products in use today but then, who cares, Schlumberger people wouldn't recognize me either.

The film or associated print, though used for formation evaluation, has another very important use, namely correlation of the formations penetrated in that well with nearby wells. This helps the geologist to ascertain structural position of the borehole as well as identify faults and changing geologic section. In figure 7-5, I have illustrated a typical resistivity curve for a newly logged well together with similar curves from nearby wells to give the reader an idea of the correlation principle. Assume well C to be the new well. At 5832 feet in the well, an anomaly is correlated horizontally across all three wells. This is the reference correlation. From that point upwards, one can easily see the other correlation points but it is obvious the sections in wells B and C are thinning relative to that in well A. Notice the lines of correlation slant downward to the right. Structure or the relative sub-surface levels of various correlation points for each well can only be accomplished through correction to some permanent datum such as sea level. This requires the geologist to account for differences in elevation of each well's zero point, usually the Kelly Bushing (KB).

Effective correlation can be done with many different types of logs, analyses and/or curves. The geologist often correlates drill time logs, as well as sample logs, both of which were described in chapter five. However, resistivity and other types of wire-line logs are the most accurate because of the consistency of the data recorded. Likewise, cased-hole logs are correlated to open-hole logs to precisely establish zones for perforation. In short, one of the major uses of all kinds of well logs is to correlate the various formation anomalies.

RESISTIVITY LOGS

In general, resistivity logs constitute the basic open-hole measurement to which all others are supplementary in nature. They have come in various forms depending upon borehole conditions, the state of the art and special requirements of the industry. The term resistivity describes an intrinsic property of various materials including those naturally occurring and those fabricated by man. Metals generally have a very low resistivity and are termed conductors, while rubber, glass, plastics, etc. have a very high resistivity and are referred to as insulators.

Fluids can have varying values of resistivity depending upon their own intrinsic makeup and their ability to dissolve electrolytes. Water has a high resistivity in and of itself but readily dissolves electrolytes, which then determine the resultant fluid's resistivity. Thus fresh water (low salinity) has a high resistivity while salt water saturated with Sodium Chloride (NaCl) has an extremely low resistivity and of course, subterranean waters exhibit different values of resistivity somewhere in between according to their various salinities.

Oil and gas, on the other hand, exhibit high intrinsic values of resistivity but don't dissolve salts of any kind. One can easily see that the resistivity exhibited by a rock whose grains are insulators is thus determined by how much water it contains as well as that water's salinity. If hydrocarbon is present, that reduces the space available for salt water and raises the resistivity of the rock. Consequently, such a curve or measurement related to a formation is valuable in determining its fluid content.

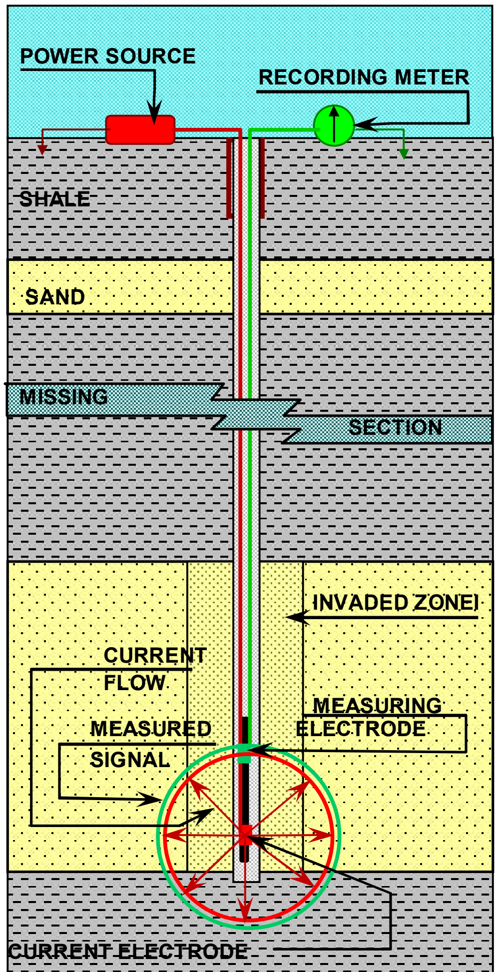


Figure 7-6 A simple illustration of a normal curve electrode system.

Resistivity measuring devices actually measure resistance, which is not intrinsic to the material but also depends upon the sample dimensions. Resistivity and resistance are related to one another by the equation;

7) $R = \rho (L/A)$

Where R is the resistance of the object; ρ the resistivity; L the length of the sample being measured and A is the cross sectional area through which the current flows. If we rearrange it to express resistivity in terms of resistance, we obtain;

8) $\rho = R(A/L)$ or $\rho = R(K)$

K means constant and simply means the last version of the equation applies if we keep the sample dimensions constant. This is done in resistivity well logging which allows the logging engineer to scale his measurements in terms of resistivity. Each particular type of device used to measure resistivity in a borehole has a different K value, which describes the geometry of the sample whose resistivity is being measured by that device. It, the value of K, in turn, has been determined by the design of the device, which has established the sample geometry.

THE ELECTRIC LOG

This was the device the Schlumberger brothers brought to America but it had undergone a great deal of evolution by the time I arrived on the scene in 1955. The same thing could be said for the means of recording the various measurements that were made. By that same year the so-called R9 recorder had emerged, which allowed the recording of 9 separate signals simultaneously. This reduced recording time and enhanced the final product.

The electric log of the 50's provided three different resistivity measurements, which combined to help the logging engineer circumvent the adverse effects of bed thickness and invasion while the borehole effect was minimal under normal conditions, i.e. fresh or low salinity mud. I don't intend to spend a lot of time on it because it eventually outlived its usefulness, that is better devices were developed. However, it lasted through most of my career and was a part of many memorable experiences. Additionally, the principles involved form a basis for other types of resistivity tools. Thus a synopsis of sorts seems in order. I'll try to make it short and light hearted as opposed to scholarly and dull. Lack of the latter should be no trouble but light hearted and even short? I don't know.

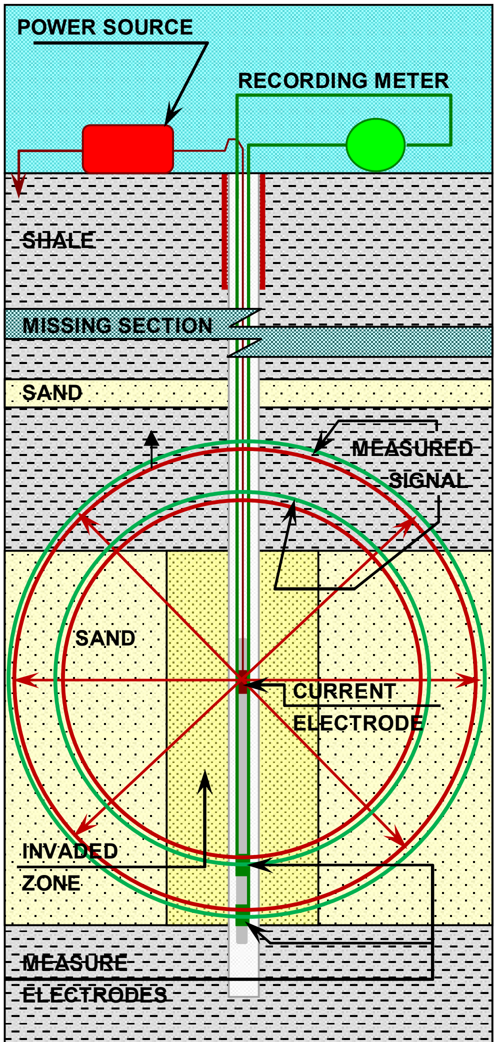


Figure 7-7 A depiction of the electrode system for a lateral curve.

The electric log that I knew consisted of four measurements, 16" and 64" normal curves, and an 18' 8" lateral curve (all were resistivity curves) and an SP or spontaneous potential curve. We'll discuss them individually in the order listed but I will include the 16" and 64" normal curves together and then describe the complete system. Even though that system left much to be desired, it was surprisingly effective and provided a good deal of relevant information for the evaluation of well formations.

THE NORMAL CURVES

The normal curve utilized a down-hole current electrode and a down-hole measuring electrode, each referenced to surface electrodes at zero potential. This is illustrated in figure 7-6. The current flow geometry is spherical in form emanating in all directions from the current electrode. This produces equi-potential spheres whose individual surfaces have the same potential throughout and whose centers are the current or red electrode. The measuring electrode (green) is placed at either 16" or 64" in our case and measures the potential on that particular sphere from which it is recorded at the surface. As one can see, making the spacing larger allows the device to measure deeper into the formation but it also measures further up and down the hole thus being influenced by the surrounding beds. To make this a little clearer, the depth of investigation was said to be twice the AM spacing or distance between current and measuring electrodes. With the configuration shown, the device would measure the potential in the lower bed quite accurately but the upper bed would be almost masked by the surrounding shale. Thus, the need for two spacings becomes obvious. The 64" spacing does a better job of determining the true resistivity of the thicker sands because it sees beyond the invaded zone, so to speak, while the 16" curve is able to see the thinner bed even though it is affected by invasion. The longer spacing is thought of as an R_t device while the shorter spacing is primarily for correlation and thin bed detection. Thus, they supplement one another in their use by the geologist in his evaluation of the well. Even so, beds less than 20' in thickness are difficult to evaluate because of invasion and the tool's response in thin beds.

THE LATERAL CURVE

Next on our list comes the lateral curve, which utilizes three electrodes down hole, i.e. one current and two measuring electrodes. It measures the potential gradient or the difference between the potentials of two spheres. The drawing of figure 7-7 illustrates the configuration used for the lateral curve. Its sampling zone is a spherical shell whose thickness is the spacing of the measuring electrodes. Figure 7-7, once again, illustrates a cross section of that sphere and is labeled as the measured signal. Such a curve picks up thin beds quite well and sees deep into the surrounding formations. Unfortunately, with this device it is hard to determine the true resistivity in beds under 18' 8" thick and, under certain conditions, it also produces a so called blind or shadow zone which nullifies readings in that interval. However, when combined with the 64" normal curve it added significantly to the ability of a well logger to analyze the results of his efforts. The combination was the best of their kind in those days and results were okay as long as borehole conditions were favorable. However, as log interpretation grew in favor, the need for a better mousetrap became apparent. That mousetrap was taking shape during the first couple of years I worked for Schlumberger in the form of an Induction log but more about that later.

CALIBRATION

I suspect all of my astute posterity, (what other kind could I have?), are wondering about accuracy. How does one know the resistivities measured are accurate? Well, there is some question when beds are thin or invasion is deep but we know the log registers accurately the values of resistivity it sees in its zone of investigation because we calibrate it against a standard. That standard was a precision resistor in the panel with a value equal to the resistance measured by the tool at full scale. Remember, back on page 190 I said the electric log actually measured resistance rather than resistivity and we had to calculate resistivity from equation 8 which I'll now repeat here.

8) $\rho = R(K)$;

where the Greek ρ represents the resistivity, R the resistance and K the dimensions of the sampled volume. If we calculate ρ for a full-scale value of resistivity, say 100 ohms, and we know the value of K, which I'll arbitrarily take as 2 we have the following;

$P = 100 / 2 = 50$ ohms

Thus we build a very accurate precision resistor of 50 ohms and it becomes our calibration standard. With the assumptions above, a 20-ohm scale would require a 10-ohm resistor, etc. Well, so much for resistivity calibration, let's move on to the spontaneous potential or SP curve, as it is commonly referred to in the oil patch. It may well be the most frequently used curve of all.

SPONTANEOUS POTENTIAL

Measurement of the SP is not a measurement of resistivity but one of a potential, which occurs in the borehole because of the differing salinities of the mud and the waters, which are encountered in the formations. Its magnitude is very small being in the range of a few millivolts or thousandths of a volt. Typical scales, with ranges or values, which are often a mere 100 millivolts and in some areas 20 to 50 millivolts is a common scale of choice. Thus, an SP measurement is sensitive to any noise and all too often is subject to outside interference, which plagues the engineer, driving him bananas, while bringing on a migraine. That's where the old title of **"Top Banana"** came from. You see; he was the #1 banana amongst a crew, which had gone bananas trying to eliminate an SP problem. I have a few experiences, which I intend to relate about that particular area myself. They will surface in my stories of my field days.

Thus, an SP measurement is sensitive to any noise and all too often is subject to outside interference, which plagues the engineer, driving him bananas, while bringing on a migraine.

APPLICATIONS OF SP MEASUREMENTS

The SP was extremely useful as a lithology indicator but equally as important as a means of determining the resistivity of formation waters encountered. It was recorded in combination with resistivity logs in all fresh or low salinity mud areas. The potential, which was observed in the borehole opposite saltwater sands, was negative relative to that observed opposite shale beds. The basic equation, which expressed this small potential difference as a function of the mud filtrate and formation water resistivities is;

9) $E\ (mv) = -K \log \rho_{mf} / \rho_w$

Where E is the measured potential difference between the sand of interest and the surrounding shale, ρ_{mf} represents the mud filtrate resistivity, ρ_w the resistivity of the water within the pore spaces of the permeable sand while K is a constant of approximately 80. Both ρ_{mf} and ρ_w are a function of temperature and must be adjusted to the temperature in the zone of interest. The equation works well in moderate to high salinity waters containing sodium chloride and when the answer is cranked out, voile we have the answer to a very important parameter needed to determine water saturation of the sand, namely the salinity or ρ_w of the water in the sand pore spaces.

SP CALIBRATION

Now, of course, we had to calibrate the SP if we expected to use the measurement for calculations with any degree of accuracy. The circuitry for the SP contained a 100-millivolt source, which was accurately derived from a very stable mercury battery. Linearity of the galvanometer could be checked as well. The engineer calibrated the SP circuit before and after the log to assure its accuracy and establish any drift that might have occurred.

AN ELECTRIC LOG ILLUSTRATION

That's enough algebra and/or calibration for a while. A change of pace seems in order and besides, I don't want you to drift off to sleep through sheer boredom, so let's consider what a set of real live electric log measurements looks like. Consider figure 7-8 while I lead you through a visitor's tour of this rather old well log presentation. I should mention that the colored formation symbols present in the depth track were not part of the log. I include them to help clarify my explanations.

RECORDING GRID

The figure is set up somewhat like a film presentation would be. That is, there are 3 galvanometer tracks as they were called where data was recorded relative to depth plus a depth column wherein depth numbers were printed every one hundred feet. The data tracks contained ten lines or major divisions, which could be scaled in appropriate units. The depths in those tracks were indicated by ten-foot lines with the fifty and one hundred foot lines being accented for ease of reading. The logs came in two scales of either one-inch per one hundred feet or two inches per one hundred feet and five inches per one hundred feet. The former was for correlation and the latter for log evaluation and interpretation. Figure 7-8 illustrates 2" per 100'.

Once the film was dry, a heading was added whereon all pertinent well data was listed. Thus each print was complete with all essential information. For the sake of room, I have left off the heading and listed scales for each track at the top of the section. Note the SP is scaled in millivolts. No units are indicated for the resistivity curves because of space but they would be recorded in ohms. The depth column's width is exaggerated in the example and has the lithology that is assumed, illustrated therein. Normally, the depth column would be clear and about 1/3rd the width of a data column. The 64"

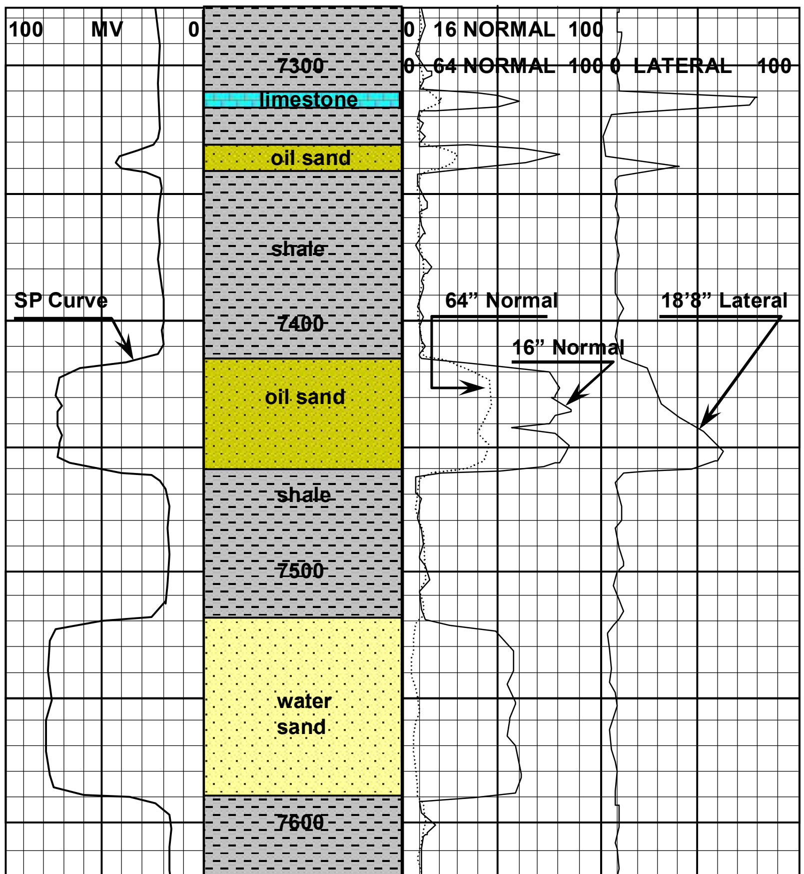


Figure 7-8 An illustration of an electric log film with SP, 16" normal, 64" normal, 18' 8" lateral and associated lithology.

normal curve is distinguished from the 16" normal by being dashed rather than solid. Now that we have described the grid for the log, let's take a look at the individual responses of each curve. We'll begin with the spontaneous potential or SP curve.

SP ILLUSTRATION

In sand shale sequences such as is pictured, the formation waters contained in the sands are usually saltier than is the mud filtrate. This produces a negative deflection or the SP moves to the left from the shales when sands are encountered. Near the surface this may not be true and deflections may be to the right or positive relative to the shales. Let's begin with limestone and proceed down hole. It shows no deflection because I've also taken the liberty of assuming it has no porosity, a situation often encountered in a young, (geologically speaking), sequences of sand and shale. If it did have porosity, then a deflection would occur. Right below that lies a thin oil sand. A deflection does occur but is too small because of bed thickness and oil content. A correction could be made from charts, which had been developed and a ρ_w calculated via equation 9. Next in depth is a thicker oil sand lying at approximately 7440 feet. Notice the SP deflection is considerably greater than in the thin sand. Probably the correction, if applied, to the thin sand, would bring it to the 55 mv registered opposite the thicker sand. The thick sand may also read slightly low because it is shaley and oil bearing. Consequently, if corrected for shale, it would also indicate the 60 millivolts registered in the water sand at 7550 feet. It isn't unusual for sands in the same vicinity to have formation waters of the same salinity but one can't always be sure. Now that you're an expert on the SP curve, let's move on to the resistivity curves. We'll describe the normal curves together because of their similarity and the lateral curve with its differences by itself.

In fact, while you are at it, put your shoulder to the wheel, your ear to the ground and your nose to the grindstone. Now try to continue your study of this amazing work in that position.

THE NORMAL CURVES

As was indicated earlier, the 16" normal curve is used primarily for correlation but it can also give the geologist an idea of the invaded zone resistivity. Notice that it registers a much higher resistivity than does the 64" curve in the thin limestone. If it were thicker, they should register the same because no invasion is possible. Bed thickness, however, holds the 64" curve down. In the thin oil sand at 7335', the 16" curve also reads about twice that of the 64" curve. The bed is still thin and we can't trust the deeper reading curve, nor can we trust the 16" curve because of invasion. So, what do we do? Schlumberger did develop a set of correction curves for bed thickness but they were cumbersome and hard to use. Consequently, engineers usually reverted to some rules of thumb, which were taken from the charts. Though only marginally accurate, they were better than nothing and allowed a ballpark figure to be determined. We can also go to the lateral curve, which I'll talk about in a minute.

Next, consider the thicker oil sand at 7440'. The 16" curve indicates a resistivity of about 80 ohms, which is comparable to that of the thin sand. That's not surprising since neither affects this curve due to bed thickness. The 64" curve manages to get out to about 50 ohms and shouldn't be bothered by bed thickness in this sand. The difference in response tells us the invaded zone is a higher resistivity than is the true resistivity of the undisturbed zone; but we still don't know what kind of fluid is in the latter.

At 7550 feet, the two curves again give drastically different readings. Notice the 64" curve indicates only about 7 ohms average while the 16" curve manages about 60. We should be getting a good answer for ρ_o (the true resistivity of water sands) from the 64" normal.

THE LATERAL CURVE

Finally, let's consider what the lateral curve is telling us in the same situations. It reads a resistivity somewhat higher than the 16" normal in the limestone thus picking out this bed very well. In the thin oil sand, it registers very low in the top of the bed because of the blind zone of 19' produced below the dense lime. At the bottom of the bed it ekes out 50 ohms, which would be regarded with suspicion. Even so, it tends to tell the log analyst that the resistivity is higher than given by the 64" normal. In the thicker oil sand (7440') it again registers a variable value throughout the sand while the 64" normal looks about the same. Using the rule of thumb I mentioned earlier, the analyst would pick the resistivity of the bed at the arrowhead designating the curve, which just happens to be about the same as the value from the 64" normal (50 ohms) and corroborates the answer we were looking for. Finally at 7550 feet, the lateral again registers about the same as the 64" normal curve, which again verifies the ρ_o value for that particular zone. Any verification we can make by other means is always welcome, for assurance sake if nothing else.

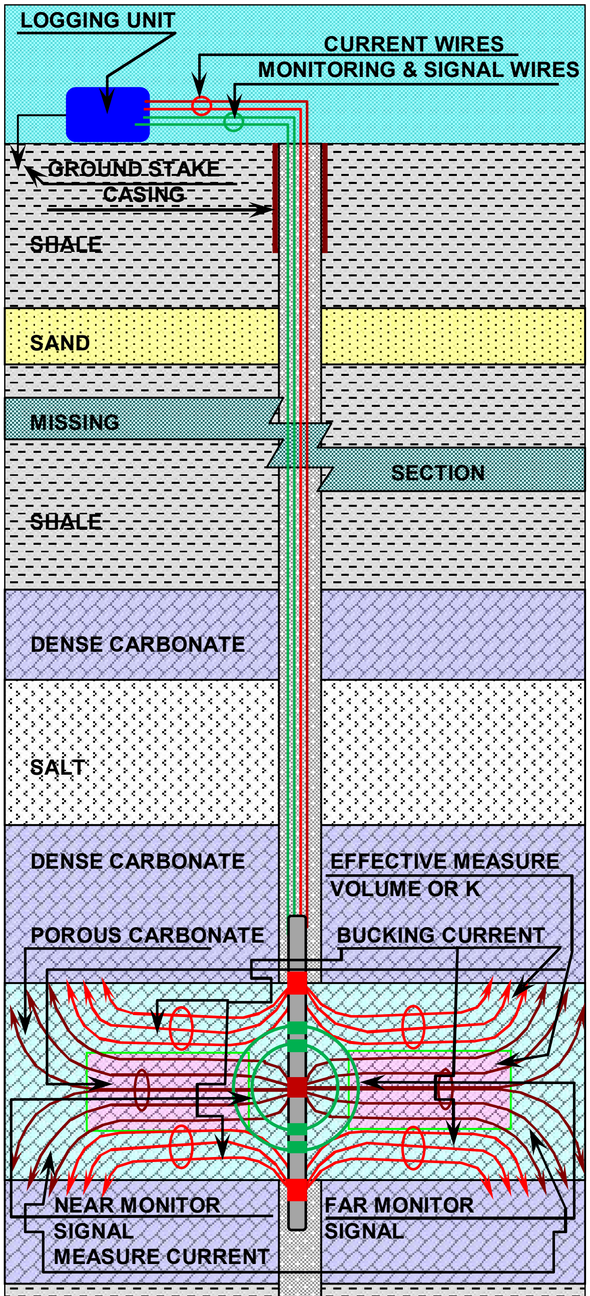


Figure 7-9 An illustration of Laterolog 7 device with its various operational currents.

A LITTLE RAMBLING

I would suppose any normal human being would be bored out of their skull at this point but remember, Grandpa Tom wasn't normal and your quest is to see what made him tick, not to satiate your own mental state of tranquility. So don't give up. I feel sure I'll be able to duplicate the previous boredom with some of the remaining Schlumberger techniques and maybe even surpass it. In view of this, I feel motivated to encourage you to review your psychological state before going any further. This maze through which you are now wading is bound to have deep import on the conclusions you draw regarding grandpa's sanity, weird interests and maybe even his distorted sense of humor. So gird up the loins of your mind, as mentioned in the good Book and while you are at it, put your shoulder to the wheel, your ear to the ground and your nose to the grindstone. Now, try to continue the study of this amazing work from that position.

THE LATEROLOG SEVEN

I believe I described the shortcomings of the electric log in terms of bed thickness and being able to read deep enough into the formation to register a true resistivity or R_t. However, I didn't explain the effects *of salt mud on the device. In some areas, sal*t beds were regularly encountered and even in fresh mud areas, like the gulf coast of the U.S., an operator might drill into a salt dome by accident or intent. Such zones of salt were dissolved by the mud, which created borehole problems and made the mud very salty. When this occurred, the extremely low mud resistivity short-circuited the formation if the electric log was used. That is, the current flowing out of the electrodes simply flowed up and down the hole without penetrating the formation to any degree. Thus the device essentially measured mud resistivity and provided no useful information. The Laterolog Seven was devised in answer to this problem, becoming the first of several laterolog tools.

ORIGIN OF THE NAME

As one might suspect, the device had seven electrodes. Ah, what imagination we engineering types have when it comes to the names of tools. We have no time for the esthetic. We may dwell on tiny technical details when describing the operation of a device but you'll find no verbosity associated with their names. The only beauty we're interested in is that of its complex design, its intricate detail and the logical nature of its operation. No sir, names should be direct and to the point without the flavoring of politics. After all, we aren't selling cars and the product speaks for itself. Just ask a Schlumberger engineer about such relative values.

As for the term laterolog, I should mention that it has no relation to the lateral curve of the electric log we just described. Rather, the term came from the fact it forced measuring current to flow sideways or laterally into the formation so as to overcome the high salinity mud.

TOOL DESCRIPTION

Consider figure 7-9 as I lead you through this most intriguing operation. Notice, there are seven electrodes on the sonde as advertised. The dark red electrode emits the so-called measuring current whose voltage drop will be measured between the far monitor electrode and the surface. It is a normal curve in that sense. However, we don't allow the current to flow up or down the hole because an opposition or bucking current is emitted from the two light red electrodes. Electric currents can't flow through or across another current flowing. The bucking current is much stronger than is the measure current and, in fact, it is adjusted upward in intensity until the measuring current is forced to flow out into the formation. This is accomplished by using four monitor electrodes to measure the voltage drop in the borehole above and below the measure current electrode. This voltage drop (the difference between the near and far monitor signals) is kept very near zero. If it increases much above zero, the bucking current is decreased automatically at the surface. If it drops below zero, the bucking current is increased automatically. Thus we can define the path of the measure current in the shape illustrated in that colorful figure of 7-9. After proceeding a few feet into the formation, the bucking current flares upward and downward to return to an electrode some 100' up the hole. The measuring current also flares or spreads and returns to an electrode about 20' up the hole because the lack of bucking current control.

The voltage of the far monitor electrode is measured relative to a surface ground stake. This results in an effective sampling volume as indicated in the figure, which wraps around the hole in a cylindrical shape. See figure 7-10 for a horizontal view. Thus the sampling volume is in the shape of a cylinder with the center removed. The greatest response or percent of the signal occurs near the far monitor electrode because the cross-sectional area is smallest at the point and drops in an inverse manner as one moves towards the outside of that sampling volume. In other words it is analogous to the radial fluid flow of chapter 5 but in the opposite direction. If interested, check figure 5-28 as well as 5-29. Anyone who does has a future in well logging.

CALIBRATION

Calibration of the laterolog seven was accomplished in the same manner as for the electric log, which we just discussed. That is, knowing the K or electrode constant for the device, a precision resistor can be built, which simulates full-scale measurement for a given resistivity scale. It then acts as a substitute for a formation of that particular value. Different resistors are needed for each available scale.

LATEROLOGL7 ILLUSTRATION

Now, let's look at a typical log that would be generated by this device as I have depicted it in figure 7-11. The laterolog 7 tool made

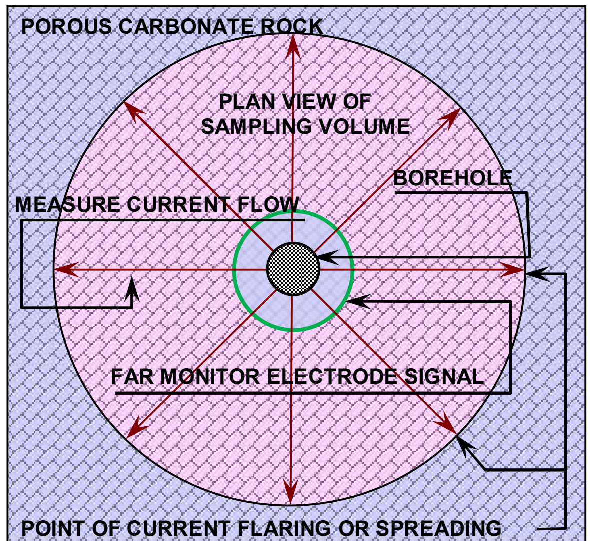


Figure 7-10 Plan view of the horizontal sampling volume or K of the Laterolog 7.

provisions to record an SP curve and the signal observed across the monitor electrodes as well as the laterolog curve, itself. The monitor curve had no scale and was recorded only to verify proper operation of the system. The SP was usually of little value in a salt mud and was usually left off. It was also plagued by noise and was often recorded separately where needed. I illustrated it here to bring to the attention of the reader that under such conditions the SP would have a positive deflection rather than the usual negative deflection because the mud filtrate is saltier than the formation water. However, more often than not, there would be little or no deflection because the mud filtrate and formation water would have had about the same salt content.

THE 64" NORMAL COMPARISON

For illustrative purposes only, I also drew a 64" normal curve to give you an idea of just how featureless that particular curve would be in a borehole with salt mud. One would hardly be able to correlate with it, let alone obtain a true resistivity value. Notice it hardly rises at all opposite the dense lime and the oil sand.

The laterolog seven had a long and useful life being particularly useful in areas of high resistivity and fresh mud such as the Tensleep formation in the Bighorn Basin of Wyoming. However, it had shortcomings as well and a better version was later developed for salt mud in carbonate areas. I'll talk more about that particular device later. Let's move on to the Induction Log, a device that has undergone a long period of evolution.

INDUCTION ELECTRIC LOG

As you have probably already surmised, the electric log, comprised of the 16" and 64" normal curves and the lateral curve, left much to be desired. They weren't effective in salt mud, a subject just addressed, and they were ineffective in beds under twenty feet in thickness, which comprise many of the oil and gas reservoirs in the world. Even thicker beds presented problems if invasion was very deep. In some areas, such as the gulf coast, invasion was usually relatively shallow in the younger sand-shale series, at least but beds less than 20 feet thick were also the norm. However, in the other areas such as the Rocky Mountains, invasion was much deeper and, in most cases, influenced existing resistivity measurements significantly. Thus, a better mousetrap was needed for measuring the true resistivity in situ. Induction principles, which provided hope for that mousetrap, had been investigated for some time for application in empty drill holes. There, it overcame the need for a conductive medium in the borehole and was now seen as a measuring device which could be focused to improve bed definition while still maintaining a reasonable investigation depth in surrounding formations.

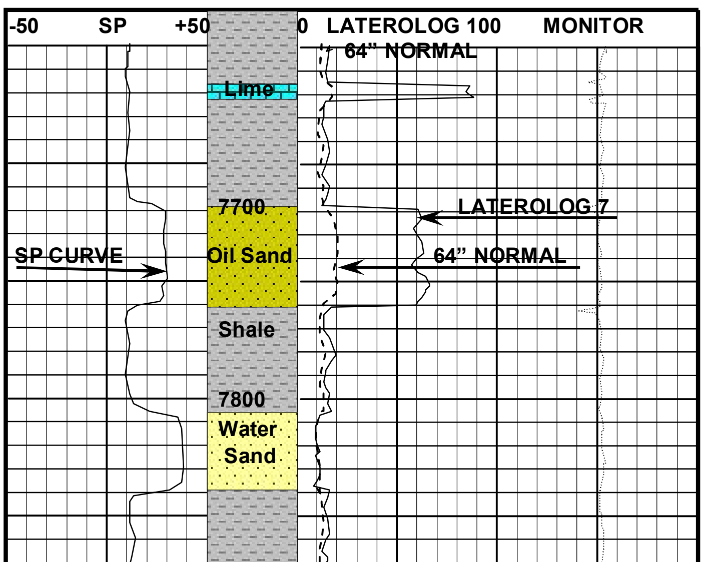


Figure 7-11 A drawing comparing a Laterolog 7 and a 64 inch normal recording with an SP curve as they would appear in a salt mud environment.

INTRODUCTION OF THE 5FF40

Work had begun on the induction electric log prior to my time but the tool became field worthy in the late fifties with the so-called 5FF40 tool. The device was so named because 5 coils were used which provided a fixed focus (FF) and the spacing between transmitter and receiver coils was 40 inches. Notice once again, how the aesthetic nature of the design engineer influenced its name. In addition it included a 16" normal curve and an SP curve to provide continuity with the electric log. It was seen as the replacement for the electric log in fresh or low salt muds and as such, continuity was essential for correlation. The advantages it had were good bed definition (6-ft.) and a depth of investigation comparable to the electric log. These characteristics allowed it to measure the true resistivity more frequently than its predecessor, the electrical survey.

THE 16" NORMAL AND SP

Before we consider the induction log principles let's quickly review both the 16" normal and the SP curves. Consider figure 7-12 as a sketch of the complete induction tool including the 16" normal and SP. I divided the sketch into left and right hemispheres and placed the 16" normal on the left with the induction on the right. On the left, you will notice a red and a green arc, which represent the equipotential spheres emanating from the red current electrode for the 16" normal. Actually they represent the same sphere but one (the red) is the generated sphere from the current emitted by the electrode and the other (green) represents the signal measured by the green measure electrode. The 16" normal current is an AC signal of 240 hertz or cycles per second, which property keeps it from interfering with the SP. The measured signal is taken relative to a surface electrode (see figure 7-6) and is sent to an amplifier, which boosts its power before going to the surface. The SP is measured on the same electrode and is essentially a DC signal. The difference in their nature (an alternating voltage versus a DC signal) allows them to be separated with the SP going up the yellow wire and the 16" normal going up the green wire after being amplified. Though designed somewhat differently, both of these measurements involve the same principles as those previously discussed in the overview of the electric log. Consequently, I'll say no more about the principles involved.

THE INDUCTION CURVE

Like the 16" normal, the induction log uses an oscillator for a power source, which generates a twenty thousand hertz signal as opposed to one of 240 hertz for the normal. Both oscillators receive their power from the surface to enable them to function. The induction signal from the transmitter (oscillator) is applied to the transmitter coil. Current through the transmitter coil produced a magnetic field (magenta dotted lines), which radiated out into the formation and produced a current in the rock that flows back and forth around the borehole (black ellipse). Actually, there would be an infinite number of such loops generated; only one of which I have shown. The number or strength of the induced signal varies with the resistivity of the formation. This alternating current flowing around the borehole generates its own magnetic field (cyan or light blue dotted lines), which radiate back towards the tool. In so doing, they intersect the receiver coil and generate a signal within it. That signal is inversely proportional to the resistivity of the formation. It is amplified, converted to direct current and sent to the surface. There it is displayed as a conductivity signal, converted to a resistivity signal and then recorded as such. Each has its advantages for correlation purposes as well as in the determination of accurate resistivity values. The resistivity value derived from the induction measurement can also be directly compared to that of the16" normal.

Oops, we slipped in another foreign term, i.e. conductivity. It so happens, it is the reciprocal of resistivity or 1/ρ, that is; in mathematical terms we find resistivity expressed as;

$$10)\quad \rho = 1/C$$

Now, you might ask, "why in the world measure conductivity in the first place when its resistivity a person wants"? Good question. It so happens, that it's easier because the tool actually responds to conductivity. You see, I told a little fib back there and now I have to correct that bit of misinformation. That is the amount of formation current is proportional to the conductivity of the formation or a higher current flows when the conductivity is increased. We could even work with conductivity and convert all the equations we listed in this chapter but the industry wouldn't like that. They became addicted to resistivity because lots of resistivity often means lots of oil or gas. Rather than trying to change their thinking, which would be of questionable value, Schlumberger decided to convert the signal to a compatible resistivity signal, which would correlate to older logs.

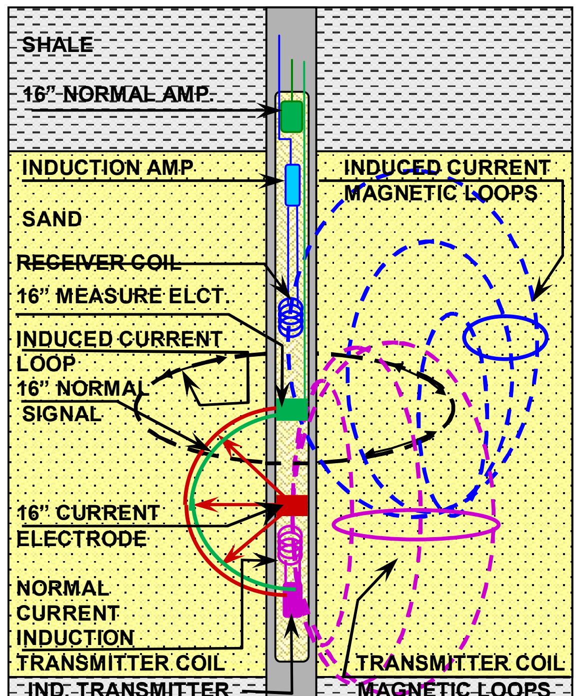


Figure 7-12 A drawing of the SP, 16" normal and Induction signals for that tool.

This alternating current flowing around the borehole generates its own magnetic field (cyan or light blue dotted lines), which radiate back towards the tool.

Besides, as you already know, they married the induction measurement to the 16" normal and it was profitable to express both measurements in the same units. Well, that's the induction principle, even if I did take kind of a back door approach to get there. Now let's consider a few additional details.

MORE ABOUT CONTINUITY

The "Induction Log" as it was termed, employed the 16" normal for a couple of good reasons. First, the curve is an excellent correlation curve, particularly in thick shales and low resistivity sands. Second, geologists are familiar with it and desire its continuity for correlation with older logs. The more advanced measurements may be correlated with a 16" normal but not nearly as easily. Why make the situation difficult. Besides, like most companies selling their services, Schlumberger was also addicted to $$$$ and those ornery geologists had a big influence on our customers decisions. The SP was automatic, of course, because it is a very useful measurement for lithology type as well as ρ_w and was still needed if the induction was to replace the electric log.

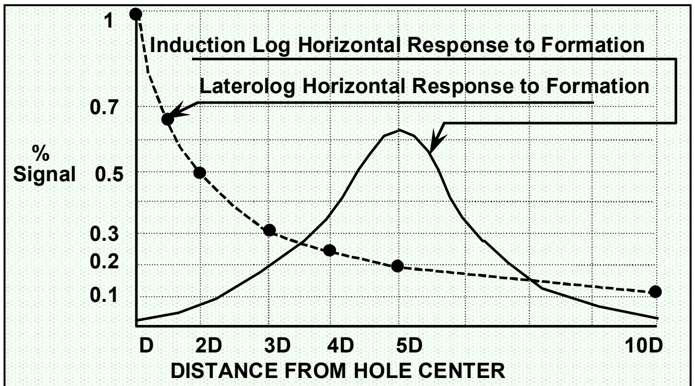


Figure 7-13 Curves depicting the geometric response of the Laterolog an Induction log tools.

TOOL RESPONSE VERSUS RADIAL DISTANCE FROM THE BOREHOLE

Figure 7-13 is included to help the reader better understand the manner in which the laterolog and induction log respond to the formation around the borehole. Because of this and the fact that the induction tool responds to conductivity while the laterolog seven responds to resistivity, we find the induction tool gives better values of the true resistivity when the drilling mud is fresh (little salt) and the laterolog gives better answers when the drilling mud is salty. Thus, some geological areas utilize one device while others utilize the other. Their use may also vary with the depth of the hole in that salt may not be encountered until carbonate sections of rock are cut deeper in the hole. This is true in the Williston Basin of North Dakota.

INDUCTION CALIBRATION

Before going on to an example of the induction log, let's talk about calibration once again. To emphasize the need for accurate calibration of any logging tool, let's make it (the need) analogous to the need for an accurate speedometer on your car. I have yet to meet a cop who would accept as an excuse for speeding, "but officer, my speedometer wasn't correct". Likewise I have yet to meet a customer who would accept a similar excuse for an incorrect log. Both would say, "Get them fixed". So with Schlumberger, we not only listened to the customer but we took action as well. We calibrated for each job and we also documented that calibration on film to verify the accuracy of the log. In the case of the induction curve, a test loop was used which gave a signal of 1000 millimhos or exactly one ohm and the recording system was then adjusted accordingly. A signal generated within the tool was matched to the loop, thus allowing the engineer to check calibration while in the hole. A loop was sent to each location using the tool and was matched to an artificial formation of exactly one ohm in a test lab in Houston, Texas. It then became the field standard. The 16" normal and the SP were calibrated as previously discussed.

AN INDUCTION LOG RECORDING

Now would seem the time to take a peek at a typical Induction Electric log as it might appear in a sand-shale sequence. Examine figure 7-14 as I walk you through the more important points. Once again, the lithology provided in the depth track isn't a recording but I have added it to make the digestion of the associated data a little easier. You see, I do have your well being at heart. It's kind of like providing an anti-acid with a good meal.

THE SP CURVE

The spontaneous potential or SP curve is recorded in track 1 and increases in a negative direction to the left, as described earlier. Remember, in a sand-shale sequence, the curve swings to the left of the shale zones when recording the potential opposite sandstones, assuming the formation water within the pore spaces of the sand is more saline (saltier) than is the mud filtrate. The scale indicates that each major division represents a ten-millivolt (10/1000 of a volt) change. Thus, the water sand at about 8750' registers about – 40 millivolts, the oil sand at about 8850 feet registers almost – 70 millivolts (–68) and the bottom water sand at around 8950 indicates about – 80 millivolts of deflection. The thin sand zone just above 8780 doesn't register its full deflection because it is too thin. If it were corrected for bed thickness, it would indicate a deflection of – 40 millivolts or the same as that of the sand at 8750'. As a review, let's see if we can figure out just what all this means in terms of water resistivity and maybe porosity.

Equation 9 provides a way to calculate ρ_w (formation water resistivity), you may remember. We might rearrange it here as;

$$9)\ \text{Log}\ \rho_w = -K \log \rho_{mf}/E\ (mv)$$

With the same mud filtrate resistivity in all zones, it is apparent the top two sands have different water resistivities than do the bottom two, i.e. their deflections (E) are drastically different. We might also surmise that R_w in the bottom two zones differs as well. However, the deflection is suppressed opposite the oil zone and must be corrected due to the higher resistivity. Such correction would bring it up to approximately – 80 millivolts. We could plug that into equation 9 along with a K of 80 (standard value) and a ρ_{mf} of 4.0 Ohms (a handy number for our example) and voile, we find ρ_w is equal to 0.4 Ohms. By the way, if we went through the same process for the upper water sand (8750'), the ρ_w value would be 1.26 Ohms. Thus, at a glance of our SP curve, we determine the location of sands or shales, and with a few arithmetic mental gymnastics, we can also determine the formation water resistivity.

THE RESISTIVITY CURVES

Next, let's evaluate the various resistivity curves. We'll examine them together, zone-by-zone, remembering the 16" normal curve is affected primarily by the formation's invaded zone or the zone containing mud filtrate, while the undisturbed zone or that volume of rock containing mostly formation water provides the primary induction curve response. If any oil or gas were present, its effect would be noticed predominantly on the induction curve. Any effect influencing the 16" normal would be a function of the invasion depth and efficiency.

