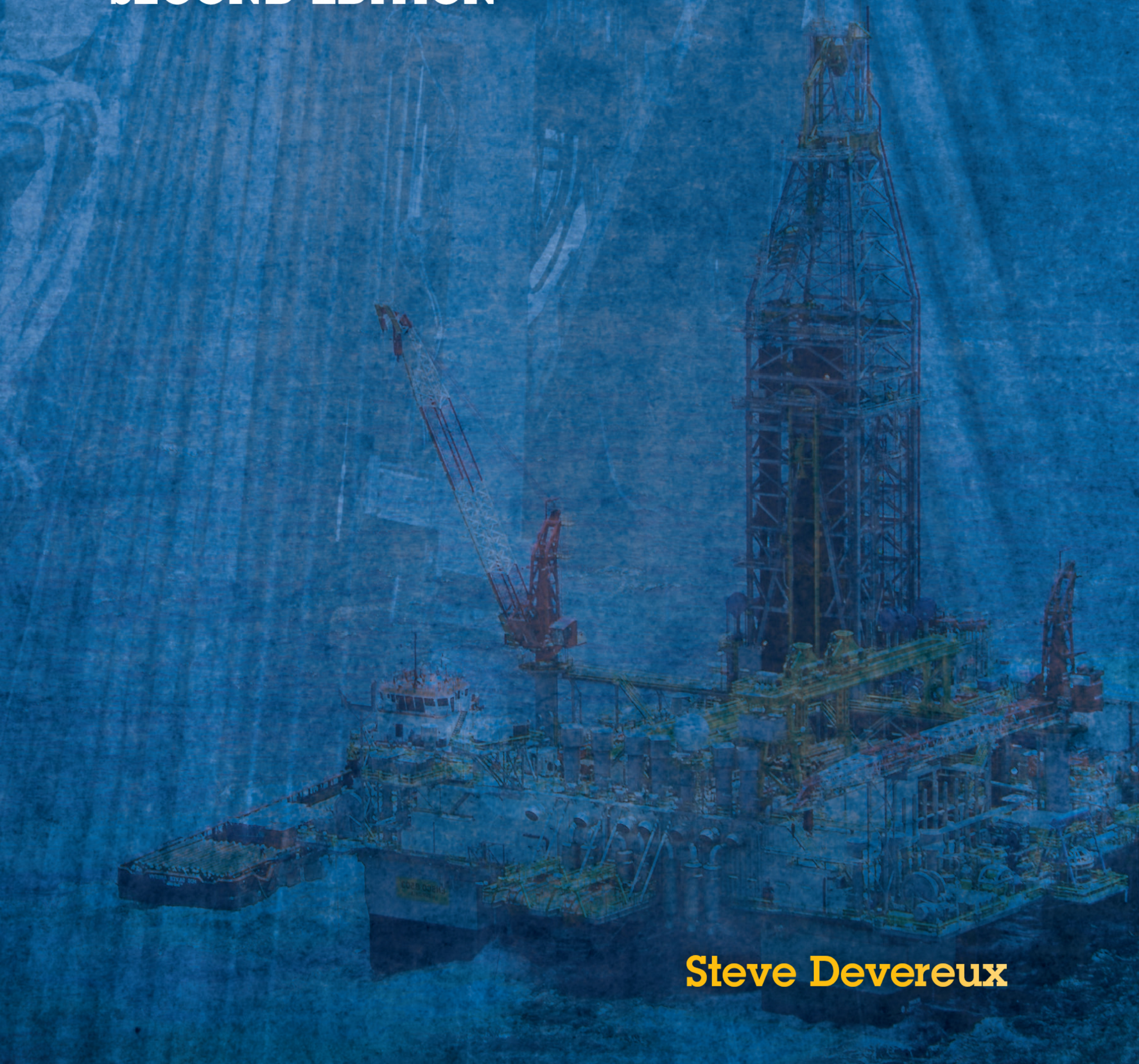
Drilling Technology

IN NONTECHNICAL LANGUAGE

SECOND EDITION



Steve Devereux

Drilling Technology in Nontechnical Language Second Edition

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PennWell®

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This book is dedicated to my family—my wife, Trish, my daughter, Robyn, and my sons, Alex and Michael.

Contents

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DRILLING GEOLOGY

Overview

This chapter will examine geology as it relates to drilling operations. It is necessary to understand something about the physical and chemical characteristics of rocks in order to understand drilling processes and problems. The chapter also describes the basic principles of hydrostatic pressure exerted by a fluid at depth, as this is important for drilling operations.

This brief chapter will cover some important concepts that should be understood for the chapters that follow.

Origins of Rock

When the earth first formed, it consisted of molten rock. As the surface of the planet cooled down, the planet surface solidified. Rocks formed by molten rock cooling and solidifying are called *igneous rocks*. Basalt and granite are examples of igneous rock (fig. 1–1).

Water and gases form the oceans and atmosphere. The gravitational pull of the sun and moon and solar heating cause movements of the atmosphere (weather) and the oceans (tides and currents). The movements of air, water, and ice erode rocks, releasing rock particles. These effects are called *weathering*.

Particles of rock, from tiny grains to huge boulders, can be carried long distances by wind and water. Eventually the forces carrying the rock particles are reduced, and the rock fragments fall to the earth's surface, or to the bottom of a water body, forming thick beds of material called *sediments*. As the water or wind slows down, the largest fragments are deposited first. Smaller fragments (being more easily carried) would move further. In this way, the rock fragments could become sorted so that a particular bed of sediment might consist of fragments all of a similar size. Large particles are deposited in high-energy environments (e.g., a fast-flowing river), and small particles are deposited in low-energy environments (e.g., a lake or swamp).

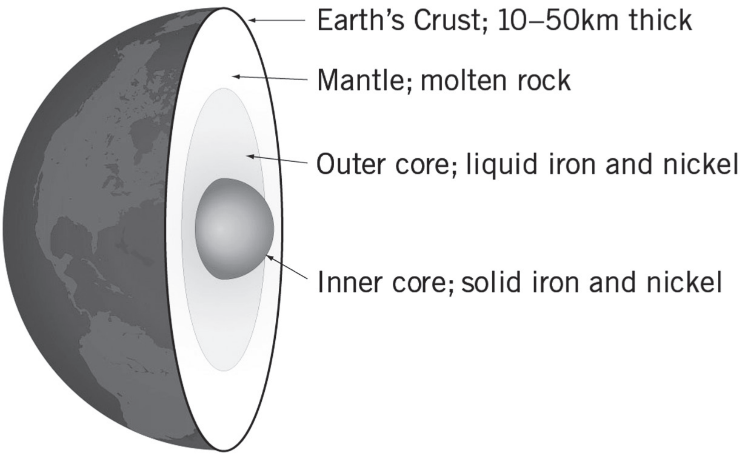


Fig. 1–1. Earth's structure

Over millions of years, these sediments became buried deep within the earth, subjected to high pressures (from the weight of rock above them) and temperatures (the earth gets hotter at increasing depths). The minerals in the sediments change chemically, forming rock. This process of forming new rock by chemical changes to sediments is called *diagenesis*. Other types of rock form by small grains of mineral becoming bonded together by minerals growing where the grains touch, such as sandstone. This process is called *cementation*.

Rocks that are formed by the diagenesis or cementation of sediments are called *sedimentary rocks*. Sandstone is one type of sedimentary rock.

Existing rocks of any type can be physically changed by high pressures and temperatures. This process is called *metamorphosis* (the same word that applies to a caterpillar changing to a butterfly). These changed rocks are called *metamorphic rocks*.

The rock cycle diagram (fig. 1–2) was first constructed by Scottish geologist James Hutton in a book published in 1795, *The Theory of the*

Earth, with Proofs and Illustrations. Starting at the bottom of the diagram (the square marked as "Magma" or molten rock), move clockwise and upwards around the cycle. Magma cools and solidifies, creating igneous rock. These rocks may be changed into metamorphic rock (branch going to the right) or, continuing around the cycle, may eventually reach the surface and are eroded.

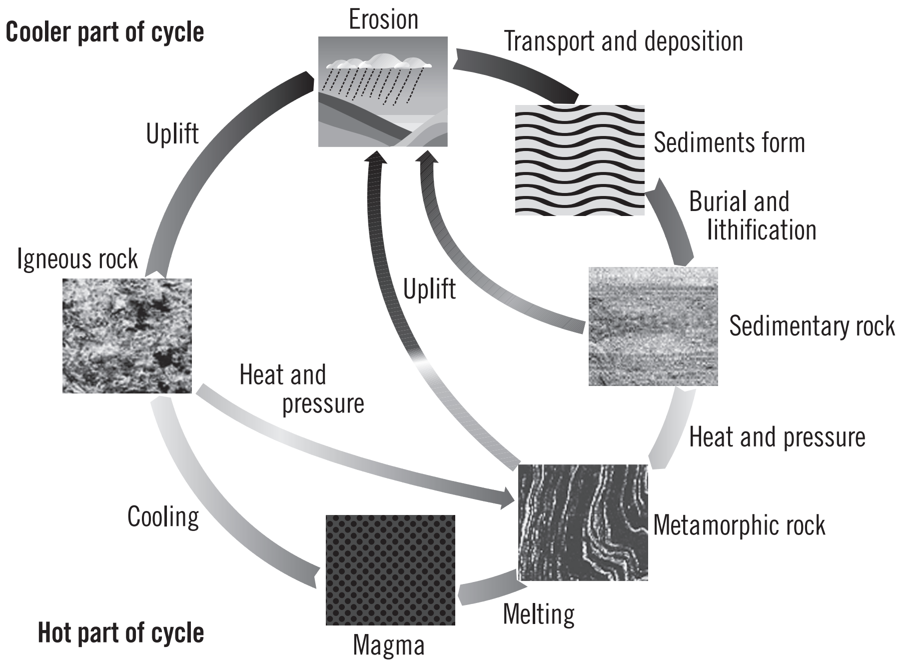


Fig. 1–2. The rock cycle

The rock particles released by erosion (weathering) are transported by wind, ice, or water. These are deposited to form sediments, which become converted to sedimentary rock (now at the right-hand side of the cycle). From here, the sedimentary rock could be eroded again, or buried deeper. If buried at sufficient depth, the pressure and temperature will metamorphose the sedimentary rock.

Metamorphic rock can be uplifted and eroded, or buried deeper and melted.

Apart from these "physical" sediments, chemical sediments also occur. Salt beds formed from the drying of salty lakes can be very thick and cause some real problems not only for drillers but also for seismic surveying. Biological sediments (such as fossilized coral reefs and coal) are also significant.

In most areas of the world, sedimentary rocks have been deposited on top of basement rocks (igneous and metamorphic). The layer of sedimentary rock above the basement rocks can vary in thickness from zero (eastern Canada) to 50,000 ft or 15,000 m. Around volcanoes, igneous and metamorphic rock may be found at or near the surface, with sedimentary rock underneath.

Plate Tectonics

Below the thin, solid crust at the earth's surface, the planet core is molten. This liquid rock may be seen at the surface in active volcanoes. On top of the liquid rock, the crust consists of plates of solid rock, floating on the molten rock underneath rather like rafts floating on water.

The earth's crust is divided into seven major plates (African, Pacific, Indian-Australian, North and South American, Eurasian, and Antarctic) and numerous smaller plates (such as the Arabian and Cocos). The plates are all moving relative to one another. Some plates are moving apart from each other (e.g., North Atlantic and Southern Indian Ocean), and new crust is formed as molten rock is exposed and cools down. Some are converging (e.g., at the western rim of the Pacific plate), where one plate slides underneath the other, and volcanoes and mountains may be formed. Others are sliding past one another (e.g., western coastal United States at the boundary of the North American and Pacific plates). The rate of movement varies from 1.3 to 17.2 cm/year.

In areas close to the edge of a plate (tectonically active areas), the rocks are under much greater stresses than normal. This can make it difficult to drill a hole that remains stable. The sides of an unstable wellbore will tend to collapse into the hole, enlarging the hole.

Movements of the plates will lead to rocks moving up or down within the earth's crust. It will also lead to rock beds becoming folded, broken, and turned over. Pressures of fluids contained within the rocks can be drastically changed from the surrounding rock. Stresses within the rock may become different in different directions. All of these different stresses can deform and break the rock layers in different ways.

Fig. 1–3 shows what happens when rock is compressed from the sides until the force exceeds the rock strength. Faults (breaks in the rock layers) develop, and part of the rock is pushed upwards. If a well is drilled across a thrust fault, part of the rock sequence will be repeated in the well. If the rock layers stretch, the opposite happens—normal faults develop. A well drilled through a normal fault will have part of the rock sequence missing (fig. 1–4).

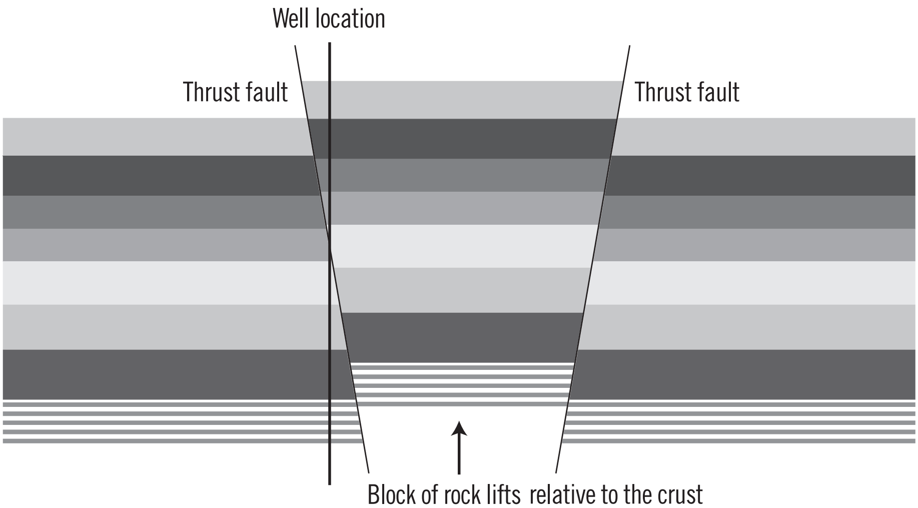


Fig. 1–3. Thrust fault, rocks were compressed together

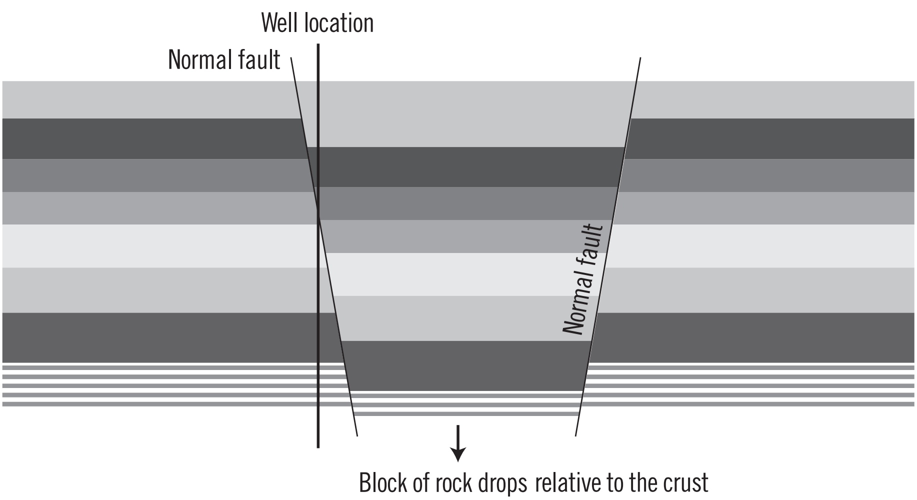


Fig. 1–4. Normal fault, rocks were stretched apart

Sometimes the surface rocks are eroded away, and then more sediments are deposited. This is called an *unconformity*; part of the geological sequence is missing entirely. The photo in figure 1–5 shows an unconformity, visible in a cliff face. The white line marks the unconformity surface.

This photo tells an interesting story. Sediments were deposited at the surface or seabed. These became buried, changed into rock, and then were uplifted back to the surface. During this burial and uplift, the rocks became tilted. Now surface erosion removed rock but at an angle to the bedding planes of the rock. Notice the angle between the lower rock beds and the white line of the unconformity surface, which would have been horizontal. Now new sediments were deposited, buried, became rock, and then were uplifted back to the surface and tilted in the opposite direction of the original tilt, but by a lesser amount. The lower rocks have had two return trips down into the earth's crust and have been tilted one way on one trip and the opposite way on the second.

Fig. 1–5. Unconformity surface shown by the white line

Lithology

Lithology refers to the physical character of the rock. Lithology is a description of the rock and is based on such characteristics as mineral composition, color, grain size, and other textures. Thus a shale could contain some sand (sandy shale) or a rock could be mainly sand with some shale minerals within it (shaley sand). The lithology will affect many drilling decisions when planning and drilling the well. If the wrong decisions are made due to a lack of detailed lithology knowledge, serious problems can result that will increase the cost of the well and could even prevent the well from reaching its objectives.

Shales

Shales consist of layers of clay minerals. Clay minerals are crystal structures of various metal oxides associated with alumina silicates in connection with varying numbers of water molecules. The metal oxides are most commonly those of iron and magnesium but may also be those of sodium, potassium, or other metals. Their presence together in varying ratios results in a wide range of clay mineral types. Clay minerals originate in sedimentary rocks by the physical and chemical breakdown of other minerals originally present. The weathered clays are carried by wind or water, or both, to an area of eventual deposition. They may then undergo further physical or chemical breakdown. More water may become associated with the clay minerals.

Eventually the clay minerals become buried under other sediments. They will be compacted, and water will be driven off. Diagenesis will alter their structure or composition to change the accumulation of clay minerals into a sedimentary rock type. The water that comes out of the shale is less saline (contains less salt) than the water left behind, so the shale gets more salty as it dehydrates.

Some shales react very quickly with water. Hydration of these shales leads to the crystalline layers expanding. During drilling, fluids are pumped down the hollow drillstring and back up the hole to clean and cool the drill bit and perform various other functions. If such a shale is drilled using water as the circulating fluid, the shales can absorb water and rehydrate. Millions of years of diagenesis can be reversed in under an hour.

These shales will swell and become soft, like unset putty. Sticky clays will fill the hole, and if the drillstring becomes stuck, the hole could be lost. Other shale types can be very stable in the presence of water and are not difficult to drill through with water-based drilling fluids (called *drilling muds*). In practice, a shale formation may consist of a mixture of different clay mineral types, so the reactivity of shale to water can vary from mild to severe. Chemicals are usually added to the drilling fluid to decrease (*inhibit*) the hydration reaction of such shales (fig. 1–6).

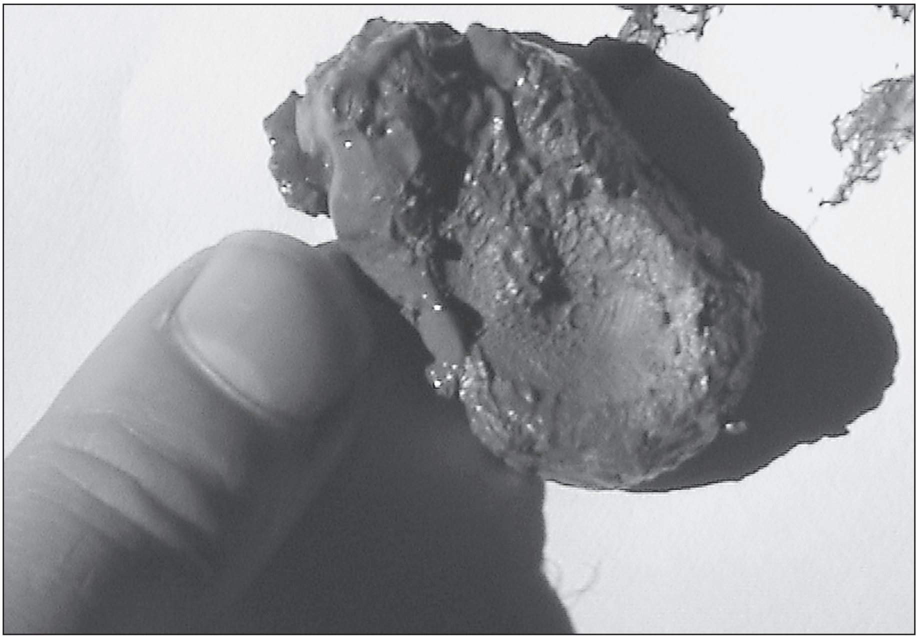


Fig. 1–6. Soft, hydrated shale from a well

Clays are deposited in very low energy environments as they are built from small to very fine particles. In order for these to be deposited, the water must be almost still. Such environments would be found in very deep water or in swamps and lakes.

Some shale minerals are completely unreactive to water (such as mica), while others may react with water to a lesser or greater extent. Some shales will consist of a mix of shale minerals.

Shales form about 75% of all sedimentary rocks and cause about 90% of all geology-related drilling problems. Successful drilling engineers need a good understanding of shale chemistry and physical attributes in order to drill wells to economically reach their objectives.

Sandstones

A sandstone structure consists of particles of sand (mostly quartz grains, often colored by the presence of traces of other minerals, such as iron). The sand grains are pressed together by the weight of the sediments deposited above (fig. 1–7). In the spaces between the grains was originally water, which may contain all sorts of dissolved minerals and salts. Over time, materials may come out of solution and be deposited where the grains come into contact with each other. This cementation might be strong or weak, depending on the minerals involved and on how much is deposited. With weak cementation, the sandstone may start to fall to pieces when drilled through. If it is a reservoir rock, the flow of hydrocarbons from the formation into the producing well may bring sand with it, which can damage or block production equipment if the well is not designed to prevent it.

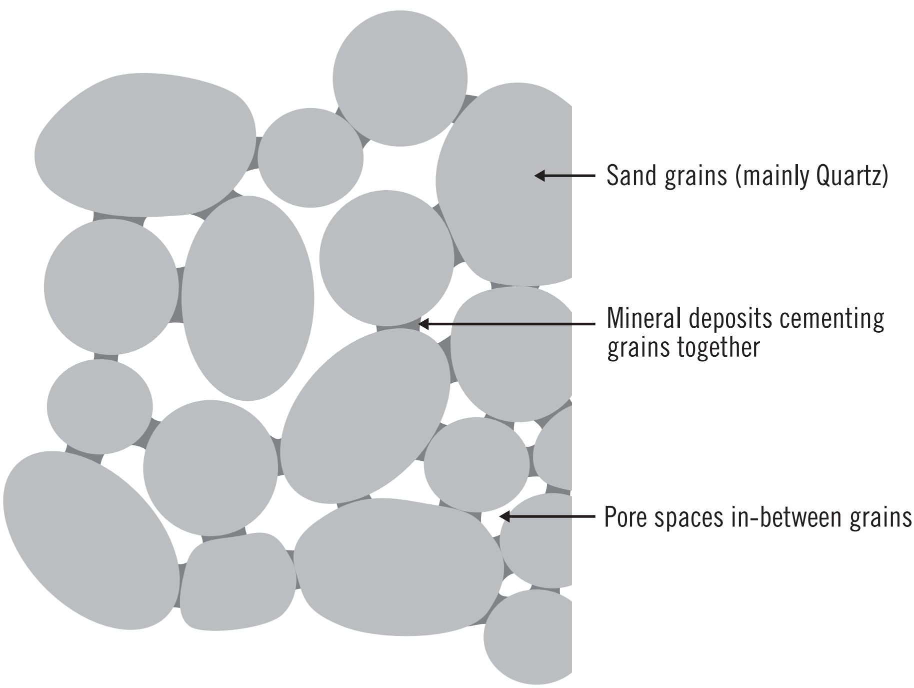


Fig. 1–7. Sandstone structure

Within a sandstone structure, clay minerals might also be found. Clays cause serious problems in a reservoir if they react with water (perhaps from the drilling fluid) because they can block the flow of hydrocarbons to the well.

Strongly cemented sandstones can be quite abrasive, leading to high rates of wear on the drill bit and other downhole components.

Sandstones make up about 11% of all sedimentary rocks.

For a sandstone (or other rock) to be capable of acting as a reservoir, there are two vital physical properties that it must have: porosity and permeability.

Porosity is a measure of the percentage of the volume of the rock that is occupied by fluids. In figure 1–7, the white spaces are marked as "Pore spaces in between grains." This sandstone therefore has porosity.

Permeability is a measure of the ability of fluids to flow through the rock. For this to happen, the pore spaces must be connected in such a way that fluids can flow along the pore spaces. It is possible for a rock to have porosity but be impermeable (shales are an example). It is not possible for a rock to be permeable but have no porosity.

Carbonates

Carbonates are composed of fossilized skeletons and mineral grains of calcite (crystals of calcium carbonate; chemical formula $CaCO_3$). Crystalline limestone is very common, and its texture can be seen by rotating the rock and observing the light reflected off the numerous crystal faces. The crystals are soft enough to be scratched by a knife.

Fossiliferous limestone is similar to crystalline limestone except that it contains fossil fragments, usually composed of calcium carbonate. Most limestones are fossiliferous.

Carbonates are often fractured due to their brittle nature. Fractured carbonates make prolific reservoir rocks, as the oil and gas can collect in the fractures. Since the permeability of fractures is very high, if a well intersects many fractures, it can produce oil at very high rates. However, drilling through fractured carbonates can cause large volumes of drilling fluid to be lost into the formation. Sometimes these formations have to be drilled with special techniques, such as using foam as a circulating medium rather than liquid mud.

Limestones often contain chunks of chert (flint), which is an *amorphous* (without crystals) form of quartz. It results from the percolation of silica-rich pore fluids. The rock breaks along curved surfaces, forming knife edges and sharp points. Cherts can break teeth on drill bits while drilling.

Carbonates comprise about 13% of sedimentary rocks.

Evaporites (salts)

Evaporite sequences occur as a result of sea water evaporating, leaving the soluble salts behind. There is a definite order of precipitation, as the least soluble salts come out of solution and are deposited first. The most soluble salts, which come out of solution last, are various rare potassium and magnesium salts. These latter salts are very soluble and would only precipitate out if dehydration was almost complete.

The complex sequences present in a mixed salt formation lead to several problems that cannot be solved by using a conventional (NaCl) salt-saturated, water-based drilling mud as a circulating fluid. The highly soluble magnesium and potassium salts will dissolve in a sodium chloride–saturated solution. This can give greatly enlarged holes with many attendant problems.

Some types of salt can flow just as ice in a glacier flows. It can create tremendous forces that act on any obstacle in its path, such as a well. It is possible for flowing salt to break a well in half or to crush the steel casing that lines the well. Salt can flow so fast that a hole can close around the drill bit as it drills, stopping the bit from turning. Often when that happens, fresh water has to be pumped down around the bit to dissolve some of the salt in order to free the bit.

As salt is lighter than most other rocks, bubbles of the salt can try to rise up through the rock above it, like a bubble of oil rising through water. Of course, it takes millions of years for this to happen, rather than a few seconds. These salt domes can be huge and can create traps for hydrocarbons. Salt domes create suitable conditions for many reservoirs in the Gulf of Mexico.

Historically, thick salt beds were hard to see through seismically. More modern techniques allow good images to be created below thick salts, and this opens up exploration opportunities. The Gulf of Mexico has a lot of thick salt deposits, and now significant reservoirs are being found below them.

Rock Strengths and Stresses

The strength of a rock will vary depending on the type of stress applied to the rock (compressive, tensile, or shear) and may also vary depending on the direction that the stress is applied (fig. 1–8). Most rock has little tensile strength; it will pull apart relatively easily. However, rock can have great compressive strength, especially if the compressive force is applied at right angles to the bedding plane of a sedimentary rock. Compressive strength is important; a rock with high compressive strength is harder to drill through, but it also tends to be more stable (less likely to fall to pieces) once a hole is drilled through it.

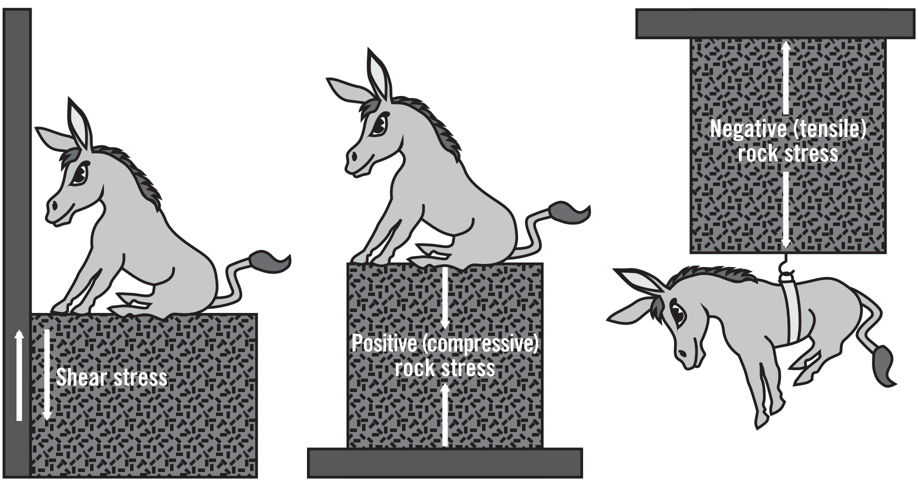


Fig. 1–8. Comparison of rock stresses

When a rock is buried in the earth, it is subjected to stresses from the rock around it. The weight of the overlying rock (the *overburden*) will apply a vertical stress to the rock. In a normal area, where there is little or no tectonic activity, the horizontal compressive stresses will tend to be less than the vertical compressive stress, and the horizontal stresses will be a similar intensity from all directions. However, where tectonic or other forces act to distort the rock, stresses may differ depending on the direction in which the stress is measured. These unequal stresses may lead to failure of the rock perpendicular to the direction of the greatest stress, so that the hole is less stable in one direction—the hole may become oval or eye shaped. It is possible to measure the hole size in different directions. If the hole is bigger in one direction relative to its size in the perpendicular direction, the highest and lowest horizontal stresses are different. The greater the size difference, the greater the stress difference.

Principal stresses

All of the stresses present in a particular piece of rock can be resolved into three mutually perpendicular planes of stress, which are all compressive or tensile (not shear). These three stress planes are called the *principal stresses* (fig. 1–9).

The Greek lowercase sigma (σ) is used to represent stresses within materials. In engineering, the convention is that tensile stresses are positive and compressive stresses are negative.

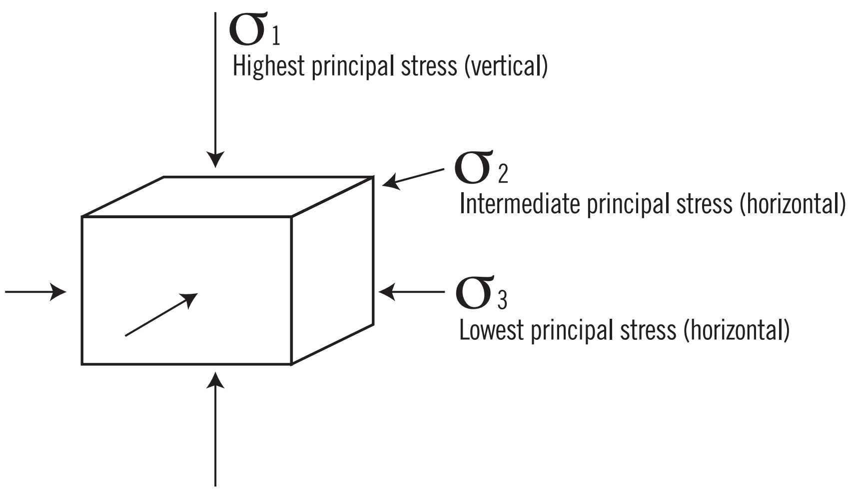


Fig. 1–9. The principal stresses in rock

Geologists, being geologists, do not use the engineering convention; rather, to a geologist, compressive stress is positive and tensile stress is negative. This is reasonable, since in the earth's crust (rock), stresses are normally compressive and only rarely tensile. In a normally stressed situation, the greatest stress, called sigma 1 (σ_1), is the vertical stress. The smallest stress, denoted sigma 3 (σ_3), is normally horizontal, and the intermediate stress, σ_2, is also horizontal, with little or no difference between σ_2 and σ_3. However, in some cases, σ_2 or σ_3 can be vertical. Understanding the stress state is very important to planning wells, which is the reason for covering it here.

Wells are sometimes drilled straight down vertically. However, most wells deviate from vertical to a greater or lesser degree, and wells may even be planned and drilled so that they finish up horizontal in the reservoir. In deviated (and especially highly deviated or horizontal) wells, these stresses can become a significant factor in designing the well, and deciding on the procedures needed to drill through it successfully can be challenging.

Of particular interest to the drillers is the ability of the rock to withstand pressure inside a hole drilled in it. This is called the *fracture pressure*. Imagine that a hole is drilled into a chunk of rock. Inside the hole is liquid. If pressure in this liquid is continually increased, at some point the rock will start to break. Fluid will leak into the rock, creating growing fractures that extend away from the hole and into the rock. The fluid pressure creates tensile forces in the rock around the hole, which eventually causes tensile failure. However, the compressive stresses around the rock will act to support the rock against the pressure. As most rocks are weak against tensile forces, the fracture pressure will be very close to the lowest compressive stress imposed on the rock, σ_3.

As rock compressive stresses generally increase with greater depth, the fracture pressure also tends to increase with depth.

Hydrostatic Pressure Imposed by a Fluid

Fluid pressures are fundamental to many aspects of oil well drilling. If downhole pressures are not kept under control, an uncontrolled release of oil and gas to the surface (called a *blowout*) can result that might lead to loss of life, massive environmental damage, damage to underground reservoirs, and damage to the rig and other surface facilities.

Fluids (liquids and gases) exert pressure in all directions against a vessel containing the fluid and against anything submerged in the fluid. This principle is used in hydraulics, where a fluid is used to transmit a force from one place (a hydraulic pump) to another (a hydraulic jack used to lift a car).

In a vertical column of fluid, gravity causes the pressure inside the fluid to change with depth. The pressure in the fluid at a particular depth has to support the weight of the fluid above that depth. This can be explained one step at a time.

Imagine a liquid (a salty water) that weighs 0.0417 lb for each cubic inch (in^3) of volume. This liquid is stored in a 12″ deep square tube that measures 1″ on each side.

Now the volume inside this tube is 12 in^3 (12″ × 1″ × 1″). If the weight of 1 in^3 is 0.0417 lb, then the weight of the 12 in^3 inside the tube is found as follows:

$$12 \text{ in}^3 \times 0.0417 \text{ lb/in}^3 = 0.5 \text{ lb}$$

Pressure is calculated by dividing a load (in pounds) by the area supporting that load (in square inches, in^2). In this case, the area at the bottom of the tube is 1 in^2, so the pressure at the bottom of the tube is found as follows:

$$0.5 \text{ lb} \div 1 \text{ in}^2 = 0.5 \text{ pounds per square inch (psi)}$$

Half way down the tube, there is only one-half of the weight of fluid (0.25 lb) sitting on the same area (1 in^2), so the pressure is one-half of what it is at the bottom of the tube. If the depth halves, the pressure halves. Conversely, if the depth doubles to 2 ft, the pressure doubles to 1 psi. For each foot of depth increased, the pressure in pounds per square inch increases by one-half. This allows a very easy way to calculate the pressure at any depth. For this fluid, it is simply the depth in feet multiplied by ½ psi. The pressure gradient is thus 0.5 psi per foot (psi/ft).

Fresh water has a pressure gradient of 0.433 psi/ft, and seawater (though it varies depending on the amount and types of salt dissolved in the water) is around 0.465 psi/ft. In a well that is 10,000 ft deep and full of seawater with a pressure gradient of 0.465 psi/ft, the pressure on bottom of that well would be 4,650 psi.

In a stack of permeable rocks from the surface to 10,000 ft, if there are no permeability barriers (such as a layer of salt or clean shale), the pressure at 10,000 ft can be calculated if the pressure gradient of the fluid inside the rock pore spaces is known. In an area where the pressure is “normal,” the fluid in the pore spaces will average about 0.465 psi/ft.

It is possible for pressures in a formation to be much higher than is normal for the depth (this is termed *overpressured*). For this to occur, two conditions are necessary:

1. There is a pressure-tight barrier above the overpressured formation.
2. There was a mechanism that created the higher pressure.

It is not necessary to go into the various mechanisms that might cause overpressures under a barrier. When such an overpressured formation is drilled into, if the formation pressure is higher than the hydrostatic pressure of the drilling mud, the mud is pushed up the well by the pressure in the formation. This is called a *kick*. If this happens, the rig crew must seal the top of the well with a piece of equipment called the *blowout preventer (BOP)* to stop more formation fluids entering the well (fig. 1–10).

Once the BOP seals the top of the well, the mud in the well is replaced with a heavier fluid that gives a hydrostatic pressure greater than the formation pressure. This process is called *killing the well*. A well that is under pressure from a formation is said to be *live*.

If the well encounters a kick that is not controlled, the well will blow out. Hydrocarbons will flow freely to the surface and may ignite, endangering the rig and the people on it, and may result in huge costs and pollution, as well.

It is very important to know how the pressure in the rock pores might vary with depth in the planned well. In a known area where other wells exist, the pressures and depths will be known, but even so, surprises may still occur. It is vital to never be complacent about downhole pressures or to assume that everything that is likely to happen is known, no matter how many wells are already drilled in the area. Most of all, the situation must never occur where a well is not strong enough to resist the pressures encountered during a kick. If the rock fractures and allows fluid to flow away from the well, control of the well has been lost. This is very dangerous.

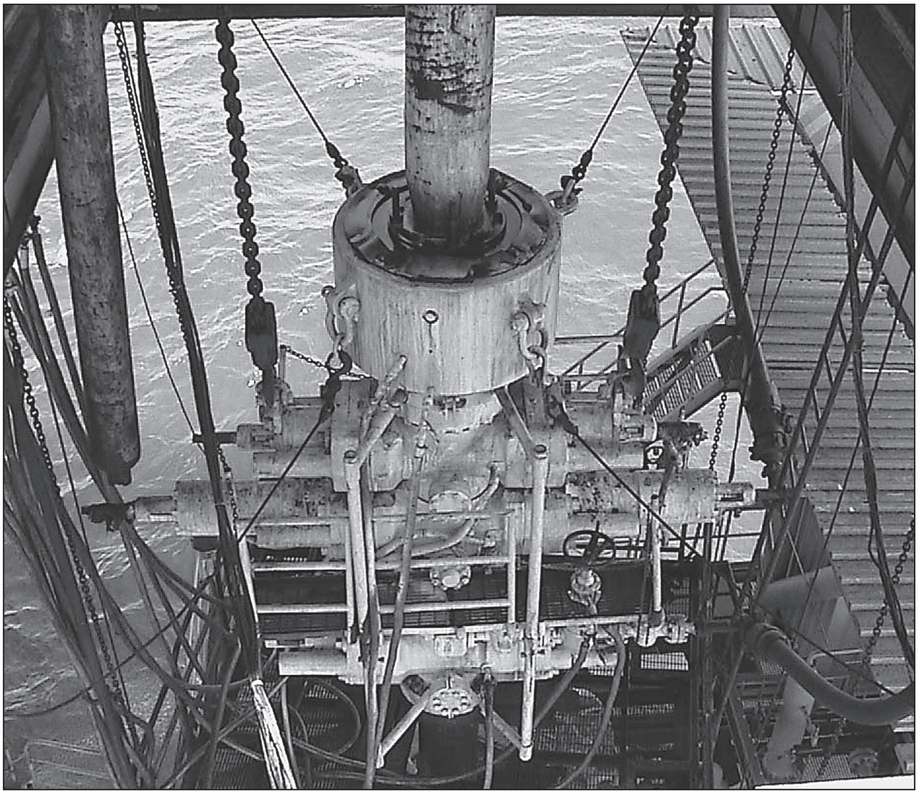


Fig. 1–10. A blowout preventer positioned on the well

Geological Input to Drilling Wells

When a well is being planned, the geologists will create a prediction showing what lithological sequence is expected as the well is drilled. The drilling engineers will use this and other information to design the well.

Figure 1–11 is a lithologic column for a planned well. The thick line with bent ends shown at 1,165 m designates a fault; the wavy line at 1,690 m shows an unconformity. The geologist will get information from various sources, mainly other wells drilled in the area and seismic surveys, but also using the known geological history of the area. For a well drilled in an unknown area, the predicted geology will involve much intelligent guesswork. For a known oil field with many other wells drilled close by, the prediction should be pretty accurate. Drillers are always skeptical of geological predictions, but they are a necessary part of planning a well.

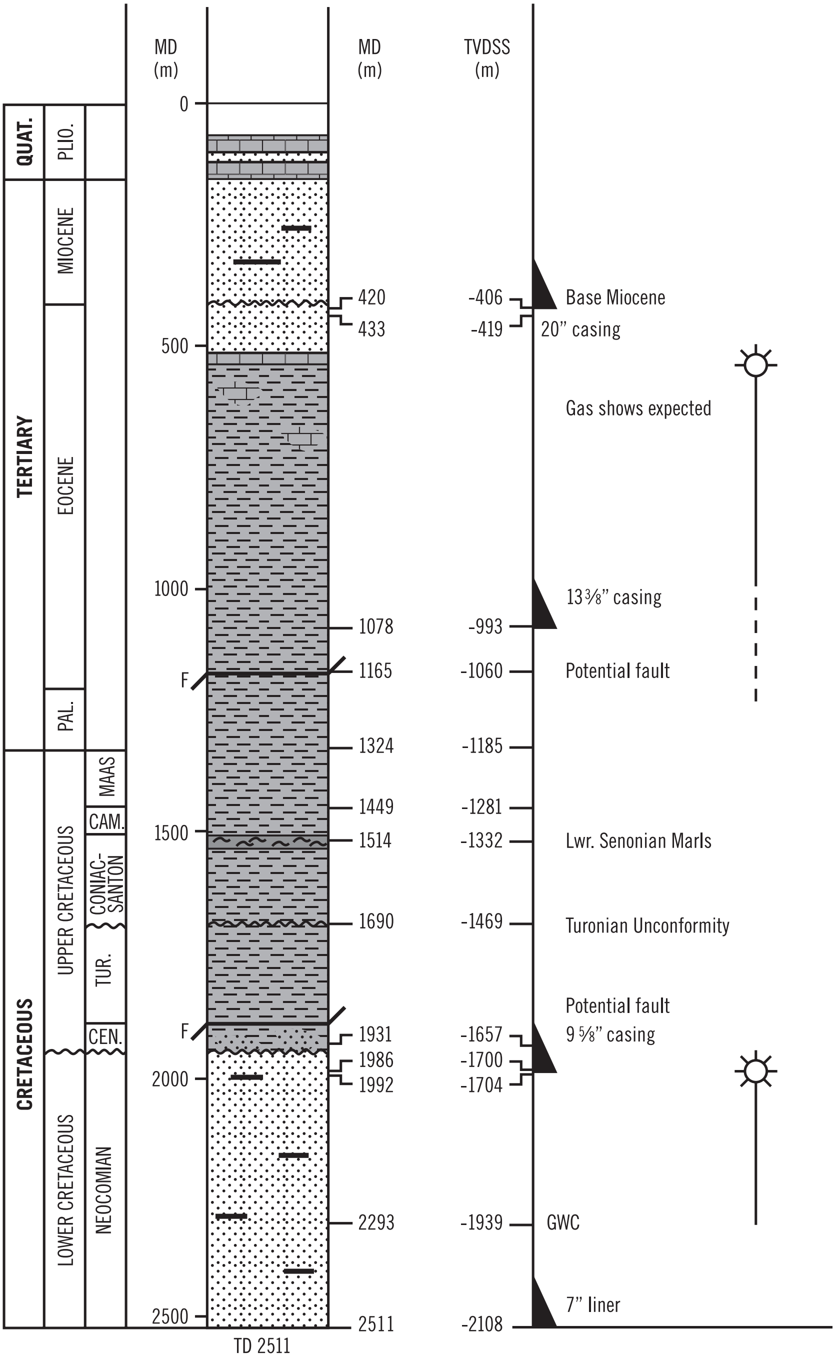


Fig. 1–11. Geological prediction for a well

Apart from the predicted lithology, there are two other critical bits of information that the geologist needs to evaluate: how the pore pressure and fracture pressure vary with depth.

Pore and fracture pressure prediction

The geologists on the project will examine all available information to predict how *pore pressure* (the pressure of the fluid within the rock pores) and *fracture pressure* (the pressure inside the well that would fracture the hole) vary with depth. The information will be passed to the drilling team, normally as a graph and also as a table showing estimated pressures at various depths (fig. 1–12).

