CHAPTER EIGHT

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SCHLUMBERGER CASED HOLE SERVICES

INTRODUCTION

Back in chapter five, I referred to "completion services" and described to a limited extent the completion of an oil or gas well. In this chapter I intend to describe those completion services offered by Schlumberger to the industry in some detail, much like the open hole services described in chapter seven of this monumental work. So, my little chilluns, hold on to your hats and get ready for the cased hole world or that world of the well bore once it has been lined with stolen, oops I mean steal, or is it steel casing. I have a hard time remembering. You see, sometimes I can't distinguish between the irony of my thoughts and the iron I am trying to describe. However, with my iron will I am bound to iron such problems out, don't you think? If not, you figure it out. After all, it's part of the grandpa puzzle, which resulted, you may remember, from sniffing too much aromatic octane for too many years.

You see, once a potentially productive horizon has been located in mother earth's nether regions via open hole geophysical means, it's a totally different story in describing how such liquid gold is brought to the surface in the quantities said horizon is capable of producing. Obviously, the operator wants his return on his investment as quickly as possible while draining every last drop of that liquid tender said well is capable of producing. Consequently, we will examine the various pitfalls involved in that operation as well as the services available to identify and control the same.

You see, sometimes I can't distinguish between the irony of my thoughts and the iron I am trying to describe. However, with my iron will I am bound to iron such problems out, don't you think?

In chapters five and seven we talked a little about the need for properly cemented casing as well as the impact of formation damage on the ability of a well to produce efficiently. We also mentioned both cased-hole and through-tubing completions in general with their associated advantages. Still another area not mentioned there is that of older wells drilled and completed before the advent of modern geophysical measurements. In such cases unrecognized pay zones often lie behind the casing and their identification through casing is essential to the operator who is trying to squeeze the last farthing from his investment. As mentioned earlier, I will describe in some detail those services offered to the industry by Schlumberger to help the operator achieve his goal with particular emphasis on those with which I had experience to some degree. You need not fear, however, because it should be no more boring than was that which you, the stalwart, waded through in chapter seven. Also, it ought to make my experiences, yet to come in later chapters, somewhat more understandable.

EVALUATING THE CASED HOLE ENVIRONMENT

As described in chapter five, even newly run casing may be less than adequately cemented in the bore hole to provide a secure leak proof avenue for the hydrocarbon emigrating from the bowels of old mother earth to some surface tank. Consider then, just what kind of problems might be associated with casing lining an older well drilled twenty or more years ago. Cement, once thought adequate, may have broken down. Casing, once pressure tight, may have developed holes through corrosion. Formation horizons once thought water productive, may, in actuality, produce hydrocarbon if properly completed. Thus, the industry would like to be able to not only determine the mechanical reliability of the casing and cement but also take a second look at the formations behind the pipe with modern techniques to minimize expensive shoot and test operations. Such operations, though useful, are the last resort because of the associated high cost. We'll begin by examining methods of determining the cement job quality. From there we'll move on to the casing itself and then to the formations, which lie behind that steel sleeve. Let's take a minute, however, to see why production strings are cemented in a particular manner.

CEMENT TOPS

One might think that establishing the depth of the cement top should be no problem. Why not just pump the annulus (void space between pipe and surrounding rock) full to the top and get it over with. Well, that's a thought but, unfortunately, one fraught with problems. First of all, it's a waste of cement and money. Consider figure 8-1 to understand this particular cost more clearly. In the sand-shale sequence pictured, only one horizon is oil bearing, which is near the bottom of the well with a single water sand lying below it. Two considerations are in order, namely to satisfy any legal requirements and to isolate the hydrocarbon zone from any potable water producing zones.

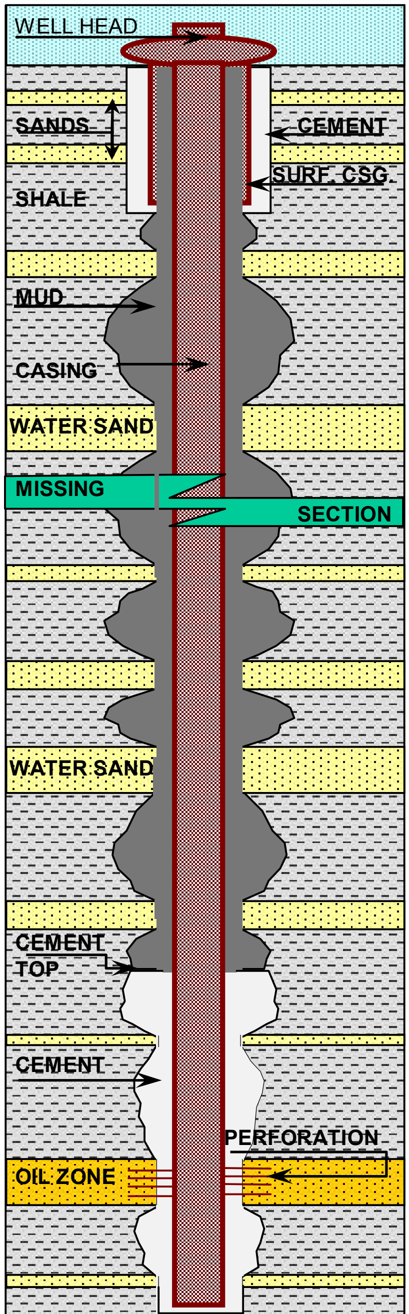

Figure 8-1 Illustration of cemented casings in typical surrounding formations.

The surface casing, in most cases, satisfies the first condition. Most states require a certain amount of surface casing to be run which is sufficient to protect any fresh water sands lying near the surface. Obviously, they can't afford to have drinking water horizons contaminated with salt water or hydrocarbon from deeper zones. Thus, sufficient surface casing is run to protect them and cemented all the way back to the surface, a matter of a few hundred feet. The complete cement sheath around the surface casing provides both isolation of potable water and a means of completely closing the well in, should that be necessary. Thus, it helps provide the safety factor necessary to assure well control.

The production string is a horse of a different color, however, because the main interest involved is to protect the hydrocarbon zone. Cementing all the way back to the surface produces no tangible benefits and simply costs the operator extra money. Besides, once the well is abandon, he may want to recover as much casing as possible for other uses. If un-cemented, it can be cut just above the cement top retrieved with an appropriate rig.

Consider the cementing costs on a 10,000-foot well. For the example we will make a few assumptions to give you an idea of the cementing costs involved. Assume total depth is 10,000 feet, the oil zone is at 9950' and the operator decides that bringing the cement up to 7000' will provide sufficient protection. Also assume he has run 7" casing in a 9 7/8" hole. As you can see, in the shale zones the hole tends to enlarge. Thus a caliper log is run prior to setting casing to obtain an average borehole size. Assume that figure is 12" over the complete hole. The cement must then fill an annulus averaging 2 ½" in thickness around the pipe. The amount of cement required per foot of hole can be determined by subtracting the pipe volume from the borehole volume, or;

1) Vol./Ft. = Aver. H. V. - C. V.

The volume of a cylinder is described by the equation;

2) $V_c = \frac{1}{4} \pi D^2 H$

Where: D = diameter of Cylinder.

H = height of Cylinder

The borehole volume per foot is then;

3) $V_h = 1/4(3.14)(1)^2(1) = 0.785\ Ft^3$

The casing volume per foot is;

4) $V_c = 1/4(3.14)(7/12)^2(1)$

$V_c = 0.268\ Ft^3$

The annulus volume per foot of hole is then,

5) $V_A = 0.785\text{-}0 - 0.268.$

$V_A = 0.517\ Ft^3$

Now I don't have any tables available to me like I used in the early days to determine the cubic feet of hole filled per sack of cement but let's assume it's 3 Ft^3, which is reasonable. That means each sack of cement will fill the hole-casing annulus about 6 feet. If the operator brings the cement top to 7000 feet, he must fill an annulus 3000' high which then takes 500 sacks of cement. If he were to bring the cement to the surface the annulus would be 10,000 feet and would require about 1667 sacks of cement. The difference in cement cost alone would be something in the order of \$2500 to \$3600. Obviously, I don't remember the cost of cement either but \$2 to \$3 per sack seems reasonable. That's a pretty good chunk of change and doesn't include the extra pumping costs as well as the technical problems associated with cementing it to the surface. It would seem obvious that any reasonable businessman would only bring the cement to the minimum level required because of cost alone. When you add in the possibility of recovering 7000 feet of casing, the potential saving is considerably more.

What if the calculations are wrong or some unforeseen problem occurs which alters the depth of the cement top? Is it desirable to document the depth of the top and take any necessary action? Yes, yes and yes. Oilmen like to know what they are doing and minimize the risk of a faulty operation.

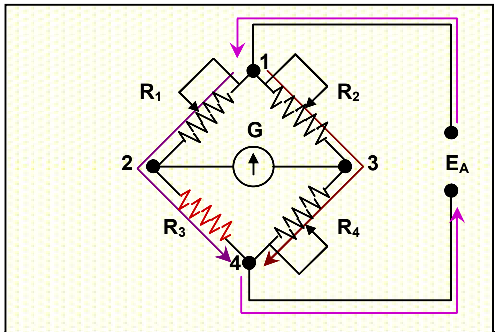

Figure 8-2 An illustration of a Wheatstone Bridge as used in the DWT.

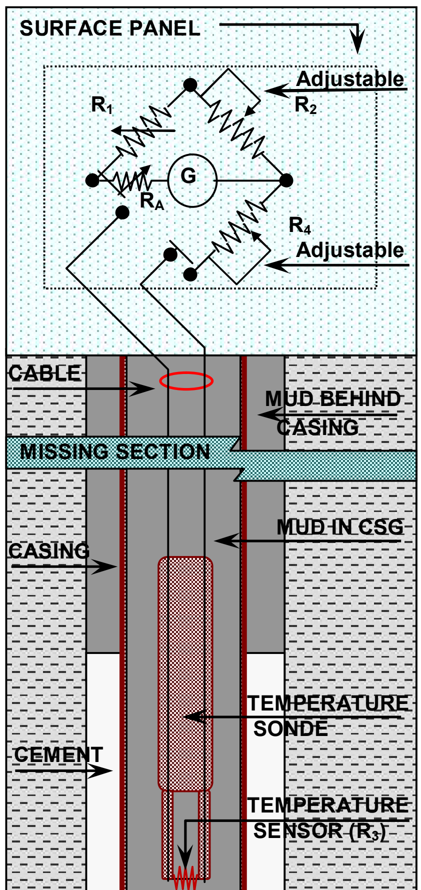

Figure 8-3 Illustration of the principle elements of the DWT (Deep Well thermometer)

So, let's get on with the first device used, to my knowledge, to validate a cement top.

THE TEMPERATURE LOG

The DWT (Deep Well Thermometer) was the first device available to the industry to determine the depth of the cement top. It could provide that information quite reliably but was of no value in establishing the actual quality of the cement below that point. It took the advent of the CBL (Cement Bond Log), which appeared in the 1960s and will be described later. Consequently, in the fifties an operator simply assured himself the top was where he wanted it and then went about solving any completion problems. Applying a block squeeze above and below a potential producing zone was rather common practice, as pointed out in chapter 5.

TOOL MECHANICS

Let's begin by describing the tool and then we will move on to a recording of temperature versus depth. The tool electronics, if one can call them that, consisted of a "Wheatstone Bridge" and a stable power supply in combination with the galvanometer of the recorder. Let me begin by describing a "Wheatstone Bridge" as best I can from memory. Those of you, who are familiar with them, please have a little mercy on me because I'm reaching back at least 40 years since I concerned myself with such things. Anyway, here I go with very little wisdom but considerable bravado.

Let's begin with the bridge as illustrated in figure 8-2. The bridge, devised by a man named Wheatstone, was to be used to accurately determine the value of an unknown resistance. In such a case, the values of R_1, R_2 and R_4 are known while R_3 is to be determined. When the bridge is balanced, there is no current flow through the galvanometer, G and the voltage at point 2 equals that at point 3. It can be shown that when this condition exists, the ratio of the resistors $R_1/R_3 = R_2/R_4$. Consequently, the value of R_3, the unknown can be calculated by the equation;

6) $R_3 = (R_1)(R_4)/R_2$.

This value can be established with the same accuracy as the values of the other three resistors, which are precision or very accurate resistors. If the bridge is balanced, equation 6

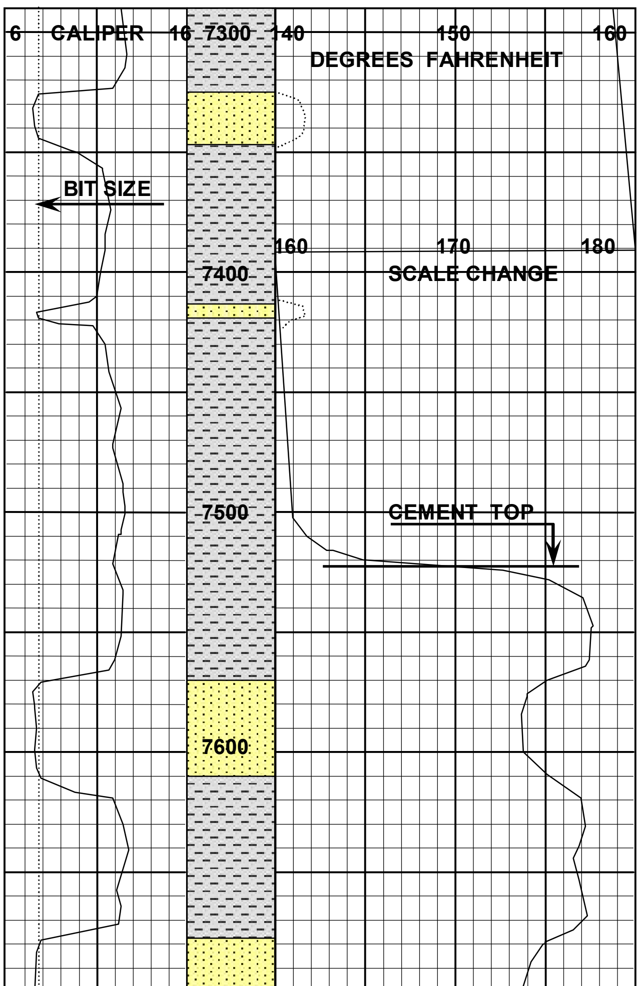

Figure 8-4 An illustration of a temperature log indicating a cement top located at 7522 feet. A temperature scale change occurs at 7390 feet.

always applies. Consequently, if we make R_2 and R_4 adjustable, we can then use them to balance the bridge no matter what the value of R_3. Neat, isn't it? Well, you may not think it's so neat but then you don't have that deep-seated need to balance things in life like I do. I'm not sure if that need made me take up engineering or if being an engineer developed that need in me during those frustrating field years where I learned to fit things together.

APPLYING THE WHEAT-STONE BRIDGE TO THE DWT

When this circuit is applied to the DWT, the same principles apply. However, the resistors are calibrated in degrees Fahrenheit or Centigrade. Consequently, the balanced galvanometer trace represents a particular temperature as determined by the settings of R_2 and R_4. As the temperature increases, the bridge loses its balance, kinda like grandpa, and the galvanometer trace deflects across the film, which is scaled in degrees per track. We'll see that a little later. To understand this principle a little more clearly, consider figure 8-3. Notice that R_3, the temperature sensor is located in the sonde down hole while the rest of the bridge is located at the surface in the panel. The resistance of the sensor increases with temperature as the tool moves down the well bore which produces the unbalance and causes the galvanometer to deflect. Assuming the galvanometer has been calibrated to register 10 degrees per track it will span two tracks when the temperature rises 20 degrees. At that point the engineer would adjust R_2 and/or R_4 to bring it back to the left hand side of track 2 on the recorder and the film scale will jump 20 degrees. See figure 8-4.

THE TEMPERATURE LOG

The scale is shifted by 20 degrees at 7390 feet. Above that point the temperature has been gradually increasing with depth according to the temperature gradient of the area, which was discussed in chapter 7. Notice it appears to increase about 1 degree per 100 feet between 7300 and 7500. If you could look further up hole, you would find that gradient continuing to the surface. At that point the mud, whose temperature we are measuring inside the casing, would be about 80 degrees. Thus the temperature at 7500 feet has increased 80 degrees. We can calculate a gradient as being;

Grad = 80/75 = 1.07 ^{o}/ft

The character of the curve changes below 7500. First it makes a dramatic increase of 16.5 degrees in only 30 feet. Then the temperature varies some 4 or 5 degrees in the next 200 feet or so for no obvious reason.

The engineer has labeled the sudden increase in temperature on the log as being the top of the cement. Let's investigate his reasoning. Cement gives off heat when it sets up or the process of cement changing from a liquid to a solid is exothermic. Thus, the cement, which encircles the casing, adds heat to the mud within it, over and above that from the formation. The change is sudden because the material around the casing suddenly changes from mud above the top to cement below that level.

I feel sure that your next question will be, "But why the variation in temperature below the top?" To help explain that question, I have added the caliper log of the open or uncased hole. It normally wouldn't appear on the temperature log. Notice that the shale zones are enlarged as discussed in chapter five. That means there is more cement and hence more heat around the pipe in those zones. Thus, we see higher temperatures opposite the shale and cooler temperatures opposite the sand zones. Logical, isn't it? Such information is odd and interesting but of no particular value. The operator is only interested in the depth of the cement top. He asks, "Is it higher than the zone he wants to complete the well in"?

As long as we are talking about the odd and interesting things associated with the temperature log, let me describe the galvanometer trace above the cement top in a little more detail. The trace is seldom a straight line as depicted. It also varies somewhat with the borehole diameter but such variations are not as pronounced as below the cement top. The variations are also reversed relative to those below the top. As an after-thought, I have sketched them in opposite the indicated sands as dotted lines in figure 8-4. The reason for this is the source of heating for the mud inside the casing whose temperature is measured by the DWT. Below the top the extra cement in the regions of enlarged bore hole raises the temperature of the mud inside the casing relative to that opposite the sands where the borehole was still in gauge. Above the top the only source of heat is old mother earth. Consequently, the extra mud behind the casing in enlarged sections of borehole heats more slowly than the smaller volumes opposite the sands and, as a result, the latter appear warmer than the shales.

Let's move on to tool calibration and then I'll utilize figure 8-5 to discuss the changing temperature of the mud column. Hopefully, I can clear up what I assume to be the murkiness in your befuddled minds. Then again, maybe the murkiness lies in my own befuddled mind. Who knows or cares, certainly not you?

DWT CALIBRATION

The DWT could measure temperatures quite accurately. Each time we replaced the sensor resistor, we checked the readings in ice water and boiling water while tweaking R_1. That

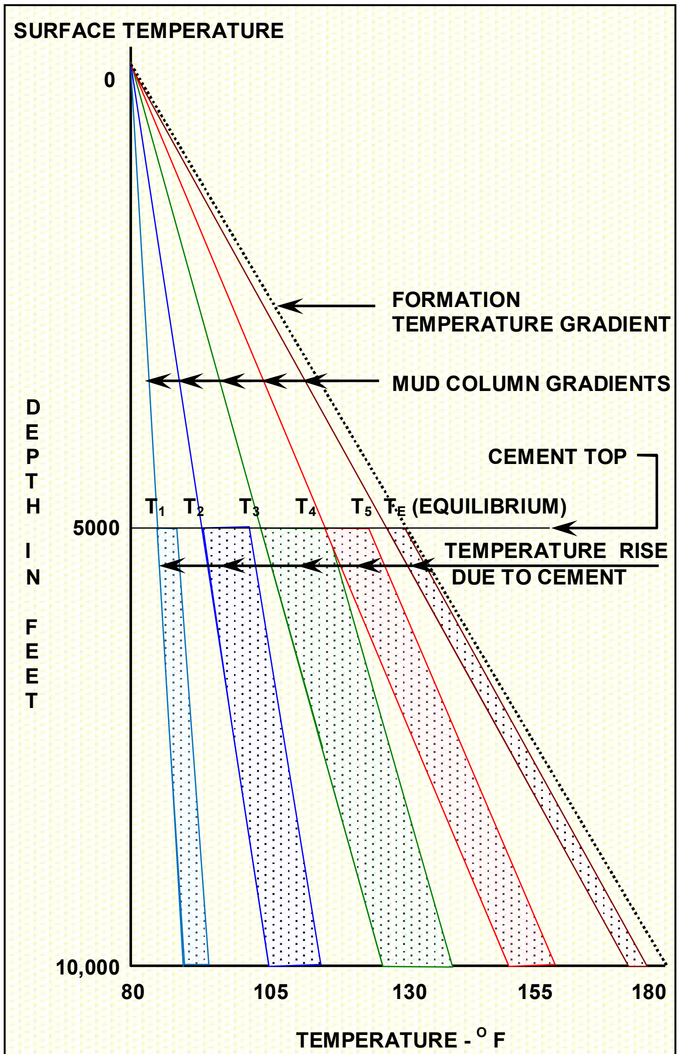

Figure 8-5 An illustration of the nature of changing mud column temperature with time.

allowed us to set the galvanometer reading exactly at 32° F. Of course, you know ice water stabilizes at that temperature when both ice and water are present in the container. Similarly boiling water stabilizes at 212° F at sea level. In the Texas gulf coast we were at sea level and had to make no adjustments for atmospheric pressure. In the Rockies, we adjusted that temperature down a little. The difference between the two (at sea level) is 180° F and the variable resistor R_A next to the galvanometer was adjusted to accomplish that, as the balance point was shifted in 20-degree steps with R_2 and/or R_4 between those two points. At the well site, we then used R_A to calibrate with.

Actually, an exact temperature was generally unimportant to the customer because the abrupt

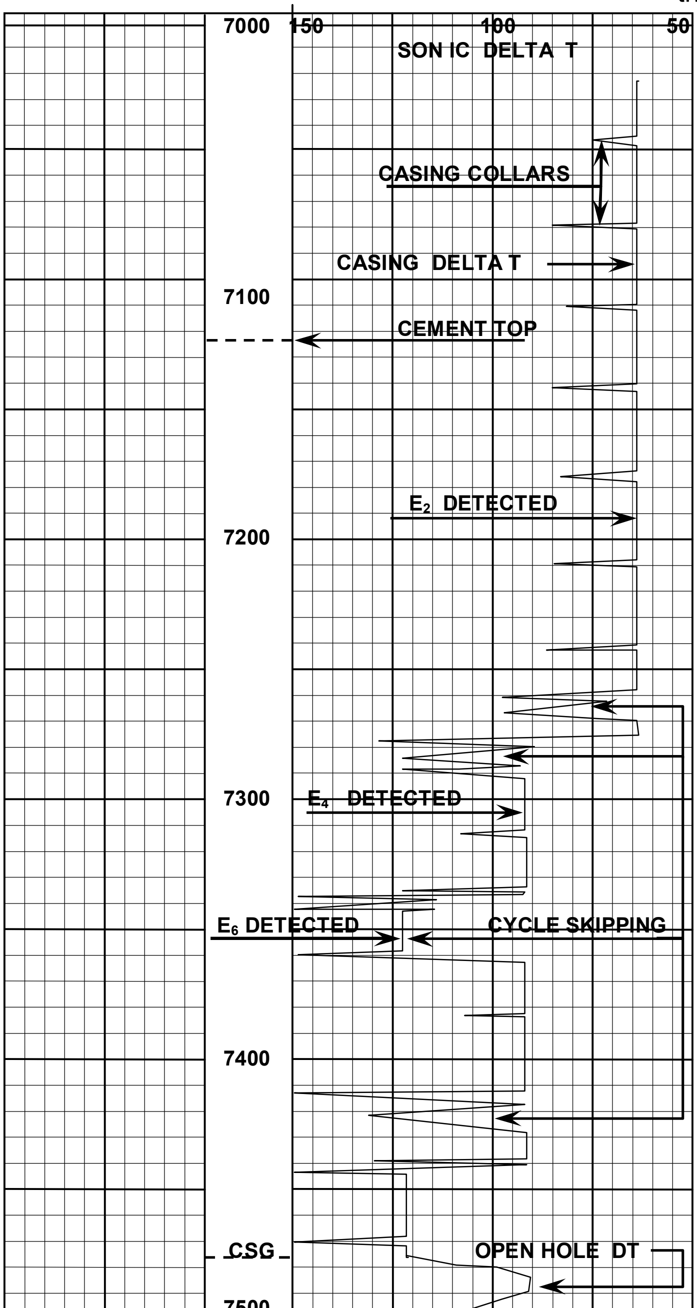

Figure 8-6 An illustration of a Sonic log, run inside casing, exhibiting cycle skipping in bonded zones.

change at the cement top was what he really looked for. Of course Schlumberger, being a firm founded by engineers, had that hankering for their product to be quantitatively correct.

RUNNING THE LOG

There is a window in time within which the temperature log must be run for a quality log. That window opened about twelve hours after the plug was bumped and closed about 24 hours later. Running a log too soon or too late resulted in no visible cement top. Thus, when a customer set up a time we were there and ran the log on schedule or typically 18 to 24 hours after bumping the plug. That last term, i.e. bumping the plug, was mentioned in chapter five. For clarification, remember when the cement was pumped down the casing and up the annulus around the bottom of the pipe, it was followed with a rubber plug, which seated or locked in place at the bottom of the casing at the float shoe or collar. It prevented the cement from backing up into the pipe after pump pressure was removed. Consequently, bumping the plug means the cement has exited the casing and the cementing is complete.

Now, let's get on to figure 8-5 and analyze the temperature window. The black dotted line represents the formation temperature gradient of the area, which is 1^o F per 100 feet. As the cement is pumped into place, it is followed with mud from the pits to push the plug down and provide sufficient hydrostatic pressure to hold it in place. Consequently, the mud within the casing is at surface temperature. If we ran a temperature log immediately, the mud in the casing would be heated only slightly and a gradient such as the light blue line with a value of 0.13^o F would be obtained. As time progresses, i.e T_1 through T_5 the column is heated by the formations and the cement. The formation heat by itself would gradually heat the mud column such that eventually we would obtain a gradient approaching that of the formations or T_5. However, the cement also adds heat to the lower part of the mud column. As the cement begins to set (light blue zone) only a small heating effect is applied. Depending upon the type of cement, maximum heat will be felt sometime between 12 and 30 hours as illustrated by the green zone. As time goes on, the exothermic reaction in the cement, which results from its setting, is completed and the additional heat produced tapers off to zero, as depicted by T_4 and T_5.

Though not apparent in the diagram, the time for the mud column temperature to reach equilibrium with that of the formations around it is somewhat less than the time for the cement heat to peak, i.e. typically 3 or 4 hours.

As is rather typical of my efforts, I covered more detail and spent more time than I intended on the DWT but why quit when you're having fun.

ADVENT OF THE CEMENT BOND LOG

The cement bond log came into being after the sonic log and somewhat by accident or maybe I should say through the curiosity of one of Schlumberger's French engineers working in an overseas location. Sonic logs were being run in wells all over the world for both porosity information and for integrated travel time to be used with geophysical data. Usually, such a log was cut off as soon as the tool entered casing because no additional useful sonic information from formations could be obtained above that point. However, one engineer noticed some rather strange sonic responses inside the casing and proceeded to log rather lengthy sections of cased hole below and above the cement top. A typical sonic log in such a situation might appear something like that shown in figure 8-6, which is a little out of place for this discussion.

A SONIC LOG IN CASING

I don't remember the delta T of steel pipe exactly. I think it was in the vicinity of 60 microseconds per foot but that's not essential in the explanation. I assumed a value of 64 shown in the top part of the log. The formation delta T just below pipe is illustrated by the smooth rounded curve. As the tool enters pipe funny things begin to happen. It registers a delta T, which is too high and is very erratic in nature. It might record a straight line for a while and then start jumping again, at least until it rose into pipe poorly bonded with the cement or above the cement top. An intermediate string is typically cemented over the bottom 500 to 1000 feet of casing, though I've shown more like 200 feet.

The explanation for the erratic nature of the curve lies in the quality of the cement job. If the cement and pipe were well bonded, signal amplitude was small and the receiver would skip cycles until an arrival strong enough to activate it came along. If there was no cement or bonding, the signal was very strong and the receiver would activate on the first negative half cycle. Even if the bonding was poor, the signal might still be strong enough to trigger the receiver with the first arrival and the tool would register the delta T of the steel casing. Opposite collars or casing connections the delta T was somewhat

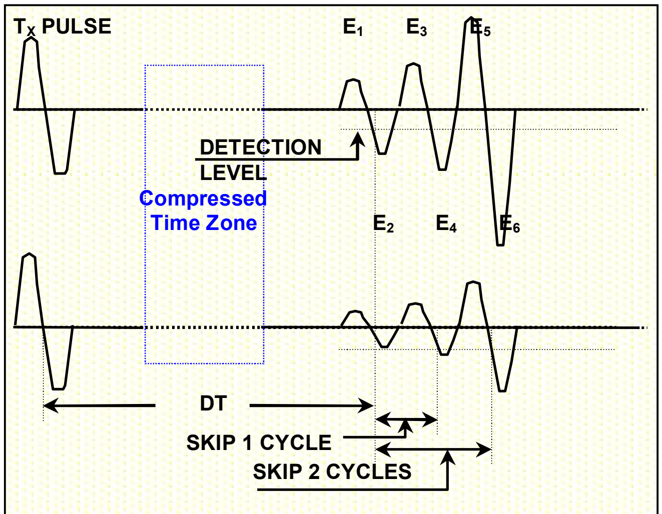

Figure 8-7 An illustration of cycle skipping, leading to an incorrect Delta T.

longer and the collar depth could be identified. This is summarized in figure 8-7. The Sonic tool utilizes the negative half cycles, as you may

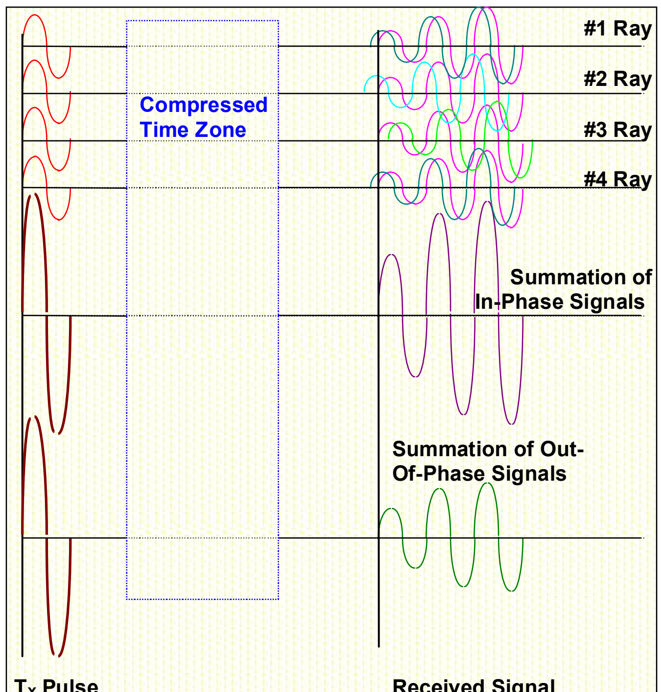

Figure 8-8 Drawing of receiver signal arrivals in and out of phase for tools shown in figure 8-9

remember, to determine delta T. The compressed time shown includes the transit time or time for the signal to travel between transmitter and receiver. That time is not to scale so as to allow the display of individual cycles. The measured time is from the transmitted pulse to the first negative pulse strong enough to activate the receiver. If it is the second or third cycle, then cycle skipping takes place and the reading is too long. Thus, low amplitude signals lead to cycle skipping. The various half cycles of the received signals are designated as E_1 through E_6 or even higher to provide reference to that particular portion of the signal arrival, which is of interest. The log results are indicated in figure 8-6 for the different half cycles detected. Each cycle skipped results in just over 30 microseconds added to delta T.