In the upper sand at 8750', the normal curve provides a value of 60 to 62 ohms and the induction curve 32 or 33 ohms. We'll settle for the lower values. We know ρ_w is 1.26 ohms from the SP and that ρ_{mf} is 4.0 ohms as measured by the logging engineer. Unfortunately, we don't know the porosity in this sand but if we assumed it contained only water, a rather dangerous assumption, we could use equation 2 to calculate F, the formation factor and see what light it might shed on the problem.

$$2)\ \rho_o = F\rho_w$$

This calculation yields an F of about 25. That is, using ρ_o = 32 as measured by the induction log

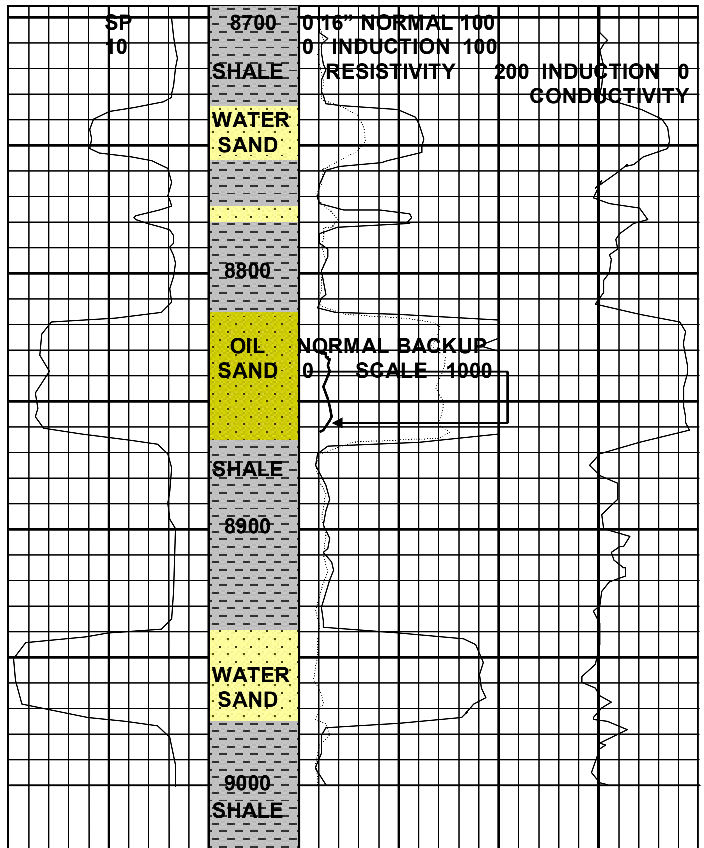


Figure 7-14 An illustration of a typical section of an Induction-Electric log in a fresh mud environment.

and a ρ_w of 1.26. We could then use equation 3 or 4 to calculate a porosity value. With equation 3 we find the porosity is 20% and with number 4 we obtain 17.9% either of which is a reasonable value. Actually, equation 3 has been found through study to be more accurate for carbonates and equation 4 more accurate for sandstones, so we'll accept the latter.

FLUSHED ZONE RESISTIVITY

If the rock close to the borehole had been completely flushed with mud filtrate, we could write an equation similar to number 2 as;

$$11)\ \rho_{xo} = F\rho_{mf},$$

This relationship expresses the resistivity of the so-called flushed zone. The only change is the salinity of the water in the pore spaces (ρ_{mf} instead of ρ_w), which gives a different resistivity we call ρ_{xo}. At this point we can't measure ρ_{xo}, so it doesn't do us a lot of good but such a measurement can be made, as you will see in a later discussion, so keep this in mind.

INVADED ZONE RESISTIVITY

There is, however, a purpose in bringing the ρ_{xo} measurement up here. That is, the 16" normal reads a value of resistivity somewhere between ρ_{xo} and ρ_o. It responds to a zone that has within its pore space a mixture of the two fluids, R_w and ρ_{mf}, whose average fluid resistivity we will call ρ_z. This allows us to write an equation similar to 2 or 11 as;

$$12)\ \rho_i = F\rho_z$$

It so happens that the 16" normal registers an average value of the invaded zone termed ρ_i but, of course, we really don't know F for sure or ρ_z. However, if we take the calculated value of F = 25 which we obtained from the induction log we can calculate ρ_z and see if it falls somewhere in between ρ_w and ρ_{mf}. Plugging into equation 12 an F of 25 and a resistivity for ρ_i of 60 taken from the normal curve, we calculate a value of 2.4, which does, in fact, lie between 1.26 (ρ_w) and 4.0 (ρ_{mf}). I suppose the reader, at this point, realizes we haven't really proven a thing. In fact, we had to assume the zone had no oil in it and that the induction log did register the true resistivity, ρ_o, both of which can be dangerous if not done with judgment. By now you probably asking; "So, why in the world would grandpa take us on such a wild tour"? Is he demonstrating his knowledge of basic algebra or what? Well, yunguns, just hold on before you become too critical and see what transpires.

It's like a little 3-D puzzle in which he fits little mathematical equations with various assumptions and designs consistent models for the reservoirs cut by the drilling bit.

THE PSYCHOLOGY OF LOG INTERPRETATION

Ah yes, I'm glad you asked that question. All these mathematical gyrations are not meant to impress but rather to expand the reader's understanding of that wonderful subterranean world which so delights the log analyst. It's like a little 3-D puzzle in which he fits little mathematical equations with various assumptions and designs consistent models for the reservoirs cut by the drilling bit. These, he hopes, also fit reality because that's what his boss (the guy paying the bill) gets excited about. Yes sir, a twenty or thirty foot thick oil reservoir really excites him because it means big $$$$$, which is the name of the game. However, if a log analyst gets him too excited about a zone, which ultimately produces water, that's a downer and he can get equally depressed. Such depression is sometimes communicable in that it results in the log analyst hunting for another guy to finance the 3-D puzzles that so delight him. Ah yes, one must temper his models of the nether world with reality if he desires to sell the results as a form of employment. More importantly, he needs the best information he can get and right now because the interpretative results of his efforts are no better than the data. It appears, at the moment, we are missing quite a little of that particular ingredient. As you well know, one can't afford to make too many assumptions. They can turn and bite the rear.

THE RESISTIVITY PROFILE

Getting back to the subject, let's draw a little graphical model of the resistivities surrounding the borehole of the zone we just discussed as a summary. Maybe that will bring it all into perspective and you won't feel all your effort was wasted. Check figure 7-15. With a formation factor of 25, ρ_{mf} of 4 and a value of ρ_w of 1.26, it depicts the magnitude of the resistivity change from 100 ohms (ρ_{xo} = 4x25) to 32 ohms (ρ_o = 1.26x25) as you proceed outward from the borehole. The color change illustrates the changing water salinity from mud filtrate (blue) to formation water (yellow). The 16" normal curve registers a value somewhere between ρ_{xo} and ρ_o, as described in equation 12, in this case 60 ohms, and the induction curve registers the true resistivity of the formation (32 ohms), which is designated as ρ_o. Thus the graph provides a visual image of the equations results.

WATER SATURATION CALCULATION

We'll skip the thin sand at 8780' or there about and go on down to the one at 8815' to 8865', which I have termed an oil zone. In fact, we'll deal with it and the sand at 8950' together because they appear to have the same formation water resistivities. The only real difference in their appearances is the resistivity registered by both the induction and normal curves, which could be due to a porosity difference, the presence of hydrocarbon in the upper sand, deep invasion or maybe some combination of them all. We can't really come up with a positive answer without more information but let's play around with some possibilities.

First, let's assume the sands have the same or at least similar porosities, a distinct possibility and also that the induction log is reading the true resistivity in both cases. If that was the case, we could take ρ_o from the lower sand of 10 ohms and ρ_t from the upper sand of approximately 70 ohms. Using equation 5 in a little different form, we can calculate the water saturation of that sand as;

$$S_w = (\rho_o / \rho_t)^{1/2} \quad \text{or,}$$

$$S_w = (10 / 70)^{1/2} = (0.143)^{1/2}$$

$$S_w = 0.38 = 38\%$$

This converts to an oil saturation of 62%, which means the zone will probably produce all oil, i.e. no water. This occurs because the water that is present is so called irreducible water, which you'll remember is tied to the sand grains by molecular forces and can't be produced.

A second possibility is that the upper sand just has lower porosity and is water bearing. If we assume that to be the case, we can use equation 2 to calculate F once again and then use equation 4 to arrive at porosity. So, let's give it a try.

$$F = 70 / 0.4 = 175$$

This converts to a porosity of about 7%, which is possible but not likely if the zones around it have in the neighborhood of 15 to 20 percent porosity. Thus, our assumptions seem valid and the odds are in our favor. Of course, little in life is a sure thing, as you well know or at least should, so let's look at another possibility.

As I mentioned a little earlier, they are always looking for a better mousetrap as well as for more things to measure and trap.

A THIRD POSSIBILITY

Another scenario is that the induction log is registering too high a resistivity because of deep invasion. Although possible, it is not too likely if the neighboring sands exhibit normal invasion. However, it's easy to see that we can't come up with a positive answer without more information. To obtain a reliable answer from wire line logs, we must have an independent means of determining porosity and also be reasonably assured that the induction log is registering the true resistivity of the zone in question.

CONFIRMING EVIDENCE

In the early days of Schlumberger, i.e. before the formation porosity could be determined and ρ_t was questionable, such information would be obtained through drill cuttings, a drill stem test (if possible) or maybe even running casing to prove the zone one way or the other. If the sand at 8850' were an oil sand, drill cuttings from that zone would have signs of oil and would support the first hypothesis. Then, if borehole conditions were favorable, the zone could be drill stem tested without running casing to see just what it would produce. This is a relatively inexpensive and often an effective way of determining what and how much fluid certain sands will likely produce. Even so, borehole conditions often prevent such testing. You may remember such an evaluation method was described in some detail in chapter five. If such were the situation, casing might be run instead and the well completed at a rather hefty expense, just to be sure an oil field wasn't being passed up. Of course, the operator would pick a more economical route if available. Obviously, more and better logging information was desirable, which spurred additional development of various devices that could obtain wire line information deemed of value.

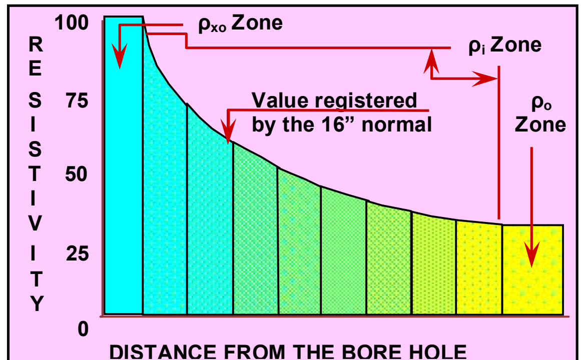


Figure 7-15 A resistivity profile for an invaded water bearing sand with $\rho_w < \rho_{mf}$.

Before leaving the log of figure 7-14, I should describe the conductivity curve in track 3 of the film. It represents the basic measurement of the induction log and is a recording of the signal sent up hole from the tool. However, it is also electronically converted to resistivity at the surface and recorded in track 2 as the dotted resistivity curve. The industry was used to dealing with resistivity as the basic unit of measurement and much preferred the presentation of data in this form. Equation 10 was the basic relation used to convert the recorded data from conductivity to induction resistivity. Of course, Schlumberger complied with the industry's wishes.

THE 6FF40 INDUCTION

The 5FF40 tool was better than the old electric log but far from an ideal tool. Further design and testing resulted in the 6FF40 device, which was far superior. As you might guess, it had 6 coils in the fixed focus system and a spacing of 40 inches between primary transmitter and receiver coils. It could see, so to speak, twice as far back into the formation as the 5FF40 and had the same bed resolution. That is, the value of resistivity registered was unaffected by adjacent beds above and below if the bed of interest was 6' thick or more. That made it a very effective tool for determining ρ_t in fresh mud environments. The basic recording was the same, but the information provided was much better. Figure 7-14 could just as well represent a 6FF40 recording as that of a 5FF40. In such a case, we wouldn't have to worry, particularly, about deep invasion affecting our answer but porosity would still be questionable.

I have illustrated the relative zones of investigation for both induction devices in figure 7-16 to kind of summarize the situation. If you can visualize either color zone being wrapped around the borehole such that the resultant figure looks like a doughnut, then you have a pretty good idea of what area each device samples. I have tried to illustrate that configuration with the dashed arcs I have drawn in. Hopefully, the arcs, along with the cross sections and your imagination, will do the job. If not, I guess you and I are both in imaginary trouble in an artistic sense.

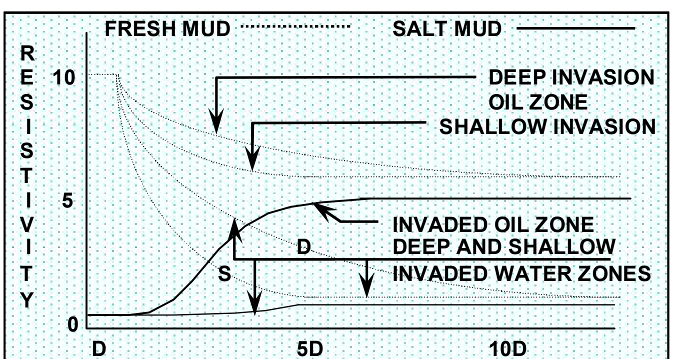


Figure 7-17 An illustration of differing resistivity invasion profiles in differing borehole conditions.

THE DUAL INDUCTION TOOL

Engineers and scientists (what a group of individuals) seem to be breeds set apart from society as a whole. They're never satisfied with the status quo. As I mentioned a little earlier, they are always looking for a better mousetrap as well as for more things to measure and trap. Those employed by Schlumberger were no different and, of course, their jobs depended upon their success. So why settle for a 6FF40 deep induction tool? Why not combine some version of the 5FF40 and 6FF40 along with a good normal curve and see if invasion profiles could be described? Maybe better values for R_t could be provided even in very deep invasion situations. Maybe bore hole effects could be completely eliminated, etc., etc., etc. Their imaginations often run wild. So in came the dual induction, which became the basic resistivity-measuring device in fresh mud before I left the company. Of course, like its predecessor, this device also included an SP or spontaneous potential curve. What would a well logger's life be without the SP curve? There would be very little trouble with noise occurring on the log but one thing you can be sure of, determination of water resistivity values would be somewhat less than spontaneous.

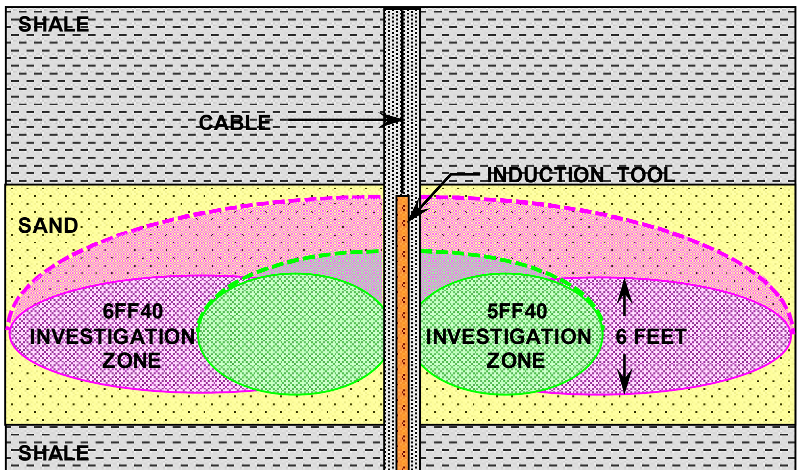


Figure 7-16 A depiction of the zones of investigation of the 5FF40 and the 6FF40 induction devices for comparison.

A LITTLE MORE ON INVASION PROFILES

Before I get too far along with this device, let me elaborate on the term "invasion profile". An invasion profile is simply a description of how the formation resistivity changes with distance from the borehole due, of course, to water salinity changes and hydrocarbon saturation. Figure 7-17 illustrates one of the more simple cases where only water salinity is involved. Other more complex ones exist. Some are very short because invasion is shallow. Some are long and drawn out because of deep invasion and others have differing shapes because of the presence of hydrocarbon. I don't intend to try to explain their complexities but only to let the reader know they are a problem that needs solving. The advent of the dual induction was the beginning of that effort. Figure 7-17 illustrates a few common profiles that involve both fresh and salt mud. These should give you the idea of the problem involved even though they don't encompass all the possibilities. Recognition of the problem has stimulated a continuing effort for finding the ideal resistivity device.

A MODIFIED DUAL INDUCTION LOG

The first dual induction tool employed a laterolog in place of the 16" normal as the shallow reading device because it could be focused and provide more consistent readings over a wide variety of borehole conditions. In spite of its superiority, the laterolog 8, as it was called, wasn't accepted very well by the industry because of correlation difficulties with older induction logs employing the normal curve. As a result, it soon gave way to a newer device called the Dual Induction SFL tool. The last three letters stand for spherically focused log. Essentially, this was a normal curve with spherically radiating current flow (see the left hand side of figure 7-12), which was able to maintain the geometry of the sampled volume over a wide variety of borehole conditions. Thus it produced a curve, which was very similar to the 16" normal under most conditions but much superior when the borehole conditions became adverse. This device provided the continuity with older logs desired by the industry and was apparently accepted as an effective answer to the correlation problem. I retired from the oil business soon thereafter and had little personal experience with it but was familiar with the principles involved. It may help you see just how resistivity measurements evolved over my tenure in the logging business. I shudder to think what has happened since I left the business in 1986. Even so, I know the changes would be exciting and useful.

THE LOGARITHMIC SCALE

During my years with Schlumberger, the choice of resistivity scales was a frequent problem. Areas in the gulf coast typically ran logs on a

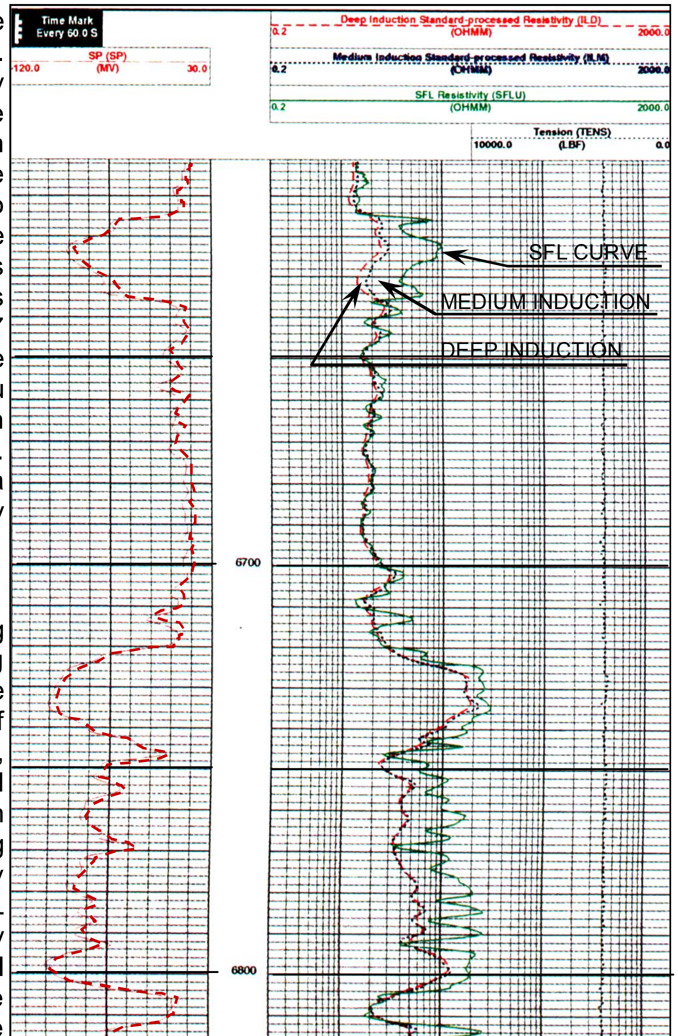


Figure 7-18 A recording of the Dual Induction – Spherically Focused Log with an SP curve.

scale of zero to ten ohms while so called hard rock areas used scales of zero to one hundred. Back up curves were necessary when resistivities were over ten (gulf coast) or one hundred (hard rock areas). See the sand at 8850' in figure 7-14 for an example of a backup curve. Notice the normal curve exceeds 100 ohms and the backup comes on and registers 150 ohms. Additionally, it was difficult to discern accurately between sands of 0.1 ohms (water bearing) and 0.4 ohms (oil bearing) in reservoirs of gulf coast offshore wells. These problems were solved with a new logarithmic scale, which is illustrated in figure 7-18. This figure is an actual recording of a Dual Induction SFL log with its associated SP curve. Note, the SP curve is still on a linear scale but all three resistivity curves are recorded as logarithms of the measured resistivity giving these two primary advantages;

1) To the right of the depth track resistivities from 0.2 to 2000 ohms can be recorded as compared to 0 to 10 ohms.
2) The range of 0.2 to 1.0 ohms covers about the same space as 5 linear divisions making it much easier to differentiate between changes in value of low resistivity zones.

A LITTLE MORE MENTAL MEANDERING

Now that's quite a load to drop on anyone all at once but most of you won't give a hoot about this chapter anyway. I'm only including it for those who are really interested in the deep dark recesses of my mind. You see, to understand grandpa one has to gain an understanding of just what drove him bonkers. When he mutters in his sleep about beautiful curves, he's not speaking of the fairer sex but rather of those recorded curves he spent so many hours observing from the seat behind that optical marvel, the R9G recorder. Beauty in his eyes was a nice quiet curvaceous recording of that lady from a subterranean world; none other than an oil or gas sand, whose lovely complexion might be thought of as sandy, whose black tresses glisten in the sunlight and whose bubbly conversation, though porous at times, may be likened to flowing liquid gold issuing forth from below. How soothing to those who struggle to find her domain amongst a bevy of lesser sands containing only a water solution of Sodium Chloride or, ugh, common table salt as well as a few other undesirable attributes.

Consequently, I decided to introduce to those truly dedicated to understanding my quirky nature the logarithmic method of scaling with the example of the Dual Induction SFL. Those with a real appreciation for the beauty of engineering logic will, undoubtedly, sigh with sympathetic emotion while lesser members of the human race may only see a bunch of unevenly spaced lines that seem to have no meaning. This type of scaling is applied only to resistivity logs. Actually, I must admit, I had no choice because my only example of the log is recorded on that scale, which rapidly became the standard.

THE RECORDING GRID

Now, let's take a quick tour through the DIL-SFL-SP of figure 7-18. First, you should notice the vertical scale is 5 inches for every hundred feet of borehole. Thus, there is a horizontal line every two feet with the ten foot lines somewhat darker and the fifty and one hundred foot lines a good deal darker. This makes it easy to pick out rather thin zones and place them accurately according to depth. Next we'll consider the various vertical tracks involved and what their purpose might be.

Track one in which the SP is recorded is a linear grid scaled from + 30 millivolts to - 120 millivolts or 15 millivolts per division. This scale allows for the recording of a positive SP opposite fresh water sands near the surface as well as the large negative anomalies at this depth. Near the bottom of the same example you can observe a sand bed that exhibits a deflection of about 7 major divisions, a value of - 105 millivolts.

The depth track is next and contains nothing but the depth numbers every 100 feet.

To the right of the depth track is the resistivity track, which spans the two linear tracks of previous examples. Refer to figure 7-14 if this isn't clear. At the top, you will notice all three curves have the same scale of 0.2 ohms to 2000 ohms with the color being the same as that of the curve to which they refer. I have also designated the curves by name to provide additional clarity. The four darkest vertical lines signify 1, 10, 100 and 1000 ohms respectively with the right edge of the depth track being 0.2 ohms and the right edge of the film being 2000 ohms. The intervening vertical lines in each decade represent the digits between 1 and 10, which allows one to read the resistivity value accurately. For example the sand at 6730' has a deep and medium induction resistivity of 16 to 18 ohms while the SFL registers 21 to 30 ohms at its extremes. The shale between 6650' and 6700' registers just under two ohms most of the way. The zone from 6616 to 6636 is an example of a deeply invaded sandstone, in that the SFL registers from 4 to 9 ohms, the medium induction varies from 1.8 to 3 ohms and the deep induction 1.5 to 2.5 ohms. Knowing the characteristics of the measurements, we can see the resistivity near the borehole is high, 9 ohms, further out it drops to 3 ohms and deep in the formation it drops to only 1.5 ohms. This resistivity or invasion profile approximates those of figure 7-17 labeled fresh mud-water sands.

The depth of invasion can be determined from these measurements with appropriate charts or via a computer program.

CABLE TENSION

For the truly observant, I should explain the recording lying along the 400-ohm line to the right of the resistivity curves. At the top you will notice a scale labeled tension, which refers to the amount of weight and or drag on the tool as it is being drawn up the hole at a constant speed of 6000 feet per hour. This scale is linear and has no markings on the film. The engineer reads it from an independent tension meter for his purposes and the film analyst is only interested in changes in its value. If the tool sticks momentarily (not moving) and then comes free the tension curve would show an increase to the left and then a sudden drop to the right as the tool comes free. This is important because we then know the tool wasn't moving for a given number of feet and the resistivity readings can't be used in such an interval. On this log all was well and the tension is constant through the logged interval. That assurance, in and of itself, adds a certain degree of confidence to any log interpretation being made by analysts.

CONTINUING ADVANCES IN COLLECTING AND PROCESSING DATA

Prior to 1978, or eight years before I retired from Schlumberger, each logging device had its own surface control panel or panels, which powered the tool and controlled the collection of data. These were universally recorded on the R9G optical recorder, as mentioned earlier in chapter 6. This was a fine system, providing flexibility in carrying only those devices to the well site that were ordered by the customer. If problems occurred, equipment could be swapped out with little trouble. A given service center or district as they were called, might have only one set of a tool infrequently used in that area while having a set or more per truck of those devices frequently called for. However, as the number of services multiplied and their complexity increased, the transportation and preparation of the myriad of surface panels became a problem. Not only were they subject to failure through improper handling; but control of the cables which were needed to connect them up became difficult. Equipment might be sent to the field with incorrect cables or such cables might fail through constant flexing during use. In addition, it was obvious that certain parts of complex control systems were being duplicated for the many different devices involved, thus multiplying costs. These problems demanded a more compact and flexible general control system and recording system, which could be adapted to the multiple services, which were now evolving. In addition, it must also provide the capacity to further expand the number of simultaneous measurements, which could be made available to the industry.

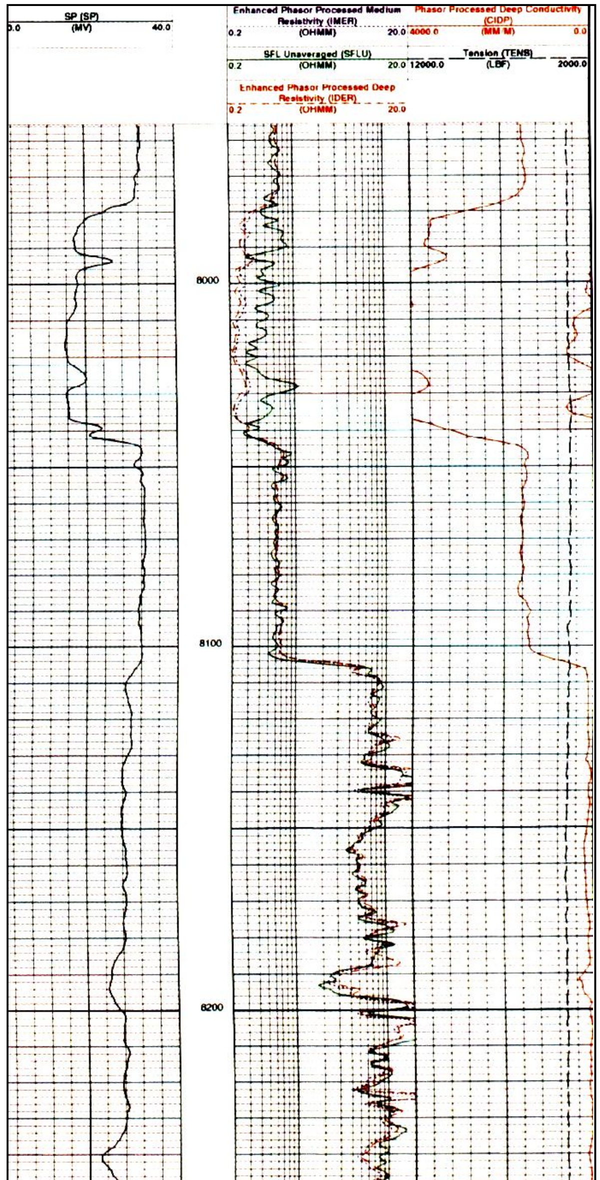


Figure 7-19 The Phasor Induction SFL Log with automatic borehole correction.

A COMPUTERIZED SURFACE CONTROL SYSTEM

Consequently, a new control, collection and processing system for data was introduced to the field. It was the first well logging system built around an on board computer and was designed to service all the instruments Schlumberger offered to the industry. Two computers as well as back up units for all critical areas of control, collection and processing of data were provided in each field unit. Thus, if failure occurred in some portion of the unit while in the field, it could usually be bypassed and the job completed without significant lost time; an essential characteristic of the field unit.

The computer based surface system speeded up the conversion of down-hole equipment from analog systems to digital systems, though the latter was also in progress with the older individual panel control surface equipment. It also opened the way for the universal use of telemetry as a means of transmitting signals between surface and down-hole equipment. The seven-conductor cable had been a bottleneck limiting the number of such signals in the past. Opening up this bottleneck was an important step in tool control and the development of more complex-simultaneous services. The revolution from individual, independent services to integrated complex simultaneous measurements had just begun when I left. I have little idea of where it is today but as an example of such development, I will include a copy of a log run with a "Phasor Induction - SFL tool along with comments from the sales brochure. It will at least help you understand that Schlumberger has always been on the cutting edge of technology with their heavy investment in research. That effort alone has contributed heavily to their leadership position in the wire line business.

THE PHASOR INDUCTION - SFL TOOL

This device is an improved induction log, which maintains the three depths of investigation for invasion profile characteristics and also improves log readings through thinner bed definition and automatic correction for borehole effects. Let me now add the comments from the sales brochure verbatim. It will give you a feel for Schlumberger's effort to educate the industry regarding measurement even though you will find terms therein, which will be strange to you. How some ever, those of you who are interested in politics have already experienced such things.

A SALES PITCH

The Phasor Induction - SFL tool uses a conventional Dual Induction - SFL array to record resistivity data at three depths of investigation. In phase (R signal) induction measurements and induction quadrature signal (X signal) measurements are combined with new advances in signal processing to provide a log with thin bed resolution down to two feet and fully corrected for shoulder effect. By adding borehole geometry measurement devices in the same tool string, borehole effect can be corrected in real time. With these environmental effects removed, a real time conversion of the data into a three-parameter invasion model can be performed at the well site.

Tool design improvements, X signal measurements, Phasor processing and bore hole corrections provide more accurate resistivity values than other induction tools in all resistivity and bed thickness ranges and bore hole conditions. The Phasor Induction - SFL tool can be combined with other tools to save rig time by reducing the number of tool runs in the well. *A personal comment: When retired from Schlumberger, the x signal was not used.*

Principle Applications

- Thin bed resolution
- Interpretation of deeply invaded formations
- True resistivity in medium to - high contrast formations
- Correlation and reservoir modeling
- Invasion profiles

Tool Specifications

OD	3 ½ inches
Max. Pressure	20,000 PSI
Max. Temperature	350^{o} F
Max. Hole size	22 inches

THE RECORDED PRODUCT

Now, let's look at the log recorded by the device in figure 7-19. It is obvious the log has much better thin bed definition as compared to the standard Dual Induction - SFL illustrated in figure 7-18. For example, notice in figure 7-18 the induction curves are unable to follow the rapid variations of the SFL but in figure 7-19, the Phasor induction curves follow the SFL almost exactly in the thin beds. That advertised benefit is obviously achieved. As for the correction for borehole effects, one would have to have more data or a comparative run with a standard tool to tell much. The real time conversion of data into a three-parameter invasion model isn't provided in the example. One can see some invasion effects on the log at the 8000' level and again at the 8240' level. The ultimate benefits however might not be apparent until the final computed products were in hand for analysis.

IMPROVED LATEROLOG TOOLS

As I indicated earlier, the laterolog seven was the first such device I became familiar with in the late fifties. It continued to be effective in high resistivity pay zones such as existed in the Big Horn Basin of Wyoming. However, in areas of very salty formation waters and associated low resistivity pay zones, as occurred in the Williston Basin of North Dakota, it wasn't and, in fact, a different device was needed. This device, called a laterolog three, proved to be the answer. Its measuring system was based on conductivity and provided better resolution in low resistivities. Its shortcoming was in the accurate measurement of high resistivities, which was handled efficiently by the laterolog seven. Fortunately, the two problems seldom occurred in the same borehole and each device served in its particular area of application for many years.

With recognition of the importance of defining invasion profiles, yet another device came into being called the dual laterolog, which provided two depths of investigation. Its design incorporated the advantages of both the Laterolog Seven and Laterolog Three providing excellent resolution through the entire range of resistivities experienced in both the areas previously referred to. Its differing zones of investigation are illustrated in figure 7-20 with the shallow configuration on the left and the deep configuration on the right. They are separated for ease of explanation only and, of course, both arrays investigate in all directions just as illustrated in figures 7-9 and 7-10 for the laterolog seven. Once the measure current flares or diverges from its horizontal flow, the signal produced by that particular device drops to zero. The depth of investigation of each device is indicated by D_I in figure 7-20; illustrating that the deep laterolog reads about twice as far into the formation as does the shallow. The two curves utilize the same electrodes, basically, but are kept separated through frequency differences and appropriate filters. It is a very complex system and was quite lengthy in its development.

As was indicated earlier, this device is effective only in a saturated salt mud environment. That is, the mud is as salty as one can make it. No more will dissolve. Such mud is necessary in areas like the Williston Basin because thick zones of salt are drilled through to get to the deeper zones containing hydrocarbon. If the mud weren't already salt saturated, it would dissolve salt from these beds and become salt saturated as well as produce severe borehole problems. Thus, salt is added at the surface.

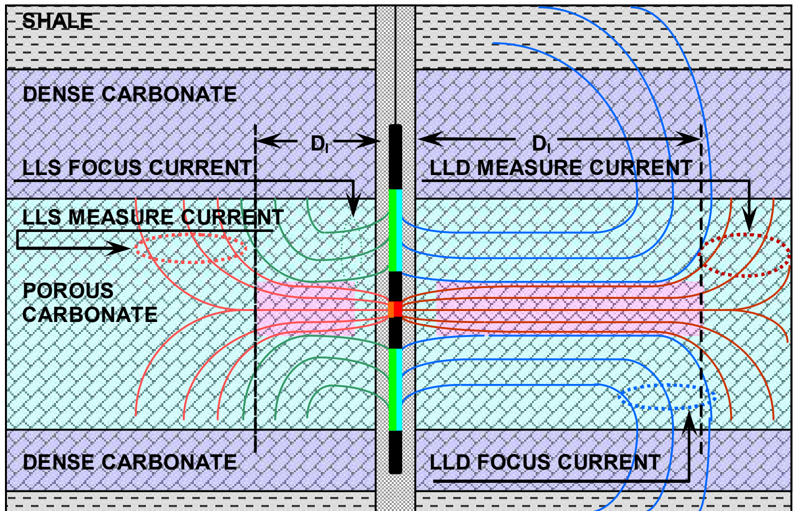


Figure 7-20 A simplified drawing illustrating the two zones of investigation provided by the Dual Laterolog.

The resulting resistivity profiles for water bearing and oil-bearing zones in such a well are illustrated in figure 7-17 by the solid lines. Notice the mud is saltier than the formation water in the example of that figure because the invaded zone near the borehole is a lower resistivity then the undisturbed deeper zone, even in a water bearing formation. In the hydrocarbon zone the contrast is much greater, of course, because of the presence of the oil. Well, that concludes the basics for measuring true formation resistivity or we might say macro resistivity because of the next group of resistivity devices I intend to discuss. However, let me close this topic with a log example taken from a sales brochure.

DUAL LATEROLOG-MSFL

Figure 7-21 illustrates a Dual Laterolog - Micro SFL with a gamma ray and caliper. In addition, the cable tension has been recorded and the sonic caliper added via a playback and merging with that later recording. The recording is the equivalent of the Dual Induction SFL but designed for salt mud environments as opposed to fresh mud environments. The explanation of the micro SFL will be included under the Micro Resistivity Device heading. The reason for the differing two calipers will also be clarified.

This example log will give you an idea of just how thinly stratified carbonate sections can be as well as an idea of the resistivity profile we have been speaking of. I won't cover everything pictured in the example at this time because all but one of the curves of track one haven't been

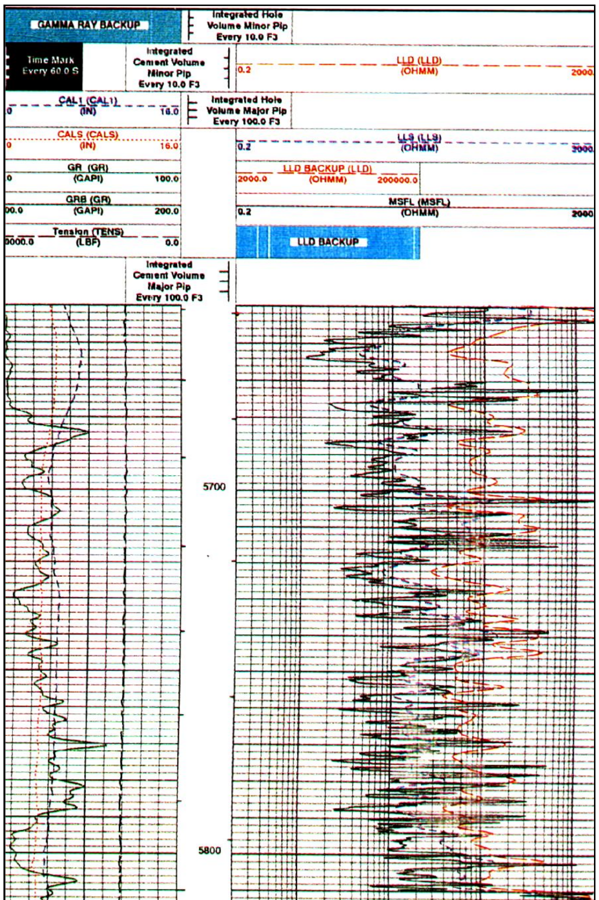


Figure 7-21 Dual-Laterolog-Gamma-Ray-Micro SFL/Cal with Sonic/caliper & tension.

discussed as yet. Only the tension curve (the rather straight dashed line about 3 divisions in from the depth track) was described in the Phasor Induction example of figure 7-19. The other four are an integration curve, a gamma ray curve and two caliper curves.

The curves of interest span the logarithmic scales to the right of the depth track. As noted on the heading, they are a red dashed curve for the deep laterolog, a blue dashed curve for the shallow laterolog and a black solid curve for the Micro SFL. First notice the extreme activity of all three curves, which point out the highly stratified nature of the carbonate reservoir. Second, notice the resistivity readings of the three curves just below 5660'. The lowest reading curve is the Micro-SFL, the next is the Shallow Laterolog and the highest reading curve is the Deep Laterolog just as you would expect in a porous carbonate and a salt mud environment, at least in a hydrocarbon zone. See the solid curves of figure 7-17 once again, which describe such a profile. The further one moves away from the borehole or the deeper a device investigates into the formation, the higher is the recorded resistivity. Also, the ratio of their individual resistivities, i.e. DLL/SLL and SLL/MSFL, are quite different than at 5797'. This illustrates a difference in invasion profiles, which helps one understand the need to describe such a phenomena for an accurate analysis. Real investigation of invasion profiles was begun in the seventies and eighties but realization of a solution had to wait on the computer and more advanced tools which came along in the late seventies. The Phasor Induction - SFL and the Dual Laterolog are good examples of just what such power can provide. The Dual Laterolog had just become available in the Williston Basin, I believe, when I left the company.

MICRO RESISTIVITY DEVICES

I doubt that you would ever guess what the title above really refers to without a little help from your jolly old grandpa. I can afford to be jolly, because I know the answer, having worked with the little suckers some thirty years. Actually, they aren't little nor do they measure extremely small resistivities. What they do do, (and that's not a no-no) is measure the resistivity of a very thin zone immediately adjacent to the wall of the borehole. You may remember that log analysts and other rather weird types refer to this zone as the flushed zone or, in terms of resistivity, the ρ_{xo} zone. You may also remember that knowing the value of ρ_{xo} and ρ_{mf} (mud filtrate resistivity) we can calculate F via equation 10, i.e,

11) $F = \rho_{xo} / \rho_{mf}$

Remember, the mud filtrate resistivity can be measured from a mud sample obtained at the well. Once we have F, porosity can be determined from equation 3 or 4 and by using ρ_t from the induction or other type log, Voile, we can determine the water saturation, S_w, through equation 5. This approach took much of the guesswork out of log analysis in many cases.

However, it wasn't perfect, not by a long shot, and the search for better methods continued in oil company labs as well as in Schlumberger's research facilities.

A RESISTIVITY PROFILE REFRESHMENT

To better understand the micro devices; let's review the resistivity profile for typical fresh mud sands similar to that illustrated in figure 7-15.

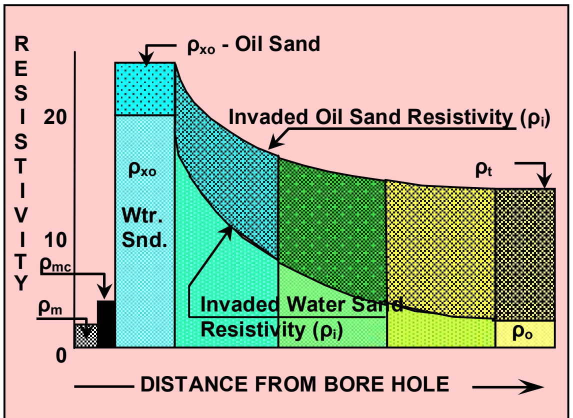


Figure 7-22 Resistivity profiles of a water and oil sand in fresh mud.

For convenience we'll just repeat it in slightly different form and call it figure 7-22. Additionally, we'll add the mud cake as well as the mud resistivities, which impact these devices too. We'll also make the resistivity profile dual in nature, i.e. that for a water sand or oil sand. Notice the mud resistivity ρ_m and the mud cake resistivity ρ_{mc} are about 2 and 4 units respectively in figure 7-22. In both of these situations, i.e. oil or water sand, ρ_{xo} is the highest resistivity in the profile. It is somewhat lower in the water zone, i.e. 20 versus 25, because there is residual oil left in the oil zone. Even though the filtrate flushes out or replaces all formation water, about 20% of the oil remains behind producing a higher resistivity. Remember, oil is an insulator and has the same effect as the rock matrix. From that point on the resistivities fall off to that value shown in the undisturbed zone, which is designated as ρ_o in a water sand and ρ_t in the oil sand. Such designations clearly distinguish the two cases.

As mentioned earlier, micro resistivity devices are used to determine ρ_{xo} in a zone which is about 2 to 4 inches wide. Thus, they can't read too deep or they are affected by the differing invaded zone resistivity and if not deep enough, by the mud cake resistivity. Getting a good value of ρ_{xo} is indeed a formidable problem. As you might expect, the situations differ in fresh mud and in salt mud environments, so we'll take one at a time. It seems logical to begin with the first micro device, namely the microlog as it was called and then move on to the salt mud environment with the special tools designed specifically for that kind of well conditions. So, let's take a look at the original microlog.

THE MICROLOG CALIPER DEVICE

The microlog device was the original micro resistivity tool and was designed specifically to measure ρ_{xo}. It was obvious such a shallow reading device had to be isolated from the borehole or the mud column would completely overshadow any response from the flushed zone. Consequently, a device was built whose electrodes were mounted on a rubber pad, which was pressed up against the wall of the hole by a spring-loaded arm. The pressure was sufficient to exclude all mud between the pad and the formation unless the wall of the hole was very rugose, i.e. rough. Thus, the device was only affected by the mud cake resistivity and flushed zone resistivity. The arms moved in and out as the borehole diameter changed always keeping the pad and electrodes pressed

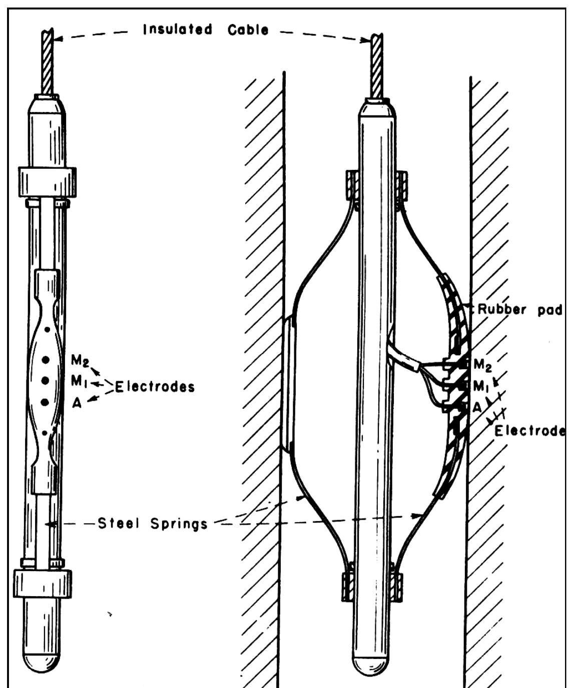


Figure 7-23 A drawing illustrating the first or original Microlog tool.

against the borehole wall. Thus ρ_m, the borehole mud resistivity, illustrated in figure 7-22 was eliminated because it was isolated from the electrode system by the pad. The mud cake, of value ρ_{mc}, however, still lies in front of the pad.