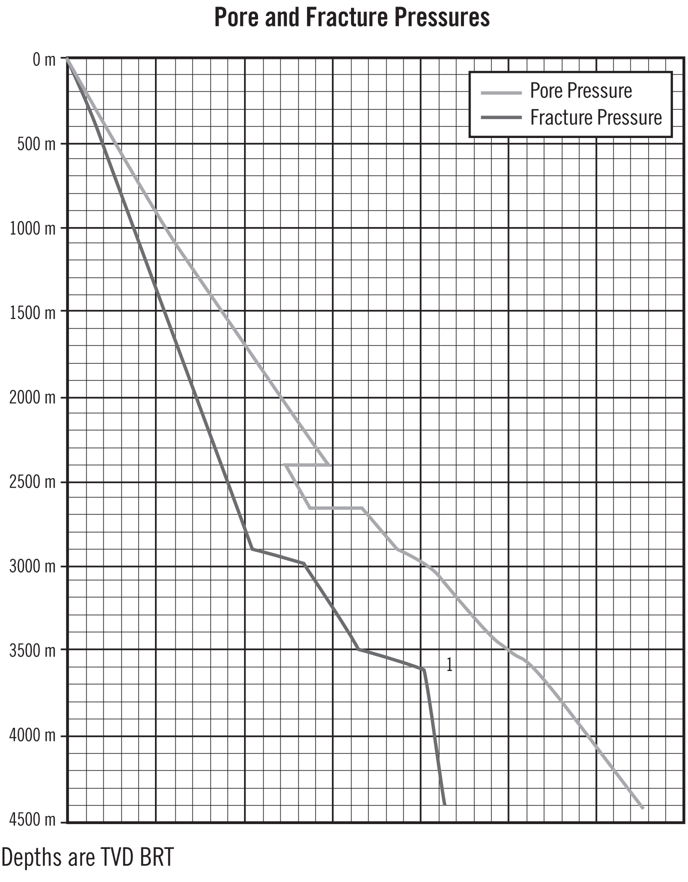


Fig. 1–12. Graph of pore and fracture pressures

Normally, both pore pressure and fracture pressure will increase with depth. However, this is not always the case, and sometimes a change of lithology can cause sudden changes in fracture pressure. Similarly, pore pressures can be normal—equivalent to a saltwater gradient of around 0.465 psi/ft—or can change below a rock that is impermeable.

These predictions are very important to the drilling engineer planning the well. They are so important that a competent engineer will not simply accept the geologist's predictions but will also examine data from other wells in the area to verify that the predictions seem reasonable.

As the well is drilled deeper, at certain depths the drilling stops and a steel pipe—called *casing*—is lowered into the well and cemented in place. Drilling then resumes through the casing, using a smaller drill bit to fit inside it. The depth at which drilling stops to run casing is called a *casing point*, and it is very carefully selected, using the predicted pore and fracture pressures.

The strength of the rock (ability to hold pressure) at the casing point must be sufficient to withstand all pore pressures down to the next casing point, with the addition of a safety margin. This is necessary so that if a kick occurs and fluids flow into the well under pressure, the well will not fracture when the BOP is closed to seal the top of the well.

Summary

This chapter examined the basic geological processes that affect how wells are drilled. It discussed how rocks are formed and showed the basic rock classifications (igneous, sedimentary, and metamorphic). That downhole stresses may vary, and how this affects the stability of the wellbore as well as causing rock faulting, was mentioned. It also summarized the main sedimentary rocks (shales, sandstones, carbonates, and evaporites) and briefly mentioned some of the drilling problems that might arise while drilling through these rocks. The principles of rock stresses and hydrostatic pressure were explained, along with what happens when the mud hydrostatic pressure is less than formation fluid pressures. Finally, the geologists' contributions to planning a well were examined.

2

OIL AND GAS RESERVOIR FORMATION

Overview

Oil and gas (collectively called *hydrocarbons*) are rarely found in the rocks where they were generated from the organic remains of plants and animals. As hydrocarbons are generated, they migrate upwards within the earth until they meet a barrier, where they may accumulate as an oil or gas reservoir. If they do not meet a barrier, they will eventually reach the surface, where they will be visible as an oil seep. The lighter hydrocarbons will evaporate, possibly leaving behind the heaviest hydrocarbon elements (e.g., the tar sands of Alberta, Canada).

There are seven recognized factors that all need to be present, in the correct order, for a petroleum accumulation to occur. These are called the *Seven Pillars of Wisdom* for oil accumulation and are given in the correct sequence in the following:

1. Source rock
2. Hydrocarbon generation
3. Primary migration to a suitable structure (reservoir)
4. Structural trap
5. Reservoir rock
6. Seal rock
7. Secondary migration within the reservoir

This chapter will describe briefly the processes involved in petroleum generation, migration, and accumulation into an exploitable reservoir. The important rock properties for reservoir creation and the properties of the fluids within the reservoir are described.

Source Rock and Hydrocarbon Generation

Millions of years ago, plant and animal remains could sometimes accumulate and become buried by material deposited above. Often this was in slow-moving or stationary water environments like swamps, lakes, coastal regions, and shallow seas. As these organic remains, together with other nonorganic particles (clay minerals, fine sands, and silts) sank to the bottom, thick beds of sediment built up over a long time (thousands to millions of years).

As the organic-laden sediments became buried deeper, they were subjected to increasing temperatures and pressures. The sediments, under diagenesis, became sedimentary rocks. About 99% of all hydrocarbon deposits are found in sedimentary rocks. Within the tiny pore spaces of the rock, the organic matter also underwent chemical transformation.

Under certain conditions, oil is generated from organic remains (fig. 2–1). The most important factor is temperature. Oil generation starts at 50°C. Conversion to oil peaks at 90°C and stops at 175°C. This range of temperature, 50°C to 175°C, is known as the *oil window*.

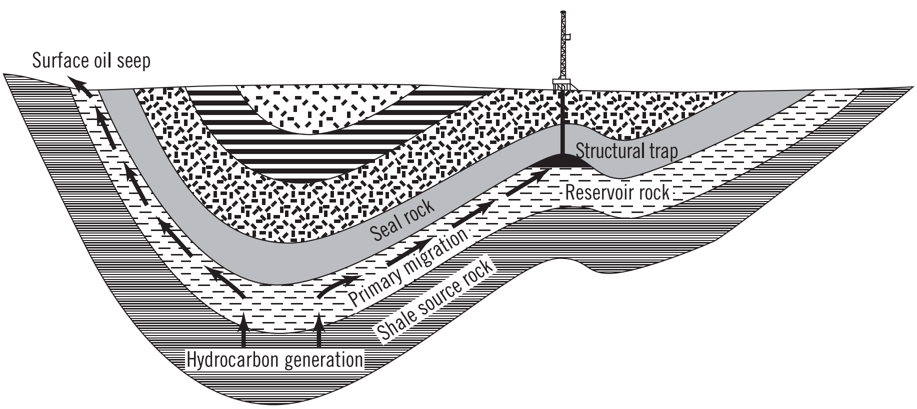


Fig. 2–1. Oil generation and migration

Below and above the oil window, decay of the organic remains will generate gas. Below 50°C, *biogenic gas* (generated by microbes) or swamp gas will result. Above 175°C, thermal gas will result. Temperatures at the lower end of the oil window will generate heavy oils, with increasing temperatures generating lighter (and more valuable) hydrocarbons. If the temperature of the rock becomes too high (above 260°C), the organic material, and therefore the oil-generating potential, is destroyed.

Petroleum is comprised of carbon (83%) and hydrogen (13%), sometimes with small amounts of sulfur (up to 2%), nitrogen (0.5%), and oxygen (0.5%). Hydrocarbons (composed of carbon and hydrogen only) make up over 90% of most crude oils. The hydrocarbons in crude oils vary in molecular size and molecular type, with the heavy crudes comprising more large molecules and the light crudes comprising smaller and more volatile molecules.

Rocks that produce hydrocarbons from organic matter buried within the rock pore spaces are known as *source rocks*. The most common organic-rich sedimentary rock, thought to be the source rock for most oil and gas, is shale. Many types of shale are black and are often referred to as *black shale*. The black color comes primarily from its organic content.

Black shale may contain 1%–3% organic matter, whereas green or gray shale has only about 0.5% organic matter. Organic-rich black shale is relatively common in many areas of the world (e.g., the Kimmeridge Clay Formation of the North Sea, which forms the foundation rock for the Humber Bridge and is an important source rock). Of the organic matter deposited in the earth's crust, only about 2% becomes petroleum. Of this 2%, only about 0.5% (that is, 1 part in 10,000, or 0.01% of the original organic matter) finds its way into a commercially exploitable reservoir. Thus the potentially exploitable petroleum deposits come from only a tiny fraction of all the organic matter that is deposited within the earth's crust. Petroleum generation is a very inefficient process.

Coal comes from the deposits of woody plant remains. Peat and poor-quality "brown" coal has been subjected to lower temperatures and pressures, while high-quality black coal (e.g., anthracite) has been buried deeper and exposed to higher temperatures. As the woody remains convert to coal, hydrocarbon gas (methane) is generated. This can migrate upwards to form a gas-only reservoir (no associated oil). This methane can also remain trapped within the coal seams, where it presents a serious danger to the miners extracting the coal.

Vital Rock Properties

Petroleum is generated within small voids, or pore spaces, of a source rock. Many rocks have pore spaces within them. Sandstone is comprised of grains of predominantly quartz, chemically cemented together with minerals that accumulate where the grains touch.

The mineral cement holding these grains together may be very strong, in which case the rock is described as being *highly consolidated* or *well consolidated*. However, in some cases, this bonding is not very strong, and such a rock would be described as *poorly consolidated* or *unconsolidated*.

Materials that have spaces within them, like a sponge, are described as *porous*. The extent of this porosity is measured as the fraction of the total rock volume occupied by the pore spaces. Porosity is expressed as a percentage; if 20% of the total volume of a rock was made up of pore spaces, the porosity would be 20%. Rock porosity is very important, for without porosity, oil cannot be generated, migrate, or accumulate in a reservoir.

Within a porous rock, it is possible for the pore spaces to be connected. Fluids (gas, oil, or water) can flow between the pores, moving through the rock. However, there are also rocks that are porous, but the rock spaces are not connected. Fluid in the pore spaces cannot move through the rock. As mentioned in the first chapter, the ability of a rock to allow fluid to flow through it is called permeability. A rock can be porous but impermeable (cement is an example of a porous, impermeable solid), but a permeable rock must have porosity (there must exist pore spaces that can be connected). Permeability is extremely important, for without it, oil generated in the source rock cannot migrate to a reservoir and cannot be exploited.

Permeability is measured in darcies. A rock cube of 1 cm × 1 cm × 1 cm sides that transmits fluid with a viscosity of 1 centipoise at a rate of 1 cc per second with a pressure differential of 1 bar has a permeability of 1 darcy. In layman's terms, a rock with a permeability of 1 darcy is very permeable. Most reservoir rocks are measured in millidarcies (1/1,000th of a darcy) rather than darcies.

Shale has very low porosity and very low permeability. Shale minerals form flat crystals that stack up like plates on a shelf. When clays are originally deposited, they are comprised of 70%–80% water. As water is squeezed out of the clay during diagenesis, these flat crystals become very close to each other. At a depth of 2,000 m, the gap between the crystals is about 10 nanometers. By the time the shale is buried to a depth of 5,000 m, this gap has closed to about 1.5 nanometers (1.5×10^{-9} m or 0.0000000015 m).

Shale has tiny pores that are connected by tiny passages. It takes a long time for the water and the oil produced within the shale source rock to migrate out of the rock, squeezed out by pressure. The actual mechanism by which the oil leaves the source rock is uncertain, but it is thought that the oil is initially in solution in the water under the high pressures that exist in the source rock.

Primary Migration

The first two conditions necessary for the birth of a reservoir are the existence of an organic-rich source rock and the conditions necessary for oil to be generated—temperature (the oil window) and time. If the oil cannot migrate out of the source rock, it stays locked within the shale and cannot be produced.

The third element required is that the source rock lies next to a permeable rock or a channel that allows the oil to migrate. In most cases, a permeable sandstone deposit provides this conduit, but it can also be provided by fractures in the rock or ancient reefs (limestone structures made up of coral skeletons with very high permeability). Fractures often allow migration vertically upwards, and this mechanism has led to many large oil accumulations, such as those found at shallow depths in Venezuela and northern Iraq.

A gently sloping formation bed can carry the oil for long distances horizontally until a trap stops migration and allows accumulation. Therefore, a reservoir can be located many miles away from the source rock that generated the oil.

Structural Traps

As the oil and gas undergoes primary migration away from the source rock, it must find a structure that has the right conditions to trap the oil and stop it from reaching the surface (fig. 2–2).

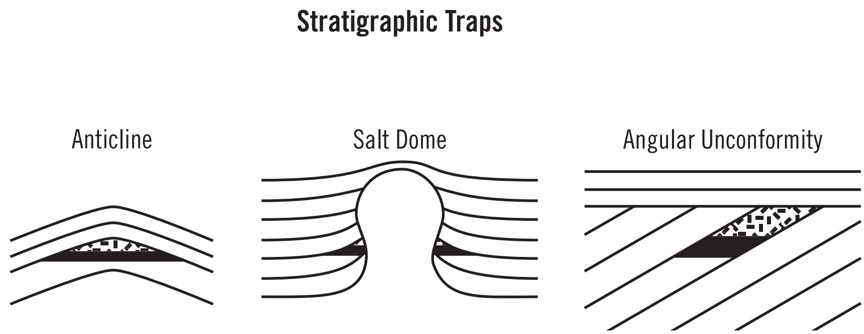


Fig. 2–2. Types of structures that can form a trap

A trap may be formed by movements within the earth's crust that deform the rock. One type of structural trap is an anticline, which has a structure like an inverted cup. Thick salt deposits can flow under high pressures, and sometimes a bubble of salt rises from the salt bed to form a salt dome. Salt domes distort the rocks above them and can provide large structural traps suitable for a reservoir. Reservoirs may also be formed by permeable beds that are tilted by crust movements, eroded after exposure to the surface, and buried by new layers of impermeable rock deposits. This is called an *angular unconformity*. Figure 2–2 illustrates these structures.

Reservoir Rock

In a reservoir, the gas, oil, and water are found in pore spaces or fractures within the rock matrix. Most reservoirs worldwide are contained in sandstone structures that have sufficient porosity to give a good volume of reserves and a high enough permeability to be able to produce it. However, limestones (carbonates) with fractures and/or pits (due to water dissolving some of the material) can give extremely high porosity and permeability. Some limestone reservoirs originate from coral reefs, and these also will tend to be prolific reservoirs, with high porosity and permeability. In the United States, around 80% of reserves are held in sandstone reservoirs and 20% in carbonate reservoirs. In the Middle East, almost 100% of reserves are in carbonate reservoirs.

Reservoir permeability ranges from a couple of hundred millidarcies to 15 darcies or more. The more permeable a reservoir, the faster the hydrocarbons within it can be produced.

Reservoir rocks often contain other materials within the pore spaces. For instance, varying amounts of clay minerals may exist within a sandstone reservoir. These can cause problems while drilling through the reservoir. The clays can react with part of the drilling fluid and expand to plug pores and passages, reducing permeability in the zone around the wellbore. This can seriously reduce or even prevent production of oil and gas from the well.

Reservoirs are rarely uniform throughout. They may consist of layers of material with slightly different characteristics, leading to *directional permeability*—the permeability differs depending on the direction of flow. Permeability might be better horizontally than vertically. Within the reservoir, there may be faults or distortions. Other rock types may be present. These things all form barriers to the free flow of hydrocarbons, and they can make the reservoir structure extremely complex. In fractured limestones, the fractures containing oil may be vertical, requiring a wellbore to be drilled horizontally in order to intersect many fractures for efficient production. Clearly, selection of where to place a wellbore in order to hit the best (most permeable) parts of the reservoir can get complicated!

Modern 3-D seismic techniques can obtain detailed knowledge of the reservoir structure, and 3-D seismic is now an indispensable tool in modern well planning. This data, plus data from other wells drilled in the reservoir during exploration, are used to create computer simulations that model reservoir structure and behavior. This in turn allows the operator to exploit the reservoir with the minimum number of wells and surface facilities—maximizing return on the money invested in developing the field.

Seal Rock

While a reservoir rock must be permeable, there must also be an impermeable rock seal above it that prevents further upward migration of the oil and gas. Often this seal is formed by a layer of “clean” shale (shale with little or no sand within it). Other impermeable seal rocks may be formed from salt or unfractured limestone.

Chapter 1 described the possibility of drilling into a formation that had a greater pressure than would be expected for the depth of the formation. A seal rock gives one of the two conditions necessary for overpressure to occur—a pressure barrier.

Secondary Migration

In secondary migration, the oil droplets move about within the reservoir to form pools. Secondary migration can include a second step during which crustal movements of the earth shift the position of the pool within the reservoir rock (fig. 2–3).

Accumulations can be affected by several, sometimes conflicting, factors:

1. Buoyancy causes oil to seek the highest permeable part of the reservoir. Capillary forces direct the oil to the coarsest grained area first, then successively into finer grained areas later.
2. Any impermeable barriers in the reservoir channel the oil into somewhat random distribution.
3. Oil accumulations in carbonate reservoir rocks are often erratic, because part of the original void spaces have been plugged by minerals introduced from water solutions after the rock was formed.
4. In large sand bodies, barriers formed by thin layers of dense shale may hold the oil at various levels. With crustal movement of the earth, accumulations are shifted away from where they were originally placed.
5. Faults (where part of the rock body has moved along a crack) sometimes cut through reservoirs, destroying parts or shifting them to different depths.
6. Uplift and erosion bring accumulations nearer to surface, where lighter hydrocarbons may evaporate.
7. Fracturing of the cap rock may allow accumulations to migrate upwards.

Wherever differential pressures exist and permeable openings provide a path, petroleum will move.

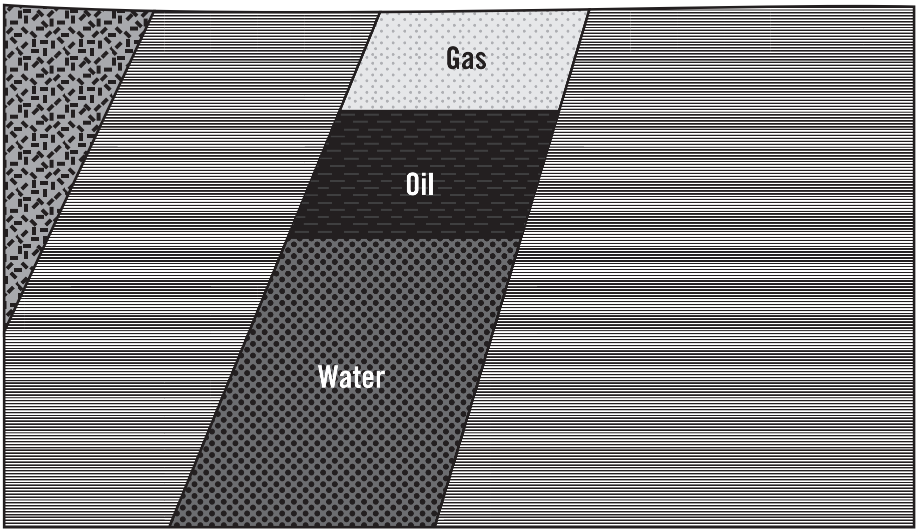


Fig. 2–3. Secondary migration within reservoir

Some (very few) reservoirs are *single phase*; that is, they contain only a single fluid type, either all gas or all oil. Oil is rarely found without some gas or some water. Gas generated from coal seams, as described previously, can be single phase. Mostly, however, reservoirs are *multiphase*—they contain mixtures of gas, oil, and water. Secondary migration will tend to separate these fluids out by gravity so that the gas sits at the top (known as a *gas cap*), oil under the gas, and water under the oil (lightest fluids at the top to heaviest fluids at the bottom). The oily part of the reservoir may contain a mixture of oil and water within the pore spaces, in which case the reservoir rock may have a layer of water adhering to the surface of the rock grains (*water wet*) or it may have a layer of oil adhering to the rock (*oil wet*). These factors and others must be considered by the reservoir engineers when deciding how to exploit the reservoir.

Reservoir Drives

What provides the energy to drive the hydrocarbons to the surface through a hole drilled into the reservoir? Most oil reservoirs, when first drilled into and produced, have sufficient pressure in the reservoir to push the oil to the surface. This energy can come from different sources.

Gas drive

The reservoir is partially or completely isolated from the pressure regime in the surrounding rock. As oil is produced, the gas cap above it expands. As the gas cap expands, it loses energy. The temperature and pressure in the reservoir drop until eventually there is not enough energy left to drive the oil out. Gas drive is not an efficient long-term production driver.

At the stage when there is insufficient pressure left, there are several possibilities:

1. Inject more gas into the reservoir to increase the pressure.
2. Ignite oil underground by injecting air. The gas from the burning oil increases reservoir temperature and pressure and drives more oil out.
3. Install a downhole pump to pump the oil to the surface. This may be a mechanical pump (with a "nodding donkey" or "horsehead" on the surface providing the power via rods connected to the pump) or a downhole hydraulic or electric pump.
4. Inject gas into the well. This mixes with the oil, which makes the column of oil lighter, allowing the reduced pressure to drive the oil out. This is called *gas lift*.
5. Inject water and chemicals in part of the reservoir to drive the oil towards the producing wells.

These techniques are called *secondary recovery.*

Water drive

Chapter 1 explained the principle of hydrostatic pressure. Liquids have a pressure gradient—the heavier the fluid, the higher the pressure gradient. In a sedimentary rock sequence, there is a local water table; that is, the rock pore spaces contain salt water, and this exerts a pressure at depth (as was explained in chapter 1).

In a reservoir that has water drive, the reservoir is connected hydraulically to the area pressure regime (such as an aquifer that is open to the atmosphere). Water from the local water table pushes the oil to the oil well. Water drive maintains the driving pressure much longer than gas drive because the pressure comes from the surrounding area. Eventually, as the oil is produced, water will move towards the well, and at a certain point, it may break through the oil and reach the well. The water will then be produced in preference to the oil, not only because it is less viscous but also because the increase in the amount of water in the pore spaces blocks the oil. This is called *water blocking*.

Problems Related to Fluids in the Reservoir

In some cases, the oil in a reservoir can become degraded by bacterial action to produce hydrogen sulfide (H_2S). H_2S is extremely toxic; exposure to over about 100 parts per million (ppm) of H_2S in the air can be fatal. While that is bad enough, steel exposed to H_2S in a wet environment can become brittle and fail (break) without warning. If a reservoir has H_2S present, the rig must be equipped to deal with it. Crews must be trained and equipped to work safely in the presence of H_2S. Expensive steel alloys must be used in the well to prevent equipment failure. H_2S is also called *sour gas*, and it has a distinctive odor of rotten eggs. H_2S quickly destroys the sense of smell.

Carbon dioxide (CO_2) can also be present in the reservoir. Exposure of steel to CO_2 in a wet environment can also cause serious corrosion problems for steel tubulars in the well.

If both H_2S and CO_2 are present in a reservoir, serious problems may arise in producing the oil and gas and in treating them before they can be sold.

Summary

1. For an exploitable petroleum reservoir to form, specific conditions arising in the correct sequence are necessary.
2. Economically exploitable hydrocarbon reserves are generated from about 0.01% of all organic matter deposited within the earth's crust.

3. Reservoirs may be formed from permeable sandstones or permeable or fractured carbonates. The oil and gas is found in the pore spaces, fractures, and voids within the reservoir rock.
4. Reservoirs can be extremely complex, requiring detailed structural knowledge and computer simulations to work out how best to exploit them for the maximum return on investment.
5. When planning and drilling wells, close cooperation between the drillers and the reservoir engineers is necessary in order to minimize damage to the reservoir.
6. If H_2S is present in the reservoir, special precautions are needed to avoid danger to the crews, and the well has to use special, expensive steels to avoid catastrophic sudden failure.

3

DRILLING A LAND EXPLORATION WELL

Overview

This chapter will tell in story form how an exploration well on a land rig in the desert might be planned and executed. An exploration well is one that is drilled in order to prove whether or not a structure in the rock contains hydrocarbons in commercially worthwhile quantities.

Some technical terms will be introduced and explained in this chapter. Also, many of the concepts that were covered in chapters 1 and 2 will be referred to. Imperial units will be followed by the metric equivalents, in brackets.

Identifying a Prospect

An operator buys the right to explore for oil or gas in an area from the government. These areas are often called *blocks* (fig. 3–1). The operator will buy a permit to explore on a block because they believe the following:

1. All of the conditions discussed in chapter 2 are likely to exist for hydrocarbons to accumulate in commercial quantities.
2. The likely cost of exploration is worth the chance of finding an exploitable field.
3. They can afford to absorb the exploration cost if nothing worthwhile is found, or can afford to develop any discovery in order to bring hydrocarbons to market.

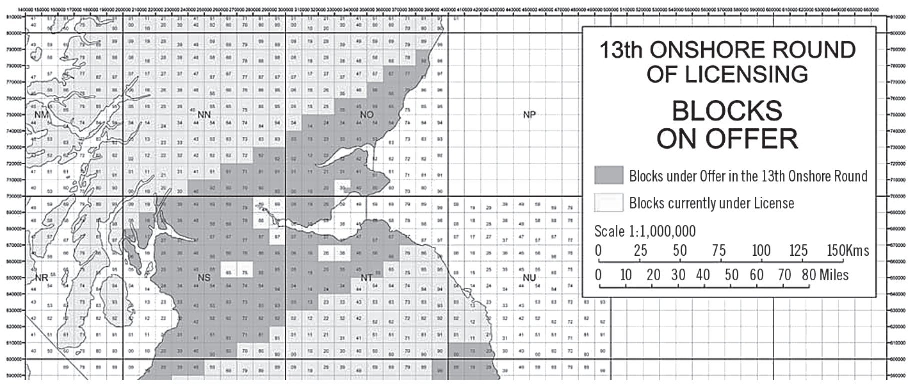


Fig. 3–1. Part of the UK onshore licensing map

Small companies sometimes pay for a block, invest enough to identify good prospects, and then look for larger companies to buy in as partners. If this works, then the new partner will likely fund the first one or two wells, "carrying" the small company, to become a partner on the block. In this way, the small company can then increase its value many times with a relatively small investment.

An exploration well is drilled to gain information. It is usually a false economy to try to drill an exploration well to later produce oil. A producing well cannot be properly designed until the reservoir is known in sufficient detail (pressures, fluids and gases present, permeability, how well consolidated the reservoir rock is, and many other factors). Many things about the subsurface conditions cannot be predicted on the first well. This means that the well design may have to change if unexpected conditions are encountered while drilling. Exploration wells should be minimum-cost wells designed to obtain essential information and be abandoned afterwards.

Well Proposal

For this example well, an angular unconformity structure is present (as was discussed in chapter 1), providing a potential trap for oil and gas. The geologists believe that it will contain a gas cap on top, with a column of oil and water below. It was decided to drill a well into the edge of the gas cap and follow the bedding plane down through the oil and into the water, so that several facts (the *well objectives*) could be established (fig. 3–2):

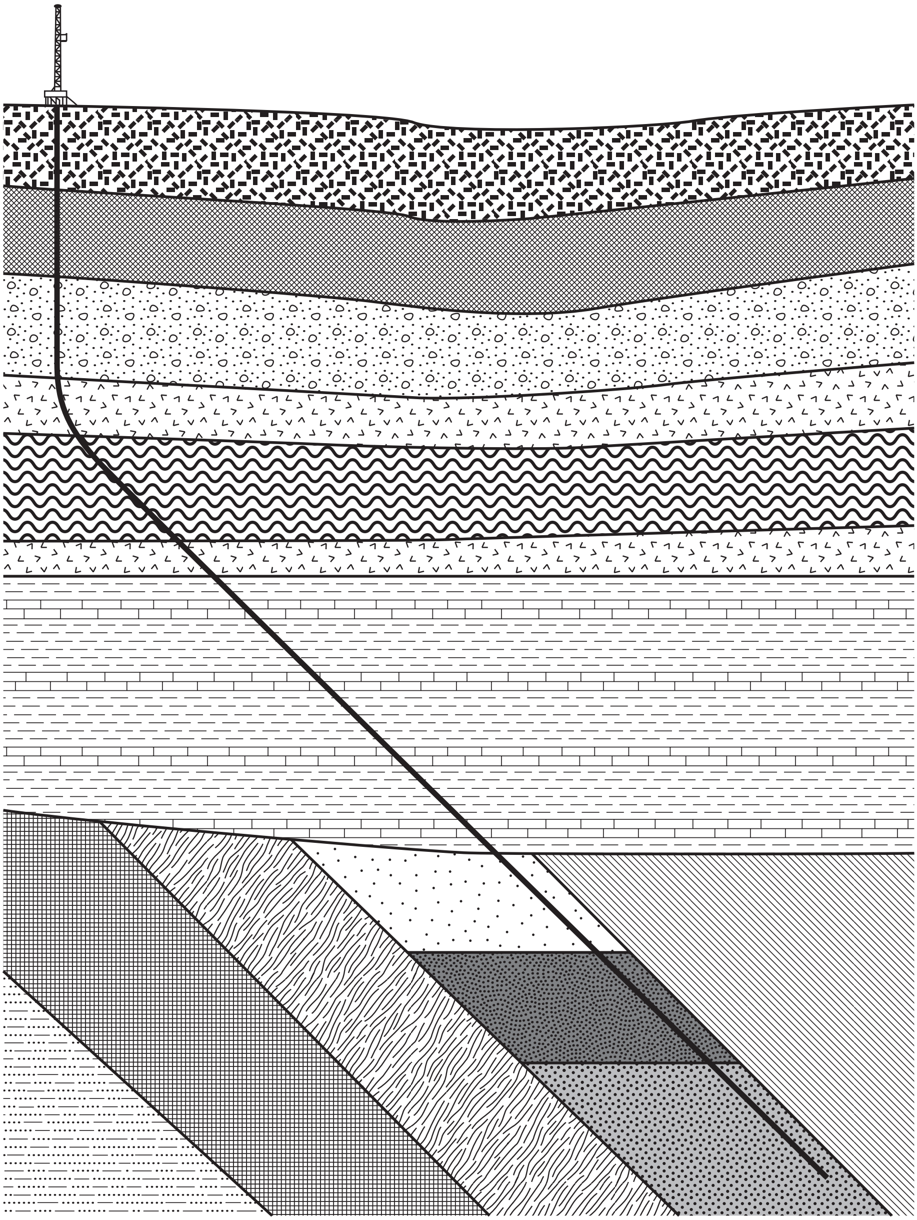


Fig. 3–2. Well path in this angular unconformity

1. Prove that oil and gas both exist in the reservoir, obtain samples of each for analysis, and measure the fluid pressures in the reservoir.
2. Determine the depths of the gas-oil and oil-water contacts.
3. Take samples of rock in the oil part of the reservoir.
4. Test the oil layer to measure the following:
   a. The maximum rate at which the oil can flow before sand starts to be produced.
   b. The maximum possible production rate.
   c. Internal reservoir characteristics, such as permeability, porosity, internal boundaries, pressures, and temperatures.
   d. Damage to the reservoir from the drilling operation. This is known as the *mechanical skin* and causes a reduction in permeability.

Now a *well proposal* document has to be written, which is a request from the exploration department for a well to be drilled. It provides the necessary information to the drilling department to start designing for the well.

Well proposal contents

Well proposal contents include the following information:

1. Type of well (exploration) and well objectives (as stated above).
2. Essential well design data:
   a. Surface (rig) location to use, if known.
   b. Downhole targets to hit; position, depth, and the acceptable margin for error.
   c. Depths and descriptions of the downhole rock strata, as far as can be determined.
   d. Expected strengths of formations down hole and pressures of fluids inside the rocks.
   e. Temperature profile; how the temperature varies with depth.
   f. What information is required from the well.

g. Whether core samples of rock should be obtained and at what depths. (A *core* is a sample of rock obtained by coring, which uses a bit with a hole in the middle and recovers a column of rock.)

h. What should happen to the well after operations are complete (abandoned or temporarily secured for possible later use).

i. The completion design for the well (see below for an explanation).

First, the drilling department needs to review the well proposal to establish that the following criteria are met:

1. The proposal is logical, and the objectives are achievable.
2. The essential well design data is complete, and there are no ambiguities or omissions.
3. The directional targets that the well needs to hit are as large as possible. The smaller the target, the more the well is likely to cost.
4. The proposal does not give rise to any inherent hazards that might create a danger to personnel or to the rig or the well.

Once the well proposal is agreed upon by all concerned parties, the drilling department will look for any available information to help the drilling engineers design the well.

Well Design and Drilling Program

A *well design* defines the final status of the well; that is, what is left behind when the rig leaves the location.

A *drilling program* is a document that the drilling engineers use to advise the rig how the well design might best be achieved. If the well design is the destination, then the drilling program is the road map to reach the destination. However, the drilling program should not be considered to be a definitive document that must be followed without modification. During the drilling of a well, there will be unplanned events or circumstances requiring changes to be made in order achieve the required well design in a cost-effective manner.

These two documents will be looked at separately.

Well design

In designing a well, there are five areas that must be defined:

- **Completion design.** The completion forms the conduit for hydrocarbons to travel up the well, through the wellhead, and into the surface production facilities. Normally, the drilling engineer is given the required completion design as part of the well proposal.
- **Casing design.** Casings are steel pipes that are lowered into the well and cemented in place. The well is then drilled with a smaller diameter hole to the next point at which the next smaller casing should be cemented in. The casing design defines these pipes and the cement sheath that seals the space between the casing and hole.
- **Directional profile.** This is the 3-D path that the well should travel to take the well from the surface rig location to the correct path in the reservoir. These paths can get quite complex.
- **Wellhead configuration.** The wellhead consists of an assembly of pressure-tight components on the surface, at the top of the well. The wellhead must handle all of the loads imposed on the well, such as the weights of all the casing strings and the internal pressures from the well.
- **Well fluids requirements.** When the drillers have finished their work, the well will have different fluids left in different parts of the well. This is defined as part of the well design.

Completion

A *completion* consists of many pieces of tubing that are screwed together. Tubes screwed together in the well are called a *string*. The device used to join tubings and casings together is called the *connection*. A completion connection must withstand the physical loads from the weight of the tubing below, plus any other loads that may arise (fig. 3–3). It must also allow produced fluids (which may include gas) to flow through the tubing and not leak. It must be easily handled by the rig.

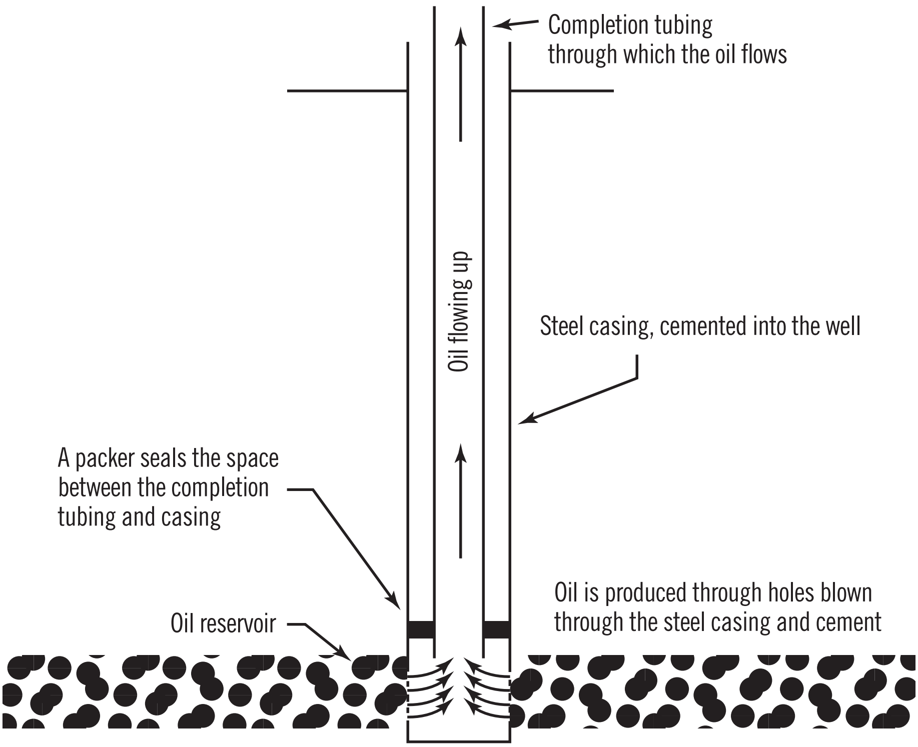


Fig. 3–3. Completion tubing in a well

Positioned within the completion tubing string will be other components that are necessary to control the flow of fluids (such as valves) or to allow other tools to be positioned within the tubing. A packer may also be used, which forms a seal between the outside of the completion tubing and the inside of the casing in which it is run. A packer would normally be used to stop hydrocarbons flowing outside of the completion tubing, as shown in the illustration above.

One device that should be installed in every completion is a subsurface safety valve (SSSV). Positioned below the surface (or below the seabed), an SSSV consists of a valve that is held open against a spring by hydraulic pressure. A small-diameter, high-pressure pipe runs along the outside of the completion to the surface, and this contains hydraulic fluid, typically at 5,000 psi (34.5 kPa), which holds the valve open. If something disastrous happens (such as a fire), the well can be quickly closed by removing the hydraulic pressure. If the wellhead were to be knocked off, the hydraulic line would break, pressure would drop to zero, and the valve would close. During the Gulf War in 1991, the Iraqi army used explosives to blow wellheads off wells in the desert. As these wells were not equipped with SSSVs, they then flowed oil to the surface uncontrollably until specialist “wild well control” experts were able to stop them weeks or months later.

In an exploration well, the completion is normally quite a simple configuration used to test the performance of the well with a production test or well test. This type of completion is called a *test string.*

Casing design

Casings in a well are designed from the bottom up. Starting at the total depth of the well, the drilling engineer first has to decide what size the hole needs to be at that depth. This will be determined by the completion design. For instance, if the completion or test string design has a maximum outside diameter of 5″ (127 mm), the smallest standard-sized pipe that this can run inside is a 7″ (178 mm) outside diameter casing. Normally, a hole of 8½″ (216 mm) diameter would be drilled to accommodate a 7″ (178 mm) casing. Thus, the size of the hole to be drilled at the bottom of the well is determined by the requirements of the completion tubing.

Given the fluid pressures in the rocks at the bottom of the well and considering the strengths of the rocks higher up, it is determined where the next highest casing string has to be cemented in place in order to contain pressures from drilling the well. For drilling an 8½″ (216 mm) diameter hole, the next standard size of casing that this size of drill bit will fit inside is 9⅝″ (244 mm) outside diameter. This would normally be placed inside a 12¼″ (311 mm) diameter hole.

Similarly, the depths and sizes of all of the casings in the well are designed by the drilling engineers.

Casings and their connections must withstand the forces imposed by the weight of the casing. Also additional forces are imposed by the act of lowering the pipe into the hole (such as bending the pipe through bends in the well path). It is also necessary to account for internal pressures and high temperatures.

Directional profile

A well may be required to be drilled vertically to the target. However, most wells have some directional requirements. A well may be drilled directionally for many different reasons:

- To reach a target that cannot be reached with a vertical well, such as below an inaccessible surface feature.
- Offshore, many wells can be drilled from a single structure. These wells must spread out so that they are widely separated within the reservoir.
- Some wells need precise placement within the reservoir to get the best production from the well, such as intersecting fractures along a particular direction, or drilling a long horizontal wellbore just under the top of the reservoir.
- If a well is flowing hydrocarbons uncontrollably to the surface, it might be necessary to drill another well to intersect it, in order to stop it from flowing. This is called a *relief well*. A relief well must be drilled very accurately.

The directional profile is chosen to achieve the well's objectives at the lowest cost (fig. 3–4).

Note that once the well starts to deviate, two depths are given for each position (such as the bottoms of casings). These are *measured depth* (which is the depth measured along the casing length) and *true vertical depth* (which is the vertical depth below the surface or below sea level).

The largest casing is called the *conductor*, as shown above. The next casing is called the *surface casing*. This terminology is explained later.

Wellhead configuration

The wellhead is the "visible" part of the well. There are different types for different purposes.

In figure 3–5 are photographs of three wellhead types.

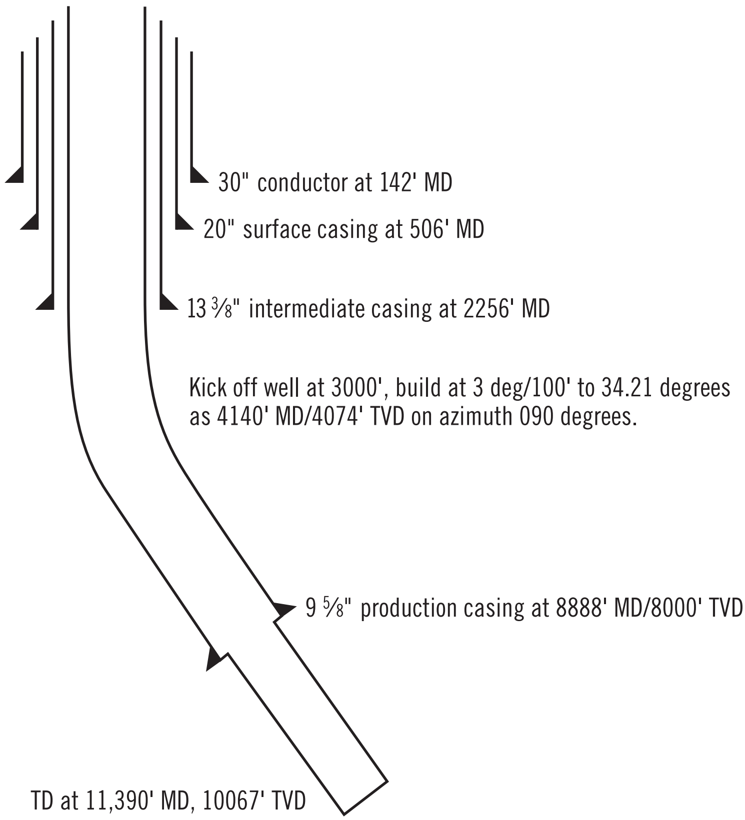


Fig. 3–4. Example directional profile with casing positions

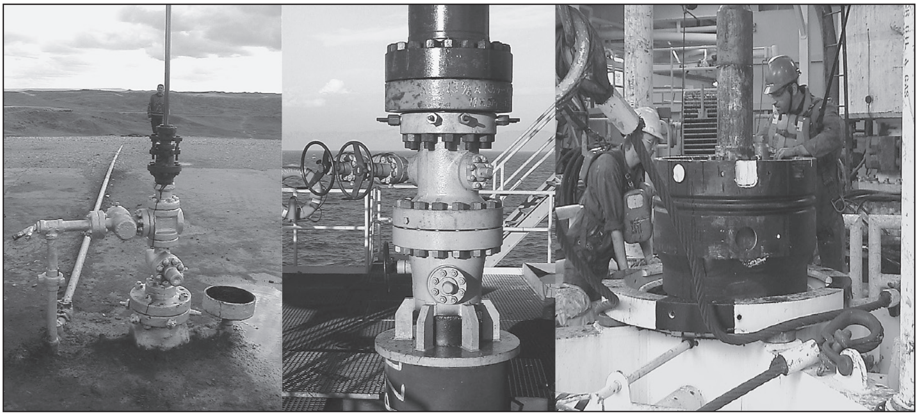


Fig. 3–5. Different wellheads

On the left is a simple land wellhead in Turkey, used with a beam pump. There is no pressure on the wellhead itself; oil has to be moved to the surface using a pump. The rod coming out of the wellhead reciprocates, lifting oil on the upstroke. The oil level inside the well can be found by measuring the time taken for a sound to be echoed from the oil surface in the well. This is done using the funnel object to the right of the wellhead, which is openly connected to the well outside of the completion tubing. There is no packer sealing between the completion and casing, so oil can rise in this space. The oil level will gradually drop as more oil is produced from the reservoir and reservoir pressure reduces.

On the right, a subsea wellhead is being prepared on a rig drilling in the Mediterranean Sea. This will be placed on the seabed. Visible is the housing on top of the largest casing string (the large object in the middle of the photo). Secured inside it is a running tool, suspended from the rig on pipe. This is used to lower the whole assembly to the seabed and then release it. Below the housing is a guide base, which has a post at each corner. From these posts, guy wires extend back up to the rig, and these will guide tools between the rig and the seabed. It can be seen that a subsea wellhead is pretty large!

In the center of figure 3–6 is a spool-type wellhead, placed on a platform in the Gulf of Suez, Egypt. At the bottom can be seen the top of a 30″ (762 mm) OD casing pipe. Next is a section of 20″ (508 mm) casing, on top of which is screwed a large steel housing called a *casinghead housing (CHH)*. The flange and webs below it sit on top of the 30″ (762 mm) pipe, so that the 30″ (762 mm) pipe supports loads from the 20″ (508 mm) casing and the wellhead.

Inside of the CHH is a profile shaped like a bowl. When the subsequent (13⅜″ [340 mm] diameter) casing is run into the well, it has a big steel hanger on the top that lands inside the casinghead housing. This positions the casing correctly during cementing and transmits loads back into the wellhead.