CLARIFYING THROUGH ANALOGY

Now, let's draw an analogy with something, I dare say, all of you are familiar with. Consider a piece of plain steel pipe hanging in the air. If

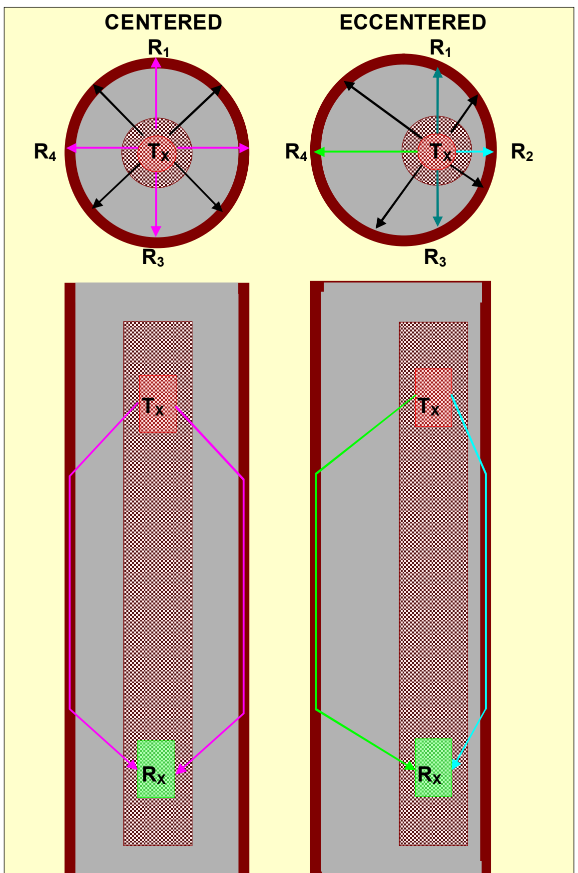

Figure 8-9 A drawing simulating signal paths between transmitter and receiver for centered & eccentered cement bond tools.

you strike it with a hammer, it will resonate with a loud sound, like a dinner gong. If you place a cement sheath around the pipe of maybe 1" to 2" in thickness and hit it again, you'll only get a quiet thud. In the first case the hammer will produce a sound of high amplitude and in the second a very low amplitude sound. Ah-hah, it would seem we now have a principle, which will tell us when a dense material, such as cement, is stuck to the pipe. All we have to do is measure the amplitude of the signal and we'll have some measure of the cement job quality.

ACCURATE AMPLITUDE MEASUREMENTS

To utilize signal amplitude to establish cement-bonding characteristics, we must be sure the signal strength variations are controlled by the cement and not by other factors such as tool position or attitude in the hole. Schlumberger had known for some time that centering the tool in the hole provided maximum signal strength for the Sonic. Consequently, if possible, the field engineers ran the devices with that configuration in the interest of log quality. With the cement bond log (CBL) such centralization became absolutely essential. So, it would seem useful, at this point, to explain this important principle and how it affects the CBL. We'll do that with a series of diagrams, which should diminish my verbiage by a factor of at least 1000, if that old adage is correct. Such reduction seems desirable considering the similarity in vocal sound of the terms verbiage and garbage, both relating to the content of the following.

CENTERED VERSUS ECCENTERED

First consider figures 8-8 and 8-9. Figure 8-8 illustrates how in phase (simultaneous) arrival of all signals at the receiver are additive, producing a maximum signal, and out of phase arrival weakens the total signal received. In figure 8-9 we have both horizontal and vertical cross sections of a cased hole to help you visualize the multiple paths traversed by the signal as it progresses from transmitter to receiver. In addition, the tool is centered and eccentered to illustrate how the signal paths vary in length as the tool position within the casing varies. I'll use figure 8-9 to help explain figure 8-8.

Consider the centered tool first. The transmitter is pulsed twenty times a second or we swing our hammer and whack the casing that many times each second. Whew, that makes me tired just thinking about it. Anyway, the sound from the transmitter (T_X) moves out in a spherical wave front. If the tool is centered, the front, depicted by the arrows in the horizontal cross section, strikes the casing in all directions at the same time. Much of the energy, as shown in the lower part of the diagram, moves down the casing and finally over to the receiver. The first portion of the front strong enough to actuate the receiver establishes the measurement. In the horizontal cross section I have shown 8 such rays of energy but, of course, there are an infinite number. If the tool is perfectly centered, the time required for the first arrival in every direction is identical and they add to each other to produce a strong signal. This is depicted in figure 8-8 by the four light magenta waves, which correspond to the light magenta rays of figure 8-9 arriving at the receiver. The total of the four is shown in the dark magenta wave of figure 8-8.

Now consider the eccentered tool in the right half of figure 8-9. The logic need not be repeated. One can easily see the casing paths in all directions are of differing lengths and the first arrivals of the various rays will be different. Again the four rays of the eccentered tool illustrate this phenomenon. Rays 2 and 3 arrive 180^o out of phase and cancel each other. If you look closely, you will see # 3 swings negative as # 2 swings positive thus negating each other. Rays # 1 and # 4 are still in phase and add to each other, producing the dark green signal at the bottom of figure 8-8. Oh, the joy derived in color-coding such phenomenon.

Consequently, keeping the tool centered has two major ramifications. First, it prevents tool position from affecting the reading and second, it utilizes the energy from all directions. This latter point allows the tool to see the circumference of the pipe and the effect of any sound reduction, which might occur. The composite signal of a well-centered tool is the sum of the rays from all directions and is therefore a function of cement bonding and channeling around the casing circumference.

THE CEMENT BOND LOG RECORDING

As has been inferred in the previous discussion, we aren't concerned with delta T in casing. It has no significance to our problem. We have shown that the amplitude of the signal arriving at the receiver is a parameter affected by the cement bonded to the casing. Consequently, the CBL is an amplitude log accompanied by a gamma ray and collar log. We'll talk about the latter two a little later but for now we want to analyze our amplitude recording, which I have illustrated in the simulated log of figure 8-10.

The amplitude curve is scaled in millivolts. Calibration is simple, requiring only an accurate

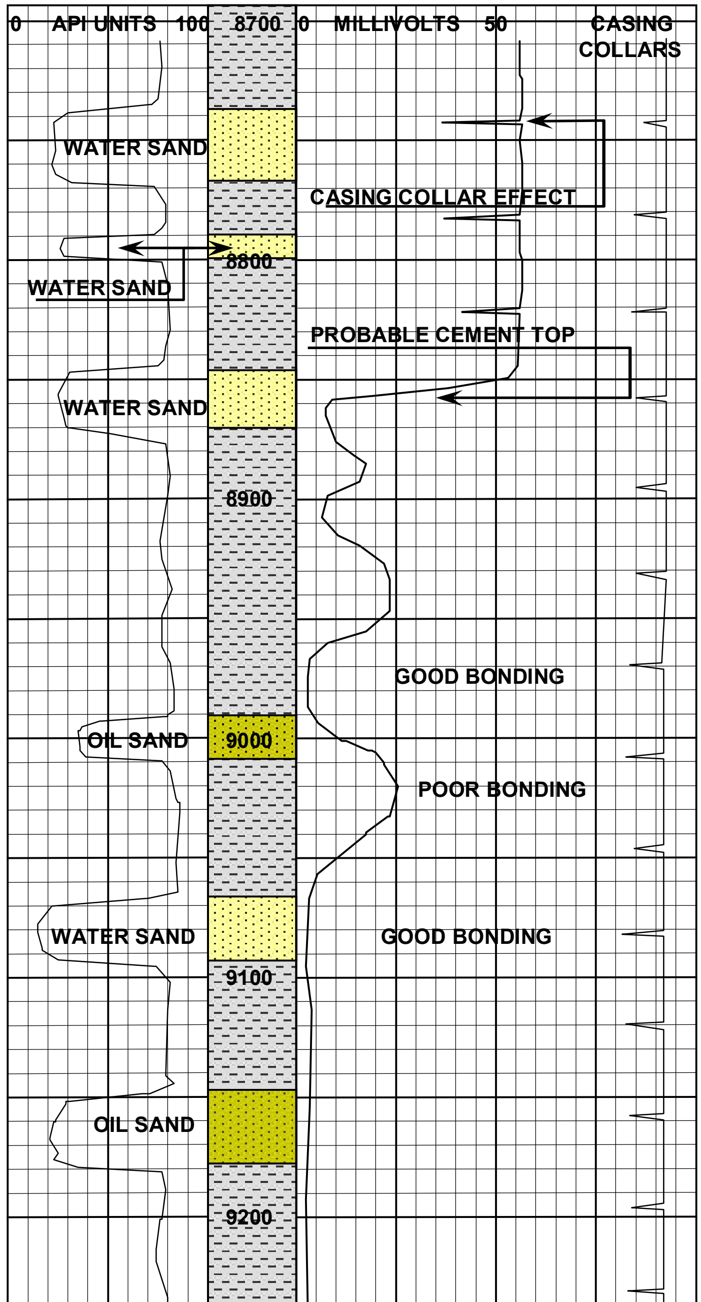

Figure 8-10 Illustration of a typical combination Cement Bond, Gamma Ray & Casing Collar log.

source of millivolt potential to calibrate the galvanometer, which source is contained in the surface panel.

Let's begin at the top of the log. In that area the amplitude is about 57 millivolts. The flat appearance of the curve above the cement top with a sharp reduction every 30 feet or so for casing collars is typical of pipe which is unsupported. Thus, we take the cement top as being at that point where the curve becomes active or has continuous amplitude variations.

Going on down hole we see variations from 2 to 25 millivolts. From a qualitative standpoint we could say that any amplitude over 5 millivolts has questionable bonding. Any given reading can be analyzed quantitatively and an apparent compressive strength of the surrounding cement calculated. During my time this was done with a nomograph and I can't remember the controlling equations. If the calculated value was near that specified for the cement used, the bonding was good. Lesser values were indications of contaminated cement or mud channeling.

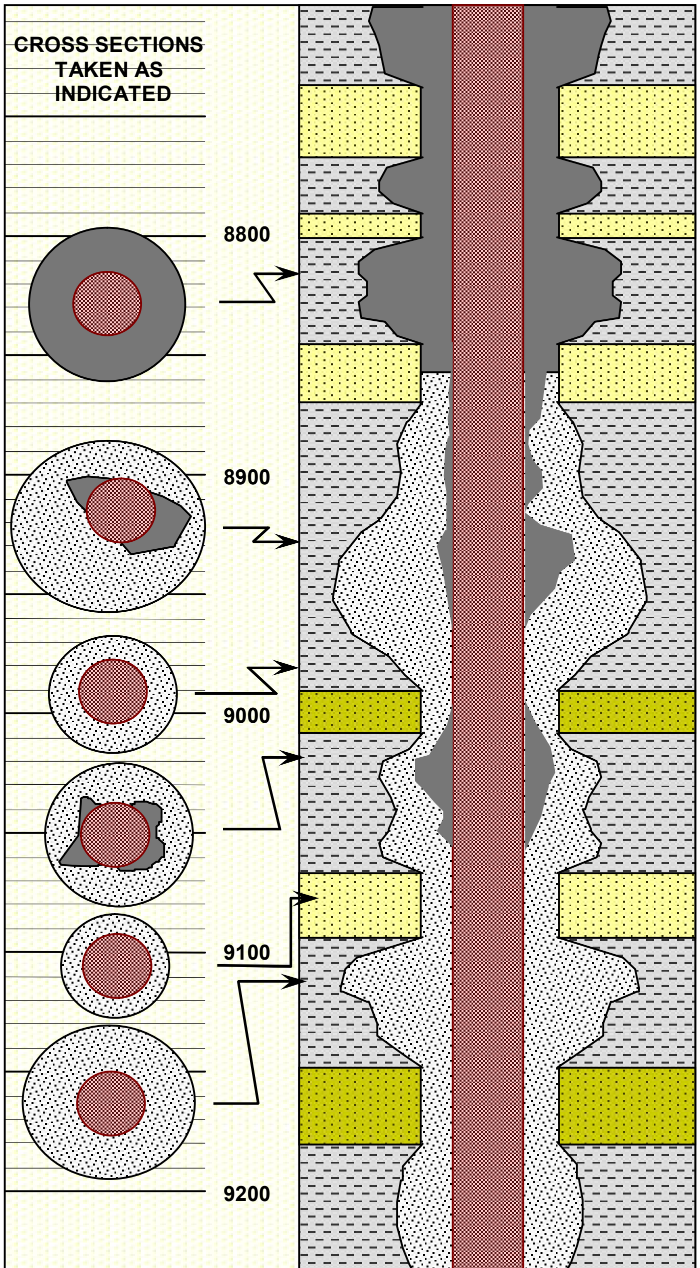

Figure 8-11 A pictorial equivalent of the Cement Bond log of figure 8-10 with cross-sections.

The term bonding deserves a little explanation. It refers to how completely the cement surrounds and sticks to the pipe and thus prevents fluid movement along the outside of the pipe. It was found in the early days of the tool that cement wouldn't stick to casing, which had certain types of coatings. Much research went into the best way to make the cement adhere to the pipe. Even so, the last I knew, the best bonding was obtained with regular old rusty pipe without a coating.

Now, getting back to our log, notice the amplitude drops below 5 millivolts from 8965' to 8990' and then rises again down to about 9055'. From there over the rest of the log it remains below 5 millivolts. Notice two apparent oil sands, identified from open-hole logs, at 8990' to 9010' and again at 9146' to 9178'. Also there is a sand containing water between the two from 9066' to 9093'. Another water-sand lies up hole from 8846' to 8870'. The question is; "Can the oil zones be perforated safely without water coming in from the adjacent water sands?" Looking at the upper oil sand, we see 25" of good bonding between it and the sand at about 8846'. That should be sufficient to isolate the sand from up-hole contamination. There is also about 10' of good bonding between it and the water sand below it. Chances are it can be perforated safely. The lower oil sand seems well isolated with good bonding for 40 to 50 feet above and below it. If they decided to complete both zones, they might well do so individually and test them before configuring the tubing, etc. for production.

Now, to kind of summarize the interpretation of the CBL of figure 8-10, I have added figure 8-11 which includes a vertical and several horizontal cross sections of the casing and cement to provide a picture of what the log is telling us. This may be more meaningful to the less technically inclined.

Here's an item of interest, which demonstrates the superiority of the CBL over the DWT. Had only a temperature log been run to establish the cement top, there would be no information available to decide how to handle the two oil sands and all would be trial and error.

The gamma ray and collar curves are used to tie the collar depths to open-hole depths. You probably remember from chapter 6 that various wire-line depths often differ by a few feet. The exact depth is important to the geologist and his maps but has little significance in the completion. Rather, it is a matter of perforating the correct log interval. Thus, cased-hole wire line units always tie to open-hole logs. We'll cover just how completion depths are controlled to provide accurate perforating a little later.

FORMATION EVALUATION FROM INSIDE THE CASING

Though most formation evaluation is accomplished prior to running casing, there is some need to be able to evaluate zones behind the casing from time to time. This is particularly true in older wells, which were completed prior to the more modern means of formation evaluation. Consequently, there has been an ongoing effort to arrive at such capability. Unfortunately, most geophysical measuring methods in such circumstances are shielded from the rock surrounding the well bore by the intervening steel casing. Only various radioactive measurements are capable of "seeing" through the casing.

These include the gamma ray and the neutron logs both of which are utilized in open-hole work and were discussed there. Actually, the measured results of these two devices in uncased hole are superior to those inside casing because the annulus and casing constitute two more variables, which can alter the accuracy of such measurements. Invasion of permeable zones, an undesirable condition in open-hole work you'll remember, is ameliorated and eventually eliminated after casing is run. With time, the mud filtrate near the borehole is completely dissipated throughout the formation, thus eliminating the flushed and invaded zones. See chapter 6 if these phenomena have fled from your memory. This makes a relatively shallow investigating device capable of seeing the so-called unaltered formation and thus, it is useful for formation evaluation through casing.

The gamma ray log, you probably recall, essentially provided a measurement of the amount of shale in the formations around the borehole while the neutron log provided an indication of the amount of hydrogen contained within the rock in various forms. The former helped the log analyst correct other measurements for the effect of shale in the rock and the latter provided a means of obtaining the porosity of the zone of interest. The neutron log could also differentiate between gas and oil or water contained within the pore space. Neither could provide a method of establishing water saturation and particularly where oil was the hydrocarbon associated with the water. This brings to the fore a new radioactive device designed to accomplish that task.

THE THERMAL DECAY TOOL

The Thermal Decay Tool is a type of neutron device, which measures the results of bombarding the formation with pulses of high-energy neutrons rather than that of a constant neutron flux as with open-hole neutron devices. To see just how this marvelous little device worked, let's begin with a review of the conventional neutron tool, an overview of the thermal decay tool and then move on to the theory of measurement involved.

CONVENTIONAL NEUTRON REVIEW

You probably remember the principles behind the conventional neutron log, namely that;

1) The formation was bombarded continuously with high-energy neutrons (5MEV).
2) The neutrons gradually lost energy through collision with other nuclei of formation and mud until they reached the thermal level or that level at which there energy is provided and sustained by the formation heat.
3) At the thermal level, free neutrons are subject to capture by any atom within whose terrain they happen to wander.
4) When a neutron is captured, the plundering party (atom) emits a gamma ray of capture, somewhat like the cry of the conqueror.
5) Chlorine atoms are brigands of renown in the world of atoms shanghaiing any and all unprotected neutrons wandering in their vicinity. They are said to have a large capture cross-section or act in a heavy-handed manner when dealing with the unfortunate free neutrons in their vicinity. The epithermal neutron log was designed specifically to overcome this particular problem (SNP), remember?
6) Because of the continuous bombardment of the formation with high-energy neutrons, the

slowing down process of the same with their ultimate capture is ongoing, never ceasing during the logging operation and the formation response continuously recorded.

TDT TOOL OVERVIEW

With the Thermal Decay Neutron Tool, the bombardment is intermittent in nature, allowing a burst of neutrons to be emitted into the

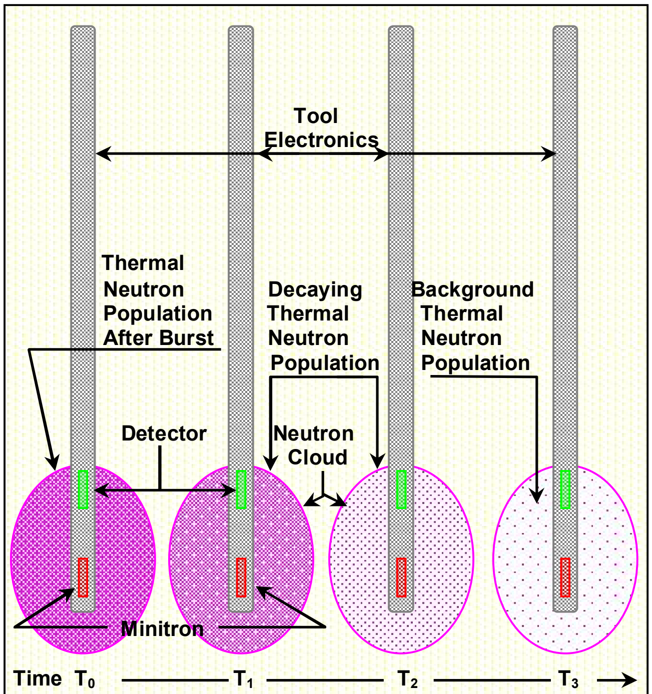

Figure 8-12 A hypothetical illustration of the thermal neutron density or population in time around the tool after a single minitron burst.

surrounding formation and then measuring the rate at which they are slowed down and captured. The Chlorine atom, which is prevalent

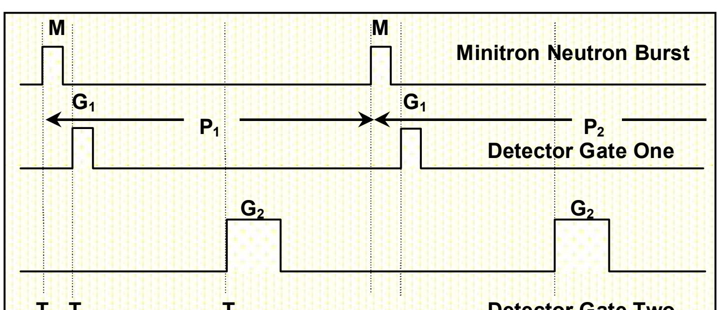

Figure 8-13 An illustration of the timing of the neutron burst and the two detector measuring periods.

in normal oil field formation waters, is, of course, instrumental in this capturing operation. The tool is most effective in high porosity environments, which have more water contained within them and thus more chlorine atoms to capture the wandering neutrons.

The operation borrows, in principle, from the Sonic and/or the Nuclear Magnetic tools, in that a burst of energy is emitted and then the device listens for the results, in this case the gradual decay of the thermal neutron population of the surrounding rock. Let's look at figure 8-13 which illustrates the timing of the neutron burst and the two periods of time (gates) during which the thermal neutron population is sampled. These measurements are sufficient to provide the data to calculate how fast the thermal neutrons are being captured, the mechanics of which are similar to that of the NML described earlier.

Figure 8-12 depicts the neutron burst and gradual decay of the thermal neutrons a little differently. There the density of the magenta color, which represents the neutron cloud, decreases as the number of thermal neutrons around the tool decreases. Thus the four pictorials of the tool illustrate one timing period of figure 8-13 which is labeled as P_1 in that diagram. Hopefully, the two will suffice to provide a clear picture of what is being done by the tool in making an individual measurement. I don't remember just what the pulse repetition frequency or PRF was. I think around twenty per second and in later models of the TDT it became variable to enhance log quality.

The minitron is a trade name for an electronic neutron generator. It utilizes an extremely high negative voltage to accelerate protons towards a target material, which emits neutrons upon impact of the protons. As I remember, the voltage was in the neighborhood of minus 80,000 volts. In any case, the tube was turned on electronically by a short pulse, lasting a matter of microseconds; during which the formation was bombarded by high-energy neutrons. As they collided with hydrogen atoms of the formation they gradually lost energy until it decreased to a level equal to the thermal level or that of any free neutron wandering through the formation. Of course certain atoms, n2otably the Chlorine atom, are on the lookout for such critters and, as I said previously, shanghai them as a member of their own little solar system. Such neutrons don't give up peacefully, however, in that they emit a gamma ray of capture, which announces to the world their predicament. At least some of said gamma rays so emitted strike the detector placed about a foot away and are counted during the time or times the detectors are activated or, in other words, during gates one and two.

Looking again at figure 8-13, you can see the detector is activated twice, as gates one and two, each time the minitron is pulsed. Of course, the neutron population and hence the gamma rays of capture decrease significantly between the two gates. To help compensate for the statistical nature of the measurement, gate two is wider having more time to count pulses and increase the accuracy of the measurement.

THEORY OF MEASUREMENT

In conventional neutron logs, the measurement of interest was the number of counts per second, which could be translated into porosity. This count rate varied as the rock parameters varied. However, with the TDT we are interested in the rate of decay or decrease in cloud density of thermal neutrons. We count gamma rays of capture as a means to an end, namely how many thermal neutrons are out there. You see the number of gamma rays counted is proportional to the thermal neutrons existing in the cloud. If we count the population of the former we have a number, or you might say a census, which is at least proportional to the latter. If we make two such measurements we can develop two equations each of which we can use to establish a decay curve.

Now, let's consider just what good this rate of decay measurement is. What information about the formations behind the casing will it provide? Well, we have already seen that it responds to Chlorine more than any other element. Also Chlorine is an element in salt (NaCl), which is common in most of the deeper subsurface waters. Consequently, we could detect Chlorine or the presence of salt water. The tool was originally called a Chlorine log as a matter of fact. Now, if a subsurface formation, say sandstone, is surrounded by other sands containing salt water but it apparently has none or at least little itself, then by inference, it must contain oil or gas. Apparently the water has been displaced by hydrocarbon. Remember chapter five. This is similar to a resistivity log as described in chapter seven which also received its conductivity or ability to conduct electricity from the salt water present in the rock. The hydrocarbon acted as a resistance raising the resistivity of the formation. Similarly, the hydrocarbon contains no salt itself and captures thermal neutrons very slowly. Thus a rapid decay of the neutron cloud indicates salt water while a slowly decaying cloud indicates possible hydrocarbon. Of course, it could also indicate natural gas or fresh water, which requires additional information from nearby formations or other measurements.

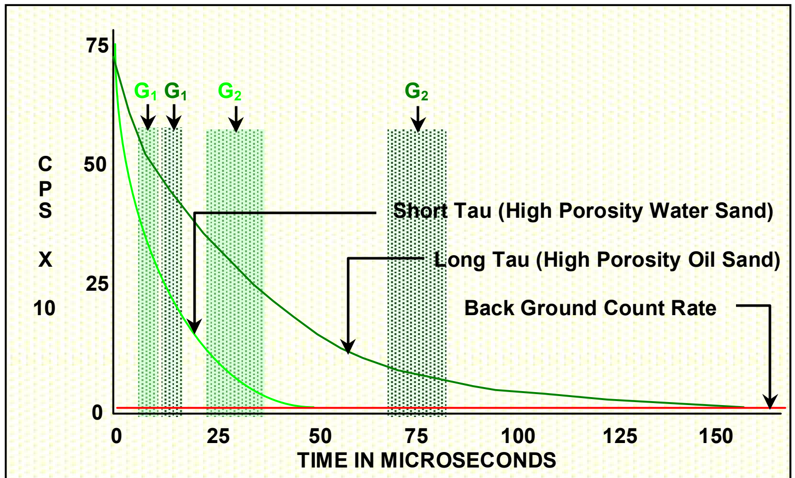

Figure 8-14 An illustration of typical thermal neutron count rate decay curves for the TDT with their associated detection gates in high porosity water and oil sands.

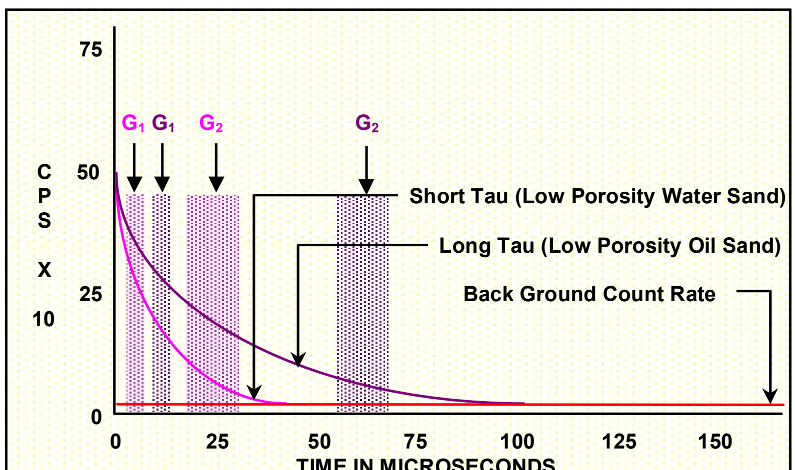

Figure 8-15 An illustration of typical thermal neutron count rate decay curves for the TDT with their associated detection gates in low porosity water and oil sands.

To see how the decay rate of the thermal neutron population is measured consider, figure 8-14. Later, we will compare it to figure 8-15, which represents a lower porosity formation. Notice there are two curves, a light green curve labeled high porosity water sand and a dark green curve labeled high porosity oil sand. The red line represents the background count rate due to naturally occurring free neutrons. All three are only qualitative in nature and are meant to represent the sandstone described. Notice too, that two gates are shown for each curve. Gate one is shorter than gate two in both cases because of the higher count rates at that point in time. The curve represents, in both cases, the density of the neutron cloud versus time after the minitron has fired. In other words, zero on the time base represents the end of the minitron pulse. Early tools had the detector gates fixed in time regardless of how fast the curve decayed. Better measurements of the decay rate could, however, be determined by allowing them to move out as the rate of decay lessened in oil sands and move in for water sands where the time decay was short. As you can see from the figure, the rate of decay is labeled Tau, the Greek letter for T. To see how it fits in to the measurement, let's look at the equation describing such a curve, as we did for the Nuclear Magnetic tool. The principles are the same. So I'll not bore you by repeating everything I went through there.

THE MATHEMATICS

The count rate at any given point in time is given by the equation,

1) $CR = CR_o\ e^{-T/Tau}$

Where CR is the count rate at any given point in time, CR_o is the maximum count rate immediately after the minitron pulse, e is the natural logarithm, T is the elapsed time since the burst occurred and Tau is the decay constant which is the item of interest because it is controlled by the fluid of the formation.

Similar to the Nuclear Magnetic Tool, the peak count rate at the cessation of the minitron pulse can't be measured because of the electrical transients generated, as the firing circuit is shut off. Thus, we can't simply measure one count rate and solve equation 1 but have to go to the two-gate system as we did with the NML. We'll repeat a similar calculation here for clarification. Assume that gate one is set at 8 microseconds and registers 375 cps while gate two is set at 30 and registers 75 cps. We can then write equations 2 and 3, as follows.

2) $375 = CR_o\ e^{-8/Tau}$

3) $75 = CR_o\ e^{-30/Tau}$

Dividing equation 2 by 3 we obtain;

4) $5.0 = e^{-8/Tau} / e^{-30/Tau}$ or

5) $\text{Ln } 5.0 = 22 / Tau$ or

6) $Tau = 22/\ln 5.0 = 22/1.61 = 13.7$

We can plug that number into equation 2 or 3 and derive the maximum count rate or CR_o.

7) $75 = CR_o\ e^{-30/13.7}$

8) $\text{Ln}(CR_o) = \text{Ln } (75) + 30/13.7$

9) $\text{Ln}(CR_o) = 4.32 + 2.19 = 6.51$

10) $CR_o = 672$ CPS

If we used equation 2 instead, we would find;

11) $375 = CR_o\ e^{-8/13.7}$ or

12) $CR_o = 672$ CPS

That is close enough for grandpa. That calculation approximated the gate positions on the light green curve of figure 8-14. Let's do the same thing for the dark green curve or the oil bearing sand and see what answer we get. We'll approximate the gate readings as 450 CPS and 14 microseconds for gate one while that of gate two is about 75 CPS and 75 microseconds. With equations 13 & 14 we find;

13) $450 = CR_o\ e^{-14/Tau}$

14) $75 = CR_o\ e^{-75/Tau}$

Dividing 13 by 14 we find;

15) $6 = e^{-14/Tau} \times e^{75/Tau}$

16) $\text{Ln } 6 = -14/Tau + 75/Tau$

17) $Tau = 34$

or about two and a half times that of the water sand. Plugging Tau back into equation 13 we can calculate CR_o.

18) $CR_o = 450 \times e^{14/34}$

19) $\text{Ln}(CR_o) = \text{Ln } 450 + 14/34$ or

$CR_o = 679$ CPS

In equation 14;

20) $CR_o = 75 \times e^{75/34}$

$CR_o = 681$ CPS

Even this is close enough for a country boy, which I am by the way because I live in this country on the outskirts of Atlanta. That's a little more engineering logic for you.