Figure 7-23 depicts the first such tool built in 1950 but one which saw many improvements over the years and still had some application in the 1980's. Soon after this introductory device, it became apparent that a caliper measurement could be added rather easily. Consequently, a variable resistor was added, which generated an electrical signal proportional to the distance between the two arms. Thus it represented a measurement of the borehole diameter. The caliper measurement was beneficial in log interpretation as well as in calculating borehole volume to ascertain the amount of cement needed to properly cement a casing string.

ELECTRODE CONSIDERATIONS

Now, let's consider the electrode arrangement and the resultant measurements. A measure current was applied to the bottom electrode termed the "A-electrode". From there it flowed outward in a semi-spherical manner as shown in figure 7-24 and returned to the metal back side of the rubber pad in the bore hole. The two electrodes designated as M_1 and M_2 were then used to measure two different signals. A micro-normal curve was obtained between M_2 and a return electrode about 15 feet away in the borehole, which we'll call N and a micro-inverse curve, was obtained by measuring the potential between M_1 and M_2. The micro-normal curve investigated about 4" from the pad and the micro-inverse curve about 1 ½" from the pad. Thus the micro-normal or M_2N signal is primarily a function of the flushed zone resistivity and the micro-inverse or M_1M_2 signal is influenced more by the mud cake resistivity. Thus, opposite a sand formation, the micro-normal will register a higher value of resistivity than will the micro-inverse. The ratio of the two, i.e. M_2N / M_1M_2, could then be entered into a mathematically derived graph or chart and a value of ρ_{xo} obtained. As has been shown earlier, F could then be derived and a porosity value calculated. As a result, the microlog became the first so-called porosity tool even though it did not measure porosity, per se. It also gave a good qualitative indication of permeability because, where mud cake was present in a fresh mud environment, the micro-normal always read a higher value of resistivity than the micro-inverse. This is illustrated in an early microlog example, probably generated in the 1940s, which I have reproduced as figure 7-25.

AN ES - MICROLOG ILLUSTRATION

I'll now give you a two-bit tour of figure 7-25, which is a composite of an old electric log and a

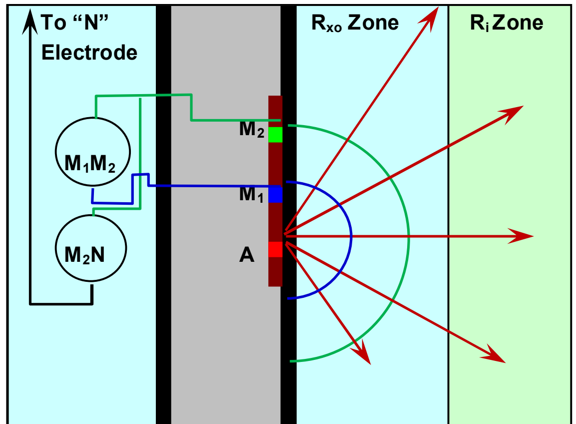


Figure 7-24 An illustration of the microlog measure current path and the resulting hemispherical potential surfaces.

microlog. In track one on the left you will see an SP curve, which, you'll remember, is a lithology curve of some value and also provides data for

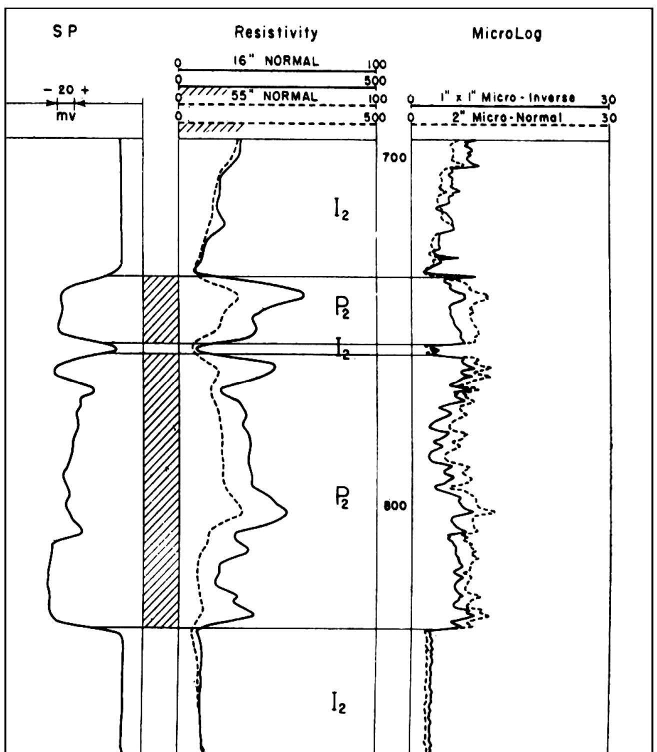


Figure 7-25 A correlation illustration of a fifties vintage Microlog with a typical electrical survey.

the determination of ρ_w. In track 2, in the center of the example, are the short and long normal curves which tend to register the invaded zone resistivity and the true resistivity respectively.

Last but not least, in track 3 is the microlog with the solid curve indicating the micro-inverse resistivity and the dashed curve representing the micro-normal resistivity.

A big sand body is indicated on the log where the SP curve deflects to the left and shale is indicated by the deflections to the right. Through the sand the short normal registers a higher value of resistivity than does the long normal, while in the shales they tend to read the same values. The microlog exhibits positive separation, primarily, through the sand body (micro-normal higher than the micro-inverse) and negative separation in the shales. The positive separation is an indication of a permeable formation and/or mud cake build up. If we had sufficient data, we could take the ratio of the two-microlog curves and determine porosity. We could then derive ρ_w from the SP and calculate the water saturation S_w with the aid of the long normal resistivity. This was a big step in log analysis making the basic log interpretation independent of outside data such as core analysis. Well, that will do for that particular example. Before leaving the microlog, however, I'll describe a few of the improvements made over the years.

The validity of that latter value, you'll remember, is critical to an accurate calculation of ρ_w from the SP as well as an accurate value of F from the measured value of ρ_{xo} with the microlog.

EVOLUTION OF THE MICROLOG TOOL

When I first went to work in 1955, the microlog device appeared much like the drawing of figure 7-24. However, the tool did have a caliper curve at that time, which we recorded simultaneously as the tool was pulled up the hole. Additionally, it utilized a hydraulic or oil filled pad for the electrodes. It wasn't always easy to go down hole with the arms open because the tool had a tendency to hang up on ledges and such. Besides, we needed to run a mud log, which I'll describe in more detail in a few minutes. Consequently, when first going in the hole with it, we closed the arms and locked them in place with a plug inserted in the bottom end of the tool. Behind the plug was a small explosive charge, which could be set off with an electrical igniter from the surface. Once we reached bottom and before starting the log, we fired the igniter, which blew out the plug and allowed the arms to open. This could be confirmed by the caliper reading. We would then run the log and, if necessary, we could usually drop back a few hundred feet to run any necessary repeat. Now, let's consider the mud log and its value for the operation.

THE MUD LOG

As you have seen from earlier examples, shales in a well usually wash out or slough off and the hole is enlarged while sands tend to remain in gauge. This reality was taken advantage of with the so-called mud log. With the arms closed the electrodes of the microlog would only accidentally touch the wall of the hole and particularly so in the shale zones. With their extremely small zone of investigation, both curves registered the resistivity value of the mud except where they came close to the wall and were influenced by the formation. This allowed us to confirm the measurement made at the surface and its associated value of mud filtrate. The validity of that latter value, you'll remember, is critical to an accurate calculation of ρ_w from the SP as well as an accurate value of F from the measured value of ρ_{xo} with the micrlog. We typically ran 1000' of mud log near the bottom of the hole before opening the arms of the sonde for the microlog.

A HYDRAULIC DEVICE

In the late fifties Schlumberger came out with the hydraulically operated microlog tool, which was a big improvement in several ways. First, it was secured by an arm on the top end only and supported directly from behind with a spring-loaded arm. This allowed the pad to tilt to some degree and seat against the borehole wall even when inclined. Coupled with the soft oil filled pad, the feature provided good pad application to the wall in virtually all cases up to the maximum diameter of the caliper of 16". Second, the tool could be opened and closed at will, which was an important feature. The earlier, explosive operated type; misfired from time to time, requiring the engineer to come out of the hole and reload before logging. The hydraulic tool overcame that problem being more reliable and also allowing closure of the tool when necessary to drop back to a deeper depth for repeats or (heaven forbid) when the tool became stuck due to some unfortunate circumstance. Prevention of even one such job crowned the tool with success in the eyes of those who ran the devices in the field. It prevented some fishing jobs similar to the one described, in chapter 5.

THE MICROLATEROLOG TOOL

This device came into use soon after the microlog. Although I'm not sure of the exact date, I do remember running the tool for the first time in 1958 near Vernal, Utah for Chevron Oil Company. As you might suspect, it was designed for salt mud environments, to be used as a ρ_{xo} measuring device, and support laterolog measurements. Every useful measurement in fresh mud was also useful in salt mud but required a device with a focused resistivity measurement to overcome shorting effects of such extremely conductive mud.

So it was with the micro-laterolog tool, which was one of the earlier devices utilizing vacuum tubes in the down-hole portion of the tool. These vacuum tube circuits provided the measure current source, the focusing current source and the controlling circuitry for the error signal, which determined just how much focus current was necessary. Additionally, they were used to amplify the measured signal and convert it to DC before sending it up hole to be recorded. Let's begin with the hydraulic pad design illustrated in figure 7-26 and the trumpet shaped measuring current pattern in figure 7-27. Together, though not quite the same scale, they should provide a clear picture.

Actually, such a cross-section taken parallel to the face of the pad (i.e. at right angles to both of those shown in figure 7-27) would be more rectangular than circular but it still flares like a trumpet as it penetrates the formation, hence the musical analogy. The two monitor electrodes, M_1 and M_2, provide the controlling signal which determines the amount of focusing current required to maintain the trumpet shaped beam of measure current and thus the sampling volume. The measure signal is taken as the potential of M_2 relative to an electrode some 15

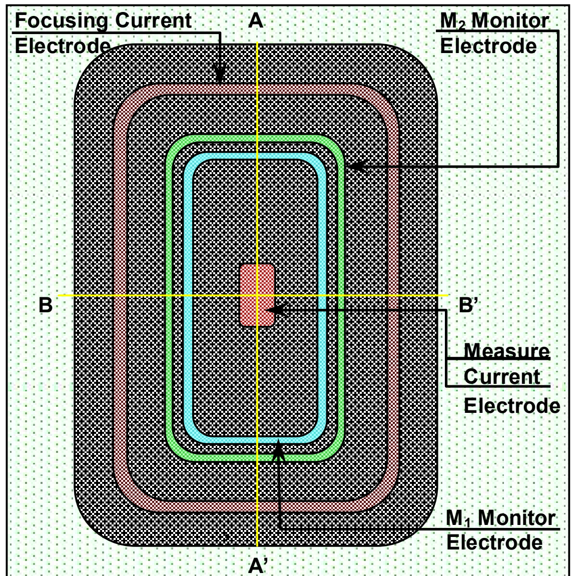


Figure 7-26 Drawing illustrating an oil filled micro-laterolog pad with electrodes.

feet away and approximately samples the volume outlined by black dotted lines in the figure of 7-27. Keep in mind that once the measure current flares, no additional signal is added to the measure signal. The trick was to design the system such that the sampling volume just reached through the flushed or ρ_{xo} zone. The signal measured was then a function of the mud cake resistivity (ρ_{mc}) and the flushed zone resistivity (ρ_{xo}). Where mud cake was thin, less than ¼", its effect on the total signal was negligible and the device registered ρ_{xo}. Salt base muds develop thin mud cakes and the device worked well in that environment, in most cases. However, fresh muds develop thicker mud cakes, (¼" to 1"), making the device was ineffective because of the intervening mud cake.

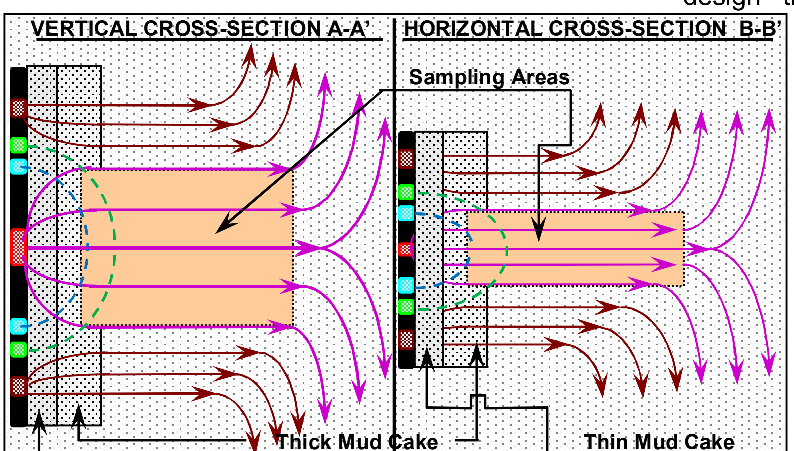


Figure 7-27 Cross-sections of the micro-laterolog pad and current patterns emanating from that pad of figure 7-26.

THE PROXIMITY LOG

Although the microlog was quite effective in a fresh mud environment, a more accurate and direct reading device was desirable. Consequently, a new tool was developed for fresh mud and given the name "Proximity Log". It was much like a Micro-laterolog in design but had a larger pad, wider spaced electrodes and investigated deeper into the formation. Mud cake didn't influence its measured signal to any significant degree. Unfortunately, it seemed to read too deep into the formation and was influenced by ρ_i. Geologists had also become dependent upon the separation of the microlog curves as an indicator of permeability. Consequently the Proximity Log never really succeeded as a fresh mud ρ_{xo} device. We, jokingly, called it "the Approximate Log".

MICRO-SPHERICALLY FOCUSED LOG

This Micro-SFL as it was termed was developed about the time I retired and consequently, I know little more than the principles involved in its design. The current beam from the pad was spherical in shape rather than trumpet shaped. This prevents it from reading as deep into the formation as the micro-laterolog and as a result, allows it to give a better value of ρ_{xo} when flushed zones are thinner. Consequently, it provides a better mousetrap for that illusive little rodent we call the flushed zone. In addition, it can now be run in combination with a Dual Laterolog and thus the three measurements provide three depths of investigation into a permeable rock and define the invasion profile. Such a combination is the salt mud equivalent of the Dual Induction SFL discussed earlier.

THE CONSOLATION

Though I know each of you, as you read this particular section, are waiting with great anticipation for my technical description of its operation, I'm afraid I'll have to forgo such a temptation. You see, grandpa didn't really get involved with it because the device was born as I retired. I am well aware of the gut wrenching disappointment you must be experiencing, for I feel the same way, not having had the opportunity to delve into the mystic world of a spherically focused current beam. But each of us must face the rigors or adversities of life, yes each has his own cross to bear, her own crown of thorns to wear. So my little chillen, keep a stiff upper lip and don't pout for there is, indeed, much more to come which will gladden your hearts and put smiles on your faces as their technical intricacies unfold. So, let's first talk about caliper logs or those devices designed to describe the shape of a borehole. Their shapes aren't always round; you know. They may start out that way but with a little swelling and sloughing of the associated shale formations; their geometry varies from elliptical to round as we move from shale to sand. From there we'll visit the world of sound or sonic measurements, as Schlumberger termed them, as well as investigate their associated wave forms. Additionally, we have yet to explore the various types of radioactive measurements which blossomed in my later years in the business, the NML or Nuclear Magnetic Log, mechanical sampling of both fluids and rock deep in the bore hole and, last but not least, the dipmeter. This latter device establishes the orientation of various depositional planes surrounding the borehole and consequently opens up the world of stratigraphic and structural geology. Thus, you see, there is still much left to dazzle the imagination and stretch the most inquiring minds. In layman's terms this means to bore the uninterested senseless. However, must I remind you, these are keys to grandpa's marvelous methodical, mystical and many-faceted mentality?

CALIPER LOGS

We mentioned caliper logs in a couple of places earlier when they were an automatic part of the other services being explained. For instance, they are an automatic part of the microlog as we mentioned but similarly they are part of the micro-laterolog and micro spherically focused log as well. As mentioned, this resulted from the need to apply a pad for the various types of very shallow investigation devices directly against the wall of the hole. To do this, one had to have an arm for the pad and a backup arm against the opposite wall, which made the measurement of borehole diameter rather simple. A variable resistor was coupled to the arms of the tool and the voltage drop across it calibrated to the distance between the arms. Voile, a borehole diameter measurement resulted. The calibration standard was easily come by in the form of two short sections of casing with differing diameters, which established two empirical check points.

There's a lot more to defining borehole shape than just measuring a simple diameter, as you will see.

AN OVERVIEW OF BORE HOLE PROFILES

There's a lot more to defining borehole shape than just measuring a simple diameter, as you will see. Oddly enough, most drill holes develop an elliptical cross-section in shape as they slough and enlarge. See figure 7-28. This enlargement is caused by the hydration of the shales as they are exposed to mud salinities different than that in which they were laid down. One theory for their shape as they enlarge is, “the holes slough faster in a direction parallel to the natural regional stress within the earth's crust”. That may well be true but whatever the reason; the result or borehole geometry is the important fact in well logging and completion of the well. Not only can the bore hole size and shape effect the measurements made with logging instruments, but it can also impact cementing and completion of a zone within a given well.

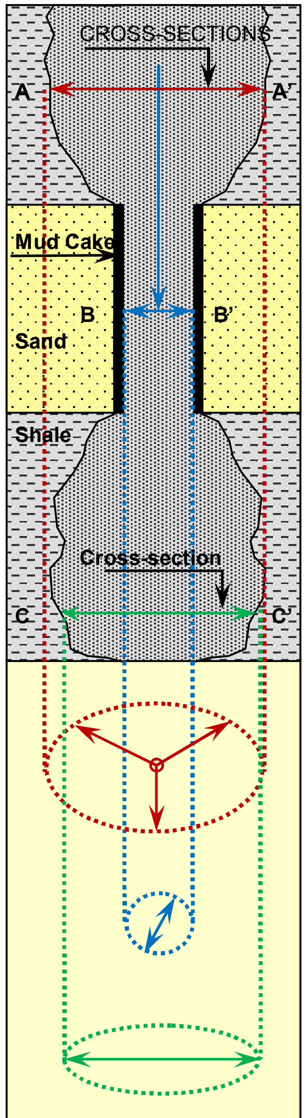


Figure 7-28 A drawing illustrating a typical borehole with its various enlarged cross-sections.

TYPES OF CALIPERS

Two arm calipers tend to align themselves with the long axis of the borehole and record the maximum diameter of the hole as indicated by the black line with arrowheads in cross-sections B-B' and C-C'. A three arm caliper, on the other hand, could not so align itself and tends to give a somewhat smaller value of hole diameter as illustrated by the dark magenta set of arrow heads in cross-section A-A'. For cement volumes the latter was preferred because it gave kind of an average value of borehole diameter. See the two calipers in figure 7-21 for a comparison. The black dashed trace in the left column (track 1) is that of the Micro-SFL, a two armed caliper while the red dashed trace is that of a sonic caliper, a three-armed device which is run in conjunction with the sonic tool. Notice that the sonic caliper (red) always registers a smaller diameter than the SFL caliper except from 5850' to 5900'. The larger the hole, the more they deviate. Neither, however, really expressed the shape of the borehole or provided a means to calculate its volume reliably.

THE FIRST CALIPER

The first caliper designed and built by Schlumberger was a tool called a section gauge. I assume it was so named because it measured or gauged the cross section of the borehole. Surely there had to be some logic and reason behind such a name. Anyhow, it was a three-arm device and could measure diameters up to about 36”, as I remember. Its sole purpose was to provide a measurement from which the completion engineer could calculate the amount of cement required to bring the top to some predetermined depth. Although not used a lot, it served well and was a part of the battery of tools offered by Schlumberger well into the 60's. Other calipers only measured diameters up to 16”, which wasn't sufficient in many cases. Eventually, extensions were developed for the two-armed devices, which provided measurements up to 30 inches and the section gauge faded into oblivion.

FOUR ARM CALIPERS

Finally, a four-arm caliper was developed which provided both dimensions (long and short) of the hole. It was an outgrowth of the High Resolution Dipmeter, a tool I'll discuss in more detail later. Both diameters were critical to accurate dip calculations and the associated geologic interpretation. After the incorporation of two measurements into that device, a caliper tool with four arms was designed for wells without the incorporation of dipmeter curves and was termed the Bore Hole Geometry Tool. It truly phased out the section gauge being able to measure both diameters accurately to about 36 inches. Thus, evolution of even this simple device has been on-going.

CALIPER CALIBRATION

Of course, calipers must be calibrated like any other measuring device. Schlumberger used a two-point calibration system. Most bore hole diameters were in the 8” to 12 “ range and consequently we set our low end calibration, or zero as it was called, in an eight inch ring and made the meter read 8 inches. We then place a 12” ring on the caliper and adjusted the high end or sensitivity to make it register 12 inches. That's easy enough, huh? Of course if the hole was larger, 16 inches or so, larger rings were needed and the calibration was made according to the expected borehole diameters. Linearity or the galvanometer deflection per inch of changing borehole size was only reliable for diameters within or close to the calibration values. As a result, each size caliper required its own calibration standard to ensure measurements were accurate. Consequently, what appears to be a rather simple measurement is more complex than one would expect, as is the borehole shape it defines. Hence, the simple caliper eventually evolved into the Bore Hole Geometry Tool.

THE APPLICATION OF SOUND MEASUREMENTS

Sound has long been used by the oil industry from the barking of orders by tool pushers, often accented with expletives, to its use as a means of defining subsurface structure through seismic methods. However, its use as a device to help evaluate formations surrounding the well bore didn't really begin until the late fifties. The original device was designed and patented by Mobil Oil Company. Schlumberger as well as other wire line companies bought the right to develop their own tools and offer them to the industry. Since that time, Schlumberger and other wire line companies have developed various services employing sound as the energy medium with differing degrees of success, which I'll now address. Each had its own trade name such as sonic log, acoustic log, etc. Schlumberger coined the name, "Sonic Log".

SEISMIC REFERENCE SERVICE

SEISMIC MEASUREMENTS

You may remember from chapter 5, that seismic evaluation of the subsurface is accomplished by detonating a series of charges at the surface and measuring the time required for reflections to appear at various locations nearby. The process is depicted in simplified form in figure 7-29. The red arcs and lines depict energy waves and reflections from the sand or yellow horizon, while the green arcs and lines illustrate similar events from the magenta or carbonate bed just below it.

A charge is placed in a hole about 50 feet deep, several of which have been drilled by the drilling truck and crew. Receivers are then placed along the surface of the ground at specified locations and connected to the recording truck. Likewise the electrical ignition system for the charge is connected to the recording truck so every aspect of the job is under the central control of the recording engineer.

When all is ready, the recording truck operator starts his recorders and detonates the charge. As the charge is detonated, a wave front expands outward from it through the ground in all directions. Some energy arrives at each receiver and indicates the time lapse since detonation. As the wave front moves downward, it strikes the various layers of rock in the subsurface. A portion of the incident energy is reflected at the edge of each change in strata.

Sound has long been used by the oil industry from the barking of orders by tool pushers, often accented with expletives, to its use as a means of defining subsurface structure through seismic methods.

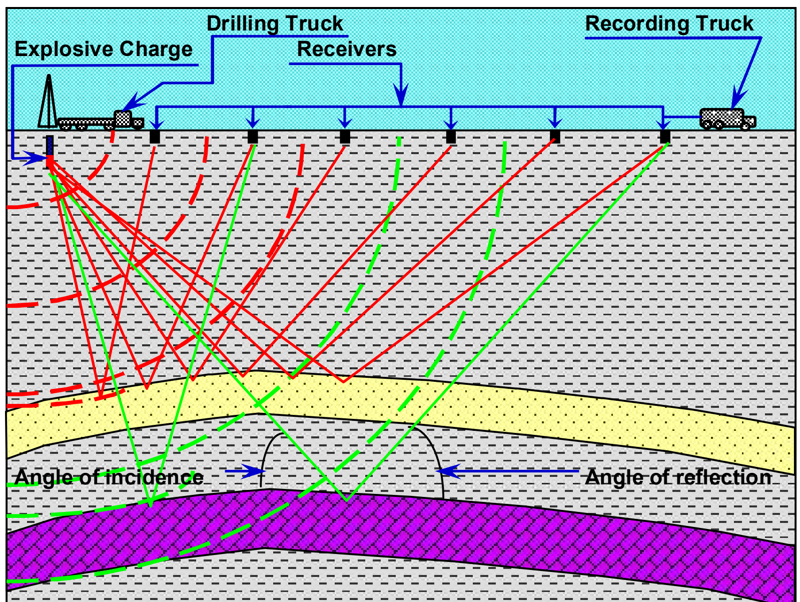


Figure 7-29 A simplified illustration of the gathering of seismic data to define subsurface structure.

Most of the energy moves through the new layer, eventually reaching the lower boundary where an additional reflection occurs. The wave front continues downward sending back portions of useful reflected energy until they become too weak to record or see. The reflections from each layer move back towards the surface and strike the receivers. A particular receiver will receive energy from only one point on a given bed boundary. Thus we can think of the wave front as consisting of rays of energy emanating out from the detonation along specified paths as illustrated. Since each receiver is in the path of a specific ray reflected from each surface, it receives a signal defining that point in time along the ray. Since the distance the ray has traveled can be calculated by equation 13, i.e. the sum of incident and reflected paths; it is possible to calculate the depth below the surface, at which a particular bed boundary lies.

13) D = V x T

Where D = distance, V = velocity of the sound and T = the elapsed time for energy arrival.

By taking numerous shots along differing lines on the surface and utilizing many receivers, the attitude of that particular bed boundary can be reproduced. Notice that time can be measured but velocity must be assumed, unless provided some way, to determine D, which is the key parameter required to come up with the structural picture. With some knowledge of the geologic section traversed, reasonable estimates for V can be arrived at. However, it is much better to know the correct value, which brings us to the purpose of the seismic reference survey providing that information. It

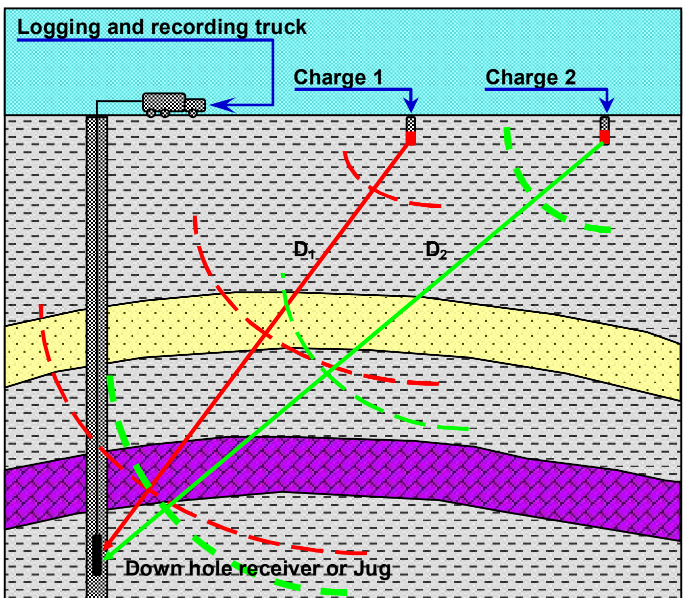


Figure 7-30 An illustration of the SRS survey.

was typically used in wildcat areas where little velocity information was available.

THE SEISMIC REFERENCE SERVICE

Obviously, if we can measure D and T, then we can calculate V. Isn't that marvelous? So, what do they do? They drill a hole through the section of interest and make similar time measurements with a receiver in the hole. This is the seismic reference survey, which is illustrated in figure 7-30. The depth in the hole is recorded on film for each station. The surface distance from the hole to the various charges is measured. D, the distance from a specific charge to the jug is calculated and the time measured when the charge is detonated. The average velocity of the rock to the specified depth is then calculated from;

14) V = D / T

Shots are taken at various depths in the hole and from various surface locations (more than just two, as shown), which provides the velocity data needed to properly interpret any seismic data for the area. We didn't have to worry about calibration in this case. All we did was place the tool at the correct depth and the seismic operator did the rest. He calibrated his instruments and we followed his orders. That is, unless he took too long and my sense of an imminent fishing job began to rise within. In that case, we moved the tool. I wanted no part of planting the sucker and then trying to fish it out. Well, that ought to be enough on that particular subject. So, on to the most popular survey with sound that Schlumberger had, i.e. the measurement of formation travel time surrounding the borehole.

THE SONIC LOGGING TOOL

When I first went to work with Schlumberger and was training on an offshore drilling rig, we were requested to run a CIS or customer instrument service. All we did was provide the winch and cable to lower the tool in the hole and the customer did the rest. The customer was Mobil Oil Company in this case and their tool was an experimental sonic tool. As mentioned, Schlumberger and other companies obtained the rights to develop their own tools. As a consequence, this device became a very important revenue source from tools utilized in both open holes and cased holes.

TOOL PRINCIPLES

Let me begin by describing the principles involved in sonic logging as Schlumberger called it. Figure 7-31 illustrates a simple single transmitter, two-receiver tool, which was the first type Schlumberger designed. The transmitter was a magnetostrictive device, which consisted of a metal core surrounded by a coil. The term magnetostrictive simply means the physical dimensions of the metal core change when it is subjected to a magnetic field. Conversely, when the cores dimensions were forced to change due to physical vibration, it would generate a weak magnetic field. Thus, a similar type device was used for the receivers. This is depicted by the coiled lines in each transducer, (receiver or transmitter), of the tool.

The transmitter would be pulsed with energy about 20 times per second, which was known as the PRF (pulse repetition frequency) and the transmitter coil would oscillate at 30 kilohertz or 30,000 times per second. This would make the core vibrate or change dimensions at the same rate and a sound wave of 30 kilohertz would emanate from the transmitter. Each pulse developed its own wave front, which traveled out from the transmitter in all directions just as they did in the SRS example. However, the wave front traveled at different speeds (velocities) in the formation, mud column and tool. Because sound travels significantly faster in most rock than in mud or the tool body, the wave front traveling down the borehole wall arrives at the receiver first and activates the receiver giving a measurement of the travel time between transmitter and receiver. The measurement is made without interference from the other two wave fronts since they come along later and are excluded by shutting the tool off with the first arrival. The time required for the sound to travel to the first receiver is the sum of the individual segments of the ray or, in algebraic form we would designate it as,

15) $T = T_1 + T_2 + T_3$.

The time to the second receiver is

16) $T = T_1 + T_2 + T_4 + T_5$.

Each path obviously includes both mud and formation. To eliminate the mud, the device automatically subtracted the time to the first receiver from that to the second and came up with the answer for travel time of

17) $DT = T = T_4 + T_5 - T_3$

If $T_3 = T_5$ then the time measured is simply a function of the formation travel time in the interval measured or T_4. That time would be divided by the spacing of the two receivers, 2' in later models, to provide the required measurement in microseconds per foot of formation. The log was then recorded in those units and the time was referred to as delta T, DT or ΔT, using the Greek symbol. This value of travel time had different applications but the log analyst was primarily interested in porosity.

Porosity, which you will remember, is designated by the Greek letter Φ and can also be determined from the travel time per foot of formation. This value was often more accurate than values obtained from the Microlog or Microlaterolog and also complemented them. If we refer to delta ΔT as Dt and porosity as Φ we can write an equation for the travel time as;

18) $Dt = \Phi \times Dt_f + (1 - \Phi)Dt_m$

That is the travel time per foot of formation is equal to the porosity times the travel time of the fluid contained therein plus the matrix volume or (1 - Φ) times the travel time in solid rock (no porosity). The latter, we refer to as matrix DT, which varies with the type of rock involved. For instance in a clean sandstone, the value is 56, in limestone 47.5 and in dolomite 43 microseconds per foot. The equation can be rearranged to determine porosity as;

19) $\Phi = (Dt - Dt_m) / (Dt_f - Dt_m)$

Now we have a porosity value that is not dependent on our knowledge of R_{mf}, which removes one variable from our calculations.

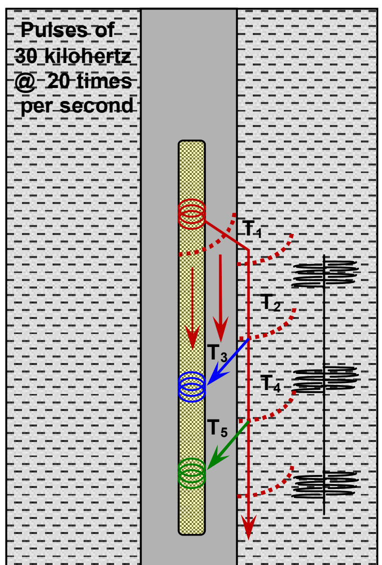


Figure 7-31 Illustration of a single transmitter – two receiver sonic tool.

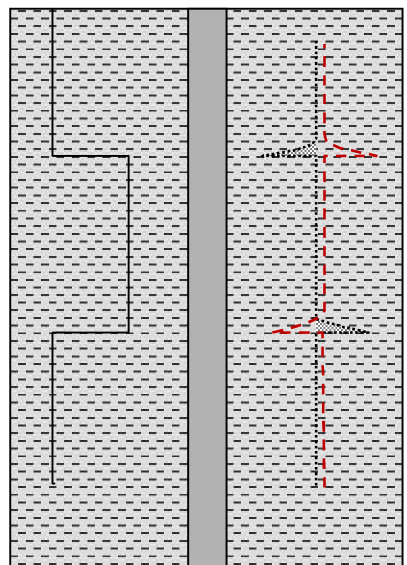


Figure 7-32 An illustration of a sonic device's response when passing a caved zone.

Maybe I should take a second or two here to explain the term microsecond. Micro in this case doesn't mean small, as in inches versus feet in the description of the microlog, but small in terms of time. Actually, it means one millionth

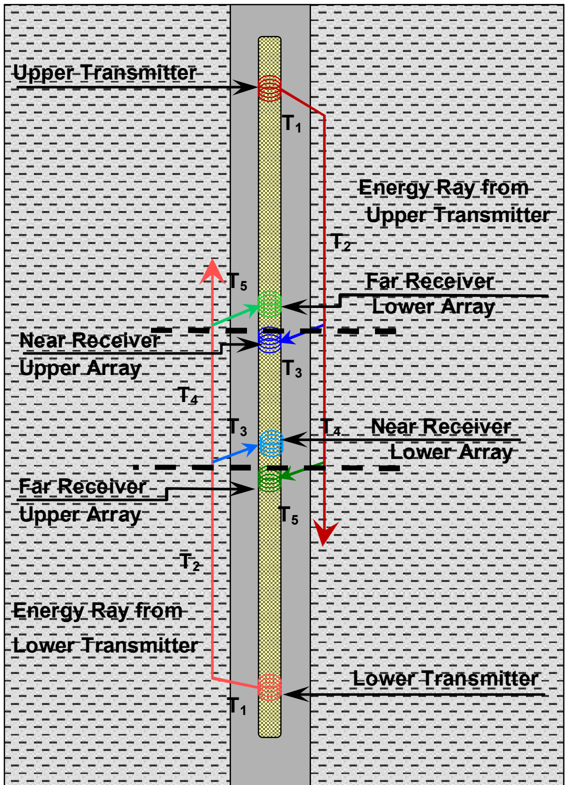


Figure 7-33 A Bore-hole compensated sonic illustration of the tool configuration.

of, i.e. a microsecond is a millionth of a second. Thus, solid quartz, as in sand grains, has a travel time of 56 microseconds per foot of formation or a velocity of about 18,000 feet per

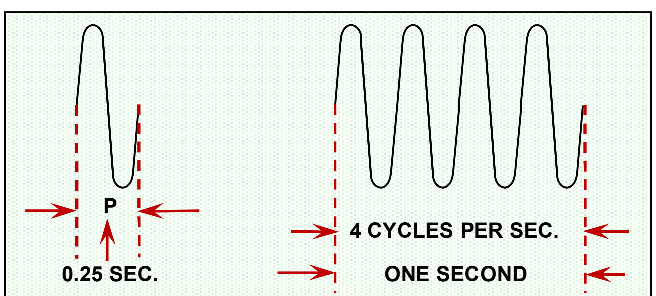


Figure 7-34 An illustration of the period of a wave, abbreviated P, as compared to its frequency in cycles per second or Hertz.

second. That's about mach 18 if you were talking about supersonic flight. Is it any wonder we have to measure the travel time in microseconds per foot?

The fluid velocity is constant at 5300 ft per second or 189 microseconds per foot. If we know the kind of rock in question and Dt is measured then voile, we can calculate porosity.

You may remember that back in equation 17 we assumed T_3 was equal to T_5, which is reasonable and accurate most of the time. However, if the tool passed from an in gauge portion of hole to a caved portion as it moved upward, such an assumption was not true and the error was manifested as a spike on the log. This is depicted in figure 7-32 by the black dashed curve. The example assumes a pure homogeneous formation with a sharp cave to accentuate the effect of the borehole enlargement, hardly a natural phenomena but suitable for explanatory purposes. Although generally not a problem, such anomalies produced errors in the use of log data from time to time and especially so when the wall of the hole was very uneven in and around zones of interest.

THE BORE HOLE COMPENSATED SONIC TOOL

Interestingly enough, had we placed the transmitter of figure 7-31 below the two receivers rather than above, the effect would be reversed as depicted by the magenta curve. Realizing this, some bright engineer said, "Why not place both arrays on the same tool and average the two readings?" Even with space in logging tools at a premium, this became possible with the adaptation of solid-state electronics to the down-hole devices. This they did and the so-called Bore Hole Compensated Sonic was born.

This device is illustrated in figure 7-33. Notice that both devices measure the same interval of formation between the red and yellow dashed lines as the device moves up the well bore during the logging operation. For the upper array the individual travel times in mud and formation are listed on the right of the borehole while they are listed on the left for the lower array. Utilizing equation 17 as a guide, we can write travel time for the upper array;

20) $T_U = T_4 + T_5 - T_3$

and for the lower array;

21) $T_L = T_4 + T_5 - T_3$

As the tool moves up the borehole and passes by the lower boundary of a cave, T_3 for the upper array becomes too big, that is larger than T_5, and T_U becomes too small. Conversely, T_5

for the lower array becomes too large and T_L registers too large an answer. The magnitude of error for the two arrays is equal but opposite and when averaged together, the correct travel time is obtained, that is;

22) $T = (T_U + T_L) / 2$

The resulting log not only gave more accurate values of Dt but also provided a curve , which could be correlated more easily and was nicer appearing.

A very accurate crystal controlled oscillator, much like that used in modern watches, was used to calibrate the sonic tool, regardless of its vintage. By adjusting its frequency we can determine the time between each of its output pulses in microseconds. For instance, a 1 megacycle frequency (1,000,000 cycles per second) has a period or time span of 1 microsecond (one millionth of a second). We can express it mathematically as follows;

23) $T = 1 / F$

Consider figure 7-34 to see the concept graphically, which also illustrates the frequency of a wave and its period of repetition. This sound wave can be used to allow the engineer to set different frequencies and make his meter or galvanometer register the correct time as given by the oscillator. A calibration was shown before and after the log to verify accuracy. I might also add that the sonic trace on the film covered two linear tracks, which was quite a feat for the galvanometer involved. In fact, we had to use one near the center of the recorder so as to minimize its swing in either direction. To assure linearity, calibration steps were in 20 microsecond intervals. In the Rockies, we typically calibrated from 50 to 150 microseconds or displayed 50-70-90-110-130-150 microsecond traces as verification of proper calibration.

SONIC LOG RECORDING

Before leaving the sonic log, I suppose I should provide an example of such a recording. Consider figure 7-35, which illustrates a Gamma Ray/Sonic/Caliper, which is typical of those run on a regular basis in the Rocky Mountain area. The same can be said for the general log format in other areas of the world. However, scales for both gamma ray and sonic vary with locale.

GAMMA RAY

Notice, the gamma ray and caliper curves are in track one along with a bit size reference while the sonic or delta T curve spans tracks two and three. Let's begin our tour with the gamma ray curve. As I said, it's kind of a lithology indicator in that most shale formations are radioactive while sands, limestones and dolomites generally exhibit little radioactivity. We tend to gauge the cleanliness of a formation by its gamma ray reading or the amount of shale. It's important because shale will alter the readings of many devices and its presence requires a correction. All the sands are registering a gamma ray reading of around 32 API units, which would indicate they have little shale or clay in them. The limestones exhibit even a lower gamma ray reading than do the sands normally, though either could have variable amounts therein.

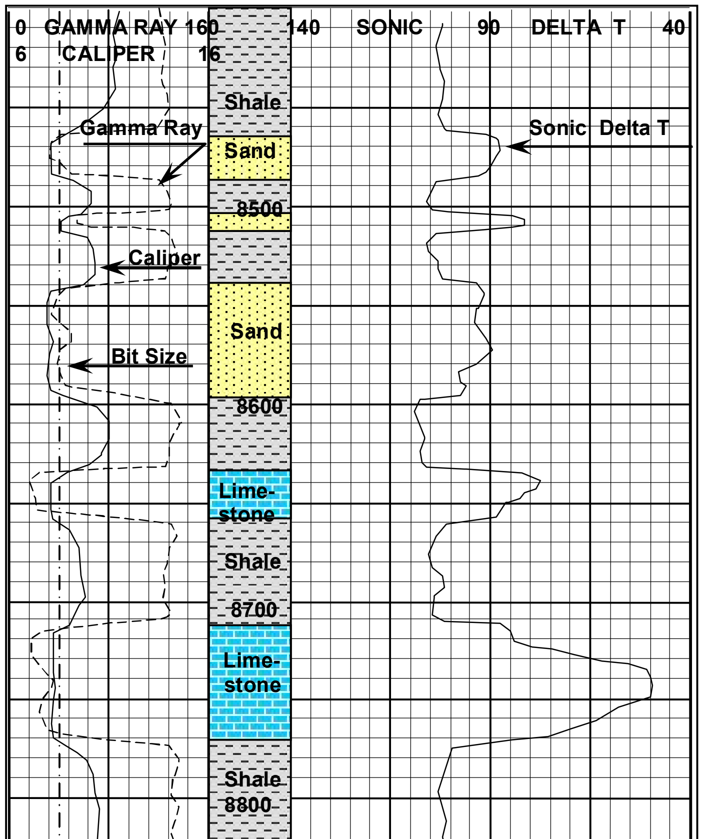


Figure 7-35 An illustration of a typical Sonic Gamma Ray Caliper log from the Rocky Mountain area.

CALIPER LOG

Now, consider the caliper log, which is recorded from a device having three arms in this particular case. The pad pressure is also relatively light which prevents them from cutting through the mud cake. As you can see, mud cake buildup is apparent in front of all the porous zones. That is, the caliper registers a diameter somewhat less than bit size. Such an indication is valuable information in that it is another indication of permeability, that illusive property so necessary for good production.

TRANSIT TIME OR DELTA T CURVE

Finally, we get to the sonic log or Delta T curve itself, which is the major measurement of interest. You can see that two tracks are dedicated to its recording and in many cases the complete span is required. If large caved or washed out sections are present the Delta T may exceed 150 microseconds per foot and a back up curve will come on. In some areas along the gulf coast, shale zones have a Delta T value in excess of 150 microseconds per foot. They too may require a backup. Now, let's examine some specific zones.