The figure above shows a cross-sectional drawing of a similar type of wellhead. The 30″ (762 mm) casing is illustrated, with the 20″ (508 mm) casing inside it and the 20” (508 mm) CHH secured on top of the 20” pipe. The 13⅜″ (340 mm) casing hanger holds the 13⅜″ casing, and this sits inside the CHH, as can be seen.

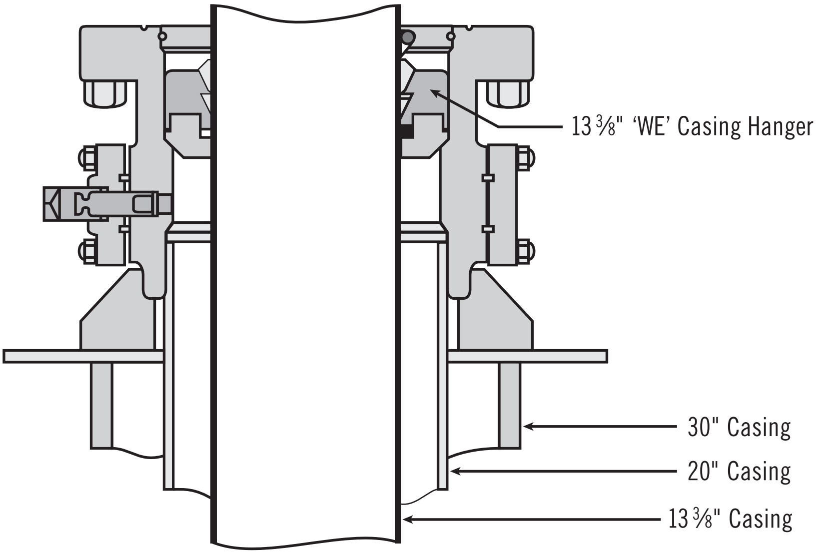


Fig. 3–6. Cross section through a spool-type wellhead
Image courtesy of GE Oil & Gas, © Vetco Gray, Inc.

The next part of the process for this wellhead would be to add another spool on top of the 20″ (508 mm) CHH. This would seal around the 13⅜″ (340 mm) pipe sticking up. At the top would be a similar profile to the top of the 20″ (508 mm) CHH, which would allow the next casing hanger to suspend the next section of casing. This next spool is visible in the center photograph in the figure above.

Well fluids

Finally, the drilling engineer will specify what fluids should occupy the different spaces within the well when the rig leaves the location. Before the completion is run into the well, the drilling fluid remaining on the inside would normally be replaced with a specially designed filtered brine. This might be called *packer fluid* or *completion fluid*. The density of this fluid is designed to give a greater hydrostatic pressure at the bottom of the well than the pore pressure. In the example exploration well, the well would be tested if oil or gas is found. For this to happen, holes are blown through the casing using shaped explosive charges. Hydrocarbons can then flow into the well and up the completion tubing. Afterwards, the hydrocarbons might remain inside the completion, or be replaced with completion fluid. If the well is abandoned, the hydrocarbons will be removed and replaced with completion fluid or drilling mud. Most likely, cement will be placed inside the well to ensure that in the future, hydrocarbons cannot flow to the surface through the well.

Drilling program

The program contains, among other things, a set of advisory instructions to the rig that show how it is thought that the well can be drilled most efficiently. Note especially the word *advisory*. It is impossible to anticipate everything that might happen as the well is drilled, and the drilling supervisors in charge of the rig operations may need to deviate significantly from the program if safety or efficiency might otherwise suffer. A well program should never be thought of as a precise set of instructions, but rather as advice that, if justified, can be changed. However, it is also important that the program contains the information behind all of the major decisions made, so that all of this original information can be combined with new information to make the most informed decisions possible. In other words, the program should not just say *what* should happen, but also *why* it should happen.

A well program is a comprehensive document and can be quite long. The major headings of a well program for drilling and completing a well may include the following sections:

1. General information
2. Well objectives
3. Potential hazards
4. Surface location and how the rig is to be positioned
5. General notes, including:
    a. References to government regulations, company policies, and oilfield standards
    b. Reporting procedures
    c. Quality control and data recording requirements
    d. A diagram of the completed well

   e. Equipment checklists and suppliers of each item
   f. Cost estimating information to allow the well cost to be calculated each day
6. Drilling notes for each hole section, including the following:
   a. Potential hazards or problems, how to avoid them, and how to recover from them
   b. Required drilling practices
   c. Recommended operational sequence of events
   d. Kick tolerance information
   e. Drill bits recommended
   f. Bottomhole assemblies recommended (explained below)
   g. Any special requirements
7. Drilling fluid design and maintenance requirements for the whole well
8. Wellbore trajectory information (that is, the path that the well will follow from the surface location to one or more downhole targets)
9. Casing design for the well and how the casings are to be cemented in place
10. Geological information on the formations expected to be penetrated
11. Logging and coring program—what electrical logs to run, and if the well is to have a core sample cut, the relevant details (discussed further in chapter 10)
12. Well completion design and program
13. Well test information, if the well is to be production tested
14. Status of the well when the rig has finished work (e.g., handed over to production, cemented up and abandoned, etc.)

Obviously, there is a lot of information contained in a drilling program. Each heading is examined briefly below.

General information

General information included in a drilling program includes the following:

1. Which country, which exploration block (blocks are usually numbered), name of drilling rig, program issue date, who the program was written by, and who approved it
2. Which offset wells were used for data input
3. A statement on shallow gas (e.g., whether likely to be present or not)

Well objectives

It is important to differentiate between primary objectives (those that the well must meet) and secondary objectives (those that are desired if they can be obtained for little extra effort or cost).

A graph is normally given, showing the anticipated well depth at each day of the operation. The actual progress can be plotted on the same graph, to show whether the well is on target, behind the curve (late), or ahead of the curve (early). The flat spots on the graph show where drilling stops to run casing into the well at the end of each hole section (fig. 3–7).

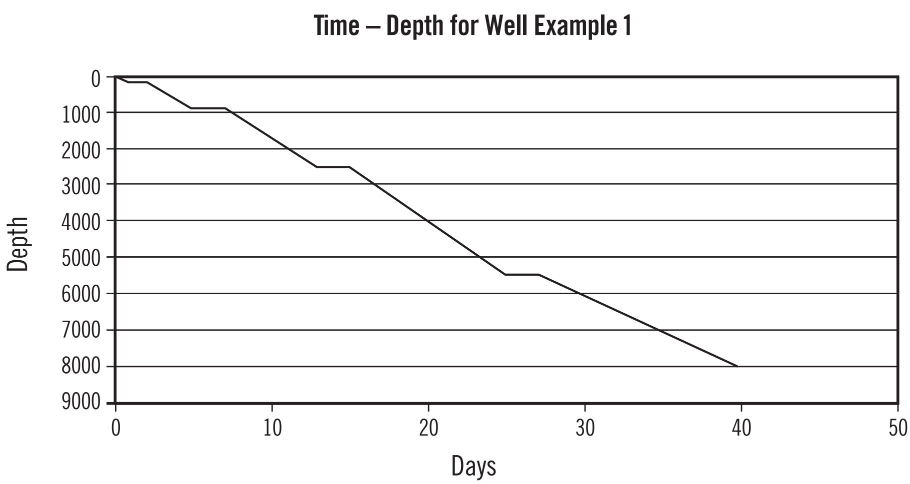


Fig. 3–7. Graph of time vs. depth for an example well

There will also be a detailed cost estimate for the well, broken down into various categories so the actual costs can be later compared to the estimated costs for each category.

Potential hazards

A list should be given of any potential hazards that the rig might encounter. These are not drilling hazards (which will be listed in the text for each hole section), but hazards that might be inherent to the location. For instance, in some areas, rigs might expect to encounter extreme weather conditions at certain times of the year. In such a case, procedures can be given for monitoring potential storms, and under specified conditions, the rig could be evacuated as a precaution after making the well secure.

Surface location

A location on the earth's surface may be given by many different reference systems. Latitude and longitude is one coordinate system. There may also be local grids or coordinate systems that the rig has to be positioned to. In any case, whichever coordinate system is to be used must be specified. Also the tolerance (the acceptable error) must be stated. For instance:

"North coordinate 112995.56 East coordinate 122473.88 using X reference system, well position to be within 5 m of specified."

The datum level for depths must be given. This could be mean sea level, lowest astronomical tide (MSL, LAT) or another suitable reference.

The water depth for an offshore well must be stated.

General notes

References can be made to relevant government regulations, company policies, or oilfield standards as appropriate.

A diagram of the completed well showing all relevant design details is usually included.

Drilling notes for each hole section

In each hole section, there may be particular problems that might be expected. A good program would anticipate these problems and offer strategies to avoid or minimize the impact of the problem. It should also offer strategies to recover from the hazard or problem if it were to occur.

The following also may be included:

- **Required drilling practices.** It may be that specific operational procedures must be used, and these can be detailed here.
- **Recommended operational sequence of events.** This gives an anticipated chronological sequence of events, such as drill to a certain depth, run (specified) electrical logs, and run casing. It includes:
  - Drill bit recommendations
  - Bottomhole assembly recommendations (as explained below)
  - Any special requirements

Drilling fluid requirements

The circulating fluid has a huge impact on almost all aspects of drilling, logging, cementing, and cost. The drilling fluid (mud) must be carefully designed to keep the wellbore stable (a stable hole stays at the same diameter of the bit that drilled it) and also to perform many other functions. The mud for each section will have specific chemical and physical characteristics that must be kept as designed.

Directional information

Everything that defines the path that the wellbore should follow must be known. Diagrams showing the well profile from the side (called the *vertical section*) and from above (called the *plan view*) must be included. As the well is drilled, the actual wellbore position is marked on the same chart, so a glance at the chart shows how closely the actual well path follows the planned well path.

Casing design

Each casing string is completely specified, including the outside diameter of the pipe, how thick it is, what sort of threads are needed to screw the casing together, what type of steel will be used to make the casing, and other information. Tools might be screwed into the casing string at particular depths, and this must be specified so that the drilling supervisor knows what to put where.

Geological information

In a wildcat exploration well, this information might be scarce or nonexistent. In any case, there will always be some intelligent guesswork involved, especially when the geologists try to estimate the strengths of the rocks (formation fracture gradient) and pore pressure. These two pieces of information are very important to drilling engineers because these are what fundamentally dictate the casing program.

The formation lithologies, permeability, porosity, composition of pore fluids, depths and thicknesses, and the stresses present in the rock are all valuable information.

Logging program

Tools can be run into the well on special electrical cable to measure various formation parameters. These are called *electric logs*. There are several classes of electric logging tools that can be used to identify important formation characteristics and to identify the fluids present in the pore spaces.

Many different formation characteristics can be measured. By combining several measurements, a comprehensive picture of any formation can be built up, identifying physical and chemical characteristics.

Coring program

In an exploration well, it is very likely that interesting formations (those with reservoir potential) are cored. In this process, a special drill bit is used that cuts a doughnut shape, leaving a column of formation sticking up the middle. Behind the bit is a barrel (called a *core barrel*) that contains this core and recovers it to surface.

Well completion design

In order to design the well, the engineers need to know how the well will be completed, and in particular, the size (outside diameter) of the completion or test tubing string. As this is an exploration well, the well will use a test string, and the size of test string can be specified at this time.

Well test information

If the well discovers hydrocarbons, a test program will be written. Although the final test program cannot be known until the hole is logged, it is known in general what the program will involve and what testing equipment will be needed. The equipment has to be arranged in advance and should be available to send to the rig as soon as a well test is confirmed.

Status of the well when the rig has finished work

In the case of this example exploration well on land, the well will be abandoned after testing. In the case of other types of wells (such as a producing development well), the drilling engineers need to know what should be the status of the well when they finish their work. It could be left unperforated, or it could be perforated and then killed with clean completion fluid, or something else.

It is normal to include a diagram illustrating the final well status. Figure 3–8 is a well drilled offshore West Africa.

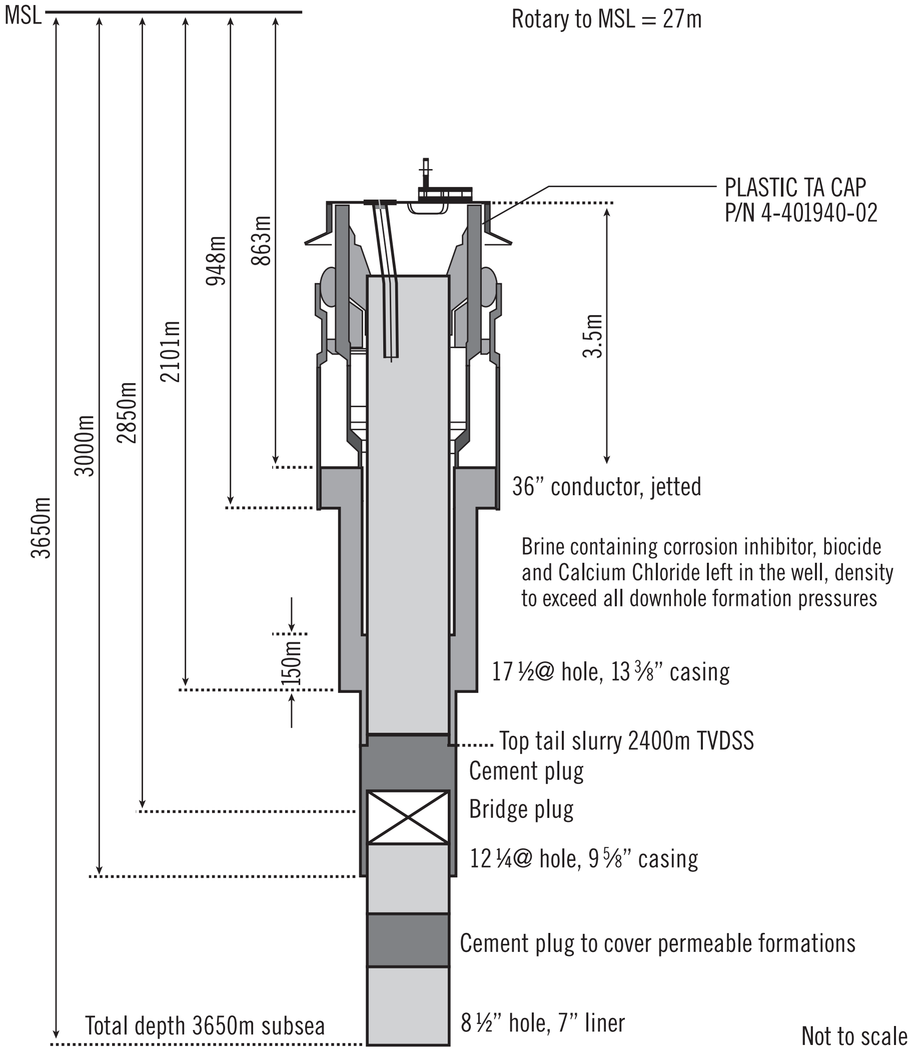


Fig. 3–8. Example diagram of a final well status

Drilling the Well

The general sequence of drilling a well is similar for almost all wells drilled. Events on the hypothetical well under discussion, complete with some typical problems that might be encountered on such a well, are discussed below.

Location preparation and conductor driving

On a land location, a preparation crew will build a location in advance of the rig arriving. The site must be cleared of obstructions. (In some areas, like the Western Desert in Egypt, unexploded World War II ordnance and mines must be cleared away!) The boundary is marked and access roads are created. A square hole with 10 ft (3 m) sides will be dug about 10 ft (3 m) into the ground and lined with reinforced concrete. Around this pit (called the *cellar*) will be a concrete or wooden pad for the rig to sit on (fig. 3–9).

Why is it necessary to dig a hole under the rig location? On top of the casing is placed a large piece of equipment called a *blowout preventer (BOP)*. Without a cellar for the BOP, the rig substructure would have to be much higher to accommodate the BOP. When the well is finished, the wellhead will be partially below ground level, as can be seen in this photo of a completed well near Lake Albert in Uganda.

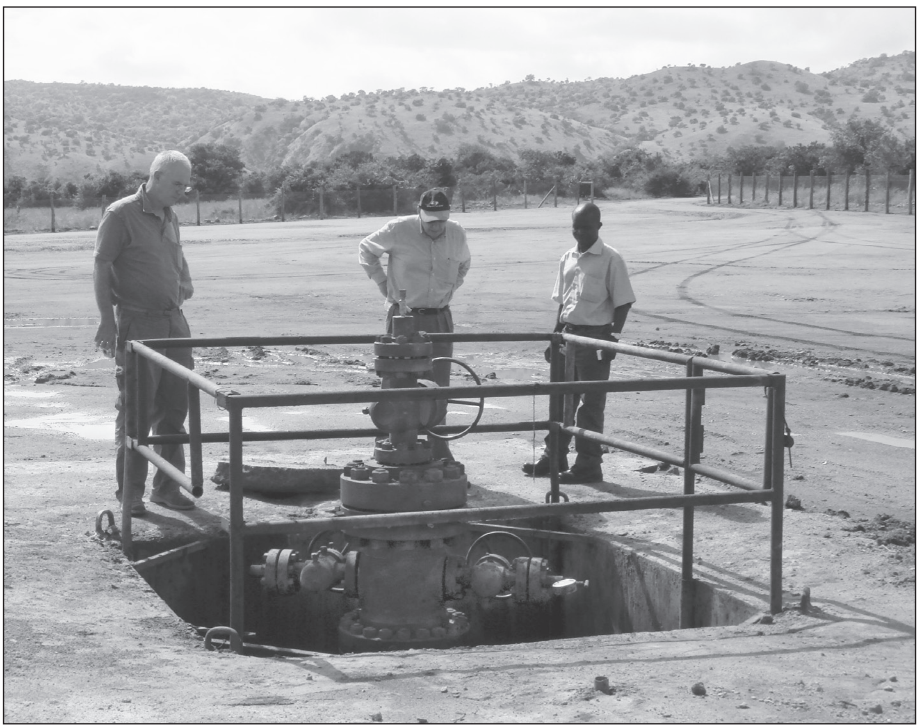


Fig. 3–9. Wellhead inside cellar after rig departed

In a remote desert location, a concrete-lined water pit is dug and a water well drilled. Water is required in large quantities during drilling, to mix up drilling mud and cement as well as to keep the rig clean. The water well produces water into the water pit. If the water well cannot keep up with the rig requirements, water can be trucked in and dumped in the water pit to supplement the water well production.

Ordering equipment

A lot of equipment is needed to drill even a shallow well on land. Depending on the country, equipment may be freely available (North Sea or Gulf of Mexico), or it may take months to order, ship, clear customs, move to the logistics base, inspect, and be ready to mobilize to the rig (East Africa). In some countries, equipment can be tied up in customs for weeks or months.

If an operator or contractor is established and well experienced in the country, these factors will be known and can be anticipated in the planning stages. With long lead time items, it may be necessary to get management approval to order those items before the well itself is approved.

Quality control is very important in order to ensure that items ordered are as per specification and are fit for purpose. If equipment fails (breaks or stops working) while drilling, repairs and downtime can be expensive, and in some cases, equipment failure can endanger personnel working around it. There are various industry standards, ISO 9000 requirements, and company procedures that can assist the drilling engineer in ensuring that equipment ordered is suitable.

Checking the infrastructure

Infrastructure covers such things as roads, airfields, harbors, and storage areas, among others. A drilling operation requires a lot of logistical support, and the infrastructure should be able to handle high traffic loads, at any time of the day or night, in all weathers. If there is an emergency situation and the infrastructure cannot support the demands of the rig in solving that emergency, people can be placed in more danger. In addition, more environmental damage may occur, and the reservoir could be damaged if the situation is not resolved quickly.

Moving the rig on location and attaching the diverter

Land rigs break down into packages that are moved by truck. To reassemble the rig on location requires care and precision. Each major part must be accurately positioned relative to the rig substructure, so that cables, walkways, pipes, and other equipment line up and can be easily connected. Each rig has a procedure, outlined in the rig operating manual, that details what must go where and in what order, for the most efficient assembling of the rig.

The rig substructure is constructed from steel beams welded together. The substructure is a large frame that supports the drill floor, generally about 15 ft to 20 ft (4.6 m to 6 m) above ground level, and the derrick (less commonly called the *mast*). The substructure itself may split into several smaller packages for transport. In the middle of the drill floor is a hole, inside of which is a powered turntable. This is called the *rotary table* and is used to turn the drillstring for drilling, as well as for other tasks.

Once the substructure is placed in the correct location, the derrick is laid out onto cradles and assembled (fig. 3–10). The cradles position the mast so that it can be attached to the substructure above the drill floor. At the substructure end, the derrick is secured by large steel pins, several inches in diameter, to allow the derrick to pivot to the upright position. When everything is ready, the derrick is rotated to vertical by winching in on steel cable attached to the derrick, and the remaining legs are pinned in place onto the rig substructure. With the derrick upright, rigging up continues until the rig is ready to start drilling.

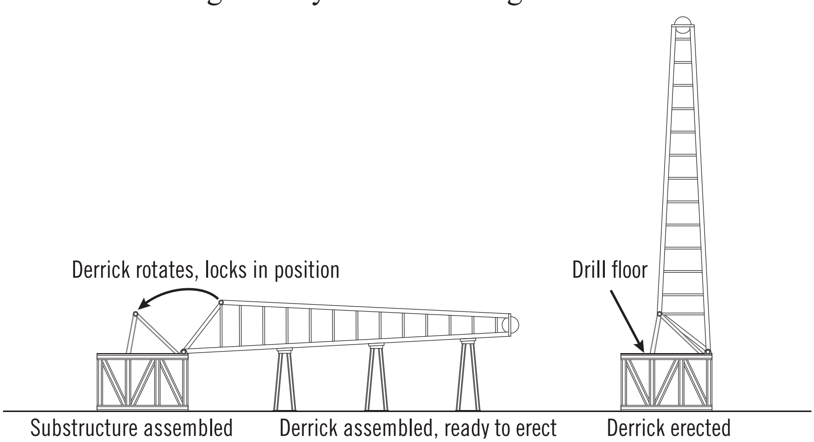


Fig. 3–10. Assembling the rig on location

The drillers measure the distance from the drill floor down to the top of the conductor pipe. Depths in the well while drilling are referenced back to the drill floor, so the conductor shoe depth = length of conductor in the ground + distance from drill floor to the top of the conductor.

The derrick has several large sheaves at the top end. Steel wire rope, called *block line*, passes over these sheaves and around another set of sheaves on a massive pulley. By winching in or out on the block line with an electrically powered drum, the pulley—called the *traveling block*—moves up and down the derrick. Below the traveling block is a large steel hook that can lift whole strings of casing pipe, support the drill string while drilling, and perform many other tasks. A large land rig would probably be strong enough for the traveling block to support up to 500 tons (508 tonnes), using block line of commonly 1⅝″ (495 mm) diameter with a tensile strength of over 100 tons (101 tonnes). (Block line may vary in size from 1″ [25 mm] to 1¾″ [44 mm] diameter.)

With the rig ready to start operating, the diverter must be attached to the conductor, which was hammered into position by the location preparation crew (fig. 3–11). The diverter contains a large rubber seal that is forced under hydraulic pressure to squeeze in around the drillstring and seal around it. Underneath this seal are usually two large pipes, at least 10″ in diameter, which should lead away from the rig in opposite directions with no bends or changes in internal size. Occasionally only one line will be fitted, leading off downwind of the prevailing wind. If a kick is experienced while drilling below the conductor pipe, the flow is diverted away from the rig by closing the diverter and opening the valve on the pipe leading downwind.

On top of the diverter is a section of pipe (called a *bell nipple*) that has an outlet to the side. This side outlet directs mud flow from the rig along a channel to the solids control equipment and then back to the mud tanks, from where the pumps circulate it back down the hole.

The space between the inside of the well and the outside of the drillstring is called the *annulus.* Mud coming out of the bit flows upwards in this annulus, lifting drilled cuttings to the surface. It comes out of the flowline outlet (as shown on fig. 3–11) and is directed to equipment that separates the drilled solids and the mud, so that clean mud can be pumped back down the hole.

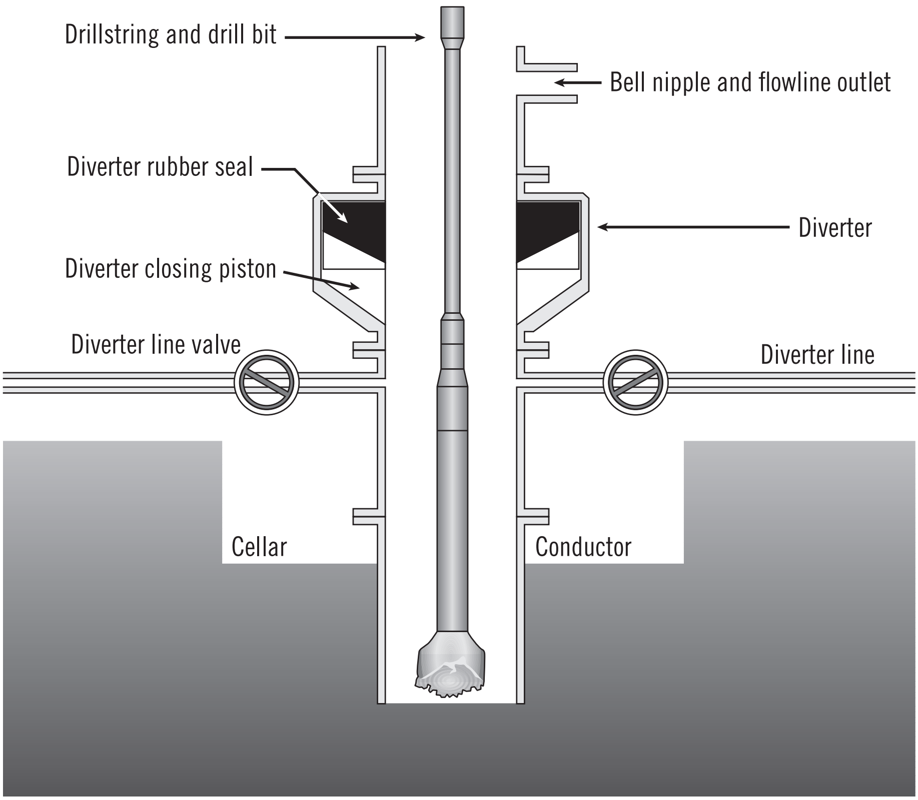


Fig. 3–11. Diverter set up for drilling

Spudding the well

With a conductor pipe that was driven into the ground with a pile driver, the inside of the conductor will be full of rubble, as the bottom of the conductor is open while hammering it into the ground. So the first thing to do is to clean out this rubble. A drill bit that is only slightly smaller than the conductor inside diameter (ID) is run on drill collars down to the top of the rubble. Mud is pumped down the drill string, and the bit is rotated and lowered. This breaks the rubble up, and the mud flowing upwards in the annulus lifts it up to the surface.

If a shallow gas pocket is penetrated, the chances of recognizing and controlling it are much better if a smaller size hole is drilled. If the gas pressure is high enough to push all the mud out of the well, this uncontrolled flow is called a blowout, as explained previously. If the well does blow out, the gas will flow through a smaller hole, and so the initial flow will be much less. This allows a few vital moments to get the diverter closed and to start pumping fluid down the drill string as fast as possible, to try to slow or stop the flow. The intensity of a shallow gas blowout is such that large volumes of rock will be removed from the well as the gas flows, rapidly making the hole much larger.

The first drill bit will be 12¼″ (311 mm) diameter (fig. 3–12). The hole it drills is termed a *pilot hole* because the hole will be redrilled later with a larger bit. The start of drilling the well is called *spudding* the well. The time that the well is spudded, by convention, is taken to be the time that the drill bit exits the bottom of the conductor pipe.

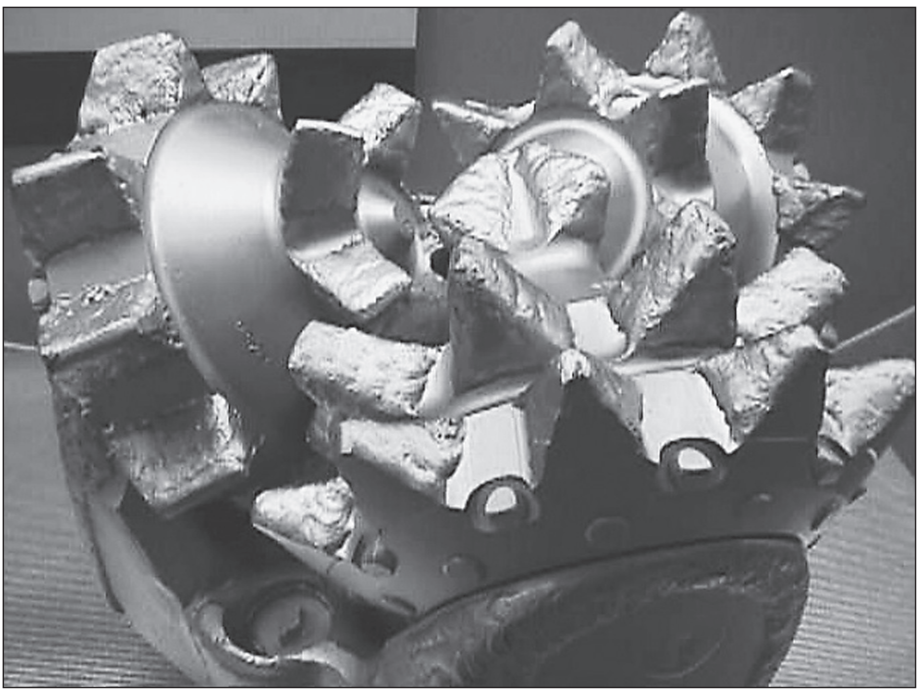


Fig. 3–12. Drillbit cutters

To drill rock, a drill bit requires a downward force to be applied, to force the teeth to penetrate into the rock. This force is provided by the weight of thick-walled pipe, called *drill collars*, which are screwed on top of the drill bit. With a large drill bit used to spud the well (perhaps a 23″ [584 mm] or 26″ [660 mm] diameter bit inside 30″ [762 mm] conductor pipe), these drill collars might be 9½″ (241 mm) outside diameter and 3″ (76 mm) inside diameter steel pipe. Each foot of this particular drill collar will weigh around 200 lb (91 kg), and drill collars come in lengths of around 30 ft (9 m). Thus a single drill collar will weigh around 6,000 lb (2,721 kg). As the bit drills deeper, more drill collars are added on top, giving more available weight with which to drill.

A drill bit also must be turned, in addition to having weight applied. With sufficient "weight on bit" and rotary speed, the bit will drill rock. Stronger rock requires greater weight on bit to be applied, so that the pressure exerted by each tooth is greater than the compressive strength of the rock. Close to the surface, rock is usually fairly soft and easily drilled, so having low weight available is not a problem.

This fluid will most often be water with various chemicals mixed in, but it may also be an oil-based fluid, a mixture of oil and water, or in some areas where conditions permit, it might be compressed air or a mixture of water and air (which produces a foam). The fluid used to drill the top section of the well is called *spud mud* because it is the drilling mud used in spudding the well. Spud mud is usually water that has clays and polymers added to make it thicker (more viscous).

The speed at which the fluid moves up the annulus is measured in feet per minute (or meters per minute on a metric operation). This speed measurement is called the *annular velocity (AV)*. To lift cuttings upwards, depending on how thick or viscous the mud is and also depending on its density, needs a minimum AV of about 50 ft/min (15 m/min). An AV greater than 100 ft/min (30 m/min) is preferred to efficiently clean the hole. The volume of mud to pump each minute to give any particular AV can be easily calculated. The larger the hole size, the more volume per minute must be pumped (fig. 3–13).

For a hole of 26″ (660 mm) diameter (D) and using 5″ (127 mm) diameter drill pipe (d) inside, the annular volume equals 0.0408 $(D^2 - d^2)$ = 26.6 gallons per foot; or 0.7854 $(D^2 - d^2)$ = 329 liters per meter). To achieve an AV of 50 feet per minute (FPM) (15 m/min), the mud flow has to fill 50 ft (15 m) of hole each minute. The capacity of 50 ft (15 m) of this annulus will be 50 ft × 26.6 gal/ft = 1,330 gal (15 m × 329 l/m = 4,935 l). In this large hole, at least a rate of 1,330 gallons per minute (GPM), or 4,935 l, is required to give the minimum AV of 50 FPM (15 m/min). In our pilot hole of 12¼″ (311 mm), the flow rate is much less; for 50 FPM (15 m/min), only 255 gal (965 l) are needed, and the preferred 100 FPM (30 m/min) is easily achieved. In soft rock, up to a limit, the more GPMs pumped, the faster drilling can progress. Thus, a 12¼″ (311 mm) diameter hole is generally drilled with a flow rate of around 600 GPM (2,271 l).

Several things limit the volume of mud that can be pumped. One limit is how fast the pumps can go at the pressure required.

Another is that if pumping very fast in softer rock, the force of the mud hitting the bottom of the hole below the bit can cause erosion of the side of the hole, making it bigger than the drillbit diameter.

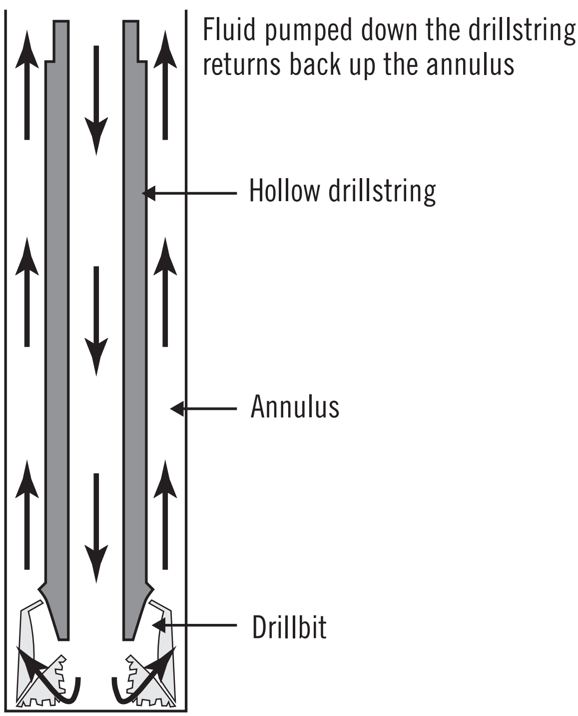


Fig. 3–13. Circulating mud around the well

A hole that is bigger than the bit (called an *overgauge hole*) is undesirable for several reasons, which will be discussed later. Also, to force mud up the annulus takes pressure, and this pressure has to be resisted by the wellbore. Circulating faster imposes more pressure on the well. It is possible that a weaker rock could become fractured due to the extra pressure imposed by circulating fast, leading to loss of drilling fluid into the rock.

Drilling the first hole section

After spudding the well, things happen very quickly. The pumps are turning at full speed, all engines are running, and there is a lot of noise. Large amounts of rock cuttings will come out of the well, and often the capacity of the solids control equipment to separate out the solids from the returning mud is exceeded. What happens then is that along with the solids being ejected into the waste pit, a lot of mud will also go over the side. Some of the equipment might become plugged up with drilled solids, requiring fast action to get it fixed and back into service.

If drilling young clays that react quickly with water, the clay might become sticky. The cuttings will start to accumulate into larger lumps, and large balls of sticky clay will be pushed up the annulus. It can appear at the top of the well as a column of doughnut-shaped clay (wrapped around the drillstring; see fig. 3–14), and these are called *clay rings*. Sometimes drilling must stop to clear up the problems before continuing. With clay rings, people must get down under the drill floor with shovels to clear it. Luckily, modern chemical knowledge is such that clay rings are largely avoided by proper formulation of the mud.

After each 30 ft (9.1 m) drilled, another drill collar is added by screwing it onto the top of the drill collars in the hole. When there are enough drill collars to give all of the required weight on bit, drill pipe is added to the drillstring, again in 30 ft (9.1m) lengths. (Each length of drill pipe is called a *joint*.) Before drill pipe can be screwed onto the drill collars, a special short length of pipe with a drill pipe connection on the top and a drill collar connection on the bottom is added. These special short pipes are called *subs*, and if a sub is used to convert one size or type of connector to another, it is called a *crossover sub*. When the sub connects the drill bit to the lowest drill collar, it is called a *bit sub*.

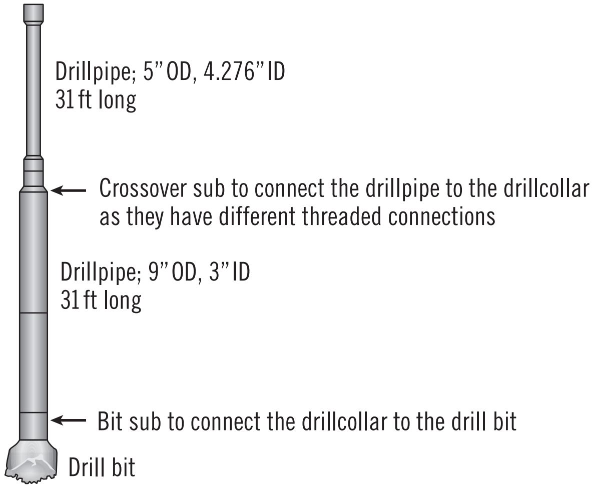


Fig. 3–14. Drillstring

Notice that although the drill collars have straight sides all the way, the drill pipe has a bulge at each end. The drill pipe itself is fairly thin, and there is not enough metal to machine a connection onto the pipe itself, so a thick section with the threaded connection on is welded to each end of a length of pipe. The pipe part of the drill pipe is called the *pipe body*, and the connection part is called the *tool joint*.

Every component added to the drillstring is measured in feet and hundredths of a foot, or in meters and millimeters, so it is easy to add all of the lengths together. The record of pipe lengths is called the *tally* (fig. 3–15).

The components from the drill bit to the bottom of the drill pipe are called the *bottomhole assembly (BHA)*. The BHA can be configured in many different ways to give a particular weight on the bit and to affect how it drills.

The well is drilled until it reaches the depth to run the surface casing.

One problem commonly experienced while drilling surface hole is mud disappearing down hole into the rock, either into fractures or into very permeable rock. This problem is called *lost circulation*, or more simply, *losses*. Losses might be slight or severe; losing only a small amount of mud an hour is called *seepage losses*. Anything over about 30 bbl/hr (4,770 l/hr) is moderate, and over 60 bbl/hr (9,540 l/hr) is serious. Sometimes the mud losses might be so severe that no mud returns are seen at the surface while pumping over 1,000 gal/min (3,785 l/min) down the drillstring!

Drill pipe tally for well XYZ	BHA length = 296.75	
Length	**Total**	**Total with BHA**
31.32	31.32	328.07
30.98	62.30	359.05
31.44	93.74	390.49
31.62	125.36	422.11
31.69	157.05	453.80
31.50	188.55	485.30
31.45	220.00	516.75
30.96	250.96	547.71
31.66	282.62	1579.37
31.57	314.19	610.94

Fig. 3–15. Example of a tally sheet

Losses are discussed in more detail in chapter 13.

Once at the required depth, drilling is stopped. Mud is still circulated around until all of the drilled cuttings are cleaned out of the well. If this is not done and the drillstring is just pulled out, several major problems become likely:

- As the drillstring is pulled out of the hole, the cuttings left in the annulus will fall down and very likely be jammed between the hole and the drillstring. This will stick the drillstring and also prevent mud from circulating (because the annulus will be blocked). In this condition, the drillstring will be stuck and might not be freed, in which case the well might have to be abandoned.
- Cuttings will settle on the bottom and thus make the well shallower than drilled. This might prevent the surface casing being run to the required depth.

- Cuttings might also settle at some intermediate depth (i.e., not on the bottom). When the casing reaches this depth, it hits the debris and starts to push it down ahead of the casing. This will most likely plug the annulus, and possibly also the casing, causing the casing to become stuck.

So whenever drilling is stopped to pull out of the hole, the well must be circulated for long enough to remove all of the cuttings from the annulus first. This is called *circulating clean*.

When drilling the surface hole, the formations drilled are generally weak and unconsolidated. The hole might not be very stable, and the sides of the hole will tend to crumble slowly (or perhaps quickly). The hole will enlarge as material falls into the wellbore. This means that the actual size—or volume—of the hole is not accurately known. Material falling off the side of the hole is called *caving*, and the bits of rock are called *cavings*. Cavings can be recognized at the surface due to their shape, size, and appearance. Careful examination of cavings can give indications of what is causing the wellbore instability.

With the well cleaned up and before pulling out of the hole, it is necessary to measure whether the bottomhole assembly is vertical. Various tools are available to do this. The drillers can then tell whether the well is vertical or if it has started to wander off course while drilling. This process is called *taking a survey.*

As pipe is pulled out of the hole, only every third drill pipe connection is unscrewed to leave three joints of drill pipe screwed together. The rig's derrick is high enough to stand 90 ft (27 m) of pipe on the drill floor, secured in special racks at the top. Three joints of pipe screwed together is called a *stand* of pipe. So if there are 45 joints of drill pipe in the hole, only 15 connections have to be unscrewed and 15 stands of pipe racked in the derrick. It is much faster that way. The stands are racked in rows, and when one row is complete, another is started. The drill collars can also be racked in stands of three joints.

After drilling the pilot hole, it is enlarged to 26″ (660 mm) to be able to run in the 20″ (508 mm) casing. In a vertical well in softer formations, this might be done simply by drilling again with a 26″ (660 mm) drill bit. The potential problem with using a drill bit to enlarge the hole is that if it hits an obstruction (such as a boulder buried in a softer formation), it might be deflected and start to drill another hole. This can be avoided by running a *hole opener*, which has a set of cutters mounted outside a short drill collar (fig. 3–16). Below the hole opener is placed a tool called a *bullnose*, which is like a short drill collar with a rounded nose and a hole in the end for mud to exit. The bullnose guides the hole opener along the original hole and minimizes the chances of cutting another hole.

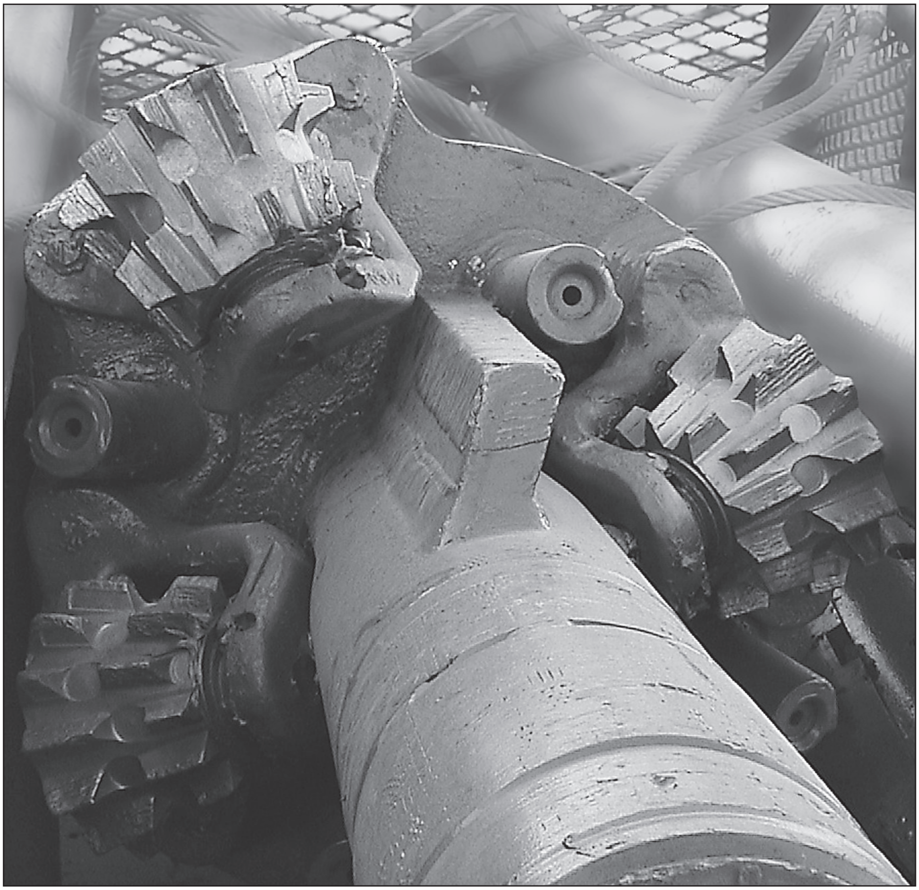


Fig. 3–16. A hole opener showing the cutters

Running and cementing surface casing

Now 26″ (660 mm) diameter surface hole has been drilled below the conductor to a depth that gives sufficient formation strength to contain any likely overpressures if a kick occurs in the next hole section. Casing is cemented in place with the casing shoe in this strong formation.

Once the cement is hard, the top joint of casing is unscrewed. The surface casing connection just above the conductor top is left a little less tight, and now it can be unscrewed by turning the top joint of casing, which is sticking up above the rotary table. Once this is out of the well, the diverter is removed from the conductor, leaving the top of the surface casing exposed. If for some reason the surface casing cannot be unscrewed, or if the connector is in the wrong place, the diverter can be lifted slightly. This will allow the rig welder to cut the casing above the connection with an acetylene torch. The diverter cannot be removed until this top joint of casing is out.