Now let's take a look at figure 8-15 which is similar to the curve of 8-14 but the count rates are lower. This might be due to a lower porosity formation and thus fewer hydrogen atoms to slow the emitted neutrons down. The same logic follows, in that salt water will cause the count rate to decay rapidly and hydrocarbon or fresh water will cause a slower decay. The lower count rate requires the measuring gates to move closer to the time of minitron firing and closer together resulting in poorer resolution between a water zone and a hydrocarbon zone. Thus, the TDT is most effective in high porosities and formations whose interstitial water is very salty.

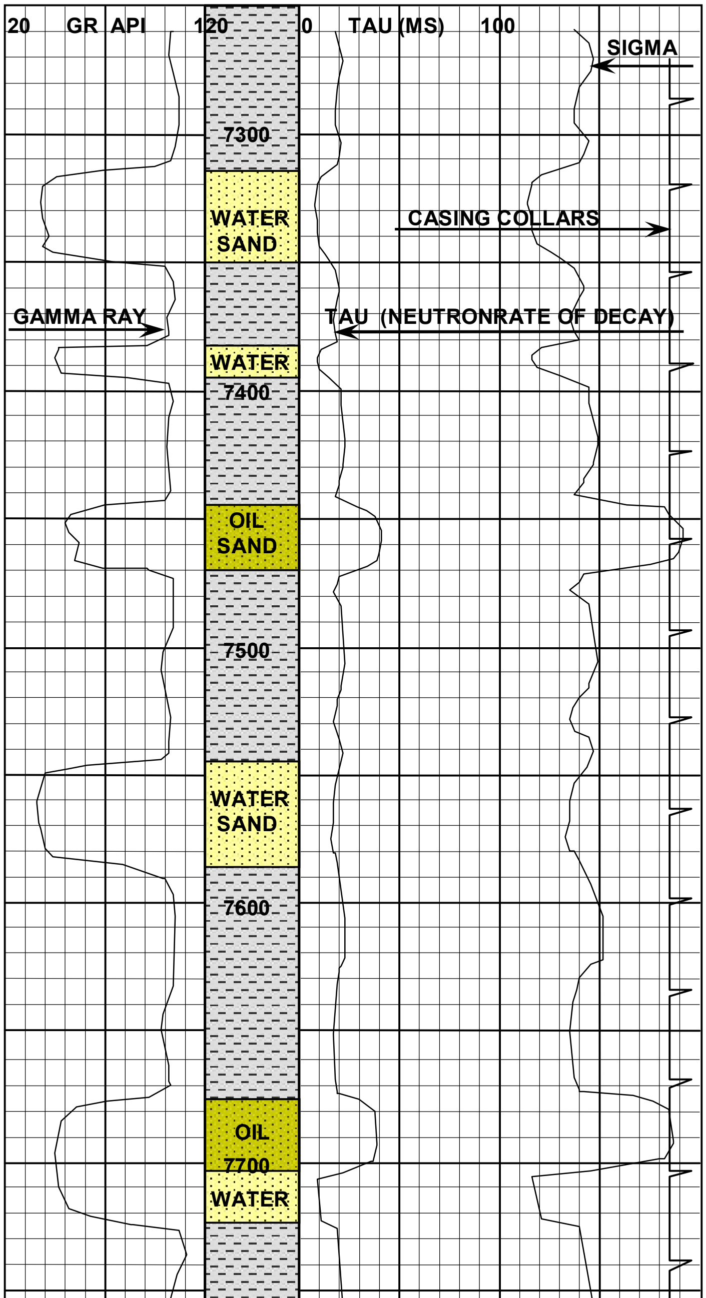

Figure 8-16 A reasonable representation of a Thermal Decay Neutron log in a sand-shale series.

THE TDT LOG

I suppose, at this point I should admit that I have only run a couple of TDT logs because my field years were in the Rockies where few were run and the tool came along after my cased hole days in the Texas Gulf Coast, its geographical area of primary application in the USA. As a result, I'm treading on the thin ice of limited knowledge further complicated by some 35 years of intervening time. If this sounds like an excuse, well, it is. Even so, being of unsound mind and a rather vivid imagination, I intend to draw my version of a TDT log. Probably, anyone knowing something about the device will never see this book, let alone read it and if they do, I'll just blame it on Alzheimer's disease. So, consider the log of figure 8-16, which is a reasonable imitation of a real one.

Consider first, the log is run inside casing below the tubing and packer. Its primary purpose is to identify or confirm suspected hydrocarbon zones. A gamma ray collar log is run in combination with it, as well. The gamma ray clearly differentiates sands from shales and makes correlation with open-hole logs easier. Usually the open hole-log would be an induction log of some variety or maybe an old ES log. In any case, the gamma ray curve correlates nicely with the SP curve of either device. The engineer would adjust his logging depths to match that of the open-hole logs. This process will be explained a little later. Both the gamma ray and the collar log are recorded on depth with the TDT curves through electronic depth correcting devices. Thus the collars are recorded at their actual depth relative to the surface reference point, which, you'll remember is ground level, the Braden head flange or maybe sea level if off shore. This is important when the perforating operation rakes place, as will be seen in this marvelous chapter.

The Thermal Decay Neutron measurement is recorded with two curves much like the induction measurement of the open-hole resistivity log. Tau you are familiar with which, of course, is the decay time constant. It appears similar to the resistivity measurement of the open-hole log and can be directly correlated to it. A second curve labeled Sigma is also shown which I believe is the reciprocal of Tau. Assume that to be the case. Since I'm not real sure, however, I didn't even indicate a scale. That foggy memory also tells me it is a measurement of the formation capture cross-section or the formation's ability to capture thermal neutrons. Obviously, such a property would be related to Tau. It, Sigma, that is, can be correlated with the conductivity curve of the open-hole log and serves a similar purpose, i.e. differentiation or resolution where Tau values are very low.

LOG INTERPRETATION

Here's another area where I suffer from both a lack of experience and a time versus memory problem. I do know the interpretation was done with either nomograms (a graphical solution of the equations involved) or with graphs. Equations could also be used but I suspect they were somewhat difficult to manipulate. I vaguely remember interpreting a couple such logs but that's about it. However, looking at figure 8-16, we can compare the so-called water sands or zones to those designated as oil bearing and observe obvious distinctions. The Tau values are low, about 10, in the water bearing zones and about 40 in the oil-bearing zones. These zones are clear-cut whereas in real life that is seldom the case. Shale obscures the effects of formation fluid differences and must be corrected for. Also, casing size, borehole size, mud salinity etc. can affect the measurement. With a nomogram I might get through such an exercise but you'd be bored stiff. I think the principle is clear, which is my primary purpose in this little exercise. You also have been introduced to one more rather amazing measuring device available to mankind to unlock ma-ma nature's secrets in the sub-surface. I found such devices extremely interesting and probably enjoyed the electronics involved as much or more than the actual geophysical measurement. Of course, the money was in the latter and the former was simply a means towards an end.

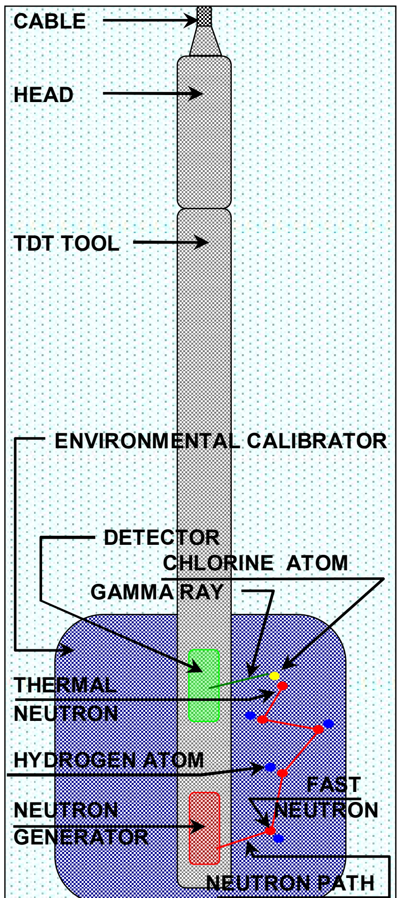

Figure 8-17 Illustration of TDT calibration in an environmental calibrator.

DEPTH OF INVESTIGATION

The tool's depth of investigation is very shallow as are those of all radioactive devices. However, after casing has been set for some time, any invasion fluid dissipates into the formation leaving native formation fluid, be it hydrocarbon or water, near the casing. Thus, depth of investigation is not a question. Only borehole and casing effects must be corrected for. The casing size and weight in pounds per foot are provided by the customer and plugged into the nomogram mentioned earlier. The borehole effect is also corrected for via the nomogram through knowledge of the open-hole size, the mud weight involved and its salinity. Reliable answers are obtained which allow effective completion decisions to be made.

CALIBRATION

The electronic circuitry involved in the processing and display of the measured values of Tau can be calibrated by inserting known values of Tau and adjusting the recording to provide that value. To be sure the neutron generator and detection system are functioning correctly, a so-called environmental calibrator is utilized. This is a device designed and verified to produce a specific Tau with a properly operating tool, which can be placed around the tool as illustrated in figure 8-17. With the tool inserted in the device, the recording is adjusted to the known value. It may well be a two-position device such that two different values of Tau can be established, i.e. high and low to assure proper linearity of the system. Time and limited familiarity with this particular tool have dimmed this once remarkable memory of mine regarding details. Even so, as you can see, the imagination is well and even thriving which allows me to incorporate calibration principles from other devices, which I remember more clearly. Of course, a competent cased-hole engineer might well call me to task but I move forward confidently among you, my posterity, realizing you have little choice but to accept my word. Besides, a little imagination is hardly a violation of integrity as one demonstrates exotic principles.

PERFORATING DEVICES

Numerous devices have been developed over the years to punch holes in casing once the pipe has been set and the well is ready to be brought into production. I am familiar with the old bullet guns, which actually shot an armor-piercing bullet through the pipe. They were in use when I went to work for Schlumberger in 1955 but lost favor rapidly as shaped charge perforating was developed. The latter grew out of such technology used and developed, I believe, in World War II. It was not only easier and safer to work with but also offered great flexibility in gun design. Other principles such as hydraulic perforating and, as I remember, chemical cutting were offered to the oil industry for a few applications such as limited entry techniques. Schlumberger was not involved in these and, to the best of my knowledge; they never really made a dent in the perforating market. Chemical cutting has been and is still utilized to cut casing for retrieval from older abandon wells but that's out of my field of experience. In any case, I will concentrate my effort on shaped charge perforating, having gained a little experience as well as a modicum of interest. Such experience was somewhat less than my involvement in open-hole service.

SHAPE CHARGE PRINCIPLES

I'm afraid I have more information regarding shaped charge perforating than I can use because of the kindness of one, Patti Oberpriller, who now works for Schlumberger in Sugarland, Texas. Sounds like a long lost cousin of the Obenchains with that name, doesn't she? She sent me enough to bore my dear posterity out of their skulls. How to handle it in providing my loved ones a clear picture of this facet of my oil field experience is a problem but, in my typically uninspired way, I will move forward and let the chips fall where they may, be they boring or of some small intellectual interest.

SHAPED CHARGE THEORY

As the name implies, providing a specific shape to a high explosive charge adds to its usefulness in specific applications. For example, its ability to penetrate solid materials can be enhanced by providing a cone shaped cavity in the face of the charge applied to the side of a rock or other solid material. Such enhancement is illustrated in figure 8-18 A and B, as taken from a Schlumberger publication. Adding a metal liner to the cone shaped cavity further improves its penetration ability as shown in C. In A, the flat sided explosive produces a small cavity with associated fractures while the cavity in B is deepened by simply making the explosive face cone shaped. C illustrates the enhancement derived by lining that cavity with metal, which, by experimental choice, turns out to be copper. The illustrations aren't quantitative but provide a simple representation of these principles.

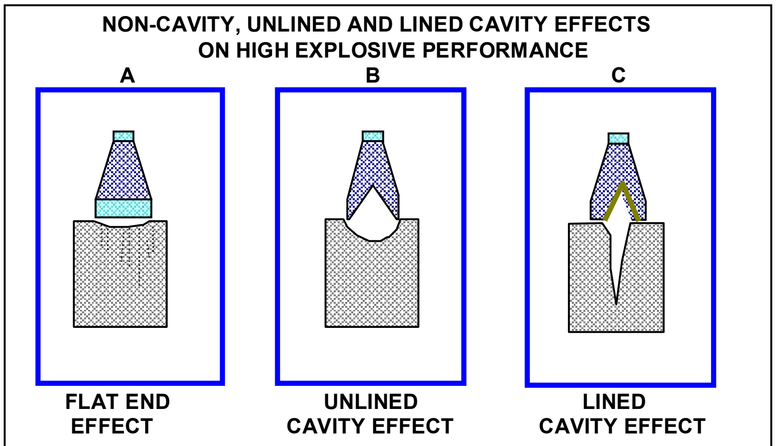

Figure 8-18 An illustration of penetration enhancement by shaping a charge & adding a metal liner to the cone.

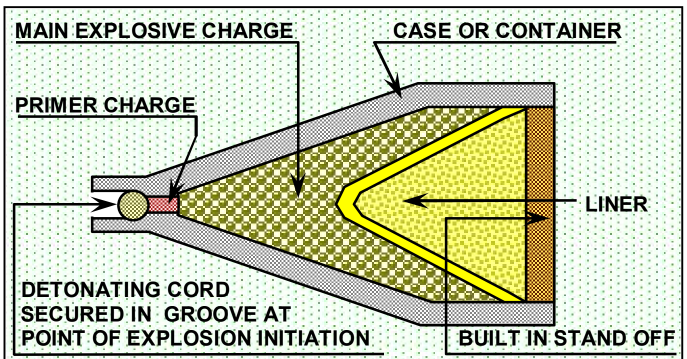

Figure 8-19 An illustration of a typical shaped charge cross-section with component designation.

TYPICAL SHAPED CHARGE CONFIGURATION

Now, let's move on to an illustration of a typical shaped charge as employed in the oil business for casing perforations. Figure 8-19 provides an illustration of the essential components of such a device. Notice that the explosive is placed within a container, which provides stability to the whole assembly and to a small degree, I suppose, focuses the explosive wave emanating from the charge towards the cone or front of the charge. The main explosive charge has a cone molded into its front or face, which is lined with copper, a metal found to provide the greatest perforation efficiency. The liner cross-section is bright yellow while the inside surface is a lighter yellow. The main charge, as I remember, was made primarily of cyclonite, a high explosive, which is relatively insensitive to high temperatures. It is detonated by the explosive shock of the primer charge. The prima cord (not part of the charge), in turn, detonates the primer charge. We'll explain its makeup a little later. It also is typically composed of cyclonite, at least for conventional operations. An electric blasting cap detonates the prima cord. As the shock wave passes the charge, it detonates the primer charge, which in turn detonates the main charge beginning at the apex of the cone. The built in stand-off indicated in the front of the charge refers to the minimum distance the charge is from the target or casing it is to perforate. At least ½ inch is necessary for optimum performance, which will be illustrated later.

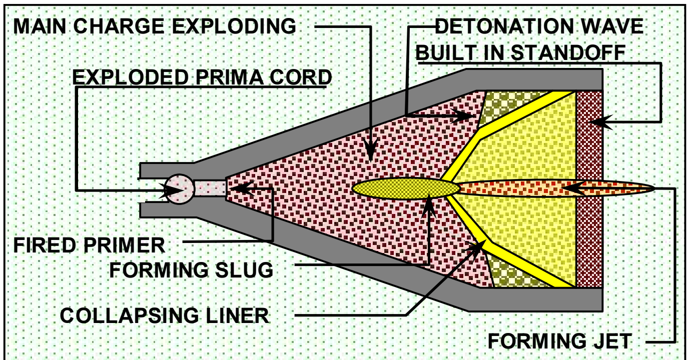

Figure 8-20 An illustration of shape charge ignition with collapsing liner and slug/jet formation.

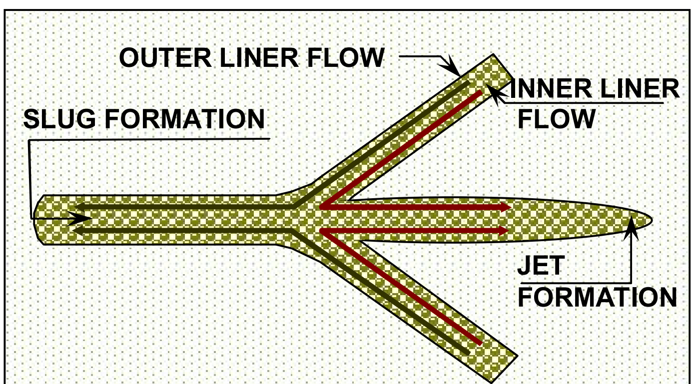

Figure 8-21 An illustration of the mechanics of jet development and slug formation.

SHAPED CHARGE JET FORMATION

When the main charge is ignited via the prima cord and primer charge, an explosive wave is initiated at its apex, which progresses towards the conical liner. This is illustrated at a later stage in figure 8-20 which also shows the liner beginning to collapse. As the liner collapses, both a jet and a metal (copper) slug are formed from the liner materials. These are also shown in figure 8-20. The mechanics of their formation are illustrated in figure 8-21 by the arrows, which describe the flow of the inner and outer liners. The properties of the jet, producing the perforation in the target, are shown in figure 8-22.

Now, consider figures 8-20 and 8-21. The latter describes the details of the liner collapse by showing the flow of inner and outer liner materials with the progressing wave of detonation. Basically the liner acts as two separate pieces with the outer half flowing backward from the liner to form the slug and the inner flowing ahead of the liner to form a high velocity, high pressure copper jet stream. The extreme pressure produced in the jet punches a hole in the target, be it rock or metal, by a mechanical action rather than a thermal or melting action.

Figure 8-22 describes the jet properties a little clearer, which are responsible for the perforating action. Notice the velocity of the jet, which is composed of minute copper particles, is twenty thousand feet per second (20,000 ft./sec.) or about 4 miles per second. What a hot rod. Talk about drag racing. Even the USAF with their latest F-22 has a ways to go to approach that kind of acceleration. Notice also the tip of the jet exerts a pressure of 5 x 10^6 PSI, which is five million pounds per square inch. No wonder the intervening casing string and old mother earth give way. The size and depth of the hole, which is punched depends upon charge design as well as explosive load and, of course, the materials being penetrated. The slug we have been talking about; follows the jet into the perforation at some lower velocity, which I dimly recollect as being in the neighborhood of 6 to 8 thousand feet per second. Needless to say, it lodges in the perforation and tends to impede fluid flow, even plugging the perforated hole, at times.

THE SLUG OR CARROT

Of course, that's a negative in terms of the perforation quality one is trying to sell to the industry. Even so, it was better than the old bullet gun and was so sold for several years after I became involved. The illustration of a sandstone target in figure 8-23 shows how a slug or carrot, as it was referred to in the field, might lodge in a perforation and thereby impede fluid flow. Notice the slug prevents the perforation debris from moving out of the perforated hole and significantly reduces flow efficiency. Needless to say, petroleum companies were concerned about the product they were buying and even more so by the less than favorable results of such perforations. Of course, there was a scramble to try to eliminate the slug by service companies who served the oil industry. We all wanted the advantage of a slug free perforation.

THE BI-METALLIC LINER

Copper provided the deepest penetrating jet but also the produced the perforating nemesis not so fondly referred to as the carrot or slug. Some companies tried to develop a method of catching them before they could enter the perforation but not too successfully. Schlumberger came up with a better method by developing a bi-metallic liner. The back or outer face of the charge liner was made of a metal with a lower melting and vaporizing temperature than copper (a zinc alloy) I ZINC, while the front or inner face remained the same. The charge with such a bi-metallic liner is illustrated in figure 8-24 for those unable to transform my words into imagery.

This would seem like an opportune time to also point out some of the design considerations for charge efficiency. The apex angle of the liner, designated as Alpha, has a large bearing on the penetration and resulting hole size produced by the jet. The smaller the angle or steeper the liner side walls, the smaller the hole and the deeper the penetration of the charge. On the other hand, the larger the apex angle, the larger the diameter of the hole produced and the shallower the perforation. As mentioned earlier, the stand-off or distance the conical liner is from the target, also influences the depth of the perforation. Such stand-off is the built in value in the charge plus the added value of the charge carrier or gun to be described a little later.

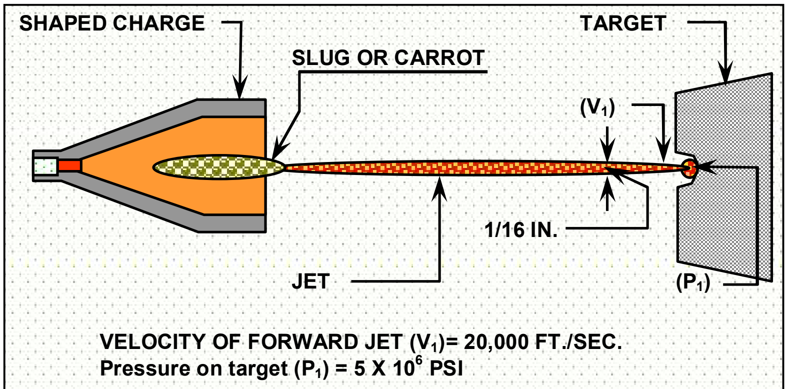

Figure 8-22 An illustration showing the approximate jet velocity and pressure exerted on the target material.

Oddly enough, the size of the charge by itself has a relatively small effect on the perforation dimensions and, if too large, can produce undesirable effects such as casing damage.

As the detonation wave collapses the liner, the zinc alloy flows back to form the slug as depicted in figure 8-21 but vaporizes in the process. Consequently, there is no slug to block the perforation or inhibit fluid flow. The inner copper liner flows into the jet as before and produces a perforation of normal proportion. Voile, a slug free charge, maintaining all the positive properties, has been produced by virtue of Schlumberger engineering.

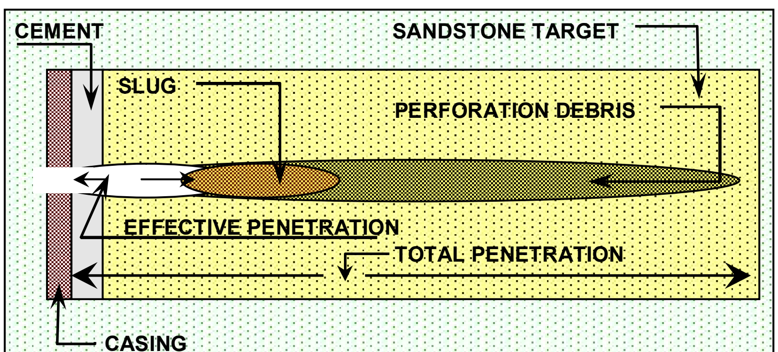

Figure 8-23 An illustration depicting a slug lodged in the perforation in front of perforation debris.

PERFORATION CHARACTERISTICS

One more diagram seems in order to help those of my posterity whose attitude is possibly perfunctory pertaining to perforations and properly prepare, even placating their probing

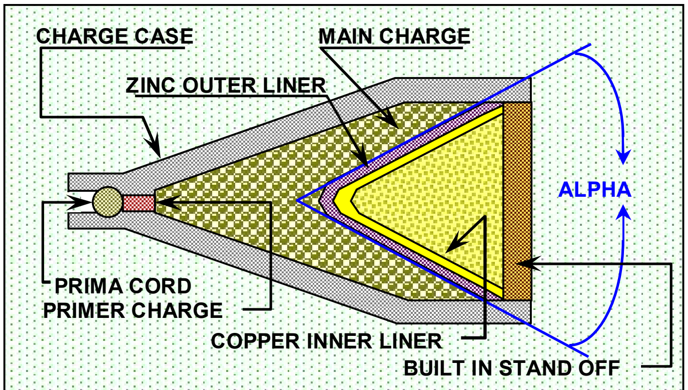

Figure 8-24 An illustration of the bi-metallic liner charge, which produced no slug or carrot.

personalities pertaining to these purely preponderant platitudes posed by properly perforating a proven petroleum producing

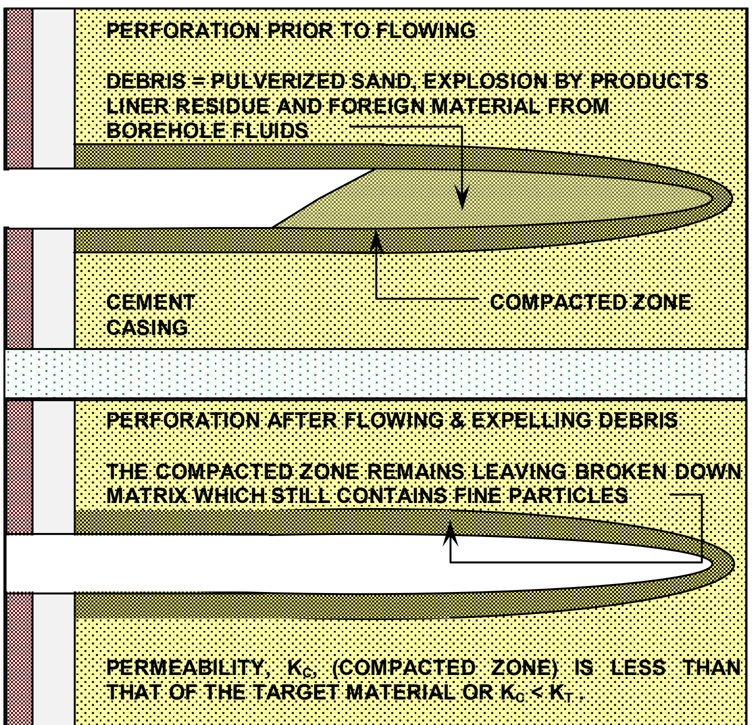

Figure 8-25 An illustration showing the character of a perforated hole in a Berea Sandstone target.

provenance. That is, maybe it will help them appreciate the need for various completion methods, which will follow. Consider the figure in 8-25, an illustration of a jet perforation before and after clean up through fluid flow from the formation into the well bore. Actually, they are targets or simulated formations used to study various perforating guns or systems.

FLOW LAB.

Such targets are part of a flow laboratory system utilized by Schlumberger to improve the charge design for various guns. The lab provides for both negative and positive differential pressures when firing a charge, i.e. the well bore pressure being greater than as well as less than formation pressure. Thus it simulates two common conditions experienced in normal completions.

Research has shown that when a charge is fired with the well bore pressure equal to or greater than that of the formation, the perforation will not clean up and debris produced by the perforating action fills the void produced by the charge as illustrated in the upper portion of figure 8-25. In fact, the debris can become packed into the perforation such that remedial clean up techniques are only partially effective. However, with formation pressure greater than that in the well bore, fluid flow through the perforation cleans it out immediately as shown in the lower portion of the figure. Obviously the debris can seriously impede production through the perforation. The compacted zone also impacts flow to a degree and can be more serious in low quality charges.

FORMATION DAMAGE AND JET PENETRATION

We talked about formation damage due to swelling clays, etc. back in chapter six, I believe. Anyway, this seems like an opportune time to illustrate how it impacts perforation effectiveness. Of course, this means another drawing as in figure 8-26. Even the most uninformed can see that formation damage slows the flow into a perforation. With severe damage it may completely shut off production. Where such damage exists, a very common phenomenon, it would obviously be desirable to perforate as deeply as possible, in hopes of penetrating well into the undamaged formation. Thus, depth of penetration of a given charge can be very important in such cases. Perforation-hole size is also important, at least to a degree, in that it drains all the fluid entering it into the casing.

Back in chapter five we talked about completion techniques a little and in so doing mentioned different gun sizes. The gun size utilized is determined by the well conditions and/or well hardware involved. If a through tubing completion is taking place, then the maximum gun size is determined by the tubing and associated hardware size. If it is a casing completion, then larger guns can be used up to that which the casing can accommodate. Gun size, of course, determines the maximum amount of explosive that can be utilized for each individual shaped charge.

PENETRATION VERSUS EXPLOSIVE LOAD

However, as mentioned earlier, penetration of a shaped charge is controlled more by design than by the explosive load. To demonstrate this more clearly, I have included yet another illustration (engineers love them you know) in figure 8-27. These measured results come from flow lab tests by Schlumberger and illustrate that explosive load is only one factor in the performance of a well designed gun.

You should notice the explosive loads, which are controlled by gun size, vary from 5 grams to 100 grams. The smallest load of 5 grams produced a perforation almost half as deep as the 100-gram charge. Also, 80-gram charges were every bit as effective as was the 100-gram charge. A 25-gram charge produced a penetration 9 ½ " or only 14 % less than the monster charge of 100 grams. Although not identified (other than blue for Schlumberger), I can say (without any bias, of course) that all the more efficient charges for the various gun sizes involved are Schlumberger charges. This was a direct result of the extensive flow lab research done to produce the most effective shaped charges possible for the industry. Man, I'm really getting into it now. If you think this bores you, wait until I finish this chapter. I will not only make an effort to shape you up but I'll also do my best to charge you to with the requirement of a reasonable knowledge of all this engineering baloney.

SHAPED CHARGE GUN CHARACTERISTICS

PHASING AND SHOT DENSITY

Shot density refers to the number of perforations per foot of hole or casing while gun phasing refers to the angular change between the axes of successive shots. Figure 8-28 clarifies that statement to some degree, hopefully. Ninety degree phasing is illustrated in the diagram but zero degree, 180 degree and even 60 degree phasing have been utilized for various applications. Ninety degree phasing means four shots per foot density with the axis of each charge being rotated 90^{o} from its predecessor, in 180 degree phasing the two successive shots point in opposite directions and in zero degree phasing all shots obviously point in the same direction. Sixty degree phasing was short lived being replaced by zero degree phasing guns shortly after its inception.

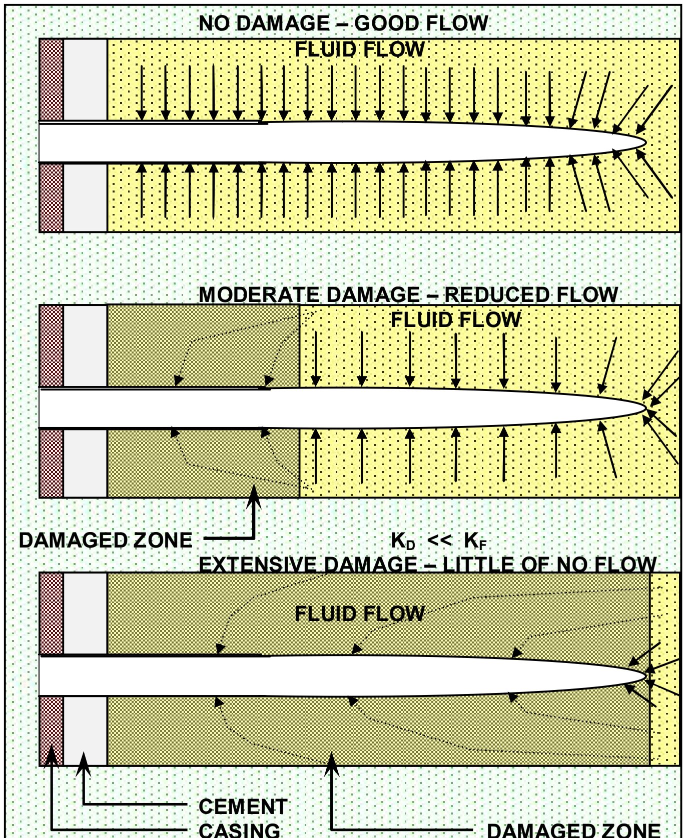

Figure 8-26 An illustration of the manner of impact formation damage plays on drainage efficiency.