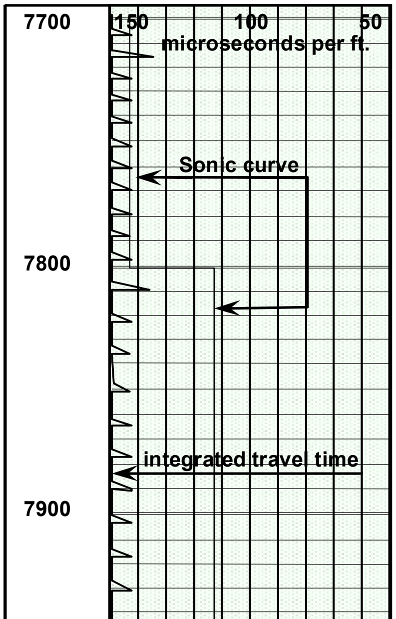


Figure 7-36 An illustration of integrated travel time record

Looking at the top sand from 8475' to 8495', we see a slight variation of the Delta T through the zone. The average value appears to be 87 to 88 or let's say 87.5. Utilizing equation 19, we have a porosity value of;

Φ =(87.5-56)/(189-56) or,
Φ =31.5/133 = 23.7%

That's good reservoir rock in the Rocky Mountain area. The thin sand at 8800' has a Delta T of 80, which would yield a porosity or Phi of 18%, which is also OK.

The thick sand from about 8530' to 8590' displays a sonic reading of 90 to 95. Using equation 19 once again, we can plug in those values with the same matrix Delta T of 56 and fluid value of 189 to arrive at;

Φ or Phi = (90 - 56)/(189 - 56), or
Phi = 34/133 = 25.5% and
Phi = 39/133 = 29.2% respectively.

This clearly illustrates that porosity within a sand body can vary. In fact such variations can be quite wide. Thus, geologists often speak of the average porosity of a given geologic horizon or bed of interest.

Moving on down to the limestones, the reader will notice the lower values of Delta T almost at once. Does this mean they have lower porosity? Well, maybe but we have to keep in mind that the matrix velocity or Delta T has now changed and what a given Delta T represented in terms of porosity before, is no longer true.

SONIC DERIVED POROSITY

We'll begin by examining the zone at 8625' to 8640' utilizing equation 19 once again. The Delta T from the log varies from 76 to 85 microseconds per foot. Using the matrix Delta T for limestone of 47.5 and plugging in 76 to the equation, we get;

Phi = (76 - 47.5)/(189-47.5)
Phi = 28.5/141.5 = 20%

While 85 microseconds per foot yields;

Phi = 37.5/141.5 = 26.5%

These values might surprise you in that they are similar to the thick sand just analyzed.

The thicker limestone lying from roughly 8700' to 8760' displays a wide range of porosity. At the top we might pick a value of 83 for Delta T while from about 8713' to 8725' the value varies from 83 to 49. The next zone is the very low porosity zone from 8725' to 8741'with a Delta T of 49 and then a gradual increase in the last 19 feet to 68 microseconds per foot. I'll calculate the porosity at the top, middle and bottom to give you an idea of the changing porosity value, which, is characteristic of limestones.

At the top of the limestone we find,

$$\text{Phi} = \frac{(83 - 47.5)}{(189 - 47.5)}$$
Phi = 35.5/141.5 = 25%

In the middle;

$$\text{Phi} = \frac{(49 - 47.5)}{(189 - 47.5)}$$
Phi = 1.5/141.4 = 1%

At the bottom;

$$\text{Phi} = \frac{(68 - 47.5)}{(189-47.5)}$$
Phi = 20.5/141.5
= 14.5%

Well, that may be more than you ever cared to know about deriving porosity from a sonic log or the recorded speed of sound through a potential hydrocarbon reservoir. If so, don't let it bother you, there's worse to come. For the time being, however, we'll move into another phase of the sonic log, which utilizes principles to which you have already been subjected, i.e. integration of travel time and other parameters.

TRAVEL TIME INTEGRATION

To minimize misunderstanding, the term integration as used here doesn't mean mingling or bringing together as in the integration of races. Rather it means summing up or adding up as in integral calculus. Thus if a formation exhibited a constant travel time of 100 microseconds per foot and we added up the time for 1000 feet, the integrated time would be;

1000x100=100,000 microseconds

It could also be read as 100 milliseconds. Remember our old friend milli from millidarcy. Well, Schlumberger and the industry chose to display the answer in milliseconds and so indicated it with a little blip for one millisecond and a big blip for ten milliseconds. A client could then add up the blips over a zone of interest and derive the total travel time for that interval and then calculate the average velocity since velocity equals the reciprocal of time. This was, of course, useful in seismic work as we explained earlier. You might ask, "Why use check shots (an SRS survey) if one can integrate the travel time in the borehole". Well, seldom is a sonic log run over the whole borehole and particularly before surface casing is set. Thus, integration of travel time is not available to the surface. The SRS survey ties the integration to the surface and also verifies its accuracy over wide intervals within the well. Consequently, they complement one another.

Figure 7-36 illustrates the method of recording integrated travel time on a sonic log. Actually this same presentation is used for the integration of other measurements such as hole volume, etc. The sonic log travel time (delta T) is idealized and shown as 75 microseconds per foot in the bottom portion of the example and then a sharp change to 105 microseconds per foot at 7800'. In the integration near the depth track, a small blip to the right represents 1 millisecond and a large one 10 milliseconds. Remember, the integration adds up the travel time for each foot of hole. At 75 microseconds per foot, it takes 13.3 feet of measurement to add up to one millisecond or 133 feet to add to 10 milliseconds. Similarly, at 105 microseconds per foot it takes about 9.5 and 95 feet respectively to add to 1 millisecond and 10 milliseconds. If you check the integration, you'll notice that such is the case in the spacing of the blips.

GENERAL INTEGRATION

If we were integrating hole volume, the sum would be in cubic feet and thus each small blip would represent 10 cubic feet and the large blips 100 cubic feet. In the example the blips looked much as I have drawn but maybe not quite as wide. With modern technology they are essentially a straight line to the right or left depending upon what they represent. Figure 7-21 illustrates such integration of both hole volume and cement volume. The latter is possible if the customer knows the casing size he intends to run for completion. Obviously, the casing volume would have to be subtracted from the borehole volume to achieve cement volume. One would expect the blips for borehole volume to be closer together than for cement volume because a shorter section of hole would be required to add up to 10 or 100 cubic feet. Note that such is the case in figure 7-21. Be careful because the borehole volume blips are on the left of the depth track and the cement volume on the right. They are deflected arbitrarily towards the depth track in each case for presentation purposes only.

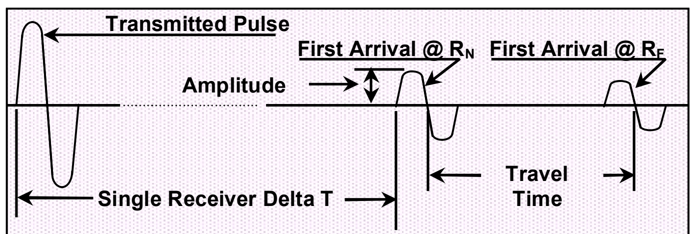


Figure 7-37 An illustration of Sonic travel time and the amplitude of the first arrival at the near receiver.

No calibration was necessary for this measurement. The summing was an electronic function that was calibrated during design and manufacturing. One could estimate its accuracy by adding up the average travel time per foot from the sonic curve and comparing it to the integrated value. That was done more to pass the time away and provide a little mental exercise than anything else because of the improved accuracy and reliability of electronic integration. With the earlier mechanical variety such a check was done on a regular basis. We had learned the hard way that such a mechanical device left a little to be desired. The consequence was integration by hand, which was a time consuming effort.

AMPLITUDE MEASUREMENTS

So far I have described the time measurement for a sound pulse to travel through one foot of formation. This was by far the most common use of the sonic device but occasionally we would be called upon to make amplitude measurements. To illustrate that concept, consider figure 7-37 which depicts the transmitted pulse and the first arrival of the signal reaching the receivers. First, I should explain that the transmitted pulse consists of several cycles of the sound wave. I've shown only one for ease of explanation and drawing. The transmitted pulse would be many times higher than the received pulses at either receiver. Similarly, the signal at the far receiver would be significantly less in amplitude than at the near receiver. Thus, relative amplitudes aren't to scale. Likewise, the time base (time between transmitted pulse and received pulses) is not to scale as indicated by the dashed line but the principle remains the same. I am only interested in describing the principle without worrying about the details.

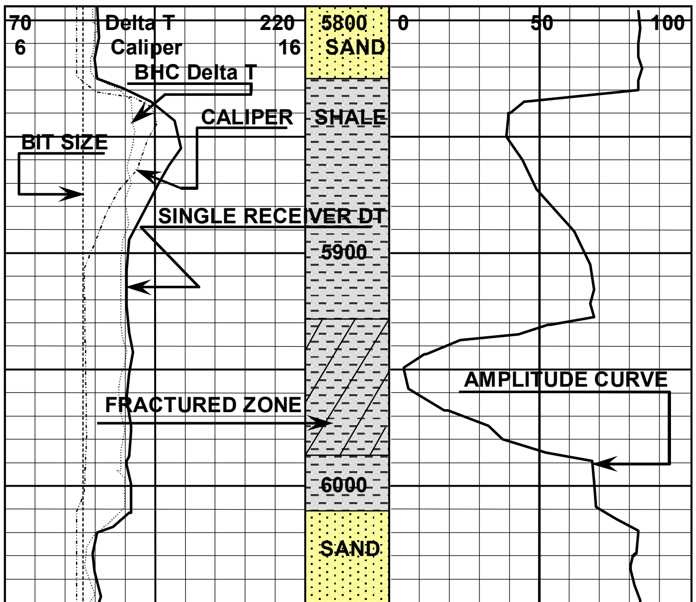


Figure 7-38 An illustration of an amplitude log with a caliper and single receiver delta T curve.

"A rock in the hand is worth two in the well". Now isn't that a neat adaptation of an old adage?"

First, note the travel time measurement or the time required for the sound pulse to travel between the two receivers. This is the raw travel time and must be divided by the spacing, 2 feet in my day, to obtain delta T in microseconds per foot. If the tool was a BHC as described above, this might represent the upper array. A similar measurement would be made with the lower array, the two measurements added together and divided by two to get the borehole compensated answer for delta T. The travel time could have been measured between the positive half cycles with the same results. We, however, used the negative half cycle because it was somewhat larger in amplitude and thus produced a more reliable measurement.

When amplitude was measured, the near receiver positive half cycle was utilized because its amplitude was more sensitive to formation fracturing. When fractures were encountered, some sound moved across the fracture and on to the receiver but some was also reflected which reduced the amplitude of the wave. Thus, the amplitude of that signal was a function of formation fracturing, among other things, and could help the geologist or operator locate such zones. Even with very low rock permeability, fractures could make an otherwise dry hole into a producer.

The amplitude was measured in millivolts, the same unit as the SP and consequently utilized a very accurate voltage source for calibration.

Lastly, note the measurement of Single receiver delta T. This measurement is described by equation 15 and includes mud travel time. It is a function of borehole size as well as formation travel time and thus is of no use in determining the latter. However, it can help the geologist analyze the amplitude log, which is also affected by borehole enlargement.

Now, let's go on to a typical amplitude log in uncased hole with its complement of curves. See the illustration of a typical amplitude log in figure 7-38. Just a couple of points need to be made relative to this log. Notice the caliper curve shows borehole enlargement at about 5850', which corresponds to a decrease in amplitude. The single receiver delta T curve seems to verify the enlargement and explains the reduction in amplitude when compared to the BHC delta T which has been traced on immediately next to the single receiver delta T. Notice they track each other almost exactly except in the area of enlarged hole. By choosing the scale for single receiver DT conveniently the engineer can make the sensitivities the same and when he traces on the BHC DT they will track except where borehole size is greater than bit size. In this way low amplitudes due to caving of the hole can be differentiated from low amplitudes due to fractures.

At about 5930' to 5985', however, a similar reduction in amplitude is seen but accompanied by a relatively constant DT and borehole size. Note the BHC DT tracks the single receiver DT and thus hole size is not a factor. As a result, the zone is construed as being fractured. Well, this device had moderate success in defining fractures and was a second available measuring option, of the standard sonic tool, for customers with such a need. Even so, its use was rather infrequent.

THE BORE HOLE TELEVIEWER

Geologists like to look at the rock they are evaluating. In their case we might say, "a rock in the hand is worth two in the well". Now isn't that a neat adaptation of an old adage? Sometimes I even amaze myself with my quaint little quips, seeming to abound to about the same degree as my obvious humility, which in turn, embellishes my writing but then, I'm an Obenchain, what more can you expect?

Anyway, they (the geologists) do like to look at the rocks and even feel, smell, taste and test them in a myriad of ways. That's why coring a zone of interest will probably never fade away no matter how advanced technology becomes. There will always be some information obtainable from a core or sample, which can't be measured by geophysical means. Of course, samples are limited as to their depth accuracy in the well and conventional cores of an interesting zone can't be taken once a well is drilled through it. So, like any progressive business, wire line companies and especially Schlumberger, look for ways to satisfy that gnawing urge of the geologist. If he likes it, chances are he will convince the company of its value. If not, you know the answer.

BHTV PRINCIPLES

Thus the Bore Hole Televiewer was designed to help satisfy that insatiable desire of the geologist. Why not adapt sonar to the borehole. If the U.S. Navy can define objects in the depths

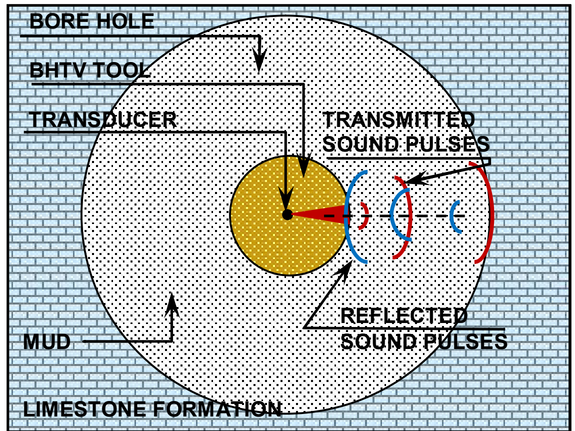
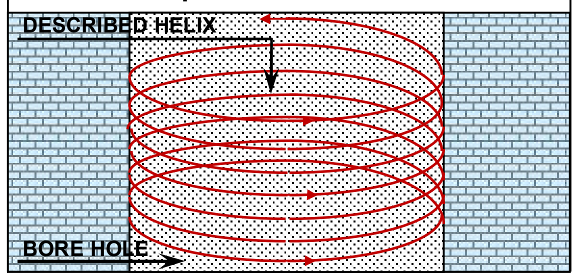


Figure 7-39 An illustration of the rotating transducer of the BHTV tool and the resulting helix described by the sound pulses striking the borehole wall as the tool moves upward.



of the sea, surely Schlumberger can define imperfections such as cracks, vugs and holes or

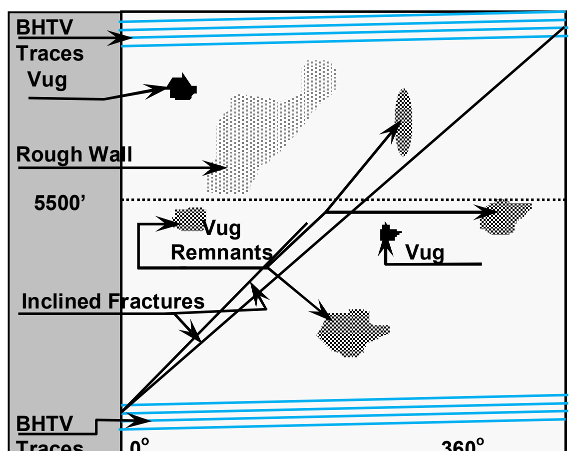


Figure 7-40 A simulated recording of a Borehole Televiewer log.

anything else, which might alter the otherwise smooth wall surface surrounding the borehole. This was the mission of the BHTV tool. So they built a tool that bounced sound pulses off the wall of the borehole from a rotating transducer that acted as both transmitter and receiver. This principle is illustrated in figure 7-39.

The mud column was the conductive medium for the transmitted pulse (red wave front) and the returned pulse (blue wave front) whose amplitude was a function of the wall material from which it was reflected as well as the smoothness of that surface. The rotation of the transducer was slow relative to the PRF (pulse repetition frequency) of the tool. A pulse would be transmitted much like one from a sonic tool and then the device would listen for a reflection. We could liken this to a person uttering a yell in a rocky canyon and waiting for the echo. The time required for the echo to return depends upon the distance of the object reflecting it and its clarity or amplitude, of course, depends upon the density of that object as well as the smoothness of the surface.

So it is with the BHTV. The recording was in black and white with a weak echo producing a black line and a strong one producing a white one. Amplitudes in between were varying shades of gray. Just as the rotation of the transducer was slow relative to the PRF, so was the upward movement of the tool slow, relative to the rotation of the transducer. Thus, the sound pulses impinging on the wall of the hole described a helix as the logging progressed. The film trace, being synchronized to transducer rotation, produced an inclined line across the film as it and the tool moved upward simultaneously.

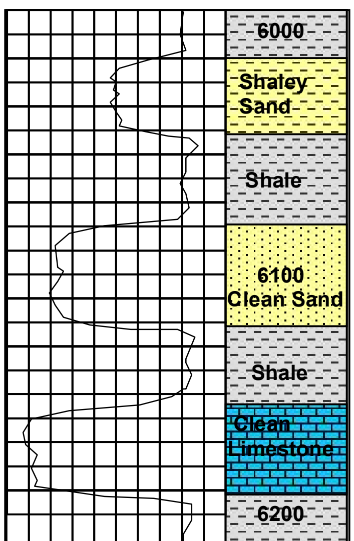


Figure 7-41 A simulated Gamma Ray recording.

BHTV RECORDING

One scan of the borehole perimeter produced one pass across the film, which was being recorded in shades of gray. Light colored areas meant a strong return from a smooth borehole wall, while darker film areas meant weaker returns due to rough walls. Thus, the black intensity of the film was inversely proportional to the strength of the echo received making vugs and cracks appear black.

The horizontal film scale was 0 to 360 degrees, the angular dimension of a circle, and the vertical scale was well depth. As mentioned earlier, the echo intensity was displayed as shades of gray along the trace described by the camera. To clarify that idea, I have added an illustration in figure 7-40, which depicts the recording and a few traces as well as the depth and angular scales.

No calibration of this device was required except to be sure the picture covered two linear tracks of the recorder. It was not a quantitative device and no calculations were made from it.

The tool worked very well, particularly when applied in cased holes and dense rocks with fractures, but, unfortunately, it didn't sell. Pictures of fractures, vugs and perforations were frequently seen but they seemed to satisfy the curiosity more than the solution to a problem. Consequently the tool died a slow death fading into the oblivion of that black hole which attracts good ideas without customer appeal to be crushed and absorbed by that infinite mass termed false profitability.

RADIATION MEASUREMENTS

Had I not worked for Schlumberger, I would probably never of dreamed of the various ways radiation can be used to measure useful formation parameters. Although I had become familiar with the various more common nuclear particles in school, I had no real idea of how they interacted with matter and consequently the numerous ways they can be used. During my early years with the company, tools were relatively simple and straightforward and I had little trouble understanding the concepts. In later years, they became more and more sophisticated and as integrated circuits came into being, the variety of their applications seemed to explode. I suspect several new devices have come on the scene since my retirement. If not, I am confident that the accuracy and complexity of those I was familiar with has blossomed and I would no longer recognize them. In my overview of these devices, I intend to begin with the simple and gradually move to the more complex. However, you have no need to fear because I'll stick with principles as I have with the other logging devices and not worry about details.

THE GAMMA RAY TOOL

Natural gamma ray radiation, a form of electromagnetic radiation, has always been with us and around us even though we have generally been unaware of it. In my lifetime our ability to detect it, measure it and generally apply it through useful devices has multiplied to a great extent. It has proven to be a very useful property in well logging as you shall see.

THE GAMMA RAY AS A LITHOLOGY INDICATOR

Although most people are aware of the more publicized radioactive elements such as plutonium, radium, etc., few have probably realized that regular old clay or shale, which contains potassium (K_{39}), is also radioactive. Not that it's dangerous, because it isn't. Our bodies have long adapted to the normal levels found in nature as in clay and shale. However, shale and clays make up a large part of the earth's sediments and contaminate the other sediments as well. Their presence is inferred, in many cases, by the radioactivity displayed by a given rock. Of course, the radioactive process is also a natural characteristic of certain other elements but they are exceptions to the rule being much less common. In general, shale is a thorn in the flesh of the oil operator. When present in sands and carbonates, they tend to destroy the permeability and thus the ability of such a formation to produce hydrocarbon. As a result, the measurement of natural radioactivity around the borehole has become extremely important and has consequently become a standard log run on virtually every well. In fact, it is so useful that the gamma ray is now combined with all basic logging tools to provide its shale defining information.

You probably noticed an active black trace in track one of the DLL-SFL shown in figure 7-21 which I conveniently ignored. That was a gamma ray record, which kind of replaces the SP in a salt mud environment. That is, it distinguishes shales from sands or carbonates and thus helps the log analyst establish the lithology of a given horizon. Water salinity or resistivity cannot be determined with it, however. I have made a simple illustration of a gamma ray log in figure 7-41, which should give you the general idea of the lithology definition the gamma ray provides.

THE GEIGER MUELLER DETECTOR

When I went to work for Schlumberger in 1955 the basic gamma ray detector was a so-called Geiger-Mueller detector. It was about three feet long. The length was required to establish a sufficiently high count-rate to minimize statistical variations. You see, gamma radiation fluctuates from the shales and causes the count rate to vary from second to second. If you make three one second measurements of gamma radiation the answers may all be different and significantly so with a GM (Geiger-Mueller) detector. If you were to sample the same zone for 2 seconds the

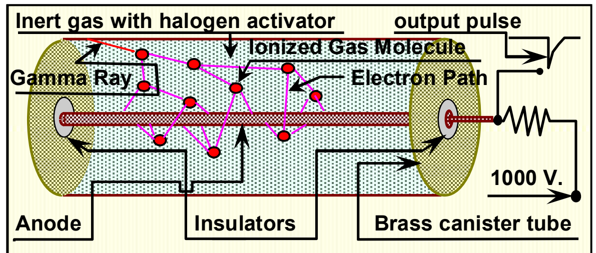


Figure 7-42 Illustration of a Geiger-Mueller GR detector tube and output pulse.

repeatability would be better and a 3 second measurement would become better yet. In fact, if you sample long enough, statistical variations won't affect the answer but, unfortunately, time is of the essence in the oil field and costs money in terms of rig time. Thus, the need for high quality is tempered, to a degree, to save rig time. Modern gamma ray detection devices, however, have minimized any quality loss.

If the log was only needed for correlation or general lithology, it might be run on a time constant of one (sampling time) at 3600 feet per hour but if the operator planned to use it for quantitative purposes, he would use a time constant of three and a logging speed of 1200 feet per hour to provide greater accuracy.

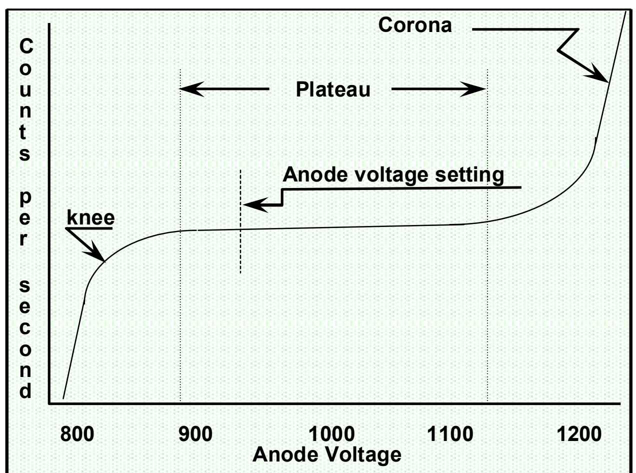


Figure 7-43 Illustration of the plateau of a Geiger-Mueller Gamma Ray detector.

The same detector, though of different design, was used for the neutron log, which I'll discuss next. It would seem beneficial to explain its principles of operation at this point even though I question whether you, my beloved posterity, will appreciate it. Of course, there is a chance that one or more of you may also have interests similar to those of your weird grandpa and find such antiquated technology interesting. Anyway, here goes.

DETECTOR CONSTRUCTION AND OPERATION

The Geiger-Mueller detector consisted of a metal can, brass I believe, which had been evacuated and filled with an inert gas such as neon activated with a halogen gas (Chlorine) and then sealed. It is depicted in figure 7-42. Note the rod going through the center of the tube is the anode, which was set at a potential of about 1000 volts positive relative to the case or zero. The counting action went something like this. A gamma ray (red path) from the formation passes through the case of the tube and strikes a molecule of the inert gas. In so doing, the gas molecule is ionized (red circle) producing an electron and a positive nucleus. It glances off and moves towards a second gas molecule. The nuclei produced are very large relative to the electrons and drift slowly towards the cathode or case. The electrons (magenta paths) are of much lower mass, on the other hand, and are attracted by the 1000-volt anode causing them to rapidly accelerate as they move toward it. In so doing, they strike other gas molecules, which ionize, producing additional electrons and positive nuclei. These multiple electrons are then launched on their paths and accelerated towards the anode, continuing to ionize other gas molecules. The process is repeated again and again until an avalanche of electrons completely ionizes the gas causing a current pulse to flow out the rod and through a resistor. The current flow through the resistor produces a voltage pulse or the equivalent of one gamma ray count. At the same time, this action causes the tube to quit conducting and it waits for another gamma ray to appear.

PROS AND CONS

The tube will detect about 1 in 10 gamma rays that strike it for an efficiency of about 10%. Though the efficiency was not real good, the tube was reliable and relatively stable at higher temperatures existing in a typical well bore. As mentioned, for the gamma ray log the canister or tube had to be about three feet long to produce sufficiently high count rates. This compromised the detector's ability to define thin beds but made statistical variations reasonable at acceptable logging speeds. Count rates produced with the neutron tool, however, were much higher, as you shall see, and the required detector length was about eight inches.

TEMPERATURE IMPACT

High temperatures existing in well bores have always complicated the design and operation of geophysical devices used to define Mother Nature's characteristics. The pure electrical devices, such as the electric log, had few problems because wires and insulation were the only elements needed down hole. However, as electronics entered into the down hole array of devices, temperature changes between surface calibration and the actual logging environment resulted in drift and even tool failure. The GM tube was reasonably stable up to temperatures of 300^{o} F as were the associated tubes and circuitry used for amplification of pulses. Even in that range of temperatures (300^{o} F), however, the engineer had to move quickly once in the hole with a tool. The idea was to run the log as quickly as possible. That is, before the temperature inside the tool rose to that of the well bore and created drift in count rates or even tool failure. However, such tactics didn't always work due of borehole conditions, etc. and it became obvious that more reliable tools were needed. Schlumberger rose to the challenge.

THE PLATEAU AND VOLTAGE DRIFT

One of the major problems was voltage drift. The voltage applied to the GM tube might be set at 1000 volts in the shop but as temperature rose, the value might increase to 1200 or even 1300 volts resulting in system failure. In normal operation such an increase would be less than 100 volts. The applied voltage for the GM detector can change 100 volts or so with little impact because of a so-called plateau in its operating characteristic. See figure 7-43. Note that the graph illustrates counting rate versus anode voltage. At voltages lower than about 800 volts no detection occurs. As the anode voltage is raised, some gamma rays are detected and the number rises rapidly with voltage. At about 900 volts the count rate levels off, that is, very little increase is observed as anode voltage is raised. At about 1150 volts the tube goes into corona or begins counting without gamma rays striking it. The operating voltage is set about 25% into the plateau above the knee which is a stable calibration point even if anode voltage drifts a little lower than when set in the shop. Once the tool is in the well, anode voltage will go up but count rates will change little if the voltage stays below 1100 volts and surface calibrations are still accurate. This concept is important to the log accuracy and is involved in neutron detectors as well as later, more advanced, detectors.

THE SCINTILLATION DETECTOR

The term "scintillation", I feel sure you are aware, means to sparkle, shine or give off light and so it is with this later generation detector of those illusive gamma rays. As I describe this most bodacious means of detecting them thar ornery critters, may that process also scintillate with such clarity that your eyes shine with delight as scintillas of additional knowledge flash through your gray matter with a transcendent impact. Ah yes, may your appreciation of this system and its intricacies equal the joy grandpa experiences relating its very last scintillating principle. As was said in the beginning, "let there be light".

As I have previously said, the GM detector suffered from low count rates when it came to detecting gamma rays and particularly so in relatively shale free rock such as a clean sandstone or limestone. Thus, statistics made it difficult to identify shale stringers and repeatability was less than perfect. Both higher count rates and better bed definition were desirable. The scintillation detector satisfied those needs and had been around for a while but was extremely temperature sensitive because of a photo-multiplier tube involved. This problem was overcome with, off all things, a thermos flask just like the ones used to keep hot drinks hot and cold drinks cold. A bit more expensive, I suppose, by several hundred dollars but of the same principle. The thermal conductivity of such a device is very low and it slows the heating within its confines for several hours. This allowed the tool to be calibrated and even run in the hole for several hours before the detector was affected.

DETECTOR PRINCIPLES

The scintillation detector also had a plateau similar to that of a GM tube but maybe shorter and the operating voltage was set in a similar manner. Figure 7-44 illustrates the construction of the device. In my tour of its operation I'll begin with the Sodium Iodide crystal on the left and follow the detected gamma ray as its representation changes form and grows in size to produce a pulse of voltage.

DETECTOR CONSTRUCTION AND OPERATION

The Sodium Iodide crystal (NaI) is activated with Thallium to make it more efficient. The material itself is highly poisonous and must be handled with care. The energy from the impinging gamma ray (red) is transformed into a scintilla or

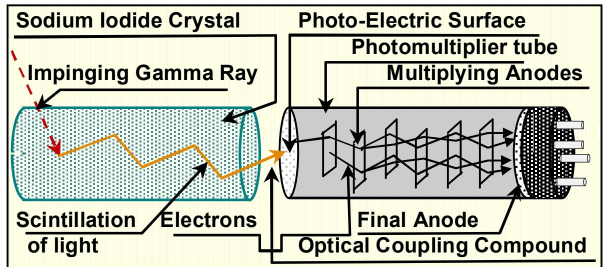


Figure 7-44 Illustration of a scintillation detector and its photo-multiplying action.

flash of light (yellow), which then passes through the crystal in a zigzag path as it strikes various inter-crystalline faces and finally reaches the photoelectric surface. This material coats the end of the photo multiplier tube and transforms the light energy into a free electron (black). Within the tube are several anodes or metal surfaces with differing potentials applied to them. The voltage rises in 100-volt steps as they progress away from the photoelectric surface. They have a high secondary electron

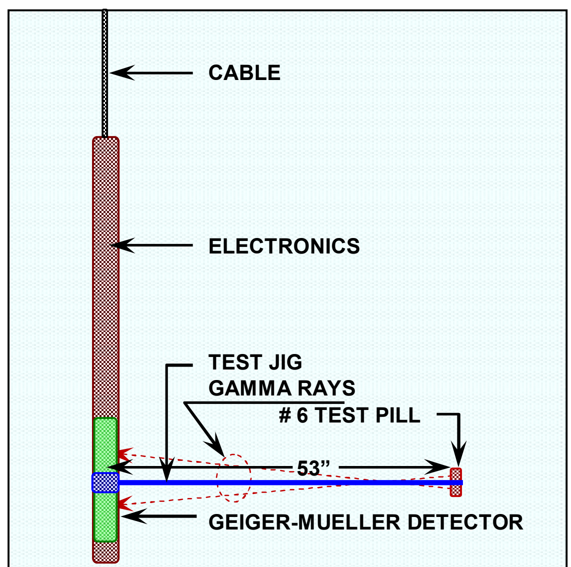


Figure 7-45 An illustration of aq Gamma Ray calibration setup.

emission characteristic. The electron emitted by the photoelectric surface is drawn to the nearest anode. As the electron strikes the plate's surface at least two electrons are knocked off and proceed to the next anode. This process continues as the electrons move towards the final anode. As I remember, a typical tube had 10 multiplying anodes. If each impact produces a pair of electrons, the result is 2^{10} electrons arriving at the final anode or 1024, which constitutes a sizable current pulse. This pulse, like that of the GM tube was then amplified and sent up the cable for recording. The scintillation detector used an eight-inch crystal if my memory serves me correctly. That, in itself, provided better bed definition. Secondly, the efficiency was much higher, 30+%, which reduced statistics with a resulting improvement in repeatability. Thus, the desired bed definition and higher count rates were achieved. The thermos flask mentioned earlier, of course, made such a detector feasible. A different design of this same type of detector is used in the Formation Density tool, which we'll discuss shortly.

GAMMA RAY CALIBRATION

Gamma ray logs had to be calibrated once they began to be used quantitatively. At first each wire line company produced their own calibration, which was fine except they couldn't be directly compared to one another. This was rather disconcerting to the oil companies because they often had occasion to compare such logs to define stratigraphy changes. The American Petroleum Institute eventually developed a standard to which all companies had to conform. It was based on differing standard formation rocks, which my old mind fails to recall the names of. In any case, they were assigned standard log values measured in API units and we had to match them in our calibrations. This was done and our standard #6 test pill (a defined source of gamma ray radiation of 165 API units) represented their standard when placed 53 inches from the tool via a jig. Consequently, when calibrating, we would record the natural back ground radiation of around 40 to 60 cps and then place the #6 source at 53 inches with the jig directly opposite the detector (See figure 7-45) and record its count rate, adjusting our meter (a galvanometer) to register the appropriate number of API units for the scale it represented. With the advent of the scintillation detector and more accurate calibrations, gamma ray logs repeated well and their values could be used more reliably for shale content measurements.

THE NEUTRON LOG

The original neutron log, which has been briefly mentioned previously, constituted the measurement of secondary gamma ray radiation induced by a high-energy neutron source. This gamma ray radiation is primarily a function of the hydrogen present in the surrounding rock and the resultant log is referred to as the hydrogen index of the rock. Because hydrogen is found in quantity in water, oil and shale, the index can be used in conjunction with the gamma ray as a porosity indicator.

The log found wide application for this characteristic in carbonate sedimentary sections. The log is also an excellent correlation curve, which can be obtained inside the casing. In shaley sand areas, the neutron log will often provide good bed definition and thus correlation whereas the gamma ray will show little difference between sands and shales, making the neutron log the depth control log of choice. This characteristic made it extremely useful in well completions, which is essential and will be my subject of discussion in chapter eight.

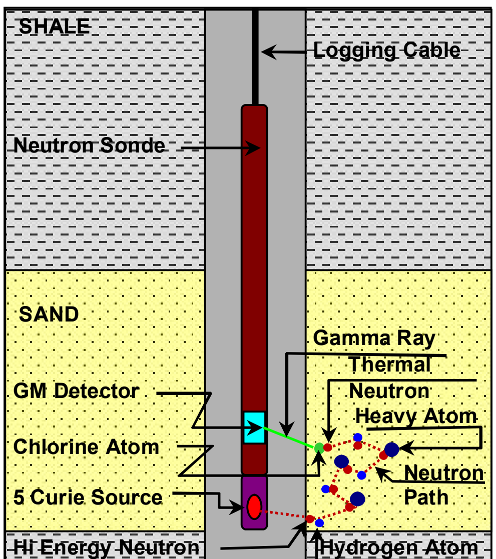


Figure 7-46 An illustration of the principle of the original Neutron log.

PRINCIPLES OF OPERATION

While referring to figure 7-46, let's review the operation of a typical neutron tool. As the illustration indicates, the high-energy neutron source was placed at the bottom of the tool, a small distance from the detector, maybe 15". The neutron source ejects a plethora of high-energy neutrons, of about five MEV (million electron volts), into the surrounding mud filled hole and rock. These neutrons collide with the nuclei of atoms in the rock and fluid and gradually slow down as they lose energy. This is depicted by the red dotted lines. As in marbles, if the neutron strikes a nucleus much larger than its own (symbolized by large dark blue dots), it ricochets off with little loss of energy to strike another further along. The hydrogen nucleus (symbolized by smaller light blue dots) has a mass almost the same as that of a neutron, of course, and when it receives a direct hit from the neutron, absorbs almost half its incident energy. The continuing collisions eventually reduce the neutron's energy to the thermal level (energy due to temperature alone, about 50 KEV) and the little critter is eventually captured by some atom or molecule looking for another neutron (I've chosen a Chlorine atom).

When captured, the atom involved emits a so-called gamma ray of capture (light green line). Considering the number of neutrons involved, many such gamma rays are produced, some of which reach the detector (cyan block) and are counted in a manner similar to those of the gamma ray log. The detector initially utilized a single GM tube about eight inches long, which produced an optimum count rate for recording purposes. Eventually it was replaced with a bundle of eight GM pencil detectors in parallel with each having about the same length but with one eighth the volume. This produced a detector of the same sensitivity but capable of handling higher count rates since each tube operated as an individual detector. It was an important improvement for neutron tools since count rates could be very high in many areas. It was still in use when I left the company in 1986.

INFLUENCING FACTORS

Just as the hydrogen atom is most effective in slowing down a high energy neutron, so certain atoms had an affinity for capturing those at thermal level or they had a so called large capture cross section. Chlorine was one of those elements and when present in abnormally high concentrations, yielded an apparent hydrogen index, which was too high. Borehole size was another parameter, which influenced the recorded hydrogen index. The larger the hole, the higher is the apparent hydrogen index (H.I.). In a similar manner mud weight and salinity could impact any quantitative answers. Of course, the original device wasn't used primarily for such quantitative work but for correlation because of its activity. Even so, considering such intent, the log was surprisingly useful as a porosity device in certain areas.

The interpretations I have provided in the sample log represent possible fluid content as shown, i.e. the response of the gamma ray and neutron curves are such that this interpretation is possible.

SAFETY CONSIDERATIONS

One might wonder about the danger of radiation exposure with this and similar devices. Certainly it could be dangerous if improperly handled but like explosives and other dangerous materials, Schlumberger had very strict safety regulations. The source was housed in a lead shield and never came out except when dropped into the well. Operationally speaking, the source inside the shield would be placed on the rotary table. The tool would be picked up from the catwalk and lowered to a point just above the shield. The top of the source would then be secured to the tool and the whole device, source and tool, lowered through the shield into the well. When exiting the well, the role was reversed and the source left in the shield before the tool was uncoupled and laid down on the catwalk. One had to be careless or woefully ignorant to be injured. Actually, I did sit on one for some time one day and though it fried my brains, I came away with a nuclear intellect and radiating smile. Or maybe that was just the nucleus of an intellect. I can't seem to remember.

NEUTRON CALIBRATION

Calibration of this device was initially designed and controlled by each wire line company offering the service but, like the gamma ray, eventually was standardized by the American Petroleum Institute (API). Once again, they had a laboratory pit or well with layers of rock of known porosity or hydrogen index. If my memory serves me correctly, there was a 1% carbonate and a Berea sandstone of 20% involved as well as some other points for linearity. Anyhow, our Houston engineering department had to match that standard and devise a system to match it for field calibration. Obviously, such a system had to be perfectly stable and yet be easily portable. The result was a rather elaborate pit and tank system for each district, which gave a two-point calibration equivalent to the two API standards and a jig to take to the well. Monthly, each tool was calibrated in the pit and tank, which was a very stable match of the API standard. The jig was a device which clamped to the body of the sonde directly opposite the detector much like the gamma ray jig of figure 7-45 but considerably shorter. It had two positions, near and far, which could be adjusted with setscrews to match the two tank positions. Once tank readings were obtained, the source was removed and the tool taken out and laid on stands. The jig was attached and the setscrews adjusted to provide an identical reading to that of the tank.

The jig could then be easily taken to the field for calibration at the well and its accuracy verified

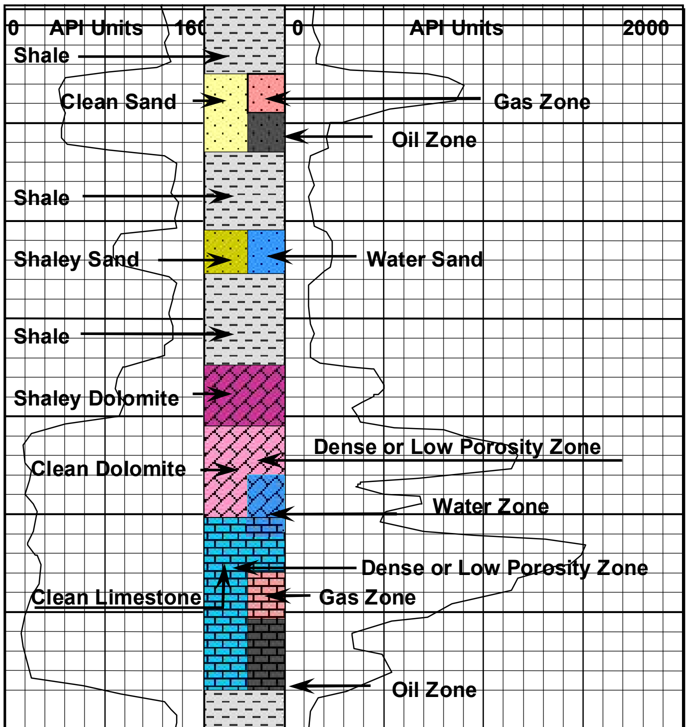


Figure 7-47 An illustration of a Gamma Ray Neutron log through a sand/shale/carbonate sequence.

on a monthly basis. The two jig positions represented API calibration values, which established the basic scale. Sensitivity and offset could be verified to meet the demands of local conditions. Thus a scale might be 0 to 2000 API units or something like 200 to 1200 API units depending upon the formation involved. Sometimes the scale was chosen while the tool was descending into the well because an established scale wasn't yet set.

A NEUTRON LOG ILLUSTRATION

At this point, it would seem appropriate to introduce you to a sample log as illustrated in figure 7-46. This hypothetical gamma ray neutron log covers a sand/shale sequence at the top and a carbonate shale section at the bottom of the displayed log. Note that the sand is coded as yellow (clean sand) or dark yellow (shaley sand) while the shale is a gray color. Similarly, the dolomite section is designated by a magenta color and tilted blocks while the limestone is blue horizontal blocks. Shaley dolomite shows up as a darker magenta. Fluid content within the rock pore space is indicated as cyan (light blue) for water, black for oil and red for gas. The interpretations I have provided in the sample log represent possible fluid content as shown, i.e. the response of the gamma ray and neutron curves are such that this interpretation is possible. Let's begin at the top or 7100 feet and then work our way down the log to 7400 plus feet while trying to provide a reasonable explanation for each zone. While we do this, remember that other interpretations for a given zone may also be possible.

THE SANDSTONE FORMATIONS

The clean sand indicated from 7123' to 7167' seems to be relatively clean throughout according to the gamma ray and registers just over 40 API units. The neutron curve, however, shows quite a variation in API units. It ranges from 200 units near the bottom to 900 near the top. A relatively low API value is indicative of a large hydrogen index in the surrounding formations, the source of which could be shale, water or oil. The gamma ray would tend to eliminate shale as the source but we can only guess between water and oil with this one log. Drill cuttings might be used to lean the probability towards one or the other.

In a similar manner, the high API reading of 900 units is indicative of a low hydrogen index, which might be cause by either gas or low porosity. Again, drill cuttings could help alleviate the controversy. My choice is obviously a gas column overlying an oil column.

At 7205 to 27, we find shaley water sand. The gamma ray indicates a higher shale content (88 API units) but essentially homogeneous throughout the 22 foot section. The neutron curve also indicates homogeneity and registers about the same API rate as the suspected oil zone at 7150 to 65'. The sand contains shale as indicated by the gamma ray and can also contain either oil or free water as well. Again, samples lend some information but additional measurements such as resistivity would be much better. Another measurement of porosity, such as that from a sonic or a density tool, would also be useful. A discussion of the latter, i.e the density tool, which is another type of radiation tool, will follow the neutron discussion and employ some of the same principles.

THE CARBONATE FORMATIONS

Next, let's move down to the carbonate section from 7270' to the bottom of the log. In so doing, also note that shale, such as that at 7250', have high gamma ray API values and low neutron API values. Now, consider the zone labeled shaley dolomite. The gamma ray indicates a relatively high amount of shale is present. This could account for the moderate neutron API reading of 450. Drill cuttings might also help confirm such an interpretation. Obviously additional logs would also help remove any controversy. One can see that, as Mother Nature becomes more complex, more data from other sources is needed to settle things.

Right below the shaley dolomite is a zone labeled dense or low porosity. Remember, the high API reading of the neutron log means a very low hydrogen index and though it looks much like the gas zone at 7140', drill cuttings or other logs would confirm a tight, dense or low porosity zone, if in fact that interpretation is correct.