At the top of the surface casing now is either a thread or a cut end. A special piece of equipment, a casinghead housing (CHH), is screwed onto the thread, or there is also a weld-on type of CHH that can be attached to the surface casing by welding (fig. 3–17). The CHH has a flange on top that is used to attach the blowout preventer. Also, the weight of the next casing will be supported by a hanger sitting inside the top of this spool. Figure 3–17 shows the CHH made up on top of the surface casing. Note also the plates below the CHH, which sit on top of the conductor and so transmit loads from the CHH to the conductor. This is also illustrated in the middle photograph in figure 3–5. The valve shown on the right of the picture allows fluids to be pumped into the well or released from the well. Any pressure inside this space can be monitored with a pressure gauge.

Once the CHH is in place (whether a screw-on or a weld-on type), the blowout preventer can be positioned and attached to the top of the CHH.

The blowout preventer equipment and control system must be tested to ensure that everything works. It is also vital to pressure test the entire BOP and each part of it to ensure that it will hold the pressure that it should. BOP systems come in standard pressure ratings of 2,000 psi (13.7 kPa), 3,000 psi (20.7 kPa), 5,000 psi (34.4 kPa), 10,000 psi (68.9 kPa), and 15,000 psi (103 kPa). BOPs also come in different sizes, the size being the nominal inside diameter of the BOP.

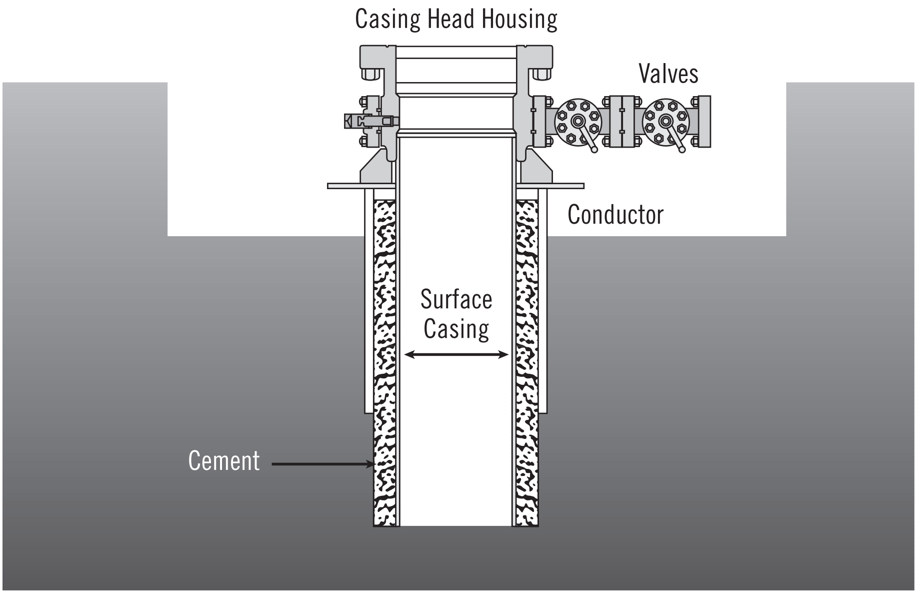


Fig. 3–17. Surface casing run, casinghead housing attached

The time to attach the CHH and attach and test the BOP on an average operation would take around 10 to 15 hours, depending on the problems encountered. While the BOP is nippled up, a survey tool is normally run inside the casing on wireline. (*Nipple up* refers to a process of assembling equipment. Conversely, *nipple down* refers to disassembling equipment.) The survey tool will measure the direction (called the *azimuth*) and inclination of the wellbore every few feet or meters. Knowing the azimuth and inclination at various depths in the well allows the actual path of the wellbore so far to be calculated. This is necessary to know exactly where the bottom of the casing is located.

Drilling out the casing and testing the formation strength

The surface casing used in this example well has an outside diameter of 20″ (508 mm) and an inside diameter of 19″ (483 mm). The *burst strength* (the internal pressure that the casing will hold without breaking) of this particular casing is 2,410 psi (16.6 kPa).

At the bottom of the casing is the *float shoe* (a valve made of cement with some plastic components). When the 17½″ (445 mm) diameter drill bit is run in to continue drilling, the first thing it will encounter is the top of the float shoe. This and any cement below it is drilled, until the depth that the previous bit drilled to is reached. After drilling to the original depth and drilling some virgin formation, the strength of the formation below the casing shoe has to be tested. Usually the well is displaced to a new mud system first, and this also ensures that the density of all the mud in the well is accurately known.

The test is done with some variation of the following procedure (fig. 3–18). The first step is to drill out through the float shoe with the old spud mud system. Once the float shoe and cement are drilled, pumping of the new mud commences, while drilling a few feet or meters of new formation. As the old mud comes out of the annulus, it is normally dumped into the waste pit. After drilling the new formation, circulation of new mud continues until all of the old mud is out and all drilled cuttings are circulated out. Once clean mud returns out of the annulus at the same density as the mud going in, a uniform fluid of known gradient fills the well.

The drill bit is pulled back until the bit is inside the surface casing. The blowout preventer is closed so that it forms a seal around the drill pipe. This leaves the situation as illustrated in figure 3–18.

Fluid is now slowly pumped into the well through the drill pipe.

As the annulus is sealed at the top by the BOP, the well becomes pressurized because the fluid has no way out. The volume pumped and the resulting pressure is recorded. At first, the relationship between the volume pumped and the resulting pressure is proportional. For example, for every 10 gal (38 l) pumped into the well, the pressure increases by 50 psi (345 kPa). After pumping 40 gal (151 l), the pressure is 200 psi (1,379 kPa). Eventually, pumping in the same additional volume results in a lower-than-expected rise in pressure. This point is called the *leak off*, because the exposed formation has *just started* to allow fluid to leak into it. If any more fluid is pumped into the well, the formation is likely to completely fracture, which will, of course, reduce its strength.

The actual pressure on the formation when it starts to leak is calculated by adding the final surface pressure to the hydrostatic pressure of the fluid in the well. For instance, assume that the fluid in the well has a gradient of 0.5 psi/ft (11.3 kPa/m) and it is 1,000 ft (305 m) vertically deep, so the hydrostatic pressure exerted at the bottom of the well is 0.5 psi/ft × 1,000 ft = 500 psi (11.3 kPa/m × 305 m = 3,446 kPa). If the final surface pressure was 230 psi (1,586 kPa), the total pressure on the formation downhole is 730 psi (5,032 kPa). This pressure must not be exceeded (and preferably not even approached closely) because if the formation fractures under pressure, fluids might travel outside the casing to the surface. If the load-bearing capacity of the surface soil is reduced, it could cause the rig to collapse, endangering lives.

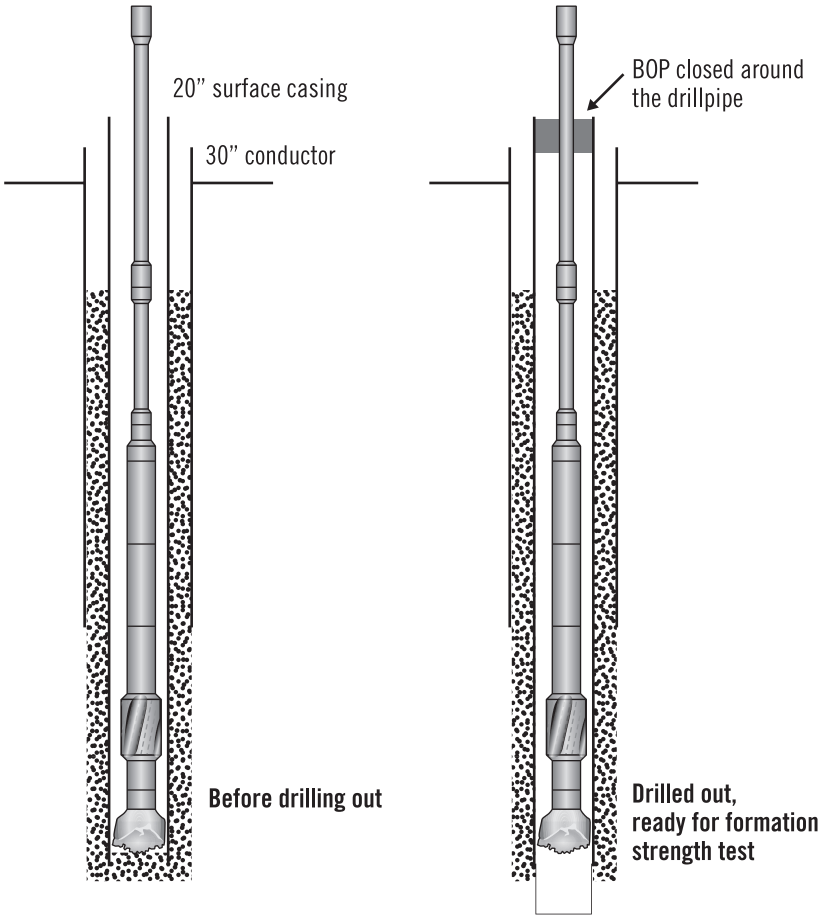


Fig. 3–18. Drilling out to test formation strength

Knowing the depth of the formation and the pressure it will bear, the formation strength gradient can be calculated. In this example, it will be pressure divided by depth, or 730 psi ÷ 1,000 ft = 0.73 psi/ft (5,032 kPa ÷ 305 m = 16.5 kPa/m). Now it is possible calculate a figure that the driller on the rig must *always* know—the maximum surface pressure that can be exerted on the well with the particular drilling mud density in the hole. It is called the *maximum allowable annular surface pressure (MAASP)* and is very easy to calculate:

$$\text{MAASP} = (\text{Formation strength gradient} - \text{Mud gradient}) \times \text{Vertical depth}$$

With the 0.5 psi/ft (11.3 kPa/m) mud in the hole, the MAASP will be 230 psi (1,586 kPa), which was the leakoff pressure at the end of the test. However, if the mud gradient is increased later on while drilling, the MAASP will reduce. So at a mud density gradient of 0.6 psi/ft (13.6 kPa/m), MAASP must be recalculated and will be as follows:

$$(0.73 \text{ psi/ft} - 0.6 \text{ psi/ft}) \times 1{,}000 \text{ ft} = 130 \text{ psi}$$

or

$$(16.5 \text{ kPa/m} - 13.6 \text{ kPa/m}) \times 305 \text{ m} = 885 \text{ kPa}$$

If the well drills into an overpressured formation and takes a kick, the maximum pressure limit at the surface is 130 psi (885 kPa). If this pressure is exceeded, the formation just under the shoe is likely to fracture.

Drilling the first intermediate hole section

After drilling out the surface casing shoe and a bit of new formation, the formation strength was tested. The well was circulated to a new mud system.

The next chapter will discuss drilling a well accurately to a target that is not directly below the surface location. However, the example exploration well here is a vertical well (with the target directly under the rig), so there are no special considerations for making the well path follow a particular course to the target. It only needs to be reasonably vertical and straight.

A well can be nearly vertical but might have a spiral path downwards. Even a slightly spiral well can cause problems, and this situation is best avoided. A drillstring under high tension (from the weight of the steel below it) in a spiral hole will touch the hole in many places, with a high force pressing into the wall. This will cause a lot of friction that will wear the pipe and make running in and pulling out the drillstring more difficult. It will also make the wellbore less stable, so that it enlarges, with all the problems related to an overgauge hole.

One tool in the driller's armory to keep the well straight is the stabilizer.

A stabilizer is run within the bottomhole assembly (fig. 3–19). Imagine a short section of drill collar, about 5 ft (1.5 m) long, with drill collar connections on top and bottom. In the middle of this collar are fastened blades that stick out, sized so that they touch the wall of the hole. If a stabilizer is run in the hole and if the hole is in gauge, the effect is to centralize the drill collars above and below the stabilizer in the wellbore. Now a drill collar, being very thick steel, is quite stiff—that is, it resists bending forces. If a bottomhole assembly is configured with a stabilizer below each of the lowest three drill collars, and as long as the hole is in gauge, the drill bit requires a very large force to deflect from drilling a straight line. Three stabilizers, close to each other and connected by very stiff drill collars, with three points of contact with the wellbore, keep the drill bit drilling in line with the existing wellbore. This type of BHA is called a *tangent* or *locked BHA*.

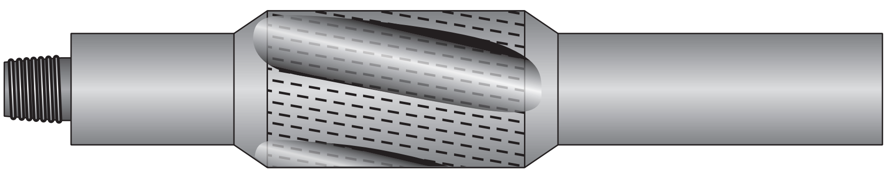


Fig. 3–19. Drawing of a stabilizer

Running this design of BHA also has some drilling advantages. In the absence of stabilizers in the BHA, if a lot of weight is placed on the drill bit (to make it drill as fast as possible), the lower part of the BHA will start to buckle. This will give unpredictable results, as the bit is no longer aligned with the center of the hole and is likely to drill a spiral hole or even veer off course. If the BHA buckles while the drillstring is rotating, significant fatigue damage will occur to the drill collars, which may eventually cause something to break. Using a locked assembly allows the well to be drilled faster and straighter. Some people consider that running more stabilizers will give more frictional force against the BHA when rotating and tripping in and out. In fact, drilling a straight hole reduces friction far more than might be increased by having a few bits of steel touching the side of a straight hole.

Now the well can be drilled ahead towards the depth to run the next casing, which is called *intermediate casing* because it comes after surface casing but before production casing. A well might have more than one intermediate casing, or it may contain none if it is a shallow well and the reservoir can be reached with only one casing string after surface casing.

Once the casing point is reached, after one or several bit runs, the bit is pulled out of the hole. Electric logs will most likely be run at this time.

Logging

Logs are discussed in detail in chapter 10, "Evaluation."

Tools are run into the hole on special steel wireline, usually 9/16″ (14 mm) in diameter. Inside the wireline are electrical wires that connect the tool to a computer unit on the rig. Logs measure physical and chemical characteristics of the formations. In an exploration well, the well is drilled to gain information, and most of this information will be obtained by using logs (fig. 3–20).

This hole section is an intermediate hole section; the reservoir is not yet penetrated. Even though the reservoir is not exposed by the wellbore, there is a lot of information that can be used to help improve the well design and drilling program for the next well. Many people have an interest in the log results, including drilling engineers, geologists, geophysicists, and other specialists.

Fig. 3–20. Logging truck running logs into a land well

Logging is quite expensive, and not just in the cost of the rig time taken. The logs themselves can be very costly to run. Some logging tools cost in excess of a million dollars, so it is vital not to lose one down the hole!

Logs run in the intermediate hole section will typically try to establish the following information:

- Formation tops and thicknesses
- Formation lithology, porosity, pore fluids salinity, and presence of any hydrocarbons
- Continuous hole profile, showing the diameter in two directions (so that an overgauge hole that is enlarged more in one direction than the other can be recognized)
- Formation compressive strengths (measured using sound waves, useful when deciding what drill bits to use on the next well)

Running and cementing the first intermediate casing

If there were any hole problems while logging, the drilling BHA and drill bit last used may be used to go to the bottom of the hole and back. This can check if there is any debris on bottom (rock material that remained in the hole or cavings that have come from an unstable formation since the last trip out). The action of a round trip with a bit and BHA can be beneficial. If there are any tight spots while tripping in (places that require some force to pass), the driller can start pumping mud and rotating the drillstring to ream out the tight spots that might otherwise cause a problem when running the casing. This round trip is called a *check trip*.

On some operations, the rig crew run in with the casing themselves. On other operations, a specialist contractor will send out people and equipment to work with the rig crews to run the casing into the well.

As with surface casing, a float shoe is screwed onto the bottom of the casing. After two joints of casing (about 80 ft, or 24 m) is run a float collar. A *float collar* is similar to a float shoe, except it has a thread at the bottom end so that casing can be run underneath it. This gives two float valves in the casing string, so that if one fails, the other acts as a back up.

The casing is run into the well. During running, the crew will put a hose into the casing every two or three joints and fill it up with mud (because the float valves on the bottom prevent mud from entering the casing at the bottom). Now the casing outside diameter is smaller than the drill bit, but it is much less flexible than the drilling assembly. It is possible to have problems running casing into the hole because of this and because of the large surface area of the casing compared to the drill string. If there is a part of the hole that is enlarged and this is just above a different rock formation that is in gauge, there will be a "ledge" in the hole. The casing might hit this ledge, and it might be difficult to pass through it. There is a better chance of getting stuck with casing because it is very large and rigid when compared to the drillstring.

Once all the casing is in the well, a casing hanger is screwed onto the top joint of casing. This has a cone-shaped profile that fits into the casinghead housing on top of the surface casing. Figure 3–21 shows the situation before the intermediate casing has been lowered down so that the casing hanger lands inside the casinghead housing.

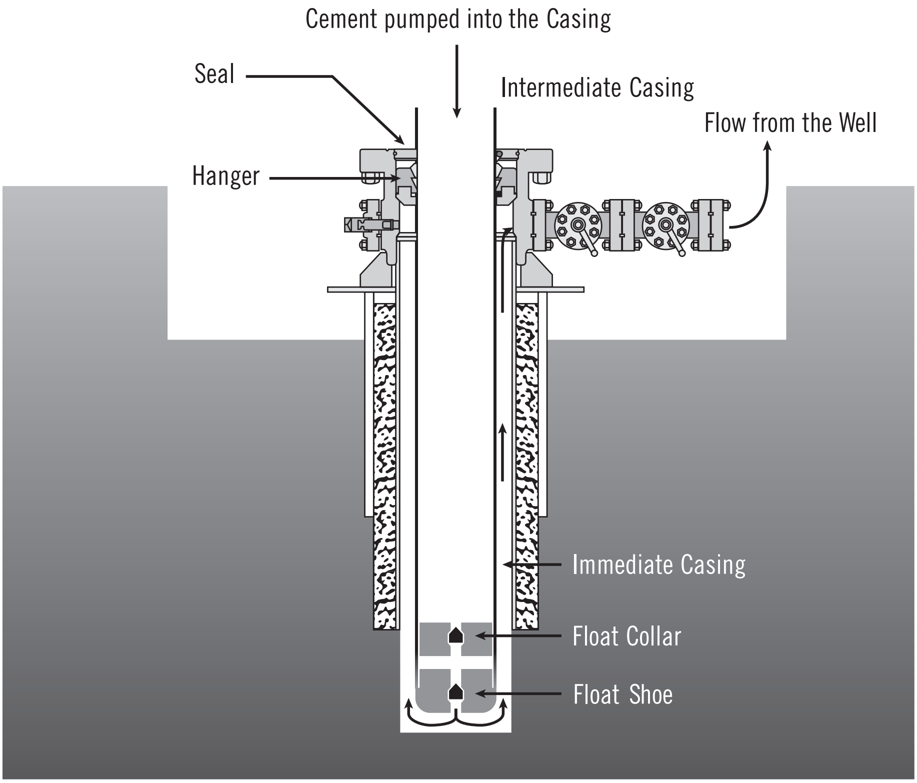


Fig. 3–21. Cementing the intermediate casing

With the casing hanger landed in the profile inside the casinghead housing, seals on the outside of the hanger create a pressure-tight seal between the hanger and the housing. Figure 3–21 also displays valves leading out from the casinghead housing. These are called *side outlets*.

After the casinghead housing is attached to the surface casing, valves are attached to these side outlets. Now when landing the intermediate casing, these valves are open to allow mud to flow from the well when pumping cement down the casing. Hoses are attached to the outsides of these valves, and the hoses take returns from the well to the rig mud tank system. This is illustrated in figure 3–21.

With the casing landed and the hoses attached, mud is circulated down the casing. Gradually the flow rate is increased, while watching the tank levels very carefully to detect the start of any mud losses down hole. Increasing the flow rate also increases the pressure in the annulus, and eventually losses to a formation down hole might start to occur. The annulus between the casing and the hole is much smaller than it was with the drillstring, and this gives higher pressures while circulating. As soon as mud losses are detected, the pump is slowed down a little. This flow rate will be the maximum flow rate during the cement job. Circulating continues until about 120% of the casing inside volume is pumped. This ensures that there is no debris (such as rags, brushes, or someone's hard hat) inside the casing that can plug the float valves, which would be disastrous if it were to happen while cementing. At the same time, this helps to improve the cement job for reasons discussed in chapter 9, "Casing and Cementing."

Once satisfied that all is well, cement is pumped down the casing. In front of the cement is a rubber or plastic plug that seals in the casing. This moves down ahead of the cement, wipes all the mud off the inside of the casing, and separates the mud and cement to avoid contamination. This is called the *bottom plug.* The bottom plug has a plastic diaphragm on the top, which will break when the plug hits the float collar, allowing cement to flow through the plug and down through the float valves.

Behind the cement is used another plug that is similar to the bottom plug. This second plug, called the *top plug*, differs in that it is solid and does not rupture when it lands on the bottom plug. The purpose of the top plug is to wipe cement from the inside of the casing and to separate the cement from the mud behind it. When the top plug lands on the bottom plug, the plugs seal and prevent further movement of fluid down the casing. This allows the driller to see exactly when the cement is in place because the pumping pressure will increase. At this time, the driller can pressure test the inside of the casing to make sure there are no leaks in it.

After pressure testing above the casing hanger to ensure that the hanger seals work, the blowout preventer can be removed. Then a housing called a *casing spool* is added to the wellhead, in which the next string of casing will land.

The assembly of casings, hangers, and spools is called the *wellhead*. The status of the wellhead is illustrated in figure 3–22.

The inside of the casing spool has a similar profile to the casinghead housing, only smaller. Each string of casing requires a casing spool to land in (with this particular type of wellhead).

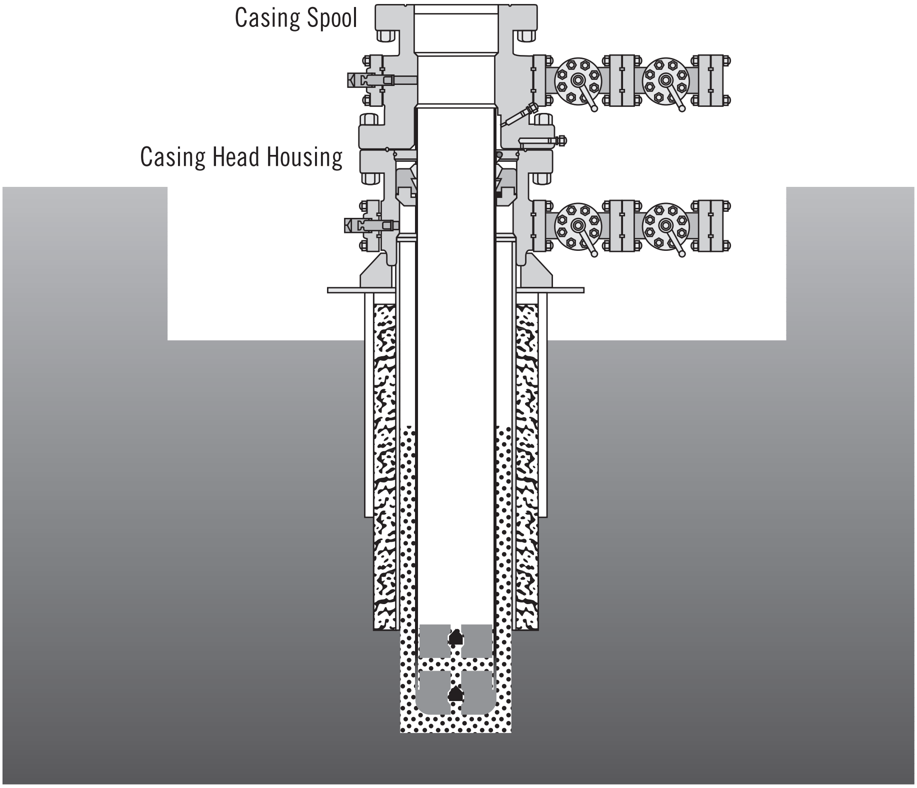


Fig. 3–22. Wellhead after cementing and adding the casing spool

The next blowout preventer will be nippled up on top of this spool. It will be smaller than the first one and will have a higher pressure rating. The side outlets that are exposed to the well have two valves attached, so that if one leaks under pressure, there is a backup valve.

Drilling the production hole section

Imagine now that another hole section was drilled and another intermediate casing cemented in place. Things will not be too different from the intermediate section described above. This new casing is set about 500 ft (150 m) above where the top of the reservoir is expected. The plan now is to drill through the reservoir and about 200 ft (61 m) below it, log the hole, and then run a liner.

This is the part of the hole that everybody is really interested in. If hydrocarbons are present, a lot of wireline logs are run over several days. If the wireline logs indicate that hydrocarbons are likely to be in commercial quantities and can be produced, a liner will be cemented in place. Holes are blown through the side of the liner to allow the hydrocarbons to be produced during a test.

A *liner* is essentially a string of casing that does not extend all the way to the surface. A liner is suspended from a liner hanger, which uses hardened steel teeth to dig into the last casing ID and so suspend the liner. The advantages of running a liner include reduced cost (a much shorter length of casing pipe, less cement needed). The disadvantages include increased complexity because of the tools that must be manipulated while a long way inside the well.

While drilling through the reservoir section, there are indications on the surface of hydrocarbon presence. When drilling through a gas-bearing zone, increased levels of gas dissolved in the drilling mud can be detected. When drilling through oil-bearing rock, the rock cuttings will show the presence of oil in the pore spaces.

At this point, it is very important to gain the maximum amount of information from the reservoir. The best way to assure this is to take a core sample while drilling through the reservoir. Often on an exploration well, the coring equipment will stand by on the rig, and on the first good indication of hydrocarbon presence, the drill bit will be pulled out and the drilling BHA replaced with a coring assembly.

A core is taken by drilling with a special bit (called a *core bit*) that has a hole in the middle. As the bit drills a doughnut-shaped hole, a column of uncut rock will stick up inside the bit. Behind the bit is a special mechanism for gripping this rock and holding it in a special container.

Coring is slow and expensive, but the value of the information usually makes this worthwhile because it allows better decisions in the short term (designing the well test) and in the long term (should the reservoir be developed, and how?).

Once the reservoir is cored (which may take more than one core bit run to achieve), the driller will run in with a normal drill bit, ream through the cored section, continue drilling to total depth (TD), and complete the well (fig. 3–23).

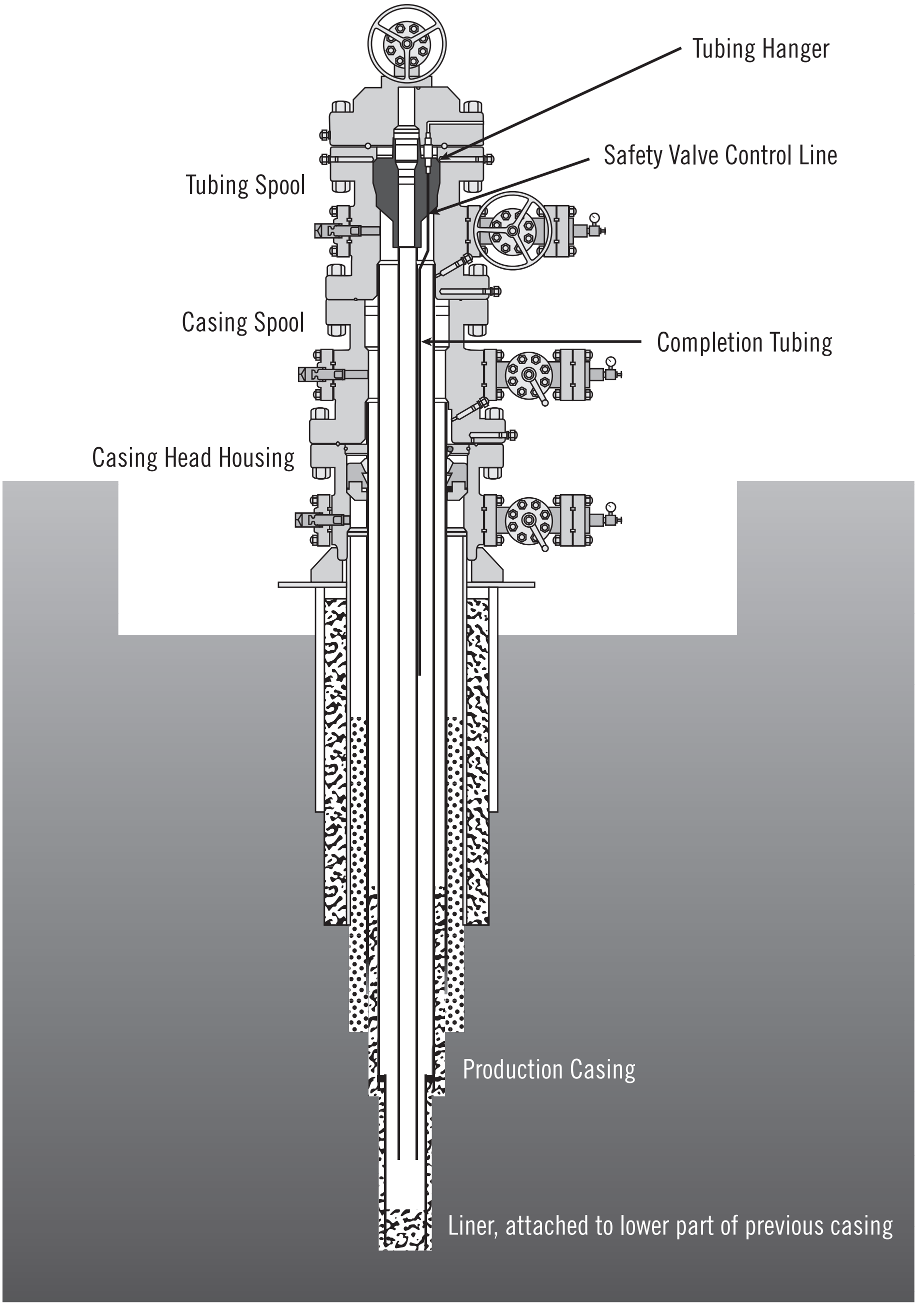


Fig. 3–23. Completed well

Logging the hole

The same logs are used here as per the previous hole section. In addition, some extra logs will help evaluate the reservoir and yield information needed to design the well test program.

One tool that will almost certainly be run will place a probe against the formation and open up a sample chamber on the inside of the tool. This can take a sample of formation fluids at the composition that is down hole for analysis at the surface. These tools can also take very accurate pressure readings and can measure the formation permeability at the wellbore face.

Running and cementing the production liner

A liner, being effectively a string of casing with the top half missing, is assembled and then run in the hole below a string of drill pipe. At the top of the liner is a liner hanger, which may be hydraulically or mechanically manipulated to move hardened steel elements out to grip the inside of the previous casing. Cement is pumped down the drillstring, with special plugs to separate the fluids. Once the cement is in place outside the liner, the drill pipe is released from the liner hanger and pulled back to the surface.

Production Testing the Well

The cuttings samples, logs, and core samples show that there is gas and that there is likely to be a commercially worthwhile amount of oil. There exists sufficient permeability for hydrocarbons to be produced into the wellbore. The inside of the well needs to be cleaned out, a string of tubing run in the well, holes made through the liner into the reservoir (called *perforating*), and the well must flow to test the reservoir's characteristics.

Preparing the well for the test string

The inside of the well contains drilling fluid that has a high level of solid materials suspended in it. These solids may be part of the mud system, drilled solids, rust products from the steel in the well, and other debris. If the liner is perforated with this fluid in the well, those solid particles will enter the perforation tunnel and can plug off pore spaces in the reservoir. This is one possible mechanism that will reduce the ability of the well to produce oil. This damage must be minimized.

First, a drill bit is made up on the BHA, followed by a tool called a *scraper*. A scraper has sets of spring-loaded blades that push against the casing, scraping off loose rust, grease, etc. When this is at the bottom of the liner, a clean, filtered brine is pumped around the well that contains very little solids. This pushes the drilling mud out of the hole. With the mud out, brine is circulated around until it is as clean as is specified by the test program. When the well is sufficiently clean, the bit and scraper are removed.

Running the test string

Now the well is clean and contains a clean, specially formulated, solids-free brine. A string of tubing is run in through which the hydrocarbons will be produced. In the "old days," drill pipe was often used, and hence the production test became known as a *drillstem test*. Drill pipe is not used any more for well testing, because there is no guarantee that it will seal with high-pressure hydrocarbons inside it.

The well should not produce hydrocarbons from inside the casing except through a separate tubing string. If tubing is in place, the well integrity is much better (safer), and the well may be controlled by circulating fluids around, which cannot be done without tubing in the well.

The tubing string will have various tools incorporated. One will be a subsurface safety valve (SSSV), as previously discussed. The SSSV is positioned some hundreds of feet or meters below the surface (or below the seabed on an offshore well). It is a valve that would normally be closed but is held open by pressure on a special line that is run to the surface outside of the tubing. If something goes wrong, the control line to the SSSV is depressured, and this closes the valve. Also if something disastrous happens, such as the wellhead gets blown off by marauding Iraqi troops, the well will shut itself in automatically. Had the wells in the Kuwaiti desert incorporated SSSVs, the result of Saddam Hussein's deliberate sabotage would have been minor oil spillage around the wellheads and not the environmental disaster that he wanted and obtained. As it was, SSSVs unfortunately were not used.

The tubing is suspended in the well at the wellhead, just as the casings were suspended at surface. After running the last string of casing, the BOP was removed, and a tubing head spool placed on the wellhead. This goes on top of the casing spool in the same way that the casing spool went on top of the casinghead housing. With the complete tubing string in the well, a tubing hanger is screwed on top of the tubing, and this lands inside the tubing head spool. Special bolts in the spool are screwed in to lock the tubing hanger in place. After pressure testing to make sure the seals all work, the BOP is removed, and a special assembly of valves, called the *Christmas tree*, is bolted on top of the tubing head spool.

Now the well is ready to perforate. In preparation for perforating, a special BOP is placed on top of the Christmas tree, which will allow the well to be perforated with wireline while having the possibility to seal around the wireline.

Perforating the well

The logging cable is now used to run perforating guns inside the tubing. A perforating gun consists of some sort of carrier mechanism, inside of which is a set of shaped explosive charges. These are run in the well so that they are opposite the reservoir. When they are detonated, the shaped charge efficiently focuses the explosive energy in a narrow path outwards. This punctures the liner and creates a tunnel through the rock, often up to 22″ (559 mm) in length.

Testing the well

Well testing is discussed in more detail in chapter 10, “Evaluation.”

The hydrocarbons produced during testing are normally burned off. There is nowhere that the fluids can be safely stored, and in the case of this exploration well in the desert, no infrastructure exists that could capture the produced oil and get it to a refinery.

Killing the well after the production test is complete

Once the well test is over, the well will be "live" from the pressure inside the tubing. The well is "killed" by pumping heavy fluid down the tubing, which will build up enough hydrostatic pressure to overcome the reservoir pressure. Once the well is completely dead, the well can be abandoned.

Abandoning the Well

A well is abandoned when there is no conceivable use for it after the well test. Well abandonment involves placing cement in the well to prevent reservoir fluids leaving the reservoir and moving up towards the surface.

Removing the test string

Once the well is dead, plugs are placed inside the tubing to ensure that, even if pressure does start to build up inside the tubing, nothing can come back to the surface. The Christmas tree can then be removed and the BOP nippled up on top of the tubinghead spool.

The bolts holding the tubing hanger in place are removed, and the test string can be pulled out.

Making the well safe into the future

The first task is to run in with some pipe and pump cement down so that it is left around the perforations. Often, special plugs will be run on wireline electric line to give additional security.

Special cutting tools are available that can cut the casing. The casings will be cut above the top of cement outside the casing so that the upper bit of casing can be pulled out of the well. Finally the conductor is cut, cement is dumped on top, and the site is restored for future nondrilling use.

Summary

This chapter examined the processes, equipment, and decisions involved in drilling an exploration well in the desert. Many new technical terms and concepts were introduced and explained.

4

PLANNING AND DRILLING A DEVELOPMENT WELL OFFSHORE

Overview

This chapter will tell in story form how a development well might be drilled offshore through a template on the seabed (fig. 4–1). A development well is drilled to produce hydrocarbons when a field is commercially exploited.

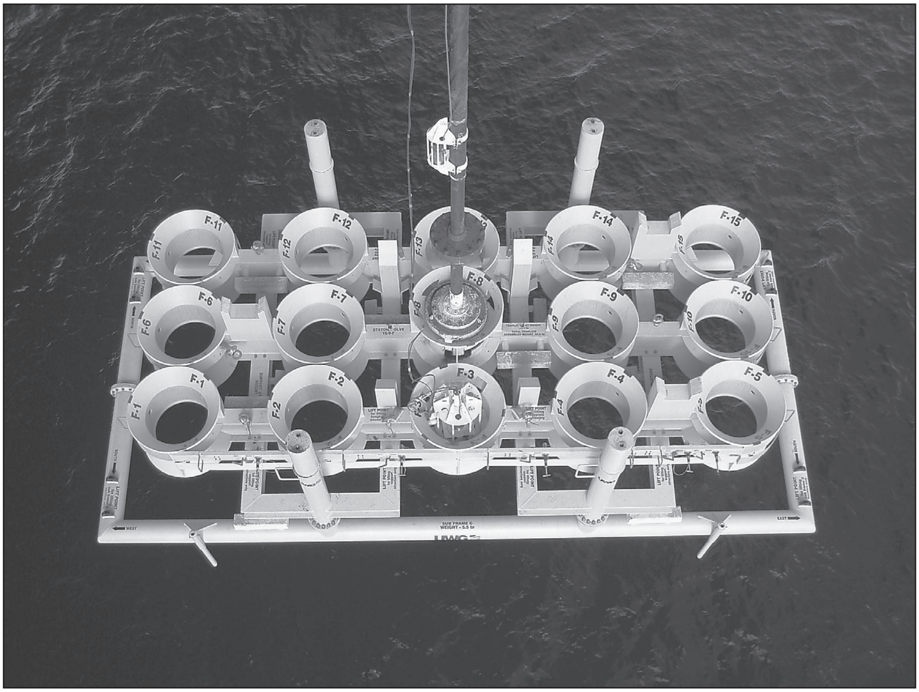


Fig. 4–1. A 15-well template being lowered to the seabed

Courtesy of Claxton, www.claxtonengineering.com.

The example well will drill a horizontal wellbore in a reservoir containing oil, water, and gas so as to efficiently produce oil.

Concepts from the first three chapters will be referred to but not explained again. New concepts specific to the type of well and rig under discussion will be introduced and explained.

Well Planning

In modern developments, wells positioned horizontally in the reservoir are becoming fairly common. This gives some advantages over vertical wells, as will be discussed later.

As each well is drilled, it will be left with a special cap on top at the seabed, called a *suspension cap*. This protects the wellhead from debris and corrosion until the platform is in position over the template. With the platform placed on the template, the wells can be connected and produced.

Coring is not often called for in development wells, but if there is some remaining uncertainty, it might be required. The logging program will also be less extensive (and less expensive) than in an exploration well.

At the seabed, all of the wells are close together. The wellbores need to be positioned in the reservoir some distance apart, which means that the wells must be drilled directionally to different places in the reservoir (fig. 4–2).

Completion design

The completion design for a development well must ensure that the well can be produced safely, efficiently, and economically. The production engineers will consider various aspects of producing the well when designing the completion. In particular, attention will be paid to the following:

1. **The well inflow configuration.** This affects how hydrocarbons flow from the reservoir into the well. Sometimes it is necessary to pressurize the well so as to create fractures in the reservoir, increasing permeability towards the wellbore. Acid might be used to create channels in the rock and increase permeability around the wellbore. These activities are termed *stimulation*.

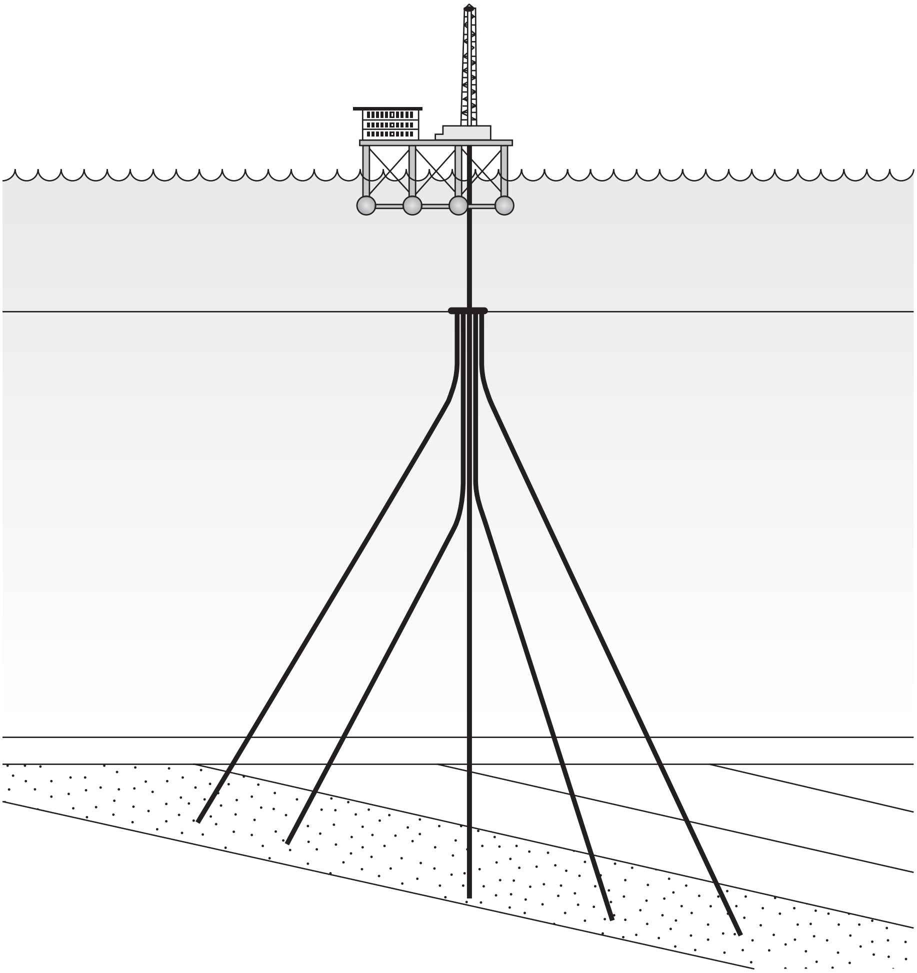


Fig. 4–2. Directional wells drilled from a floating rig through a seabed template

2. **The well outflow configuration.** This affects how the hydrocarbons flow from the bottom of the well to the surface. This will dictate the size and type of tubing used, as well as accessories run as part of the tubing string (such as downhole valves or pumps).

Sand control measures may be needed if the well would produce sand along with the oil or gas. One method of keeping the sand down hole is to use a screen, such as the one shown in figure 4–3.

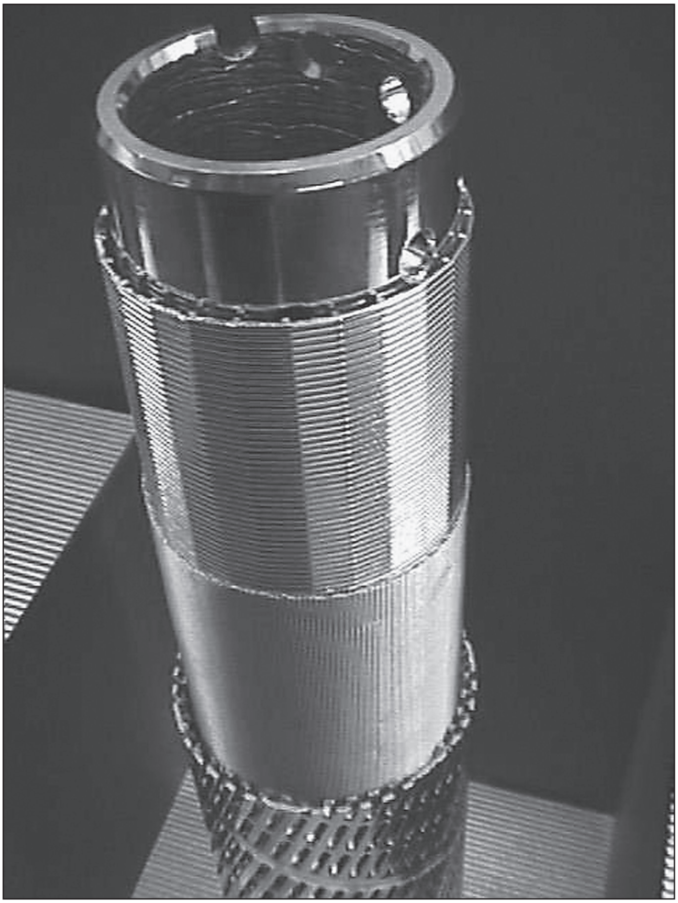


Fig. 4–3. Sand control screen, cut away to show screen elements

If the well gets too close to the oil-water interface, the water (being less viscous than the oil) will "break through" the oil and flow to the well. This is called *coning* (fig. 4–4). Once coning starts, the well will produce water and not too much oil. Similarly, if the well gets too close to the gas, the gas will be preferentially produced. In a vertical well, there is only a short interval of the well that can be perforated to produce the oil. This means that to produce a reasonable amount of oil, the speed that oil has to flow towards those few perforations is high, which will tend to draw gas from above or water from below towards the well.