The application and reason for the different phasing will be described a little later. In figure 8-28 both horizontal and vertical cross-sections of a shaped charge gun or carrier are shown. In the horizontal section the slice is taken through the top charge thus exposing the internal construction of the charge. Three other charges whose axes are each rotated 90 degrees follow in succession below it. The vertical section to the right illustrates more clearly the vertical alignment and rotating nature of the shot axes.

The figure also illustrates that the detonating cord is strung the length of the gun and secured in each charge next to the primer charge. When

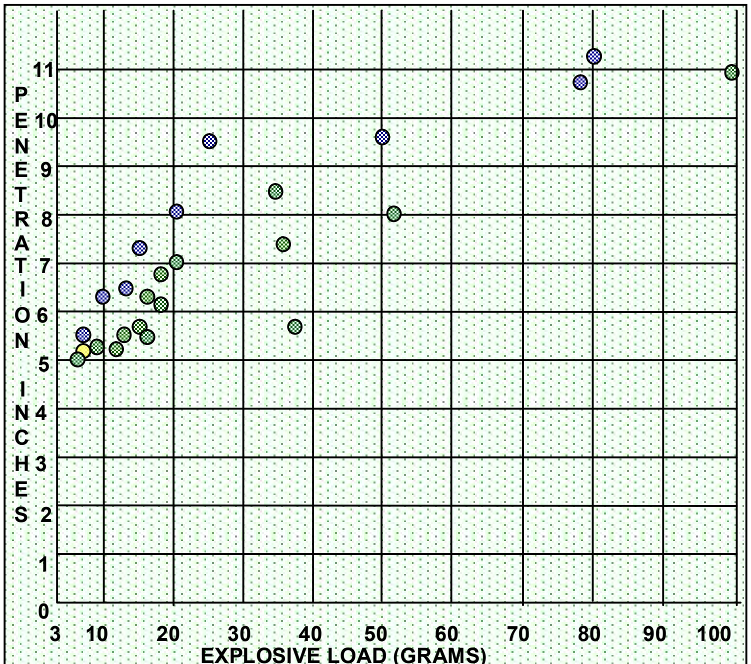

Figure 8-27 An illustration of perforation depth versus explosive load as determined in the flow laboratory.

ready to fire, the detonating cord is ignited at the bottom of the gun with a blasting cap. Ignition of the cord proceeds along it at 18,000 feet per

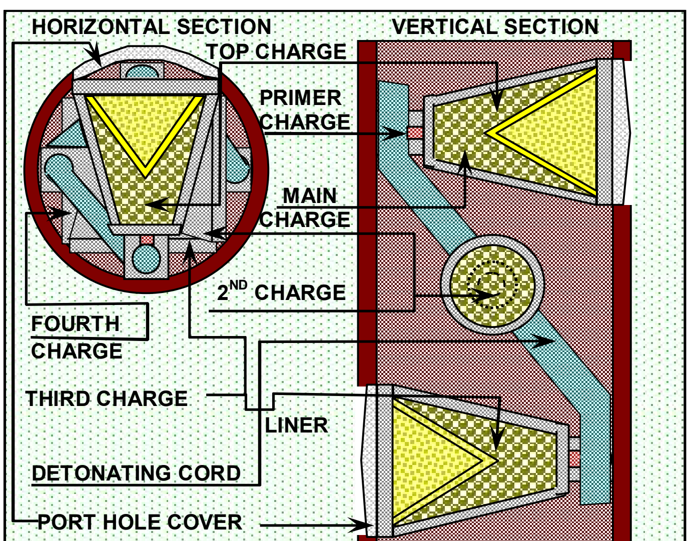

Figure 8-28 Illustration showing both horizontal and vertical cross-sections of a 90^o phasing gun.

second firing each charge as the explosion passes by. Thus, the firing of all the charges is, for all practical purposes, simultaneous and instantaneous in nature.

Loading every other shot or every fourth shot is a simple way to achieve a lower shot density or lesser number of holes per foot. Where spaces of one or two feet exist between desired zones being perforated, blank sections can be left in a single carrier. If zones are separated by several feet, multiple carriers can be run with each one controlled by a separate blasting cap. Should single shots be the order of the day, short one shot carriers with their individual blasting caps are utilized which are then detonated individually when a specific shot is properly positioned. The latest system is called a “Selectric System” which probably utilizes somewhat different principles than those I remember. Even so, the end result is individual control of each shot. Consequently, there is unlimited flexibility available to the oil operator as far as shot density or placement is concerned. In fact, it seems whatever need arises with the oil operator, the industry develops a device to answer it. Schlumberger has certainly been a leader in such developments. They were always sensitive to the customer’s needs and sometimes seemed to anticipate them before the customer did during my tenure.

GUN TYPES AND APPLICATIONS

Many different types and sizes of guns are necessary to provide service for the oil operator under a host of operating conditions. We mentioned briefly casing guns and through tubing guns with some of their different applications. Now, let’s get into a little more detail. Such a statement by grandpa must send shivers up your spine. However, comments such as, “Oh, no, here comes another load of garbage which he expects us to wade through”, will never be a sufficient excuse. You see, I’ll be preparing the final exam up there while I’m waiting for all you yung-uns to appear. Ya better knuckle down and read it.

Casing gun size is basically limited by the size of casing run in the well, that is, its ID or internal diameter. Typical sizes of production strings most frequently seen in the oil field during my time were 4 ½”, 5 ½” and 7”. The ID’s of such strings depended upon the casing weight per foot or wall thickness. In any case, 3”, 3 ½”, 4” and 5” casing guns were developed to provide a selection of the largest size gun possible. Basically, the larger the gun, the larger the charge can be and the deeper the penetration. This assumes, of course, proper charge design. Just as importantly, the maximum size gun also provided the best stand-off within the casing required for deep penetration of all charges. Smaller casing guns would produce uneven stand-off and uneven penetration as shown in figure 8-29.

Where a gun must be run through tubing, it is necessarily much smaller than the ID of the casing and the variation in the quality of the perforations becomes even more pronounced. The optimum stand-off cannot be maintained, quite obviously, in all directions for ninety degree phasing and we get the results of figure 8-29. As you can see, such problems further compromise the limited ability of smaller charges to produce a deep perforation with a reasonable entrance hole size since such stand-off is in the order of inches.

This problem resulted in zero degree phasing for the more effective through tubing guns, which were positioned with a magnet to assure optimum stand-off. With such a gun all shots would be in the approximate direction of shot A of figure 8-29 whether the density was 1, 2 or 4 shots per foot. Such an arrangement is illustrated in figure 8-30 which shows the gun being held next to the casing to provide optimum stand-off and penetration. This is accomplished with a oriented magnet, which is strong enough to hold the face and direction of the charges next to the casing. It has been shown that zero degree phasing drains the reservoir in all directions just as 90 degree phasing does, making a single direction of no consequence.

TYPICAL GUNS DURING MY TIME

I have included a photo of a perforating truck of an early sixties variety with the guns of that era displayed along-side it. On the extreme right, you will notice two guns labeled as “Bullet Guns”. They disappeared in the sixties because of their relatively poor performance when compared to the shaped charge gun. The other guns shown are of the shape charge type.

On the extreme left are two so called capsule guns labeled as 1 11/16” and 2 1/8”. They were expendable guns, that is, they completely blew up leaving only fragments of the aluminum casings surrounding each charge. Only the head and gun adapter were retrieved with the

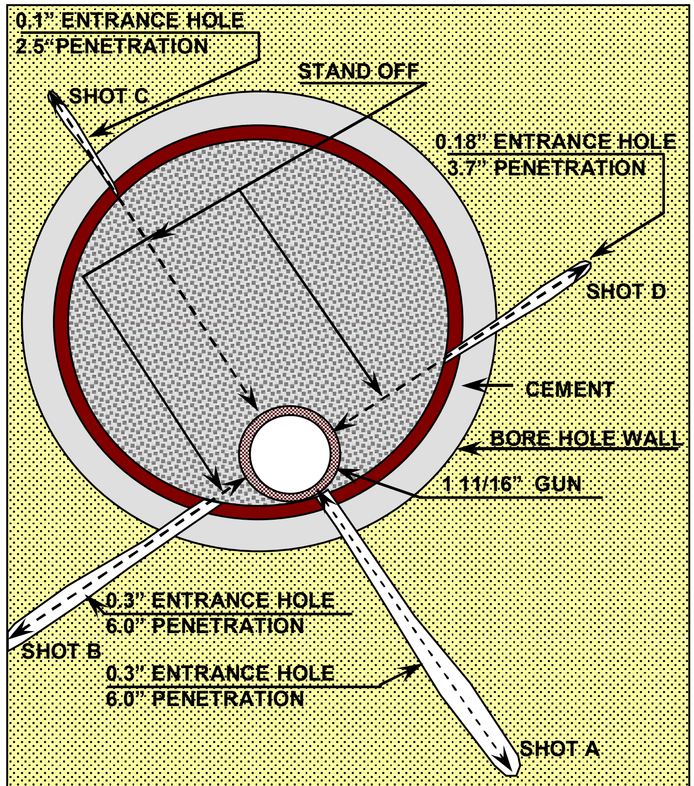

Figure 8-29 An illustration of a random perforating pattern for a conventional 1 11/16” gun phased 4 shots per foot in 7” casing set in a simulated Berea Sandstone target in the flow lab..

cable from the well. The smaller gun was designed to go through 2” tubing and the larger

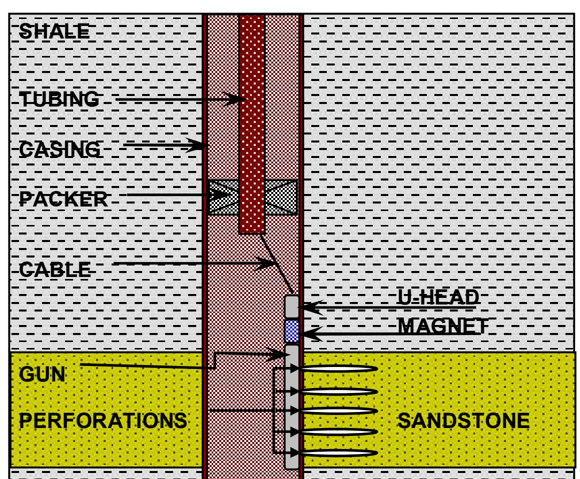

Figure 8-30 An illustration of a thru-tubing gun positioned with a magnet.

through 2 ½ “. They were quite popular for a time because of good perforation performance for their size. Any length gun could be built by simply adding charges. On the down side, however, was the junk, aluminum fragments, left in the well by such guns and the damage they could inflict on unsupported or poorly supported casings. In time they gave way to other types of expendable guns and the so-called scallop gun, which I'll describe in more detail a little later.

Notice the variety of casing guns available in both diameter and length. The standard guns

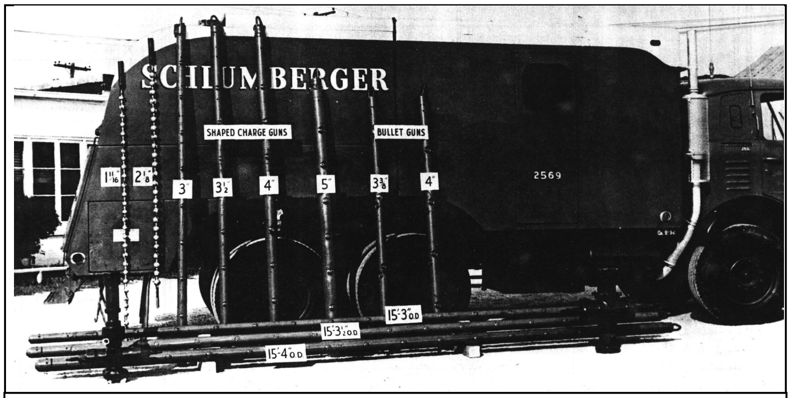

Figure 8-31 A photograph of a sixties era perforating truck with the available arsenal of perforating guns displayed.

were 6 feet in length (the 5"gun shown) but 10-foot guns were common, i.e. the 3", 3½" and 4" guns. Also available were the fifteen-foot guns lying on the ground in front of the truck. These carriers, as they were termed, were made out of high strength steel, which absorbed all the shock of the explosion that wasn't directed towards the perforation. They consequently protected the casing from undesired shock and also collected all the debris, which could be brought out of the well. In time such carriers would swell on the backside opposite the porthole cover, as in the photo of figure 8-28. A given carrier was good for a limited number of jobs or operations and would be discarded when the so-called knobs or swelling became too severe. If used too long, the carriers might crack within the knob and allow well fluid to leak into the gun. This, of course, would cause a misfire, i.e. the blasting cap would be disabled by the fluid.

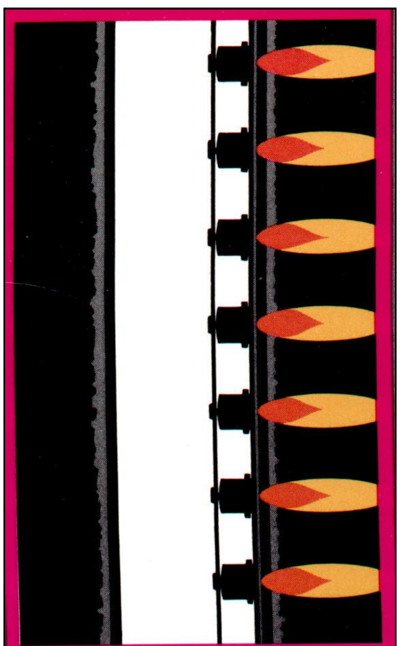

Figure 8-32 Illustration of a thru-tubing Enerjet gun.

THE ENERJET GUN

During my years in the business, the quality of perforating charges was continually improved to incorporate the best characteristics of previous guns and improve on any weaknesses perceived. For example, the capsule guns gave way to a strip gun called the "Enerjet Gun" which was semi-expendable. That is, the body or carrier for the gun was brought out of the hole but the individual charge cases were left as fragments. This gun is illustrated in figure 8-32. Notice the phasing is zero degrees and thus, it would be positioned against the wall of the casing as described in figure 8-30. As I remember, the charge cases were made of ceramic to allow them to break up into grains, somewhat like sand and be washed out of the well in a similar manner. As far as I know the gun is still being used for some applications.

THE PIVOT GUN

Another interesting gun is the "Pivot Gun". It is an improved version of the Swing Gun which was introduced by a competitor of ours back in the sixties, I believe. In any case, it provided very good performance because of its design, even though it only had a diameter of 1 11/16". The one shown in figure 8-33 is the latest version, I suppose, in that I received the information from Schlumberger in 1998. One can easily see that the gun OD is rather large with the charges in shooting position, maybe as much as 3 ½". Though I'm not sure of the exact diameter when open, the maximum stand-off in 7" casing would be in the order of 2 to 3" but more than likely, only about ½ inch.

The latter value assumes the gun would be positioned as shown in figure 8-34 A when open inside casing. This position results in near optimum performance for the charge involved. Similarly the charge is more powerful than that of most 1 11 /16" guns because the folding mechanism allows a larger charge to be used. I was rather amazed at the performance measured in the flow lab and illustrated in figure 8-35, which I'll talk about a little later.

With the hole slightly inclined from the vertical, it seems obvious the gun will seek the low side of the casing and assume the position A rather than B because of the stability of the former. Consequently, the stand-off would be as shown for position A rather than B with the resulting improved performance. If it were necessary, a magnetic positioning device could also be utilized to assure that position A was always accomplished. I doubt such a device is used with it, however, because it wasn't in my time.

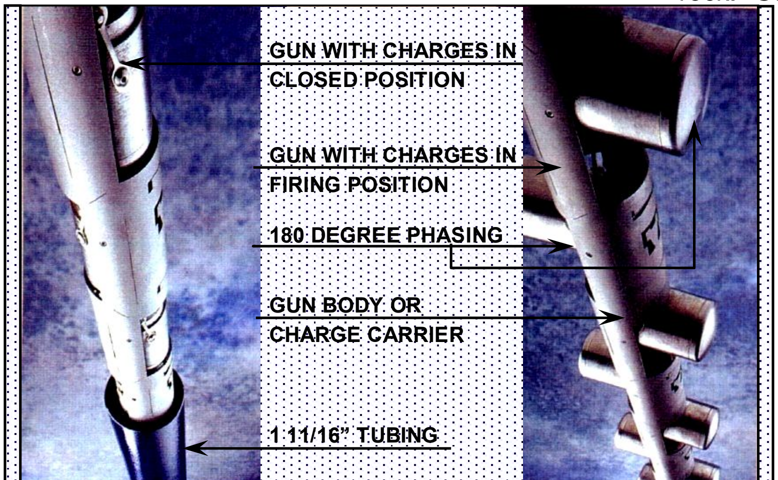

Figure 8-33 An illustration of the 1 11/16" Pivot Gun, a thru-tubing gun with unusual penetration characteristics.

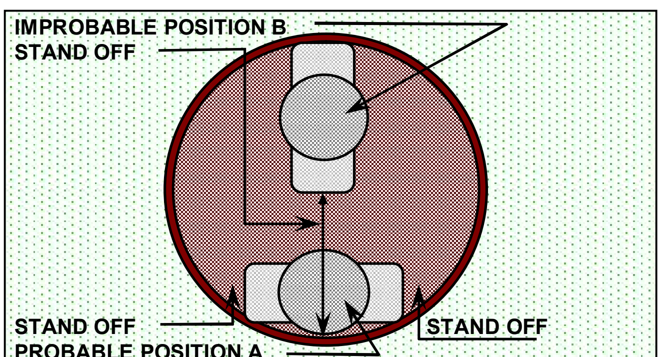

Figure 8-34 Illustration of the probable and improbable standoff of a Pivot Gun in 7 inch Csg.

CHARGE PERFORMANCE

Now let's talk about the penetration of the Pivot gun charges as shown by the illustration of figure 8-35. As you can see, the end of the perforation is at 28 ¾" as shown by the tape measure along-side the opened target sample. The sample material used in this case was cement whose compressive strength was 5500 PSI or pounds per square inch. That means a one square inch piece of the target could support 5500 pounds without giving way and shattering. In other words, it is a pretty solid rock. Such material is a standard material used for Schlumberger comparison purposes because it's easy to produce and is similar to the industry standard. For API purposes, i.e. the American Petroleum Institute, the target is specified by that organization for comparison between perforating companies. This particular charge penetrated that target 26.63" with an entrance hole of 0.34", which is truly remarkable performance. In fact, it is more than most casing guns of larger diameter. You may wonder where the first nine inches of the target are in figure 8-35. Let it suffice to say, there simply wasn't enough room to scan the whole picture on my scanner. I settled for the last 20 inches or there about, hoping you would concede the jet must have penetrated the first nine inches of cement as well. Actually, it also penetrated about one half inch of steel and a half-inch of hydromite cement which is used to seal the target material into the sample case.

MORE ON THE FLOW LABORATORY

I have included this test sample to give you an idea of just how powerful shaped charges can be as well as an understanding that Schlumberger spends a great deal of money to provide the best performing guns in the industry. That's not just idle talk either.

Their flow lab is able to provide X-ray photos of a charge actually detonating so that a person can see the formation of the jet and, in past times, the slug. They can also regulate temperature as well as target pressure and bore hole or hydrostatic pressure, which allows them to simulate down-hole conditions under which the guns will operate. Thus the shooting conditions can be overbalanced (bore hole pressure greater than the target or formation pressure) or under balanced (target pressure greater than bore hole pressure). Such capability is essential to understanding how charge debris and compacted or shattered rock influence the performance of a given perforation. Good stuff, huh? At least that's true for an ex-Schlumberger hand.

BIG SHOT TWENTY ONE GUN

There is one more specialty gun that came into being about the time I left Schlumberger, I believe. It seems I heard about it and that's about all. I received the stats with the rest of the material from Schlumberger and thought it was interesting. Of course, I realize your ideas and mine clash a little when it comes to what is interesting but need I remind you, this is my book and I choose the material that goes therein. Besides, I got a neat picture of that gun being detonated. Admittedly, it is an artist's rendition of the gun firing but it looks real. I know, because I've seen more than one going off in safety demonstrations.

A GRAVEL PACK REVIEW

This particular gun is utilized in gravel packing operations. I talked a little about that in chapter five. For review, you might remember that in producing from very high porosity sands, the sand grains themselves tend to flow into the borehole and block efficient production. To prevent this, a screen was set through the sand and gravel packed behind it to block the sand movement and thus keep the hole clean. I'm not sure what all the drawbacks were with such a system but, apparently, a better system would consist of regular casing set through the zone and perforated with many holes per foot. It apparently did a better job of holding the sand back. Of course, gravel had to be pumped through the perforations into an annulus between the casing and the sand body to block the latter so it could not flow with the oil.

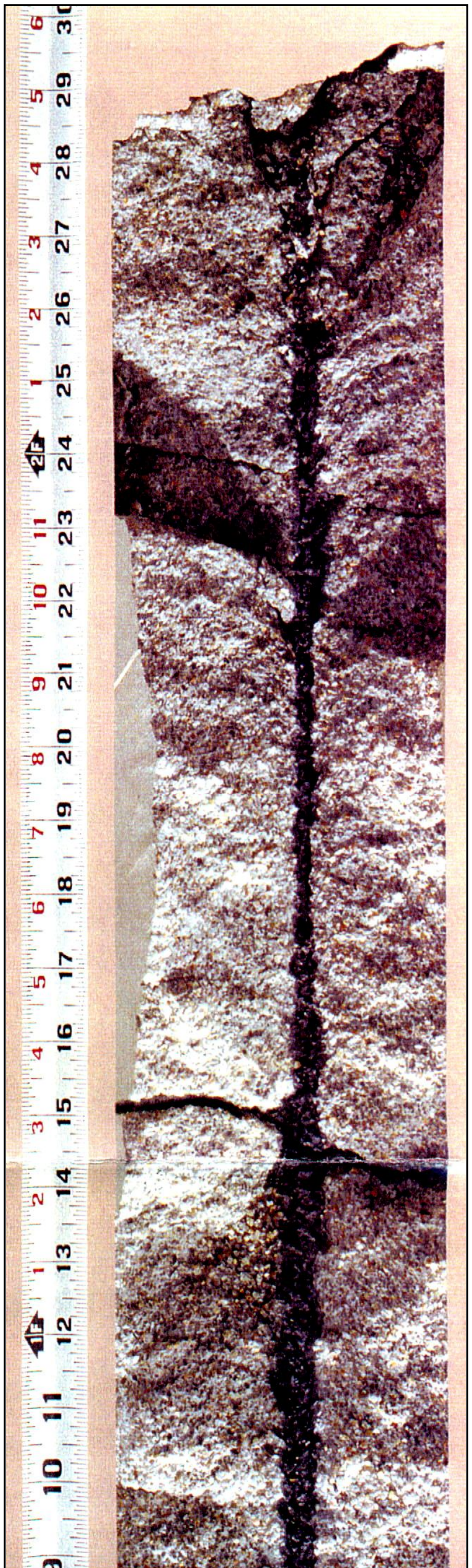

Figure 8-35 Illustration of the Pivot Gun perforation. The cement target is 5500 PSI compressive str.

Thus the oil operator could set casing through the sand, call out a perforating company to punch the holes and then go about packing the gravel. To work effectively, there must be a high density of holes in the casing, which are large enough in cross section to efficiently pump the gravel through to the annulus lying between the casing and the oil formation.

PERFORATION PATTERN

This is where the "Big Shot 21" came in. It produced a shot density of 21 holes per foot of section, which were evenly and symmetrically spaced around the periphery of the casing. Each hole is 0.77" in diameter. The gun was phased in alternating horizontal rows of sixty and one hundred twenty degree patterns as illustrated in figure 8-36. The result is much like a very course screen, which is thick enough to last indefinitely and designed to do the job. It should never have to be pulled and repaired as does regular screens set in such a well.

Notice how symmetrical the perforation pattern is. Of course, it's set by the charge position in the Big Shot 21 carrier. The figure illustrates the inside surface of the casing over a two foot section which has been unwrapped from the cylinder configuration to that of a plane surface to better display the pattern. The pattern is realized by shooting three shots in the same plane with intervening angles of 120°and 7 planes or groups of shots per foot. Every other group of shots is rotated 60°, which causes the individual perforations of each layer to lie mid-way between those of the previous group or layer and thus produce the pattern of figure 8-36.

A NEAT PHOTO

As I mentioned earlier, the photo of figure 8-37 may well be an artist's rendition but it is realistic to say the least. It, of course, comes from a sales brochure, which attempts to demonstrate the power of the gun. I was impressed because it reminded me of the safety demonstrations we provided all employees back in the late sixties in an effort to get their attention regarding the very real danger of perforating guns. We fired some casing guns and one expendable, a so-called crack jet, inside a three-foot in diameter cement target in an open area from a distance of a hundred yards or so. Needless to say, all employees were duly impressed and were somewhat more conscientious in following the recommended procedures from that point on. From figure 8-37, a person can sense the power involved. Not only is there a thunderous roar while the ground shakes but debris is flung for a hundred feet in every direction. It is hard to see how anyone could survive an accidental explosion when preparing a gun to go in the well. Some have, however, by the grace of God, I guess, as described occasionally in a safety brochure.

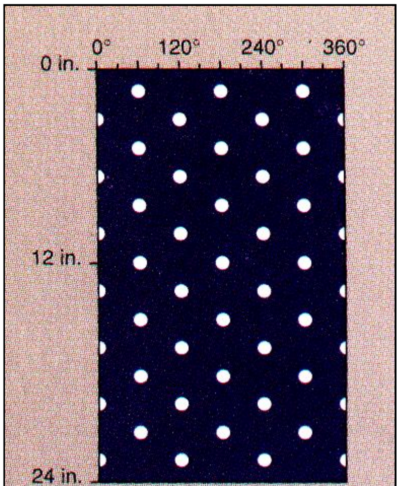

Figure 8-36 An illustration of the Big Shot perforation pattern in unrolled casing.

Figure 8-37 Photo of a Big Shot 21 perforating gun gun being discharged. Some power, huh?

We also placed paper targets around the carrier guns at different angles and distances. The exploding charges shredded many such targets with shrapnel. They clearly pointed out the need to stand at either end of the gun if it was necessary to be in the proximity while loading. One would be ripped apart if standing along-side such a gun. At either end I suspect one's hearing would be seriously damaged even if shrapnel hadn't hit him. That and the psychological impact of being next to such an accident would affect a person for life.

THE SCALLOP GUN

The scallop gun is a thru-tubing carrier gun without porthole covers. It is expendable in that such a carrier can only be used once. It has several primary advantages; which are that it leaves no debris, can be positioned for good performance, does not damage poorly supported casing and is reliable in most hostile environments. It came in two sizes as I remember, i.e. 1 11/16" for two inch tubing and 2 1/8" for two and a half inch tubing. Its name comes from scallops machined into the carrier tubing at appropriate points and with proper orientation. The face or direction of perforation for each charge lies directly behind a scallop as illustrated in my drawing of figure 8-38. The scallop minimized the steel the charge had to fire through and thus aided performance but its primary function was to prevent the burr produced by the shot from increasing the gun diameter. You can see a burr on the casing of figure 8-37 which is a little more realistic. The gun size was critical in that it would just barely go through a so-called landing nipple in the bottom of the tubing. Any increase in size due to the burr or swelling would prevent its retrieval from the well. The gun required a certain minimum hydrostatic pressure to be in place to keep gun swelling behind each charge from exceeding design tolerance. See figure 8-38 for an illustration of the same.

I'm sure you are wondering why the difference between the top three scallops and the bottom three. Early guns were simply scallop guns as described above and as portrayed by the top three scallops. Later, the domed scallop came out as portrayed by the bottom three scallops. This further improved perforation performance by increasing stand-off within the gun to the optimum value of around ½". The burr I described is illustrated for both scallop types by the bottom charge of that group which is shown firing, as is the swelling of the carrier. Of course both types of scallop guns were phased at zero degrees and positioned with a magnetic device to achieve their optimum performance.

Well, I've just about beaten this poor dog to death, the discussion of perforating guns, I mean. Let's move on to another area before I lose your attention which I'm sure has been riveted by my outstanding drawings, photos and humble verbal approach in the associated discussion. I will go so far as to mention some other gun arrangements for special purposes but nary another word about charge performance.

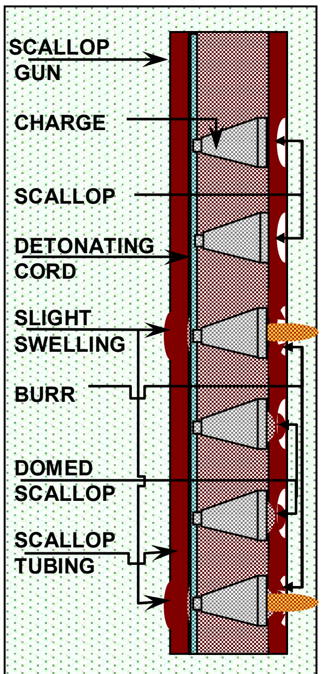

Figure 8-38 A drawing depicting both scallop and domed scallop tubing gun principles.

MULTIPLE COMPLETIONS

I touched on this subject back in chapter five, which you all undoubtedly memorized. Even so, there are unusual methods used in such operations, which weren't discussed, particularly that of oriented perforating, and I would like to touch on those before moving on to other associated services in typical perforating operations.

It is not uncommon for a given well to penetrate more than one potential producing horizon, which is obviously a plus in terms of recovering the operator's return on investment. The question is, should he produce all as quickly as possible to maximize early return or should he complete and produce one at a time beginning at the bottom and moving up the hole horizon by horizon? Of course, much depends upon the individual operator and his philosophy towards the business and, equally at play, are the surrounding circumstances in terms of other operator's actions. Additionally, in older wells, some productive zones were never recognized as such when the well was originally drilled. Through improved technology, such as the TDT, they were defined later after depletion of the original objective. Thus both approaches are frequently used.

CONVENTIONAL MULTIPLE COMPLETIONS

In general a multiple completion was approached much like a single completion with the exception that the production casing had to be large enough to accommodate all tubing strings and associated equipment necessary for the anticipated number of zones to be simultaneously produced. Depending upon the problem the operator may decide to utilize two strings of tubing for two zones, three for three or he might produce one or two through tubing and another through the annulus. One such condition, a triple completion utilizing two tubing strings and the annulus is depicted in figure 8-39 to clarify the situation. Various special problems are associated with such completions from the wellhead control equipment through the running of tubing strings, as well as perforating and producing the wells. Later, work-over activities, on a given zone, are also complicated by the presence of the others. All in all, multiple completions are more expensive than a series of single completions but may pay off through early return.

PERFORATING STANDARD MULTIPLE COMPLETIONS

My area of interest is, naturally, that of perforating which Schlumberger offered to the industry. The bottom zone was perforated in a rather conventional manner, usually through tubing with a magnetically positioned gun such as the scallop gun. Upper zones to be produced through another tubing string or the annulus were another question, however, in that the casing must be perforated without damaging the longer tubing string running through the zone. I have attempted to illustrate both types of operations in figure 8-39 as well as the tubing arrangements.