Next is the zone from 7330' to 7360', which I have shown as containing water. Obviously, it could just as well contain oil and have a similar hydrogen index. We can't be sure from this log alone but we can be sure it has good porosity. Again, drill cuttings would help in such a confirmation. Notice it is clean, i.e. no shale, as indicated by the gamma ray log.

Right below the water zone is a dense zone, as indicated by the low hydrogen index. It has a somewhat lower porosity than the zone at 7320' and might be considered too low for any hydrocarbon production although a low porosity gas zone is obviously a possibility.

Next in line is the gas zone at approximately 7390', which looks very similar to that at 7320' or at least has a similar maximum hydrogen index. The H.I. varies from the top ten feet to the bottom ten feet, i.e. 7380 to 90' and 7390 to 7403'. That might be due to a porosity increase in the lower portion or a greater percentage of oil mixed with the gas. Either would increase the H.I. or apparent porosity.

Finally, the bottom zone from 7404' to 7340' contains oil but varies in porosity with the bottom twenty feet being somewhat lower than the upper 16'. Once again, the interpretation of the gas and oil zone from the gamma ray neutron log could just as well be all water with the hydrogen index change due to nothing but porosity. Other measurements are needed to confirm the presence of oil and/or gas, be they drill cuttings or additional logging services.

Well, the neutron log just discussed employs the original principles I had to learn when joining Schlumberger. Though many improvements have been made in both detector types and their associated circuitry since that time, the overall tool calibration and operation remains much as it was then, except for the introduction of API

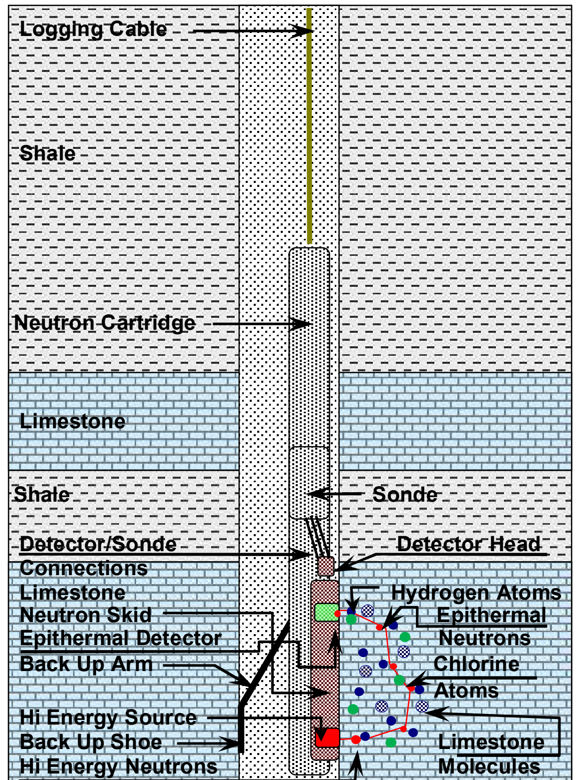


Figure 7-48 A drawing illustrating the SNP or sidewall neutron porosity device.

standards in the late fifties. This was discussed in some detail under calibration, you'll remember. The standard neutron tool was still a popular cased-hole device in 1986 and even enjoyed some open-hole application at that time. However, as you might suspect, a better neutron mousetrap did come along in the late 1960's. Will there ever be a time, which ends such mousetraps? I would hope not.

THE SIDEWALL NEUTRON DEVICE

In the previous neutron discussion, I mentioned that borehole size variations influenced the accuracy of the older neutron log as did high salinity formation waters. B**ore**hole enlargement would raise the apparent porosity or hydrogen index of a zone because of the extra fluid (mud) around the tool. High salinity formation waters would also result in an optimistic porosity because of the unusual ability of the chlorine atom to capture low energy or thermal neutrons (i.e. neutrons unattached to any atom whose energy is derived from its surrounding temperature). This ability of the Chlorine atom was referred to as a large capture cross section. Remember, the original neutron log counted gamma rays emitted by an atom capturing a thermal neutron. The resulting count rate was proportional to the thermal neutrons present and thus to the amount of hydrogen in the fluid filled porosity. However, only a normal capture cross-section, i.e. the ability to capture thermal neutrons, was considered in the design. Corrections for this aberration of the Chlorine atom had to be made, if and when it occurred, to provide a correct answer.

PONDERING THE NEUTRON LOG'S SHORTCOMINGS

Schlumberger research was looking for a better way to make neutron measurements just as they were for every other geophysical measurement we made in the oil patch. So, they asked the obvious question, "How can we eliminate bore-hole effect and the effect of changing salinity of formation fluids?" If so, we can limit the effects on count rate or hydrogen index to porosity, lithology and fluid type. The first part of the question resulted in placing the neutron source and detector in a skid shoe, which was pressed against the wall of the hole. The second produced a new type of detection system, which counted the epithermal neutrons present in the formation. An illustration of the tool is provided in figure 7-48 which we will use to explain its operation in a little more detail.

A CHANGE IN DETECTOR PRINCIPLES

An epithermal neutron is a neutron, which has just more energy than that provided by the thermal state (in the order of 100 KEV) and consequently, it can't be captured until it suffers additional energy loss. Thus, it's immune to the large capture cross section exhibited by the chlorine atom. Any thermal neutrons around won't be counted by the epithermal neutron detector but rather, those epithermal neutrons which happen to strike the detector. This solves one of the concerns posed by log analysts, i.e. neutron measurements in formations with highly saline waters. In such cases, which occurred rather frequently in the gulf coast, it would be advantages to eliminate this need for correction.

ELIMINATING THE BORE HOLE

Notice a skid is included with the sonde body, which is pressed up against the formation by a back up arm and associated back up shoe. The skid is made of very dense metal separating the neutron source and epithermal detector. This prevents neutrons from reaching the detector through the skid shoe and/or via the borehole. The skid is always pressed against the side of the hole and the dense metal acts as a shield. Only a portion of those neutrons emitted into the formation will arrive back at the detector and be counted. This design eliminates the borehole effect, which was often a concern in log interpretation as previously mentioned.

DETECTION PRINCIPLES

I have illustrated three different atoms/molecules in the formation, which we have talked about. The hydrogen atom, being nearly the same mass as the neutron, is most effective in slowing it down for capture. As shown, many collisions with various types of molecules will occur before it reaches the epithermal state necessary for detection. The limestone molecule is characteristic of the rock while the chlorine and hydrogen atoms would be more characteristic of the fluid types involved. Obviously, many other types of atoms may be present in the formation but the measurement responds primarily to the amount of hydrogen present. Such hydrogen is typically present in water, oil, shale, and to a lesser extent gas. The measurement can also be affected to a small extent by the type of sedimentary rock other than shale, i.e. in limestone, dolomite and sandstone reservoirs and particularly so at low porosities where little water or oil is present. This can be corrected for when the log analyst has knowledge of the lithology type with which he is working, as you will see later on.

THE RECORDED LOG

The resulting log from a sidewall neutron porosity tool (SNP) would look much like that of a conventional tool as illustrated in figure 7-47 except it would include a caliper. Thus, it would provide no value to illustrate such a log. Primarily, it was scaled in limestone or sandstone porosity units rather than API units and the results were much more accurate, of course. Changing lithology or rock type would require a small correction from the recorded scale. This could be done very easily by appropriate charts, which were provided. The biggest problem was ascertaining the correct lithology. We can write an equation for porosity as related to SNP response as follows.

24) $\Phi_A = \Phi_T + (1 - \Phi_T)\,\Phi_M$ where;

PHI$_A$ (Φ_A) is the apparent porosity of the log
PHI$_T$ (Φ_T) is the true porosity
PHI$_M$ (Φ_M) is the apparent porosity of the matrix or solid rock.

The latter term may need a little explanation. If there were no porosity at all, the tool would still register an apparent value depending upon the rock type. This is subtracted in the recorded log for the matrix chosen but must be corrected for when other lithologies are encountered, a process we'll talk about later.

Mud cake has little effect on the SNP even though it is a pad type device pressed up against the borehole wall. The hydrogen index of mud cake must be close enough to that of the formation to minimize need for correction.

I'll quit the neutron log for now, although it will reappear in cased-hole work. Of course we won't need to repeat the theory since you are all experts now. By the way, an expert is a drip, which has lost its driving pressure (ex-spurt).

MEASURING FORMATION DENSITY

Engineers and scientists have long known that the density of any rock is related to the amount of void space within it or the porosity. In addition to the matrix, such density also depends upon the material, if any, filling the void space, i.e. gas, liquid or solid. The problem was how to measure it in situ, i.e. in the borehole. Measuring it in the laboratory was relatively simple but when one throws in 20,000 feet or more of cable, 300 to 350 degrees Fahrenheit environmental temperature, mud cake, rugose or rough borehole walls and a myriad of other problems, it's easy to see that the job won't be easy. Other companies had preceded Schlumberger in that effort and had little success but a short while later we came out with our first such device, an uncompensated log or one that made no effort to correct for seating of the pad against the borehole wall. It was relatively short lived with a better device already under design or on the way. However, let's take the situation a step at a time.

PARAMETER BASIC RELATIONSHIPS

The relationship between porosity (PHI or Φ) and formation parameters is given by,

25) $D_B = D_F(\Phi) + D_M(1-\Phi)$ where;

D_B is the measured bulk density
D_F is the density of the fluid in the pores
D_M is the rock particle density

The density of a material can be determined by transmitting high energy gamma rays through it and counting the number that arrive at a detector placed on the other side or some

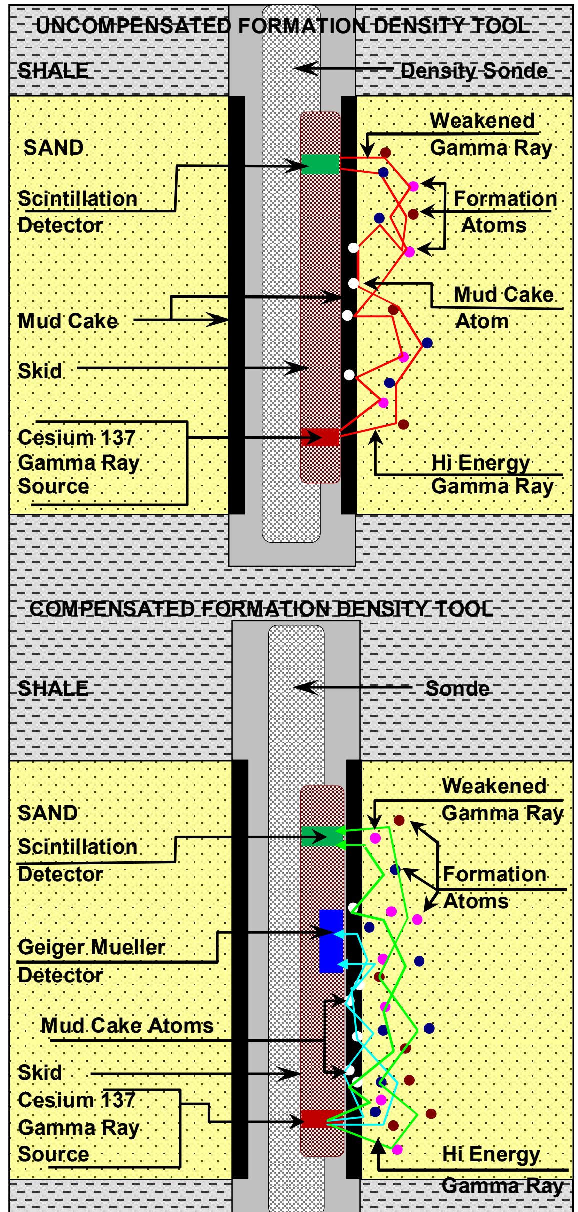


Figure 7-49 Illustrations of the FDL (uncompensated formation density tool) and the FDC (compensated density tool).

distance away on the same side. This is easily accomplished in the laboratory but deep in a drill hole with rough surfaces, variable fluids and intervening mud cake the story is quite different.

As with most tools, the first density tool was only moderately successful. Derived porosity from this tool was good as long as borehole conditions were optimum. However, recorded bulk densities and resulting porosity calculations were frequently optimistic requiring corrections, which were necessary due primarily to mud cake between the skid face and the formation. The pad simply couldn't completely cut through the mud cake leaving a portion to be averaged in with the formation density.

VISUALIZING THE PROBLEM

Figure 7-49 will help you gain a better understanding of the problem. It illustrates the original skid as well as the later skid providing a certain degree of automatic compensation for the mud cake and other materials that might interfere with proper skid application to the formation face. I'll use both in my effort to explain the tool's operation.

The sonde and skid appearance will be very familiar, being similar to the SNP just discussed but the theory of measurement will differ considerably. Hopefully, you'll find this device at least as exciting as the SNP, which I feel sure, enthralled even the most technologically indifferent among you. Heaven forbid that my posterity would be so genetically inclined. None-the-less, realizing that such possibility exists, I have dug deep within my soul to drag every bit of artistic talent, which might be hidden and have employed the same in figure 7-49. Surely, even the most insensitive among you will appreciate the color coordination and logical depiction of the operation of this device. Admittedly the desktop computer deserves much of the credit, although it also created numerous headaches for this old man.

THE FORMATION DENSITY TOOL

Let's begin with the uncompensated tool illustrated in the upper half of the drawing. I might just as well have used a porous carbonate as the sandstone for the porous zone. Besides, in my example I elected to add a rather thick mud cake commonly present in sand shale series, demonstrating an important principle. This principle clarifies the need for and superiority of the compensated tool to follow.

This particular device actually preceded the SNP with the latter being adapted to the sonde and cartridge of the FDC or compensated formation density tool. Remember, this device is used primarily to determine porosity and thus, measurements of interest are porous zones, which might contain hydrocarbons.

GAMMA RAY EMISSION TO DETECTION

The tool utilizes a skid made of very dense metal to effectively isolate the detector from the cesium 137-source as well as isolate both detector and source from the borehole. The source is capable of emitting very high energy gamma rays (in the vicinity of 5 million electron volts, i.e. 5 MEV) into the formation where a portion of them find their way to the detector after colliding with numerous atoms along the way. Of course, some also collide with atoms in the mud cake as they traverse their path towards the detector. The collisions with atoms weaken the gamma ray and many, if not most, never get to the detector. In fact, the denser the formation, the more collisions and the less probable a given gamma ray will so arrive. Thus, the count rate of the detector varies inversely with the density of the intervening rock, i.e. lower density, higher count rate and vice versa. Don't you just love those colored atoms? Don't they brighten up your day? They may appear just a bit large but, after all, you have to see them to imagine all those collisions going on. It reminds me of the Atlanta inter-states with their collisions and colorful language one hears during rush hour, as road rage seems to come to the fore and manners get lost in the shuffle.

NATURAL GAMMA RAYS

Now, the more perceptive among you, may wonder about interference from natural gamma ray radiation, which we discussed a little earlier. Good point, we can't have those ornery critters getting in among our herd en route from the source to detector. Well, we know such animals are a little on the weak side. They're just a bit puny and when tested have a strength of around 50 KEV (50 thousand electron volts). Our stalwart engineers capitalized on this weakened condition by placing a fence in front of the detector, which they couldn't crash. They call it a window which rejects gamma rays under 75 KEV. I don't remember its composition but it effectively rejects natural gamma rays. The source to detector spacing is such that many of the source gamma rays have an energy level of 100 KEV or more and come right on in for counting. The detector, as you have probably already noticed, is of the scintillation type and operates in a manner similar to that described in the gamma ray tool. It is physically smaller but still contains a sodium iodide crystal activated with thallium along with a photo multiplier tube and the necessary coupling gel.

THE COMPENSATED DENSITY TOOL

I mentioned earlier that mud cake could present a problem in the determination of an accurate formation bulk density. As you can see from the diagram of figure 7-49, the gamma rays emitted from the source do interact with atoms in the mud cake. If the density of the mud cake is the same as the formation, it makes no difference but if it is significantly higher or lower, the calculated apparent porosity will be in error. So what do we do to handle that? Well, as I have said before, Schlumberger had some pretty bright scientists and design engineers working for them, almost as bright as us field types, in fact. So, they got their heads together and concluded that a shorter spacing could be used to correct the primary spacing. Such spacing would be affected more by the mud cake than that of a longer one. Consequently, the equations expressing count rates as a function of the mud cake density and thickness as well as the formation density for the two spacings could be solved simultaneously to derive the true bulk density of the formation. This required two detectors mounted in the skid rather than one, which then provided both the short spacing counts and those of long spacing detector. These were sent up hole and processed in the panel to provide the corrected bulk density of the formation. Although I don't understand all the mathematical intricacies involved, the result was two recorded curves; one being the desired formation density and the second being the amount of correction necessary. This concept is portrayed in the lower portion of figure 7-49. Other than the two detectors and their resulting measured counts, the systems are identical. Notice the near detector is a Geiger Mueller type rather than a scintillation type. This was necessary because of the high gamma ray flux or resulting count rate at that distance, which would swamp the scintillation detector. You see, such flux or gamma ray concentration varies inversely with the cube of the distance from the source. Cutting the source to detector spacing to one half that of the far detector multiplies the gamma ray flux by eight, a significant increase. Thus, the less efficient Geiger-Mueller detector found a purpose for its poor conduct, which seems to be a sign of the times.

A TYPICAL FDC RECORDING

Before we leave this sophisticated little device, it would seem appropriate to analyze a typical log, hypothetical of course, and take time to familiarize you folks with the terms we have been throwing around. Now take a gander at figure 7-50 to get an idea of what a typical FDC log would look like. By the way, FDC stands for; you guessed it, formation density compensated.

LAYOUT OF THE LOG

Track 1 contains the gamma ray and caliper curves. Notice the caliper is scaled from 6" to 16" and the gamma ray from 0 to 200 API units. The bulk density curve occupies tracks 2 and 3 and is scaled from 2.0 grams per cubic centimeter (cc) to 3.0 grams per cc. The delta rho curve (dotted) is scaled from -0.5 to +0.5 grams per cc allowing for either negative or positive correction for mud cake.

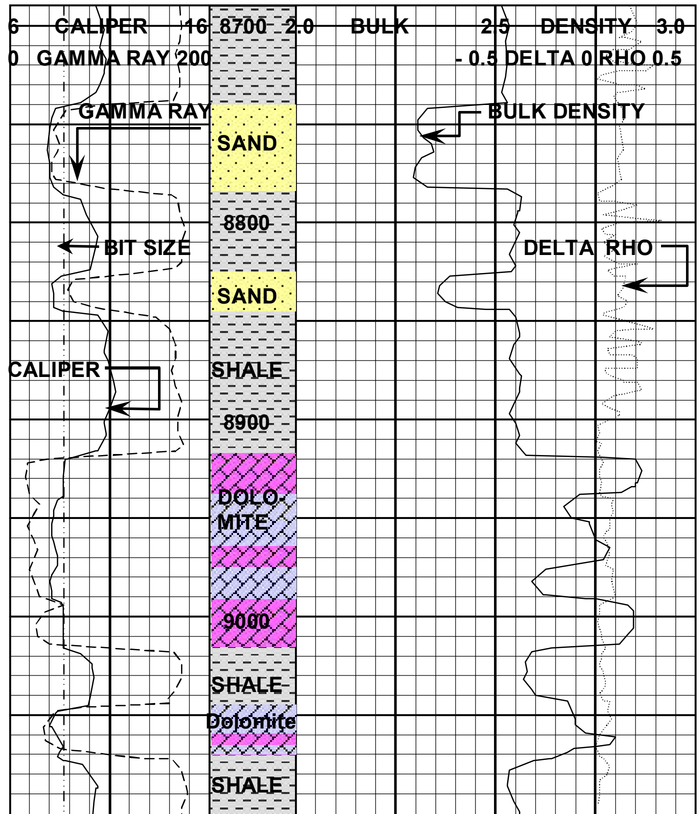


Figure 7-50 An illustration of an FDC (compensated formation density log) in sand, shale & carbonates.

By the way, rho is the Greek letter equivalent to our R and was used by Schlumberger to designate density in grams per cc. Consequently, the bulk density curve might be referred to as rho while the correction applied to it as delta rho ($\Delta\rho$) where delta, signifies the difference or change. It, delta, you'll probably remember, is also is a Greek letter, which has been used to indicate the travel time per foot for the sonic log. As you can see, we engineer types like to use Greek nomenclature to keep others off balance and make ourselves appear more intelligent. In fact, we even comment when somewhat confused, "Well, it's all Greek to me". How-some-ever, don't repeat that because I'll venomously deny having ever said it.

DELTA RHO

Now, let's make a few observations regarding each of the curves. First, look at delta rho. You have probably already observed that in this particular well the correction is always positive which simply means the mud cake is less dense than the formation rock. Such a situation is typical for regions like the Rocky Mountains where porosities are low (high density rock) and drilling muds are relatively light (low density) because formation pressures are seldom extreme. In areas where the borehole is enlarged such as shales (8790 to 8825 or 8845 to 8920), the correction is positive because the metal pad can't seat well against the caved out wall and a certain amount of mud separates it from the formation. In zones of hard competent rock such as the dense dolomite from 8920 to 8930, the correction is approximately zero (check the caliper) because the pad seats well and there is no mud cake. In porous zones there is mud cake build up as in front of the sands and the low-density dolomite, (again check the caliper). Notice the measured bulk density is raised about 0.05 grams per cc in most porous zones as indicated by delta rho.

THE CALIPER CURVE

Next, observe the caliper throughout the section. Notice the borehole diameter is at gauge or bit size in front of the real dense or hard zones, less than bit size in the porous zones and greater than bit size in the caved zones which are shale in this case. We indicated bit size with a dashed line for reference. Obviously, the caliper is useful in helping to determine the validity of the correction applied to the bulk density curve.

THE GAMMA RAY

The gamma ray comes next. This serves as a review of the gamma ray discussion. You may remember that shales exhibit relatively high radioactivity compared to sands or carbonates. It does not distinguish between low porosity and high porosity as you can see by comparing the zone at 8980 to that at 9000'. It is, however, a good indicator of lithology or maybe I should say shale content. Thus, it appears much like an SP curve and correlates very nicely with it.

THE BULK DENSITY CURVE

The bulk density curve, (rho or ρ), responds mostly to fluid filled porosity which lowers the rock density. You may remember that quartz has a density of 2.65 grams per cc but when combined with fluid filled porosity, as are the sands in this log we see densities in the range of 2.3 to 2.35. On the other hand, pure dolomite or the matrix rock has a density of 2.87 grams per cc. (cubic centimeter). The zone at 8920 to 8935 approaches that value indicating essentially no porosity. At 8980' the dolomite exhibits a density of 2.6, which would indicate appreciable porosity. To clarify the situation, we'll use equation 25 and calculate a couple of porosity values. Take an average reading of bulk density through the sand at 8740 to 8785'. It looks like about 2.31 grams per cc. Quartz or the sand matrix has a density value of 2.65 grams per cc, while water is 1.0. After substitution in equation 25 we get;

$$2.31 = 1.0(\Phi) + 2.65(1\text{-}\Phi) \text{ or,}$$

$$2.31 = \Phi - 2.65\Phi + 2.65 \text{, or}$$

$$1.650 = 2.65 - 2.31 = 0.34 \text{, or}$$

$$\Phi \text{ (porosity)} = 20.6\%$$

We could make a similar calculation in the dolomite at 8980' where the density curve reads 2.6 grams per cc. Dolomite matrix is 2.87 and water remains at 1.0 g/cc., so we have;

$$2.6 = 1.0(0) + (1\text{-}0)2.87 \text{, or}$$

$$2.6 = \Phi - 2.87\Phi + 2.87 \text{, or}$$

$$1.870 = 2.87 - 2.6 = 0.27 \text{, or}$$

$$\Phi \text{ (porosity)} = 14.4\%$$

Now, isn't that neat. The answer would be similar if the zone contained oil, which is a little lighter than water but is mostly flushed out by the invading filtrate. Remember the flushed zone described earlier. Consequently, the accuracy of our answer depends mostly upon our assumption of matrix density, a number which is often quite easy to estimate accurately. In complex rocks, that may not be the case, so we'll spend a little time in that area before moving onto another tool. Is this exciting stuff or is this exciting stuff, tell me!

COMPLEX ROCK MATRICES

I would assume even the least interested reader would, by now, realize that the formation rock composing a possible oil or gas reservoir can vary from a rather simple entity to one which is extremely complex with most such reservoirs lying somewhere in between. Additionally, the borehole environment makes the measurement of such reservoir parameters difficult, to say the least. However, the many devices you have just been subjected to, particularly in their improved forms, have also provided approaches, which help unravel many, if not most, of the characteristics Mother Nature has disguised. With my limited understanding of the same, I will try to describe the ones I became familiar with during my years in the business.

A SUMMARY OF PERTINENT EQUATIONS

We'll begin by summarizing the many equations derived at this point, describing the various unknowns involved and trying to add to the reader's understanding of the same. I suspect only a very few (and maybe none) of my posterity will really be interested in this kind of detail but it constitutes one more facet of grandpa's rather demented intellect.

1) $S_w = 1 - S_h$

2) $F = \rho_o / \rho_w$

3) $F = 1 / PHI^2 = 1 / \Phi^2$

4) $F = 0.62 / PHI^{2.15} = 1/\Phi^2$

5) $F = a / PHI^n = a/\Phi^n$

6) $S_w = (R_o / R_t)$ ½

9) $E_{(MV)} = - K \log \rho_{mf} / \rho_w$

11) $\rho_{xo} = F\rho_{mf}$

ρ = resistivity in the preceding equations.

18) $\Delta T_{log} = PHI \times \Delta T_{fluid} + (1 - PHI) \Delta T_{matrix}$

24) $PHI_{log} = PHI \times HI_{fluid} + (1 - PHI) HI_{matrix}$

25) $\rho_{bulk} = PHI \times \rho_{fluid} + (1 - PHI) \rho_{matrix}$

ρ = density in the last equation.

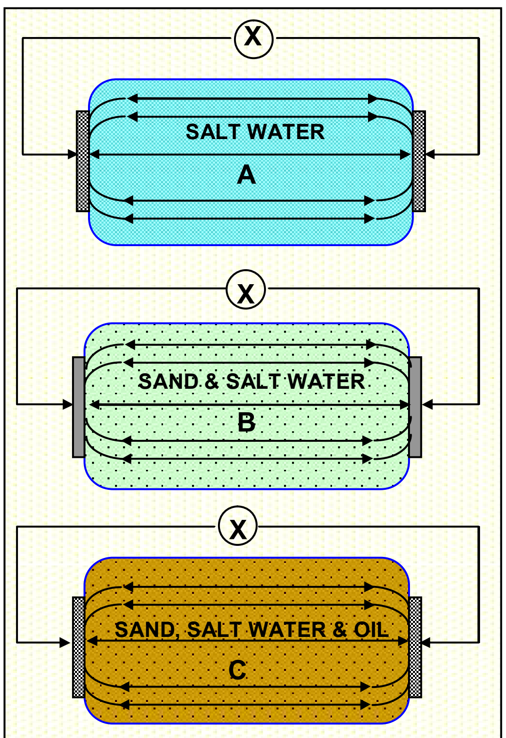


Figure 7-51 Drawings illustrating the measurement of the resistivity of salt water, salt water with sand and salt water with oil and sand.

These equations represent all of importance to this particular interpretation discussion and have the same numbers as they received earlier in this chapter. We'll consider them in numerical order and make any comments that seem pertinent now that you are all well founded in basic log interpretation. Watch out though, we may even make some impertinent ones.

EQUATION ANALYSIS

EQUATION # 1

Equation 1 is rather straightforward and simply states the pore space is filled with either hydrocarbon (gas or oil) or water. That is, the water saturation in percent is 100% of the void space minus the percent of space filled with hydrocarbon. Easy enough, right? But it is still an important principle.

EQUATION # 2

In considering the second equation, you should remember that the rock matrix will not conduct electricity but the water within its pore space will. How well the latter conducts depends upon its resistivity or its reciprocal, conductivity. That is;

$$C_w. = 1 / \rho_w$$

Assume that we were to measure the resistivity of a jar of salt water and found it to have a value of 0.1-ohm meters per meter^2. (See figure 7-51 A) If we then filled the jar with sand and let the excess water run out, we would have the equivalent of very high porosity sandstone of maybe 40%. That is, 60% of the water will have run out to accommodate the added sand. If we now measure the resistivity of this sand - water mixture, we will obtain a higher resistivity, which we call ρ_o. See Figure 7-51 B. It would have a value of about 0.5 ohm m /m^2. Using equation 2 we could calculate F, the formation factor, as;

$$F = 0.5 / 0.1 = 5$$

This is the factor or ratio by which the resistivity is raised because of the sand or formation and thus, is termed the formation factor. Doesn't that have an aesthetic ring to it? Ah, what imagination and beauty lurks in the hidden recesses of the engineering mind. It makes me so proud to realize I possess a few such genes.

EQUATIONS # 3, 4 & 5

Equation number five is, of course, the general form of the relationship between porosity (void space in the rock) and the formation factor just discussed, while equations 3 and 4 are simply special cases of the same.

We mentioned in the early part of the chapter Archie, a research scientist for Gulf Oil, derived equation number 3 while scientists of the Humble Oil Company, now the Exxon Company, derived equation #4. We also mentioned that #3 was used more for interpretation of carbonates while #4 was used more in the unconsolidated sandstones of the gulf coast. Other researchers have established still different values for both of the so-called constants we term as n and a in equation #5. These have been derived from core analysis in specific oil fields developed by their associated companies. Maybe they should be termed variable constants, an oxymoron if I ever heard one. This is accomplished through conventional core studies from which rock samples are obtained as described in chapter five. The exact value of these constants is more important in evaluating the reserves of a field or the oil in place than it is in exploration work. Slight variations in calculated porosity from any of them will never alter a decision of whether to run casing in a well or not. Schlumberger derived their own values of both n and a, as 0.81 and 2.0 respectively for general sandstone analysis but stuck with Archie for carbonates, as I remember. To gain an appreciation of the effect of these constants on calculated porosity, let's take the jar of sand used for equation 2, and compute the porosity with all three.

3) $PHI = (1 / 5)^{1/2} = (0.2)^{1/2} = 45\%$

4) $PHI = (0.62 / 5)^{1/2.15} = (0.124)^{1/2.15} = 38\%$

5) Schlumberger's equation

$PHI = (0.81 / 5)^{1/2} = (0.162)^{1/2} = 40\%$

EQUATION # 6

As mentioned, Archie developed this equation as well. Similarly, it ended up with some controversy regarding the constant n taken as 2 by Archie. The general form would be;

6) $S_w = (\rho_o / \rho_t)^{1/n}$

This constant was varied somewhat in specific fields and rock types through research by various companies but we (Schlumberger) generally stuck to 2 for our fieldwork.

To continue with our jar of sand, let's dump 60% of the water out and replace it with oil. That gives us a water saturation of 40%, a rather typical value for clean sands. (Figure 7-51C) We already know that the resistivity of the sand saturated with water of 0.1-ohm meter^2/meter is 0.5-ohm m^2/m or ρ_o of equation 6. So, if we know the water saturation and ρ_o, we can calculate what ρ_t should be.

$\rho_t = 0.5 / (0.40)^2$

$\rho_t = 3.125$ ohm m^2/m.

Now, that process is using equation 6 backwards, in that we would normally measure both ρ_o and ρ_t and then calculate S_w. In fact, it would be very difficult to replace 60% of the water with oil. So, let's change it a little and say we simply replaced a good deal of the water with oil and want to know how much water is left. We simply measure the resistivity after adding the oil, which, we'll say, comes out to be 3.5 ohms. I'm going to leave off the m^2/m for simplicity. Now we can calculate the water saturation.

$S_w = (0.5 / 3.5)^{1/2} = 38\%$

Let's vary n just a little bit to see the effect. For an n of 2.2 and 1.8 we get respectively;

$S_w = (0.5 / 3.5)^{1/2.2} = 41\%$

$S_w = (0.5 / 3.5)^{1/1.8} = 34\%$

You can see that small variations in n would not affect decisions to run casing or not but they can make significant differences in reserves or oil in place to companies involved. Thus, they run studies to establish the best possible value of n.

EQUATION # 9

The value of R_w is critical to log analysis and can be obtained in various ways. The SP is the most useful in exploratory work because nearby samples from other sources are often non-existent or at least scarce. The equation is very good in typical saltwater sands but corrections are needed in highly saline waters and brackish or relatively fresh waters. Also, the presence of shale in sand alters the calculated value. Empirical corrections can be made through charts, which are usually quite good. One has to be careful, however, in brackish waters because they are highly variable.

As has been pointed out earlier, the engineer measures ρ_{mf} at the well site and accurate values are obtained where samples are both collected and measured with care. The constant K is a function of temperature, which is obtained from a measured bottom-hole temperature. Its accuracy is good and presents little problem. That leaves E or the recorded value of the SP in millivolts (which sometimes must be corrected to SSP, static SP, in thin beds) as a means to determine ρ_w. In most cases such calculated values of ρ_w are reliable but reliability drops off, as the number of empirical corrections increase. Appropriate water samples can also be used.

EQUATION # 11

This equation is the same as equation # 2 but with different values of measured formation resistivity and water resistivity. ρ_{mf} is the mud filtrate resistivity as used in equation # 9 and the same remarks made there can apply here. ρ_{xo} is obtained from a micro device, i.e. a microlog or micro-laterolog as described earlier in this chapter. Both measurements are easily controlled and accuracy of the resultant F is good unless there is residual oil in the flushed zone. This constitutes both a problem and an opportunity. Such residual oil saturation, S_{xo}, is given by a variation in Archie's equation for water saturation as follows;

$$S_{xo} = (\rho_{xo} / F\rho_{mf})^{1/2}$$

In this case, we must obtain the formation factor, F, from another source, such as a density, neutron or sonic log while both ρ_{xo} and ρ_{mf} can be measured and S_{xo} can then be determined. This apparent problem with residual oil saturation can be turned into a plus, as you shall see, if other porosity devices are available.

EQUATIONS # 18, 24 AND 25

The devices involved in securing the data for these three equations all sample the formation relatively close to the borehole or an area similar to the ρ_{xo} zone. Consequently the fluid involved in the first term on the right hand side of the equation is usually mud filtrate. Residual oil would require little or no correction but gas in this zone will alter readings significantly in a quantitative sense. This usually occurs in high porosity sands such as are found in the gulf coast but presents a lesser problem elsewhere.

Values for fluid parameters are as follows;

Sonic: Δt_{fluid} = 189 msec./foot (assumes water)

Neutron: HI_{fluid} = 1.0 (assumes water)

Density: ρ_{fluid} = 1.0 gms/cc (assumes water)

Should the values differ slightly from the assumed values, there are now computer techniques to correct for them.

Lithology is frequently known well enough to be able to use matrix values for sandstone, limestone or dolomite and one device will suffice for a good porosity value. However, carbonates are frequently composed of a mixture of limestone and dolomite, while sandstone can sometimes be limey, dolomitic or shaley. An additional measurement can help solve the problem and the extra measurement may well be worth the cost through improved reservoir parameters. This is what a log analyst would classify as a complex rock matrix.

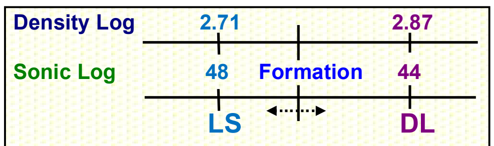


Figure 7-52 A drawing illustrating the matrix values of dolomitic lime.

Consider a dolomitic limestone. The matrix parameters will lie somewhere between those of limestone and dolomite as shown in Figure 7-52. Without knowing the proper values, errors in porosity calculations can be significant. Consider the Density tool equation.

25) $\rho_{\,bulk} = PHI \times \rho_{\,fluid} + (1 - PHI)\, \rho_{\,matrix}$

Rearranging the equation to solve for PHI or porosity, we obtain;

26) $PHI = (\rho_m - \rho_{log}) / (\rho_m - \rho_f)$

Using a limestone matrix value of 2.71 and assuming a log value of 2.5 we find;

PHI = (2.71 - 2.5) / (2.71 - 1.0) or

PHI = 0.21 / 1.71 = 12.3%

Using a dolomite matrix value of 2.87 with the same log reading we find;

PHI = (2.87 - 2.5) / (2.87 - 1.0)

PHI = 0.37 / 1.87 = 19.8%

This, of course, is a significant error and can result in a bad decision.

Using a Sonic measurement of say 65 microseconds per foot and a limestone matrix we would calculate;

PHI = (65 - 47.5) / (189 - 47.5)

PHI = 17.5 / 141.5 = 12.4 %

Using Dolomite as the matrix the answer is;

PHI = (65 - 44) / (189 - 44)

PHI = 21 / 145 = 14.5 %

Using both devices and solving the equations simultaneously we get the following;

$DT_{log} = PHI \times DT_{fluid} + (1 - PHI)\ DT_{matrix}$

$D_{bulk} = PHI \times D_{fluid} + (1 - PHI)\ D_{matrix}$

We know that $PHI_s = PHI_D$, thus

$(\rho_m - \rho_L) / (\rho_m - \rho_f) = (\Delta_L - \Delta_m) / (\Delta_f - \Delta_m)$

ρ_m = A% x 2.71 + (1 - A) x 2.87 = 2.87 - 0.16A

Δ_m = A% x 47.5 + (1 - A) x 43.5 = 43.5 + 4A

ρ_f = 1.0 and Δ =189

Substituting these values, we find;

0.37-.16A /(1.87-.16A) =21.5 - 4A/145.5-4A

(0.37-.16A)(145.5-4A) = (21.5-4A)(1.87-.16A)

$53.8 - 24.8A + .64A^2 = 40.2 - 10.9A + .64A^2$

13.6 = 13.9A or A = 13.6/13.9 = .98 = 98%

Rock is 98% Limestone and 2% Dolomite

ρ_m = 2.87-.16(.98) = 2.713

Δ_m = 43.5 + 4(.98) = 47.4

The density equation becomes;

PHI = (2.713-2.5) / (2.713-1.0) = 12.4%

The Sonic equation becomes;

PHI = (65-47.4) / (189-47.4) = 12.4%

If we raised the density log reading to 2.57 g/cc and keep the sonic reading at 65, we find the percentage of limestone dropping to 26% and the dolomite percentage rising to 74%. The matrix values then become;

ρ_m = 2.87 - .16(.26) = 2.83

Δ_m = 43.5 + 4(.26) = 44.54

PHI_D = (2.83 - 2.57) / (2.83 - 1.0) = 14.2%

PHI_S = (65 - 44.54) / (189 - 44.54) = 14.2%

We could do similar calculations with the Density and Neutron or Neutron and Sonic. We could also add in a third variable such as quartz which has ρ_m = 2.65, a Δ_m = 56.5 and a very low matrix HI which I can't seem to remember. Anyway, if I had that number and plenty of time I could solve 3 equations with three unknowns and determine the percentage of limestone, dolomite and quartz or sand. Obviously computers are needed to do this with any degree of efficiency and their advent into the logging business brought massive changes to both the technology of gathering data as well as in the processing of the same. This change or advent of a rising star, so to speak, came to the field in the late seventies but, unfortunately, my star was beginning to wane. Many capable young engineers arrived on the scene with this change. Consequently, I became only vaguely familiar with the exciting new technologies and software involved before my retirement in 1986. Though I shudder to think of advances since, it would be interesting to be involved.

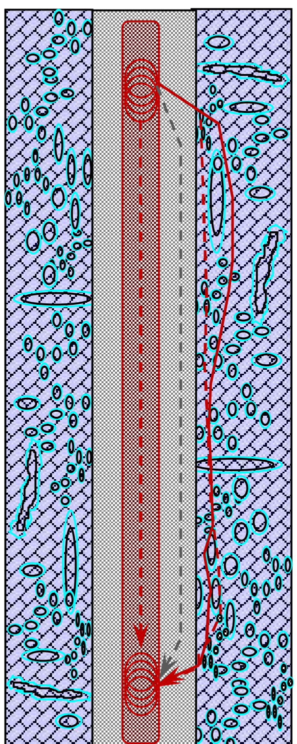


Figure 7-53 An illustration of sonic wave propagation in a vugular reservoir.

TYPES OF POROSITY

Up to this time we have considered inter-granular porosity only, the most common type, (figure 7-1), but old Mother Nature sometimes slips in vugular porosity, which we described back on page 250 and illustrated in Figure 7-2. She also has been known to present a few fractures to those trying to unravel her mysteries, just to keep things interesting I would guess. The latter little critters really add little to the porosity and we can disregard them for that particular variable but I point them out to erase this obvious question mark from your inquiring minds. They do, you'll remember enhance the permeability around a well bore, however, by acting as pipelines extending from deep within the formation to the periphery of the well.

VUGULAR POROSITY

Vugular porosity is random in nature, i.e. not evenly disseminated as is inter-granular porosity, and is created by percolating ground waters, which move through the rock along existing permeability paths such as fractures. Thus, it in combination with the surrounding dense or very low porosity rock, presents a non-homogeneous pathway of travel to the sound wave of the sonic tool. This peculiar phenomenon is illustrated in figure 7-53 and will help clarify an unsuspected problem, which had plagued well log analysts in the early days of the Sonic Log.

DISTANCE, VELOCITY AND TIME

I believe I mentioned under Sonic principles that the travel time, Dt, was determined by the first sound wave from the transmitter, which strikes the receiver. Such action is depicted in Figure 7-37 where it was explained that the negative going signal is used.

Travel time in the mud (blue arrow) and down the tool (red arrow) is slow because mud velocity is only 5300 ft. per second and tool design makes the apparent velocity within the tool in the same range. Rock, on the other hand has a velocity of maybe 8,000 feet per second up to 23,000 feet per second, or so (yellow arrow). That makes the time required for sound to travel the path down the tool or the mud column longer than that required to travel the greater distance to the wall of the hole, down the bore-hole wall and back to the tool or;

Time = Distance / Velocity or

2ft./5300 = 377 microseconds

Whereas in the slower formations, even with a longer path of about 2.7 feet, the time would be less, i.e.;

2.7ft./8000 = 337 micro seconds

This principle allows the tool to record travel time through the formation. I might add, that travel time refers to the total time required for sound to reach the receiver whereas Dt, delta t, is the time required to travel one foot.

Now, you are probably asking, "what all this has to do with vugular porosity"? This is a question I now hope to answer. Remember, the vugular porosity is randomly spaced in the rock. That is, there are sections of solid rock (no vugs) and other sections with vugs of varying size. The variable nature of the vugs in both size and distribution produce sections of rock whose composite velocity, due to fluid and rock matrix, varies and thus presents two or more paths of differing velocities to the sound pulse emanating from the transmitter. Portions of the sound wave will travel down or through all these formation sections towards the receiver. The wave portion following the fastest path (more rock and less vugs) modified by distance arrives first and is recorded by the tool as the travel time. Others arriving within microseconds are eliminated and have no effect on the recording. The path of this first arrival lies in portions of rock with fewer vugs and the associated porosity is somewhat less than that of the overall rock. Thus, in such reservoirs, the Sonic tends to register too low a porosity. The ratio of true porosity to Sonic porosity is known as the vugular index or, in equation form,

27) Vugular index (I_v)= PHI_{true} / PHI_s

The higher this number is, the more vugular the rock and consequently, its associated permeability. Thus, a high vugular index is indicative of a good carbonate reservoir.

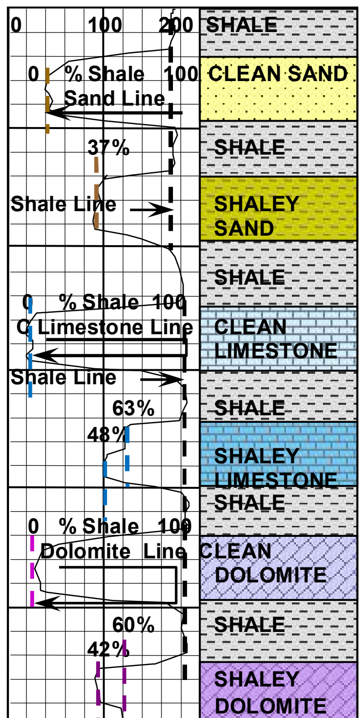


Figure 7-54 A series of formations illustrating how differing amounts of shale affect their specific gamma ray readings.

VUGULAR DOLOMITIC LIMESTONES

Dolomitic limestones or limey dolomites are quite frequent in nature and good reservoirs within them are generally vugular in nature. As a result, they are a common problem for which Schlumberger technology has an answer. The true porosity and matrix composition are derived with the Density – Sidewall Neutron tools as described previously. With knowledge of the matrix composition, the matrix velocity for the sonic calculations is established and an apparent sonic porosity derived. This is then compared to the true porosity derived from the Density - Neutron to obtain the vugular index.