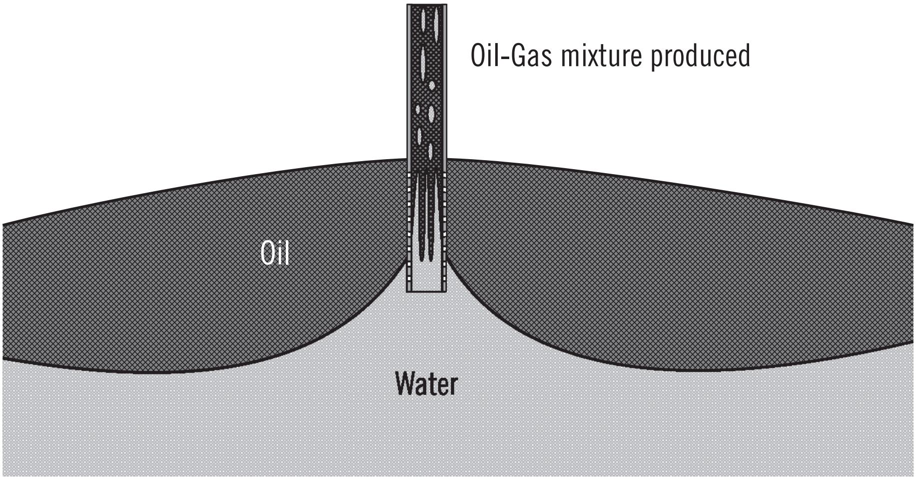


Fig. 4–4. Water coning up to the well

A well can be drilled that bends up to the point that it is horizontal in the reservoir. This horizontal section can be thousands of feet long. With a horizontal well, the contact area between the reservoir and well is large, so flow rates in the reservoir towards the well will be low, which will reduce the tendency of gas or water to break through. Also the horizontal bore can be accurately placed in the best part of the reservoir, even to the extent that it can follow the top of an oil reservoir to remain as far as possible above the oil-water contact. This is called *geosteering* because the well is steered with reference to the geological conditions in the reservoir. How this remarkable feat is achieved will be covered later.

Although horizontal wells cost more than vertical wells to the same reservoir, the well produces more and for longer and so can be a better investment.

Completion design is normally done by the production engineers. However, the completion design affects almost every aspect of the well design, so the drilling engineer must know, at least conceptually, what the completion will look like.

Hole and Casing Sizes

With a development well, the contingency to run an extra string of casing if unexpected hole problems are encountered is less important than on an exploration well. If a well can be drilled one size smaller (for instance, 20″ conductor instead of 30″), generally it will be cheaper to drill the well by around 15%. There is a strong incentive to avoid building in unnecessary contingencies against remote possibilities when the cost penalty is so large.

The hole size of the final section is dictated by the required size of the completion tubing and also by the type of completion. In a traditional completion, the completion tubing extends all the way down to the reservoir, inside the production casing or liner. A completion can also be designed using a liner as part of the completion tubing. One advantage is that the well can be drilled using smaller hole sizes and thus save a lot of money. If the production of the well requires 5″ diameter tubing, the well could be finished by drilling a 6″ hole for a 5″ liner, rather than by drilling 8½″ hole for a 7″ liner. This is illustrated in figure 4–5.

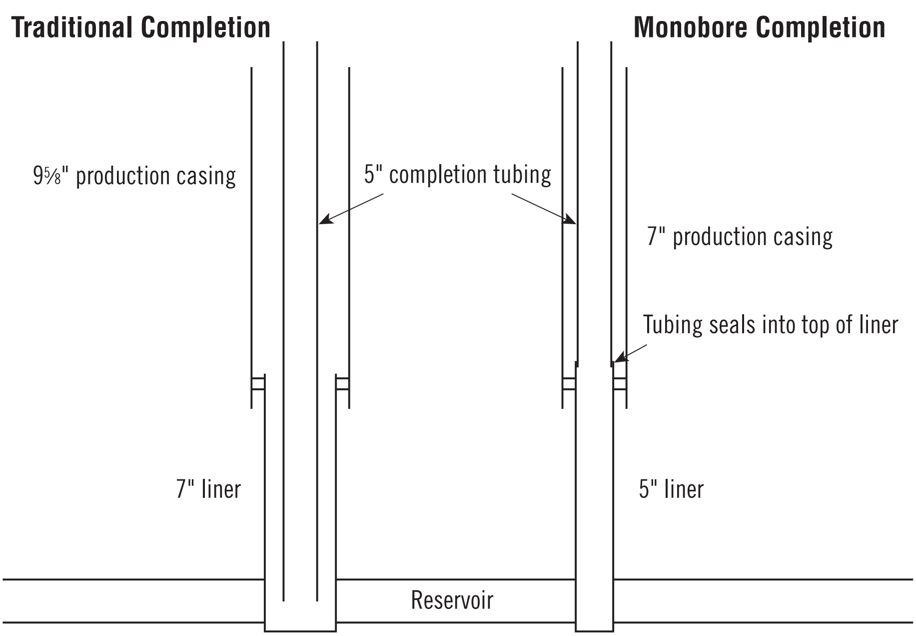


Fig. 4–5. Traditional vs. monobore completion

Where a 5″ production tubing connects to a 5″ liner, the inside of the conduit from the reservoir to the surface will all be the same diameter and is all therefore accessible from the surface with wireline and other tools. This type of design is called a *monobore completion*.

In a horizontal well, the target location is not directly underneath the rig, so the well must be drilled along an accurate path to the target. Once in the reservoir, the well must remain a certain distance above the oil-water contact but not so far above it that it approaches the gas-oil contact.

The BHA navigates through the reservoir by measuring the characteristics of the reservoir while drilling, using logging tools that are constructed inside a drill collar. These techniques are called, logically, *logging while drilling (LWD)*. The logging tool for this job measures electrical resistivity—the closer it approaches water, the lower the resistivity measured. As the reservoir was repeatedly logged during the exploration and appraisal drilling, the engineers have a good picture of how the resistivity varies with depth. (*Appraisal drilling* refers to drilling done after a discovery is made by an exploration well to further appraise the discovery.)

Initially, the well is drilled vertically. At the kickoff point, the rotary drilling assembly is pulled out. (A *rotary drilling assembly* is a configuration of drill collars and other downhole tools that drills by rotating the drillstring from the surface, as opposed to an assembly that powers the bit with a downhole motor.) Next, a special directional drilling assembly is run in the well (see fig. 4–6). This is designed to exert a side force at the bit, so that the bit starts to drill away from vertical. The direction that the well drills towards is determined by aligning the side force in the appropriate direction.

The direction of the well relative to true north is called the *azimuth*, and it is usually measured in degrees clockwise. True east will be 090°.

The angle between the wellbore center and vertical is called the *inclination*. The horizontal section of the well, if it is exactly horizontal, will have an inclination of 90°. A vertical well has an inclination of 0°.

There are various tools and techniques used to deviate the wellbore. Directional drilling techniques are covered in more detail in chapter 8, “Directional and Horizontal Drilling.”

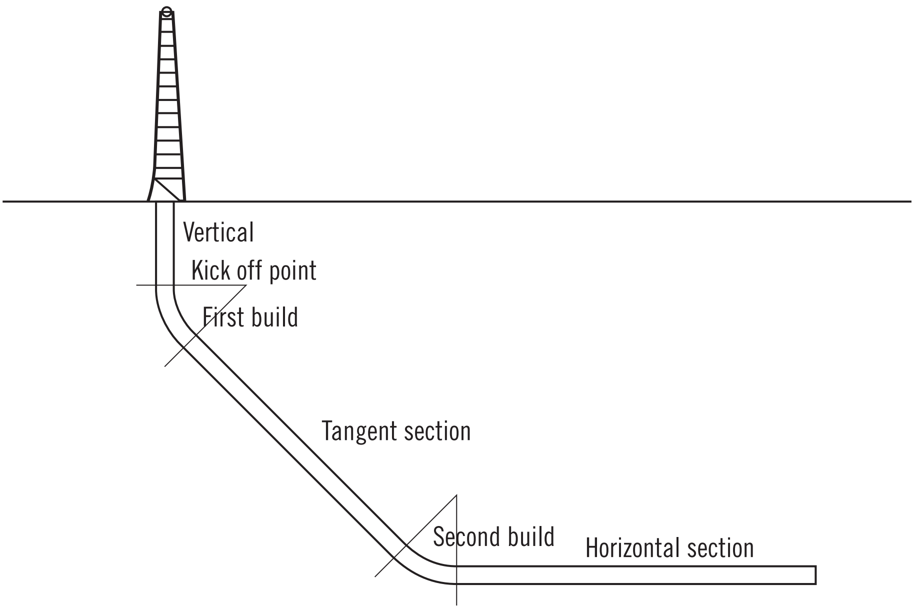


Fig. 4–6. Directional well terminology

Writing the Well Program

With a development well, the engineers have access to a wealth of data from drilling the exploration and appraisal wells. The drilling engineers must learn all the lessons that the previous wells can teach. Of course, this is difficult, even if the information is both complete and accurate (which it often is not). However, there are problems that make this reviewing process even more difficult:

1. Information is often incomplete because people do not always record all the relevant information. Also, records sometimes are missing for a variety of reasons.
2. In many operations, experience from earlier in the project is not properly documented. When engineers leave for another project, their hard-won experience goes with them.
3. Most people do not readily admit mistakes, so instead of learning from problems, the problems become hidden. In some companies, admitting to mistakes can threaten promotions or even careers.

Drilling the Well

This example well will be drilled from a floating rig. A floating rig moves with the tides, waves, and currents. Floating drilling requires special equipment and techniques to deal with this movement.

Spudding the well and cementing the conductor

A *template* is a welded steel structure that is placed on the seabed (fig. 4–7). At each corner, a steel pipe is cemented into the seabed to secure the template. Within the template are placed large pipes with a conical guide above; these are called *conductor slots*, and their purpose is to allow conductors to be placed through them.

The template has four posts welded around each conductor slot. Guide wires are attached to these posts, extending back up to the rig. These guide wires are used to guide tools into the well. When a well is spudded, the drilling assembly is loosely tied to the guide wires with ½" Manila rope. As the bit enters the slot, the rope breaks. As the hole is drilled, spud mud is pumped down the drillstring, and the mud and cuttings exit the annulus at the seabed. After pulling out with the drilling assembly, the conductor is run in on drillpipe and cemented in place, similar to the way that a liner is run, as described in the previous chapter. The conductor is guided with rope on the guide wires into the conductor slot.

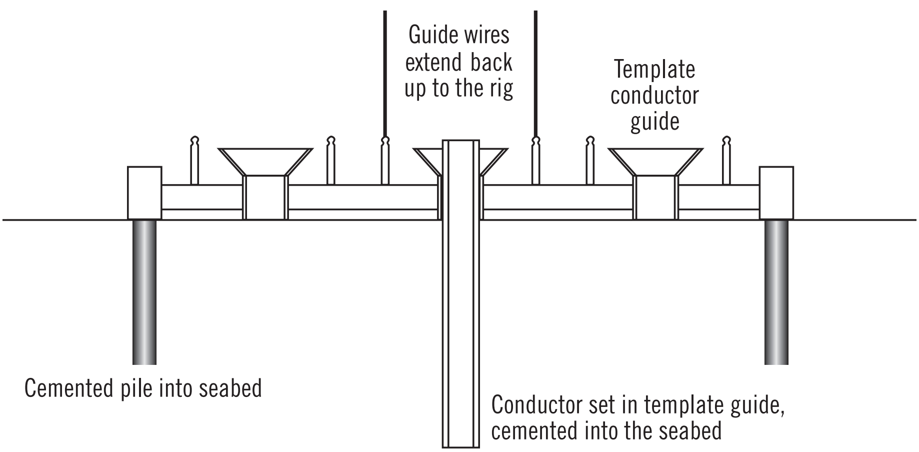


Fig. 4–7. A template set on the seabed (side view)

Drilling for surface casing

With a floating drilling rig, surface hole is drilled with returns to the seabed. No diverter is run. If shallow gas is encountered, the rig can, if necessary, drop the drillstring and move off location, away from the gas flow. The gas will flow to the sea, and the gas plume will disperse as it rises. Any current will move it away from the rig. If a very strong flow was encountered in shallow water, the rig might be endangered by the gas flow destabilizing the rig, causing it to capsize.

As before, the BHA is guided to the template using rope on the guide wires. The surface hole is generally not logged. Of course, no cuttings samples are possible because they are dispersed on the seabed around the template. As this is a development well, the geology is known, and so the surface hole terminates at a predetermined depth, where the formation is known to be strong enough to hold pressure if a kick is taken.

The surface casing is run and lowered into place using drillpipe. At the top of the casing is screwed a special tool that contains the cement plugs, and it is cemented in a very similar manner to a liner in a land well.

On top of the surface casing is a subsea wellhead housing, which is a section of thick-walled pipe. Inside is a profile that the next casing hanger lands on.

On the outside of the wellhead housing is a profile onto which the blowout preventers are latched (fig. 4–8).

Special underwater blowout preventers are set on top of the well after setting surface casing (fig. 4–9).

After testing the subsea BOP on the rig to ensure it functions correctly and holds pressure, large diameter pipe (called *riser pipe*) is connected to the top of the BOP and used to lower the BOP into the sea. Hydraulic hoses and electrical cables are secured down the outside of the riser to connect the BOP to the rig. This allows control of the BOP functions and transmits status information back to the rig. The BOP is lowered down to the template, guided by the guide wires. At the top of the riser is a special joint called a *telescopic joint* (figs. 4–10 and 4–11). This fastens under the rig, and it opens and closes to allow for the up-and-down movement of the rig once the BOP connects to the wellhead housing. The BOP is lowered so that the hydraulically controlled latch goes over the wellhead outer profile, and then the latch is closed and forms a pressure-tight seal.

Fig. 4–8. Subsea wellhead housing showing latching profile

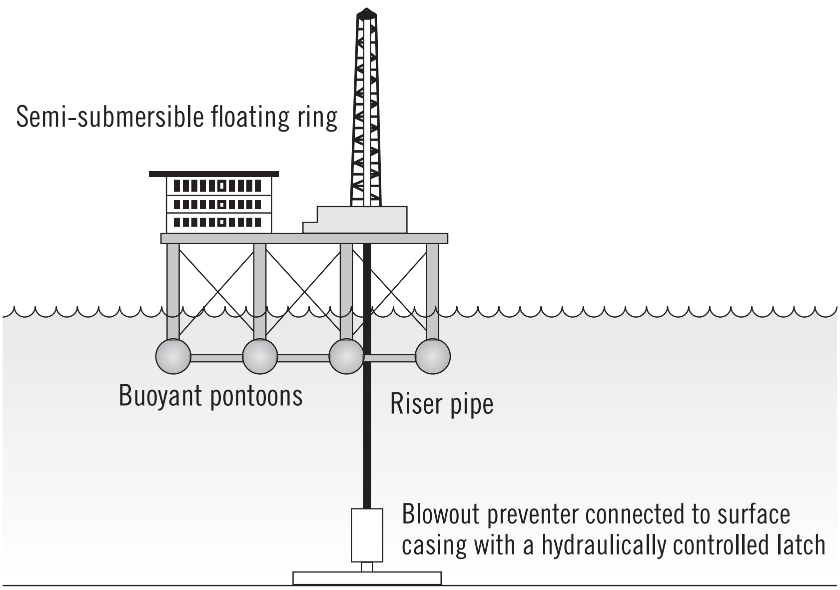


Fig. 4–9. BOP latched onto wellhead housing

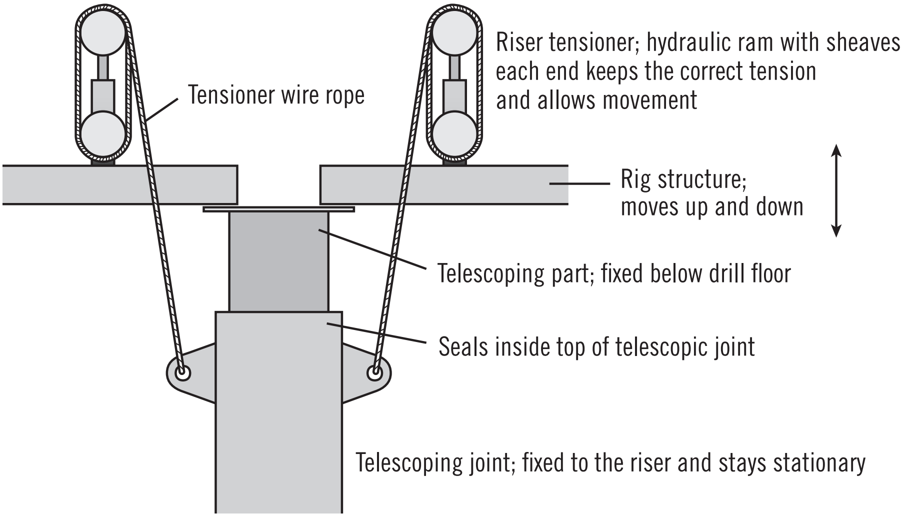


Fig. 4–10. Arrangement of telescopic joint and tensioners

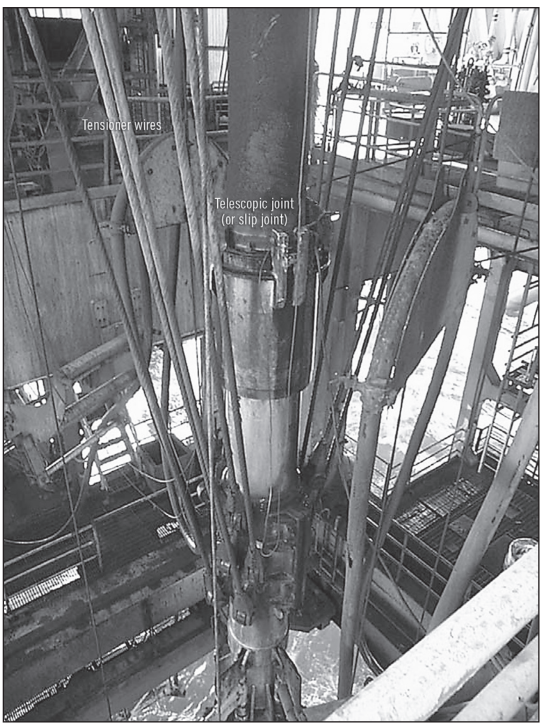


Fig. 4–11. Telescopic joint

The riser is supported by tensioner wires attached to the bottom part of the telescopic joint. These tensioner wires are attached to pulleys on the ends of hydraulic rams, which are powered by pressurized nitrogen cylinders. In effect, the tensioner acts like a very powerful spring, the strength of which is set by adjusting the nitrogen cylinder pressure. In very deep water, the tensioner force required to support the riser weight is quite high. The riser pipes have shaped "floats" attached to their outside, which reduce the amount of tensioner force needed. As the rig moves up and down (*heaves*), the tensioners allow the wire to respond and maintain the correct force to support the riser.

In summary, the rig has drilled a hole, cemented a conductor in place, drilled surface hole, and cemented surface casing in place. The BOP was tested on the rig, and then it was run on riser pipe and latched to the wellhead housing on top of the surface casing. The BOP sits on the seabed, controlled by hydraulic hoses from the rig.

Heave compensator

With pipe in the hole, either for drilling or for other operations such as running casing, compensation must be made for rig heave. This ensures that the drill bit stays on bottom with the correct weight on bit, or that the casing can be landed in a controlled manner, while the rig floats up and down on the waves (fig. 4–12).

The traveling block (used to suspend and control the drillstring) can be compensated for in a manner similar to the way that the riser tensioners work, as described above. The compensator cylinder hydraulic fluid is energized by compressed nitrogen. The upward force exerted by the compensator is adjusted by changing the nitrogen pressure. If the upward force just suspends the drillstring, then reducing the nitrogen pressure to "lose" the desired weight on bit will allow the bit to sit on bottom with the desired downward force. The amount of heave that can be compensated for is governed by the maximum stroke (movement) of the compensating cylinder rod.

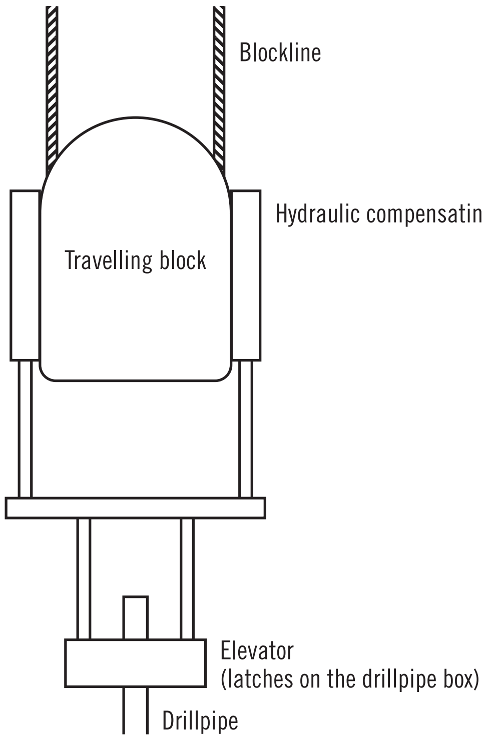


Fig. 4–12. Heave compensator—principal of operation

Kicking off the well

When drilling a directional well, the kickoff point has to be carefully chosen. For the kickoff to be controllable, the hole has to be stable (stays equal to the drillbit diameter) over the buildup interval. A significantly enlarged hole makes accurate directional control impossible.

The kickoff should be started and finished in one hole section. It is better not to run casing halfway through the kickoff, because if the casing is drilled out and a curved wellbore continued, the drillpipe can wear a groove in the casing shoe on the inside of the bend.

Apart from the damage to the casing, the drillpipe can get stuck in this groove when pulling out of the hole. It is better to finish the kickoff and protect it by running casing reasonably quickly afterwards.

If the well is kicked off high up and the displacement of the bottom of the well is low, the inclination of the well will be low. (*Displacement* is the horizontal distance between the target and the location directly below the wellhead.) Below about 15° inclination, it is difficult to control the azimuth of the well. In that case, a deeper kickoff would be preferable because that will give sufficient inclination (which is more controllable) to reach the target.

On the other hand, the lower the well is kicked off, the more hole has to be drilled to reach the target. Higher inclinations start to cause a variety of problems, such as more severe wellbore instability, and it gets harder to circulate cuttings out of the well (especially at inclinations above 40°).

On this well, it is better to avoid the complications of drilling a kickoff without fluid returns to the rig. The kickoff will be done in the first intermediate hole section.

There are quite a few considerations for selecting a kickoff point. In addition to the kickoff depth, a decision is necessary for how quickly to build up inclination. The severity of a change in wellbore direction is measured in degrees per hundred feet of hole (or per 30 m on metric operations). The buildup rate should not be too high, because this will increase wear on downhole components while drilling. Too low a buildup rate will take more time to complete the kickoff. A build up rate of around 2½° to 3° per 100 ft is usually planned. At 3°/100 ft buildup rate, about 1,000 ft of hole have to be drilled to attain an inclination of 30°.

The surface casing will be drilled out once the BOP is latched and tested. This will be with a normal rotary drilling assembly to the kickoff point because the well is vertical above the kickoff point. Once the kickoff point is reached, the rotary drilling assembly is pulled out of the hole.

From the bit up, the directional assembly will consist of the drill bit, a downhole motor, bent sub, MWD tool (which measures and transmits directional information to the surface), drill collars, and drillpipe. The MWD tool is set up so that the azimuth of the inside of the bend on the bent sub is known. This is important because the drilling assembly will drill in the direction that the inside of the bend points. The inside of the bent sub bend is called the *tool face*, and the direction it points at any particular time is the *tool face azimuth (TFA)*. The MWD tool transmits three pieces of information to the surface—the wellbore inclination and azimuth at the depth of the tool, and the TFA. This information allows the driller to guide and correct the direction that the well drills.

When drilling with a downhole motor, the motor exerts a torque on the drill bit so that the bit turns and drills. There is also a reactionary torque exerted above the motor. A long string of drillpipe is pretty flexible and will act like a long spring, which will get a little wound up with the reactionary torque from the motor. For this reason, while drilling, the tool face azimuth will move around even though the drillpipe on the surface does not rotate. Without a constant surface readout of the TFA, it would be much more difficult to align the drilling assembly in the right direction.

The directional BHA is assembled on the drill floor, and the motor is tested by pumping mud through it. If that is okay, the MWD will be added, and that too will be tested. When all is ready, the assembly is run to just above the bottom of the hole. Once mud is pumped through the drillstring, the motor will start turning, and the MWD will start working and transmitting data to surface. As data is received, the tool face azimuth is known, and the drillstring is turned to align the TFA in the correct direction.

With the tool face azimuth aligned, the drillstring is lowered until it touches bottom. The motion compensator is about half open. Then the pressure on the compensator is reduced (so that it supports less of the drillstring weight); the bit takes weight and starts to drill.

While drilling, the main determinant of the buildup rate is the angle of the bent sub and the distance from the bent sub to the bit. However, if the weight on bit increases, the buildup rate will tend to increase. The adjustment is limited, because if too much weight is put on the bit, the torque required to drill exceeds the motor output torque, and the motor stops rotating (it stalls).

Drilling the tangent section

After first build is complete, the well must be drilled in a straight path to the second build position. This is done with a rotary drilling assembly that is designed to drill straight ahead.

In a critical well like this one, where the wellbore has to be drilled accurately, an MWD tool can be run as part of the rotary drilling assembly. The MWD transmits inclination and azimuth information to the surface.

To determine the exact position of an object in space (e.g., an aircraft), it is necessary to know its height above the ground and its geographical coordinates (north-south and east-west). Position within the earth is expressed in the same way: the vertical depth below a particular reference (e.g., mean sea level or the drill floor), called *true vertical depth (TVD)*, and the geographical coordinates.

It is simple to calculate the position of the wellbore within the earth from the inclination and azimuth at known depths. The measured depth (MD) along the hole from the surface to the MWD tool is always known. For each survey, there are three items of information: the MD along the wellbore, the inclination, and the azimuth. While there are several ways of calculating the position, the most commonly used is called the *minimum curvature method* because it assumes a perfect arc (segment of a circle) between two survey points.

Knowing the current position, inclination, and azimuth of one survey point, the distance along the hole to the next survey point, and the inclination and azimuth of the second survey point, the position of the second point can be calculated. These calculations can be done by hand but they are somewhat tedious, and computer programs are used nowadays for this. If two surveys had exactly the same azimuth and inclination, determining the new TVD and coordinates would be simple trigonometry, but even in a tangent section, the wellbore is almost never perfectly straight, and so perfect circular arcs are still assumed.

In a deviated well, the measured depth is either equal to TVD (in the initial vertical part of the well) or is greater (as the well starts to deviate). Both depth measurements are important; hydrostatic pressures and formation fracture pressures are calculated using TVD, but the lengths of objects placed in the wellbore, such as casing, are calculated using MD (fig. 4–13).

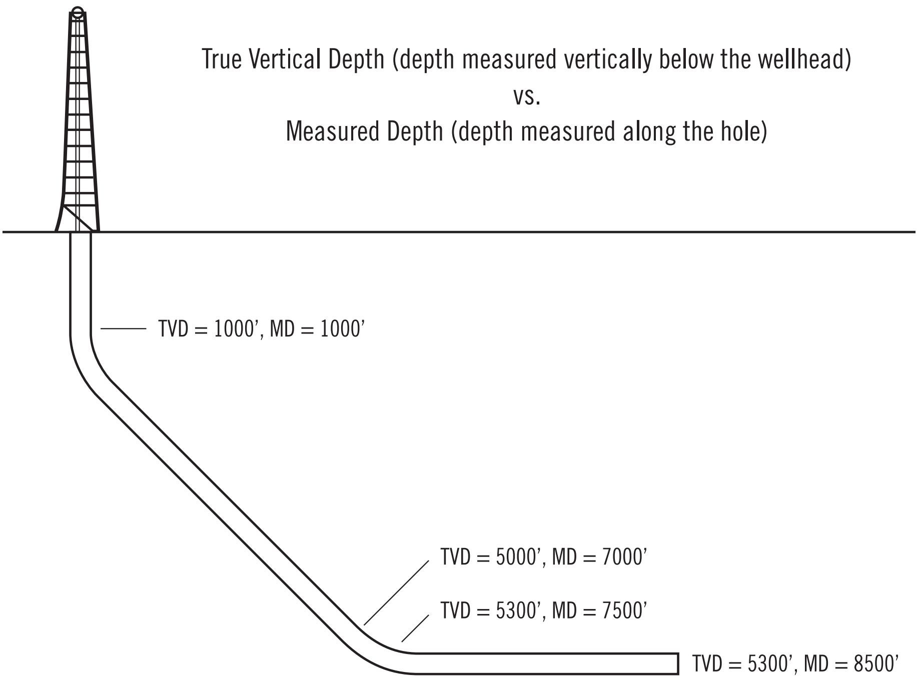


Fig. 4–13. Calculating depths in a deviated well

Locating the casing point

With the exploration well described in the previous chapter, the casing point was planned to be roughly at a certain depth. The casing was set when a suitable formation was drilled into. In the development well, the formations are reasonably well known and described. The decision as to where the casing will be set can be made in the well design.

As drilling continues, the sequence of formations encountered (identified by rock cuttings sampled at the surface) is compared to the expected sequence and so the geological position of the bit is known. If drilling is fast, it may be necessary to stop drilling and circulate bottoms up for a sample. (*Bottoms up* is an expression referring to the time or volume to circulate in order to bring mud at the bottom of the well up to the surface. If circulating at 600 gal/min, and the annular volume is 24,000 gal, it will take 40 min to circulate bottoms up.) Otherwise a formation might be completely drilled through before the cuttings can reach the surface. Often a higher formation can be used as a kind of marker, if the distance from this formation to one of interest is accurately known. There are sometimes more immediate signs; a sudden change in the speed that the bit drills indicates a change of formation drillability. (*Drillability* refers to how easy a formation is to drill and is closely related to the compressive strength of the formation. A lower rock compressive strength gives a higher drillability. However, there are exceptions. A PDC bit might go from a high-strength formation where it drills fairly fast because the formation is suitable for PDC drilling to a formation of lower compressive strength that does not favor PDC drilling.) In this case, drilling speed might decrease rather than increase, which could help identify the next formation in the geological sequence. The change is recognized straight away and may then be confirmed by stopping to circulate bottoms up for a sample of the formation.

Once the casing point is reached, drilling stops, but circulation continues until the cuttings remaining in the annulus are out and the wellbore is clean. The time to circulate the well clean is greater than the time for bottoms up, because the cuttings in the annulus will fall through the rising column of mud so that they rise slower than the mud itself. Circulating until all the cuttings are out is called circulating clean.

Logging

On most hole sections of most wells (except in development projects where very many wells have already been drilled), logs will be run. Different specialists need information from downhole logs. The geologists want to confirm the properties of the formations penetrated and any fluids within the formations. The drillers want to measure the diameter of the hole, using a tool (called a *four-arm caliper*) that measures using two pairs of arms so that the hole size is measured in two places (fig. 4–14). This allows accurate calculations of cement volumes. It also indicates how stable the wellbore is and if the wellbore is more stable in one direction than the other.

The drilling engineers also want to improve drilling performance on the next well, and it is very useful to measure rock mechanical properties, such as compressive strength. Compressive strength can be calculated by sending a sound wave into a formation and placing a microphone some distance away along the wellbore. The properties of the sound wave are modified by traveling through the rock, and this change can indicate, among other things, compressive strength.

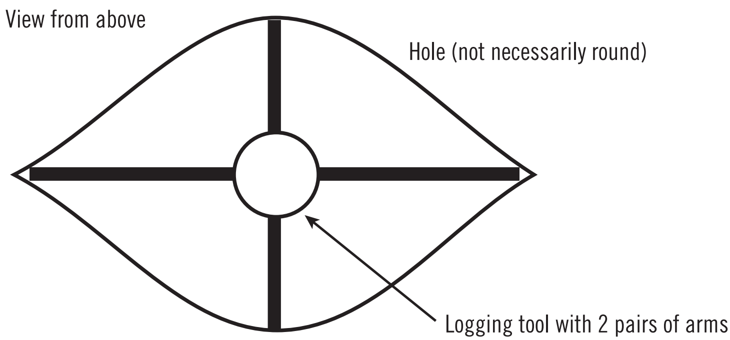


Fig. 4–14. A four-arm caliper, which measures the hole size in two axes

Logging in a directional hole is more difficult than logging a vertical hole. Any roughness of the borehole wall will impede progress of the logging tool. The tool may stand up on a ledge and not run any further. It is more likely to get stuck, as its own weight presses it into the side of the hole. Generally, if the wellbore is smooth, logging tools can be successfully run on wireline up to around 60° inclination.

In bad wellbore conditions or if the hole inclination is too high for wireline logging, the logging tools can be attached to drillpipe and run in the hole, with the electrical cable inside the drillpipe. Logging on drillpipe takes a long time and thus is very expensive. In this case, only the most important logs needed for decision making on the well will be run.

An alternative is to run a logging while drilling (LWD) tool as part of the drilling assembly. LWD tools were fairly crude when they were first developed, but modern LWD tools can take logs of sufficient quality that they can replace wireline logs in some cases.

Bringing the well to horizontal

The well is now drilled at an inclination, towards the second kickoff point. The problem with the second kickoff is that it must be exactly right (fig. 4–15). If the well becomes horizontal just a few feet too low or too high, it will take a lot of drilling to get the well back to the desired TVD. If the formations above the reservoir are just a few feet thicker or thinner, or if their dip angle is just a little bit different from what is expected, the well might end up in the wrong place.

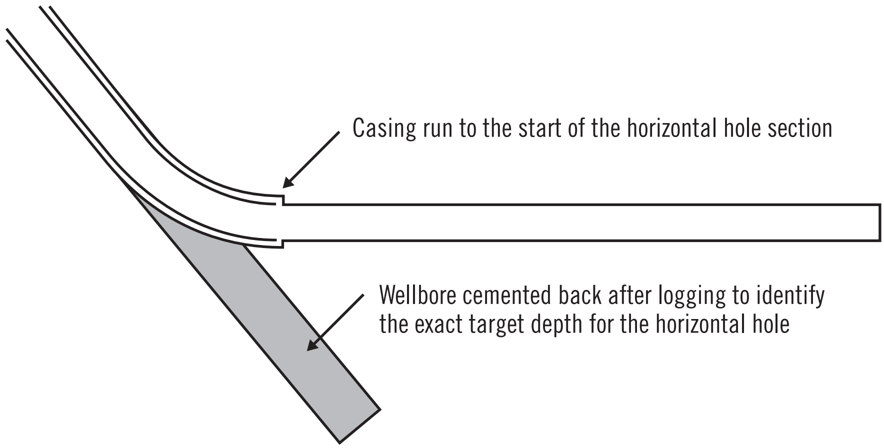


Fig. 4–15. Identifying the second kickoff point

To guarantee accurate knowledge of the downhole geology, the well continues straight past the planned second kickoff point and into the reservoir. Logs are then run, and the real situation can be identified. The drilling assembly is pulled out, and plain pipe is run in (without a bottomhole assembly). Cement is pumped to the bottom of the well so that the top of the cement is above the required kickoff point and the pipe is pulled out of the hole. Now a steerable motor assembly is run in, and the cement is drilled to the point where the kickoff should start. During this time, the drillstring is rotated so that the steerable motor drills straight.

It is important that the cement is designed with a higher compressive strength than the formation. If the cement were weaker, it would be difficult or impossible to leave the old wellbore and start a new one.

Once the kickoff point is reached, the steerable motor tool face is aligned in the proper direction, and the well starts to deviate away from the original wellbore.

The steerable drilling assembly will include both an MWD tool (to measure directional parameters) and an LWD tool (to confirm the geological position). The well is drilled to become horizontal at the exact TVD (to within four or five feet, possibly less) that is required by the reservoir engineers. At this point, casing can be run to protect the well into the reservoir and to isolate the reservoir from the formations above.

The reason for drilling horizontal wells is to increase the production potential of the well. If a beautiful horizontal well is drilled in the reservoir, it would not be good to run steel pipe inside it and pump cement around it. Cement has a nasty habit of plugging the reservoir and restricting production. Instead, the well will be left to produce as drilled, if the rock is strong enough to produce without collapsing or producing solids. Otherwise, some kind of screen can be run that is not cemented in place but that holds back any produced solids and supports the hole if it starts to collapse.

Drilling the horizontal section

Production casing is run and cemented with the casing shoe in the reservoir and horizontal. A steerable motor assembly with MWD and LWD is run in to drill the final horizontal hole through the reservoir.

The LWD tool in this well has two sensors, a resistivity sensor and a gamma ray sensor. If the drilling assembly drops towards the oil-water contact, the resistivity reading will decrease. If the drilling assembly builds up towards the shale on top of the reservoir, the gamma ray reading will increase.

Shale minerals are naturally radioactive, and thus they give off gamma rays that can be detected. The level of radioactivity is not enough to harm humans, which is just as well, considering that most of the upper earth's crust consists of shales! It is also possible to tell from the gamma radiation spectrum (the frequencies present in the radiation) what type of mineral is responsible for the radiation. Thus, a particular shale can be recognized by its gamma radiation spectrum.

Using knowledge of the reservoir structure, the LWD and MWD readings allow accurate navigation in the reservoir. It is possible to drill with a high degree of accuracy; within three or four feet either way.

It is very important to minimize damage to the reservoir as it is drilled through. Normally a well is drilled so as to remain overbalanced on the pore pressures with the mud hydrostatic pressure, but this pressure will tend to force mud and mud solids into the formation. It is possible to drill the reservoir section underbalanced; that is, the formation pore pressure exceeds the mud hydrostatic. The reservoir will continually flow while the well is drilled. If the problems of hydrocarbon production while drilling can be handled, this almost guarantees that there will be no significant damage to the formation face. There are horizontal wells drilled in Texas that produce enough oil during drilling the reservoir that the well is paid for by the time the well reaches the target depth!

On this rig, there is no facility to handle produced hydrocarbons, and so the option to drill underbalanced is not available. The fluid used for drilling the reservoir will be a special mud with no clay solids added. Clays are especially damaging because they plug pore spaces and cannot be removed with acid. Instead, acid-soluble solids such as calcium carbonate can be used. These can later be removed by pumping acid down the well.

Once the well is drilled to the target depth, the drillstring can be pulled out. A sand screen is run into the bottom of the well, over the full horizontal section, to prevent sand from being produced with the oil. This is fixed in place using a hanger (somewhat similar to a liner hanger).

Suspending the well

The well needs to be left in a safe and stable condition while further wells are drilled and later while the platform is put in place on the template. The practice of leaving a well for later reentry is called *suspending the well*.

After placing the sand screen in the reservoir, the well has special plugs (*bridge plugs*) set in the production casing. Cement will be placed on top of at least one of these plugs, as extra insurance that any gas coming into the well cannot migrate up to the surface. These can be drilled out later on.

Most operators and government regulations require at least three physical barriers to prevent hydrocarbons reaching the surface. In this well, one barrier is provided by the hydrostatic pressure of the fluid in the well, one by the bridge plug, and one by the cement plug.

Finally, a suspension cap is placed on top of the wellhead. This is a special cover that latches onto the wellhead. Corrosion inhibitor fluid is pumped into the cap to help resist corrosion during the time that the well is suspended.

Summary

This chapter has examined tools and techniques used to drill a horizontal production well from a floating rig through a subsea template and to suspend it for later reentry.

The equipment required allowing movement between the rig and the seabed was discussed in detail.

5

RIG SELECTION AND RIG EQUIPMENT

Overview

This chapter will discuss how a rig might be selected. The different types of rigs will be described, and an indication of their comparative costs will be estimated, although the actual rate for a rig can vary widely depending on the state of the industry and the price for oil. Major items of rig equipment will then be discussed in sufficient detail that their function within the rig operation and their operating principles can be understood.

Selecting a Suitable Drilling Rig

The classification of drilling rigs deals with the environment in which the rigs have to function. Figure 5–1 illustrates the classifications of the various available rigs.

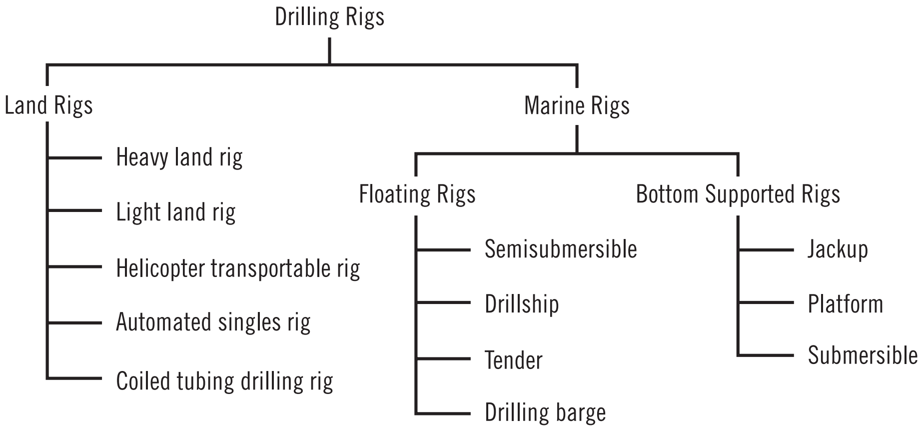


Fig. 5–1. Classifications of drilling rigs

In addition, there are some special units available for working on oil and gas wells that would not be classed as rigs, such as coiled tubing units (CTU), snubbing units, and workover hoists. Coiled tubing units consist of a large drum containing a reel of steel pipe that is quite flexible. This pipe can be lowered into the well to perform various operations, such as pumping fluids, manipulating downhole tools, running logs in difficult or high-angle wells, or even drilling. Snubbing units allow pipe to be forced into the wellhead under pressure, so that jobs can be carried out without having to kill the well and risk damaging it. Workover hoists are similar to a very small rig and may be used to pull or run pump rods out or in, or to perform small jobs that do not require much power.

The maximum load that can be suspended within the derrick or mast is also a consideration. Deeper wells require a stronger derrick because the well will require deeper strings of casing to be run, which will weigh more.

The cost of the rig is an important consideration. A better, more highly equipped rig will cost more, but the performance gain should offset at least some, if not all, of the extra overall cost.

The requirement for a rig is dictated by the drilling program, working environment, rig availability, and cost.

Classifications of Drilling Rigs—Descriptions

Each classification of rig shown in figure 5–1 is described in the following sections.

Heavy land rig

A heavy land rig (fig. 5–2) will be suitable for drilling deep or very deep wells (over 10,000 ft). The maximum load that the derrick is capable of suspending will equal or exceed 1,000,000 lb. The rig will have two, possibly three, high-pressure pumps (described later) for circulating the drilling fluid around the well. The blowout preventers available for use as drilling progresses will be high pressure (rated to 10,000 psi or higher). Storage capacity for consumable fluids and powders will be high; it will need to store and use large volumes of drilling fluid, diesel oil, cement powder, and mud chemicals. The rig systems have to be able to transfer and mix these to produce the required cements and drilling fluids. The rig is transported by a fleet of trucks to the required location.

A heavy land rig typically costs around $80,000 a day.

Fig. 5–2. Land rig in the desert

Photo courtesy of Schlumberger.

Light land rig

A light land rig will be suitable for drilling shallower wells. It might also be used for working over an existing well that requires major repair or replacement of the completion. In this case the old completion is removed from the well and a new completion is run.

It will most likely have two high-pressure pumps for circulating drilling fluid around. Capacities in general will be lower than for a heavy land rig. The rig is transported by a fleet of trucks to the required location.

Heavy and light land rigs might include accommodation for the crews, or the crews might be accommodated elsewhere while not working (in a hotel or a central camp, for instance).

A light land rig might cost around $25,000 to $40,000 a day.

Helicopter transportable land rig (*heli-rig*)

In remote areas where suitable roads do not exist, a rig can be placed on location by helicopter. A heli-rig can be broken down into small packages; the maximum package weight will be around 6,000 lb. Heli-rigs are used in jungles and mountainous regions.

On heli-rig operations, everything is transported by air. The heaviest loads are lifted early in the morning because the air is coolest and the performance of the helicopter the highest.

A helicopter will generally be stationed at the wellsite when not in use, so that it is immediately available for *medivac*, or emergency medical evacuation, in the unfortunate event of an accident requiring medical care beyond that provided on the rig.