Let's begin with the simplest or deepest zone, which requires a standard approach, that is, a magnetically positioned thru-tubing gun such as the domed scallop. The operator usually provides one or two casing collars located deeper than the bottom end of the tubing, which are used for gun positioning. We'll talk more about that later, but a couple will suffice. Other than the associated christmas-tree at the surface, Schlumberger's well control equipment would be standard thru-tubing gear and the operation would proceed in a normal manner.

For the middle zone the magnetically positioning device would be replaced with a mechanical device, which prevents the gun from shooting

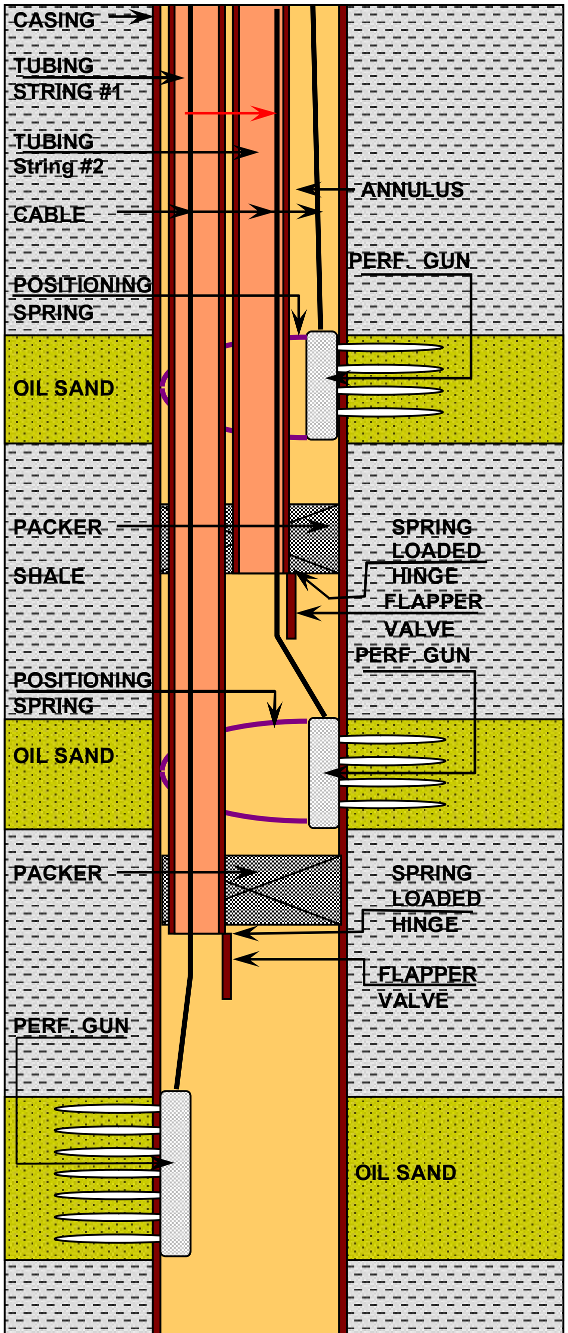

Figure 8-39 An illustration of the three perforating operations performed on the triple completion of a well.

until the arm (dark magenta) is fully opened. This necessarily means the face of the gun is against the casing wall rather than the tubing and assures the operator that perforations will be made through the casing into the zone of interest without damaging the tubing running to the lower zone.

If the third zone were to be completed and produced through the annulus as shown, an approach similar to that of the second zone would be used for perforating it. I understand the operation is very tricky from talking to engineers who have been involved with it. Apparently guns and arms can get tangled up with the tubing and create problems but I'm not concerned with any practical problems. I am only trying to describe the operation's logic.

As you can see, packers are utilized to isolate the three zones within the casing so there is no mingling of production. This allows more efficient production from each zone because of fluid type and pressure differences. Occasionally when zones are close together and have similar reservoir characteristics, they will be co-mingled and produced through the same tubing string, which saves all the hardware normally associated with multiple completions.

Having never been involved in a perforating operation where multiple zones are completed, I'm stretching my credibility, at least from a practical standpoint, and need to get on to another subject before getting into too much trouble. Even so, I hope this effort at least demonstrates the several principles involved.

TUBINGLESS COMPLETIONS

The oil industry in this country was continually looking for ways to reduce costs such that known low productivity zones could be economically produced. The big fields have all been discovered, at least on land, and only marginal reservoirs seem to be left. Efforts such as fracturing, horizontal drilling, etc. have been employed to raise productivity of such reservoirs. In a similar manner, in the early sixties the concept of "tubingless completions" came into being. I believe the old Humble Oil Co., now known as Exxon, advanced the method. In any case, it was applicable in areas where conventional multiple completions were the order of the day. The idea was to conserve on casing costs as well as associated hardware expenses. It brought into being a whole new area of technology requiring, primarily, new and smaller designs of existing well hardware along with new perforating techniques. Once again, it is the latter that I will deal with primarily but I want to briefly describe the concept of "tubingless completions" first.

Consider figure 8-40 first, which displays both a horizontal and vertical cross-section to help visualize the situation. The vertical section is taken as shown by DD' in the horizontal section. Though I show perforating guns in each casing, forget them for the moment. As I understand it, a somewhat questionable premise, the casing strings are all clamped together with the upper strings resting on a so-called combination collar and shoe as they are run in the hole. This provides rigidity and prevents them from interfering one with another while being run. The longest string, C in the diagram, has a conventional float shoe attached on the end, which allows the cement to be pumped in once the string is in place. Regular cementing practices apparently apply. Each string has a separate wellhead installed. Thus, they are like three individual wells drilled side by side. Correlation logs, i.e. a gamma ray or neutron log, which are required prior to perforating, would be run in each string to identify its collar depths relative to the formations surrounding the hole. As you will see, these collars are then utilized to position a perforating gun so that it can accurately open the desired zone.

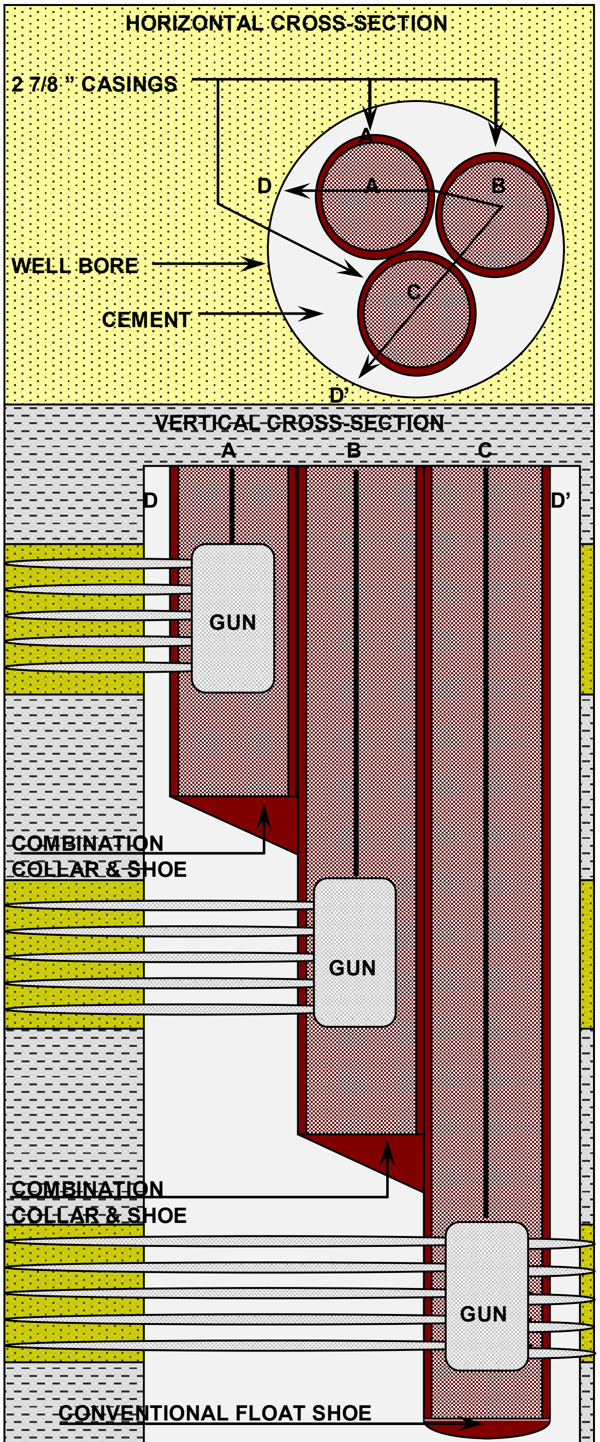

Figure 8-40 An illustration of a triple zone tubingless completion & perforating guns.

PERFORATING

Naturally, a conventional 90-degree phasing through tubing perforator can be used on the longest string. The rub comes in when the two shorter strings are completed. The operator has to be sure the perforating gun doesn't damage the other two strings. Initially, an eccentric mandrel was placed just above the zone of interest for each of the shorter strings and a spring actuating device similar to the one shown in figure 8-39 was used. When the gun was properly oriented, the spring would expand into the eccentric mandrel and arm the gun. With this accomplished the gun had to be pointed away from the other two strings by virtue of the mandrel's orientation. The casing was then properly perforated. The system had some drawbacks in that the mandrels had to be placed accurately in the string and the gun had to be tailored to match the configuration of the casing mandrel. A better mousetrap was needed.

DENSITY ORIENTATION

Some bright guy came up with the concept of measuring the density of the material around the casing and then orienting the gun such that it shot towards the low density. Obviously, steel casing was denser than was regular sandstone. I am vaguely familiar with the Schlumberger system used in the early sixties because I was stationed in Farmington, New Mexico where such a system was then in operation. However, I was a sales engineer primarily involved with open-hole services and only gained rudimentary knowledge of it. Let's see if I can come up with a reasonable explanation even though it might not pass the approval of one experienced in the operation.

I'll utilize the illustration of figures 8-41 and 8-42 to guide you through the principles involved. The first, i.e. 8-41, depicts the down hole orienting system and the latter the density principle involved as well as the surface polar plot used to establish the radial shooting position. Notice the orienting string of tools is anchored at top and bottom and the center portion is allowed to ratchet via swivels and an electric motor. Actually, I believe it was mechanically actuated to prevent the gun from being accidentally set off. I can't remember but the orienting unit had to have power of some kind for recording gamma ray count rate, maybe batteries. In any case, the center portion of the string could be stepped around in something like 15 or 30-degree steps. Thus 12 to 24 such steps would bring the gun and orienting unit full circle. I chose 15 degree steps in figure 8-42.

To perforate a given zone the engineer would first position the gun vertically by checking the depth of nearby collars. These depths have been established through a correlation log. Once in proper vertical position, he would begin rotating or ratcheting the tool in steps and measuring the gamma ray count rate at each position. The count rate would be recorded or plotted on polar coordinate paper as illustrated by the green points in figure 8-42. The points are connected to provide the radiation pattern.

I have also included a cross section of 2 tubing strings (white = string with gun) (dark red = second string), the red gamma source and a blue dashed outline of the Schlumberger tool string to allow you to better visualize the process. Normally, only the plot with its scale would be shown. The zero degree phasing of the gun is oriented such that it is opposite the direction of the gamma ray source and detector, as I remember. Once the operator's representative approves the pattern, the engineer positions the gamma detector and source at the high point of the pattern (in this case to the north west as pictured on the polar plot) and the gun is then fired in the direction opposite to that of the high radiation.

Plots are more complicated as additional tubing strings are added. I have never seen orienting plots where more than three tubing strings were involved; however, I suspect four would be the

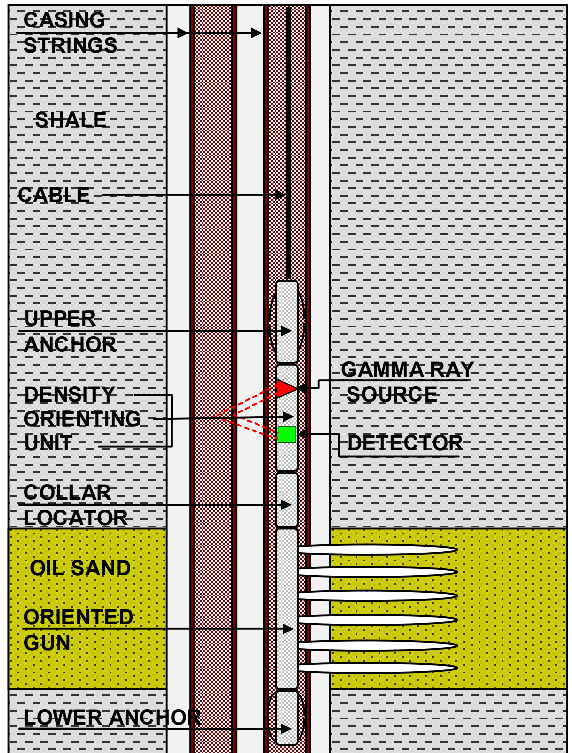

Figure 8-41 Illustration of a density orienting device with an attached gun.

maximum that could be reliably defined.

OTHER GUNS & METHODS

There have been other guns utilized over the years, which have come and gone, being

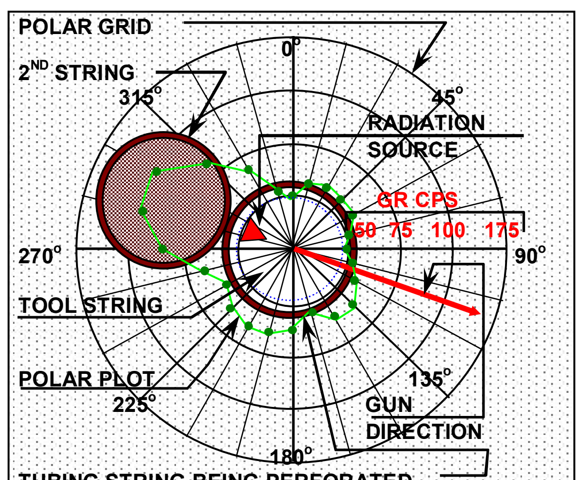

Figure 8-42 A typical orienting pattern with the perforating direction illustrated.

replaced by better mouse traps. There are also a variety of through tubing guns for even smaller tubing than the two inch I have been describing. There was a 1 ¾" Chain Jet, I believe, and who knows what else that I've forgotten. They are only smaller variations of the ones I've illustrated and I think, the important principles are covered. There's special equipment for hostile environments, i.e. high temperatures (above 350° F as well as for H_2S, neither of which I had any expertise with because they occurred in other geographical areas. Additionally, it's hard to say what innovations they have come up with today. The ones I've described may be as obsolete as I am. In any case, I'll get on with other phases of completion work including some I'm more familiar with.

AUXILIARY COMPLETION SERVICES

There were certain wire line services besides cement evaluation and perforating which were

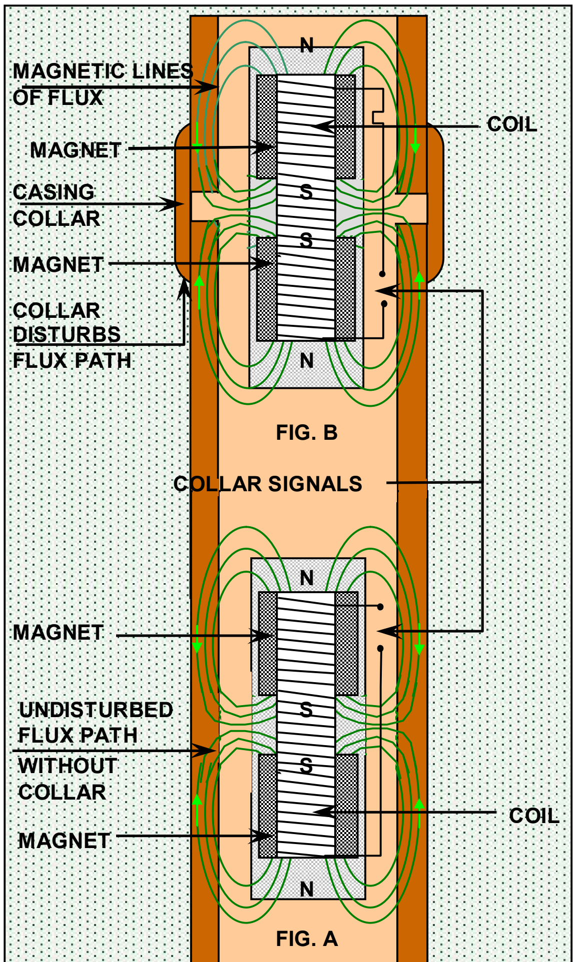

Figure 8-43 A collar locator drawing showing it passing a collar within casing.

required on many if not most jobs. The foremost was a depth control log, which was a part of the CBL when such was required. If the evaluation of cement wasn't a problem, a simple gamma ray collar log or maybe a neutron collar log would be run. In addition, setting bridge plugs and production packers were also a frequent occurrence and it seems worthwhile to spend a little time describing their purposes.

DEPTH CONTROL LOGS

Depth control for wire line operations is of paramount importance to the oil operator. There was a big difference in the capability of the various perforating companies in deriving the same with their own wire line measurements. Schlumberger was by far the recognized leader but even in our case, problems could occur making it necessary to have some kind of a permanent reference to check within the casing. That reference was the casing collars or connections between the casing joints. Typical lengths for casing sections were 30 to 35 feet, which meant a collar was required at that frequency throughout the well. The collars must be identified and their depths established through any zones of interest. This was accomplished with a collar locator and a radiation log of some sort. The gamma ray collar log was the simplest and usually sufficed. Sometimes, however, the delineation of zones was poor with a gamma ray because the sands were shaley. In that case, a neutron often provided the desired detail. Some operators preferred to run a gamma ray neutron collar log, which was a little more costly. We've already covered the principles of the various radiation logs in open-hole (chapter 7) and will not repeat it here. We will, however, illustrate just how they were combined with the collar log for depth control purposes. First, let's describe Schlumberger collar locator principles. I'll really have to reach back in the old gray matter to come up with an explanation like I had to give in my perforating exam back in 1956.

THE COLLAR LOCATOR

Various principles have been used to locate collars within a casing string. Schlumberger settled on a magnetic device, which proved to be far superior to other sonic or mechanical devices used by other service companies in the oil industry. Figure 8-43 illustrates the principles involved even though it may be rather crudely drawn. Your best imagination is required.

The collar locator is shown in two different situations, i.e. in one moving up through casing

(A) and in the second passing a collar connecting two joints of casing together (B). The locator is composed internally of two magnets with like poles facing each other and a coil of wire wrapped around them. The opposing fields force the magnetic field (lines of flux) out through the locator shell, which is composed of a non-magnetic material.

The field seeks the lowest path of magnetic resistance, or reluctance as it's termed for a magnetic circuit, which is the shortest possible air or fluid gap to the adjoining casing. It flows through the casing and across the shortest possible gap to the north-pole at the other end. All is well as long as the magnetic path doesn't change, that is no signal is induced into the coil. When it comes to a collar as in B, the path is interrupted by the gap between the joints of casing and the field disturbed. This change in field induces an electrical signal in the coil wrapped over the magnets. The change is then recorded as a collar signal (in the order of a few millivolts) and is taken from the two ends of the coil. No electrical power is required and, consequently, it can be safely hooked to the gun without danger of setting it off. The signal from the collar is too weak to discharge the gun. Even so, it is isolated from the explosives by relays or diodes.

THE COLLAR LOG

As mentioned earlier, the collar log is simply a recording of the signal derived from the collar locator as illustrated in figure 8-44. Its purpose is to provide a depth reference in the casing string to which the depth of the guns being used can be tied or compared to. There we show it recorded in conjunction with a gamma ray log, the most common depth control log. We also show two curves (the SP and the Short Normal) from an open-hole resistivity log, namely the Induction-Electrical log for comparison purposes. Note the gamma ray log is recorded with two polarities so both the SP and a resistivity curve can be compared to it more easily. Note also that corrected collar depths are shown next to the depth track for a true depth reference in the casing string. This enhances the engineer's ability to accurately position the gun.

To better understand this rather confusing effort at depth control, consider figure 8-45 which illustrates the tool configuration for both the depth control log and the gun collar log equipment. Because the depth control log utilizes two sensors at different depths, in the A or left side of the figure, only one can be used as a reference and recorded on depth. The gamma ray is chosen because its depth will be compared to and corrected to that of the open hole logs, i.e. SP and resistivity curves. Thus, you see them at the same depth in the illustration. The casing collar locator (CCL) is

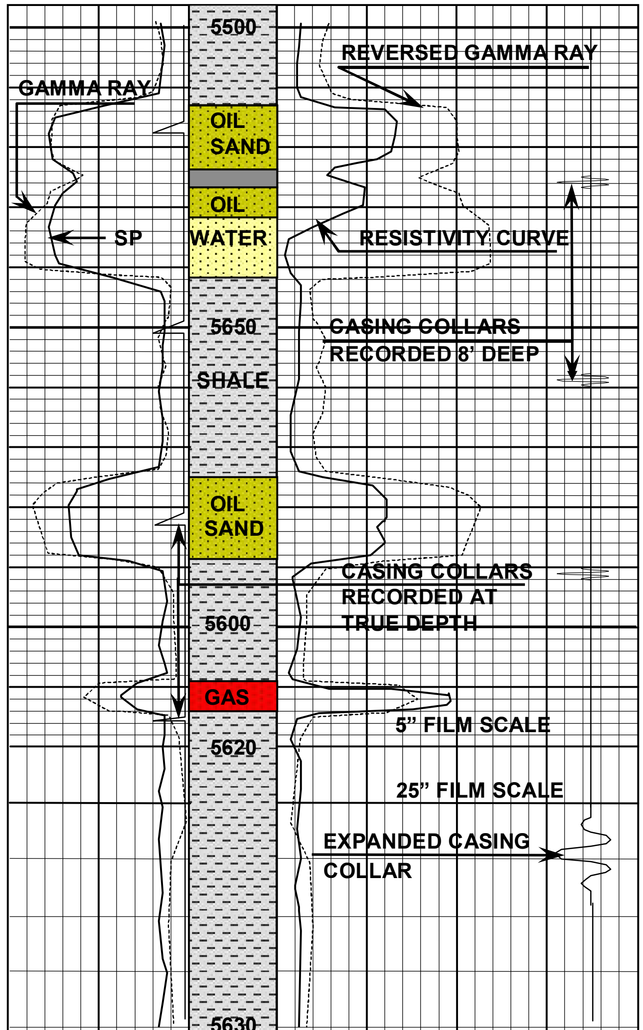

Figure 8-44 An illustration of a Mae West PDC perforating depth control log with a collar log super-imposed on a SP – Resistivity log.

positioned 8 feet above the gamma ray detector and will detect the casing collar 8 feet before the gamma ray arrives at that depth. Since the depth lines of the log are registering the depth of the gamma ray, the casing collars will be recorded 8 feet ahead of time or 8 feet deep. They represent a permanent reference to which the corrected collars can be compared to verify the accuracy of the correction, which is accomplished electronically in the surface panel.

The corrected collars, after being verified, are used as the permanent reference within the casing for later operations.

The more perceptive of you yung-un's might question the need to locate collars when a radiation log can see through the casing and register the formation characteristics. Why not utilize that tool to position guns and other equipment. The answer is multifaceted in that other operations beside perforations require depth control such as setting bridge plugs, etc. Also multiple gun runs are often required. Casing collar locators are shorter and much more rugged. Thus, they can withstand the explosive shock and require less riser; necessary for well control. Additionally, their use is safer than that of a gamma ray because no power is applied from the surface. There may be other reasons but that should suffice.

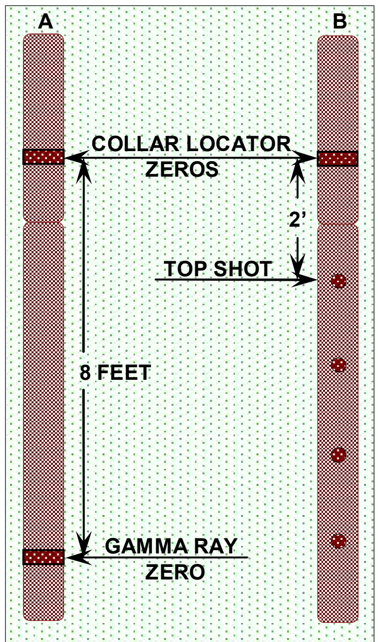

Figure 8-45 An illustration of a gamma ray tool and shaped charge gun, each with their collar locator.

Now let's consider the collar log which is recorded with the gun to verify its depth before the gun is fired as illustrated in the B or the right hand side of figure 8-45. Notice that there is only two feet between the top shot of a typical gun and the locator zero point as opposed to 8 feet or so on the depth control log. We could also reference the bottom shot but the distance would then vary with gun length and make an operation more prone to mistakes. Consequently, the top shot has become the standard reference for charge depth.

The perforating truck utilizes two depth meters, one over the winch-man's position for his reference and one on the recorder for the engineer. On a typical operation, the gun would be zeroed, at the winch-man's position, on the top shot relative to the rig zero as explained in chapter 5. His odometer would then always register the depth of the top shot. The engineer's recorder would be zeroed on the collar locator so that it always registered the depth of the casing collars. Once the tool string is lowered to the general area where perforation was to take place, a collar log was run to verify the correct depth of the perforating string. Using figure 8-44 as an example, the engineer's odometer would be adjusted until collars appeared at 5518', 5551', 5583' and 5616' or the depths of the corrected collars as shown. Once the customer was satisfied the depths were correct, the gun string was stopped by the winch-man with the top shot positioned at the selected depth and the gun was fired. If multiple runs were required, the second gun was also run into the well, positioned via the collars and shot as would be any additional guns required.

Multiple guns can be run with a select fire system. When this system is being used, the distance between each gun's top shot and the locator were determined ahead of time and recorded. The bottom gun would always be fired first, the next one up second, etc. Consequently, the position of the bottom gun's top shot or maybe only shot was positioned first and the gun fired. The string was then repositioned such that the second gun from the bottom was properly positioned according to its top shot and fired with the process continuing from the bottom up until all carriers were fired. The string was then brought out of the hole.

Depth control could be very complex where completion or work over rigs were involved, multiple gun strings utilized and long strings of well control equipment required. We'll describe that a little more clearly when covering the various types of well control equipment in use. Before we leave this particular subject, however, let's look at a typical perforating record recorded with a collar log just prior to perforating and a gun position record as illustrated in figure 8-46. The collar log, as described earlier, verified that proper depths were established prior to firing the gun.

However, it also became useful to record the actual position of the gun when the trigger was pulled or the gun fired. This eliminated any questions about the engineer stopping the gun at the wrong depth even though the collar log was recorded clearly and correctly. Questions such as that might arise if the well didn't perform as the operator supposed it should. Though improper depth might be one explanation, such things as formation damage, poor cement jobs and pressure differentials might also be an explanation. The gun position record at least established the fact that the gun was at the proper depth when fired. Thus it became a standard part of the perforating record in the early sixties, if I remember correctly. In any case, figure 8-46 is a photo of an actual record which was presented to the client and which demonstrates the principles I have described.

In track 1 on the far left, is the collar log. The depths of the collars shown thereon would be exactly the same as the corrected collars of the gamma ray log. On the far right is the gun positioning record. To establish that trace once the collar log has been run, the engineer drops the gun some distance below the zone to be perforated to include one or two casing collars and begins recording as the gun string moves slowly up hole. He stops the gun at shooting depth and immediately shuts off the recorder. Because the recorder depth meter or odometer is recording the depth of the collar locator, the end of the trace marks the position of the locator when the tool was stopped. Knowing the exact distance to the top or bottom shot then enables the engineer to mark the exact position of the perforating gun before it was fired. In the case of figure 8-46, the locator stopped at 10,181' while the gun spanned the zone from 10,185' to 10,189', which is so marked through drafting on the film. As indicated, 20 shaped charges were fired in a space of four feet or five shots per foot. Such a record removes questions regarding the actual perforated interval and improves customer confidence in the work. Should multiple gun runs be made or a select fire system used; a film for each gun position would be recorded and presented.

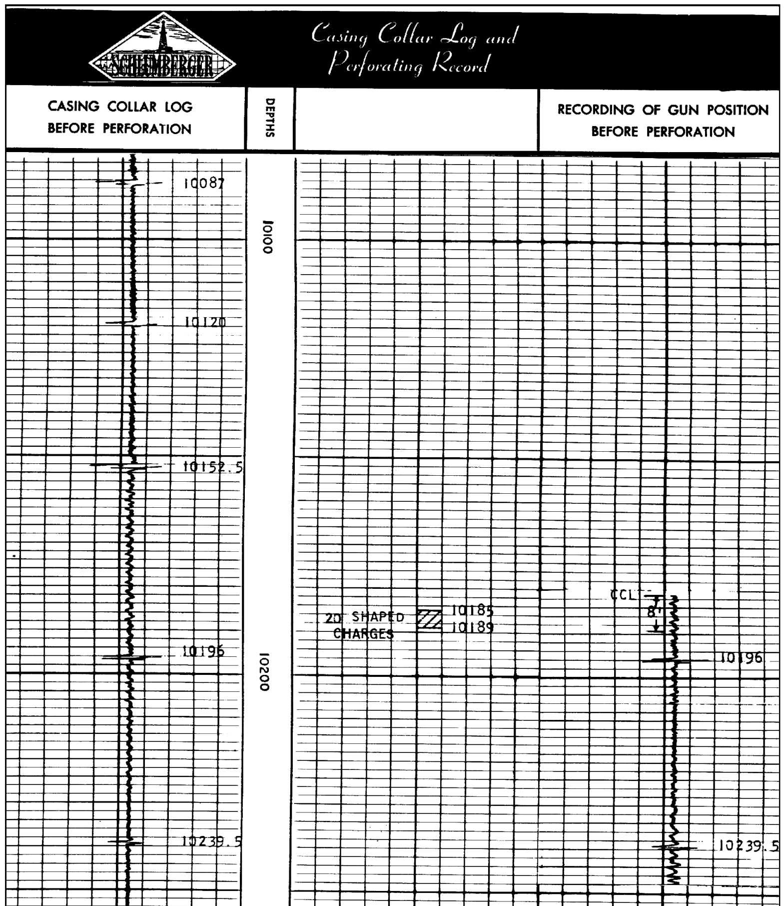

Figure 8-46 An rather poor illustration of a typical collar log with a gun position record to verify perforation depth.

OTHER USES FOR COLLAR LOGS

Once a collar log is run in conjunction with a radiation log, it provides permanent references in the casing string relative to the formations of interest around the well bore. Any device, which needs to be placed accurately in the casing, can be accomplished then, through referencing the depth to the recorded collars. As a result, a depth control log is typically run over any section or sections in the well that might have any potential at all for production.

In wire line work, other services needing accurate depth control are junk basket runs, plug back operations with or without dump bailer, casing cutting operations and eventually production logging services of various kinds. The basic depth control log consisting of collars and a radiation log then becomes the base or reference for those operations.