SHALEY RESERVOIRS

On page 318, I discussed the gamma ray log as a lithology indicator, which primarily differentiated between shale with radioactive K_{39} and other non-shale, non-radioactive types of rock. At this point I will expand on that thought.

The common oil field reservoir rocks made up of sandstone, limestone and dolomite are non-radioactive in and of themselves. Occasionally, some radioactive element such as Thorium or Uranium will be deposited with a particular sediment and louse up the works making it radioactive in spite of a lack of shale. That is the exception, however, and any radioactivity present in such sediments can usually be related to the presence of shale. Thus, the gamma ray recording provides a means of determining how shaley a given reservoir is. To help visualize this, consider Figure 7-54. This illustration depicts the three major reservoir lithologies with variations of zero to 100% shale contained therein. The coloring isn't quantitative nor does it illustrate shale variations within the reservoir but it does make shaley formations look different than the clean reservoirs, which was my primary objective. In each case of reservoir evaluation, the log analyst must take into account the percent of shale therein.

THE SANDSTONES

In a given sand shale sequence one can usually find at least one clean sand as identified by a fairly low gamma ray reading. Such a reading might be 20 to 30 API units. If none are close by, he may have to assume a typical value such as just mentioned. He might strike a line through that reading to represent a zero shale line (see figure 7-54). He would then establish a 100 % shale line of maybe 170 API units as shown. The sand of interest (the shaley sand just below) would have an average line struck through it. We assume the shale content varies linearly with the gamma ray count rate. The ratio of the distance between the zero line and the shaley sand line to the distance between the zero line and shale line becomes the percent of shale contained therein. In our case it is;

% Shale = (90-40) / (170-40) = 38%

THE LIMESTONES

When we consider the limestones, two factors change. First the zero now becomes about 25 API units instead of 40. This is typical by the way. The shale radioactivity has also changed which isn't unusual. The shale line registers about 185 or so. The shaley lime just below has two zones with different degrees of shaliness. One registers about 100 and the other close to 125 API units. Consequently, if we decide to calculate the percent of shale, we get;

% Shale = (100-25)/(185-25) = 80/160 = 53% and

% Shale = (120-25)/(185-25) = 95/160 = 59%

THE DOLOMITES

If the dolomites were in close proximity to the limestones we would probably use the same zero shale line. Let's assume that to be the case. The clean dolomite reads about 25 API while the shaley dolomite has two zones of 95 and 120 API units respectively. Putting a pencil to those we obtain;

% Shale = (30-25)/(185-25) = 9%

% Shale = (95-25)/(185-25) = 44%

% Shale = (120-25)/(185-25) = 59%

EFFECTS OF SHALE

I have already mentioned that shale tends to destroy permeability. It also affects the readings of the various instruments we have lowered into the hole and we can adjust them by knowing the percent of shale contained therein. For instance, it will lower resistivity because the shale typically has values of 0.5 to 10 ohms while oil and gas reservoirs have values from 5 to 100 ohms. It will also alter the density, sonic and neutron responses because they also differ from the shale free matrix. Again, corrections can be made to adjust porosity and resistivity values. These adjusted values will usually show a decrease in porosity but a higher resistivity and thus lower water saturation. Prior to such techniques, shaley reservoirs were often overlooked because of their apparent high water saturation.

RESIDUAL OIL SATURATION

I mentioned earlier how knowledge of residual oil saturation in the flushed zone, i.e. S_{xo} could be an advantage. If it is relatively low in value, the mud filtrate has effectively moved the oil back into the formation, which indicates good permeability and productivity of the zone. If the value is high, i.e. near the S_w calculation for the formation itself, little oil has been moved by the filtrate, which points to poor permeability and poor productivity. This can be valuable information for the oil operator, which he can take into account in his completion decisions. Let's consider a hypothetical example with the following parameters for a particular sandstone;

PHI_D = 25%, ρ_t = 10 ohms,
ρ_w = 0.25, ρ_{mf} = 2.5 & ρ_{xo} = 40.

Using the Schlumberger equation for F versus PHI, we obtain a value of F.

$F = 0.81/PHI^2 = 0.81/0.0625 = 13$

Using Archie we calculate;

$Sw = (F\rho_w)/\rho_t = (13 \times 0.25)/10$ $Sw = 32.5\%$

Oil saturation = $1 - S_w = 1 - .325 = 67.5\%$

$S_{xo} = (F\rho_{mf})/\rho_{xo} = (13 \times 2.5)/40 = 81\%$

ROS = $1 - S_{xo} = 1 - .81 = 19\%$

The filtrate has consequently moved;

$(67.5-19)/67.5 = 69\%$

of the oil out of the zone. This indicates very good permeability.

Well, I doubt if any of my posterity waded through the foregoing equations. The exercise wasn't meant to demonstrate that I passed Algebra 1 in high school but rather to give anyone interested an idea of what kind of information can be gleaned from an oil reservoir through wire line geophysical measurements. Any who might have fought their way through it should be commended, in my opinion, and also served warning that their minds are undoubtedly warped, much like grandpa's. Such a demented intellect bodes ill for one's future in that it leads to logical and even rational decisions, which many in this world don't seem to understand. In any case, I wish you well and hope you too find pleasure in describing your life's stories for your posterity. It is fun being in control of the story and trying your best to make something worth reading out of an average life. Such effort necessarily promotes the discussion of your favorite topics, which in turn leads to boredom of those on another wave length. That's enough of my philosophizing for now. Let's move on to another geophysical measurement of interest.

THE NUCLEAR MAGNETIC TOOL

At this point, you might be wondering just what other parameters of the earth's formations we could measure to provide useful information. Well, we still have a few. Old mama nature is diverse enough and stubborn enough that research engineers will continue to come up with new ideas and methods for some time to come, I would guess. However, one parameter we talked about, but only described a qualitative means for its estimation, is permeability. Good permeability provides the pipeline from formation to the well bore for effective drainage of the reservoir. Without it, formation stimulation, such as fracturing, is required to properly drain the reservoir. Obviously, a good value of formation permeability would be beneficial to estimate recoverable reserves as well as for the design of more effective completions. The Nuclear Magnetic tool seemed to offer that possibility for a time and was pursued for several years.

When I left the business, this particular service had been discontinued but I suspect it will be back as technology advances. Such changes tend to open doors that seemed to be locked tight before their advent. In any case, the principle upon which the tool was based was discovered and patented by Chevron Oil Company who, in turn, licensed Schlumberger to develop an effective instrument and market it in the oil field. I found the measurement theory involved especially interesting and chose to include it, or at least a synopsis of such measurements, to pique your imagination.

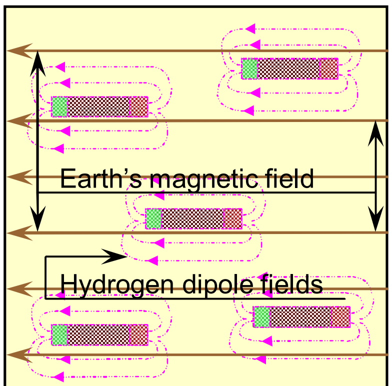


Figure 7-55 Illustration of hydrogen dipoles magnified for clarity.

MEASUREMENT THEORY

The key element involved in this device is the Hydrogen atom, which is prevalent throughout the earth's crust and found in various combinations with other elements. For instance shales have a large concentration of Hydrogen bound together with such things as Aluminum, Oxygen, Silicon, etc., which are contained in the clays within the shale. They are secured, that is, they can't move, by the molecular forces involved. Water also contains Hydrogen as does oil and even natural gas. The fluid or gaseous nature of these latter three, however, will allow the molecules containing hydrogen to move, unlike those in the shale and other rock types.

The Hydrogen atom acts like a miniature magnet or dipole, as it is termed. Thus, it has both north and south poles just as the earth or a conventional magnet (Figure 7-55). If free to move, the magnetic field of the dipole causes it to line up with the strongest surrounding field, which is usually that of the earth. Those in shale or another solid substance remain, of course, in their state dictated by the binding molecular forces. Now these Chevron scientists, being ever inquisitive, wondered what would happen if they disrupted the normal state of these Hydrogen atoms, which were free to move. Could they detect their presence? When they removed the disruptive force, would the little critters return to their normal state lined up with old mother earth's field? Could they derive some useful information from such a measurement? Well, they could, they would and they did. However, there were lots of problems involved and they finally turned the practical development of such a tool over to Schlumberger to provide a field worthy device. Our company was recognized as having a pre-eminent research and design group and thus would be most likely to solve such problems. Over the next several years, our research and design people were moderately successful and turned out a logging device called a "Nuclear Magnetic Tool" which I will now try to describe and which you must try to adsorb in your consciousness.

TOOL DESCRIPTION

Like most logging tools, the down-hole device was composed of a sonde containing the sensors or hardware used to produce and detect

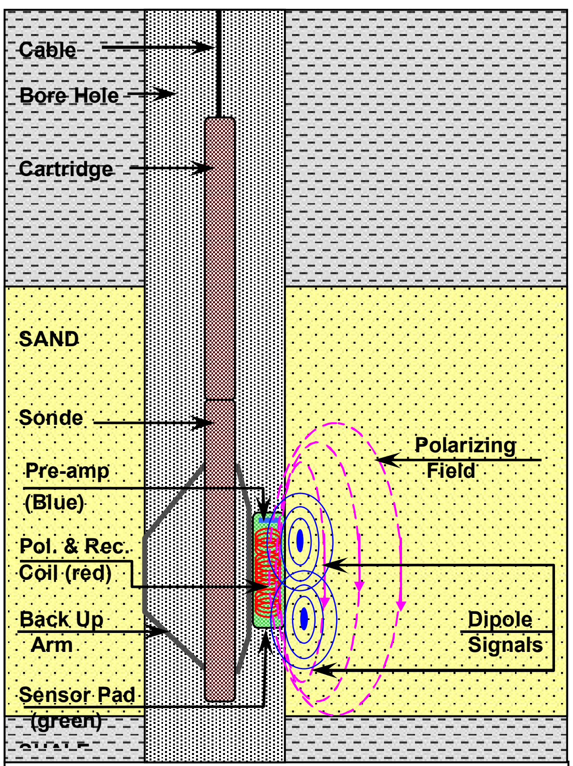


Figure 7-56 Illustration of the Nuclear Magnetic Tool with its associated signals.

any signals generated and an electronic cartridge containing the necessary control and amplification circuitry. A surface control panel then provided the necessary processing circuits for signal recording as well as the power control for the cartridge and sonde. The down-hole components, i.e. cartridge and sonde, are illustrated in Figure 7-56. I will refer to them as I attempt an explanation of the measuring principles involved with this interesting concept.

THE SONDE

The sonde is composed of the lower half of the reddish cylinder, the back arms to apply the sensor against the wall of the hole and the sensor pad (green) within which a large coil (red) and a pre-amplifier (blue) are placed. Like any micro device, the sensor has to be applied directly to the wall of the hole and isolated from the borehole fluid to prevent the fluid signal from overcoming the formation signal. The latter is so weak that it must be amplified immediately before being sent to the cartridge. Hence the need for a pre-amplifier placed in the pad.

THE CARTRIDGE

The cartridge placed directly on top of the sonde contains the circuitry necessary to alternately switch on and off a polarizing current as well as the receiving circuitry to pick up the formation signal. Besides supplying power for polarizing the formation and powering all the necessary circuitry, it also amplified the signal and prepared it for transmission to the surface. There it was processed by panel circuitry for presentation on the recorder.

SIGNAL GENERATION PRINCIPLES

We mentioned the Hydrogen atoms (dipoles), which were free to move in the fluids contained in the formation. Remember the sensor has been isolated from the fluid in the borehole. The free dipoles of the formation are lined up with the earth's magnetic field, which is essentially horizontal, until we come along with a polarizing current and a field of our own. A strong direct current (DC) is sent through the red coil in the pad for a few milliseconds. It produces a field in a vertical direction, which is illustrated by the dotted, magenta colored ellipses. This field is stronger than that of old mother earth and jerks the dipoles into a vertical position, which is essentially at right angles to their original alignment. The current is then shut off and the tool listens for the results.

Without the magnetic field of the tool to hold them vertically, the dipoles try to revert to their original position parallel to the earth's field.

They spin around their long axis much like a top and their combined magnetic fields radiate outward or at right angles to the long axis of the dipoles. Just as a spinning top begins to wobble in ever widening circles due to the earth's gravity, the dipoles also begin to wobble, due to the earth's magnetic field, which is now trying to realign them to their original position. This phenomenon, called dipole precession, is illustrated in figure 7-57.

The precession of the spinning dipoles produce a moving magnetic field ever so weak (represented by the dark blue ellipses in figure 7-56), which induces a signal in the red coils. To visualize this process a little more clearly, go back to figure 7-55 and consider the individual fields of each dipole shown. The magnetic lines shown, as fixed in place, actually expand outward from the dipole at right angles or perpendicular to the dipole's axis and spread further apart as they emanate from the dipole. The sum of those lines, called magnetic flux, from all the dipoles involved is additive and constitutes the signal to be measured.

These are now the receiving coils, having been switched to the receiver after the polarizing power is shut off. As the dipoles spin, the magnetic flux cuts through the receiver coils and induces a voltage we call the received signal. Once again, the total signal is the sum of all the dipole signals reaching the sensor pad at any given instant but it is still very weak. Consequently, it is amplified immediately, at the pad by a preamplifier, before any noise can be picked up and is sent to the cartridge for further processing. The initial signal is strongest with later arriving signals gradually fading out with time as the dipoles realign themselves with the earth's field. It is the decay rate or the rate of signal fading of this phenomenon, which is of interest since it is related to the number of free dipoles. The number of free dipoles, in turn, is related to some degree with the formation permeability, the formation parameter of interest.

Figure 7-57, once again, illustrates this process for a single dipole. Let's go to it for a deeper explanation. At the far left in the diagram we see a single spinning dipole, which has been aligned with the polarizing field of the device. Actually, the diagram shows the dipole at right angles to the field so as to illustrate the field strength by the arrow. Note its value is multiplied by 1000. Now, mentally rotate the arrow 90 degrees so its point is sticking out of the page and it is aligned with the dipole. Note, the dipole is spinning like a top and is standing vertically with its crown, which we will call its north pole, sticking out of the page. Thus the dot you see would be the equivalent of the north pole of any of the various ones shown in figure 7-55 or the red ends. The long vertical reddish brown line to the right of the dipole represents shut off of the polarizing field. The initial dipole signal right after shut off is shown just to the right of that event. The rest of the diagram, to the right of the initial dipole signal, is then used to demonstrate the process of precession as the dipole wobbles to align its self with the earth's magnetic field, which is horizontal in the diagram. Now, let's examine the precession of

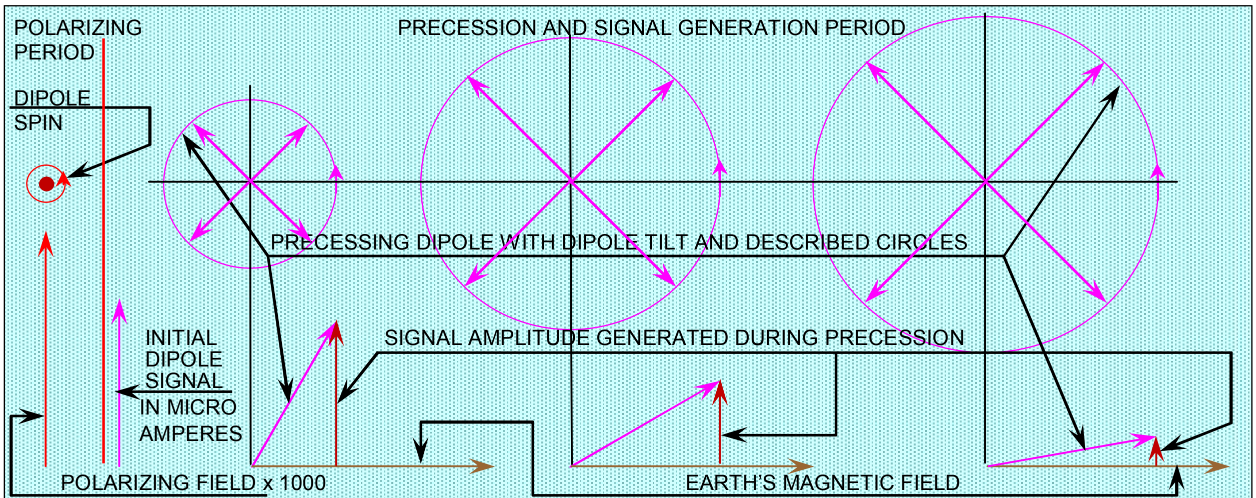


Figure 7-57 Dipole spin during and after magnetization as well as the resultant signal generation produced as precession progresses with the polarizing field removed.

the dipole as it wobbles and generates a smaller and smaller signal in time.

The right side of figure 7-57 illustrates three different attitudes of the dipole as it precesses. The first, at the left, shows the dipole leaning about 30 degrees from the vertical, the second about 60 degrees from the vertical and the last about 80 degrees or almost horizontal. This activity is illustrated in the lower part of the diagram by the magenta arrow. In that same part of the diagram, the brown arrow illustrates the magnitude of the signal it generates in that position. Note that it is less than the original dipole signal and steadily decreases as the inclination of the dipole increases. In the horizontal position, no signal will be produced. In the upper portion of the diagram we see three circles of expanding radii, which are illustrated by magenta arrows. These are the horizontal projections of the dipole represented by the arrows of the lower section. They are meant to illustrate the arrow circling the base of the dipole as its head describes the circle shown.

TABLE I

T	RC	E (voltage)
0	1	10.00
1	1	3.68
2	1	1.35
3	1	0.50
4	1	0.18
5	1	0.07

The primary principles to be taken from this rather difficult description is; first, the dipoles act like magnets with magnetic fields; second, their moving fields can generate a voltage in appropriate circuitry; thirdly, that voltage drops exponentially as the dipole reorients itself with the magnetic field of the earth and; fourth, such hydrogen dipoles exist in fluids, which have hydrogen as a component of their makeup. Now, for the mathematically astute of my posterity, let's move on to a mathematical description of the process just described. If the preceding hasn't eliminated your desire to learn this exciting phenomenon, the mathematics might well accomplish that process.

THE MEASUREMENT OF SIGNAL DECAY

The curves of Figure 7-58, illustrating a natural law governing common phenomena, are called natural logarithm curves. The discharge of a capacitor is a good example of this phenomena and is one with which I have some familiarity. We'll look at that breed of animal first and hopefully, that will simplify that which comes later. If not, it will at least give you a painful introduction to that which you'll have to endure for both the NML and TDT tools, which are yet to follow.

CAPACITOR DISCHARGE THEORY

In the discharge of a capacitor, the charge on the capacitor is expressed as follows;

28) $E = E_o\, e^{-T/RC}$ where;

E_o is the initial capacitor charge

E is the charge left at any given time

T = time since discharge began

R = circuit resistance

C = circuit capacitance

The letter e designates the natural logarithm

The term $e^{-T/RC}$ (natural logarithm function) governs the curve shape and slope. The term RC, known as the time constant, controls the general steepness of the curve. Such a curve progresses from E_o, the maximum value to essentially zero in five time constants or 5 RC. The rate of discharge at any given instance (the slope) depends upon the remaining voltage or charge on the capacitor. Thus, the initial rate of discharge, slope, is steep because the voltage is maximum. As the capacitor discharges, the remaining voltage in it approaches zero, which causes the slope to flatten, as described pictorially in figure 7-58. I have also listed it numerically in Table 1.

THE NUCLEAR MAGNETIC EQUATION

The equation expressing the remaining signal

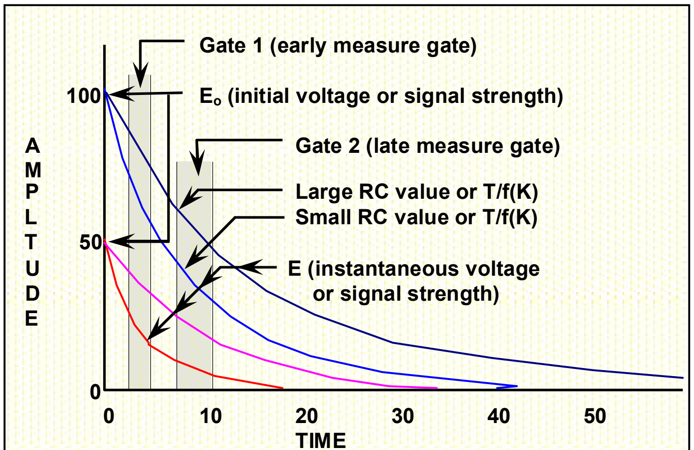


Figure 7-58 Illustration of the rate of decay of voltage on a capacitor or the signal strength received from the free fluid dipoles of an NML tool.

strength of the Nuclear Magnetic Tool at any given instance is similar. Though I may not have it exactly correct, I believe I do in principle and it will provide the basis of my explanation, so give heed my beloved posterity. It is;

29) $E = E_o\, e^{-T/f(K)}$ where;

E = signal at any given instant

E_o = signal at end of polarization

T = time since polarization ended

$f(K)$ = a decay constant which is some function of permeability

E_o, the initial signal strength or amplitude, varies with the formation and is unknown. I suppose it is related to the amount of fluid present and thus the porosity. It cannot be measured because of large transient voltages produced by the termination of the polarizing current. We can, however, measure the amplitude of the remaining signal at two different known times (illustrated as gates 1 and 2) and then determine a value for both E_o and f(K). These gates are produced in the cartridge and open the measuring circuits long enough to measure the signal voltage at those particular points in time.

As you can see, f (K) would be the equivalent of the RC time constant for the capacitor and would similarly control the slope of the curve at any given point in time. As I understand it, that term is called the free fluid index or FFI, which is related to the formation permeability designated as k. It would seem f(K) might also be influenced by fluid viscosity but I am unsure of that. The trick in deriving a quantitative value of k (formation permeability) is to define this function f(K) in quantitative terms, which to my knowledge was never done. I suppose Chevron had some relationships but probably kept them confidential. Even so, it would indicate high versus low permeability and was of some value. The idea was similar to that of the old neutron log whose measurement was termed the Hydrogen Index. It was related to porosity but never quantitatively defined. So likewise was the FFI (Free Fluid Index).

EQUATION MANIPULATION

We'll put in some hypothetical values for measured signal and time (gates 1 & 2) to illustrate how E_o and f(K) can be derived. This principle is also utilized in cased-hole work, which you'll run into in chapter eight. Now, assume the gates are set at 20 microseconds and 50 microseconds after the end of polarization and the respective signals measured are 50 microvolts and 20 microvolts. Utilizing equation 29 we can calculate the magnitude of the initial signal strength;

a) $50 = E_o\, e^{-20/f(K)}$ and;

b) $20 = E_o\, e^{-50/f(K)}$ or;

c) $E_o = 50\, e^{+20/f(K)} = 20\, e^{+50/f(K)}$ or

d) $2.5\, e^{+20/f(K)} = e^{+50/f(K)}$ or;

e) $e^{+50/f(K)} / e^{+20/f(K)} = 2.5$

f) $50/f(K) - 20/f(K) = 0.916$

g) $f(K) = 30/0.92 = 32.75$

h) $E_o = 50\, e^{20/32.6} = 92.1$ and;

i) $E_o = 20\, e^{50/32.6} = 92.1$

Notice both equations give the same value of E_o thus verifying the calculation. Thus, the initial signal strength can be calculated and a value for f(K) determined as demonstrated. Those were the numbers provided by the tool, I do believe. A calculation was made for each polarizing cycle, which occurred probably 20 times a second, or every 50 milliseconds. The polarizing time might have been 20 milliseconds (I don't really remember) and the listening time 30. In any case, you can see how it worked. In principle the process would have been similar to the sonic device in which the transmitter was pulsed 20 times a second and in between the tool listened for the received signal but with the NML, a different parameter of the formation is being measured.

The tool was run most frequently in our Vernal, Utah district by Chevron in the Rangely field. The formation of interest was thick sandstone called the Weber, which had extremely variable permeabilities. We did no log analysis because Chevron did all their analysis. No one else ran the tool to my knowledge because it was still qualitative in its answers and somewhat experimental in nature. Consequently, I never became particularly knowledgeable in the interpretive area. I did run the tool a few times and also had some interesting moments working on the electronics as a Division Engineer. That's where I really became familiar with it.

FFI RECORDING

As I remember (it has been 30 years for goodness sake) the log contained a gamma ray curve in track one along with a caliper curve. Tracks two and three were utilized for NML information. I believe track two was used to present FFI, while track three had another parameter, which I can't recall, recorded in it. I believe it was initial signal amplitude, E_o. FFI, which was indicative of formation permeability, was the important curve according to my limited knowledge. I won't try to include a sample log since it could only substantiate my ignorance.

I'm sure Chevron was trying to gain all the information they could regarding the value of all curves. Had I been more directly involved, maybe I could provide a clearer description.

My point in including this overview of a now defunct tool is simply, "I liked it, including the theoretical considerations involved". I hope you, my more technically inclined posterity, will likewise find these principles interesting. If not, it's not a complete loss because I did find it stimulating trying to bring faint memories to the fore. Frankly, the effort warmed my old bean a little, as well as taxed any gray matter still residing therein. The result is bound to be a major setback for Alzheimer disease but of course, provides little or no regard for the non-mathematical reader.

MECHANICAL SAMPLING

Would you believe it? I think I am done with open-hole geophysical measurements relating to the compositional description of the formations surrounding a borehole. Of course, that doesn't mean I'm done. No, you aren't out of the woods yet. You see, in spite of all these fancy measurements that can be made, the geologist would like to see, touch, smell and even taste the rock he is analyzing. You probably still recall my modification of an old adage in which I said, **"A rock in the hand is worth two in the well".** Now we could add a "bottle of formation fluid" to that rock or maybe we should say, **"A bottle of fluid in hand from the rock is worth two in the well".** Yes siree, those geologically inclined folks like to see, touch and smell samples of their objective horizons. So, what has Schlumberger provided to satisfy that particular desire? Well, over the years, they came up with three different mechanical devices to help satisfy those particular yearnings of the geologists. We'll discuss them, one at a time, starting with sidewall sample taking guns, the first of them.

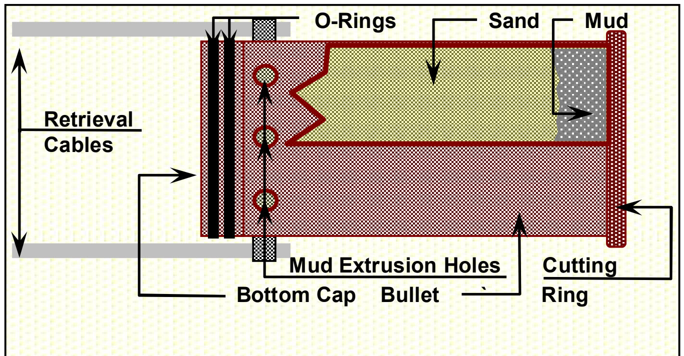


Figure 7-59 A sample taking bullet illustration of with a cut-away view of recovered sand & mud.

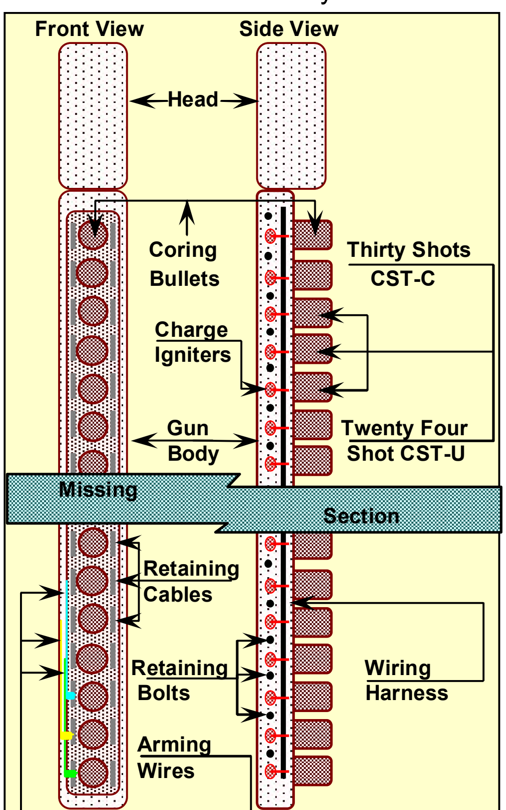


Figure 7-60 A side-wall coring gun, as configured in my day.

SIDE WALL CORING

By the time Schlumberger gets to the well, the geologist already has drill cuttings, which he has collected from the return line of the mud circulation system. He may also have the data from a conventional core or two (Both types of samples were discussed in chapter five). So, why in the world would he want additional samples of the formation drilled? Well, I hope to be able to provide the answer.

First, I feel sure that you'll remember, the drill cuttings leave much to be desired. They are contaminated with other debris and the depth from which they originated in the well is questionable. Thus, they are of limited value. Conventional cores are great but expensive, and can't be taken after the well is logged. They require the geologist to know the stratigraphic section well and to pick proper coring points or depths to begin a coring operation before the well has been drilled to total depth.

Consequently, any zone of interest found through log analysis must be sampled in a different way. If borehole conditions are good, they might run a DST (described in chapter 5 as well) but that is also expensive and won't provide a piece of rock to look at. That, my dear child, is where the sidewall core comes into the picture.

BULLET DESCRIPTION

Schlumberger developed two standard gun sizes for different well bore diameters. They utilized cylindrical shaped bullets with one end closed and one end open. See figure 7-59. For soft rock areas; i.e. gulf coast high porosity sands; a cutting ring was placed on the front of the bullet to cut a hole somewhat larger than the bullet diameter itself. The ring was left in the formation allowing the smaller bullet to be more easily retrieved.

The bullet bottom was closed off with a cap around which two O Rings were placed, the combination keeping the powder behind the bullet dry. The bullet body, made of thick steel, could withstand the tremendous impact of the bullet striking the formation rock when fired. Holes, drilled near the rear of the bullet body, allow trapped mud within the bullet to escape when the chunk of formation enters the cylinder, as the bullet is shot.

At the bottom of the cylinder near the bottom cap, two retrieval cables were attached with their opposite ends attached to the gun body. As I remember, they were 18 inches in length. They could withstand about 1000 pounds tension each and were used to pull the fired bullet free from the formation, where they hung along-side the gun. Of course such dangling bullets increased the gun's total diameter and consequently the tool drag as it moved up-hole. Such was a real pain while shooting cores in smaller holes.

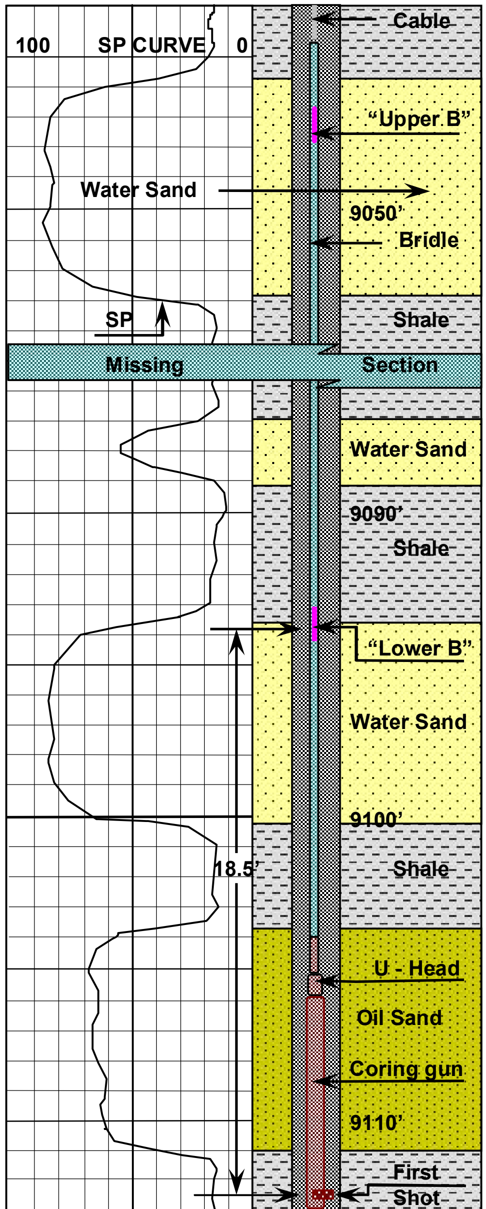


Figure 7-61 An illustration the method of exercising depth control when taking samples with a side-wall coring gun.

THE SIDE WALL CORING GUN

The large or thirty shot sidewall coring gun is shown figure 7-60. The smaller 24 shot gun is similar in every respect except size and was utilized in smaller diameter drill holes. The bullets are also smaller in size and consequently the recovered samples are somewhat smaller. What I describe about the bigger gun also applies to the smaller. The only fundamental difference was size.

The large gun had a rectangular shape facing to the front with thirty chambers drilled therein. Beside the chambers on either side were grooves cut the length of the gun to contain the retrieving or retaining-cables. The latter were coiled up in a circular shape to keep them from becoming entangled with anything else. They were secured to retaining bolts, which ran through the body of the gun. A pair, whose combined strength was 2000 pounds, was hooked to each bullet as shown in figure 7-60. A wiring harness (composed of three insulated wires) ran the length of the gun and was connected to cable connectors 1, 2 and 3. Igniters for bullets 1, 4, 7, etc. made connection with conductor one, igniters for 2, 5, 8, etc. connected to #2 and bullets 3, 6, 9, etc. to wire three. A so-called arming wire for bullet # 4 was hooked to the retaining cable of bullet # 1. Another for # 7 was hooked to the retaining cable of # 4 and so forth. A similar system was employed for bullets # 5 & 8 as well as for #6 & 9. The arming wires prevented the igniter contacts from making connection to the wiring harness running the length of the gun. Thus, only bullets # 1, #

2, & # 3 were armed when the gun first went in the hole. Any current applied to wire # 1 could only fire bullet # 1 while current on # 2 could fire # 2 bullet only etc. When # 1 bullet fired, it jerked out the arming wire to the # 4 bullet and it was now armed. A special drop out circuit automatically disconnected the power on wire # 1 when it fired eliminating the possibility of # 4 also firing. Consequently, the engineer could fire one bullet at a time in a selected zone. That is, once bullets 1, 2 & 3 were fired, bullets 4, 5, & 6 were armed, and then they, in turn, armed bullets 7, 8 & 9 etc.

In the loading process, a clean gun, which had been thoroughly checked for any defects, was laid on the gun-loading bench. Thirty powder cartridges were placed in it, one in each chamber. Clean bullets with cutting rings installed, retaining cables in place and bottom caps on with O-Rings installed are then placed in the chambers. The retaining cables were then secured to the gun body with the retaining bolts and as the igniters were installed, the arming wires were run to the proper bullet number. In the process, insulation and continuity were constantly checked with safety meters to assure proper operation. Safety was obviously a major concern in the operation.

OPERATION OF THE SAMPLE TAKER

In chapter six we talked about depth control and the variations one could expect because of cable measurements, tool drag, etc. If an engineer wasn't careful he could take samples off depth and lead the geologist astray. That is, the samples might not be representative of the zone he was looking at on the log. Samples were always taken after the logs were run and, at least, qualitative interpretations made. From this information the geologist would then give the depths at which he wanted samples to be taken, as referenced to the primary log. All sample depths were then tied to the primary log. To see this more clearly, consider figure 7-61.

I cheated a little with the film grid and made depth lines every foot instead of two feet as on a normal five-inch film but it makes no difference since we are dealing with principles here.

Let's say the geologist ordered a sample from each foot of formation in the zone labeled oil sand. Once the gun depth was confirmed we would shoot samples each foot beginning at 9110 feet and ending with 9104 feet or a total of seven samples.

The depths are confirmed by observing the SP curve as taken from the lower B electrode on the bridle. We know the distance from the B to the first shot is 18'6" and so we'll add that amount to out electrode depth for our first shot. As the tool is dropped into the well, the engineer keeps the depths fairly close by observing the bell we talked about in chapter six.

Once near shooting depth, he sets his depth exactly by observing the SP. For accurate tie in (depth comparison) he needs a thin bed or sharp change in the SP. This occurs at 9088' and so he watches for it as the tool is moved slowly up the hole. As he passes this sand, let's assume it registers 9090'. In noting that, the engineer would take out 2' with the crank that adjusts the depth meter. He would check the depth again and maybe observe a couple of other sands for good measure. Once satisfied, he would move to shooting position. If the depth meter reads 18.5 feet shallower than the first shot, then the winch must be stopped at 9110' minus 18.5' or at 8991.5 feet. With the shot in position, the engineer quickly fires a shot and asks the winch operator to come up. They watch the weight meter, which will register an increase if they got a core. The increase can vary depending upon formation conditions. Assuming all went well, he would now have the operator stop the winch at 8990.5 feet and shoot the second core. The depth difference between the lower B and the second bullet is only 18' 3.5" but that's close enough for government work. As he prepares for the third shot he might adjust six inches and have the operator stop at 8990' or just 18' above the third bullet, which would be positioned at 9008 feet. He would continue the process correcting 6 inches for the first two shots, then 6 inches for the next 3 shots until the job is complete.

The customer might order samples in all the sands shown or even scatter them way up the hole. If samples were taken over a rather large depth range, the engineer would tie in from time to time to verify his depths.

Once completed, the winch operator brings the gun out of the hole, the retaining cables for each bullet are cut and the sample is pressed out with a special press. Each sample is carefully placed in a marked box by number, which can be correlated to the engineer's control sheet. This assures the customer that the proper core has been provided for the depth selected and he can have confidence in their analysis.

The geologist may have a laboratory examine and test the cores or he may do it himself. The information gained can verify hydrocarbon presence, sand type, a qualitative measure of shaliness, etc. Generally speaking, the porosity values obtained from sidewall cores have been optimistic or high because the sand in the core is disturbed during the process. However, it was found that a small piece of core near the bottom cap or rear of the core stayed intact and the porosity values derived were representative. Even so, more sections of hole can be analyzed more accurately and cheaply through various geophysical devices provided to the industry. In spite of that, the CST service is tremendously useful and sells like hotcakes in some areas of the country. Having a rock in ones hand to feel, smell and taste will probably never be replaced.

THE CORE SLICER

Conventional coring has always been the standard of the industry in terms of obtaining quantitative values of both permeability and porosity. Sidewall cores were good for qualitative examination and had the great advantage of being able to be obtained in selected areas or zones of interest after the hole was drilled. Conventional cores had to be obtained during the drilling process and any zone of interest missed was just tough luck. Another solution had to be found. Of course, any measured values of permeability or porosity derived from the sidewall cores were suspect because of the manner in which they were obtained. Consequently, the question was asked, **"Could a core comparable to the conventional core be taken from the side of the hole after the well was drilled?"** Various attempts were made over the years with little success until Schlumberger developed the Core Slicer.

This device was an impressive tool and worked quite well but, unfortunately, was put out to pasture for lack of demand. You see, a complex and expensive tool has to be kept busy to be economical. This can be difficult to make happen, even with a special person assigned with a special vehicle to run it around an area like the Rocky Mountains. Expenses are high and it must be kept busy to be profitable. It appears there was too little coring demand over and above conventional coring and this unique tool didn't make it. Even so, the idea was extremely interesting, in my opinion, and I decided to include a few remarks about it. I won't get into detail because it was a short-lived device, which I had the pleasure of becoming fairly familiar with. Besides, in thirty years I have forgotten a heap of what I knew at that time which wasn't too much.

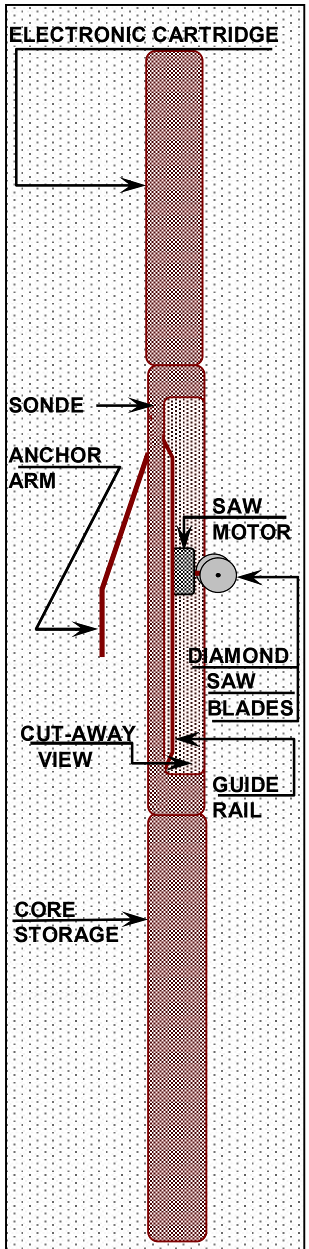


Figure 7-62 An illustration of the core slicer tool configuration that is run in a well.

TOOL OVERVIEW

Let's refer to figures 7-62 and 7-63 as the essential mechanical components and their purposes are discussed. Unfortunately for you, I have to draw the major mechanical components from memory and, having but little of that or artistic talent; you must try to visualize the tool as I describe it. Even the description may be wanting in that it has been a long time since I worked with the tool and a lot of water has passed under the bridge. I suppose you've noticed the frequency of that particular excuse but heck, I don't have any other.

We'll begin with figure 7-62, which depicts the major components of the tool and a few minor ones to illustrate the anchoring and application principles. The tool would be anchored to the walls of the hole by expanding an anchoring arm or shoe. Upon command by the engineer the sawing mechanism would ride up a rail which was sufficiently high to cause the saw blades to emerge from the sonde shell and engage the formation while cutting into it to a depth of about one half of the blade's diameter or one inch. As sawing progressed, the motor and blades would travel along the rail in a downward motion for about three feet and then back into the sonde shell. I can't recall all the mechanism required to cause the core, which had been cut, to fall back into the sonde shell but fall it did and slid into the core storage container. The container would store three or four cores, each of which was about three feet long. Consequently, that number could be taken each trip into the well, which saved a lot of rig time.

Now consider figure 7-63 (an after-thought), which details the saw mechanism itself. Once again the drawing may not be too accurate but it will allow me to explain the principles. Actually, little explanation is necessary as the reader can see the two blades were so oriented as to cut a V shaped segment of rock from the borehole wall which then broke loose and could slide into the sonde receiving receptacle.

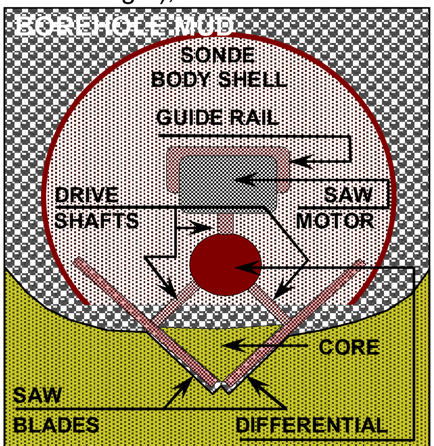


Figure 7-63 An illustration of a cross-section taken thru the core and saw mechanism.

FIELD PROCEDURE

I don't intend to draw a borehole view of the tool in operation. Except for the tool itself, the scene would appear much like the sidewall core gun in figure 7-61. In fact, the tool would be positioned in the same way such that the engineer knew exactly what depth the core was being cut from. Thus, the SP from the lower B would be observed and appropriate corrections made to place the saw blades at the selected depth. The engineer then anchored the tool by expanding the anchor shoe and pushing the saw blades over against the opposite wall of the hole. The pressure of this mechanism against the borehole wall was sufficient to hold the weight of the tool and prevent it from moving during the operation. Next, the engineer would apply power to the saw blades as well as a separate motor, which advanced the saw along the guide in a downward direction. The time required to make a cut was determined by the hardness of the formation being sampled as well as its cohesiveness. If the core didn't break up, the cutting would proceed without incident and the core would be retrieved into the tool. If the rock were full of vugs and/or was fractured, pieces of core would break loose and possibly jam the saw blades.