Heli-rigs will include accommodation for the crews.

A heli rig might cost around the same as a heavy land rig, depending on the capacity. Running costs apart from rig cost will tend to be higher because one or two helicopters are kept with the rig.

Automated singles rig

One of the recent developments in rigs is for highly automated rigs that use pipe handling systems to lay down all the drillstring components when pulling out of the hole. It might or might not have provision to rack a few things vertically in the derrick. An example of this is the Drillmaster rig, shown in figure 5–3. The rig is truck mounted; it is raised off the ground on a frame, and the derrick pivots upright. Rather than a wire rope, the block is moved by a hydraulic ram. In front of the rig is a magazine, where drillpipe, casing, and other tubulars are stored vertically.

Fig. 5–3. The Larchford Drillmaster automated singles rig, drilling in the south of England

As it does not have a large derrick, it is less visible. The equipment that emits the most noise—generators and pumps—is housed in soundproof containers so that it is also fairly quiet. This makes it a good neighbor!

Due to the high level of automation, these rigs also work with fewer people than a conventional rig.

A variation on this theme is the Huisman LOC 400 casing drilling rig. This rig is designed to drill with casing, whereby the casing itself is used to drill the well rather than drillpipe. A drilling assembly is suspended at the bottom of the casing, retrievable by wireline. After drilling to the depth required, a wireline runs in, latches onto the assembly, and pulls it back to the surface. The casing stays where it is, cemented in place. The rig shown in fig. 5–4 all fits into 18 loads the same size as a standard 40 ft shipping container, so it can be moved by truck or boat. Casing drilling is described later.

Fig. 5–4. Huisman LOC 400 casing drilling rig

Photo courtesy of Northern Dutch Drilling Company.

Coiled tubing drilling rig

Coiled tubing has made amazing advances. Instead of drillpipe, reels of coiled tubing unreel pipe directly into the hole. One major limitation of drilling with coiled tubing is that the tubing itself cannot rotate. Drilling is done using a downhole motor to turn the bit. However, as the pipe does not rotate, it has to slide. This gives rise to all sorts of problems, such as poor hole cleaning, inability to slide in highly deviated holes, and stuck pipe. Coiled tube diameters up to 5″ are thought possible.

The rig shown in figure 5–5 is the rotating coiled tubing rig designed and built by Reel Revolution Limited. It overcomes the limitations of nonrotating coiled tubing; the complete reel rotates around the center of the well, with automatic counterbalance weights keeping things smooth. The large A-shaped mast is used to start the well and set conventional surface casing, and then the reel can take over. Note the road wheels stuck onto bits of the structure; it transforms into roadworthy trailers that are then towed to the next location. The rig is highly automated; the company claims that someone could sit in an office in Dallas and drive it remotely!

Fig. 5–5. Rotating coiled tubing rig near Odessa, Texas

Photo courtesy Reel Revolution Limited.

Semisubmersible

A semisubmersible rig is large, and some are very large. The rig sits on steel columns (between three and eight of them), under which are buoyancy chambers (called *pontoons*). When under transport between locations, the pontoons are partially empty (with some water as necessary for stability) so that the rig floats high out of the water.

Once the rig is in position over the well site, ballast water is pumped into tanks located within the pontoons and columns. The rig thus becomes lower in the water, and in this position, the rig will move less than it would in the transport state when influenced by the waves and wind. A big semisubmersible rig can continue to operate in pretty bad weather.

A large semisubmersible rig may be capable of carrying most or all of the equipment and supplies needed for drilling an entire well. If an exploration well were required in a remote area, this would be a serious advantage, as the rig could pick up supplies at a suitable place and proceed to the well location without requiring supply boats being mobilized over large distances.

Fig. 5–6. Semisubmersible rigs offshore Ghana

Accommodation for all personnel is available on the rig. There will also be catering and some leisure facilities, such as a gym, cinema, library, and satellite TVs in the bedrooms. Many of the crews and supervisors will work on a rotation of 28 days on board followed by 28 days off.

Semisubmersible rigs may be self-propelled or they may have to be towed by tugs between locations. On location, they might be anchored in place, but they can also be dynamically positioned, as explained later.

The limit of water depth for a semisubmersible rig is dictated by the amount of riser pipe that can be carried or run or by the capability of the anchoring system if the rig is anchored.

A semisubmersible rig (also called a *semisub rig*) might cost between $300,000 and $400,000 per day, depending on the age, equipment, and area of operation.

Drillship

A drillship has a ship-shaped hull. Approximately centrally located is a derrick, under which is a large hole through the hull. This is called the *moonpool*.

Drillships vary in size, but the biggest can carry everything needed to drill fairly deep holes in fairly deep water without resupply. They can be moved quickly between locations. Drillships are often positioned dynamically over the well rather than being anchored in place.

Drillships can be expensive to hire! Daily expense can range from $230,000 for an old one to more than $400,000 for a modern DP drillship.

Drilling tender

A drilling tender has a ship- or barge-shaped hull containing the accommodation and all equipment except the derrick, BOP, and ancillary equipment. The tender is moored against a platform, and the derrick is installed on the platform deck. Cables and hoses are run from the tender to the rig to provide power, drilling fluid, compressed air, communications, and control systems, etc. (fig. 5–7).

A ramp can be suspended from the platform, using cables from posts on the platform to the end of the ramp. To transfer personnel between the platform and tender, it is necessary to climb a set of steps on the front of the tender, step (or jump) onto the ramp, and then walk up the ramp stairs to the platform. The ramp is called a *widow maker* with typical offshore humor and some truth. Happily, widow makers are rare nowadays, and better designs allow safe transit between the stationary platform and the floating tender.

Fig. 5–7. Drilling tender with derrick on platform

Photo courtesy of Schlumberger.

In the North Sea, semisubmersible drilling tenders have been used to support a drilling package placed on a platform.

Drilling tenders are used for development drilling from established platforms. They might be inexpensive ($30,000 a day) for a barge-type tender as shown in the photo to $100,000 a day for a modern semisubmersible tender in the North Sea.

Drilling barge

A barge has a large, rectangular hull that floats over the well, anchored in position. A derrick is positioned at the end opposite the accommodation, on a cantilever over the hull. They can drill wells up to around 20,000 ft (fig. 5–8).

Barges are used in shallow waters (up to 50 m) that do not have large waves or strong currents. A number of these drilling barges operate on Lake Maracaibo in Venezuela.

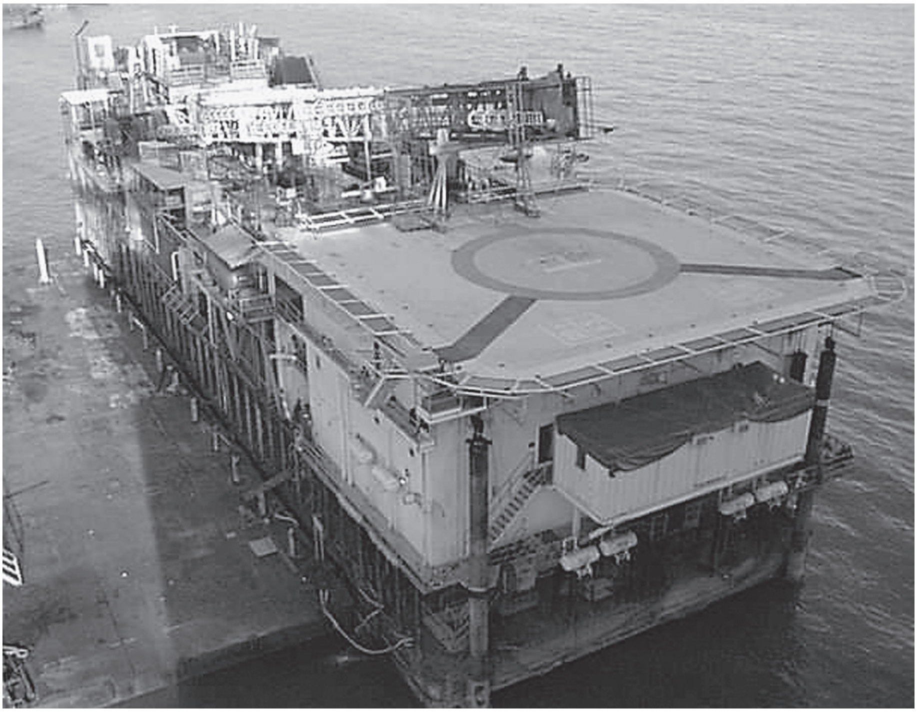


Fig. 5–8. Drilling barge with derrick stowed for moving

Photo courtesy of Schlumberger.

Jackup

A jackup rig has a floating hull, usually triangular shaped but sometimes square. At each corner is a large steel leg. The rig is towed to the wellsite with tugs (fig. 5–9). Once in position, the legs are moved down until they contact the seabed. By jacking the legs further down, the hull raises up out of the water. This forms a temporary platform (fig. 5–10).

The derrick is located on a large cantilever beam that moves out from the hull, placing the derrick over the side of the hull. This allows a jackup rig to move next to a platform and position the derrick above a well within the platform structure. Exploration wells are drilled by spudding directly into the seabed. A platform is not installed until a decision is made to develop any hydrocarbon discoveries.

A jackup rig might cost $50,000 to $250,000 a day.

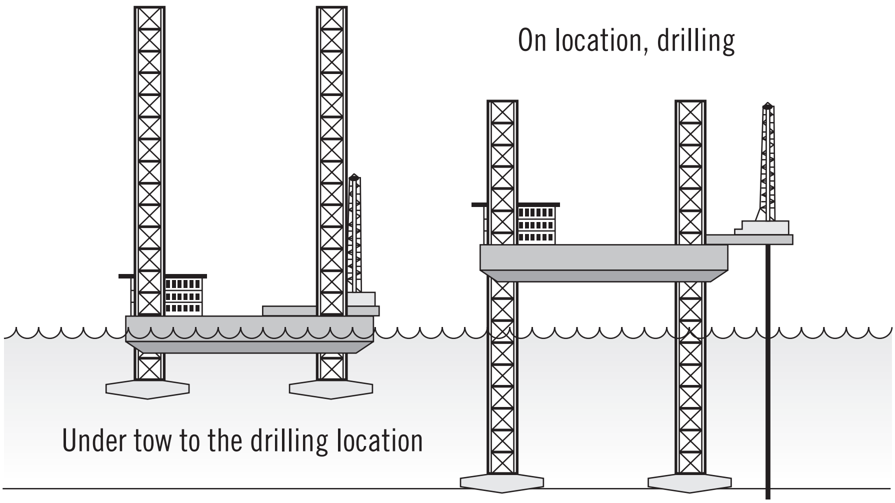


Fig. 5–9. Jackup rig, under tow and on location

Fig. 5–10. A jackup rig drilling in the Gulf of Suez

Platform

A platform is fixed in position on the seabed. A conventional platform is built on a framework of legs and bracing tubes and may include accommodation and a complete self-contained rig package (fig. 5–11). The platform compared to a jackup begins with a more complete and stable setup.

Fig. 5–11. Conventional platform with self-contained rig package

Photo courtesy of Schlumberger

A conventional platform could be installed with the capacity to drill quite a lot of wells. A large platform might have the capability to drill more than 30 wells by piledriving conductors into the seabed through guides set into the platform substructure. The rig package sits on top of large steel beams, where it is moved around the available well "slots" by using hydraulic cylinders to skid the rig around on the beams. Once the wells are all drilled, the rig package may be removed to reduce platform weight and increase space.

In deep or very deep water, a platform may be designed to float but is tethered to the seabed with steel pipes. This is called a *tension leg platform (TLP)*. Advantages of a TLP include the following:

- The platform is completed in an onshore yard, while the wells may be drilled with a floating rig through a template. Once the platform is ready, it is floated to the location, where the legs are attached and the wells connected back to the platform. The time from the decision to develop the field to producing oil can be relatively short, as platform construction and drilling happens at the same time.
- After the field is abandoned, the platform can be untethered, removed, refurbished, and redeployed to another location or to a yard for disposal. The future cost to the industry of removing fixed platforms worldwide is likely to be huge, even if some of them can be toppled on site and left as artificial reefs to encourage fish stocks. The cost of removing a TLP will be much smaller than for a conventional fixed platform.
- A TLP platform could be installed in water as deep as 10,000 ft. This is far deeper than any fixed structure that could be used.

Submersible

Two types of submersible rig are used:

- A barge-type structure with a flat bottom, which is towed to a location in shallow, static water and sunk to sit on the bottom in up to about 20 ft of water. These rigs are also called *swamp barges*. The derrick can be adjusted to account for slight tilts caused by the bottom being at a slight gradient. These rig types are not common, with only about 12 operating worldwide.

- A structure similar to a lightly built semisubmersible, with columns and pontoons. The rig is floated to the location, where it takes on ballast to sink to the bottom in up to about 130 ft of water. The bottom has to be fairly level. Deck load capacity while moving is low, but once on bottom, this type of submersible can take on board a large weight of supplies. In the water depths that these rigs would operate in, a jackup type rig would also be able to operate well.

Rig Systems and Equipment

Dynamic positioning

With a drillship or semisubmersible rig, it is possible to station the rig above the well by dynamic positioning.

Underneath the rig are attached small propellers mounted on housings that swivel. On the sea bed, transponders are placed at known locations. *Transponders* are electronic devices that wait for a coded signal from an interrogating transmitter. When that signal is received, a reply is transmitted. The interrogating transmitter measures the time for the signal reply and, knowing the speed of the transmission wave, can calculate the distance from itself to the transponder. If four transponders are placed on the seabed a reasonable distance apart, the 3-D position of the interrogator in relation to the transponders can be calculated. The rig positioning system uses these transponders to keep a constantly updated rig position relative to the wellhead. If the rig starts to move away from above the wellhead, the positioning system computers control the thrusters to push the rig back to its defined position.

As described in chapter 4, a floating rig uses a blowout preventer on the seabed, and the rig connects to the top of the BOP with a riser pipe. Between the top of the BOP and the riser is a special joint that allows some angular movement between the riser and BOP. However, if this angle is exceeded (usually 5°), something will be damaged. If the rig moves outside a certain distance from vertically above the wellhead, a disconnect sequence has to be initiated. This sequence closes the BOP, cuts the drillpipe, and disconnects the upper part of the BOP, thus disconnecting the rig from the well. This disconnect sequence may also be used in an emergency if the rig has to move away from the well in a hurry.

High-pressure pumping equipment

While drilling, fluid is pumped down the drillstring and back up the annulus, as was discussed in chapter 3. Every rig has two or more pumps that together can pump mud at the required flow rates and pressures. Modern pumps are *triplex* (they have three cylinders), and fluid is only pumped when the piston moves forward into the cylinder (fig. 5–12). These pumps use reciprocating pistons with diameters up to around 6″ and piston strokes of up to around 12″, with maximum pump speeds of around 150 strokes per minute.

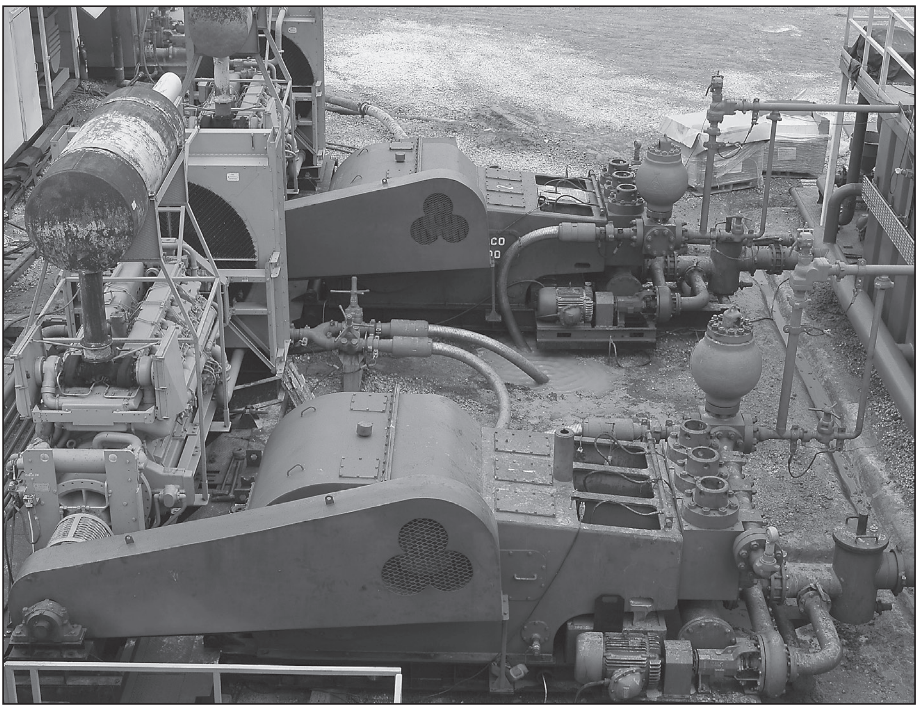


Fig. 5–12. Triplex mud pumps

At the start of the well, the requirement for output pressure is relatively low (below 1,000 psi). At the same time, the pumps must give a high flow rate; drilling the top hole section of perhaps 26″ will require flow rates in excess of 1,200 gal/min. As the well is deepened, the pressure requirement increases, but the volume requirement decreases. The pump cylinders and pistons can be changed, so that for higher pressures and lower flow rates, smaller cylinders and pistons can be fitted.

The power required for a given flow rate and pressure can be calculated. The formula for hydraulic horsepower is:

$$\text{Hydraulic horsepower (HHP)} = PQ \div 1{,}714$$

where

P is the pressure in psi, and

Q is the flow rate in gallons per minute.

For a given hydraulic horsepower, pressure is inversely proportional to flow rate; if the pressure doubles, the flow rate must halve for a given HHP. This is fortunate because if a pump is capable of producing a certain HHP at a certain pump speed, the maximum pump pressure can be increased by fitting smaller cylinders and pistons. This also lowers the maximum available flow rate.

The pump output flow is directed into a series of high-pressure pipes leading to the drill floor. On the drill floor is a manifold (called the *standpipe manifold*), which is a set of pipes and valves that allow the flow to be directed to different places (fig. 5–13). Normally while drilling, the standpipe manifold is set up to direct the flow down the drillstring. Also on the standpipe manifold are positioned pressure gauges that allow the driller to monitor the pump output pressure. This is very important to make sure that drilling continues efficiently and safely.

Fig. 5–13. Standpipe manifold on a land rig

Active mud system

The active mud system is a system of tanks, lines, pumps, and valves to facilitate circulation of mud around the well and through the solids control equipment. The solids control equipment is described in the following section.

The active system tanks have some means of allowing mud into the tank and also have a route out of the tank. As discussed earlier, drilling mud usually consists of a liquid (water or oil, or both) within which are suspended solids such as clays (for viscosity) and barite (for density control). (Barite is a naturally occurring mineral, $BaSO_4$, of high specific gravity [4.2] that is used as an additive in drilling fluids and cements to increase density.) Other solids materials will enter the mud from the well as drilling progresses. If the mud is allowed to stand in the tanks with little or no movement, solids will start to settle on the bottom of the tank. To avoid this, mud tanks are equipped with agitators. An agitator is simply a large paddle attached to an electric motor. As the motor turns the agitator, the mud is continually moved, and this reduces the tendency for solids to settle on the bottom. Usually the corners of a square or rectangular tank will still be relatively static, even with agitators in the tank, and solids will often settle out here.

Settling of solids in the bottom of tanks is detrimental. It reduces the effective volume of the tank. Solids settling will also reduce the density of the mud, and this will require treatment of the mud to restore the density. Settled solids can also plug pipes and valves in the bottom of the tank. At some point, the tank has to be emptied, and the sludge on the bottom dug out. It is better if agitation is sufficiently vigorous to reduce settling as much as possible.

It is crucial that the driller knows how much mud is in the active system and in particular is able to identify when the total volume increases or decreases. An increase in mud volume may indicate that fluid is entering the wellbore from a downhole formation (a kick); a decrease may mean that mud is being lost downhole. In either case, action must be taken. Each tank in the active system (as opposed to reserve tanks containing mud) must have a means of accurately measuring the volume in that tank in such a way that the driller can be alerted to any change in volume.

There are two common systems in use:

1. A float is attached to some kind of system that measures its position relative to the bottom of the tank. As the tank dimensions are known, the volume can be calculated from the height from the bottom of the tank to the float (fig. 5–14).

2. An ultrasonic detector is positioned above the tank. A sound signal is generated, and the time for the signal to bounce off the mud surface and return to the detector is measured. Knowing the speed of sound in air, the distance from a known point (the sound generator) to the detector via the mud surface can be calculated, and this can be converted to a volume for that particular tank.

The driller has an instrument, called the *pit volume totalizer*, that can display the volume in any particular tank and can also add up all of the surface active volumes so that any change in the total surface volume may be detected. The PVT also includes alarms that can be set so that changes beyond a set amount lost or gained will cause an alarm to sound.

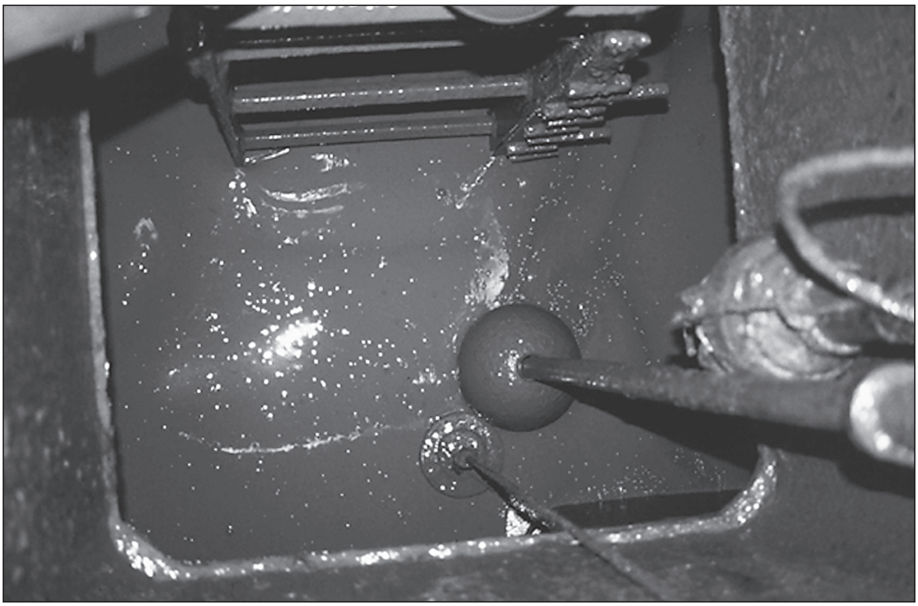


Fig. 5–14. Mud tank with float-type level indicator

Photo courtesy of Schlumberger.

Solids control equipment

When the drilling fluid leaves the annulus at surface during drilling, it contains rock particles of various sizes that have entered the mud either at the drill bit or after falling off the wall of the hole. If the solids control equipment does not work efficiently, some of these rock particles can be pumped back down the well, and these become ground up even smaller by mechanical action in the well. The smaller they are, the harder it is to remove these particles from the mud when it returns to the surface. Smaller particles also have a greater ability to negatively affect the physical properties of the mud, which then will need expensive chemical treatments to restore the desirable properties to drill efficiently.

The solids control equipment consists of a series of items to remove progressively smaller rock particles. The first and most important item of equipment that the mud passes through is called a *shale shaker*. The shale shakers are basically a set of vibrating mesh screens that filter out large rock particles and allow the liquid mud to fall through the screens to a tank below (fig. 5–15). These vibrating screens are designed so that solids filtered out of the mud move along the screen to the edge, where they fall off into a chute for disposal. Sometimes a screen will break or split or develop a hole, and then some of the drilled cuttings fall through with the mud into the tank below. It is very important that the drill crews are alert to damaged shale shaker screens. If large amounts of rock bypass the shakers, this will overload the other solids control equipment and cause problems all the way through the system. The screens are replaced if damaged.

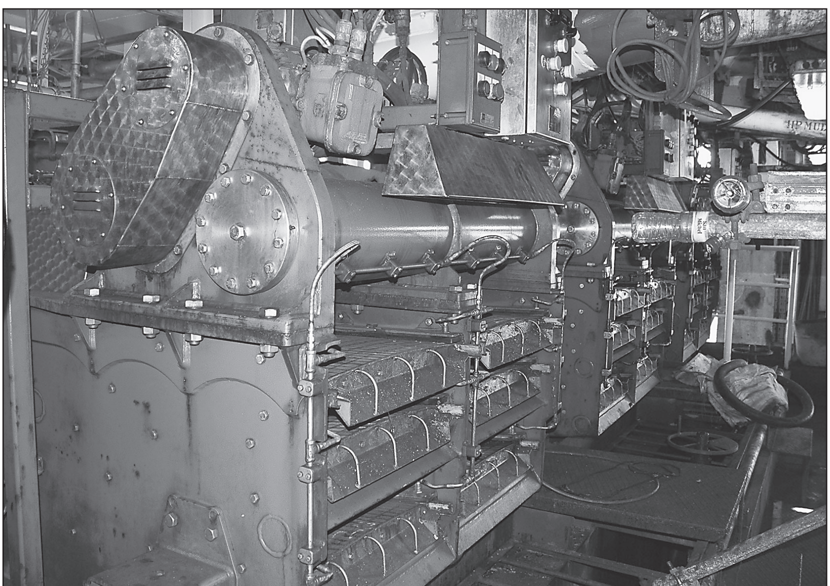


Fig. 5–15. Shale shakers

Next comes the sand trap. The sand trap is a tank that usually sits underneath the shale shakers. Flow from the shale shakers goes into the sand trap. The purpose of the sand trap is to give temporary protection to the rest of the system if a shale shaker screen splits. In this case, the larger solids will settle in the sand trap, and they can be later dumped through a large butterfly valve on the bottom of the sand trap.

Mud from the sand trap flows out at the top through a cutout in the top rim of the tank. The mud will then flow into another tank. This mud, having routed through the shale shakers and sand trap, will still contain smaller rock particles. This second tank will be used to feed a centrifugal pump that will pump the partially cleaned mud into a hydrocyclone system.

A hydrocyclone is a simple but ingenious bit of kit with no moving parts. It is comprised of a cone with a small hole at the bottom (narrow) end. At the top of the cone is an inlet pipe, positioned so that mud entering the cone does so in such a way that it swirls around the inside diameter. An outlet pipe exits upwards, but the bottom end of this pipe sticks into the top of the cone (see fig. 5–16).

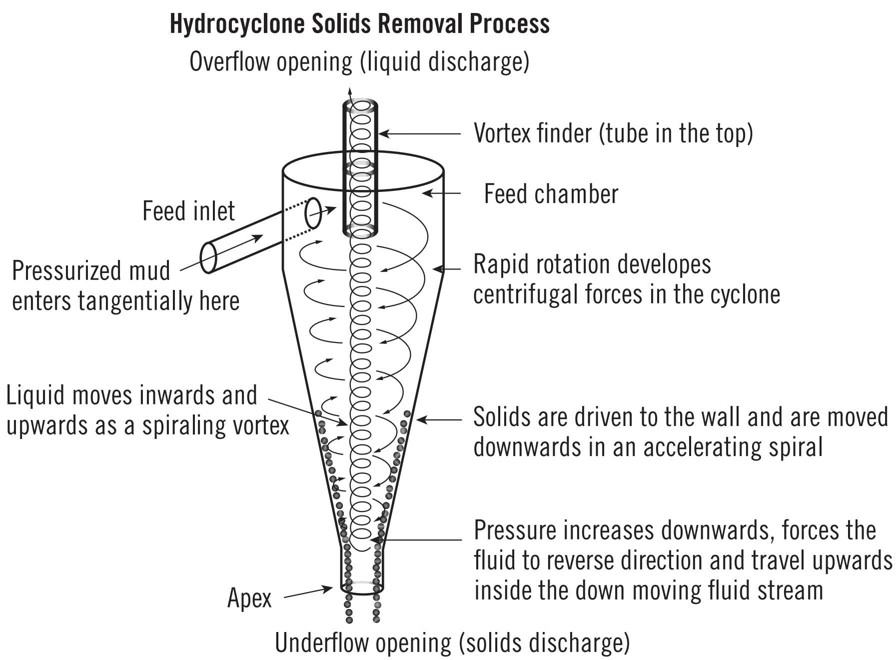


Fig. 5–16. Hydrocyclone—principle of operation

Picture courtesy of Baroid.

As mud moves round the inside of the cone top, it eventually comes back to the inlet pipe position, where more mud is coming in. This forces the mud stream downwards, into the cone. As the cone gets narrower, the fluid speed has to increase to accommodate the flow rate. Very high centrifugal forces are exerted on the fluid stream, so the heavier solids particles will move towards the outside of the fluid stream—moving towards the cone. As the fluid stream nears the bottom, pressure builds up to the point where the fluid changes direction and starts back upwards, spiralling up inside the descending mud, which stays close to the cone inside surface. The solids particles, being heavier, cannot change direction so readily and are ejected at the bottom of the cone. The cleaned mud stream exits at the top of the cone, out of the overflow opening.

All of this happens very quickly—it will take only about 1/6 of a second from the mud entering the cone at the inlet to it exiting at the overflow.

Larger cones process larger volumes of mud and remove larger particles. Smaller cones process smaller volumes (per cone) but can remove finer particles. Most rigs will have a set of 3 or 4 large cones, around 12″ diameter at the top. These are called *desanders* because they remove particles of sand grain size. Most rigs will also have a set of perhaps 16 or 20 small cones, 4″ diameter at the top. These are called *desilters* because they remove particles of silt grain size (fig. 5–17).

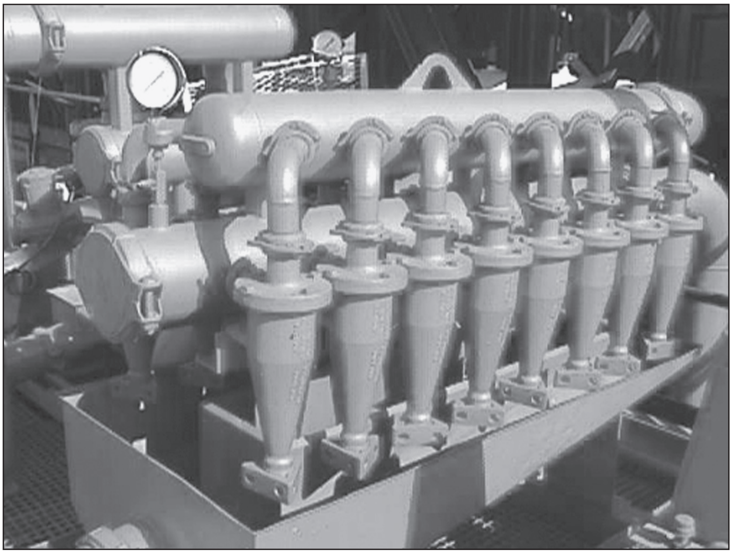


Fig. 5–17. A bank of 4″ desilter hydrocyclones

So far, the mud has been processed by the shale shakers, sandtrap, desanders, and desilters—each stage removing progressively finer particles. If it is felt necessary to remove even smaller particles, a centrifuge (or several centrifuges) may be used. The cleaned mud ends up in the mud pump suction tank, from where the mud pumps circulate mud around the well again.

Hoisting equipment

The most visible part of a drilling rig is the *derrick*, or the mast that is around 140 ft taller than the drill floor. The derrick has a set of sheaves on the top, over which steel rope can pass.

The sheaves at the top of the derrick are called the *crown block*. These sheaves support loops of steel rope that pass through sheaves on the traveling block.

The drawworks drum is usually powered by one or more DC electric motors. As the drawworks reel in the block line onto the drum, the traveling block moves up the derrick (fig. 5–18). The drawworks drum is also controlled by a braking system. To lower the traveling block, the brake is released, and the weight of the traveling block and any load under it will move the block downwards and unreel rope from the drum. The brake is used to control the speed of movement. By this means, the rig can pick up or lower pipe in the well with very fine control of movement and force.

At the deadline end of the block line is a *sensator*, or a tool that measures physical force and transmits this information to an instrument or control system. The sensator measures the pull on the wire rope. This is connected to a large dial with hands that indicate the weight of traveling block and any load held under it. This instrument, called the *weight indicator*, must be calibrated for the number of times that the line loops around the crown block.

The weight indicator is one of the most important instruments that the driller has in front of him at his controls. Every operation involving control of the traveling block is monitored on the weight indicator, which is why it is so large. It is the largest instrument face on the panel.

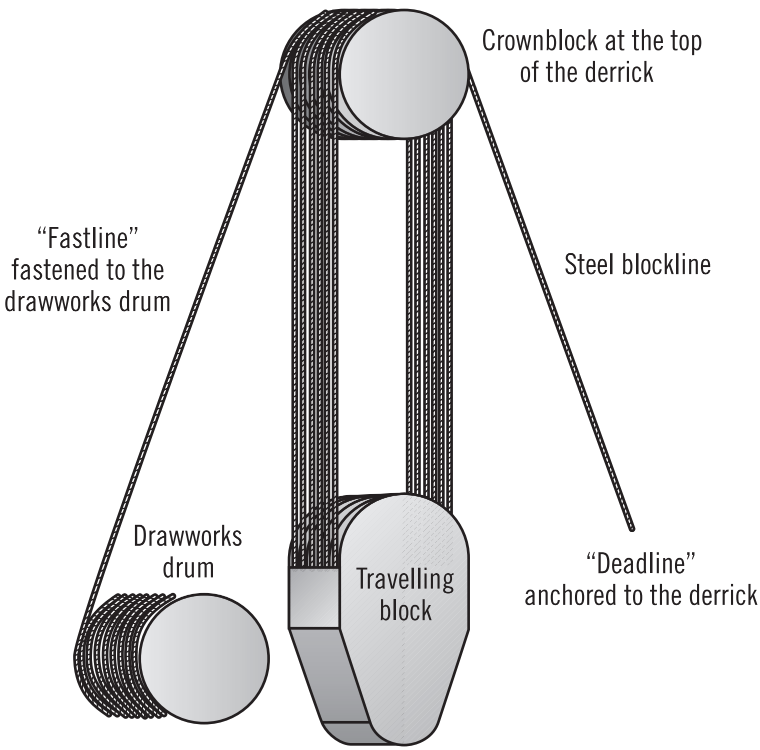


Fig. 5–18. Hoisting system schematic

Rotary equipment

As well as controlling movement of the drillstring up and down, it is necessary to be able to rotate the drillstring. There are several ways of achieving this rotary movement.

At the top of the rig substructure and the bottom of the derrick is a platform called the drill floor, as explained previously. This is where the rig crew works most of the time while tripping pipe in or out of the hole, drilling, logging, and for most other operations (fig. 5–19). Somewhere in the middle of the drill floor, directly underneath the crown and traveling blocks, is a piece of equipment called the rotary table (fig. 5–20).

Fig. 5–19. Driller at the rig floor controls

Photo courtesy of Schlumberger.

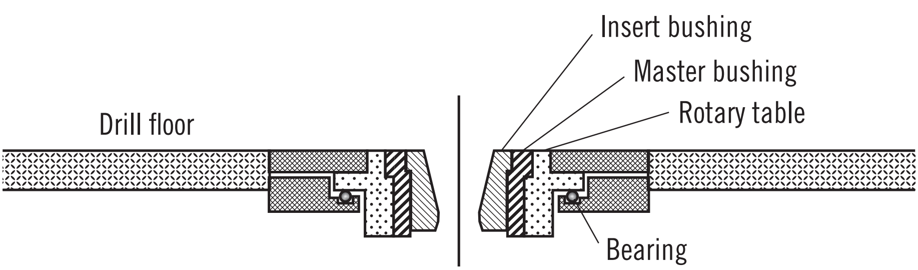


Fig. 5–20. Section through the rotary table

The rotary table assembly is comprised of a steel housing with an electric motor, gearbox, and power train underneath. This motor and transmission system is connected to a hollow steel cylinder (the rotary table), which can then rotate. Bearings underneath support the load of the rotary table and anything supported inside it.

The rotary table has another cylinder, called the *master bushing*, placed inside it, and this in turn can accommodate different sizes of sleeves that adjust the size of the hole in the center. These sleeves, called *insert* *bushings*, have a tapered profile inside (see fig. 5–20). This taper allows the drillstring to be suspended in the rotary table by using wedge-shaped tools called *slips* (described in the section on drillpipe handling tools later in the chapter).

On top of the master bushing are four holes spaced 90° apart. These drive holes allow torque to be transmitted to the drillstring by using a special square or hexagonal section pipe called a *kelly*.

During drilling, the kelly (suspended from the traveling block) is screwed on top of the drillstring. Steel rollers fit on the square or hexagonal faces, and these rollers are in a steel cage that has four pins underneath. These drive pins locate in the holes of the rotary table and thus allow torque to be transmitted from the rotary table to the kelly and subsequently to the drillstring (fig. 5–21).

Fig. 5–21. Drill floor and rotary table with the drillstring hanging in slips

Photo courtesy of Schlumberger.

With more modern rigs, rotary movement and torque is transmitted to the drillstring directly from a motor and transmission system that is suspended from the traveling block. This is called a *top drive*. It may be electrically or hydraulically powered. If a rig is fitted with a top drive, it will still have a rotary table because sometimes rotation is needed from the drill floor to manipulate tools directly when the top drive cannot be used. Also if the top drive should fail, the rotary table and kelly can be used while the top drive undergoes repair.

Drillpipe

The drillpipe represents a large investment for the drilling contractor. Drillpipe comes in various sizes; probably the most common size worldwide is 5″ outside diameter (OD) pipe that has an inside diameter of 4.276″ and comes in joints of about 31 ft long. The ends of a joint of drillpipe have welded onto them a piece of thick-walled pipe on which threaded connections are machined. Joints of pipe are screwed together using these connections. Two of the basic characteristics of drillpipe that identify the pipe are the OD and the type of connection.

Drillpipe is not only specified by OD and connection but also by the type of steel used to make the pipe. In the oil field, steel used in making downhole tubulars comes in various grades, which are defined by characteristics such as carbon content of the steel, amounts of impurities, and heat treatment. For drillers, one of the most important properties of the steel is the strength—how much force can be applied to the pipe before it fails.

There are several grades in common use (though other grades are available), such as E75, X95, G105, and S135.

The number part of the grade refers to the minimum yield strength of the steel, in thousands of pounds per square inch. The minimum yield strength is arrived at by testing a sample of the steel in tension and measuring at what force the material increases in length by a set percentage. For normal strength steel, E75, the minimum yield is found at the point when the sample has increased in length by 0.5% and the minimum yield stress is 75,000 psi. For higher strength steels, it is more; grade G105 is 0.6%, and grade S135 is 0.7% stretch, to give 105,000 and 135,000 psi, respectively.

If the minimum yield strength of the material and the cross-sectional area of the pipe are known, the strength can be calculated. For instance, for 5″ grade E drillpipe, when new, the cross-sectional area at an inside diameter of 4.276″ is 5.274 in^2. If this is multiplied by the minimum yield of 75,000 lb, the maximum force that can be applied to the drillpipe is 395,595 lb. Higher strength pipe has a correspondingly higher maximum force.

When used for drilling, drillpipe is subjected to wear. As it is rotated, parts of the pipe will touch the wall of the hole and the inside of the casing. As drillpipe wears, the thickness of the pipe wall (and hence the cross-sectional area) also decrease, and so the strength of the drillpipe decreases. To allow for this, drillpipe is given a classification that relates to the degree of wear. New pipe is just that— it is within the original manufacturer's tolerances. Next comes premium pipe, which has up to 20% uniform wear on the thickness at the OD. Two other classifications are class II and class III, but these are rarely used except in drilling very shallow wells or water wells.

Apart from transmitting torque to the drilling assembly and physically supporting the weight of the entire string of pipe, the drillpipe also has to withstand very high pressures from the inside. While drilling deep wells, the pressure at the surface could exceed 3,000 psi, which the drillstring has to be able to withstand.

To specify a particular pipe to use, a drilling engineer has to state the size (OD), grade (of steel), connection type, and classification.

Drillpipe handling equipment

There are three particular items of equipment that are used on a rig to work with drillpipe: the slips, elevators, and tongs.

The slips are wedge-shaped pieces of steel that fit inside the insert bushing. The angle of the outside matches the inner profile of the bushings. The slips have steel teeth on the inside face that grip the drillpipe. The more weight is applied to the teeth of the slips, the more the slips are forced down the tapered profile, and the tighter they grip the drillpipe (fig. 5–22). In this way, the drill crew can easily hang the entire weight of the drillstring (hundreds of thousands of pounds of weight in a deeper well) in the rotary table using the slips. This is necessary when tripping into or out of the hole to allow connections to be screwed together or unscrewed.

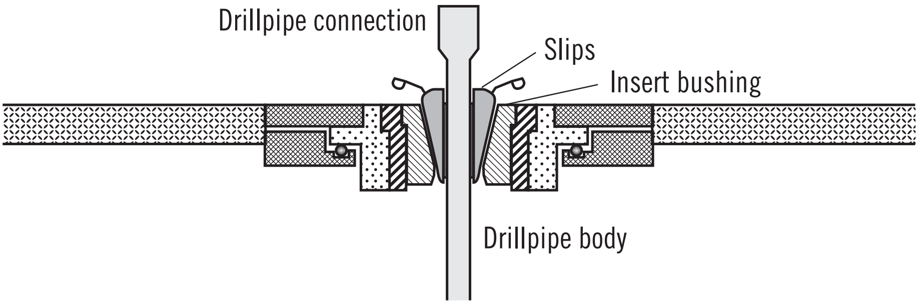


Fig. 5–22. Drillpipe suspended in the rotary table using slips

Different designs of slips are used to suspend other tubulars in the rotary table. When running casing or screwing drill collars together, different sizes and types of slips are used. It may also be necessary to remove the insert bushings for drillpipe and place bushings of a larger ID into the master bushing to accommodate larger pipe.

As can be seen from figure 5–22, a drillpipe connection has a larger OD than the pipe body. Underneath the connection is a tapered section, which offers a smooth transition between sizes. On modern drillpipe, this taper has an angle of 18°. To lift up the drillstring, a tool called an *elevator* wraps around the drillpipe body, and the inside of the elevator has an 18° taper that matches the taper on the drillpipe connection. Elevators are made in two halves, with a hinge at one side and a latch at the opposite side (fig. 5–23). To close the elevator around the drillpipe, it is lowered alongside the pipe (suspended from the traveling block), and the two halves are hinged together under the connection taper. The latch closes as the halves come together and locks it shut.

The slips are used to suspend the drillpipe at the rotary table, and the elevators are used to pick up the pipe with the traveling block. The tongs are used to tighten the drillpipe connections.

At the top end of the drillpipe is a threaded female connection, called the *box*. At the bottom end (as normally run into the well) is a threaded male connection, called the *pin*. When drillpipe is screwed together, the pin is placed inside the box, and the upper pipe is turned clockwise to screw the pin into the box. Normally this is done with a pneumatic tool that rotates the pipe. Once the two halves of the connection have come together, it is necessary to tighten them up fairly accurately to within a specified torque range. Drillpipe will normally be torqued up to around 24,000 foot-pounds (ft-lb); large drillcollar torques may be in the range of 65,000 ft-lb to 75,000 ft-lb.

Two tongs are used; one is placed on the box OD and the other on the pin. The box end tong (called the *backup tong* because it backs up the box while the pin moves) is fastened with a length of wire rope to a strong point on the rig floor. The pin end tong (called the *makeup tong* because it is the one that makes up the connection) has a tension sensator attached to it, which measures the pull on a chain that the driller uses to exert a large force on the end of the tong. This chain, the *makeup chain*, is powered by the same electric motor that powers the drawworks.

Torque is expressed as a force multiplied by the length of a lever or arm, hence the term *foot-pounds*. A normal rig tong has a 4 ft arm, and to exert a torque of 24,000 ft-lb requires a pull of 6,000 lb.