PLUG BACK OPERATIONS

A well having multiple horizons that appear to be productive often utilize sequential completions beginning at the bottom of the well and plugging back to higher ones as deeper zones are depleted. Such a situation is depicted in figure 8-47 which illustrates five potential hydrocarbon zones. Such zones may or may not all be productive and must be tested individually, particularly where inadequate logs were provided when the well was drilled. In such a case, a plug will be set and the next higher zone perforated and tested to determine whether it is, in fact, a viable producer. The potential for production will also be established.

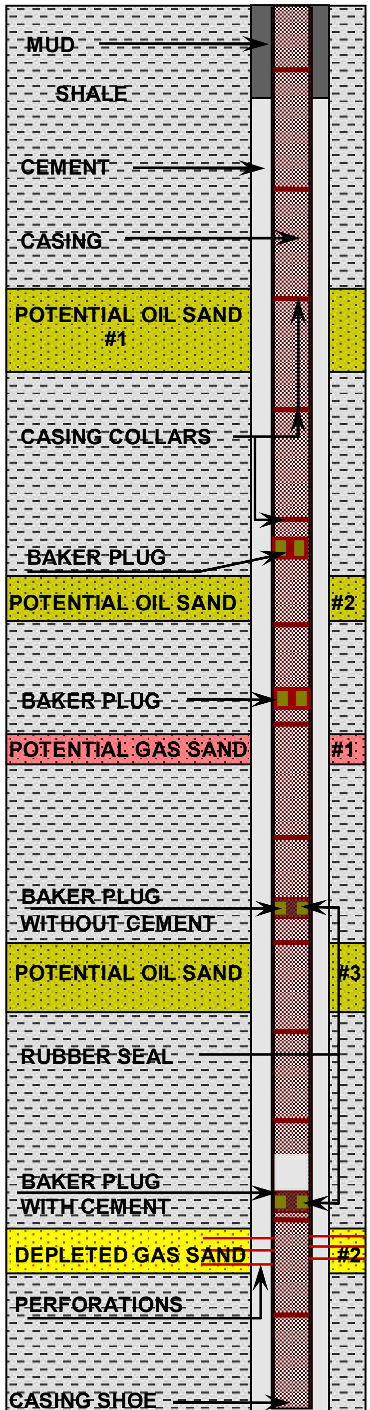

Figure 8-47 An illustration for a series of plug back operations.

The plugs involved are generally made of cast iron and are produced by different service companies. Most commonly, we used plugs manufactured by Baker Oil Tools. Sometimes we would pick up the plug and take it to the well and other times the customer would obtain it. In either case we used a Baker Setting Tool, which we leased from that company, to accomplish the job.

Occasionally, an operator will test all potential horizons before actually completing the lower most zone. He then has a better idea of what the well is worth. However, more often than not, the operator will complete the lower zone and if the production is satisfactory, he will deplete it before moving up the hole. The first completion would be known as a new well completion while later ones up the hole would be known as work-over completions. The baker plugs used to isolate earlier zones from a later completion are designed to effectively seal the casing off below the plug. They include a durable rubber like seal, which is pressed firmly against the casing when the plug is set as shown in the diagram. However, many operators liked to dump 10 feet, or so, of cement on top the plug to assure a better seal as depicted with the lower plug. This was accomplished with a dump bailer. Customers varied in their approaches to the problem. Some wanted no cement, some just one bailer and some multiple bailers.

SETTING A BAKER PLUG

The Baker plug had to be smaller than the ID of the casing, of course, and also able to expand sufficiently to provide the seal when set. Consequently, different size plugs were required for different casing sizes and their run in diameter was only slightly smaller than the casing ID. Any junk in the hole or burrs due to perforations could stop the descent of the plug and even cause it to stick in the casing so that it couldn't be retrieved. As a result, we had to provide assurance that the minimum casing ID was larger than the plug OD as well as clean out any junk suspended in the mud column. This was accomplished with a so-called junk catcher which had a gauge ring attached to the bottom whose diameter was just larger than the diameter of the plug to be set. A run was made with the basket to a point just below the depth at which the lug would be set being sure not to enter the perforations of the depleted zone. It was brought out and any junk examined. If junk was retrieved, runs were made until the basket came out junk free. It was then safe to run the plug. The basket was run, of course, with a collar locator so depths could be verified. Similarly, a locator was used when running the plug in the well. Once the plug depth was verified and it was in the appropriate position, the setting tool was fired which set the plug firmly in the casing and released it from the setting tool by shearing a calibrated weak point. The plug's release could be clearly felt in shallower wells, i.e. less than about 8000 to 10,000 feet, and could also be verified by noting the loss in cable tension.

The dump bailer was a device that could be run in combination with the Baker setting tool so that upon release of the plug the BST (Baker Setting Tool) could be raise a little to let the cement run out and settle on top of the plug. Depending upon casing size and how many feet of cement the operator wanted, extra runs could be made with the dump bailer to accomplish the order. Dumping cement on top of a plug was a nasty job under the best of conditions. The

Schlumberger crew had to mix the cement after the plug, setting tool and bailer had been rigged up which was no fun particularly. It usually involved a washtub or fifty-gallon drum and was mixed by hand. Water had to be carefully selected because contaminants could change the setting time of the cement, as could well temperature and the slurry consistency. One couldn't be too careful with the preparation because, even partial setting of the cement before ready to dump could mean disaster. I have a little story to tell about that when I describe field experiences in Wharton, Texas. Talk about a lesson written in stone or concrete. Oh me oh my, what a fun time.

MECHANICS OF A BAKER PLUG

I'm not sure I should even try to illustrate the mechanics of the plug, let alone explain them but then, I never was very smart, so here goes nothing. The main disadvantage I have is my

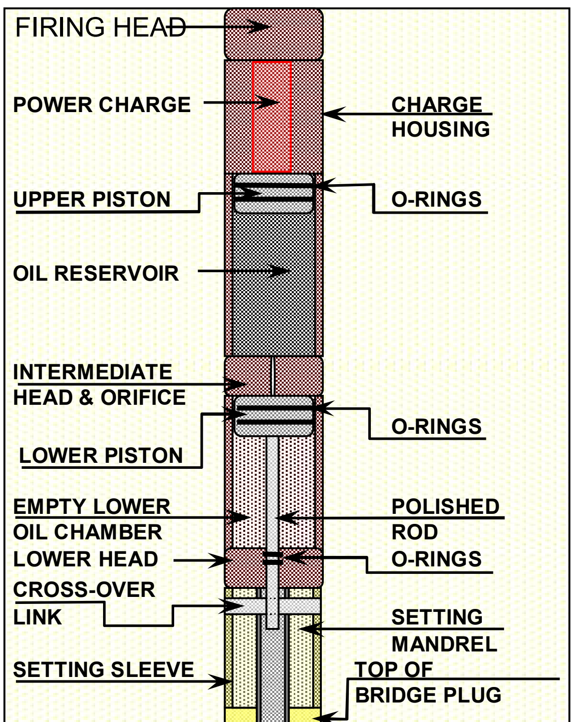

Figure 8-49 **A drawing illustrating the mechanics of the Baker Setting Tool.**

aged brain with its calcified neurons while the main advantage I have is the lack of familiarity with such equipment on the part of my readers. Let's hope the former doesn't out-weigh the latter and I can at least sound intelligent.

What I've tried to show in figure 8-48, with my limited memory and artistic ability, is a Baker Bridge Plug cross section with one side activated or expanded and the other side prior to

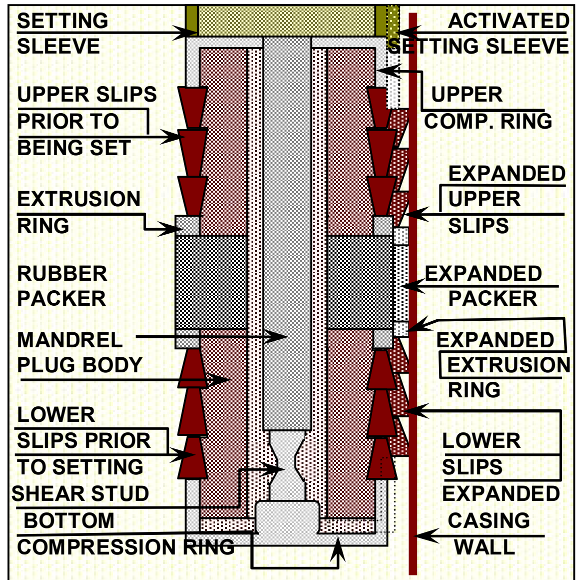

Figure 8-48 A drawing illustrating the mechanics of a Baker bridge plug.

setting. Though the drawing is far from accurate as imagined in the dim recesses of this 75-year old brain, I feel sure I can describe the basic principles involved. The plug has a cast iron body with an opening through the center in which the mandrel of the BST fits and is connected to the shear stud. The shear stud is a carefully machined connector hooking the mandrel to the bottom of the plug, which is closed off. Around the center of the plug is a rubber packer whose composition and durometer rating is so designed that it will stand up in the well environment. Even so, an extrusion ring placed next to the packer keeps the rubber from extruding up or down the hole from the center when pressed tightly against the casing wall. Basically, the slips are metal teeth, which bite into the casing when expanded and pressure from the compression rings, whether in an up or down direction, pushes them away from the plug center. Thus, they hold the plug in position and the packer element seals off the periphery of the plug. The lower slips prevent movement in a downward direction and the upper slips do so in an upward direction. They are set and bite into the casing when the shear stud is broken at a tension of about 50,000 pounds, I believe. In any case, it's a bunch of tension, more than the mandrel can bear. Likewise, it's almost as much as I had to bear when things went awry on a job as a field engineer or later, as a district manager.

PLUG SETTING ACTION

The basic setting action goes something like this. When the setting tool is fired, the setting sleeve pushes down against the upper compression ring of the plug while the mandrel holds the lower compression ring stationary. This action pushes the upper slips along the inclines illustrated in figure 8-48 causing them to expand in diameter eventually engaging the casing. Once the upper slips are set (can move no farther because of the casing), the body of the plug is pushed down or the lower slips move up relative to the body of the plug because they are held in place by the tension mandrel. Thus the two sets of slips are, in effect, pushed or pulled toward the center.

Small screws holding the slips in place are sheared as the slips move along an incline towards the center, which, as mentioned, causes them to expand in diameter. They in turn push the ring on either side of the rubber packer causing it to expand in diameter. As the packer seals against the casing wall, the slips bite into the steel wall or are set. Once this action is complete, the body of the plug can move no more. Consequently, as the setting sleeve continues to push down, the tension in the mandrel builds up to a value sufficient to shear the stud holding it to the bottom of the plug. The slips cannot move backward or relax because the teeth are secured into the casing wall. The result is great mechanical strength and a good seal, both of which are necessary for zone isolation. I never was sure just why some operators preferred to dump ten feet or so of cement on top, which seems like a dubious backup to me.

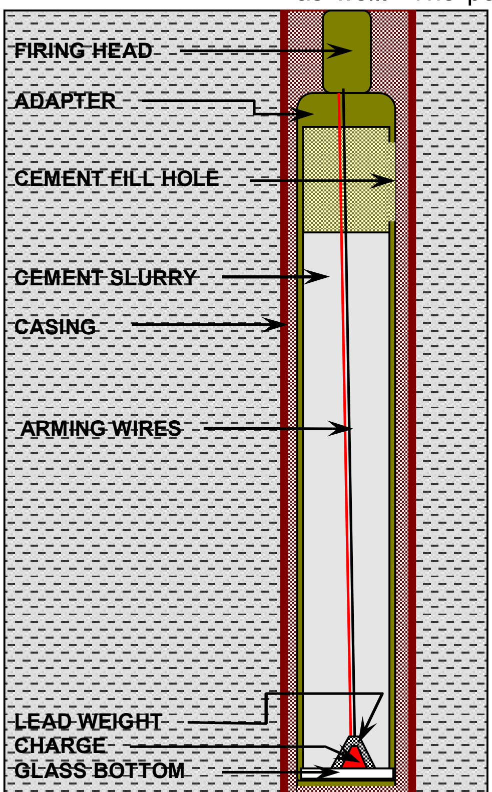

Figure 8-50 A drawing illustrating a dump bailer without a bridge plug.

THE BAKER SETTING TOOL

Not having learned my lesson in trying to draw a bridge plug cross section, I will now attempt to draw a rough diagram of a Baker Setting Tool which is illustrated in figure 8-49 and use the same in my explanation of this device.

The device had an electrical firing head, which contained an igniter that would fire at about ½ of an ampere, as I remember. In any case, it in turn ignited the power charge shown just underneath it which burned slowly rather than exploding. The slow burn is necessary to provide a slow build up of pressure on the piston below it. As the charge burns, the resulting gas pushes the upper piston down as it expands which in turn forces the oil in the reservoir through the orifice at a specified rate. The exiting oil, in turn, pushes the lower piston down to provide room for the oil and, of course, moves the polished rod secured to its base downward as well. The polished rod has a crossover link connected to it, which rides along a slot in the periphery of the setting mandrel. The link also connects to the setting sleeve and consequently applies the force from the lower piston to the sleeve. The mandrel is threaded into the lower head of the setting tool and is also connected to the shear stud as shown in figure 8-48. This obviously holds the bottom of the plug firmly as the setting sleeve pushes down on the upper slips. As mentioned earlier, the upper slips set and when they can't move any more, the body of the plug moves down which causes the lower slips to ride up the lower incline and they are set in turn. The action has the same effect as if the lower slips were pulled up but the action is as explained. Once both sets of slips are set, nothing can move except the setting sleeve, which builds up tension on the shear stud being held by the mandrel. When that tension exceeds its strength of approximately 50,000 pounds, it separates and the setting tool comes free from the plug. At shallower depths, as mentioned earlier, three distinct actions are felt, namely the setting of the upper slips, the setting of the lower slips and the shearing of the weak point or shear stud, in that order. The latter is the strongest and can still be felt in wells too deep to feel the first two actions. It was always a relief for the engineer when the final thud was felt.

SAFETY

All standard safety regulations imposed by Schlumberger were followed to assure the device wasn't fired on the surface. Although not as dangerous as a perforating gun, it was treated the same. Those operational procedures will be described a little later as we get deeper into the perforating operation. Let me say here, however, that when a junk basket or Baker plug were being run, the clearance between the tool string and casing was very small and both operator and engineer had to be on guard to be sure the tool didn't stop going in or hang up when coming out. Descent as well as ascent cable speeds were relatively slow to allow the device to sink ahead of the cable and to assure it didn't hang up on a collar or some unexpected junk or protrusion. Such problems could lead to that nemesis of all engineers, namely a fishing job. I never met a fishing job I really liked and I've seen plenty.

ADDITIONAL DUMP BAILER DETAILS

The dump bailer consisted of one or more sections of pipe of a size, which could be run in the production casing of the well in question. When run with a BST (Baker Setting Tool), the pipe acted as an extension of the setting sleeve while a mandrel running from the BST mandrel to the shear stud of the plug ran down its center. The top of the plug acted as the bottom of the bailer and prevented the liquid cement slurry from running out. When run alone in cases requiring additional cement, it contained a glass bottom to hold the cement. A small charge was placed on top of it and was connected to a firing head on the bottom of the collar locator as depicted in figure 8-50. Through the collar locator depths are checked carefully, assuring the engineer that the depth of the bottom of the bailer was accurately known. The bottom of the device was then positioned just above the earlier cement or plug (if no cement had been previously dumped) and the charge fired. The glass bottom broke open allowing the cement to run out, as the bailer was moved slowly upward. The winch operator might move the bailer up and down a few times to help empty the cement. When the operator was assured that the bailer was empty, which condition was accompanied by a decrease in cable tension, he would bring the dump bailer out of the hole to prepare for the next service.

PRODUCTION PACKERS

Production packers were illustrated both in chapter 5 and in figure 8-39 of this chapter. Their purposes were to provide zone isolation and to improve production efficiency by closing off the annulus. They differ from a bridge plug primarily by the opening or openings through their centers, which accommodate the production tubing employed. Such tubing may be utilized to run the packer in the hole and set the same via mechanical means or it may simply be seated in the hole of a packer previously set by a wire line company. Both approaches are used although the wire line method seemed to be the most common.

Where the packer is set by wire line, a representative of the company, such as Baker Oil Tools, providing the packer, is on site. The wire line company provides the setting tool and the Baker representative the sleeve and release mandrels. The construction of the latter item and just how it was secured within the packer is not clear to me at this point. Although I have watched a Baker representative rig the packer to the setting tool, I can't recall the mechanism clearly enough to explain it. The setting action, however, is the same in that one can feel the upper slips set, the lower slips set and finally the shearing of the mandrel connection to the packer. A typical packer has a flapper valve on the bottom of it across the opening as described earlier, which closes, via a spring, unless pushed open by the tubing, which is later employed. See figure 8-39 for a visual description. This prevents upward flow until tubing and surface equipment are both in place and ready for such flow.

In a casing gun operation, the hydrostatic pressure within the casing is overbalanced, so to speak, or higher than any expected formation pressure.

PERFORATING OPERATIONS

A CASING GUN OPERATION

In a casing gun operation, the hydrostatic pressure within the casing is overbalanced, so to speak, or higher than any expected formation pressure. This assures well control after the well is perforated to perform any additional gun runs. As explained earlier, such an operation has both negative and positive aspects and its use depends a great deal on known formation parameters. By the time I left the business, many such operations were still conducted but the momentum was towards through tubing, under balanced operations where the hydrostatic pressure in the casing was less than formation-pressure. As previously explained, this provided better well performance.

On a new well, the first operation to be run was some sort of depth control log as already described. In later years, in the Rocky Mountain region at least, this log was combined with a cement bond log, which allowed an evaluation of the cement job as well as the establishment of collar depths relative to the zone of interest. In earlier years a temperature log was typically run to establish the cement top even though the quality of the bond was still in question. Actually, such an operation would occur whether the eventual completion was to be through tubing or via casing guns. If there was questionable bonding between potentially productive zones (8980’) and nearby water bearing strata (9050’), as in figure 8-10 at 9000 feet, the operator may elect to perforate and squeeze the zone of poor bonding to correct the problem. Thus, in the case sited, he might shoot 8 shots or so over two feet at about 9000’ and pump or squeeze cement into the void to assure isolation between the water zone and the oil-bearing strata at 8980’. After the cement had time to set up, i.e. 48 hours or so, he might run another CBL over the zone to be sure the procedure was effective. Assuming all was well, he would proceed with the perforation operation.

PRESSURE CONTROL FOR CASING GUNS

Even though the well is to be perforated in an over balanced manner, pressure control equipment is utilized almost universally because of safety and the possibility that the formation pressure experienced will be greater than anticipated. Such things have happened with the well coming in; that is, the pressure pushing all the fluid out of the hole along with the wire line equipment being used. Besides being a mess, a fire might well ensue with its associated dangers and cost.

The pressure control equipment utilized provides for containment of the well fluids with the wire line equipment in the hole and the safe removal of the same from the well once it is brought back to the surface. Such a system is depicted in figure 8-51. The customer’s well control equipment consists of everything below the coupling just above the blind rams, which are shown in their closed position. The well can obviously be closed off with these rams, as necessary, when equipment is out of the hole. The operator can also close the pipe rams around the tubing when necessary with the pipe in the hole. The ram

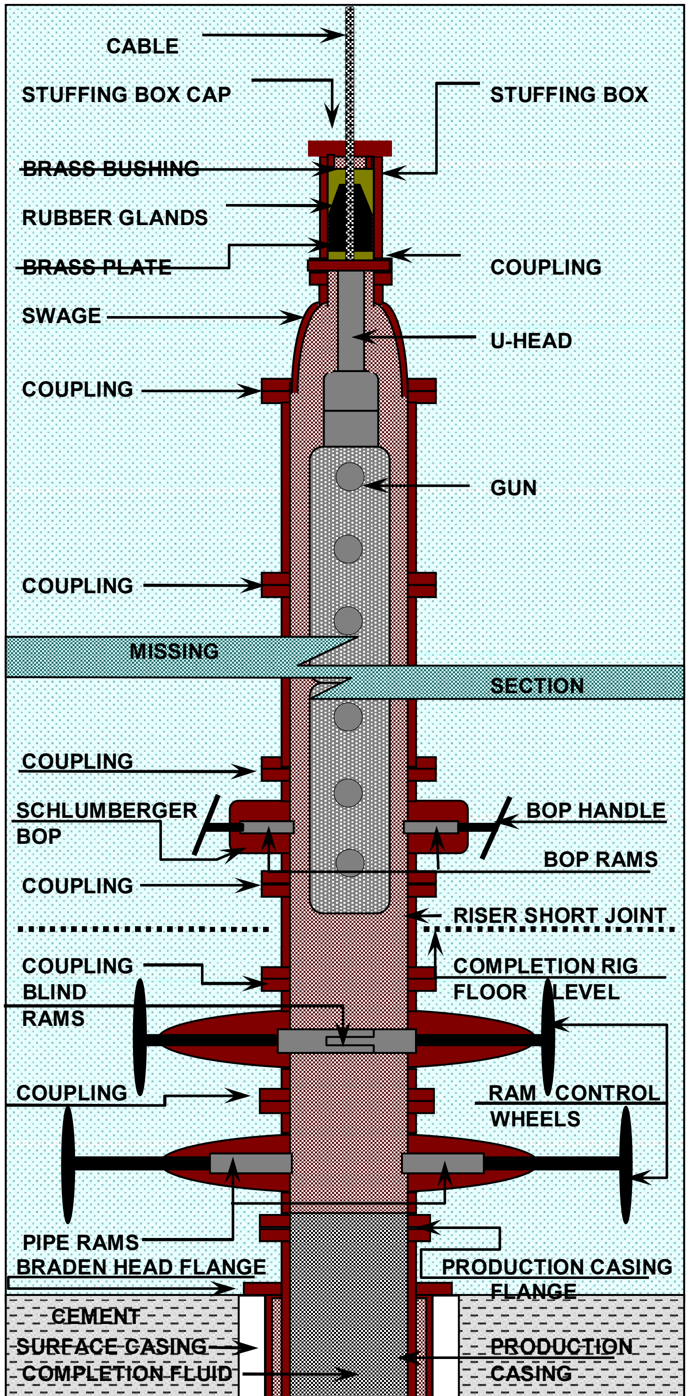

Figure 8-51 An illustration of pressure control equipment for a casing gun perforating job.

control wheels were used to manually close a given set of rams as required. Towards the end of my tenure in the oil field, such rams had been largely replaced by hydraulic rams, which were activated from the driller's console on the rig floor. Notice the production casing is contained inside whatever length of surface casing is being used but extends through the zone to be completed. The wire line well control equipment includes everything above the coupling on the topside of the blind rams. The rig floor, though not shown as such, is indicated as being just above the blind rams. This would be the completion rig floor, which would differ in height from that of the original drilling rig, having been moved in after production casing was set.

Now, let's get on with a description of the wire line pressure control equipment. Basically, its function is to safely control the well, should it begin to flow while wire line equipment is in the hole. Once that equipment has been brought to the surface, even with the well trying to flow, the latter can be closed in with the blind rams, the wire line equipment can be removed and the operator can then go about his business. To prepare for a perforating operation, a short joint of riser (steel casing) is attached to the top of the rig BOP's to make the well head accessible for the wire line BOP and is typically provided by the wire line company. It may be 4 to 6 feet in length as opposed to a standard riser length of 8 feet. The object is to position the wire line BOP 2 to 4 feet above the rig floor to make it readily accessible for operation as required. Above the BOP sufficient riser in 8-foot sections is utilized to completely cover the longest string of guns to be run. That is, the distance between the swage on top of the riser and the blind rams must be greater than the total length of the wire line equipment allowing it to be contained in the riser and the blind rams closed. In figure 8-51 we show a missing section, which simply means the length of the riser is variable for the situation at hand. This allows safe removal of the wire line equipment after an operation if the well is flowing. The swage adapts the stuffing box to the diameter of the riser being used.

The stuffing box contains a set of rubber glands with a hole through the center whose diameter is the same or maybe slightly less than the cable diameter. Thus they seal around the cable and prevent fluid leakage in spite of cable movement. The brass bushings and the brass plates hold them firmly in place and provide variable pressure to assure a good seal as determined by the pressure from the top or cap of the stuffing box. Consequently, the rubber bushings are the working seal during perforation and movement of the tool string up and down the hole. They, of course, wear out and need to be changed from time to time which points out

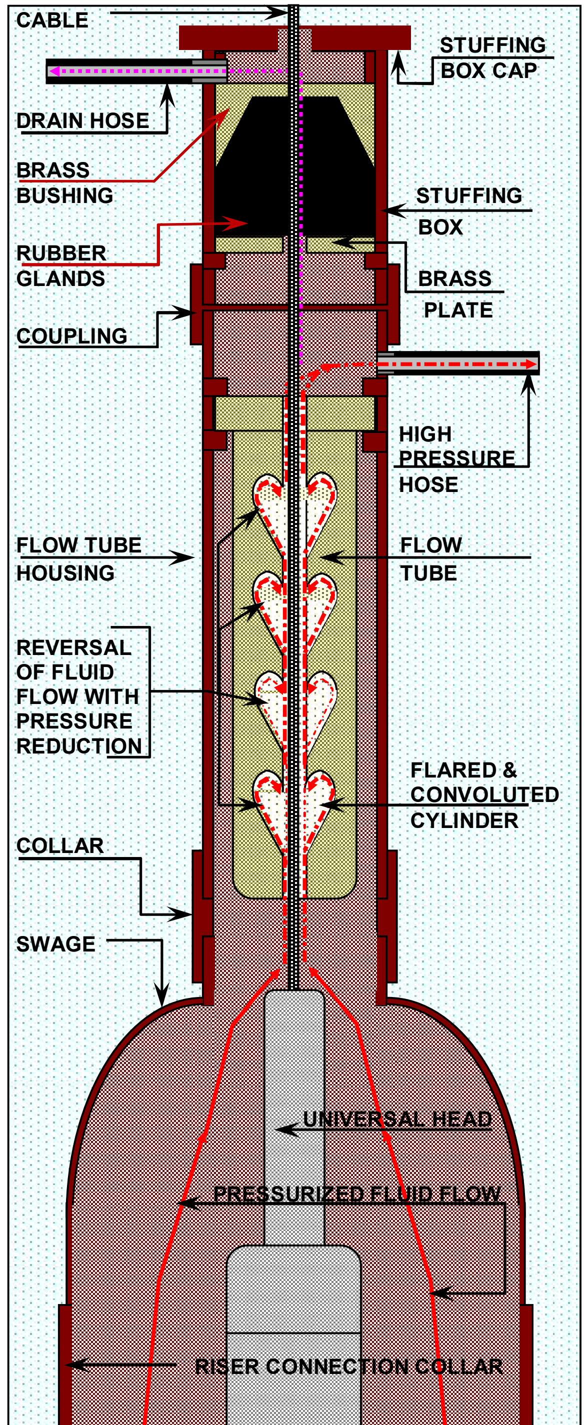

Figure 8-52 A simplified drawing of a flow tube functioning with a stuffing box.

the function of the wire line BOP. Should fluid leakage become too severe during an operation, the tool string is stopped, the wire line BOP rams are closed around the cable providing a second seal and the rubber glands are changed. The BOP is then opened and the operation is continued. This particular system provides safe exiting from the well for pressures up to a couple thousand pounds per square inch but is not designed to allow entrance into a well with such pressure. Of course, with casing guns the completion fluid provides an overbalance and pressure only occurs with the unexpected.

REENTERING A WELL UNDER PRESSURE

Though this type of operation is the exception for over balanced situations, it may occur for such things as completing the final perforations or running a production packer. To accomplish this, i.e. get the tool string to drop into the well once the blind rams are opened, there must be sufficient weight in the tool string to overcome the well pressure and the friction of the glands sealing off the cable.

To understand this principle more clearly, first, consider the pressure pushing up on the cable. A typical cable for casing gun operations is 7/16" in diameter or it presents a surface for the well pressure to be applied against of 0.15 square inches. The pressure on all other items in the tool string is equalized in all directions with the net surface area being that of the cable cross-section. That is,

$$A = \tfrac{1}{4}\,\mathrm{Pi}\,D^2$$

$$A = \tfrac{1}{4}(3.1416)(7/16)^2 = 0.15\ in^2$$

If the well pressure is 1000 pounds per square inch, it will take 150 pounds of tool weight to balance the well pressure alone. The friction of the glands will require additional weight and, as the pressure rises, this friction also increases in providing the necessary seal around the cable. The problem of providing such weight may well prove impractical. Thus, the logical approach is to look for a way to reduce the pressure on the glands and their grip or friction on the cable.

> **Fluid had to flow up the tube to make the system work. Consequently, a small diameter hose, connected to the flow tube housing just above the flow tube proper, provided a path for it to exit the pressure equipment.**

Early in my career, the above problem was solved with a device called a set of "flow tubes" which were mounted just below the stuffing box as depicted in figure 8-52.

The flow tube consisted of two brass pieces, which were bolted together to form a cylinder with a hole through the middle. The half cylinder in each piece was carefully milled to make it only slightly larger than the cable for which it was designed. At regular intervals along the surface of each semi-cylindrical groove, the diameter of the surface flared and was then convoluted or doubled back to the original diameter as illustrated in figure 8-52. A portion of the fluid flowing up the tube under pressure in this convoluted space reversed its direction as it followed the surface of the cylinder, thus canceling a portion of the pressure forcing fluid along the cable. See the red dashed arrows within the flow tube in figure 8-52. I don't remember the number of such flared zones in a given tube but it was in the order of 8 or 10, as I recall. In any case it was sufficient to reduce the pressure of the exiting fluid to such an extent that the glands could seal around the cable with very little friction thus negating any need for additional weight.

Fluid had to flow up the tube to make the system work. Consequently, a small diameter hose connected to the flow tube housing just above the flow tube provided the path for the fluid to exit the pressure equipment. The red dotted line indicates the path of such fluid. This hose had a valve on the end and was lashed to a portion of the rig so it wouldn't whip around as the fluid exited. The rate of flow was controlled by the valve and was minimized to keep the produced fluids at a minimum. However, too low a flow would increase the pressure on the stuffing box requiring greater pressure on the glands and consequently reducing their life. A happy medium was reached, which seemed to satisfy both requirements quite adequately.

At the top of the system just above the brass bushings, a drain hose was connected which drained any well fluid escaping the glands to some predetermined place of safety. The fluid path is indicated by the magenta dotted line. The pressure on that hose was atmospheric and it served only to keep such fluid from running all over the riser and rig floor. Needless to say, the flow tubes were less than satisfactory. Besides the loss of well fluid, the pressure one could operate against was relatively low.

A THROUGH TUBING OPERATION

Through tubing operations began as simply a way to work over or re-complete an existing well in a different zone at minimum cost. In fact, in my early years, the well would be loaded with salt water of sufficient density to hold the formation pressure in check and then swabbed down to allow the well to unload. Usually, in my early years in Wharton, Texas, only one trip was required to complete a zone through tubing and the operator might under balance the well such that the wellhead was under pressure when we exited it. Of course, we simply closed the main valve of the "christmas tree" (chapter 5), then rigged down and left location. The operator then let the well unload after assuring himself that everything was ready. In other cases, the operator might allow the well to unload while we were coming out of the hole by opening a wing valve on the tree. As the tool string neared the surface, the well pressure would begin pushing the equipment out of the well and the winch man would have to suck the cable on to the truck quickly to stay ahead. If not, the cable would begin piling up on the ground. Of course, as the string approached the wellhead, he slowed the winch speed so that when the tool bumped the stuffing box at the top of the lubricator or riser, he didn't apply too much tension and sever the weak point.