The electronic circuitry, however, was well designed. It had sensing circuits, which would anticipate the binding of the saw much as a person would when they feel a normal saw blade dragging. Upon sensing such a situation, it would automatically back up until the blades were free and then advance once again. The binding might occur from rock particles falling into the cut or simply core movement. The latter was the biggest problem. If a section of core broke loose, it might well fall in a position so as to jam the blades before the automatic circuits could react. The engineer would then have to back the saw blades up and then go forward again trying to free the blades so they would spin once more, much as you would a circular power saw. It could get tricky and didn't always work. As a last resort the anchor could be released allowing the tool to fall away from the wall and free the whole mechanism. However, this caused the loss of the core and was only used when nothing else worked. Obviously, it took practice and experience to become proficient with the device. Because of this, a special engineer was assigned to the tool so as to be as effective as possible. We did everything we could think of to make the service sell but the number of jobs per month simply didn't pay the special engineer's and operator's salaries along with the cost of a special vehicle and tool depreciation. As the Division Engineer, I got involved with jobs from time to time and became reasonably proficient myself, which was somewhat beneficial in my work.

When the tool was anchored in place, the winch operator would keep the logging cable moving by going down-hole 50 to 100 feet and then back up to the cutting depth. This action continued during the whole cutting operation to minimize the chances of the cable becoming differentially stuck in mud cake up the hole from the zone of interest. Remember that problem from chapter 6 under fishing? When the core was completely cut, the winch operator brought the cable back to sampling depth before the anchor was released so the tool couldn't fall down the hole. At that time the tool would be moved to another coring point or brought out of the hole as appropriate.

The core obtained from the core slicer was just as representative of the formation of interest as a conventional core would have been. The same types of testing could be done on it with similar results and the cost was a fraction of conventional coring. Horizons missed during drilling could easily be spotted from the logs and cored. One would think the market would have been there, but it didn't materialize.

Well, so much for the core slicer. I would tell you more if I knew any more or could retrieve any more. Consider yourselves lucky I don't and/or I can't. You see there are advantages to having a grandpa with an obsolete and somewhat less than perfect memory. So, let's move on to our last mechanical sampling device, the Formation Tester.

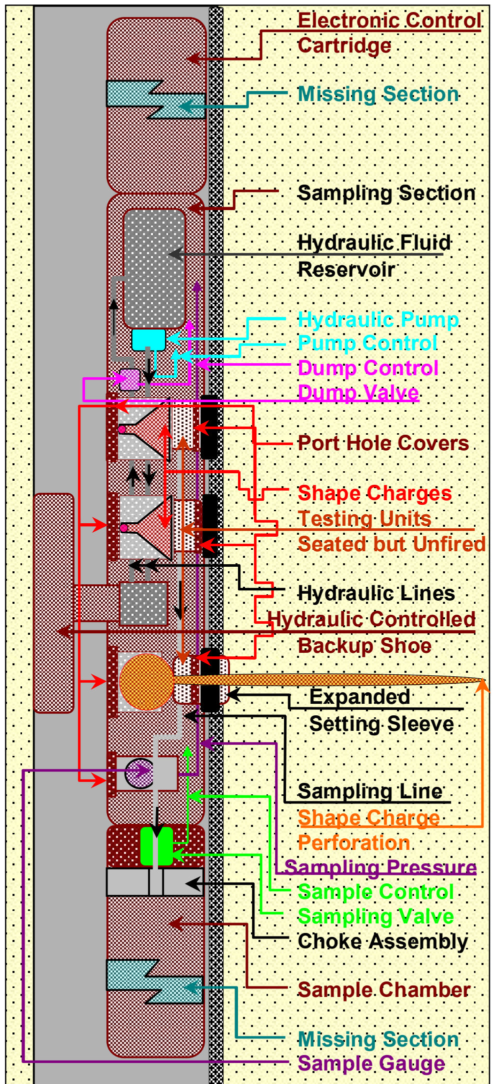


Figure 7-64 An illustration of the essential components of the Formation Interval Tester.

THE FORMATION TESTER

Just as there was a need to obtain samples of the rock after the well was drilled, so was it desirable to obtain fluid samples from zones of interest identified from the various logs run. A drill stem test might be run but, as I mentioned in chapter 5, it was frequently impossible to test very far off bottom. The shales erode as drilling progresses while the sands and carbonates usually stay in gauge. That situation makes it difficult to find reliable points to set the packers necessary to isolate the zone to be tested. As a result, casing often had to be run to properly test a zone, which looked promising on the logs. That, of course was expensive and the need for a wire line tester, which could set without packers outside the zone of interest, was evident. That need motivated the design of the Formation Tester or FT for short. Don't you just love the originality of some of Schlumberger's alphabet soup? You must admit, it is logical; one of an engineer's stronger traits. Anyway, let's take a peek at the principles behind the mechanics of this device and its operation.

TOOL OVERVIEW

As with the previous tools, we'll employ a poor man's drawing of the FT to help explain the operational mechanics. So, take a gander at figure 7-64 while I try to cogitate sufficiently to assemble a reasonable explanation. There is nothing exact about this drawing. I doubt that the design engineers would even recognize what it is meant to represent. How-some-ever, I have reached back in the dim recesses of my mind (30 + years ago) and tried to illustrate how the components I remember fit in, functionally speaking.

THE BIRTH OF THE FT

The testing tool came into being as the FT or Formation Tester, which was designed specifically for open holes. It came into being about 1956 or so and was utilized primarily in the Gulf Coast as far as the USA was concerned. The packer or pad used to seal off the testing opening from the mud column was of a completely different design than what I have illustrated in my drawing. The packers I show came along with the FIT or Formation interval Tester, an improved version that surfaced in the sixties, I believe. The device graduated from a one-test, one sample version to an eventual four test - two sample version. That is the original device could recover one sample with a size of one gallon and record the associated pressure profile. The latter version was capable of recovering two samples (both five gallons) and recording the associated pressure profiles as well as recording pressure profiles for two additional zones.

DEPTH CONTROL

Let's take a minute to review the depth control process, which is much the same as for the Core Slicer or a sample taker gun. If you consider figure 7-61 once again and pretend that an FIT is on the end of the line instead of a core gun, the process would be the same with only the distance between the lower B and the point of sampling changing.

TOOL OPERATION

Like the Core Slicing Tool, the Formation Tester had to be secured in the hole opposite the zone, which was to be tested. This was done with a backup shoe, which once again could support the tool's weight when it was firmly seated. A hydraulic system was used to open and close the testing or sampling section of the FIT. Once the tool was in position, the hydraulic pump was actuated which pumped fluid from a reservoir within the tool to the chamber behind the piston supporting the shoe. The shoe was pumped out until the borehole wall was engaged and the doughnut packers pressed against the wall on the other side. Then the internal hydraulic pressure was built up sufficiently to hold the tool in place and push the packers through the mud cake to seat against the formation wall. As time went on, in high porosity areas, a setting sleeve expanded and then moved out into the formation to prevent the weight of the mud column from rupturing the packer seat. Should that happen, it would ruin the test.

The recording of sample pressure versus time, which we will illustrate later, was then started. The shape charge in the selected chamber was fired which exposed the flow line and the associated pressure transducer to the formation and any fluid entering in. It also pierces the formation for several inches, allowing the fluids to drain more effectively into the tool. Notice that the inside chambers are all covered by steel caps or porthole covers. At this point the sample valve is closed and the tool volume exposed to the formation is very small, a few c.c.s (cubic centimeters). It fills rapidly subjecting the sample gauge to the associated pressure, which rapidly builds up to that of the formation. At that point the engineer opens the sample valve and allows the formation fluid to drain into the sample chamber of five-gallon capacity. In most cases the fluid is run through a choke, a small orifice, to control the rate of fluid entry. As the fluid flows in, the sampling pressure registered by the sample gauge drops to a value determined by the choke size. When the sample chamber is full, the pressure seen by the sample gauge rises to formation pressure once again. The engineer then records a final shut in pressure, closes the sample valve and has the winch man come up to sampling depth. He closes the tool by actuating the dump valve and the sampling pressure rises to hydrostatic. The hydraulic

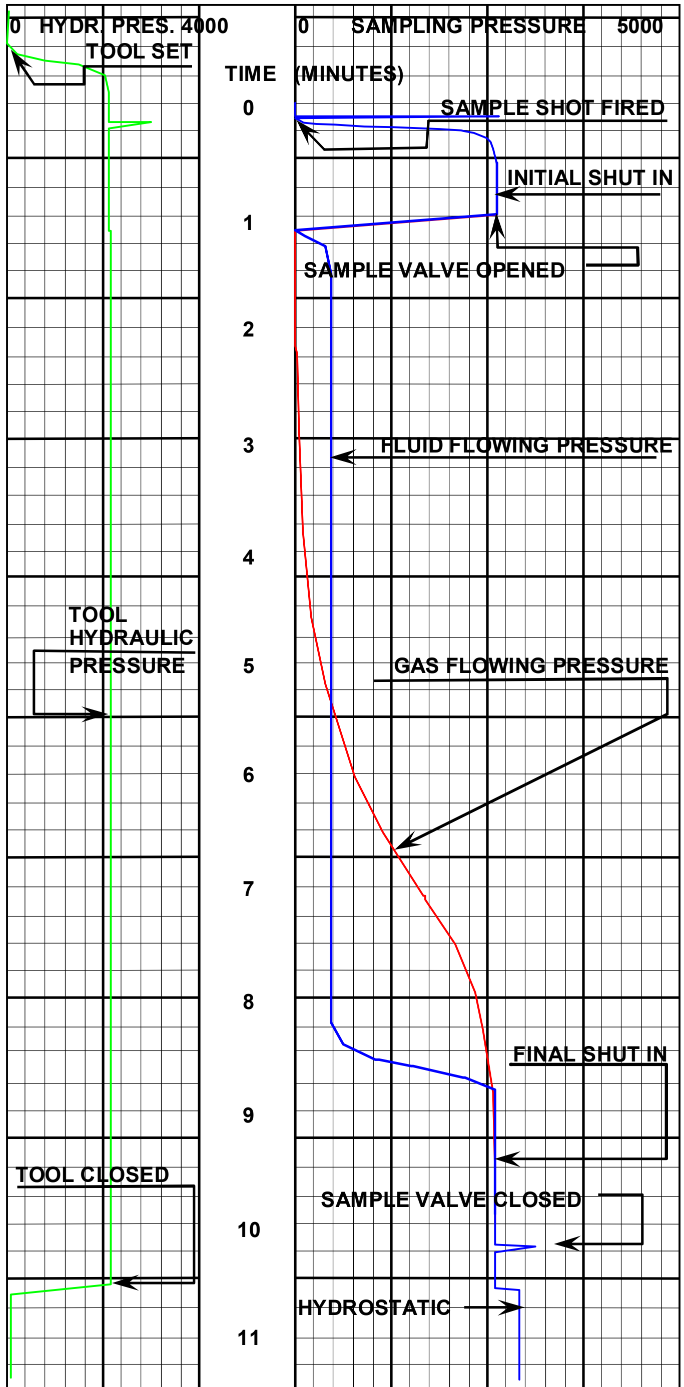


Figure 7-65 A drawing illustrating a typical Formation Tester pressure profile recording.

pressure within the tool drops back to zero and, of course, the hydraulic fluid has returned to the reservoir allowing the shoe to retract. If you feel inclined, you can relate the previous explanation to both the tool illustration of figure 7-64 and to the pressure recording, which is provided by figure 7-65. Of course, wading through the explanation with figure 7-64 will be time consuming if you locate each part spoken of.

The winch operator moves the tool to another zone for the next sample, as designated by the engineer. With a second sample chamber, not shown, two samples can be retrieved from two different zones on one trip rather than having to take time to come out of the hole and drain the first sample from the tool. Also the engineer can run pressure curves on two additional zones without collecting a sample if the customer so desires. The benefit of the latter feature lies in the value of reservoir pressure information. The FIT is particularly adept at establishing pressure buildup data in multiple zones on a single trip into the well, from which valuable reservoir characteristics can be established. This facilitates data gathering for reservoir pressure maps, which are much like structural contour maps and isopach maps you experienced in chapter 5. The contours involved define equal pressure points in the wells tested rather than bed thickness.

PACKER SEATS

Now, here's a point of interest. Notice that the setting-sleeve on the chamber, which has been fired, has moved out through the doughnut shaped packer and slightly into the sand. This action helps maintain a packer seal in less competent formations by cutting through the mud cake ahead of the packer and supporting the sand just in front of it. In a typical well, the hydrostatic pressure is about 200 pounds more than is the formation pressure. The instant the charge fires, i.e. just prior to fluid flow, the pressure on the inside drops to essentially zero. The mud behind the hydrostatic pressure tries to break through the formation in front of the packer but the extended sleeve supports the sand helping prevent its erosion from in front of the packer seat.

Now let's move on to the pressure recording I referred to. Like everything else I have drawn it from memory, I'm sure it isn't totally correct and particularly for the FIT. I had little field experience on the FIT but as I remember it, there was a small pressure chamber, which was filled for the initial and final shut in pressure recordings. I believe the engineer was able to open it after the charge was fired and again after closing the sample valve. Maybe it protected the pressure transducer or something. Obviously, I don't know. Anyhow, my pressure profile will do to explain the essential principles.

PRESSURE RECORDING PROFILE

Figure 7-65 illustrates a typical pressure profile as recorded versus time. Such profiles vary zone to zone within a well, from well to well and from geologic area to geologic area. No one profile would explain all the different formation characteristics one might observe. As I go through this one, I may deviate for a moment to describe something different that I encountered.

Looking at the profile, you will observe a significant difference from the normal Schlumberger recording. That is, the pressure is recorded as a function of time rather than depth. We described the depth measurement process back in chapter 6 but how in the world would we measure something versus time? The answer is simple or I wouldn't try to explain it.

The Schlumberger logging unit has two depth meters, one of which is on the recorder and the other above the winch man's panel. Typically, as the tool is lowered into the hole, the winch depth registers that of the sampling section or shot depth while the recorder depth is set to register the upper B depth. Thus, at the approximate sampling depth the B depth is tied into the primary log SP. Once proper depth is assured, the tool is stopped at the zone of interest according to the winch depth. The recorder is then disconnected from the system depth drive and connected to a motor with a transmission to move the film at a specific rate or distance per minute. Though the recorder will still print depths (false, that is), the film grid can be scaled in minutes and such an operation is accomplished by the engineer after developing the film. It only takes a razor blade and lettering.

When everything is ready, the motor and recorder are turned on to begin the time base. With the tool at the proper depth, the engineer opens it or sets the back-up shoe. Notice the hydraulic pressure as recorded in track 1 increases from zero to a little over 2000 pounds. That seems about right. Once the tool is set, the engineer has the winch operator slack off on the cable and observes the weight to be sure the tool is safely set with no movement at all.

With this assured, he fires the sampling shot as indicated on the film record. Notice the pressure registered by the sampling transducer has been recording zero. It momentarily spikes due to the shot and settles back to zero. The pressure begins to rise almost immediately because of the small volume exposed to the formation. That volume fills with mud filtrate and the sampling pressure rises to the initial shut in pressure. With the sampling pressure leveled off at initial shut in pressure, the engineer opens the sampling valve. This connects a five-gallon sample chamber to the sample line leading from the formation. As the fluid is dumped into this chamber, the sampling pressure drops to near zero with one of two actions following. These two actions depend upon the type of formation fluid entering the tool and the choke size being used at the entrance to the sample chamber.

FLUID ENTRY

With fluid coming in (water or oil, blue curve), the flow line immediately fills up and the resulting backpressure is registered on the sample transducer. Its value depends on the choke size being used. The smaller the choke the higher the pressure registered. That pressure is held until the chamber is filled at which point the value rises to formation shut in pressure. With that accomplished, i.e. a full tool recovery, the engineer would close the sample (after recording final shut in for a while) and prepare to release the tool. Once the tool was back to sampling depth, the dump valve would be actuated allowing the back-up shoe to retract and the tool to come free. Then the tool would be moved to the next sampling depth.

GAS RECOVERY

If the primary fluid recovered is natural gas, the pressure build up would follow the red curve as the gas was compressed. Flow would continue until the pressure in the sample chamber reached the formation pressure. Once the engineer was satisfied that such had been reached he would close the sample valve and go through the same procedures as just mentioned for fluid recovery. Consequently, only the pressure profiles differed between the two types of fluid being recovered.

RECORDED PRESSURES

Now, let me add a word about pressures. I mentioned initial shut in, flowing pressure and final shut in. The initial shut in pressure occurs before any fluid has been drained from the formation. That is, the necessary fluid to fill the sample line is inconsequential and once complete; the sample gauge registers the formation pressure, which is then termed the initial shut in pressure to differentiate it from later pressure measurements, which will vary with both time and formation characteristics.

With the sample chamber open, the recorded pressure drops because of restrictions in the formation and tool. If fluid and a choke is involved pressure drop occurs within the rock because of permeability restrictions. If the fluid moves into the tool faster than it can through the choke in front of the sample chamber, then a backpressure is felt in the sample line and is recorded as the flowing pressure. That value represents the pressure drop across the choke. Obviously, the value registered is a function of choke size as well as formation pressure, fluid flow rate and formation permeability.

If the sample chamber fills completely, the formation shut in pressure will once again register on the sample gauge. In low permeability formations this may not occur. Consequently, once the sample chamber is closed, a second very small chamber can be opened on later models of the FIT. Being of small volume, it should fill relatively quickly and provide the desired final shut in pressure. This value will be the same as the initial shut-in in higher permeability formations. If the reservoir is limited by size and or very low permeabilities, the final shut in pressure may be less, which is valuable information, as well.

DETERMINING PERMEABILITY

There is a reservoir engineering equation, which allows the calculation of permeability from a function of pressure build up. At this point, this old gray matter can't come up with it though I know it is related to the slope of the build-up curve. I used it a few times when running FT's but apparently not enough to really make it register in the old bean. I can say that a faster build up indicates higher formation permeability and thus one with higher production rates. Such derived permeability values are considered the most accurate because it is accomplished in situ or in place without disturbing the rock involved.

Well, that about winds up my little dissertation on the FT, which, by the way, isn't one of my strongest subjects. I expect you guessed that. I never got deeply involved with it because it was a specialty tool having a specialist operator to maintain it and a specialist engineer to run it some of the time. In the Rockies, however, they finally did away with the engineer and allowed the logging engineer assigned to the specific truck to run the tool. That's where I received what little experience I did get with later tools. I also ran the original FT while working in Wharton, Texas. As I move on to the next subject, the simple statement, "So much for that", seems like an appropriate close for the FT.

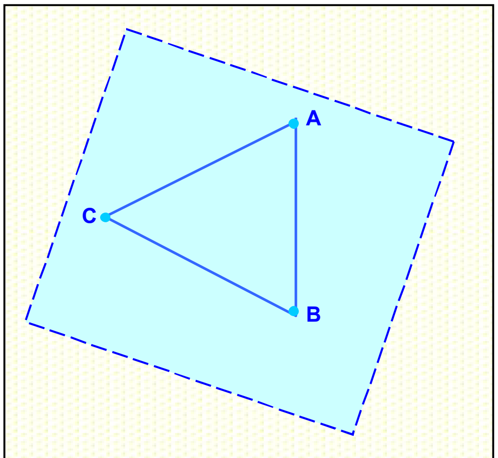


Figure 7-66 A drawing illustrating that 3 points determine a plane.

THE DIPMETER

The dipmeter is a device that evolved from a rather simple tool for structural determination, when I first went to work in 1955, to a complex high-resolution device, which could help unravel both structure and complex stratigraphy. Let's begin by discussing the term "dip" as it applies to geometry or geology and see what ramifications it may have before getting into the details.

DIP OR INCLINATION OF A PLANE

A plane is, of course, a flat surface which may be real or imaginary and which may vary in its lateral extent, at least in a real sense. I have attempted to illustrate the same in figure 7-66 as the light blue sheet. Now, it's time to review a little geometry or in the case of many of you, I suspect, receive a lesson of the same.

Somewhere back in the dim recesses of the past, some mighty mathematician figured out that three points determine a plane or attitude of a flat surface as depicted by points A, B, and C of the blue sheet. You can add additional points within the plane but they won't further define such a surface. Three will do just as well. That's an important principle for our dipmeter. Also, depending upon the position of those points, the plane can be horizontal, vertical or tilted at some angle to the horizontal. Furthermore, the direction of such tilt will make some angle of incidence with a horizontal plane as well as the direction of true north. Now, let's see if I can depict that with a drawing, which will illustrate those particular specifications, as seen in figure 7-67.

Whew, that was some challenge for poor old grandpa. After all that, I doubt you can see the intersecting planes, one horizontal and one inclined and surely my maze of arrows and lines must be confusing. So, let me now try to explain. First, the amount of dip or angle of inclination is measured in degrees between the horizontal and inclined planes and is represented by the Greek letter PHI, Θ, just like porosity a little earlier. Second, the direction of dip is referenced to true north and is represented by the Greek letter Theta, Φ. This is the dip bearing and is measured in degrees from true north in the horizontal plane. Together they define the attitude of the plane or the amount and direction in which it slants. As I mentioned earlier somewhere, a picture is worth a thousand words. Of course, any real value in this case is related more to grandpa's words and artistic ability than reality.

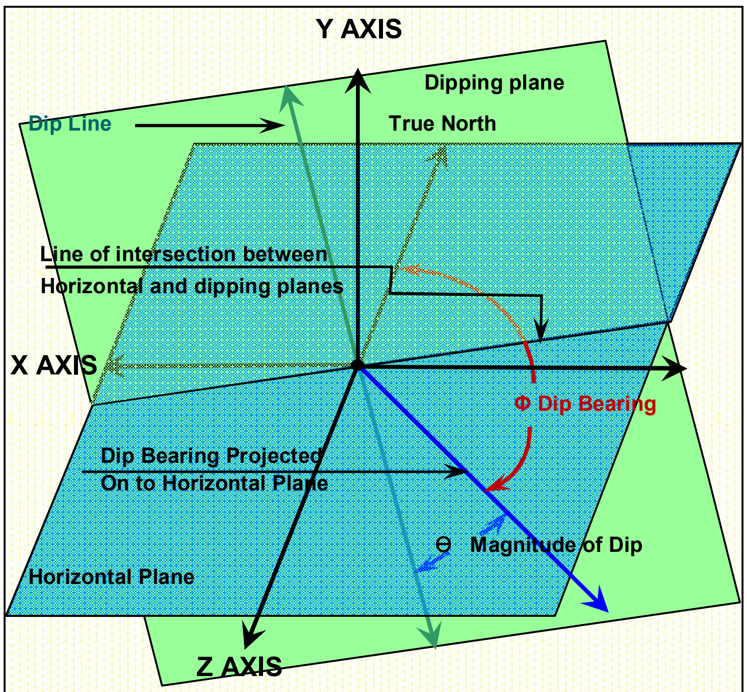


Figure 7-67 Dip magnitude & direction illustration of a green dipping plane relative to a horizontal blue plane.

DIPS IN MOTHER NATURE

We talked a little about dip back in chapter five relative to anticlines and synclines I believe. I referred to that as structural dip, which is an important parameter for the geologist to obtain in his exploration work. However, the term dip may be used to describe other bedding characteristics such as regional dip and cross bedding within formations. The first refers to the average inclination of formations over a large area or region. Structures lie within that region and produce anomalous dips or structural dip along the regional trend. The second refers to very restricted or localized bedding planes within a formation, which are produced by depositional currents. Consequently, we have major bedding planes parallel with the formation boundaries and thus, the associated structural dip and also mini bedding planes within a formation due to a phenomenon called cross bedding.

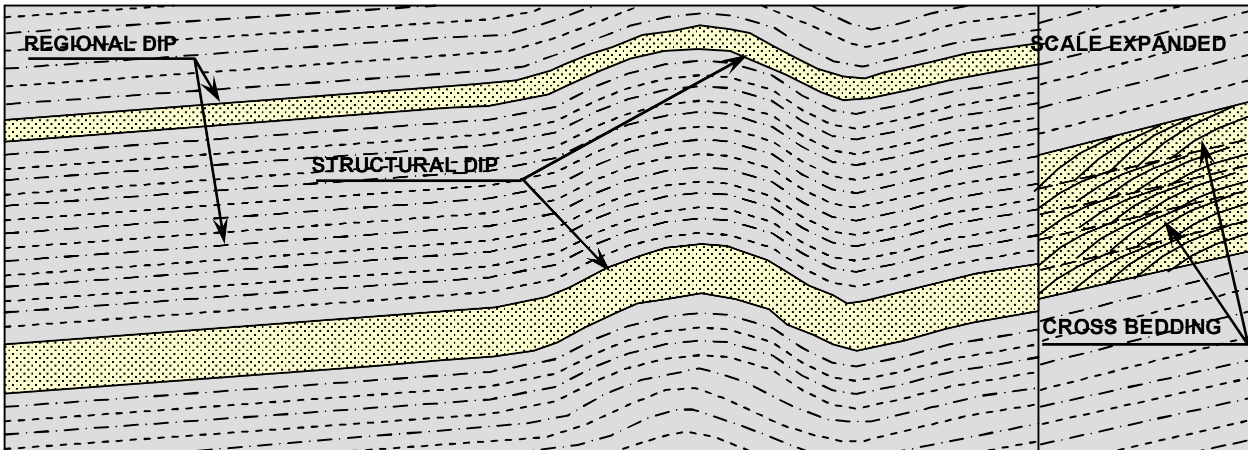


Figure 7-68 A representation of three different types of geologic dip, which occurs in sediments.

Figure 7-68 illustrates these types of dip. I suppose visualizing the dips I have described, particularly cross bedding, may tax your imagination a little but do your best anyway. I'm going to try to clarify things a little later on but the results of such efforts may be more akin to stirring up the muddy bottom of a pool. The more my effort to clarify stirs things up, the murkier they become at times. How-some-ever, it's my book and I'll do as I want.

DIP DISTORTION

Faults and compaction in less competent formations distort both structural and regional dip. Experienced personnel can recognize such distortions from modern dipmeter data and identify the implied phenomena. This requires a geologic background and an interest in that field. Such information can be of great value to a geologist trying to unravel stratigraphic and structural geology. Consequently, after discussing the principles of the dipmeter tool, I'll spend a little time describing some of these data types so as to give you a better idea of the Dipmeter's application.

DIPMETER HARDWARE

The concept of determining the dip of a bedding plane seems straight forward enough. Such dip can be determined by drilling three wells and correlating logs run in each of the three, as described in figure 7-5. Obviously, this is expensive and though the information may be good, the operator may have drilled one or more dry-holes because of lack of structural data. The obvious question is, "could a tool be devised to measure formation dip in only one bore hole?" Of course, the answer is yes or I wouldn't be writing this particular section now, would I? Consider figure 7-69 A which illustrates the principles involved. Now I realize it is extremely busy and may appear to be just a mass of arrows, intersecting planes and labels. None-the-less, bear with me as I try to explain just how all of this fits together. If you get through it successfully and, heaven forbid, understand what I'm trying to explain, you'll probably know more about the dipmeter than I.

THE ILLUSTRATION

First, there is a borehole, which has been drilled through a sand stringer (yellow) sandwiched within a shale beds (gray with black bedding planes). Within the borehole is the dipmeter tool (dark red), which has four sets of arms (reddish brown). They in turn, support four pads (gold color) applied against the wall of the hole. The current electrode in each pad (red) focuses a very thin measuring current into the wall of the hole and is isolated from the mud column by the dip pads. The current flow responds to very small changes in the material properties of the changing formation lying directly in front of it, both in terms of thickness and resistivity magnitude.

At the top along the axis of the tool I have placed a rectangular coordinate system described by the X-Y-Z axis. I have arbitrarily place the direction magnetic north parallel to the Z-axis. This system provides the reference for the dip measurements. I have also depicted the dip of the associated formations as being to the southwest, which is designated by the brown arrow. That arrow lies in the plane labeled dipping sand stringer and inclined plane. The portion directly behind the tool is out of view, and part of that in front of it is under the horizontal blue and dipping yellow planes. The edge of that portion of the horizontal blue plane behind or underneath the yellow dipping plane is designated with a heavy dashed blue line to illustrate its position within the borehole. The intersection of the blue and yellow planes is shown in green because of the color combination, i.e. blue and yellow.

My three dimensional effort is meant to illustrate the horizontal plane (blue) cutting the inclined plane along the line of intersection labeled A - A'. Admittedly, the blue plane doesn't appear horizontal but you'll have

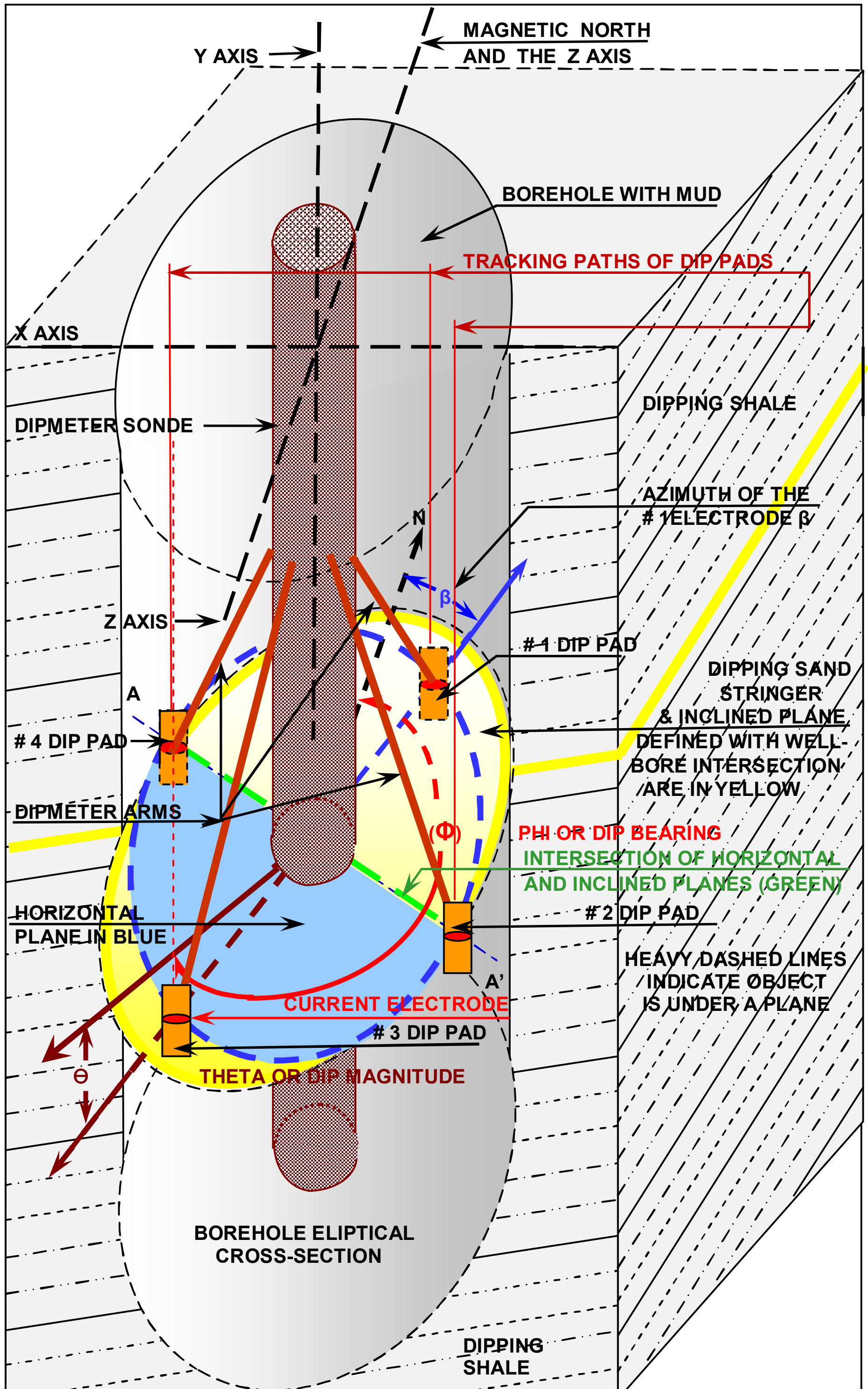


Figure 7-69-A An illustration of borehole and formation parameters measured by the dipmeter in a borehole, which are needed to determine both magnitude and direction of formation dip.

to take my word for it. I fought this drawing for quite some time, trying to make it acceptable and in harmony with my explanation, which will soon follow. If I am successful, you may walk away with a reasonable understanding of the tool, its mechanics and the complex means by which it gathers data for dip computations.

The elliptical nature of the dipping plane or sand stringer within the borehole is meant to depict the plane it defines and should be thought of as imaginary. The horizontal surface is likewise imaginary and defines the reference from which formation dip is measured. I have indicated two angles within the latter which must be determined by the tool i.e. **B (Beta)** and **Ɵ (Theta).** Beta is the bearing of the # 1 electrode or the degrees (angular distance) removed from magnetic north. Theta is the direction of formation dip, which is also referenced to magnetic north. Now, the latter (Theta) is calculated later with the magnitude of the dip from the data provided by the inclinometer and dip curves. Both must be corrected for the magnetic declination (the deviation of magnetic north from true north) at the well site location or that geographic point. Such calculations constitute a rather complex geometrical problem, which was solved mechanically through an ingenious device in the early days of the dipmeter and, later on by computers, which seem to have universal application in the solution of any vexing problem. Let me assure you that computing dips every two feet through a rather lengthy geologic interval was, indeed, vexing prior to the advent of the computer and continued so until the tool evolved to its present status with 4 arms.

INCLINOMETER DATA

The tool will seldom be vertical in attitude whether due to borehole deviation or simply "tool tilt" within the borehole. Since the plane, cutting through all four current electrodes, which was defined as horizontal in the preceding, is always perpendicular to the tool axis, information must be provided to allow correction of the tool axis to the vertical where that plane will, indeed, be horizontal. This is provided by the so-called inclinometer, a device whose essential parts are illustrated in figure 7-69 B. It measures the magnitude of tool tilt and its direction relative to the number one electrode. The magnitude is measured by a weighted pendulum like device, which maintains a vertical attitude by virtue of the weight on the lower end. A potentiometer, an electrical device, is coupled to the pendulum, which generates a signal proportional to the angle of borehole deviation from the vertical. The direction of tool tilt relative to the # 1

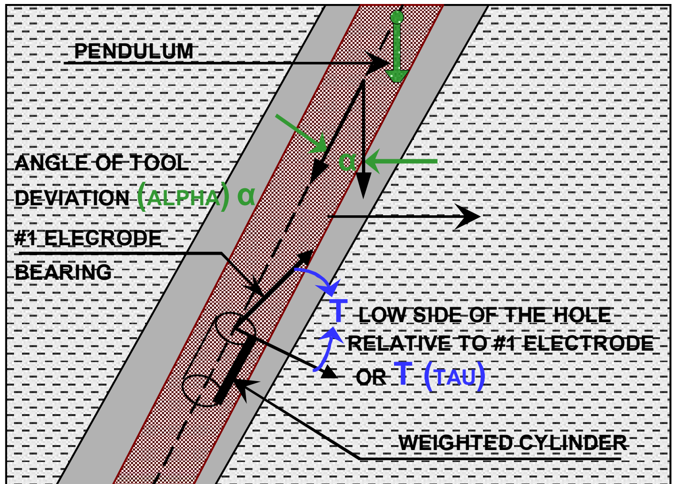


Figure 7-69-B An illustration of tool tilt in a borehole and its means of measurement.

electrode is established through a weighted cylinder. The heavy side seeks the low side of the hole and also moves a potentiometer arm to generate an electrical signal proportional to the

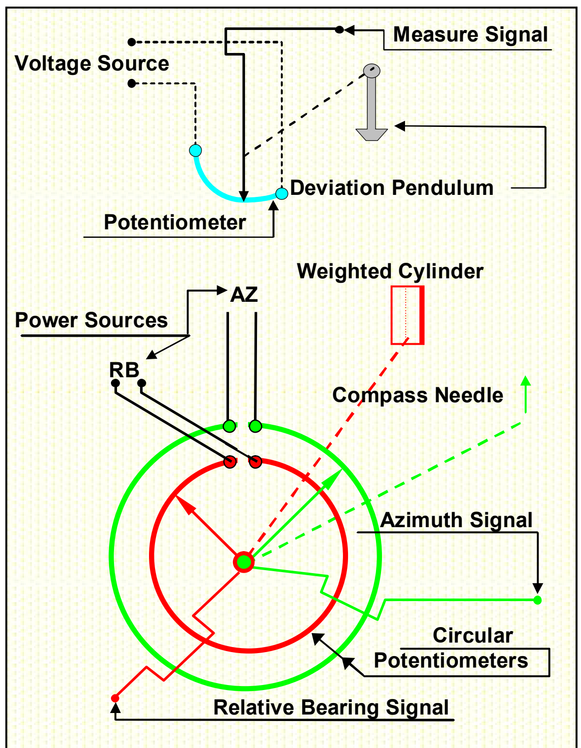


Figure 7-70 Illustration of inclinometer signal generation for the dipmeter.

angle between the # 1 electrode and the high or opposite side of the cylinder. In figure 7-69 A, you may notice the bearing of the number one electrode is constantly being measured also. Consequently, the direction and magnitude of tool tilt relative to north can be calculated. In figure 7-69 B, both borehole deviation and tilt within the borehole are illustrated to show that both may contribute to the attitude of the tool.

These inclinometer measurements are summarized in figure 7-70. Note that the signals from each device come from the movable contact of the potentiometer which slides along the resistor (represented by the thick line) tapping off voltages proportional to the position of the contact. The movable arm or contact is in turn mechanically coupled to the sensor (dashed lines in figure 7-70) making the measurement, i.e. the compass needle, the weighted cylinder or the pendulum. The sensors fix themselves on a specific parameter such as magnetic north, direction of tool tilt from the vertical and provide the torque to move the arm of the potentiometer, as required. The body of the potentiometer or that segment between the two power terminals is secured to the sonde body and moves, (rotates, changes tilt, etc.), as the sonde does. This causes the potentiometer arm to move along the body of the same, generating a change in signal. How this manifests itself on the film recording will be demonstrated shortly, I hope, through the ingenuity of grandpa.

DETERMINING FORMATION DIP

Now that we know the attitude of the tool, let's see how the formation dip can be determined. You may remember figure 7-66 where we illustrated the principle that three points determine a plane or flat surface. This plane can be established over a wide area such as between three wells from which correlations are made or within a single bore hole where three or more correlations are made from different points on the perimeter of the well.

To see how these points are established in a single well, consider figure 7-69 A once again. There, we show four micro-resistivity pads, which are mechanically mounted to the body of the tool by arms that allow the pads to move in and out as the borehole diameter changes. The pads describe a circle or ellipse, that is, those opposite each other remain the same distance from the sonde body at all times. Caliper measuring systems constantly monitor these distances. The arms also fix the current electrodes of the four pads in a plane perpendicular to the tool axis. In figure 7-69 A we have assumed the tool and borehole are vertical by designating that plane as being horizontal, i.e. the dashed blue ellipse. Now consider the resistivity change that will be seen by each electrode as it passes the sand stringer (yellow), which is dipping to the southwest. Looking closely at the four electrodes we note that # 1 electrode is slightly below the sand stringer while the #3 electrode is well above it and the # 2 electrode and # 4 electrodes are about even with it. Though the diagram may be wanting in portrayal of these facts, you will have

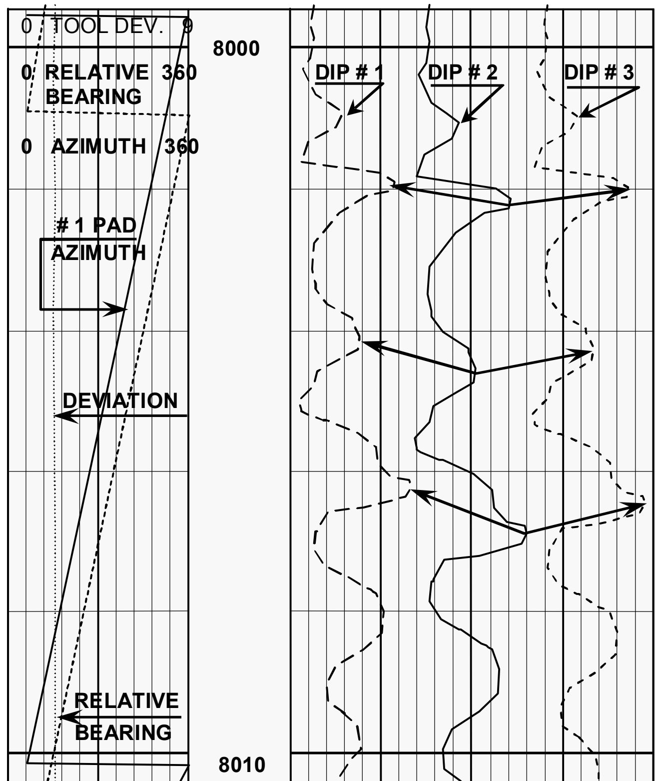


Figure 7-71 An illustration of dipmeter curves and inclinometer data for a 3 arm dipmeter taken from a short section of 60 inch film.

to take my word for it. This is necessary to give a dip to the southwest. When we correlate the resistivity curves from these four electrodes, establish the angular and vertical location of each electrode around the perimeter of the hole (its diameter is given by the calipers) and then correct for tool tilt with inclinometer data, we find the deepest point of the stringer to be on the southwest side of the borehole. The point at which the # 1 electrode passes the stringer is the shallowest of the four electrodes and is almost the same as the direction of magnetic north, being at a bearing of 30 degrees or so. The # 2 and 4 electrodes pass the stringer at or about the same time and the # 3 electrode passes the stringer last. A little later we will try to illustrate the recording of such information on film but will only show three curves, the number necessary to define a plane. Such simplification is indicative of my practicality or maybe laziness.

RECORDING AND COMPUTATIONS

Initially, dipmeter correlations and computations were made by manual means. This required both a 60-inch per 100-foot as well as a five inch per 100 foot of borehole as scales for the film. The field engineer used the latter to assure proper operation of the tool while the 60-inch was used in the dip computations. The large scale was required to provide the necessary resolution for measuring curve displacement.

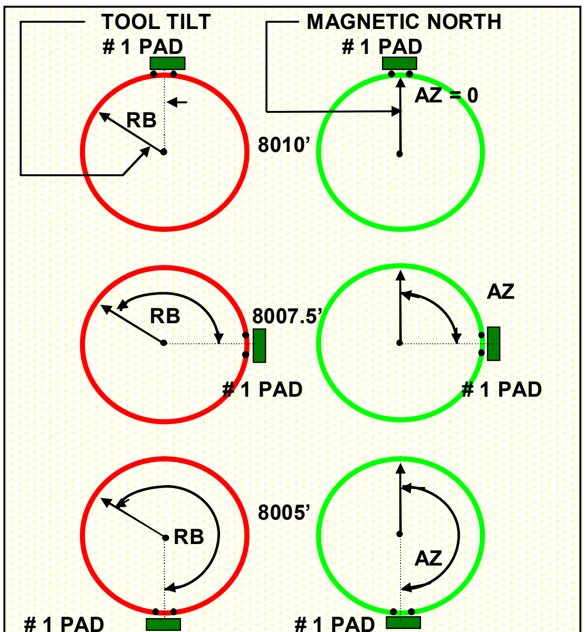


Figure 7-72 An illustration of azimuth and relative bearing signal generation during tool rotation in a borehole.

Consider, in an eight-inch borehole wherein a dip of 3 degrees would produce curve displacements of approximately 0.2 inches. That is, the same anomaly or feature on two different curves would only be a maximum of about 0.2 inches apart. Smaller dips, which occur frequently, obviously produced even less displacement. Consequently, one can easily see the need for large scale recordings.

CURVE QUALITY

The curve recorded from each electrode had to be of good quality to allow the precise correlations required. Also, very thin features or narrow anomalies were used for those correlations. This required a focused measuring device of either a conductivity or resistivity mode. The former became the norm because such data was used most frequently in low resistivities where conductivity resolution was superior. Unfortunately, borehole conditions often made it difficult to get continuous high quality dip curves. The most common problem was a so called floating curve which resulted when one of the three pads was making poor contact with the borehole wall and produced a rather featureless curve. Precise correlations could not be made and the needed dipmeter information was lost. A solution to this problem came along with the four-arm dipmeter, to be described in more detail a little later though I portrayed it in figure 7-69 A. Now, let's move on to the old manual computations.

MANUAL COMPUTATIONS

Once the data was gathered through correlation and was also neatly tabulated, the formation dip calculations were made. When you consider that tool attitude was constantly changing due to changing tilt and tool rotation, the required calculation could be laborious in mathematical terms. To simplify this calculation, a mechanical gadget was provided whereby the person doing the calculating could reproduce both tool tilt and the curve displacement measured by the three electrodes relative to true north in the office. That is, he made a simulation of the tool itself at that point in the hole where the calculation was being made. He could then read both the magnitude and direction of dip from the model.