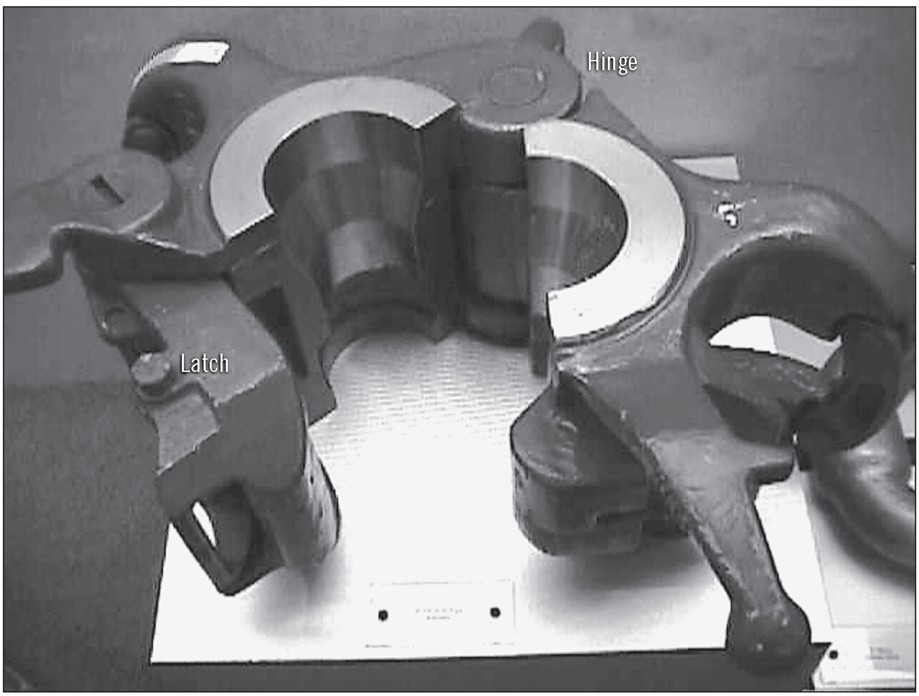


Fig. 5–23. A 5″ drillpipe elevator, open

Summary

This chapter discussed rig selection for particular wells and described some of the different types of rigs available. Major items of rig equipment and their operating principles were covered in sufficient detail for the operating principles to be understood.

6

DRILL BITS

Overview

This chapter will describe the basic classifications of drill bits and the major design features of each type. The process of bit selection, which is actually quite complicated if done properly, will be outlined in sufficient detail to show the main considerations involved. It will hopefully give an accurate impression of the complexity of bit selection and how critical this is to operational economics.

Drill bits can be separated into two major categories: roller cone bits and fixed cutter bits (figs. 6–1 and 6–2).

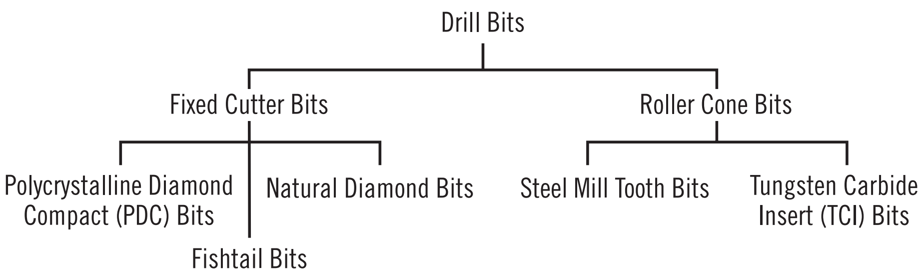


Fig. 6–1. Types of drill bits

Roller Cone Bits

Roller cone bits have one, two, or three cones that have teeth sticking out of them. These cones roll across the bottom of the hole, and the teeth press against the formation with enough pressure to exceed the compressive strength of the rock. Roller cone bits can handle rougher drilling conditions than modern fixed cutter bits, and they are also a lot less expensive. On a relatively cheap drilling operation (land rig), it is usually more economical to use roller cone bits except in the smaller hole sizes (8½″ or smaller).

Roller cone bits are available with steel teeth milled from the same block of metal as the cones. These are called *steel tooth bits* or *mill tooth bits*. The other type of roller cone bit consists of steel cones fitted with teeth made of tungsten carbide, which are fitted into holes drilled into the cone surface. Mill tooth bits are very robust and will tolerate severe drilling conditions, but they wear out relatively quickly. Tungsten carbide tooth bits will not tolerate shock loadings but can drill for long distances before wearing out. Of the two types, tungsten carbide teeth bits are more expensive than the same size of steel tooth bit, all else being the same.

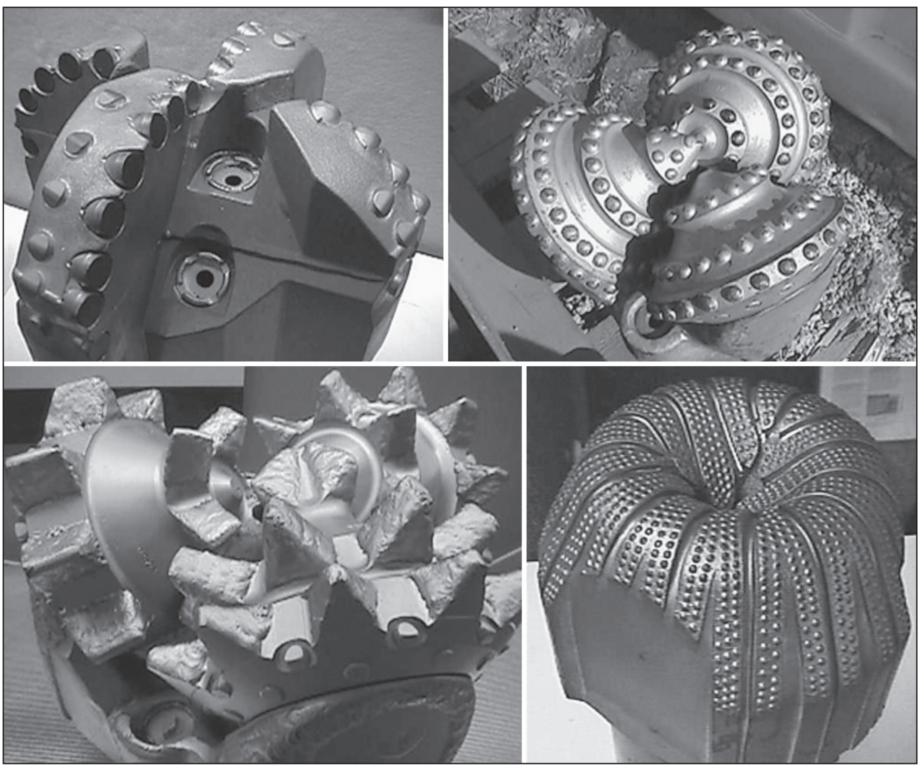


Fig. 6–2. Selection of bits (clockwise from top left): PDC bit, TCI bit, natural diamond bit, and mill tooth bit.

Recently the technology was developed that allows tungsten carbide teeth to be coated with a layer of diamond. This can significantly increase the useful life of a TCI bit in abrasive rock.

The outside cutters on a roller cone bit cut at the outside diameter of the hole. These cutters, called *gauge cutters*, are especially vulnerable to wear, and if drilling in an abrasive sandstone, these outer teeth lose material and cause the hole to be drilled undergauge. (As previously explained, underguage refers to a less-than-normal bit diameter. For example, if a 12¼″ drill bit wears at the outer edge, and as a result, drills a 12″ hole, the hole is considered undergauge because it is less than the unworn (new) bit diameter.

Fixed Cutter Bits

Fixed cutter bits are divided into diamond bits and polycrystalline diamond compact (PDC) bits (fig. 6–3). Fixed cutter bits have no moving parts, so they can drill for a long time as there are no bearings to wear out, only the cutting surfaces.

Diamond bits drill by wearing out the rock under the bit, producing very small cuttings called *rock flour*. Although diamond bits can drill the hardest rock, they drill slowly and are very expensive. Diamond bits are generally used in the formations with the highest compressive strength or in formations that are very abrasive and thus would destroy other bit types too quickly.

The diamonds used in these bits are normally naturally occurring industrial-grade diamonds.

PDC bits drill with a disk of diamond mounted on a tungsten carbide stud. The cutting action is similar to a lathe tool cutting steel. In the right conditions, they can drill very fast (over 100 ft/hr) for great distances (thousands of feet). They are quite costly, especially large ones.

PDC bits may be constructed from a machined steel body, where the tungsten carbide studs are mounted on steel pegs that fit into holes machined in the body. They may also be constructed from molded tungsten carbide; these are called *matrix body bits*. As always, there are trade-offs; steel bodies are cheaper to produce than matrix bodies, but matrix bodies are harder wearing and can be produced in complex shapes more easily.

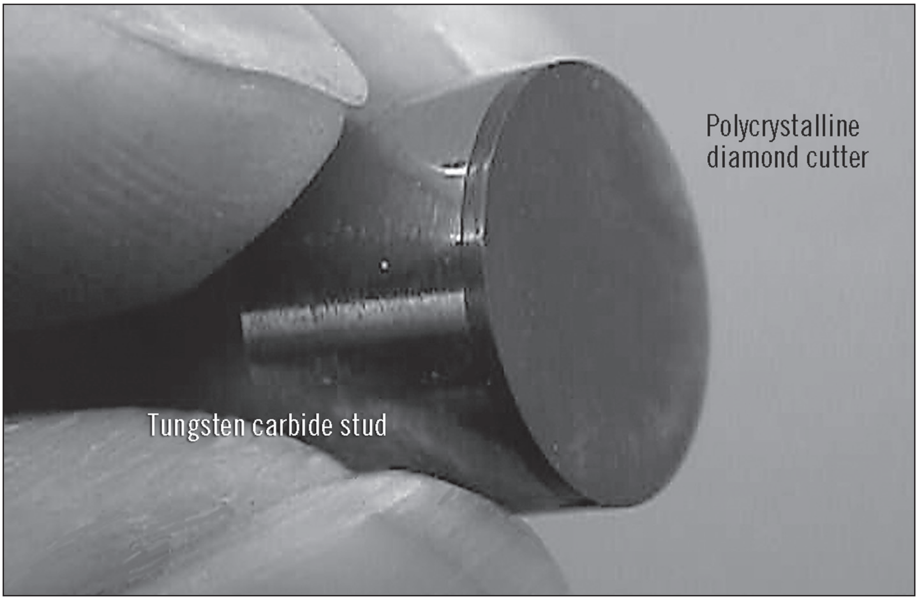


Fig. 6–3. PDC cutter

PDC and diamond bits are made in many different shapes. The shape of a bit will influence whether the bit can be easily made to drill directionally or whether it will tend to drill straight ahead. The shape also affects how many cutters can be mounted on the bit (due to the different surface area). Examples of two extremes are shown in figure 6–4. The bit to the left has cutters mounted on the side. Combined with its slightly concave, almost flat profile, this bit cuts sideways easily. The parabolic profile bit on the right will be much more stable directionally.

One other type of fixed cutter bit should be mentioned. In the early days of the oil well drilling industry, the drill bit was made from steel and was resharpened at the wellsite by a blacksmith. These bits resemble a fish's tail when viewed from the side and thus were called *fishtail bits* (see fig. 6–5). They work by scraping the rock and were only suitable for soft formations. It was not until the advent of the roller cone drill bit (invented by Howard Hughes and patented in 1909) that the capability of drill bits extended to drilling at greater depths and harder rock.

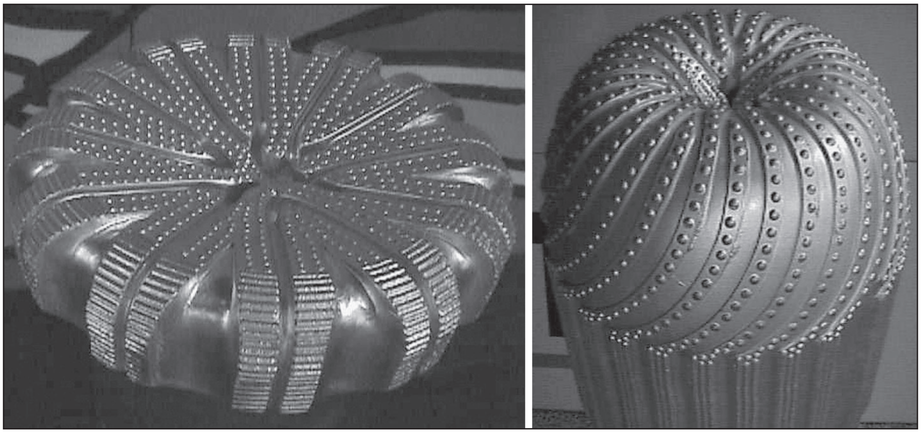


Fig. 6–4. Bit profiles (diamond bits)

Fig. 6–5. Fishtail bit

Core Bits

Core bits cut a doughnut-shaped hole, leaving a column of rock sticking up the middle of the bit (fig. 6–6). Behind the bit is a special tube that holds this core of rock and recovers it to the surface.

Core bits were mainly diamond bits, though some core bits were made with a ring of small roller cones and steel teeth. Since PDC bits were invented, core bits are now predominantly PDC designs, with natural diamond core bits being used for very hard, abrasive formations.

Core bits often drill faster in the same formation than equivalent regular bit designs. This may be because they have less rock to cut.

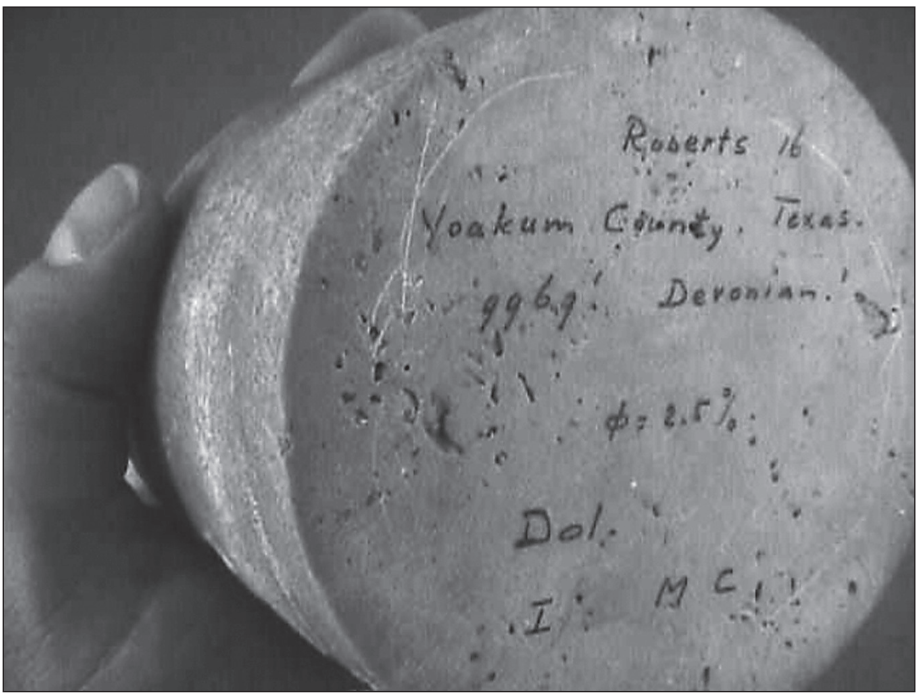


Fig. 6–6. Rock core sample

Optimizing Drilling Parameters

As the bit drills, it starts to wear out. The teeth that cut into the formation in order to drill will wear. The bearings that allow the cutting cones to turn will wear. The more weight put on the bit, and the faster it turns, the greater the rate of wear. Also (up to a point), the faster it drills. As the bit wears out, it will not drill as efficiently, and the rate of penetration (ROP) will decrease. (The rate of penetration is the speed at which the bit drills, usually measured in feet per hour or meters per hour.) Eventually the bit slows down so much that it is not economic to leave it drilling any longer, so it is pulled out of the hole and changed for another one.

The faster a well can be drilled, the cheaper it is. Time-related costs on a drilling operation are high (up to $950,000 a day on a modern generation floating rig offshore; a land operation probably costs more like $80,000 a day). In general, to drill faster, the weight on bit (WOB) and the rotary speed (revolutions per minute, abbreviated to RPM) can be increased. Increasing either or both of these parameters also increases the rate of wear. So it is very important that the driller can find the optimum set of drilling parameters to achieve a good rate of penetration and a moderate rate of wear.

If the WOB is increased, the teeth penetrate deeper into the formation and create larger cuttings. However, there is a point beyond which increasing the WOB does not increase the ROP. This can be because the teeth fully penetrate the formation, and the formation then touches parts of the bit that do not drill. It could also be that at the RPM used, the teeth do not have time to penetrate further before they get pulled out again as the bit rotates. So the driller can keep a constant RPM and increase the WOB a little at a time, each time measuring the ROP. Eventually he can recognize the point at which increasing WOB does not significantly improve performance.

If the RPM increases, a tooth penetrates the formation more times in a minute. However, there is a point beyond which increasing the RPM does not increase ROP. This is because the teeth do not have time to penetrate as much as the WOB would otherwise allow. So by first establishing the optimum WOB, and then holding that constant while increasing the RPM, the driller can find the best combination of WOB and RPM with which to drill. In general, drilling economics are improved by drilling as fast as possible (but within the constraints that other factors might place on ROP) while not exceeding the optimum drilling parameters so that the bit drills for a reasonable time.

The procedure for optimizing the drilling parameters is called a *drilloff test*.

Effect of mud hydrostatic pressure on ROP

Normally, the hydrostatic pressure of the mud is greater than the formation pore pressure. This is deliberate to maintain control of the well. This overpressure gives rise to a condition known as *chip hold down*.

As a tooth penetrates into the formation, a chip of rock is dislodged. Underneath the chip is the native formation pore pressure, and above it is mud hydrostatic pressure. This pressure differential tends to hold the chip in place. If this happens and the chip's departure from the bottom is delayed by a small fraction of a second, the next tooth down may hit the chip instead of virgin rock. The overall effect is to slow the progress of the bit. In practice, with tricone drill bits, it can be seen that there is in fact a strong correlation between mud overbalance and rate of penetration.

This phenomenon can be turned to advantage. If the bit penetrates a region where pore pressures start to increase, the rate of penetration will also increase. As the natural tendency of a bit in a particular formation is to decrease the rate of penetration with depth, an increase (unless explained by a change in lithology) is one signal that a kick might be imminent, and it should be investigated.

PDC bits are less affected by chip hold down. Thus, in exploration wells, tricone bits are preferable so that changes in the pore pressure regime can be identified.

Effect of mud solids content on ROP

A low solids content mud will give a better rate of penetration in a similar fashion to low mud overbalance. The reason is not clear, but it is speculated that the mud solids may slow down the equalization of pressure under the chip. With a solids-free system, the drilling fluid can more easily penetrate past the chip to reduce the hold down effect.

Drilling Hydraulics

Most drill bits incorporate nozzles, which direct the flow of drilling fluid so as to efficiently clean cuttings from the bottom of the hole and from the cutting structure. If cuttings are not moved away from the bottom quickly, the cutting structure may end up cutting on cuttings, which reduces the ability to cut virgin rock. These nozzles fit into holes (called *nozzle pockets*) on the bottom of the drill bit (fig. 6–7). This allows the drillers to be able to select nozzles with different inside diameters. A smaller diameter nozzle will increase the speed that mud flows through it (for a given flow rate). If the mud flows faster through the nozzle, it will expend more energy at the bottom of the hole, which may give greater drilling penetration.

Fig. 6–7. PDC bit showing nozzles

The rate of penetration of any drill bit is limited by the ability of the mud to clean the bottom of the hole. Up to a point, increasing the flow rate and increasing the speed with which the mud flow hits bottom will increase the rate of penetration. In softer formations, this force can be sufficient to remove rock by hydraulic force. Unfortunately, this often causes an overgauge hole to be drilled as rock is eroded from the gauge area of the bit.

Grading the Dull Bit

When a bit is pulled out of the hole after drilling, it is referred to as being *dull* (as opposed to *sharp*). The dull bit will have various features caused by downhole conditions encountered by the bit. If these features are properly recognized, together with information recorded while drilling, an accurate picture of downhole conditions can be built up. This then allows a better choice of bit to be made for the same depth in the next well to be drilled. These drilling records and dull bit analyses (called *dull bit gradings*) are therefore very important to improving future performance. It is also important to properly grade the bit in order for the next bit in the hole to be properly selected and run.

For instance, tungsten carbide teeth are quite brittle, so they can break when shock loads are encountered (fig. 6–8). If a dull TCI bit has a high proportion of broken teeth, one possible cause may be excessive vibration of the drillstring while drilling. Other causes could be hitting the bottom of the hole too hard with the bit, excessive drilling parameters (high WOB and high RPM at the same time), or some steel junk in the hole. If tungsten carbide teeth are not properly cooled due to insufficient flow rate or clogging up of the bit with formation cuttings, they go through many cycles of heating and cooling as the bit rotates. This causes cracking of the teeth (called *heat checking*), and it also leads to broken teeth. It is very important that the true cause of these broken teeth is established before decisions are made on the next bit to run in the same well and at the same depth in the next well.

Dull bit gradings are recorded using a standard system of letters and numbers. There are eight characteristics that are noted under this system. Four relate to the cutting structure, one relates to the bearings, one to the wear of the bit gauge, one to any other dull features, and the last shows why the bit was pulled out of the hole.

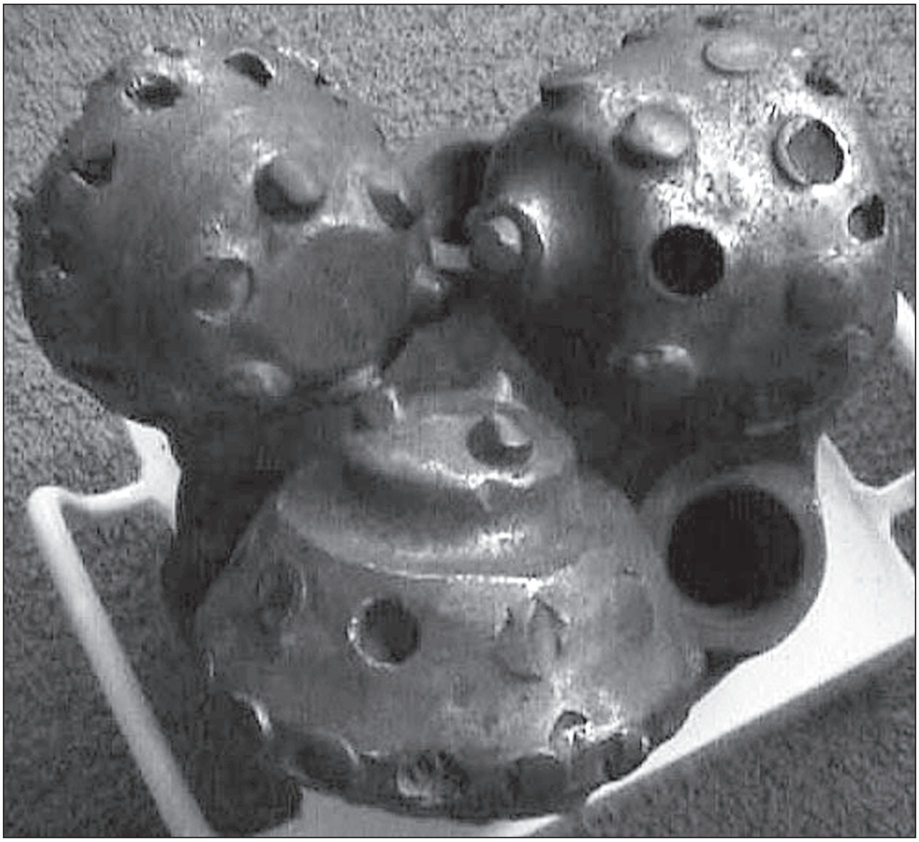


Fig. 6–8. Broken TCI cutters

One problem with dull bit grading is that different people will tend to give slightly different gradings to the same bit. This is mostly because some do not properly recognize the important dull features. It is a very good idea for all dull bits to be photographed, and the photo kept in the files relating to the well, so that questions about the grading later on might be resolved.

Bit Selection

There are many different drill bits to choose from. Good bit selection is vital to achieve the best drilling performance and therefore to reduce the cost of drilling.

The most important source of data for analysis is the drilling records of other wells in the vicinity. The performance of other bits that have drilled through the same formations in other wells shows what particular bit features are important and which should be avoided or are not needed. Dull bit gradings are especially important, but to see the full story, it is also important to be able to analyze the drilling performance (rate of penetration) and the drilling parameters (WOB, RPM, and flow rate) for each foot drilled. This takes some time to complete, especially if there are a lot of wells to analyze, but the work will be amply repaid in optimized performance.

Electric log data can also contribute to bit selection. Sonic logs (which measure the speed of sound through the formations) can be interpreted to give rock compressive strengths, which clearly help in bit selection. Gamma ray logs analyze clay content and may indicate the best size of PDC cutters to use if PDC bits can be economically run.

If a directional well is drilled, bits that resist a change of wellbore direction should be used in the straight sections. Bits that do give some side cutting action can be run over the hole sections where a change of direction is required.

On exploration wells where pore pressures are poorly known, it is better to avoid PDC bits because it is important to recognize changes in pore pressure while drilling. As PDC bits are less sensitive to pore pressure changes, predictions are better with tricone bits.

In deeper, small-diameter holes, PDC bits start to give some significant advantages as they have no moving parts. Small roller cone bits have small bearings and the bearing condition, usually monitored by watching torque while drilling, cannot be monitored properly due to the high torque from the long hole. The cost difference between small PDC bits and small roller cone bits is also relatively small, certainly when compared to the larger bit diameters.

In the end, bit selection is an economic decision: Which bits are most likely to drill to the next casing, logging, or coring point for the least overall cost?

Drillbit Economics

If a bit is used past the end of its economic life, the rate of wear accelerates, and eventually parts of roller cone bits might drop off in the hole. This is a problem that will cost a lot of money to solve because special tools have to be used to recover the bits of junk from the hole before drilling can resume. This is called *fishing*, which can be defined as "a set of activities to remove unwanted material from the wellbore before normal operations may resume." Fishing is discussed in more detail in chapter 13, "Drilling Problems and Solutions." The economic life of a drill bit is measured by calculating how many dollars are spent to drill the distance drilled with that bit. This calculation is repeated frequently as drilling continues. Within the economic life, the cost per foot (or cost per meter) decreases. Eventually the cost per foot starts to increase. This indicates the end of the economic life of that drill bit.

The cost per foot is calculated by adding together the cost of the bit and the cost of the time spent so far during that bit run (dollars per hourly rig operating cost × hours), and this figure is divided by the distance drilled:

$$\text{Cost per Foot} = \frac{\text{Bit cost \$} + (\text{tripping hours} \times \$1500) + (\text{drilling hours} \times \$1500)}{\text{Feet drilled}}$$

The time starts when the new bit is screwed onto the BHA, and it includes the time taken to run it in the hole. The estimated time to pull out of the hole at the end of the bit run is also added.

Assuming the hourly operating cost is $1,500, with a low-cost rig (e.g., a land rig) and a high-cost drill bit (e.g., large PDC bit), the bit would have to drill extremely fast and for a long time if the economics were to compare favorably with a roller cone bit. The dominant factor in this case is the bit cost. However, with a high-cost rig (latest generation semisubmersible in a high-cost area like the North Sea), a high-cost bit is justified if it drills fast and stays drilling for a long time.

Sometimes the bit is pulled out before the minimum cost per foot is seen. This happens if conditions indicate that the drill bit is damaged, if casing point is reached, or if logging is required before the next casing depth. There may be many reasons why the bit run might terminate early.

Leaving the bit in after cost per foot starts to increase should seldom, if ever, be done.

Summary

All major types of drill bits were discussed in this chapter. The relative advantages and disadvantages of each were covered, demonstrating the many factors that have to be considered when deciding which drill bit to use and what drilling parameters to recommend. Drilloff tests, drilling hydraulics, and grading the dull bit were described. Drillbit economics and how to calculate the end of the economic life of a bit were examined.

7

DRILLING FLUIDS

Overview

A drilling fluid is a combination of liquids, solids, and sometimes gases that is pumped around the well.

The drilling fluid plays many functions in drilling wells. If the mud properties (physical, chemical, and rheological) are incorrect, safety and economics are affected. (Rheology refers to the study of fluids in motion, and rheological properties such as viscosity can impact several key mud functions.) Properly designed drilling fluid is essential to safe, efficient, and economic drilling. It is also not well understood by nonspecialists. In some companies, the relationship between the quality of the mud and the final result is ignored simply in order to find the cheapest, rather than the most appropriate, mud system. This likely leads to a higher overall cost of the well and possibly lower productivity, too.

Functions of the Drilling Fluid

The drilling fluid has to carry out all of the functions listed here at some point in every well drilled:

- Control formation pore pressures to assure proper well control.
- Minimize drilling damage to the reservoir. (This damage reduces the amount of oil or gas that can flow out of the well.)
- Stabilize the wellbore so that the hole diameter remains equal to bit diameter, or at least minimizes hole enlargement.
- Remove cuttings from under the bit while drilling.

- Carry drilled cuttings to the surface while circulating.
- Suspend the cuttings to prevent them falling back down the hole when pumping stops.
- Release the drilled solids at the surface so that clean mud can be returned downhole.
- Keep the bit cool.
- Provide lubrication to the bit and drillstring.
- Allow circulation and pipe movement without causing formations to fracture.
- Absorb contaminants from downhole formations and handle the difference between surface and downhole temperatures, all without causing serious degradation of mud properties.

To perform all these functions requires characteristics that may sometimes be contradictory. This requires the best overall compromise to balance the various needs.

Basic Mud Classifications

Drilling fluids can be divided into seven major classifications, depending on the continuous phase fluid and the type and condition of the major additive within the continuous phase. (As defined in the Dowell Drilling Fluids Technical Manual [1994], the continuous phase of a drilling fluid is the main component of the system, the carrying phase into which everything else is mixed.)

1. Fluids with water as the continuous phase (fig. 7–1), and with clays present dispersed throughout the water ("dispersed water-based muds").
2. Fluids with water as the continuous phase and with clays present inhibited from dispersing throughout the water ("nondispersed water-based muds").
3. Clear fluid systems based on water with soluble salts used to control density ("solids free" systems or "brines"). Brines may include acid soluble solids that can be removed from the reservoir face by circulating acid past the reservoir.

4. Fluids with oil as the continuous phase and less than 10% water by volume, with any water forming an emulsion of water within the oil ("oil muds").
5. Fluids with oil as the continuous phase and more than 10% water by volume, with the water forming an emulsion of water within the oil ("invert oil emulsion muds").
6. Fluids with air as the continuous phase ("air drilling").
7. Water-based systems incorporating air present in gaseous form within a liquid ("aerated" and "foamed" systems).

Each of these types will be briefly described. Their particular properties and uses will then be covered.

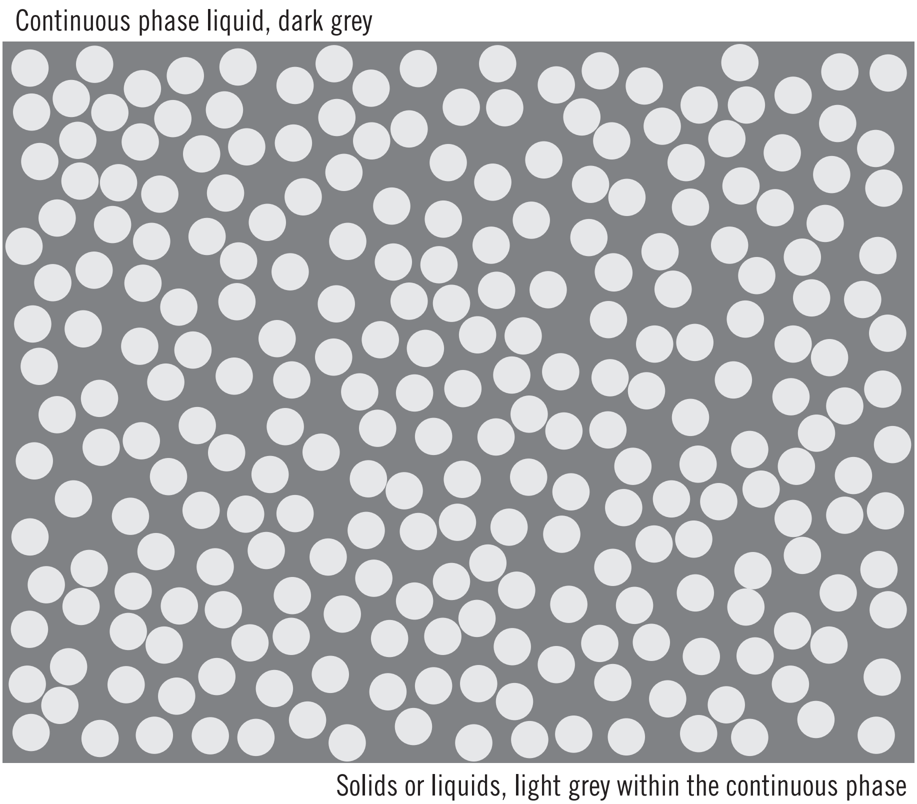
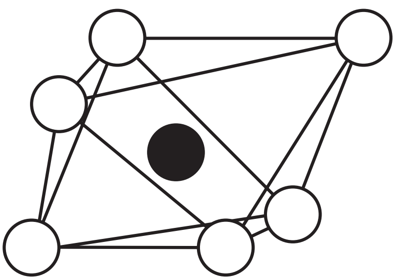


Fig. 7–1. Continuous phase

Dispersed muds

In the first part of chapter 1, clay mineral types and clay hydration were discussed. Some clays react strongly with water (they hydrate) and will expand in the presence of water. Water that is allowed to enter the crystal structure can cause the crystal lattice to expand because of changes in electrostatic forces. This expansion is described as dispersion. Water molecules are polar; that is, the water molecule, while being electrically neutral overall, has positively and negatively charged areas in different parts of the molecule. The polar nature of water can be increased by the addition of alkalis such as sodium or potassium hydroxide. The more polar the water, the more that reactive clays will disperse.

The potential reactivity of a clay formation will depend on the types of clays present and the physical environment. Some clays are more likely to hydrate and expand than others. One highly reactive clay mineral in the presence of supplied water is montmorillonite. The montmorillonite crystal structure (fig. 7–2) comprises large, flat sheets (platelets). These sheets are formed from alternating layers of two different crystal structures. This structure is called mixed-layer clay.



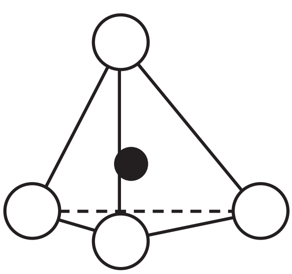


Fig. 7–2. Montmorillonite structure

Montmorillonite is added to the mud to give it certain useful properties. Commercially supplied montomorillonite is known as bentonite.

Fully dispersed, a clay such as montmorillonite will have its clay platelets completely separated and held apart by negative charges on the faces of the platelets. The theoretical surface area of fully dispersed montmorillonite is around 800 m2/g. It is this huge surface area of dispersed montmorillonite that causes dispersed mud with added bentonite to become viscous.

A mud designed so that clays are dispersed (either added like bentonite or from drilled formations) is called a dispersed mud.

Nondispersed muds

A mud in which the hydration and dispersion of a drilled clay is minimized is called nondispersed. There are a number of ways to achieve this. The most common is to limit the amount of water that reacts with the clay by encapsulating the clay with polymer as quickly as possible, to prevent further access of water to the clay. (A polymer is a repeating chain of units [called monomers] that are chemically joined together to form a long chain. Some polymers can be millions of units long.)

The electrical charges on the surface of the clay particle attract sites on the polymer chain that have an opposite electrical charge. The result is that the long chain of the polymer can wrap itself around the clay. Very long chain polymers can hold several clay platelets together (fig. 7–3). Such mud systems are described as encapsulating polymer muds.

Originally the polymers used as drilling fluid additives were naturally occurring starches that were easily extracted, such as corn starch, which was first documented in use in 1937. Other natural polymers were also tried and entered common use. Now, synthetic polymers are often tailored to specific drilling situations.

Polymers can perform several different functions, such as the following:

1. Increase the viscosity of the fluid. Viscosity is the degree of resistance to flow of a fluid. A highly viscous fluid will need more pressure to pump it through a pipe than a fluid with lower viscosity.

2. Increase gelation properties. When the fluid becomes stationary, it forms a gel. This allows solids in the mud, including drilled rock cuttings, to be suspended within the gel so that they do not fall down through the mud.
3. Decrease fluid loss into the formation. A mud containing solids that is in contact with a permeable formation will lose water and dissolved chemicals into the formation. As this happens, solids in the mud will form a plaster or cake on the face of the formation. This loss of liquid, or filtrate, into the formation is called fluid loss. Some chemicals can reduce the amount of fluid lost to the formation in this way. A low fluid loss is sometimes desired in a mud.
4. Act as a surfactant. This will allow oil and water to mix together in an emulsion.

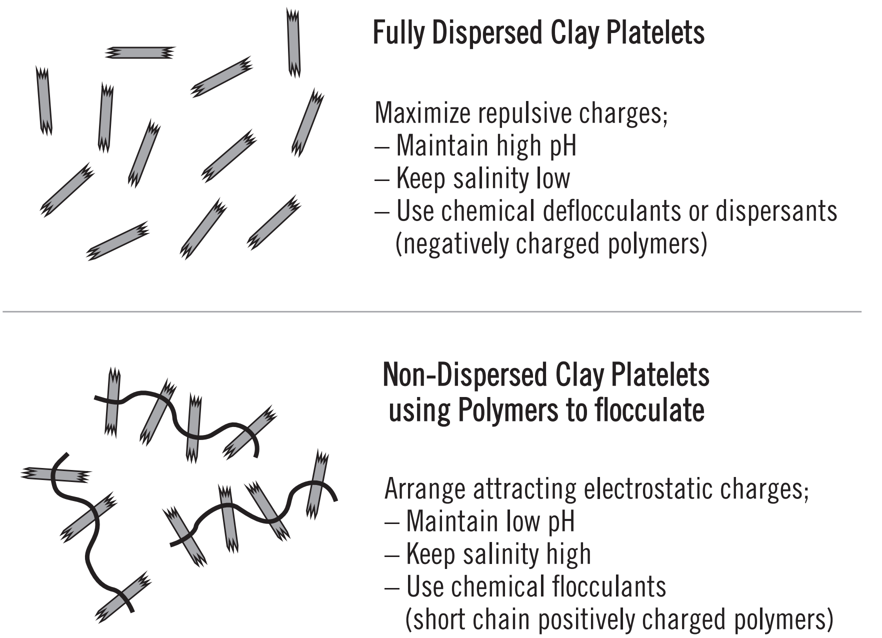


Fig. 7–3. Using polymers to bind clay platelets

Solids-free brines

Brines are used when working within the reservoir so as to minimize damage to the formation that would slow down the flow of oil or gas to the well. Sometimes a solids-free or a brine system is used for drilling through the reservoir. Later on during completion or workover operations, these systems are again useful to reduce or eliminate damage. (As previously discussed, a workover is the process of repairing damage to a well, often by removing the completion and running a new one.)

Brines can be formulated as solids-free systems with density gradients up to 1.07 psi/ft (2.47 SG). Solids weighting materials and fluid loss additives that are acid soluble can also be added, such as calcium carbonate and iron carbonate. While being able to overbalance formation pressures, properly designed brines do not create formation damage, whether by plugging the reservoir with irremovable solids or by causing reactions with formation fluids or solids. Potential interactions of brines in the reservoir include the following:

- Scale from the reaction of a divalent brine with dissolved carbon dioxide, producing an insoluble carbonate. (Divalent brines are those containing calcium or zinc salts.)
- Precipitation of sodium chloride from the formation water when it is exposed to certain brines.
- Precipitation of iron compounds in the formation resulting from interaction with soluble iron in the completion fluid (most common with zinc bromide, $ZnBr_2$).
- Reaction of formation clays with the brine.
- Corrosion of casings and tubulars.

Oil muds and invert oil emulsion muds

An oil mud is comprised of various solids and additives mixed into an all-oil continuous phase, with little or no water (10% or less by volume of liquid).

With an invert oil emulsion mud, water is present at more than 10% by volume within the continuous oil phase as an emulsion. The water (brine would be more accurate because it will contain dissolved salts) forms tiny droplets that are completely surrounded by the oil. The droplets of brine are held in an invert emulsion in the oil phase because they are coated by emulsifiers (fig. 7–4). Emulsifiers are surfactants that have an organophylic end and a hydrophylic end to their molecule. Each end aligns itself to be in either the oil phase or the water phase so that the emulsifier molecule forms a link between the oil and water.

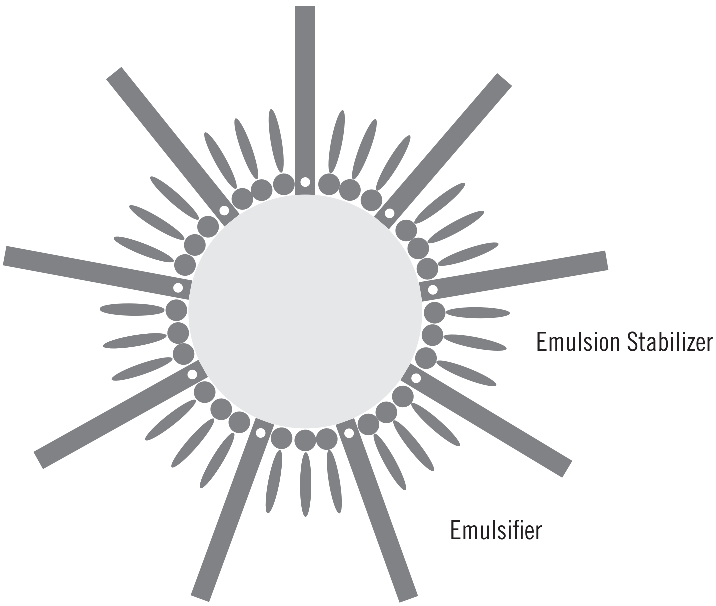


Fig. 7–4. Emulsifiers around a water droplet

While the terms oil mud and IOEM have specific definitions, terms such as oil mud and oil-based mud, among others, are interchangeable and really define fluids where the continuous phase is oil. If water is present, it is as an invert emulsion (water emulsified in oil). The presence of a water phase in an oil mud allows for versatility in control of parameters such as rheology.

Many different oils have been used in the past, including crude oil, diesel oil, oils extracted from fish or plants, and synthetic oils. Some of these oils are toxic, carcinogenic, and flammable (crude and diesel oils), which are undesirable for safety, environmental, and health reasons.

Air as a circulating medium

It is possible to circulate with compressed air. For this to work, the following conditions are necessary:

1. The formations to be drilled must remain stable without hydrostatic mud pressure to support them.
2. There must be no danger of a fluid influx into the well (oil or salt water).

The areas of application are hard, dry formations, such as dry geothermal zones and dry gas production zones. While drilling through a gas-bearing reservoir, the well produces gas while drilling.

Aerated and foamed muds

Aerated mud is simply injecting standard drilling mud with air, effectively lightening the fluid column. The main advantages are the following:

1. Maintaining full circulation in loss zones.
2. Increase ROP by reducing chip hold down (as explained in chapter 6).
3. Reduce the incidence of differential sticking. This occurs when a permeable formation is exposed in the wellbore and the following conditions are also present:
   - The mud hydrostatic pressure is greater than the pore fluid pressure
   - Mud solids have built a plaster on the formation face
   - The drillstring is allowed to remain stationary for awhile.

   If these conditions are all present, it is possible for the drillstring to become stuck. The greater pressure in the wellbore pushes the pipe into the wall, and friction then makes it hard to move the pipe up or down or in rotation. If the overbalance is high enough, the pipe cannot be moved. Reducing the drilling fluid density reduces the sticking effect.
4. Reduce formation damage.

Air may be injected at an appropriate rate in proportion to the mud circulation rate. Generally, the technique is limited to a maximum depth of about 2,800 ft, as injection pressures become excessive at greater depths.

In a foam mud, the liquid is a continuous phase and contains encapsulated air bubbles within it. The percentage of liquid will vary between 2% and 15% by volume.

The lifting capacity of stable foam is superior to that of drilling muds; cuttings are circulated out of the well more efficiently with foam. It is possible to displace fluids from the hole using foam. Oil and saltwater influxes are likely to destroy the foam stability, precluding the use of foam in those conditions.

Designing the Drilling Fluid

In selecting the most suitable type of drilling fluid, many different factors must be considered. Overall what is required is a mud system that gives the lowest overall cost of drilling each hole section, except for through the reservoir. The direct cost of the fluid itself (the cost per barrel of mud) is but one component of this overall cost. If serious hole problems occur because the mud was not optimized for the formations in an effort to “save money,” obviously much more money will be spent than would have been saved on the mud bill.

When drilling through the reservoir, the key is to minimize damaging reactions between the mud and the reservoir that lower the production possible from the well. If a well loses only 10% of its potential production rate due to avoidable damage from the mud, the cost to the operator in lost profit over the full life of the well will be large.

Mud cost must be considered but only to choose between technically suitable systems. Therefore what should happen is that for each hole system, all technically suitable alternatives should be defined and then the cost of each can be compared for a final choice.

Physical, rheological, and chemical characteristics can be defined for each hole section, leading to a list of requirements for the mud system of choice.

Mud physical properties

Density. Primary control of downhole pressures is obtained with a mud of such density as to exert a greater hydrostatic pressure on the formation than exists within formation pores.

The lower safe limit of mud density is calculated by the density to balance formation pore pressure, plus a small additional amount as a safety margin.

Some formations require a minimum hydrostatic pressure to keep them stable. When a hole is drilled through a rock in the ground, the stresses in the surrounding rock will tend to push the rock into the hole. If mud hydrostatic pressure is kept high enough, it pushes back against the rock and so supports it. The required density gradient is likely to be something greater than that required to maintain well control.