I'm not sure who realized first that under balanced perforating jobs improved well performance. I suppose it came about from situations like I just described. In any case, it wasn't long until such an operation became a standard in higher porosity formations where formation stimulation was not an issue and deep penetration of the jets wasn't too important. That is, under such conditions invasion was shallow and damage resulting from the same was likewise relatively shallow.

Initially, negative pressure differentials, or formation pressure greater than well bore pressure, were kept relatively small but it didn't take long to figure out larger differentials did a better job of cleaning out the perforations. Customers soon began swabbing down the well prior to perforating to provide such differentials and wire line companies had to respond with better pressure equipment to accommodate the same. With that challenge the grease injection pressure equipment was born which I shall now attempt to describe with the aid of figure 8-53. I claim no expertise in this area but then, I'm not speaking to a group of experts on the subject either, so I guess I can proceed without fear.

GREASE INJECTION PRESSURE CONTROL

I'm certainly no expert on this type of equipment, having run it once or twice during my tenure with

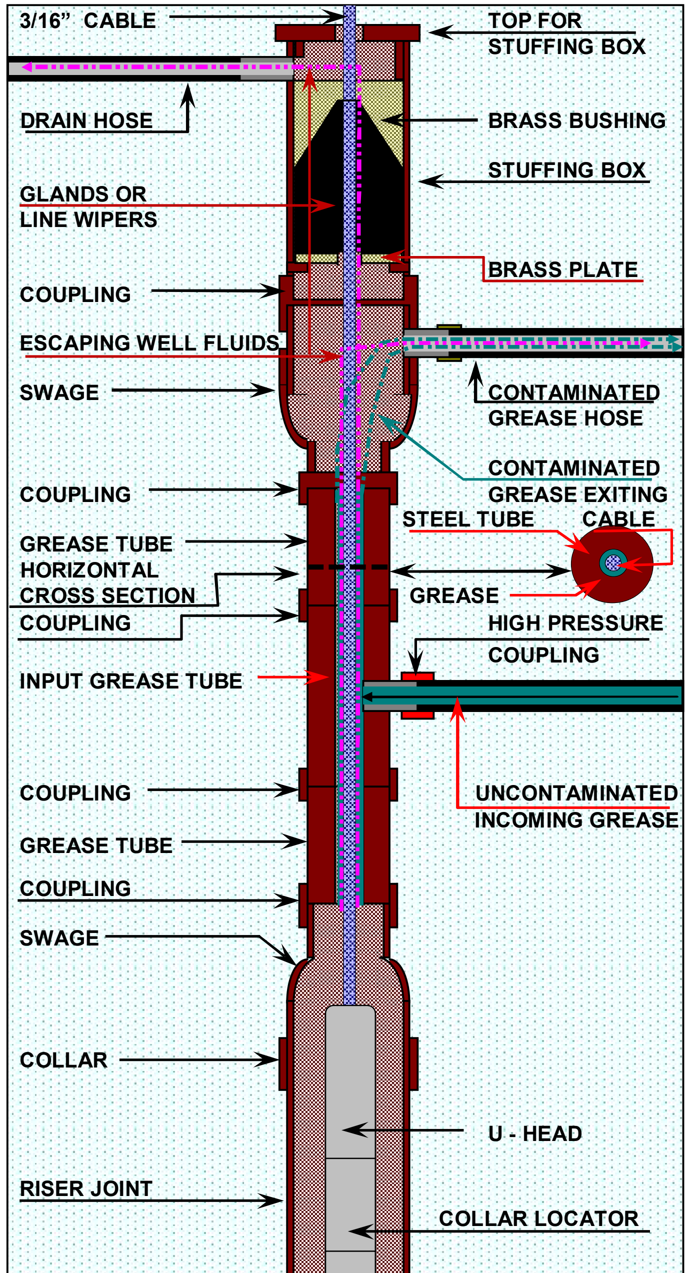

Figure 8-53 An illustration of Grease Injection pressure control equipment with a joint of riser.

Schlumberger. Even so, I hope to be able to explain the principles of this type of gear because it replaced the flow tube and, as far as I know, is still the only control equipment used for wire line tool entry into wells with high pressure and, quite frankly, I find it interesting. So, let's begin with a description of the various components involved. I should also admit that I may be missing a few pieces but, hopefully, the primary ones are there.

Starting at the top of figure 8-53, we have a stuffing box with drain hose, brass bushings, line wipers or glands, brass plates and housing. It is similar to that utilized with the flow tube but a later improved version. Its purpose is to seal around the line or cable causing the majority of grease contaminated with well fluids to exit via the return hose provided to the right. Any escaping fluids and grease getting by the wipers are then drained with the hose designated as such to eliminate the mess it would make running out the top of the riser. The line wipers will also help seal off the well, should the grease seal give away and the appropriate action is being taken to re-establish it. The grease tubes are, of course, the primary seal for entry and exit from the well. Each tube is comprised of a piece of steel about 3 feet long with a carefully machined cylindrical hole through the center. The hole is lined with a very hard so-called "wear tube", as I remember, to lengthen the tubes' lives. The diameter of the hole through which the cable feeds is very slightly larger than the cable it is designed to seal around. In figure 8-53 the size of the grease annulus is exaggerated to make it more visible.

Close tolerances are necessary to establish and maintain a seal. As the tubes wear, beyond specified tolerances, they must be junked. Three such tubes are typically used in lower pressure jobs with the center one always being the one fed from the grease pump. With higher pressures 5 or more, I suppose, tubes are used with the same symmetrical configuration. At the bottom of the tubes a swage is utilized to connect them to the necessary riser and BOP. A grease pump, with the ability to pump at pressures higher than that of the formations is required to pump the grease into the tubes via the high pressure hose involved. The pump is automatically triggered by a pressure sensor and pumps additional grease as required to keep the seal.

The secret, as I understand it, to establishing and maintaining a seal with this type of gear lies in the small annulus between cable and tube, the very viscous or stiff grease and the ability of the pump to overcome the well pressure. A very viscous fluid requires a higher pressure to move it through a pipe than does one of lower viscosity. Likewise, the smaller the pipe, the greater the pressure required. Combining the two parameters, i.e. very small annulus and very high viscosity grease, in the grease tubes

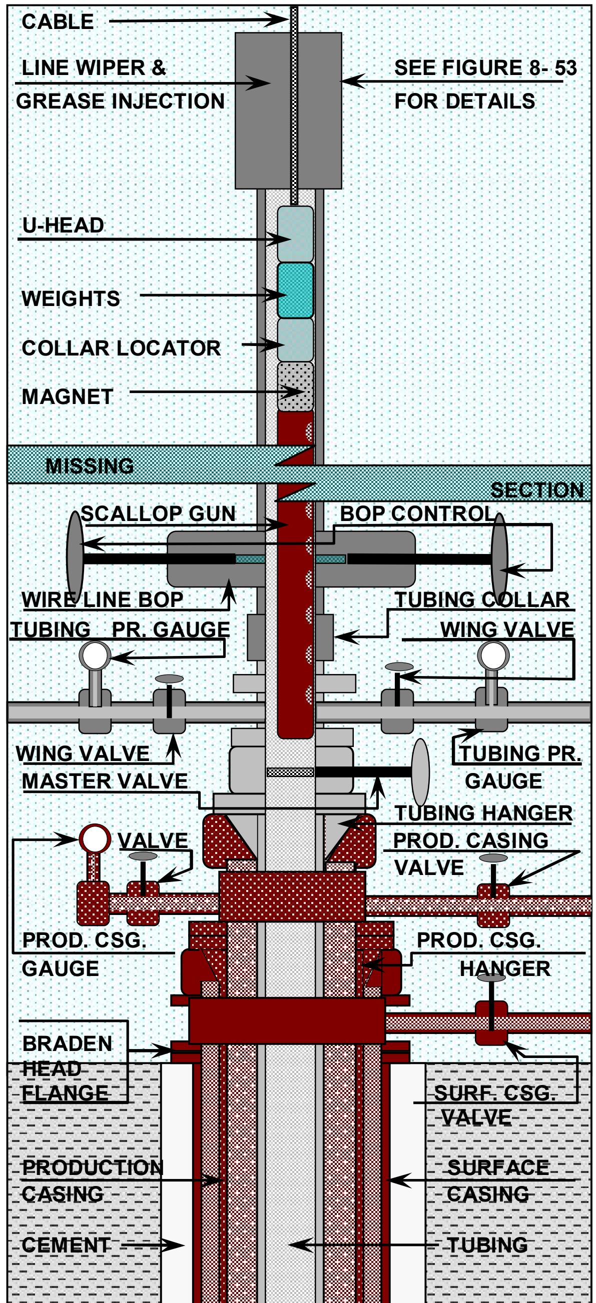

Figure 8-54 A drawing illustrating thru-tubing pressure control equipment and a well-head or christmas-tree (oil field jargon).

enables them to hold very high pressures. See the horizontal cross section of figure 8-53. The pump, having high-pressure capability, can pump the grease into the center section and both up and down the adjoining tubes. Cable movement will disturb the grease and the seal would be lost except the pump is automatically controlled, as mentioned previously and continuously pumps in more grease to compensate for any lost by cable movement.

OPERATION OF GREASE INJECTION EQUIPMENT

With the master valve of the tree closed, the equipment is rigged up with the riser necessary to cover the tool string between it and the master valve. The perforating string is inside the riser and pulled up against the grease tubes to prevent upward movement. The grease pump seals off the tubes after which the master valve is opened allowing the string to be lowered into the well. Sufficient weight is used to overcome the expected pressure pushing up on the cable. One might note that 3/16” cable has 18% of the cross section of 7/16” cable and consequently requires just over 1/6 the weight necessary to balance the well pressure. In our example of 1000 pounds pressure used earlier, the weight required is 28 pounds rather than 150. For 5000 pounds well pressure the weight required goes up to 140 lbs. or still less than that required for 7/16” cable at only 1000 lbs. pressure. Obviously small cable is essential for working with high pressure and the smaller the better. Of course, there is a practical minimum where a conductor is involved and a reasonable line strength required is maintained.

As the tool string is being removed from the well, the grease seal is degraded by the upward movement of the cable through the grease tubes as well as by the fluid pressure from the well. That is, contamination of the grease within the tubes lowers its viscosity and unless constantly replaced by the high-pressure grease pump, the well fluids may begin to escape or blow through the grease. Should the seal be lost, it is necessary to stop the cable, close the wire line BOP around the cable to provide a temporary seal and then re-establish the grease seal. Once that is accomplished, the BOP is opened and upward movement can be resumed. (A wire line BOP is only designed to provide a seal around the cable when stationary.) Now, let’s move on to an illustration of a typical configuration of wire line pressure control equipment for through tubing work.

THROUGH TUBING PRESSURE CONTROL

We will utilize figure 8-54 to describe the overall setup of pressure control gear for a through tubing operation with figure 8-53 providing the grease equipment details. Let’s begin with the casing at the bottom and work our way up the diagram. In the ground you will notice the surface casing secured and sealed to the formations with cement. The Braden head flange topping the surface pipe is the depth reference for the well. Even though drilling measurements are made from the Kelly bushing of the drilling rig, they are referenced as being some specified distance such as 15 feet above the Braden head flange or maybe ground level. The latter two are normally at the same elevation on land rigs.

Secured and sealed to the top of the Braden head flange is the production casing-hanger, which also has a port leading to a pressure gauge. This allows the annulus between surface and production casing to be monitored for pressure. Actually, the adapter for the gauge may be a separate unit but who cares, the principle is the same. The production casing is secured and sealed to the casing hanger as well as cemented on the bottom end for some thousands of feet. It too has a combination tubing hanger and access port adapter for pressure measurement and tubing attachments. Again, they are probably separate units but my drawing is complicated enough as it is. Besides, I’m doing all this from memory and can only hope to provide a generalized picture. Come on kids, give me a break and don’t expect perfection from this old man. Pressure monitoring of the annulus may indicate problems such as a leaking packer or tubing.

The length of riser, BOP and well head between the master valve and the grease equipment must be greater than the total length of the tool string being run so tools can be isolated from the well by closure of the master valve.

The tubing is then landed and hung in the production casing with the tubing hanger sealing off the casing annulus. A master valve is then bolted to the top of the tubing hanger, which provides ability to shut the well in as needed. On high-pressure wells there may be two such valves in series with the top one being the working valve. Should it need to be changed because of frequent use, the lower valve is closed until the job is finished. With infrequent use, the second valve lasts for the life of the well

Next comes the flow line adapter (I’m not sure of its real name), which provides a means of diverting well production into either of two lines. Each has a valve to control flow as well as a gauge to monitor flowing pressure. Above the flow lines is a tubing collar, which provides access to the well through the tubing. During production a pressure gauge is mounted in the collar and can monitor shut in pressure if both wing valves are closed. It is removed for entry into the well during work over.

For any production or work over operations, the necessary pressure equipment can be attached as I have illustrated for perforating access. The length of riser, BOP and well head between the master valve and the grease equipment must be greater than the total length of the tool string being run so tools can be isolated from the well by closure of the master valve. This distance depends upon such things as gun length and well pressure, the latter determining the number of weights necessary in the tool string. High-density weights are used to minimize the number required. If totally expendable guns are being used and there is no pressure initially on the wellhead, the length of riser is reduced to that required to cover the U-head and locator. Such was common in my day but I do believe such guns are outmoded today, though some are semi expendable. Anyhow, I suppose you all clearly understand the system used for through tubing perforating. Such understanding, if for no other reason than my humble but clearly outstanding drawing, results from a most lucid explanation. Well, on to other subjects, whether they are exciting, the same old gobbledy gook or whatever else creeps into this poor benighted mind of this old man.

OPERATIONAL DEPTH CONTROL

We explained earlier that accurate depth control was assured through the use of a perforating depth control log, which is true but there are many practical problems, which can complicate any given operation. Such things as all the joints of casing being the same length or nearly so, makes it possible to identify collars one joint off depth or about 33 feet. Magnetized pipe may destroy all magnetic marks on the cable as described in chapter 6. This is so common off shore that logging, as well as perforating jobs, utilize the automatic marking device described in the same chapter. When running through tubing, there may be only 1 or 2 collars available below the packer to check. Packer depths and well TD's may be in error. These items increase the possibility for error. Difficulty in establishing an accurate surface zero for the device can add to the problem as can a poorly adjusted truck measuring wheel or weak marks on the cable. Experience and utilizing several cross checks can keep the perforating engineer out of trouble,

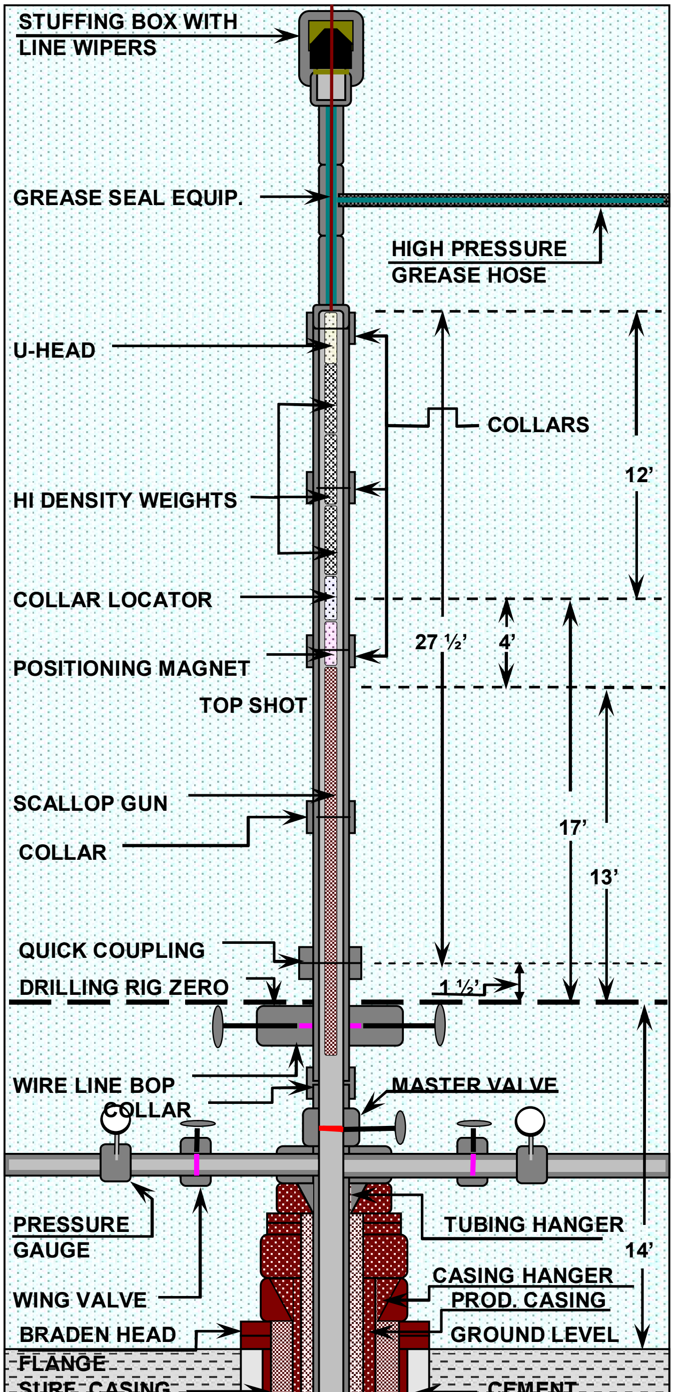

Figure 8-55 An illustration outlining the means of setting the trucks depth meter properly at 00' before entering a well, which is shut in.

as far as depths are concerned. Discussing all of these is really out of the question but I thought I would go through normal depth control as used on land. I will also assume cable magnetic marks are in place and identifiable, though this is seldom the case. However, this will give you a hint of the complex operation required to properly establish surface zero, which is critical to such a measurement. It will also help you visualize a number of potential sources of error, which can plague the engineer. Experience helps but a clear head is essential.

BASIC DEPTH CONTROL UTILIZING FULL RISER

Once again I will use an illustration as seen in figure 8-55 to help cover this rather complex subject. Hopefully, that which is missing in the text in explanation will surface in the illustration.

The problem begins with the fact that the original drilling rig is gone and the zero they used (Kelly bushing) is now some 14 feet in the air and hardly visible. To be on depth with the collars and formation of interest, we must honor that zero. To further complicate the picture, the tool string has to be picked up with the riser while inside it and can't be seen. The depth meter on the recorder will be set to read the depth of the collars because the engineer must verify those depths once in the general area of perforating. The winch meter, which the winch operator observes will be set on the top shot of the perforating gun because he will position that shot according to the engineer's instructions. Both the collar locator and the top shot of the gun are well up in the riser and consequently unobservable. So what is to be done?

As the top shot passes the drilling rig zero while going into the well, the winch meter will read 00000' and as the collar locator goes by, the recorder depth meter registers zero.

Well, let's make lots of measurements as depicted on the diagram. The engineer measures from the top of the U-head, which will bump up against the pressure control gear, to the collar locator (12') in the drawing. He also measures from the collar locator to the top shot, another 4'. He then measures from the top of the riser (bottom of the grease tubes) to the quick coupling, which will attach to its mate on top of the wire line BOP. The quick coupling of the BOP is also determined as being 15 ½' above the Braden head flange or ground level. With this information, he can determine that the collar locator will be 17' above the drilling rig zero when the riser is attached to the BOP via the quick coupling and the U-head is bumped up against the grease tubes. Similarly the top shot will be 13' above the rig zero. Once the equipment is all in place as shown, he sets the depth meter on his recorder at 99983' and the one on the winch panel at 99987'. As the top shot passes the drilling rig zero going in the well, the winch meter will read 00000' and as the collar locator goes by the drilling rig zero the recorder depth meter registers 00000'.

In a manner similar to an open hole logging job described in chapter 6, the engineer checks the first magnetic mark depth as it is registered by the bell and writes it down. He then has the winch man drop the string to bottom while he notes the bell at regular intervals and keeps it ringing on the same number. This assures him the CCL depth is close to being right. Once the tool string drops out of tubing, the engineer checks a collar or two and corrects the locator depth to that shown on the collar log. He then runs a collar log and shows it to the customer for his verification of depths. With agreement reached, the winch man drops the tool string below the zone to be perforated with, hopefully, one casing collar between the starting position and the perforating depth. He then slowly records collars, about 1000' per hour, including the intervening collar and, as the winch stops at the shooting depth, shuts off the recording light. This last exposure of the collar trace indicates the depth of the locator when the string was stopped, as illustrated in figure 8-46 providing verification of proper shooting depth.

Well, I've told you about all I know about perforating and some things I don't know. Or, as old Zeke use to say, "It ain't my ignorance that done me in but what I know'd that wasn't so." In any case, if some of what I know'd ain't so, you'll never know and I doubt that anyone that does know will ever come across it. So, let's get on to my next and last major area of **no** expertise and see if I can come up with a reasonable story.

PRODUCTION LOGGING

If wells could be drilled, cased and put on production without additional troubles, the oil operator's life would be sweet. Unfortunately, casing corrodes, tubing leaks, packers fail cement jobs don't hold, water floods go awry and gas - oil ratios change along with a host of other problems too numerous to list. Needless to say, information is necessary to correct such problems and provide a way for the operator to travel the path of least expense. Hence, as problems are delineated, service companies come up with solutions, which they hope will be profitable to them, and the customer. In the production of hydrocarbons, the result has been a whole array of measuring devices.

THE TEMPERATURE LOG

This particular device was described in some detail back on page 368 of this chapter as a means of determining cement top depth. Consequently, I won't wade through the theory again but simply describe the applications it has as a production-logging device. Keep in mind, however, that the tool simply measures the temperature of the environment it finds itself in at any given time. Temperature changes or anomalies, rather than a specific value of

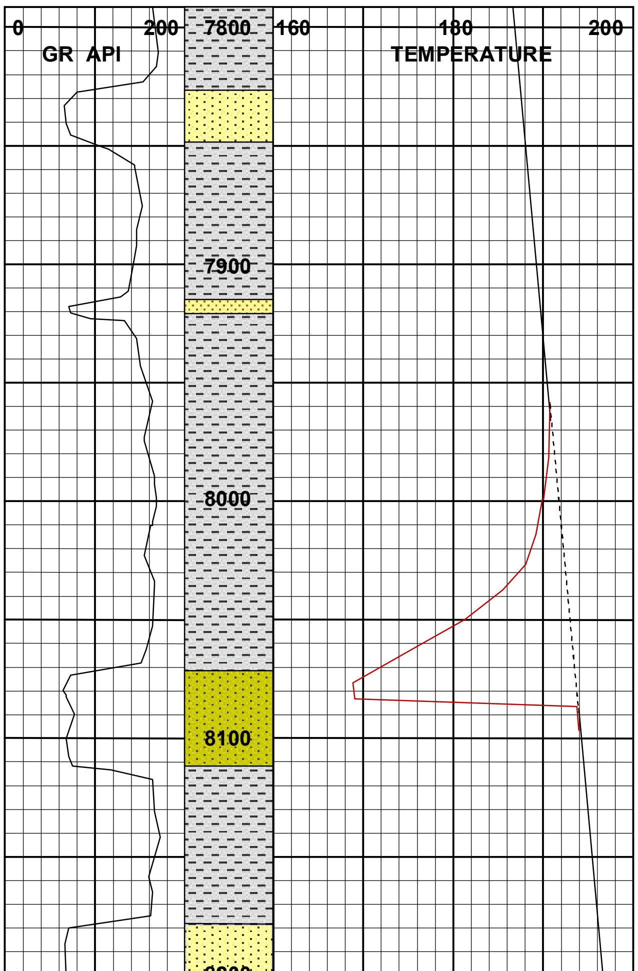

Figure 8-56 An illustration of gas entry into a well as defined by the temperature log.

temperature, are the keys to identifying well characteristics and problems. I'll try to explain at least a couple of these situations so as to help the reader understand the wide application temperature devices have in the oil field for identifying them and providing the operator with sufficient data so he can take the best action.

GAS ENTRY INTO A WELL

The thermal gradient of a well tends to be rather constant in a given area and the temperature within it gradually rises with depth. This is depicted in figure 8-5. However, gas entry into the well causes a cooling effect, which causes the gradient to deviate over the zone of entry as illustrated in figure 8-56. The natural gradient is defined by the black temperature curve, which is dotted over the anomaly produced by the gas entry into the well. The recorded curve would be a composite of the two black solid portions plus the red solid portion. The dashed zone simply indicates how the curve would have responded without gas entry. Notice the temperature drops from an expected 194 degrees at 8180' to 169 degrees at that point clearly defining the gas entry with its associated cooling effect.

If the well had been making little or no gas and suddenly began producing an increasing amount, one might wonder if a gas cap up dip had broken through into the perforations or if the cement job failed and gas from the sand at 7920' was coming down behind casing and out the perforations at 8180'. Obviously, more information is needed. There is no good way of determining the answer that I know of, other than running a CBL and then perforating, testing and squeezing off undesired zones.

WATER FLOODS

Temperature logs are used to determine where, in reality, the flood water is going, i.e. whether it is being pumped into the desired zone or escaping along the cement annulus to a so called thief zone or zone of lower pressure. Consider figure 8-57 as an illustration of such a situation. The black temperature curve is the gradient due to the earth's natural temperature increase while the blue curve portions are the zones cooled by the floodwaters. Although some water is being pumped into the production zone, most is going up hole through the annulus between casing and rock to a lower pressure or more permeable zone above. The blue arrows indicate this loss of flood-water. It would appear the cement job is not holding and a squeeze job is in order. Such work would be done and then a cement bond log would probably be run to verify the quality of the bond between the two zones. A bond log might also be run prior to the squeeze to improve its placement as well as effectiveness. The zone of interest shows some cooling effect as does the shale in between the two zones. The latter effect is due to the continuous fluid flow along the annulus between casing and the borehole wall. However, the thief zone is cooled to even a greater degree because of the quantity of fluid taken in. Thus, the temperature is very valuable in the analysis.

MANOMETER & GRADIOMANOMETER LOGS

A manometer is an instrument designed to measure pressure. There have been various types utilized over the years, apparently, from the literature I received from Schlumberger. The latest ones, using either a quartz crystal or a sapphire crystal as sensors, are much improved over the old manometer I was used to. The manometer we were using when I left the company was a part of the so-called production combination tool or PCT. This tool could run in combination a temperature sensor, a flow meter or packer flow meter, and a manometer, as well as a gradiomanometer. They had to be run

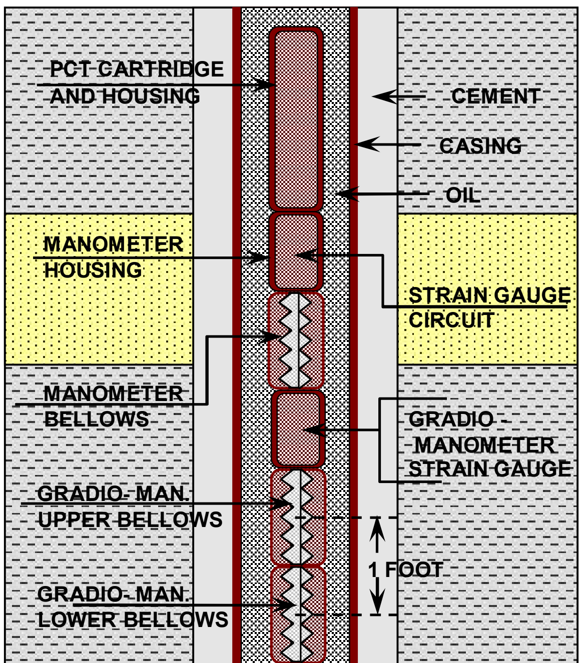

Figure 8-58 A simplified illustration of the manometers bellows and housings.

sequentially, however, but a good deal of time was saved in terms of well entry and stabilization. Additionally, a casing collar locator as well as the gamma ray curve could be recorded simultaneously with any of the other devices. The various sensors I'm in the process of describing, or have described, make up that cadre of equipment.

The manometer of my day utilized a sensor composed of a bellows and a strain gauge, as I understood it. The bellows would change volume (decrease) with increasing pressure, which provided input to a strain gauge circuit,

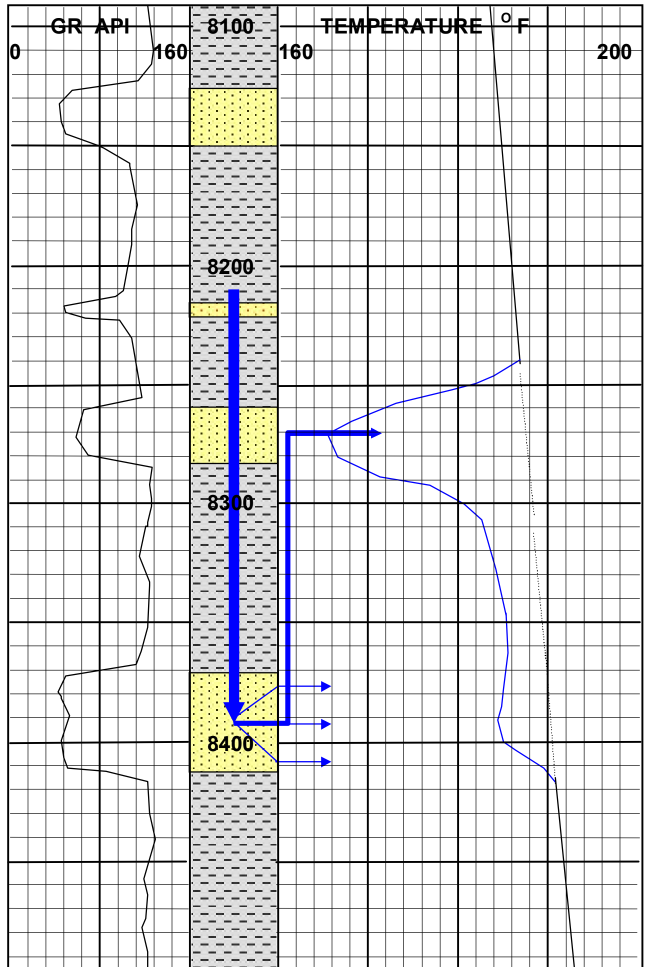

Figure 8-57 An illustration of a thief zone taking flood water from an intended producing zone.

producing a pressure readout value, as a result. The pressure measurement was then sent to the electronic cartridge for processing before being sent up hole to the surface equipment. The gradiomanometer measures the pressure gradient as the name implies and is, in effect, two manometers with one of their bellows a foot deeper than the other. The difference in their pressure measurements is then the pressure produced from one foot of the fluid in which it is immersed or the gradient in psi per foot. Both of these concepts are depicted in figure 8-58 in a very simplified manner. The two strain gauge circuits feed an amplifier in the PCT cartridge, which processes the signals before sending them to the surface where they will be recorded on film. Decisions made from such measurements can make or break profitability

MANOMETER & GRADIOMANOMETER RECORDINGS

Both the manometer and gradiomanometer recordings are illustrated in figure 8-59 which is out of sequence because of space problems. I had to insert illustrations of the flowmeter so as to fit two diagrams to the page. The two manometer curves normally wouldn't be superimposed because of their sequential nature but once again time and space are saved and the principles are still demonstrated by placing them in one figure.