Of course, the process was slow but worked fine when the number of dips necessary to calculate structural information was relatively few in number. In the sixties dip calculations began to be used for stratigraphic information which required high-density calculations or a dip about every two feet, in the zones of interest. Fortunately, the computer came along at that time and the data began to be recorded on magnetic tape as well. Dip calculations were then made from the tape via the computers in Schlumberger interpretation centers.

THE DIPMETER FILM RECORDING

Figure 7-71 illustrates a typical film record or log of an old style three arm dipmeter. I'll use it to explain the data available and how it was used. This illustration is meant to simulate a 60-inch per 100 feet record to illustrate the resistivity correlations. Note that only ten feet of section are shown. Normally we would have logged several thousand feet and ended up with several hundred feet of 60 inch film. We would have also recorded the log on a scale of five inches per hundred feet for the engineer to confirm the overall activity of the inclinometer.

Consider the resistivity or conductivity curves first. Remember, one is the reciprocal of the other. Later tools used conductivity because of improved resolution in low resistivities. I think I already said that somewhere earlier. Oh well. Note the # 2 curve appears to be the deepest with # 3 being next and # 1 the shallowest. This is analogous to what I portrayed in figure 7-69 for the four arm device. As dip direction changes so will the relative depth of these curves. Now, in terms of depth, we could use the # 1 pad as the reference and record # 2 as being + 0.2 feet deep with # 3 being + 0.1 feet deep at 8002 feet. At 8004' it would appear more like # 2 is 0.3 feet and # 3 is 0.1 feet. At 8004+ feet the readings change to 0.6' and 0.3' respectively. Consequently, we can say dip is increasing in that interval but not yet describe its exact direction. That will have to wait for the inclusion of inclinometer data.

Now, consider the inclinometer data recorded in track 1. Notice, the tool deviation is shown by the short dashed curve, the azimuth by the solid curve and the relative bearing by the long dashed curve. Whereas the deviation-curve is constant (1½ degrees) over the interval, the azimuth and relative bearing range from 0 to 360 degrees in that ten foot interval. This tells us two things. First the tool tilt is constant, a normal situation over long intervals of hole, and second the tool is spinning and made one complete revolution in that ten feet. Tool spinning is bad news for the dipmeter because computational accuracy is limited in such intervals. However, one rotation every hundred feet or so is rather normal and acceptable. They tell us such spinning results from torque build up in the cable but who cares as long as it is within acceptable limits.

Let's take a minute and translate the readings we see on the film to the sensor simulations of figure 7-70. We will do this pictorially in figure 7-72 for three stations or depths. In the top portion of the latter, we show the # 1 electrode in the direction of magnetic north or at a position just below 8010 ft. in figure 7-70. No azimuth signal is generated because the potentiometer arm is at zero voltage on the resistor. The relative bearing arm is however at an angle of about 55 degrees or so and an equivalent signal is measured. This shows up as a little over one division on the scale of 0 to 360 degrees for the relative bearing (RB) in figure 7-71. At 8007.5 feet the tool has rotated 90 degrees in a clockwise direction and thus the resistor of the potentiometers rotated with it. The arms remain fixed by the compass sensor and the relative bearing sensor. The azimuth arm now

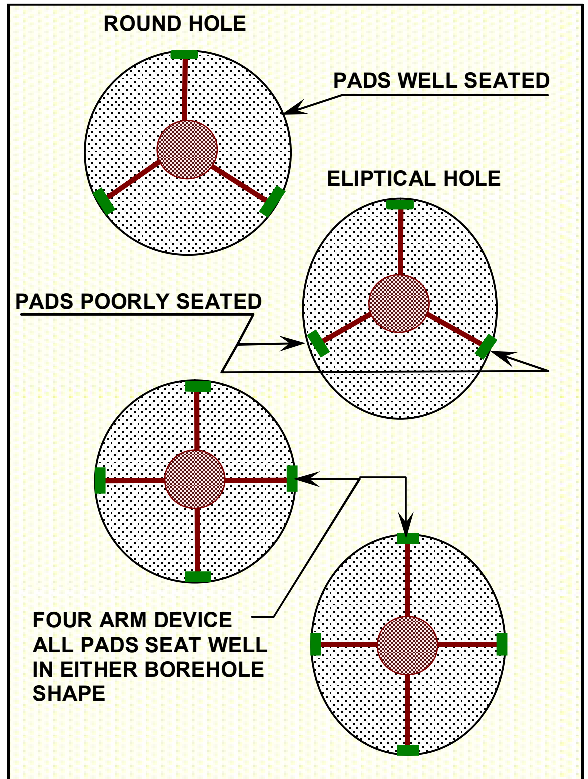


Figure 7-73 An illustration of comparative pad seating for three and four arm dipmeter tools in round and elliptical holes.

generates a signal equivalent to 90 degrees while the relative bearing generates one equivalent to 145 degrees. At 8005 feet the tool has rotated another 90 degrees or half way around. The azimuth signal now becomes one of 180 degrees and the relative bearing one of 235 degrees. Consequently, we can see the two signals parallel one another as the tool rotates while moving up hole.

Now, how do we determine the direction of tool tilt from all of this? Number one pad direction is easy but how about tool tilt. When we speak of tilt, we actually mean the direction the bottom of the tool deviates from the vertical. From figure 7-72 we see that direction is about 305 degrees from magnetic north and of course it is constant throughout the drawings. We know the relative bearing is zero when the # 1 electrode is in the same direction as the tool deviation because that measurement is referenced to # 1 pad. At 8001 feet the relative bearing has switched to zero and the azimuth of # 1 pad registers 305 degrees or there about which is the direction or the bearing of tool deviation. Of course, we can get the same answer any place on the log by reading the difference between the azimuth and relative bearing curves. Thus at 8006 feet the azimuth of # 1 is 140 degrees and the relative bearing azimuth is 195 degrees. To determine the bearing of tool deviation we simply subtract the RB from the AZ or 140 minus 195, which is a minus 55 degrees. To convert that to a positive number or bearing we add 360 degrees. This gives us 305 degrees or the same value as we determined for the azimuth of the # 1 electrode when it was in the same direction as tool deviation. Whew, what an exercise. I probably shouldn't have ever started that but I did and I finished it. Not bad for an old goat. As I consider the preceding gobbledy gook, I must admit that no one will probably have the interest or desire to wade through it. Oh well, that's life.

EVOLUTION OF THE DIPMETER

I'll take just a moment to run through the evolution of this complex tool during my tenure with Schlumberger. When I began in 1955, the old station dipmeter was being phased out, though still in existence. That device was only designed to determine structural dip . By experience, engineers learned that correlations from such a tool had to be made primarily in thick shales to obtain valid structural dip. They knew such dips were distorted near sand bodies. Thus, they would find several such thick shales in a well and log those sections or stations from which the name was derived. They began by recording three SP curves and later went to resistivity curves. Obviously, the SP would be of no value in thick shales, hence the change to resistivity records.

By 1955 or 56 the Continuous Teliclinometer Dipmeter had been introduced and was run by a specialist engineer. It was transported in a van and maintained by a special operator, which made for an expensive operation. Results were better but it was still used primarily for structural dip. The dipmeter computer simply avoided calculating dips near sand bodies. Experience was the key to determining accurate dips.

Around 1960 the Poticlinometer Dipmeter, a simpler, more reliable model, was introduced. It was a good device and was reliable and simple enough so as not to require a specialist engineer. Eventually, even the specialist operator was done away with and the local electronic technician maintained the tool. Though operationally, the Poticlinometer was a good tool, it had one major flaw. The three arms were linked together and made angles with one another of 120 degrees, i.e. the three points for our plane. Such linkage would not allow good seating of all pads in elliptical holes. You may remember that the drill holes tend to wash out or

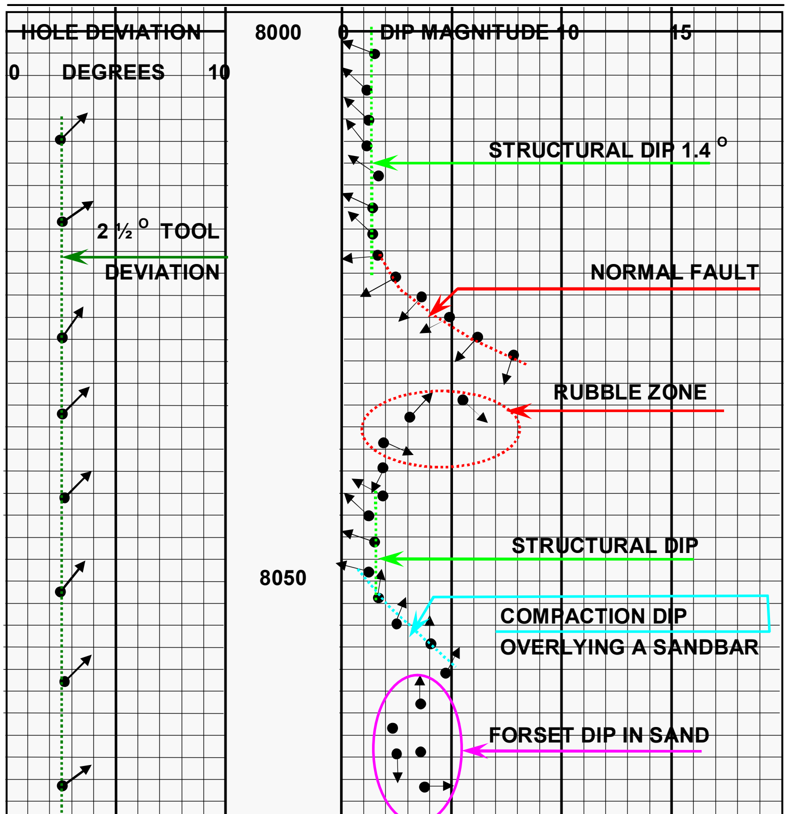


Figure 7-74 An illustration of one method of displaying the dipmeter data calculations for interpretive purposes.

slough in the shales particularly. This caused the loss of much dip information because one or more pads would float or be poorly seated. See figure 7-73. This particular problem was solved with the introduction of the four-arm dipmeter (also included in figure 7-73). Each set of two arms operated independently of one another and the four arms held the tool in the center of the hole. A caliper for each set of arms was recorded which gave more accurate bore hole size and shape information. With four resistivity curves, five correlations could be made for the same depth allowing cross checks of the correlation and hence dip computation. It provided quality control. Other improvements made this device decidedly superior to its predecessors. Dipmeter interpretation had begun to evolve prior to the four-arm tool and created a need for high-density dip computation. Along with the need for reliable pad seating, the need for resolving the dip of very thin stratigraphic layers within a bed and immediately around the same became apparent. Thus, many improvements were incorporated in this device to make it truly a more effective tool.

DIPMETER INTERPRETATION

I've spent a lot of time describing just how dipmeter data is gathered but that leaves one very important area remaining, i.e. that of interpretation of said data. All the data collected in the world will be of little use unless someone can interpret it and inform the people making decisions what it means. I'm no expert in this area, you can be sure, but I was close enough to the activity to gain a reasonable understanding of the process. The real experts involved spent all their time interpreting dipmeter logs, which became a field of endeavor in itself.

Figure 7-74 illustrates the way dipmeter data was displayed for interpretive purposes when I was involved with it. I hope I remember it well enough to correctly display it. I believe the general format is correct. However, the formation dip in tracks 2 and 3 were coded to signify the quality of correlation. This gave the interpreter an extra measure of confidence if all dips were of relatively high quality. Now let's get to the dip data sheet.

Track one is straight forward indicating the magnitude and direction of tool tilt. This would also be the borehole deviation direction if one neglected the tool tilt within the borehole. Even so, it gave a person a good idea of where the borehole was going. Tracks two and three contain the formation dip information, which is once again presented in both magnitude and direction. The dot represents the magnitude with the arrow indicating the direction. Thus, at 8010 feet the structural dip is 1.4 degrees at an azimuth of approximately 315 degrees or northwest. We find similar dips at about 8045 feet, which support the shallower ones. Generally speaking, the structural dip is given by lower magnitude dips, is consistent in direction and will be found well removed from a sand body, fault or other geologic phenomena, which might be able to distort it.

A zone from 8022 to 8030 feet shows an increasing magnitude of dip with depth. There are various reasons for such a pattern. However, if it were associated with missing geologic section it would probably be an indication of a normal fault. Such a fault might be intimated through correlation of resistivity logs with other wells in the area but the dipmeter indication could spot it almost to the foot. Dips immediately below the highest calculated dip of the pattern would be random, which results from

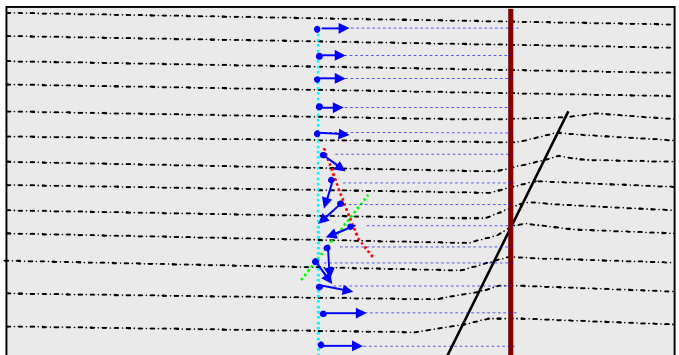


Figure 7-75 Formation drag along the face of a fault plane with its associated dip distortion, providing a means of fault identification.

rubble or broken sediments within the fault zone. Below that we might also find some higher dips with a decreasing pattern of magnitude. The patterns above and below the fault occur because of bedding plane distortion resulting from drag or friction between the two faces of the fault plane.

This is illustrated in figure 7-75. Notice structural dip, as depicted by the light blue dotted line, is consistent above and below the fault and of some low value consistent with the bedding planes. However, as the well approaches the fault from the top, the dip begins to increase and change direction due to the drag, which pulls the bedding planes in the direction of its movement. The effect increases with depth until the fault is crossed. At that point the dip will usually change abruptly to some other value even though still distorted by the drag on the lower fault plane surface. It may also become random in nature within the fault due to fragmented rock. With depth the dip magnitude drops off to that of structural dip and the direction will swing around to the direction of that controlling factor once again as shown.

I could draw similar patterns for various other geologic phenomena but I don't want to bore my posterity and besides, it's a lot of work for an old man. Let it suffice to say, some other changing dip patterns, I became aware of, were due to channels carved within a sediment by currents, fore-set beds, increasing dips due to differential compaction of sediments, unconformities, thrust faults and probably some I've forgotten. In any case, as I'm sure you can appreciate, it took a man with a good geologic background in the area in which he worked and with a visual imagination of what type of geologic phenomena would explain a given pattern of dip, to properly utilize the data provided by a good high-resolution dipmeter. I've illustrated two more patterns in figure 7-74. Both were just mentioned. Notice the increasing dip pattern at approximately 8054 feet and then some steeper random dips below. The increasing pattern of dip could result from differential compaction as previously mentioned and could be substantiated by comparing it to the resistivity log. Similarly the fore-set beds would be found within a sandstone or high-energy deposit with confirmation from other sources.

Well, that's enough on this particular subject. If I'm only a novice on this subject, how in the world could I hope to make experts out of my posterity? As smart as you all must be and as good as I am; I just don't believe it is possible. However, I do need to spend a couple of minutes describing the surface calibration and film we ran with the dipmeter tool. It was essential for us and the customer to validate the recorded data accuracy.

WELL SITE CALIBRATION

We'll begin with the dip curves. Basically, these were un-calibrated curves because they were used for correlation and not quantitative calculations. The engineer had to be sure they displayed normal activity so as to achieve a good correlation curve. He also had to verify that the # 1 pad went to the # 1 dip channel, the # 2 to # 2 and # 3 to # 3. That may seem a bit ridiculous but believe it or not, a sonde had been wired incorrectly in the past with the wrong pads feeding information to the three channels. Obviously, formation dips calculated from such a tool would be wrong. Thus, we had to verify the sonde wiring was proper. This was accomplished by turning the tool power on while it was hanging in the derrick and intermittently shorting each pad to mass or ground. This resulted in the tested curve dropping near zero in an intermittent fashion. Each pad was checked as shown in figure 7-76 which verified both proper wiring and response.

The inclinometer check came next. To verify proper directional measurement, the tool was tilted with its bottom nose pointing north as verified by a regular compass. The deviation curve would register the angle of deviation while the relative bearing and azimuth curves gave the direction of tool tilt. You probably remember that the relative bearing reading was subtracted from the azimuth to arrive at the direction of tool tilt. To be correct that difference had to be close to zero or a north bearing. The check was not quantitative in nature and was used only to verify the tool, in fact, pointed north and not south. Once again, it seems, the almost unbelievable occurred, i.e. a compass needle in a tool was reverse polarized and all readings were 180° in error. In 30 some years, I never saw such a thing but we religiously recorded

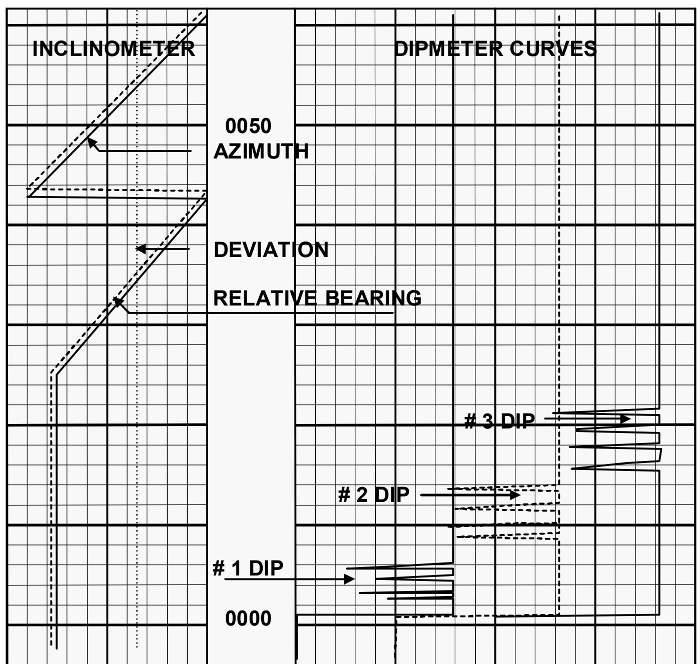


Figure 7-76 An illustration of a typical dipmeter test film for a three arm device demonstrating proper electrode channels and #1 pad north deviation.

north to verify all was well with the tool before actually running the log.

Actual quantitative calibration of the inclinometer was done in the hole prior to surveying via a calibration network for the scale involved. The scale for azimuth and relative bearing was always 0 to 360 degrees but the deviation scale depended upon the expected and/or noted deviation while the tool descended into the well. I mostly surveyed rather straight holes, i.e. not deviated intentionally, and used a scale of 0 to 10 degrees. Dip curves, as I remember, were adjusted for full-scale deflection, one track, to assure the same sensitivity for all three. Well, I believe I've exhausted the dipmeter and probably you, so let's go to a relative of the dipmeter.

THE DIRECTIONAL SURVEY

We talked a little about this subject back in chapter five but only mentioned this survey in passing. The directional survey was a very important survey in many parts of the country when small leases, 40 acres or so, were the norm. Wells may deviate from the vertical by accident or on purpose and bottom out in a nice reservoir on someone else's land. In such areas, it's not uncommon for the law to require such a survey to establish the exact location of bottom of the hole. In other cases it may be desirable simply to assure the geologist that TD is close to being directly below the surface casing. A well with considerable deviation in it can cause the oil operator to draw the wrong conclusions regarding structure or other geologic parameters affecting decisions.

HARDWARE INVOLVED

I began my career with Schlumberger in the Texas Gulf Coast where salt domes were prevalent and small leases abounded. We must have run directional surveys on half the wells we logged. The tool, which was in use at that time is illustrated in figure 7-77, the diagram I'll use to explain the principles involved. It was called the Photoclinometer Survey tool because, as you shall see, we actually took photos down hole of the system, which measured both direction and magnitude of tool tilt. The cartridge was nothing more than a camera, which could be controlled from the surface. It utilized 35 mm film, which was advanced by a motor driven ratchet system. Film exposure was controlled by the time the engineer applied power to a bulb within the cartridge. The camera was pre-focused on a glass dish with inscribed scales as well as a small steel ball, "BB", whose position was photographed relative to the scale. This is illustrated in figure 7-78. We'll use both figures together to better describe the operation.

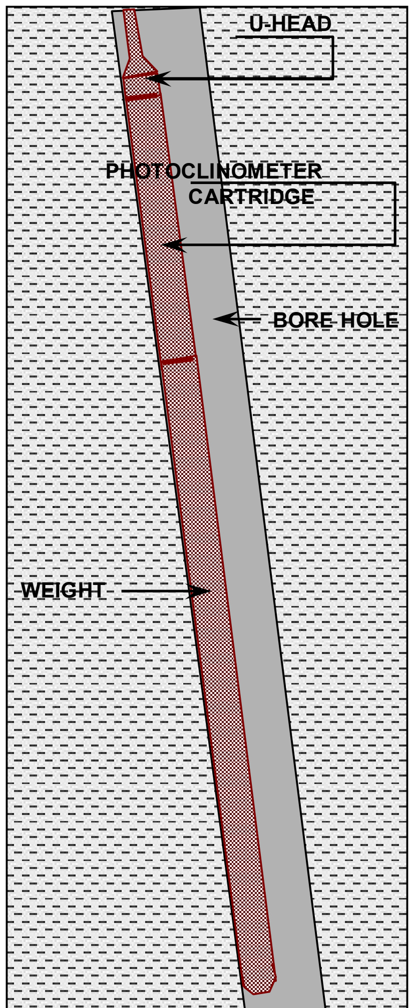


Figure 7-77 A Photo-clinometer measuring both the direction and magnitude of deviation in a borehole.

The weight was made of brass and was about ten feet long as I remember. Its purpose was two-fold, namely to provide weight for easier descent into the hole and to provide length to allow the device to measure the deviation over about a fifteen foot interval. This helped minimize exaggerated tool tilt due to caved out sections of the borehole, which, of course, were the norm.

The surface control panel contained variable voltage control to apply power to the motor and advance the film. It also had a forward and reverse switch for film direction, which, of course allowed the engineer to rewind his film. The switch, which applied power to the down-hole light bulb, (film exposure) was timed by the second hand of the engineer's wristwatch, of all things. Though we weren't selling photographs, the timing was still critical, at least within limits, to produce readable measurements.

Now, let's examine figure 7-78. It includes a vertical cross section (top section) as well as a plan view (bottom section) to illustrate the relative positions of light source, inscribed glass and camera as well as the reading for a specific hole deviation of N 15 degrees E or an azimuth of 15 degrees with a deviation magnitude of 4 degrees. It also shows the bowl shaped cross section of the inscribed glass. You may wonder about the red line marked vertical. Of course, I had to skew the vertical because the ball will obviously come to rest in the low point of the glass and a vertical will run through that point at 90 degrees to the glass surface. As you can see, it was either that or tilt the whole drawing to indicate the hole deviation. As is normal for me, I chose the easy way out.

RUNNING THE SURVEY

Before going in the hole with the tool, the engineer would place the proper inscribed glass in the tool (there were different scales of 10°, 25° and 50°). We discussed with the customer the probable maximum deviation we would see and make a decision based on Totco measurements. The glass chosen was the smallest possible so as to provide the best resolution. It would be oriented in the cartridge so that it registered north as verified by a standard compass. He would then load the camera and test it for proper film advancement before going in the hole.

The weight and cartridge were then hooked to the cable and lowered to the bottom. Depending on the vertical resolution desired, the engineer would then stop the tool at appropriate depths. It might be every 100 feet near TD and then every 500 to the surface casing. At each station the winch would be stopped long enough for the ball to stop moving on the glass and then the film would be exposed providing an image of the ball and inscribed lines of the glass. The depth of each shot was then recorded on a tally sheet for later use in product preparation.

Before moving, the film would be advanced to prepare for the next station. The engineer would call out the depth of the next shot and the winch man would move quickly to that depth and the procedure would be repeated. When complete, the engineer would rewind the film as the tool was brought out of the hole. It was then developed and examined for complete information. If all was okay, the operation was complete and our logging unit was released.

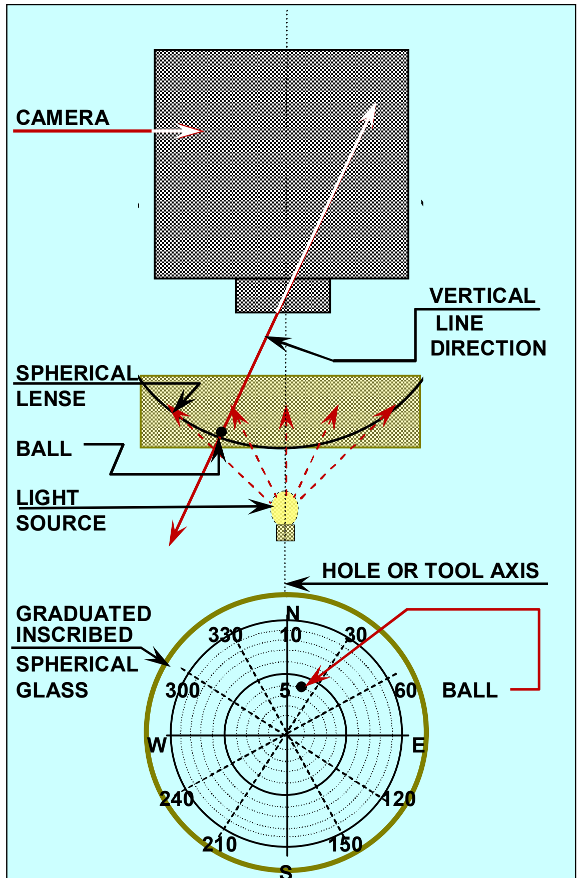


Figure 7-78 Illustration of the camera, light source and graduated spherical glass for the Photoclinometer tool.

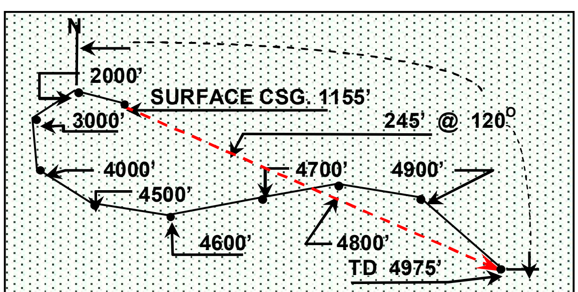


Figure 7-79 A typical plan view of deviation calculations from casing to TD.

COMPUTING THE SURVEY

Once back at the barn, the engineer would complete all paper work, which included the computation of the bottom-hole position of the well and then graph the results. Often we called the operator immediately to give him the location of TD because the rig would be waiting to see if any borehole correction was necessary before running pipe. With that done we could go home for some shuteye before coming back to the office to draft the results. A completed graph (plan view) of stations and bottom-hole position might look like the sketch of figure 7-79. It is rather typical for a well to deviate in an up dip direction but with other influences they may wander in almost any direction. What I have shown is typical of my plots some 45 years ago.

Although I didn't calculate the coordinates exactly for the bottom position, TD would lie about 245 feet E-SE of the surface casing shoe at an azimuth of 120 degrees. If you want something more accurate, I guess you'll have to do the math.

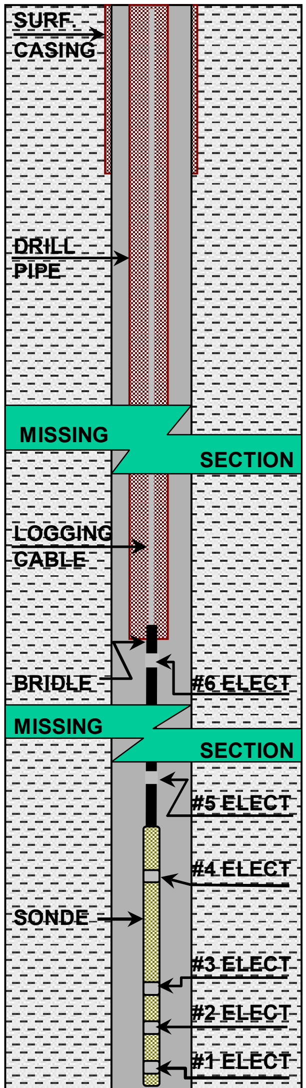


Figure 7-80 A survey illustration through drill pipe.

THE CONTINUOUS DIRECTIONAL SERVICE

As you might suspect, the old Photoclinometer, which I just described, gave way to technological progress along with everything else. In the sixties somewhere, the continuous directional became available and utilized the same principles as the dipmeter for tool attitude. Three measurements were made which were identical to the dipmeter but the sonde was removed and a weight similar to that of the Photoclinometer was connected in its place. This provided the necessary weight and length to keep the tool parallel to the borehole axis, an essential characteristic you may remember. Of course, the down-hole film was done away with and the engineer could monitor the measurement at all times as the tool descended to bottom. With this tool a continuous film, 5" was recorded back to surface casing. From that recording, the engineer took the data necessary to compute a product for the customer similar to that of the Photoclinometer as shown in figure 7-79.

Some of you may have realized that with the sonde missing, a # 1 electrode no longer existed. So, what did the azimuth curve read? Well, it read or indicated the direction of tool tilt. Consequently, the tool was tilted in the direction of magnetic north as established with a standard compass. A record of such was included with the tool's calibration. It then became a part of the permanent record as evidence the tool was working properly if questions were ever raised regarding the position of the bottom of the hole.

TOOLS FOR SPECIAL SITUATIONS

To my knowledge, I believe I have covered about all the different types of tools Schlumberger offered to the oil industry for measurements in open or uncased holes. There were, however, some special size tools as well as tools with extra high temperature ratings for special conditions. They operated on the same principles as those already discussed and need no explanation regarding theory. I will address the need for them, however, as well as how their special characteristics were achieved to broaden your view of conditions we experienced in the oil patch. Schlumberger was the leading provider of surveying services and was called upon to meet any and all conditions the paying customer might encounter.

SPECIAL TOOL SIZES

Back in chapter five we talked a little about wells that were intentionally deviated at angles up to nearly horizontal. Maybe it didn't strike you as a problem at the time but one might wonder how do you lower a tool on a cable to bottom when the hole is nearly horizontal? One might also wonder what an oil operator did when hole conditions were unusually bad for any of several reasons. How could a log be obtained under such borehole conditions? Surely information would be just as important in those wells as in others. Let's consider bad-hole conditions first, which means drill holes that have swelling clays around them, crooked holes and holes that simply have a lot of debris falling into them all of which can prevent a logging tool from descending in the well to secure the desired information.

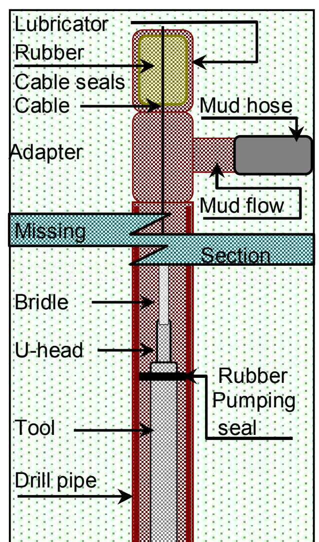


Figure 7-81 The tool, lubricator & drill pipe as seen in pump down operations.

THROUGH DRILL PIPE LOGS

The first log developed for severe borehole conditions was an electric log. Because of its simplicity and ruggedness, the ES log remained a viable tool even up to my retirement. It provided a good log for correlation purposes but, as you saw earlier, left much to be desired as far as making quantitative calculations from the derived data. Even so, correlation was the most critical need of the operator and Schlumberger locations had that service available. To see how it worked, see figure 7-80.

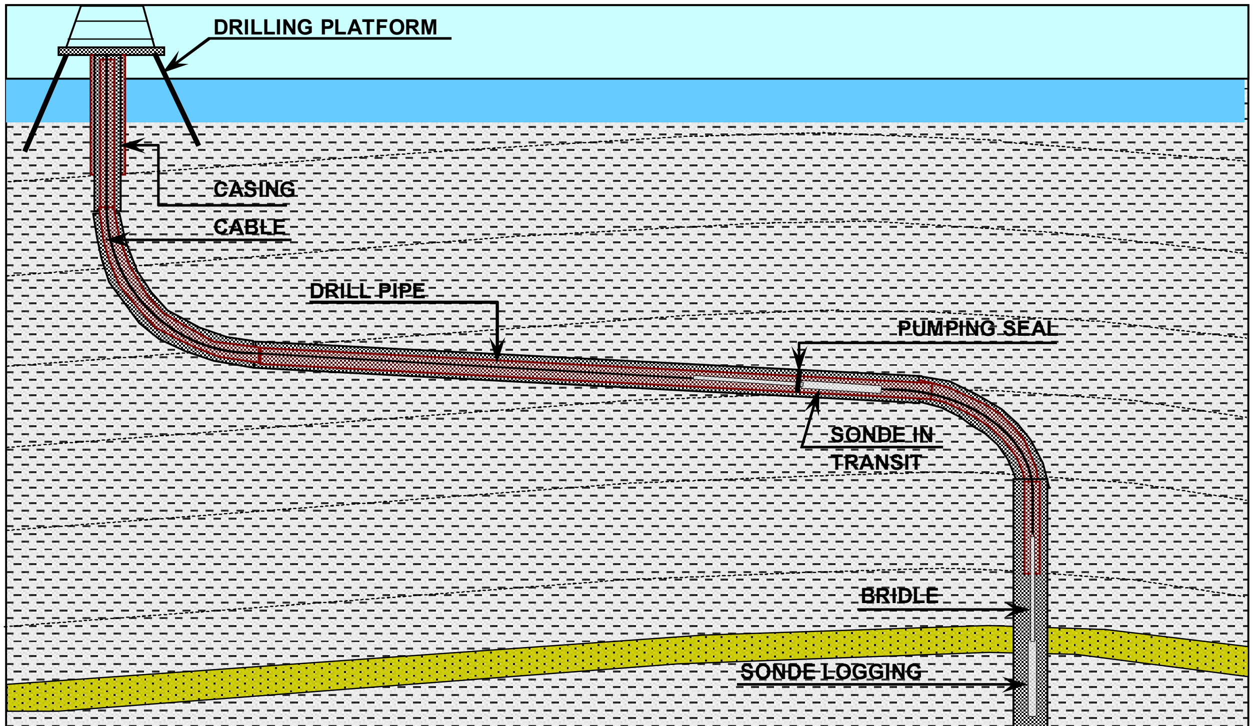


Figure 7-82 A simplified illustration of a pump down logging operation on an offshore platform.

Usually, the section of bad hole was limited to a given horizon or depth within the well. One might log down to that point but no further. In such a case, the operator might trip the hole several times in an attempt to get regular tools to bottom and thus obtain the best possible information. If unsuccessful, the decision might be made to log through the drill pipe. The drill pipe was run in through the bad section borehole to act as casing.

Schlumberger would then be rigged up and the ES sonde lowered through the drill pipe with an ID, which was typically a little over two inches. The drill stem sonde, as it was called, was 1 11/16 inches in diameter. Once out the bottom of the pipe (no bit was used) a conventional electric log could be run. Notice, the through drill pipe sonde had the same electrodes as a conventional tool and provided the same information with slightly more borehole effect. The latter was unimportant for correlation. With conventional drilling the above procedure usually provided the necessary logs, at least in those portions, which were open hole. If the section behind drill pipe couldn't be logged, a gamma ray neutron log might be run through that particular section to provide continuity between the sections of hole below and above the bad section. It would at least identify sands present. That device was also 1 11/16 inches in diameter as you might expect.

Highly deviated wells provided a little different problem and, of course, were commonly encountered off shore where 12 to 24 wells or even more were started from a small area on the platform and purposely deviated in various directions to properly drain the formation. With the sonde down the drill pipe as far as it will go by itself, the mud pumps are started and the mud pressure on the pumping seal around the tool forces the sonde down the drill pipe through the horizontal section while the cable is being spooled off (see figure 7-81). Once the sonde exits the pipe in the steeper section of hole, the tool drops by itself to bottom (See figure 7-82). The section of hole with a high angle may vary up to 80+ degrees from the vertical. The section of borehole shown as being vertical may, in reality, be deviated significantly as well.

The log is then run up to the drill pipe. The operator may want to run the log through as much hole as possible. If so, the tool is brought out of the hole, the pipe is raised maybe a stand or two and the tool is then run back in to log the additional hole now exposed. As I understand it, the remaining hole is sometimes logged in 90-foot sections. That is, each time a stand of drill pipe is set-aside in the derrick, the log is run, or at least is attempted, over the additional 90 feet of hole now exposed. Thus, the log is accomplished in pieces and spliced together which doesn't provide the best product and the process is time consuming as well.

OTHER TYPES OF SERVICES

Though the ES did its job well, better measurements were desired and particularly so off shore where so many wells were highly deviated. This need led to the development of a 2 5/8 inch induction tool. The bigger tool could only be accommodated with 5½-inch drill pipe but still found a good market. I believe the 2 5/8" dimension was determined primarily by the sonde because the electronics weren't that much different from the gamma ray neutron tool. In any case, a 1 11/16 variety of the induction was never developed.

A 1 11/16" sonic tool was developed in the same time frame as the induction if my memory serves me correctly. That would have been about 1970. The sonic tool was only a two-receiver device and consequently wasn't compensated to eliminate borehole effect. Even so, it was valuable when needed. Of course, it could also be used as a CBL or cement bond tool, which we will discuss at length in chapter 8. Later, a 1 11/16 mono-cable CBL tool, designed strictly for cased hole, was also developed.

In summary, Schlumberger had available for open-hole work a 1 11/16 ES tool, a 1 11/16 GRN (gamma ray neutron), a 1 11/16 sonic device as well as a 2 5/8" induction tool and, I believe a 2 5/8" GRN. If there was anything else, this 75-year old brain can't recall it but I guess I should be thankful for whatever measure of recall it does have.

HIGH TEMPERATURES

Temperature increases with the depth of a borehole. On the average, one can take a surface temperature of 80 degrees and add 1 degree per 100 feet of depth to arrive at the bottom hole temperature. Thus a 10,000' hole would typically be 80^o + $100(1^o)$ or 180^o. Of course, the gradient or temperature increase per 100' varies considerably with geography. The Gulf Coast, for instance has a higher gradient than the general Rocky Mountain area and consequently a 10,000-foot well in that locale will be hotter than most places in the Rockies. However, there are localized areas in the Rockies (between Casper and Rock Springs, for instance), which have more of a Gulf Coast gradient. Gradients can also change with depth. Thus temperature might increase 1 degree per 100' from the surface to 10,000' and then start rising at a rate of 1.2 - 1.3 degrees per 100 feet.

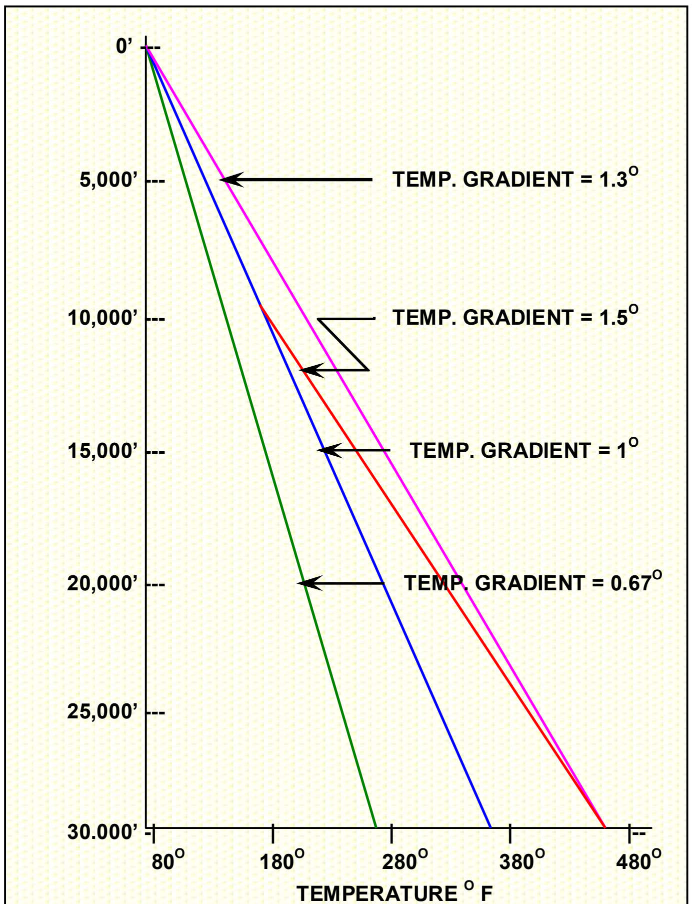


Figure 7-83 Earth's typical temperature gradients.

The concept of temperature gradient in the earth's crust is illustrated by figure 7-83. The blue line illustrates an average gradient of 1^o per

100 feet. Notice that at 10,000 feet the temperature would be 180° as I mentioned earlier. The green line describes an unusually low gradient of 0.67° per 100 feet but such cool places do exist. Notice that such a gradient would produce a bottom hole temperature of about 150° whereas the magenta colored line describing a gradient of 1.33 would produce a bottom hole temperature of roughly 210°. Now, let me make one last comment in this area. Notice the red gradient beginning at 10,000 feet, which is described as being 1.5° per 100'. This type of thing does exist in certain geographical areas. Why, I don't believe we really know but it is surmised that high gradients are associated with deep-seated magma intrusions or melted rock moving up through faults, etc.

Because of the gradient's variable nature, Schlumberger always measured the bottom-hole temperature. A special thermometer registered the maximum temperature encountered at the bottom of the well. The average temperature gradient could then be determined for a given depth and thus a probable specific temperature at that depth. This approach didn't account for changes in gradient within a well but such changes usually occurred on deeper wells and were defined as multiple logging runs were made during the drilling operation.

SPECIAL HIGH TEMPERATURE TOOLS

In areas where temperature gradients were unusually high, deep wells frequently produced temperatures in excess of 350°. Our standard tools were designed to function up to 300 or 350 degrees Fahrenheit. Even then, they had to be heat tested before going into such a well to be sure they were up to snuff. We didn't take their reliability for granted. The need for tools to operate in the range of 300 to 500 degrees was met with special sets of tools termed hostile environment tools. They were rated to 500° F and were kept at strategic locations around the country and/or world. The types of services available were limited because of demand as well as design, production and maintenance costs. As I remember they included the GRN, an IES and maybe a sonic device along with a regular ES survey.

Anyway, this was accomplished by placing all heat sensitive components inside a Dewar flask to slow heat build-up within. Figure 7-84 illustrates the principle of such a design. The flask was much like a coffee thermos, which had a very low thermal conductivity and maintained the temperature within for several hours. As you can see, the electronic chassis with its heat sensitive components was placed inside such a flask and the connections to out-put circuits were run through a thermos plug (rubber), which also had a low thermal conductivity. The result was an environment, which was protected from the ambient temperature of the well bore for a significant time. When technicians worked on the tool; the head was removed first, the flask was taken out of the housing and the electronic cartridge pulled from the flask. Once repair was completed, the system was reassembled and the electronics could then operate in a 500° environment for 3 or 4 hours once again.

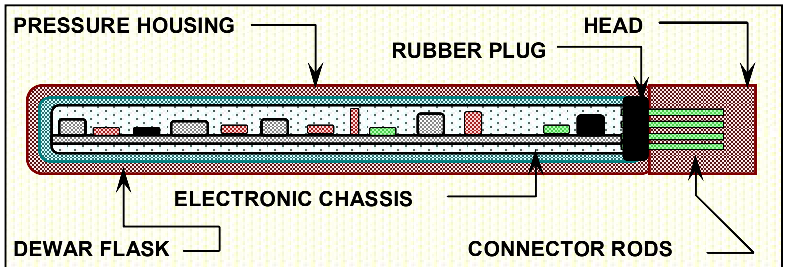


Figure 7-84 A drawing depicting a Dewar flask being used to protect electronic components from high temperatures.

MEASUREMENTS WHILE DRILLING

In chapter five we made reference to "Measurements while drilling" regarding the position of the bit. When I left the business, Schlumberger was already into this particular field but for a different reason. The need to run short resistivity logs with the bit in the hole for geologic correlations had become apparent in offshore locations where rig time was costly and the need for several correlation logs before total depth was reached was the rule. Schlumberger had entered that particular race with gusto.

As mentioned previously, I believe, the technical nature of this particular chapter may make it of little interest to most of my posterity. However, if one or more of them are inclined to read and even understand the foregoing, then my effort will have been worth it. As most readers will surmise, such material was the love of my life while in the business world. If I had a forte, it surely lies in the technical realm. However, my interest lies more in applying technical and scientific principles to develop a device for the benefit of mankind than in tool design.