As you can see, a rather straight-line recording scaled in PSI constitutes the record of the manometer. It looks much like a temperature curve in that it increases in a linear manner with depth according to the density of the fluid column. What might not be obvious is that the gradient or slope of the curve changes with the increased density of the standing water column as the tool enters it near the bottom of the hole in figure 8-59. I show the oil- water contact as being at 8943' or 8944'. Look closely and you will notice an increased slope or an increasing PSI with well depth below that contact.

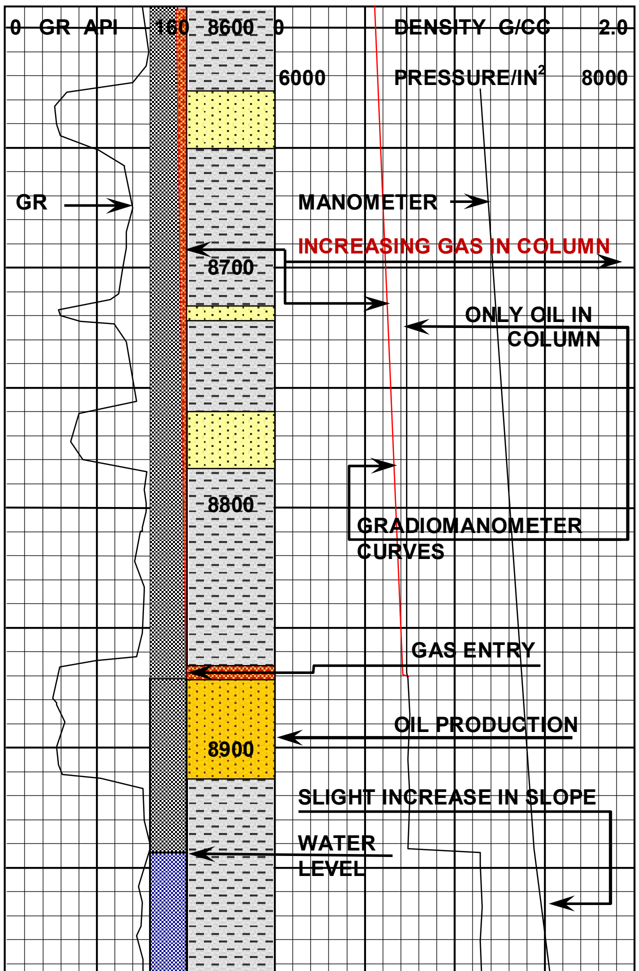

Figure 8-59 An illustration of manometer and gradiomanometer records in a well.

The gradiomanometer, of course, measures the slope of the manometer curve and as long as that slope is constant, so will be the reading of the gradiomanometer. Notice the gradiomanometer defines the oil - water contact much more sharply and is useful in highlighting such density changes. Should gas be entering the well through the perforations, as I have illustrated near their top, one would see a change in density on the gradiomanometer as determined by the combination density of the oil and gas. As the tool moves up hole and more gas breaks out of solution, the density will gradually change reflecting that phenomena. I have attempted to illustrate that condition as well as one in which there is no free gas in the column. The latter case is in black while the column of oil containing free gas is illustrated in red. Notice the separation between the two increases as depth decreases indicating an increasing amount of gas in th column as more and more breaks out of solution. This may be a little exaggerated for a 350-foot change in vertical position but it serves to illustrate my point, which is my major concern. Needless to say, even that isn't too much of a concern because none of my readers are apt to know anything about the subject. Ha-ha.

THE FLOWMETER

The flowmeter is another valuable tool for measuring yet another production characteristic of a well (take a peek at figure 8-60). The rate of flow within a well bore will change as new fluid comes into the casing or as existing fluid leaves the casing. One might expect the former or addition of flow as perforations are passed with the device. You might, however, question why fluid would leave the casing at any point other than the tubing output and then into the separator or tank.

There may well be more reasons than I can enumerate or even imagine for the suggested response of a flowmeter but I'll try to explain a couple I have encountered in my time and in my limited experience. They may seem obvious but they do demonstrate the purpose of the device.

First consider a low-pressure zone within a perforated interval. Such may occur where other wells have depleted the thief zone but not the intervals producing in the subject well. If the pressure in such a zone is less than that of the fluid column, it will draw the fluid into the perforations much as a lost circulation zone would in a drilling well. Other zones may be pressure balanced and exhibit no fluid entry or exit from the casing. You see, even as electric current necessarily follows voltage differences in household wiring or water in a household plumbing system flows from higher to lower pressure, fluid flow in an oil well follows any pressure differences it experiences.

A second but similar situation is that of a casing leak. Casing corrodes over time and should such corrosion be in an area with poor cement, as it usually is, the fluid from the well bore will exit the casing, assuming a pressure gradient exists, and follow the same to some low pressure formation. I will try to illustrate both of these situations a little later in log form but first, let's consider the two types of flowmeters (i.e. the packer type and the continuous type) available to the industry.

THE CONTINUOUS FLOWMETER

The continuous flowmeter provides a continuous flow record as the name implies as the tool is moved slowly up or down the hole. Downward movement of the tool increases the rate of fluid moving past the spinner blade and is used in lower flow situations. Absolute flow is immaterial in that it is the changes in flow and their magnitude as a percentage of flow that is of interest. When flow rates are higher, the recording is made while moving the tool upward or with the direction of flow. This obviously decreases the fluid flow relative to the spinner blade.

Flowmeter tools are necessarily run through tubing to the desired depth where flow rates are measured within the casing. This dictates a tool size of 1 11/16", which is only a fraction of the internal diameter (ID) of the 51/2" casing or 11.4%. To maximize fluid flow past the spinner blades and thus increase their sensitivity and ability to measure lower flow rates, the continuous tool had spinner blades, which folded out from a vertical position once the tool was below tubing. This is illustrated in the left or A diagram of figure 8-60 by spinner blades and the protective frame around them, which are larger than the OD of the tool itself. When the device was pulled back into tubing, the cage collapsed and the blades returned to their vertical position. I don't remember the exact diameter of the blades but they were something like twice the tool OD or maybe 3 inches. This translates into something like 36% of the area of typical 5½ inch casing as opposed to the 11.4% stated above or a 200% improvement. The spinner shaft illustrated in figure 8-60 connects the blades to a small generator producing an AC signal. This signal is appropriately processed so the number of revolutions can be counted. One revolution of the shaft produces one pulse, which is counted like a radiation count. Consequently, the number counted per second is the spinner revolutions per second, as scaled on the log.

THE PACKER FLOWMETER

The packer flowmeter was designed to measure very low flows by forcing all the well fluid to move through the tool and past the spinner blades rather than the majority of it bypassing them as with the continuous variety. Even with the fold out blades, 64% or about 2/3 of the fluid movement was missed. Thus, the threshold or lowest rate of flow to which the continuous device would respond was quite high. I'm not real sure of the mechanical configuration of the packer and spinner for the packer type flowmeter but what I show in figure 8-60 B will have to do. As you can see; the inflatable packer seals off the annulus between tool and casing which forces all fluid movement to take place through the tool body and past the spinner

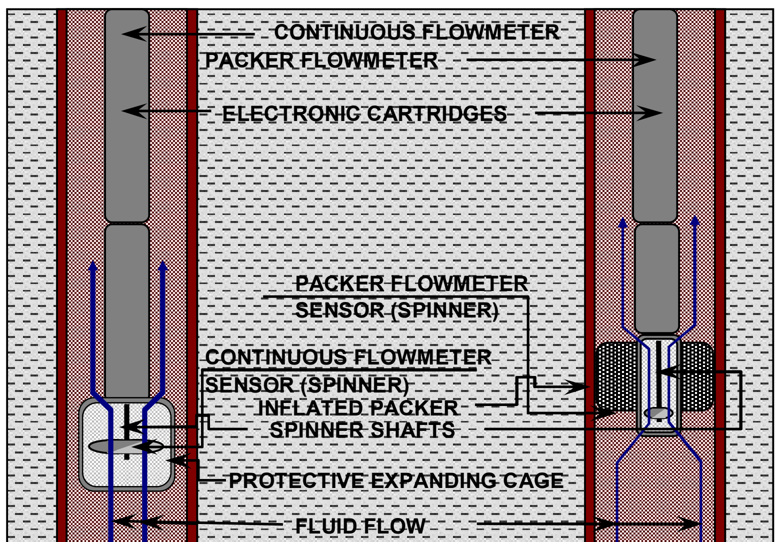

Figure 8-60 An illustration of both the continuous flowmeter (left) and packer flowmeter (right) principles.

blades. Consequently, it responds to a much lower flow rate.

The revolutions of the spinner blade, once again, generate an AC signal whose cycles are counted and processed by the cartridge for recording at the surface. It has a couple of drawbacks, namely the recording is made in a stationary position because of the packer and

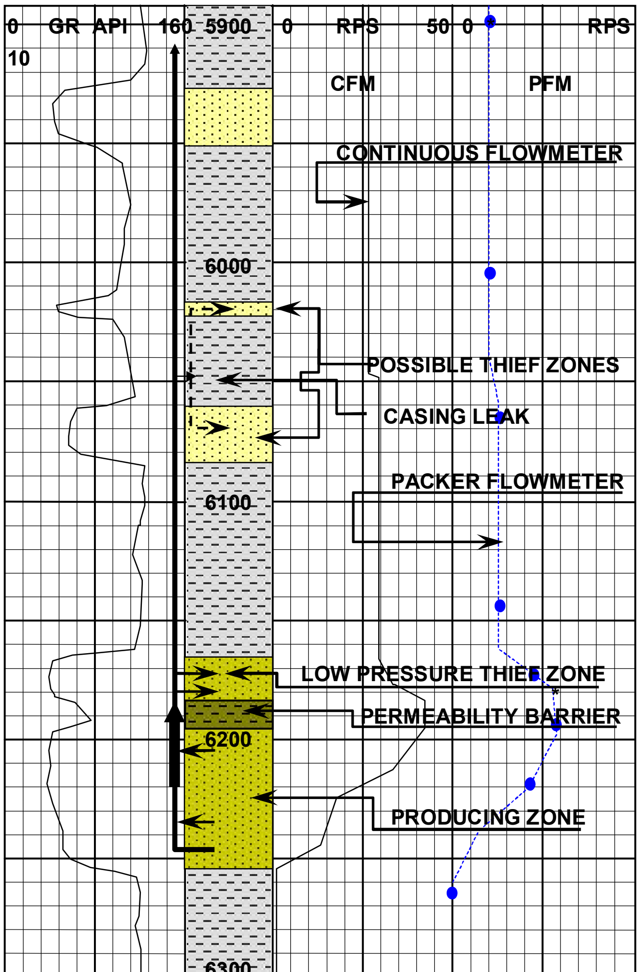

Figure 8-61 An illustration of hypothetical continuous and packer flowmeters run through an oil zone and a casing leak & 3 thief zones.

inflation of the latter restricts the down-hole flow. This choking effect can make the well perform different from its natural state and thus compromises the value of its information. However, for such low flow rates, it was the best we had at the time and as far as I know, is still the only means for recording lower flow rates.

FLOWMETER RECORDINGS

Once again I'll place the continuous and packer flowmeter recordings on the same grid to conserve space and time without any loss in the explanation of the principles involved. So, take a gander at figure 8-61, a simulated recording of both these devices. The blue trace with the large blue dots is the profile of the packer type.

What I have illustrated is a hypothetical reservoir perforated from 6255' up to 6165' or a total of 90'. The upper 20' is a depleted reservoir or at least one whose pressure is somewhat lower than that from 6195' to 6255'. Even though the two reservoirs are in the same major sand body, they are separated by an impermeable zone (6195' to 6205') and apparently not connected laterally.

THE CONTINUOUS FLOWMETER

The continuous flowmeter records a value near zero below the perforations and as the tool moves upward the spinner rotation begins to increase rather rapidly for about 10' and then at a lesser rate for 20'. This indicates a major entry of fluid into the bottom 10' with additional coming in for the next 20' but at a lesser rate. The spinner RPS (revolutions per second) is proportional to the total flow up the casing. Thus, as the curve increases to the right, the flow is increasing or fluid is being added to the well. The slope or steepness of the curve reflects how fast the extra fluid is being added per foot of formation. From about 6210' to 6225' the spinner speed increases rapidly once again indicating another zone of high productivity. Then the spinner RPS continues to increase but the slope decreases from 6210' to 6195'. Next the flow rate stabilizes or stays constant for 10' indicating no entry or exit of fluid. At 6185' the spinner RPS drops sharply at first for 10 feet and then somewhat slower for another 10 feet bringing us up to the sand and perforation top at 6165'. The drop of 13 RPS over that 20' interval indicates a major loss of fluid with the explanation being a probable low-pressure zone isolated by the impermeable layer. In such a case, the perforations above the impermeable layer would be squeezed off to isolate it from the producing zone. Such remedial work would add about 55.5% to the production of the well or about 277.5 barrels of oil per day if we assume the current production is 500 BOPD. Translating that into dollars, we get $8325 additional per day at $30 per barrel.

But wait, we aren't done yet. Remember there was another little decrease up-hole a ways at about 6045 to 6050 feet. There was no zone of interest nor were any perforations at that depth.

Yet, there was an unmistakable drop of about 3 RPS at that point. That drop means we are losing more oil probably through a casing leak caused by corrosion of the pipe or maybe the separation of a casing collar. If we can get the lost oil back, we will boost production an additional 11% or increase revenue another $1650 per day. The logical explanation is that the oil is escaping through the casing leak and traveling to the sand above or below where it is disappearing back into old Mother Nature. Well, the operator would probably run a CBL over that zone as well. Had he run an earlier one for the deeper problem he could have solved this one, as well. He might just perforate at the leak and squeeze, feeling sure the cement would find the channel. With that leak patched, production is back up where it should be at 832.5 BOPD with revenues up $9975 per day or a boost of 66.5% from $15,000 to $24,975.

THE PACKER FLOWMETER

I have included the packer flowmeter curve to simply show the difference between it and the continuous variety. Notice the scale is 0 to 10 RPS as opposed to 0 to 50 for the previous example. This reflects the poorer production and would translate to 100 BOPD compared to 500. The device is stopped at each station, the packer inflated and a reading taken. The packer is then pumped down or deflated and the tool moved to the new station and the process repeated. Each reading is then plotted on the depth grid and the points connected as shown in blue. This represents the flow profile and as you can see the same general conclusions could be drawn even though the curves are slightly different. Going through the calculations as we did before, we find a total increase in production by rectifying both defects of 190% or from 100 BOPD to 290 BOPD. That increases revenue from $3000 dollars per day to $8700. You can see that rectifying problems through production logging can be very profitable. Of course, these were hypothetical problems but not too far from reality, I would say. At 2005 oil prices, you can double those additional income figures.

THE RADIOACTIVE TRACER LOG

This particular log, as the name implies, was designed to trace the path of fluid movement within and external to the casing. In so doing, conclusions can be drawn regarding casing leaks, cement jobs and low-pressure zones. The tool contained a dispenser from which small amounts of radioactive iodine could be ejected and, as they followed the fluid movement, their path of travel and destination could be determined by a gamma ray detector. Once again I must admit before-hand my relative ignorance of a tracer log operation because I never ran one. I did, however, discuss results with cased-hole engineers and thus have a limited understanding. As a result, the following imaginary situations are relatively accurate.

A simplified illustration of the tool is shown in figure 8-62 to help describe the principles involved. As shown, the tool configuration has two gamma ray detectors, one above the ejector

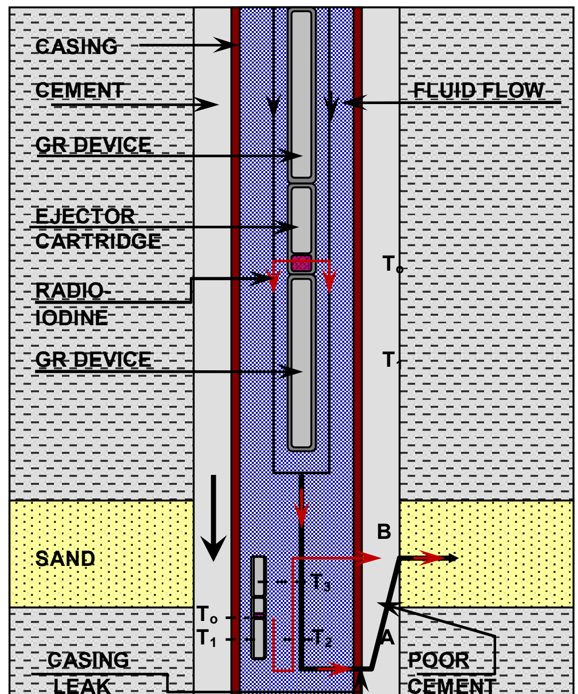

Figure 8-62 An illustration of a radioactive tracer device ejecting radioactive iodine to determine the direction of fluid flow.

and one below. In some applications of the device, even the direction of fluid flow is open to question. Thus, this arrangement allows the direction to be established by the detector responding to the radioactive iodine ejection.

Basically, the procedure is something like this. The tool is stopped at a designated point and the film of the recorder is placed in time drive rather than the usual depth drive. Both detectors record background radiation as the film moves. The record is a rather straight line because of the low sensitivity of the detectors. A small amount of radioactive iodine is then ejected and moves either up or down the well with the latter being shown in figure 8-62, (ignore the miniature drawing with its red arrow for now). Depending on the rate of flow or fluid movement, sometime later the blob of radioactive iodine passes a detector and a significant increase is noted in the count rate. Usually, one such ejection is sufficient at a given station. Having determined the direction of flow, the tool is repositioned (in this case moved down hole) and a second ejection is made. If, as assumed in the diagram of figure 8-62, the well is an injection well for water flooding, the casing leak may be robbing only a portion of the floodwater. Once the tool is below the casing leak, the rate of downward flow will decrease and the time required for the iodine to pass the detector will increase. Noting this, the engineer can move the tool back up the hole in increments until the point of fluid exit is established. I have illustrated the recordings for the preceding situations in figure 8-63 as example #1, black and blue respectively. A flowmeter log or recording could also identify such a leak and maybe in less time but yet another advantage of the tracer tool is available to the customer. That is, the tracer tool sees outside the casing because the gamma rays pierce its metal wall and thus detect fluid movement outside the casing as well. They may also complement one another.

To illustrate this particular phenomenon, consider the miniature tool for a moment. This was added to the diagram to help you visualize what would happen if the distance from the casing leak was greater than the tool length and the tool was positioned just above the leak. In its travels, the radioactive iodine would leave the ejector (T_o), first move quickly down the hole past the lower detector (T_1) and a strong response would be noted. Then as it left the casing and moved up through the cement to the thief zone a later and weaker response would be noted on the lower detector (T_2) and a little later a similar response on the upper detector (T_3). Thus, the direction of travel outside the casing is indicated in figure 8-63 as example #2.

Sometimes the customer simply pumps radioactive iodine down the tubing, allowing it to go into the thief zone. A gamma ray log can then be run and the thief zone is identified by comparing the before and after radioactive logs as illustrated in figure 8-64. The half-life of radioactive iodine, as I remember is about 10 days. Consequently, within a month the radioactive response of the formations is back to normal. In the example, I arbitrarily illustrated a situation as described in figure 8-63 with the leak below the thief zone. As you may have

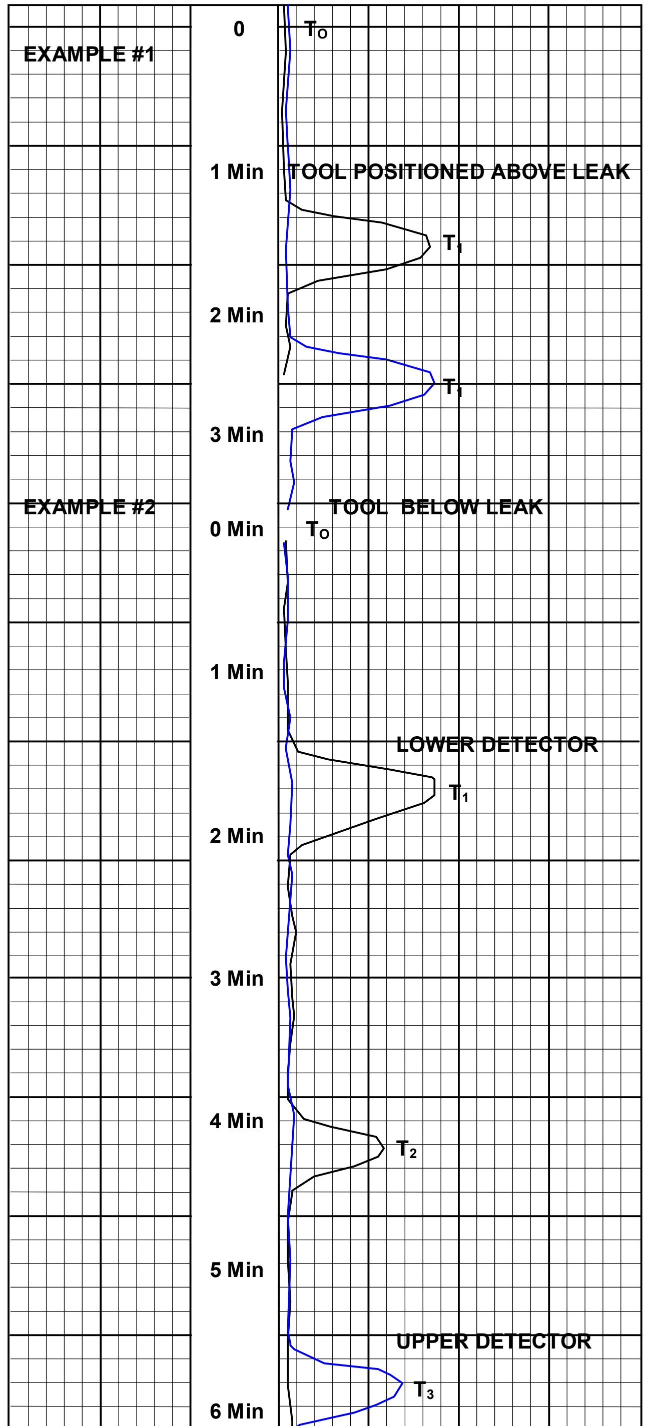

Figure 8-63 A simplified tracer log of 3 records; Ex. 1 above & below a casing leak & example 2 just above a leak with a response from the annulus due to a thief zone just above the tool.

noticed, being arbitrary is one of my many talents, which most certainly brought about this momentous work or, is the proper word ridiculous? You will have to be the judge.

Well, that about concludes all the technical stuff I remember about cased-hole services, some of which I know'd and some of which I know'd that ain't so. As shaky as I am on production logging, which I never participated in, I felt the principles and tools involved were interesting.

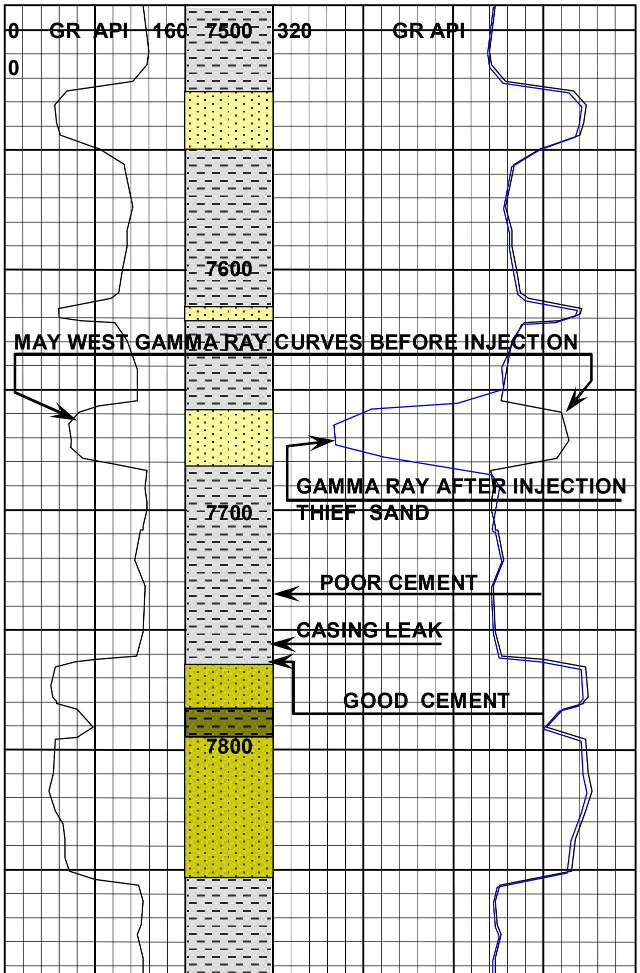

Figure 8-64 A hypothetical illustration of gamma ray logs run on a well before and after injection with radioactive iodine.

Actually, I did get involved with the hardware from time to time as a DE (Division Engineer) but never made a field job. Even so, I think my make believe examples are close to reality and at least demonstrate what can be done to help the oil operator solve production problems. As with any business, problem solving brings its own rewards and companies like Schlumberger make their living by offering various solutions for the perplexing problems facing oil field operators in finding and producing that black gold.

SPECIAL CASED HOLE UNITS

WIRE LINE UNITS

I thought this chapter was complete and then ran across some nice drawings, which I had over looked. They were furnished by courtesy of my very congenial source in Houston, namely Patti Oberpriller, whom I thank once again. Let me begin with the 5800 series truck, which was the backbone of Schlumberger's production services fleet when I left in 1986. It was equipped with the Cyber Service Unit (CSU), the computer operated surface control system I spoke of in chapter 6. A drawing of the truck is displayed in figure 8-65. This was a big truck carrying 20,000' plus of logging cable. It usually carried double cable drums of either 15/32" multi-cable or 7/16" mono-cable depending upon the district requirements. Along with that, a second drum of 3/16" cable was provided for through tubing work. Thus the truck could perform any type of cased-hole log or casing gun job as well as thru-tubing jobs.

Another more specialized truck was apparently provided later for through tubing work and slick line work. This particular truck post-dates my

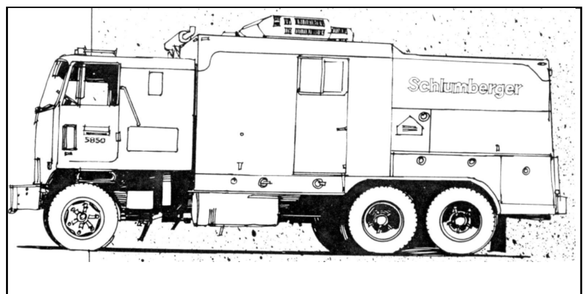

Figure 8-65 A 5800 series truck with a CSU installed for production service work.

tenure with the company but the picture I'm about to include (figure 8-66) provides a better view of the back end of the unit with its various pieces of equipment. The electric cable is 7/32" or just 1/32" greater than the old 3/16" cable I was familiar with. It is utilized for through tubing work including logging as well as perforating. The slick line is not electric but is 0.92" in diameter allowing it to be run more easily in high-pressure situations. It can be used for battery-operated devices such as pressure monitoring, etc. of producing wells. Notice the truck is smaller than the 5800 series unit and carries a much lighter load. It also satisfies the multiple demands, which brought about its specific design.

MAST UNITS

On initial completions of a new well, a rig was usually on site and provided the means whereby the wire line unit could rig up pressure gear and sheave wheels as well as lower the tool string in the well. “Work over wells”, however, are a different story and a good deal of wire line work needs to be done without adding the cost of bringing in a special rig to accomplish it. As a result, wire line companies provide mast trucks, at a price naturally, which can handle the operation. The capability of such rigs has varied over the years but the general appearance is the same. The drawing I found illustrates the principles involved as shown in figure 8-67. It is a big truck, carrying a hydraulically operated derrick and wire line. The derrick can be raised

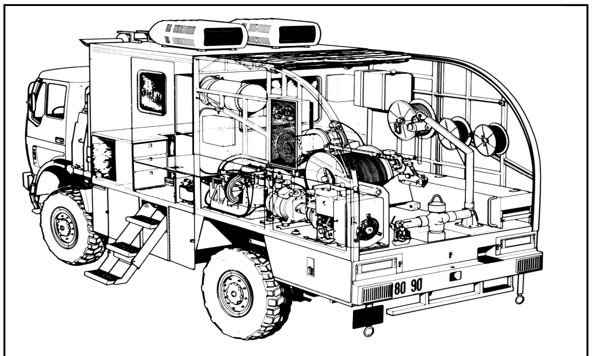

Figure 8-66 An artist’s rendition of a production services truck for thru-tubing work and various monitoring services.

into position quickly after positioning the unit. Since this unit includes both mast and wire line, I assume it provides total capability for work over

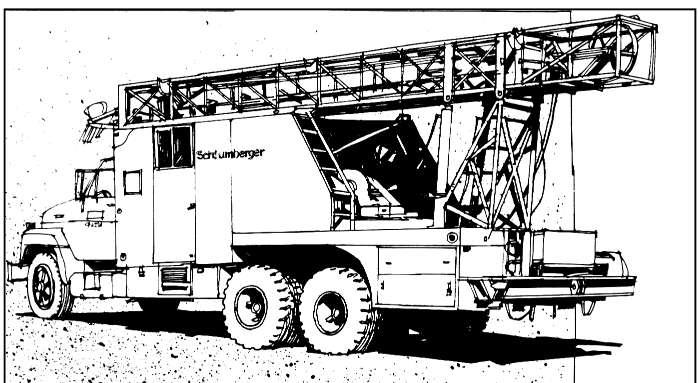

Figure 8-67 An artist’s rendition of a special truck for production services including wire line and derrick.

jobs and reduces manpower requirements. This was always a consideration for Schlumberger because of the associated cost.

Let me conclude this chapter with a drawing of a newer off shore unit designed to handle the CSU. The tell tale sign is the air conditioners,

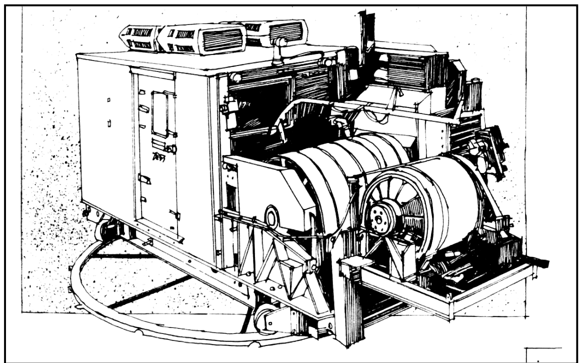

Figure 8-68 An artist’s rendition of an off-shore unit with equipped for production services with both double drum and CSU.

designed and installed for the computer rather than the comfort of man. As you can see, it is a double drum unit capable of both tubing and casing work. It is the equivalent of the 5800 series truck for land, which is the backbone of the production services fleet. You may notice it is on a circular track, which allows it to address any well on a platform without difficulty. The inside would obviously have a CSU unit similar to that illustrated in chapter 6.

Well, I’ve completely run out of things to talk about for both open-hole and cased-hole situations. I suppose this is a good place and time to move on to other experiences in Schlumberger, which, for my less technical posterity, will be a relief. It should enable them to continue reading more easily and maybe even introduce a laugh or two as you consider the variable field situations Schlumberger engineers ran into on a regular basis. Of course, there will be a good deal of family life situations as well.