The upper safe limit of mud density will be given by one of several factors:

1. Losses or formation breakdown may be induced if the hydrostatic pressure plus circulating pressure losses exceed formation strength. Circulating pressure losses refer to the pressure necessary to force fluid to flow along a pipe or annulus. The pressure at the bottom of the well while circulating equals mud hydrostatic pressure plus the pressure required to force the mud to flow up the annulus. This extra pressure imposed while circulating along the open hole can be enough to fracture weak formations in some cases.
2. A high mud density will give a reduced MAASP. (MAASP was explained in chapter 3 in the discussion of drilling out the casing and testing the formation strength.) This means that the well is less able to withstand a kick than with a lower mud density.
3. Rate of penetration is generally reduced with higher weights due to chip hold down (as explained in chapter 6).
4. Sticking in the hole becomes more likely at higher mud densities.
5. Some shales contain tiny fractures. When mud or filtrate is forced into the fractures, this lubricates the fracture faces. It also changes the stress regime in the near-wellbore zone. The wellbore will become unstable, and chunks of the shale will fall off into

the well. (As explained previously, filtrate is the liquid part of the mud. When mud is forced against a permeable zone, the solids in the mud form a plaster or "wall cake" against the formation face. Some of the liquid fraction will filter through this cake and into the formation. This liquid fraction [water plus dissolved salts] is called filtrate.)

6. Higher mud densities have higher solids content, and this will adversely affect mud rheology, possibly calling for more additives to control this.

On balance, the correct density within this range of maximum and minimum will normally be closer to the lower limit.

Fluid loss. The fluid loss property of a mud indicates how well the mud forms a seal against permeable formations. To test fluid loss, a sample of mud is placed inside a chamber, which has a standard filter at the bottom. The chamber is closed and 100 psi is exerted on the mud sample. Filtrate is squeezed through the filter into a container below, and wall cake builds up on the filter. The standard test measures the amount of filtrate collected in 30 minutes, with the thickness of the filter cake given in 1/32nds of an inch or in millimeters. A description of the filter cake might also be made, using descriptions such as hard, soft, tough, rubbery, firm, etc. Figure 7–5 shows a filter press, which is used to test the fluid loss.

A high fluid loss mud will build up a thicker, stickier wall cake, which is likely to lead to problems such as pipe sticking in the hole. Ideally the mud should build up a thin, tough, and impermeable cake fairly quickly.

The test for fluid loss is a comparative test. It does not indicate how much filtrate will actually be lost to the formation, or how thick the filter cake might actually become. These things depend on many factors, such as the actual pressure overbalance, the permeability of the downhole formation, and the effects of mud flow or pipe movement eroding the filter cake.

Fig. 7–5. A filter press

Sand content. Sand is normally the most abrasive solid present in the mud, and a high sand content will increase wear on pumps, valves, and other equipment. However, all solids in the mud will contribute to mud abrasiveness. Sand content should be kept as low as possible by using the solids control equipment properly. The sand content is measured by passing a fixed volume of mud through a 200-mesh sieve into a marked glass container. The sand sits in the bottom, and the sand content is measured directly from the marks.

Mud rheology. Rheology is the science of the deformation and flow of fluids. When discussing the rheology of fluids in the well (mud, cement, or brines), what is of interest is the relationship between how fast the fluid flows and the pressure required to maintain that flow rate (either in the pipe or in the annulus). The relationships between these properties will affect circulating pressures, surge and swab pressures, and hole cleaning ability. Surge and swab pressures occur when the drillstring is lowered in the hole and fluid is displaced upwards. This imposes temporary extra pressure on the hole and is called surge pressure. When the drillstring is lifted upwards, fluid has to flow downwards as a pressure drop or suction is created by the withdrawal of the steel volume. This causes a temporary pressure reduction on the hole and is called swab pressure. Hole cleaning ability refers to the ability of a drilling fluid to lift cuttings out of the hole at a certain flow rate. This ability is related to the fluid density and rheology.

To fully specify a drilling fluid that must perform specific functions, the required rheology must also be defined. The rheology not only affects the relationship between flow rate and pressure, it also affects the flow rates at which the flow regimes change.

At very low flow rates inside the pipe and annulus, the fluid will move with all parts of the fluid moving in the same direction and at roughly the same speed. This is called plug flow, shown as “Stage 2” in figure 7–6.

If the flow rate is increased, the drag at the edge will cause the central part of the fluid to flow faster than the edges. The resultant flow is called laminar flow. It is less efficient for transporting cuttings up the hole.

If the flow rate is further increased, the flow will become chaotic. The average flow direction will be in one direction, but within the fluid, there are numerous eddies and swirling flow. This is turbulent flow and is the most efficient for hole cleaning.

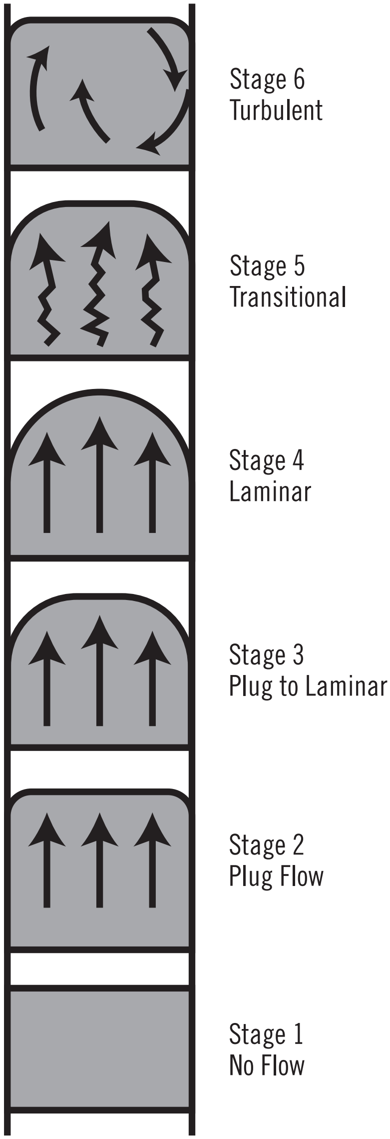


Fig. 7–6. Different flow regimes

Mud chemical properties

The chemical characteristics of the mud are mostly determined by wellbore stability considerations of the formations drilled through in a particular hole section. In addition, the mud should not damage the reservoir (reduce permeability), or at least damage done to reservoir permeability should be capable of being repaired (e.g., by using acid to remove plugging solids) or bypassed (explosive perforations penetrating through the damaged zone).

A brief description of different problems and required chemical characteristics follows.

Reactive shales. Many hole problems are caused by incompatibility between water and shales (the reverse of diagenesis, discussed in chapter 1). This may be solved by using oil/water emulsion muds (with oil as the continuous phase) or 100% oil muds. This isolates water from the shales and so prevents hydration. Oil muds are becoming increasingly difficult to use in some areas due to environmental concerns and resulting government regulation changes. These muds are also expensive.

Water-based muds may use various chemical inhibitors to control reactive shales, such as potassium chloride (KCl). KCl works by swapping places with sodium ions in the clay structure. As the potassium ion is smaller than the sodium ion, this causes the clay structure to shrink rather than expand.

Other useful chemicals include polymers, as described previously in this chapter. Clay crystals have electrostatic charges on their faces and edges. If a polymer molecule also has opposing charges along its length, the polymer sticks to the clay crystal and prevents water from reaching it.

Another development is the use of soluble silicates in clay stabilization. These are soluble at high pH (alkaline; above pH 10) but precipitate out of solution as solids if the pH drops. As tiny amounts enter the pore spaces between crystals, the pH drops, and silicate precipitates and forms a barrier to further water penetration. Use of silicates seems to cause the clay to harden over time. As silicates are cheap, readily available, and environmentally friendly, their use will no doubt increase into the future.

Salts. A nonsalt-saturated, water-based mud will leach out salt formations, causing extreme hole enlargement and possible cementing problems. This can be addressed by using either salt-saturated water mud or an oil-based mud.

In complex salt sequences containing the most soluble potassium and magnesium salts, a mixed salt system is required to address the particular mix of salts present in the formation.

Reservoir damage. Mud filtrate can be extremely damaging to formation fluids. There are two areas of particular concern: pollution of water sources and reduced productivity of the pay zone. There are two approaches in these cases, and they may be used together. The first is to prevent filtrate invasion by using additives to plug off pore throats where the formation is exposed. The second approach is to use a mud that has a nondamaging filtrate. In the pay zone, productivity damage from filtrate may occur in several ways:

1. The filtrate may contain fines (small solid particles) that bridge off the zone of invasion. If this zone is deep, perforations may not be able to penetrate completely through, and so the well will be less productive. If the fines were acid soluble, acid treatments may remedy the situation partially or completely. However, weighting agents and drilled solids are usually not acid soluble, so fluid loss control becomes very important in the production hole section. Acid-soluble materials (such as calcium carbonate) may be used.
2. Chemical reaction between filtrate and formation fluids may produce solid precipitates or blocking emulsions. As noted above, if these are acid insoluble, the resulting damage may be permanent.
3. The filtrate may react with the clays within the formation. Oil-based muds should give only low amounts of oil filtrate; no water should be present.

Corrosion of downhole steel components. Tools and tubulars used in drilling, casing, and completing the well can be subject to corrosion by the mud. For most casing strings, mud is left in the annulus after the cement job, which will remain for the life of the well. Mud properties may change over time due to bacteriological action. This can produce H_2S (especially when the mud contains organic additives) or low pH levels. Oil muds produce oil wetting of metal surfaces and will protect against CO_2, H_2S, and H_2O corrosion.

Hydrogen sulfide–related problems. Hydrogen sulfide (H_2S) may enter the mud from a permeable formation, either as a kick or from within drilled cuttings. Apart from the extreme toxicity of this gas, it causes hydrogen embrittlement of most steels, which degrades tensile strength. If H_2S is anticipated, an excess level of lime in the mud will help. The alkaline lime will help neutralize the acidic H_2S. The reaction forms active sulfides such as CaS or $Ca(HS)_2$, which will liberate H_2S if exposed to a mild acid. Once H_2S has been identified in the mud system, zinc oxide (ZnO) may be added. ZnO is an effective scavenger of H_2S and active sulfide salts. This reacts to form stable zinc sulfide. It is not recommended to use ZnO before H_2S is identified, as it will mask a slow entry of H_2S into the system. Recommended concentration of ZnO is around 2 lb for each barrel of mud.

Summary

This chapter covered one of the most important systems on the rig for safe and efficient drilling—the drilling fluids. First the functions of a drilling fluid were listed, and then seven distinct classifications of mud were described. Drilling fluid design was covered in some detail for the physical, rheological, and chemical requirements.

8

DIRECTIONAL AND HORIZONTAL DRILLING

Overview

Directional drilling—the process of accurately guiding a well through a predefined target or targets—is a source of great interest for many people outside the drilling industry. This chapter will first give some of the reasons for drilling directional wells and will look at how the desired well path is designed. The tools and techniques for deviating the wellbore will be described. Accurate navigation is a prerequisite to drilling directional wells, and the navigational tools available to the driller, along with their advantages and limitations, will be covered. Deviated wells have their own special problems, which will be examined. Finally, this chapter will discuss some specifics concerning drilling horizontal and multilateral wells.

Why Drill Directional Wells?

Drilling a deviated well to a target that is not vertically below the rig location will always cost more than drilling to the same target vertically. The justification for spending that extra money comes down to the total cost of achieving the well objectives being lower by drilling a directional rather than a vertical well. Some of the particular reasons could include the following:

- **Single surface location for multiple wells.** To effectively drain a reservoir requires wells flowing from different parts of the reservoir. If all those wells come together to the same surface location, all the production facilities can be at that location, which may be cheaper than connecting wells from many surface locations. The production staff need only to work on one location, so the running costs are less, and the rig only needs one location to be available. Drilling from an offshore platform is done this way; an offshore platform could have 30 or more wells spreading out into the reservoir, all coming together on one (or sometimes two) platforms (see chapter 4).

- **Salt dome drilling.** If a salt dome creates structures around it that capture hydrocarbons, it may be easier to drill around the salt dome rather than through it to reach the reservoir (see chapter 2).
- **Multiple exploration wells from a single wellbore.** A well can be drilled, evaluated, and then cemented back. The well can then be deviated from the top of cement to a different target. This might be done to evaluate different compartments in one reservoir (where internal barriers in the reservoir chop it into several parts) or to extend the knowledge of the structure from one well.
- **Onshore drilling to an offshore reservoir.** If an offshore target can be reached from shore, the economics can be much better than drilling from offshore. Wytch Farm on the South Coast of England is the largest onshore oil field in Western Europe—but a large proportion of it is offshore (fig. 8–1). Development in this environmentally sensitive area was made possible economically by drilling under the sea from the land. The wells expanded the boundaries of extended reach wells at that time. (An *extended reach well* is one where the horizontal displacement of the well is at least twice the vertical depth.)

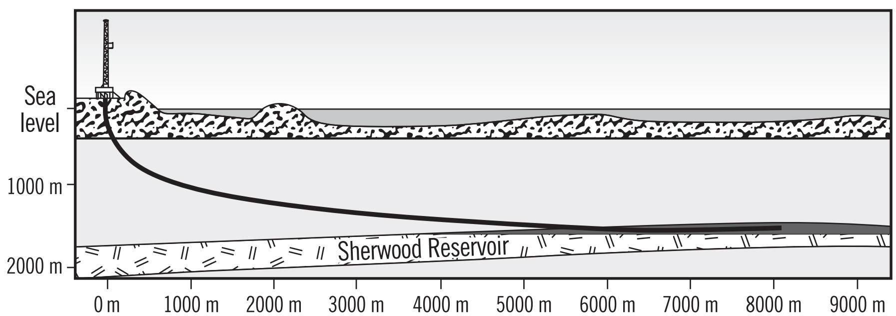


Fig. 8–1. Wytch Farm development well schematic

- **Optimum orientation in the reservoir.** Reservoirs are not nice and even, the same in all directions. Permeability will be better in one direction than another. In a fractured limestone reservoir, the well should intercept as many fractures as possible to get the best production. These factors will determine which direction the well should be drilled in the reservoir. Some wells follow very complex well paths, turning corners, to get in the best position in the reservoir.
- **Remedial work (sidetracks).** A well might be cemented back to a shallower depth, and a new wellbore drilled away from the original bore, for a number of reasons. One reason might be due to drilling problems, such as stuck pipe that cannot be freed and must be cut. Or an old producing well might be sidetracked to another location.
- **Relief wells.** The worst reason to have to drill a well is to create a relief well. For example, a well has suffered a blowout and is still blowing hydrocarbons into the environment. For some reason, the well cannot be killed at the surface. Another well, the relief well, is drilled to intercept the blowing well. Dense mud is circulated down the relief well and into the blowing well, killing it from the bottom. The *Deepwater Horizon* disaster in the Gulf of Mexico in April 2010 was one of these situations. The BOPs on the seabed would not operate to shut in the well at the seabed. Two rigs moved in to drill relief wells to depths below 18,000 ft to shut down the blowout.

Directional Well Planning

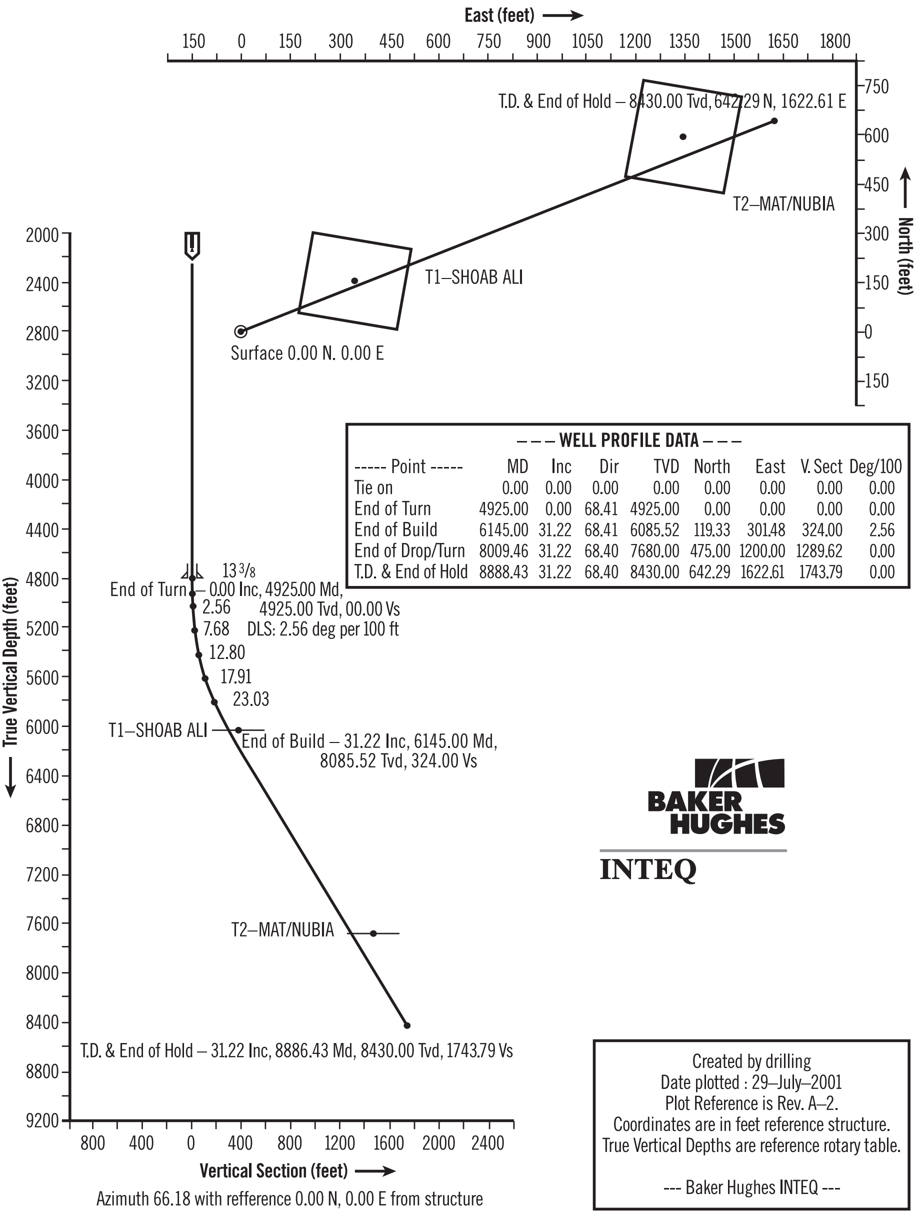
It is the job of the geologists and reservoir engineers to decide where the wellbore should be placed. This could be as simple as determining one single target, often defined as a tolerance of say 100 m around a target point (so that would be a *round target*). It does not matter at what angle the well enters the target. At the other extreme, the well may have to penetrate multiple targets, and the final target could be defined as a cylinder that the well must stay within, or perhaps the well must be drilled to follow the "roof" of the reservoir and stay within a certain distance of the cap rock above. This is called geosteering and will be covered later in this chapter.

It is now the job of the drilling engineer to look at the possible surface locations (there may or may not be a choice about this) and then design a well path to meet the target requirements at the lowest cost. Some flexibility as to the surface location (such as a desert or offshore when drilling straight into the seabed) can be a great help in minimizing cost.

As an example, figure 8–2 shows a planned well profile, from a plan view (looking down from above) and a side view. This is a simple directional well. There are two targets to hit, shown as rectangles on the plan view and lines on the side view. The simplest (cheapest) directional well profile is a build and hold to the target, called a *J-shaped profile*. Note that the well does not try to hit the centers of the targets; a target is an area, not a point. By using the available area for the plan, the cheapest profile to achieve can be designed. While in practice very small targets can be hit, it costs more money to get within a small target than to hit a big one. In the well shown in figure 8–2, the lower target will be hit on its edge closest to the surface location. There are advantages compared to planning to hit the target center:

1. Going for the closest edge means that the well can be built to a lower inclination (angle from vertical), and less hole needs to be drilled.
2. If the well does not build angle fast enough, and the well might miss the target, getting a higher build rate does not sacrifice drilling speed. The opposite case—having to reduce inclination to get into the target—does require sacrificing drilling rate. This is because making the bit build angle generally requires more weight on the bit, whereas dropping angle requires less weight on the bit. There are tools that this does not apply to; rotary steerable tools can deal with this. Rotary steerable tools are very expensive, so unless the drilling operation has a very high daily cost, these types of tools would not be considered for the purpose of correcting a directional problem. By aiming at the low edge, any directional correction work needed does not sacrifice drilling speed.

There are some other considerations in planning the well path. When the well changes direction, the drillpipe has to bend around that curve. If the well is curved close to the surface, as the well gets deeper and the weight of drillpipe below the curve increases, the drillpipe tension in the curve increases. This causes a greater side force between the wellbore wall and the drillpipe in order to curve the pipe. This side force can cause problems, such as metal fatigue and wear on the pipe, or can cause stuck pipe.



– – – WELL PROFILE DATA – – –

----- Point -----	MD	Inc	Dir	TVD	North	East	V. Sect	Deg/100
Tie on	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
End of Turn	4925.00	0.00	68.41	4925.00	0.00	0.00	0.00	0.00
End of Build	6145.00	31.22	68.41	6085.52	119.33	301.48	324.00	2.56
End of Drop/Turn	8009.46	31.22	68.40	7680.00	475.00	1200.00	1289.62	0.00
T.D. & End of Hold	8888.43	31.22	68.40	8430.00	642.29	1622.61	1743.79	0.00

Fig. 8–2. Directional well plan

The rate of change of direction is measured in degrees (of directional change) per 100 ft or 30 m (of hole drilled). This is called the *dogleg severity*—a dog's leg being bent, it is a descriptive expression of a bent hole. A high dogleg severity should be avoided shallow in the hole because of the resulting high forces between the pipe and the hole wall.

Vertical wells are never truly vertical. The drill bit will experience side forces while drilling, for a number of reasons. The well might penetrate rock bedding planes at an angle other than 90°, and this will tend to make the bit walk away from vertical. A harder lump of rock within softer rock can push the bit off its path. Vertical wells often drill in a slight spiral, like a stretched spring. If a well is planned to be vertical, directional drilling techniques are still used to keep the bit going as straight and vertical as possible.

Deviating the Wellbore

In order to make a well deviate from vertical to follow a predesigned path, it is necessary to develop a side force at the bit. The amount of side force and its direction are critical to following the designed path. Of course the hardness of the rock being drilled through and other characteristics such as bedding plane angles all have an influence.

There are a number of techniques for developing a controlled side force at the bit. Two techniques from the early days of rotary drilling are jetting and whipstock. These are normally used to start the well path deviating, with different techniques used to continue after that initial kickoff away from vertical.

Jetting

Tricone drill bits have three drilling cones, and in between each cone is a nozzle (see chapter 6). If a large nozzle was set into one nozzle pocket and two small nozzles were in the other two, most of the flow of mud would go through the big nozzle. Drilling fluid comes out of the drill bit with great force, and if the formation is not too hard, the fluid will erode the rock away. With one big nozzle directing most of the flow towards one part of the hole, a pocket will be washed into the rock in that direction. By aligning the bit in the desired direction and pumping hard without rotating, the well can be deviated.

After washing away 5 or 6 ft, the bit is rotated and drilled conventionally. The procedure can then be repeated as necessary, until about 12° of angle is built up or until the rock becomes too firm to jet. A rotary build drilling assembly is used (fig. 8–3) so that once some angle is achieved, the well can continue to build angle while drilling and rotating.

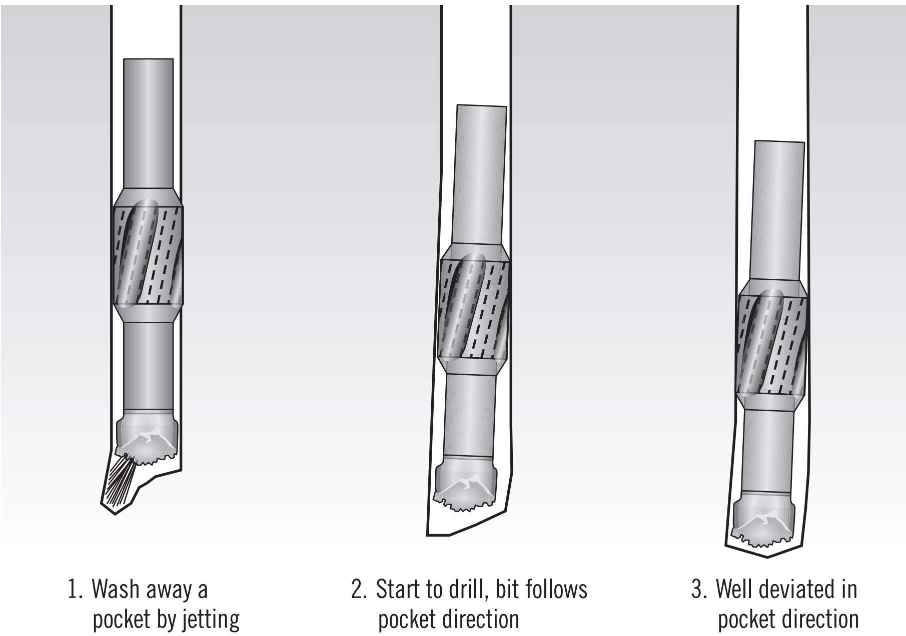


Fig. 8–3. Jetting to deviate

In the right conditions, jetting can be the fastest and cheapest way to kick off the well.

Whipstock

After drilling the well to the kickoff point, the bit is pulled out of the hole. A *whipstock* is a wedge that is set in the hole. The fat edge of the wedge is on the bottom of the hole. The drillstring is rotated and lowered. Forced against the side of the hole, it starts to cut out of the original hole.

After drilling below the whipstock, the bit is pulled out of the hole again. The whipstock is pulled out with the assembly. At the surface, the whipstock can be removed. The drilling assembly is run back in. The ledge at the bottom of the hole will be worn and cut away as operations continue.

Whipstocks are also used to deviate the well out of casing (fig. 8–4). Instead of a drill bit, a mill is used that can cut metal. In this application, the whipstock is left in place to guide tools through the cut in the casing.

The drillstring will bend to allow the bottomhole assembly to go around the curved hole.

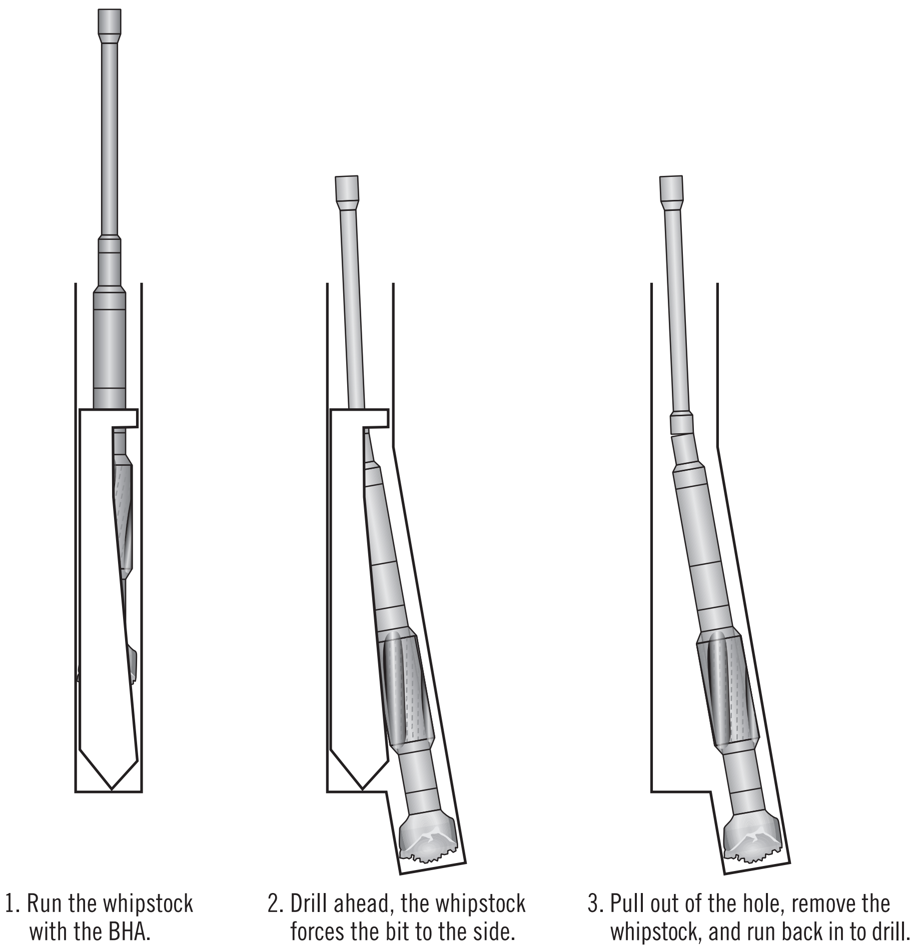


Fig. 8–4. Whipstock to deviate

Steerable motors

A steerable motor is a downhole motor, powered by pumping mud through it. The lower part of the motor has an adjustable bend (fig. 8–5). Before running the motor in the hole, several things are done to set it up:

1. The bend is adjusted for the directional performance required of the motor. The bend will vary from 0° to something less than 2°.
2. The tools above the motor that transmit navigational information back to the surface are connected to the motor and calibrated, so that the driller can see which direction the bend points towards when drilling. These tools, called measurement while drilling or MWD, are described later.
3. Other components in the system will be adjusted or tailored for the required directional performance (the required dogleg severity according to the well design).

Referring to the drawing on the right in figure 8–5, the main components of the system are shown from the bottom up:

- Drill bit. When mud is pumped down the drillstring, the motor turns. As the bit sits on a bent housing, it does not point straight ahead. A side force at the bit results from this, which causes the bit to drill a curved hole.
- Undergauge stabilizer. Behind the bit is usually an undergauge (smaller diameter than the bit) stabilizer. This forms a fulcrum, with the motor behind acting as a lever, to allow the side force to be generated at the bit.
- Motor. Above the stabilizer is the motor itself, with the bottom part having the adjustable bend.
- Dump valve. At the top of the motor is a dump valve. This allows mud to be diverted at the top of the motor if need be.
- Stabilizer. A stabilizer above the motor acts as the far end of the lever, exerting an opposing force at the drill bit.

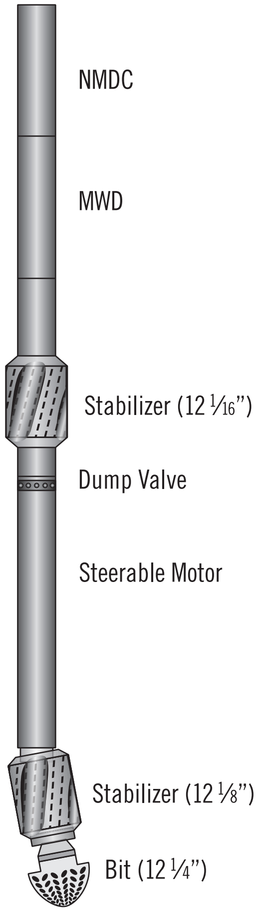


Fig. 8–5. Steerable motor assembly

While drilling, the motor can be orientated in a desired direction, and the bit drills a curved hole. This can be used to turn the hole, drop angle, build angle, or some combination of build/drop and turn. The whole drillstring can also be rotated so that the bit will drill straight ahead. This is why it is called a *steerable motor*—it has the capability to really be steered to cut the required path, which can be quite complex.

Steerable motors are very commonly used for initially kicking off the well from vertical and for continuing to drill and control the well path after the kickoff. As the well inclination increases above about 60°, it starts to get difficult to make such an assembly slide (drill without rotating the drillstring) while drilling. Another issue is keeping the hole clean; rotating the drillstring greatly improves the transport of cuttings out of the hole, and at high inclinations, sliding the string can lead to cuttings beds building up and sticking the drillstring. What is needed is a steerable tool that works with the drillstring rotating, and they do now exist. The drawback is that they are expensive.

Rotary drilling assemblies

If a drill collar is supported at each end in a position other than vertical, the weight of the drill collar will cause the middle part to sag. This effect is used in rotary drilling assemblies to create a side force at the bit in order to build or drop angle (fig. 8–6).

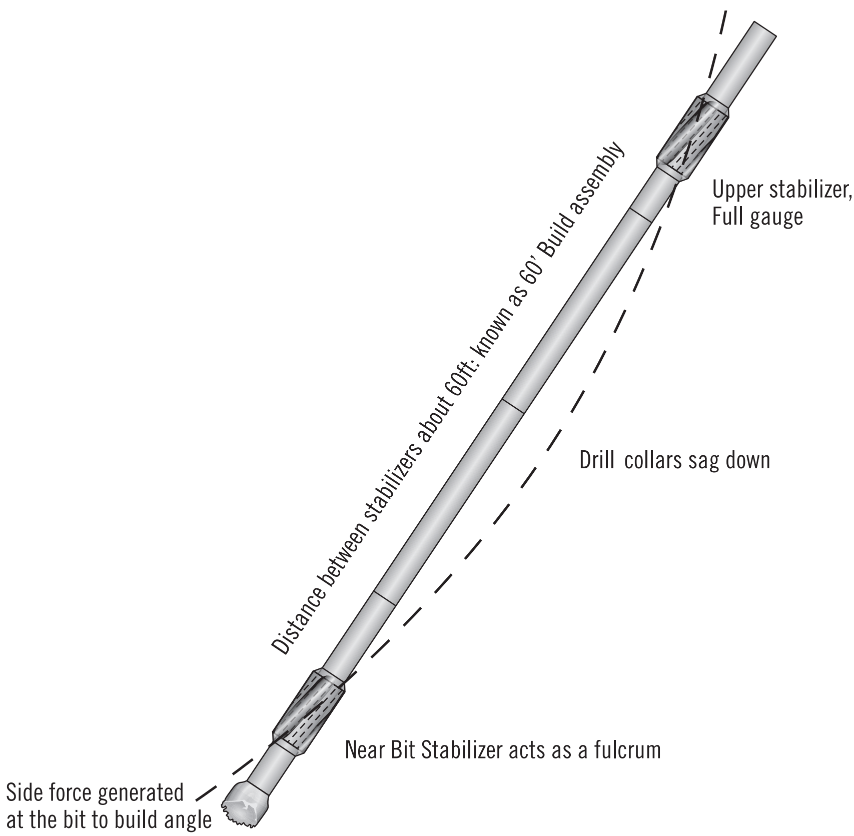


Fig. 8–6. A 60-ft build rotary assembly

Stabilizers are positioned so that drill collar sag tends to push the bit into the low side of the hole or to push the bit up to the high side of the hole, or to have very little or no side force. This is achieved by selecting both the positions of the stabilizers and whether the stabilizers are the same size as the drill bit (full gauge) or smaller (undergauge).

For a rotary build assembly to work, the hole needs some inclination (over about 12°) to create the sag. The higher the inclination, the more side force is generated with a particular rotary build assembly. The near bit stabilizer (NB stab) acts as a fulcrum, so the drill collars above can be thought of like a lever—push down on the upper part of the lever, and the opposite side pushes up. If the NB stab is undergauge, it will develop less upwards side force, and so the stabilizer gauge has an effect. If the next stabilizer up is (or becomes) undergauge, this will increase the build effect because the upper part of the lever will be moved downwards.

The weight applied to the bit also has a large effect. With sag in the drill collars, applying weight from above will increase the level of sag as the drill collar starts to buckle. Therefore the more weight that is applied to a build assembly, the faster it will build.

To drop angle, no NB stab is run. There will be either 60 ft or 90 ft of drill collars between the bit and the first stabilizer. The sag, minus the NB stab fulcrum, pushes the bit to the low side and therefore will tend to drop angle.

To get the drop started, light weight on bit is run. Once the trend is established, it can be increased by adding some more weight on bit. However, as this type of assembly is poorly stabilized by its nature, it will tend to follow any natural formation trends and often will wander off sideways as well as dropping. Azimuth cannot be well maintained, and this then might require a trip out of the hole to change the BHA configuration in order to correct the errant well path. A drop assembly is also known as a *pendulum assembly* (fig. 8–7).

The drill bit also has an effect. A drill bit can be designed so it has some side cutting action. This will increase the effectiveness of the build or drop assembly. On the other hand, if it is necessary to deviate as little as possible, a bit could be selected that had no side cutting action and would therefore try to drill straight.

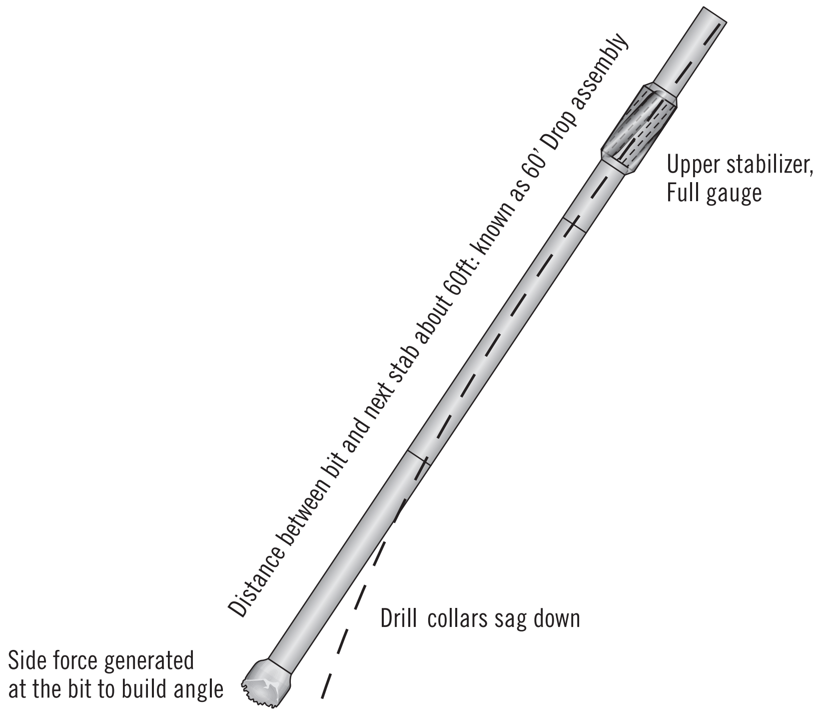


Fig. 8–7. A 60-ft drop or pendulum assembly

Once the well is pointing in the desired direction and angle, it can be locked up to drill straight. This is known as a *tangent assembly* (fig. 8–8), or sometimes a *packed assembly* (because it is packed with stabilizers) or a *stiff assembly* (because it is very stiff; that is, it resists bending forces). In this situation, the directional performance of the assembly is far less affected by natural formation trends or drilling parameters such as weight on bit.

In order to get the best drilling performance, it is usually necessary to get a high weight on the bit. One of the advantages of a tangent assembly is that high weight on bit can be used to drill fast, without a high risk of the hole heading off somewhere it should not go. Even a packed assembly will tend to build very slowly with high weights. Rotary assemblies also have a tendency to turn to the right. To account for these natural tendencies, the well can be kicked off and positioned so that it is pointing slightly to the left of a direct track and slightly low. Then the well will slowly build and turn right when using the best parameters for drilling fast.

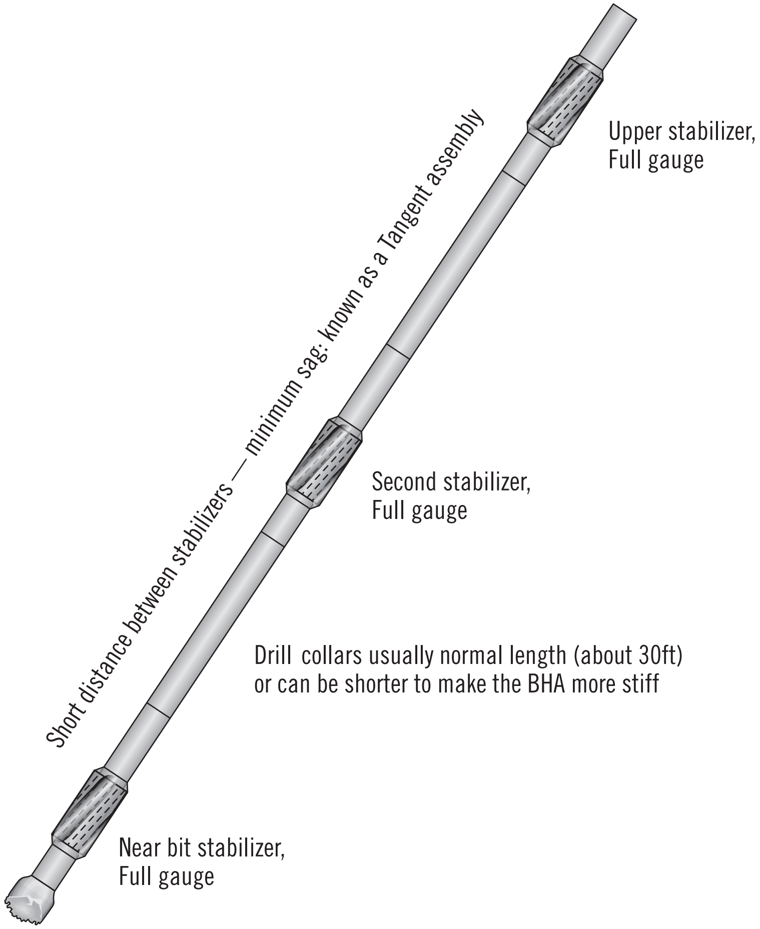


Fig. 8–8. Tangent rotary assembly

A locked assembly can also be run with a slightly undergauge second stabilizer, which would give an increased build tendency.

Rotary steerables

The approach in each different tool is the same, though the mechanics vary. The rotary steerable is run immediately above the bit, a kind of replacement NB stab. Modern tools will have three blades positioned close to the drill bit, much like stabilizer blades. These blades move in and out. The control system works so that as the tool turns, the blade turning opposite the desired direction of deviation pushes against the side of the hole, imposing a side force on the bit to make it drill a curved hole.

A computer within the tool controls the movement of the pads. Surface commands can be sent down to the tool by creating pressure pulses in the drilling fluid (fig. 8–9).

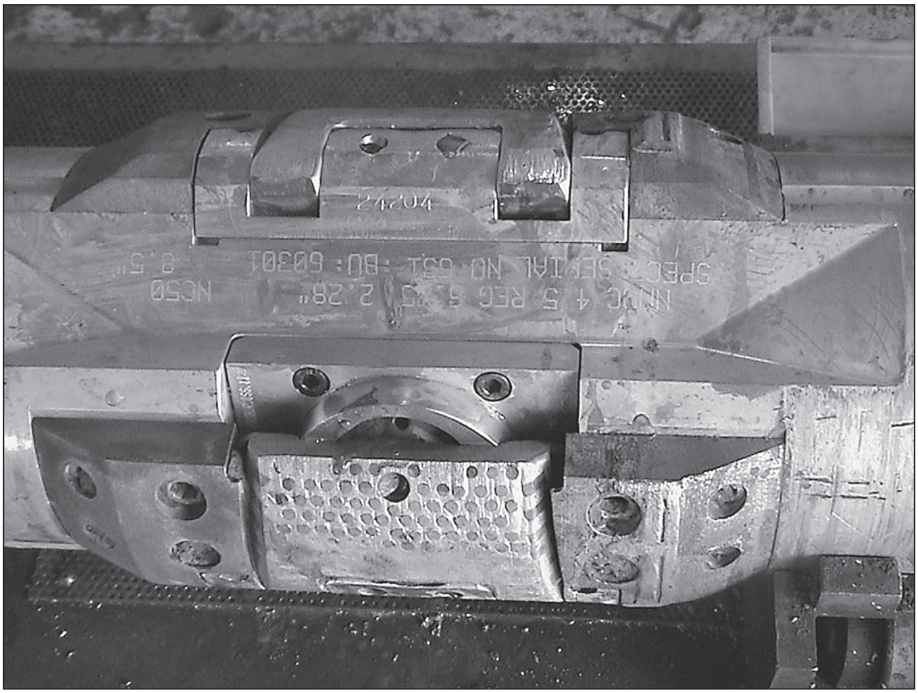


Fig. 8–9. Schlumberger PowerDrive pads

With a steerable motor, adjusting the well path in a series of slide drilling and rotary drilling does not create a nice smooth curve. The hole deviates with many small but sharp doglegs, with straight intervals in between. One of the big advantages of the rotary steerable tool is that it creates a nice smooth curved hole. This then leads to a more stable wellbore and less resistance when tripping in and out of the hole. At high inclinations, it would be easier to run casing or logging tools through a smooth curve.

When drilling long horizontal hole sections, it becomes very difficult to drill while sliding. Rotating the string breaks the friction between pipe and hole. For long horizontal or extended reach wells, rotary steerables have allowed holes to be drilled that are not possible with sliding motor assemblies.

Historically, a major cause of lost horizontal holes (which could not be completed to reach their objective) was inadequate hole cleaning. Cuttings build up in the hole next to the sliding drill pipe. Rotating the pipe stirs up the cuttings and gets them into the moving fluid stream.

As well as the possibility of commanding the tool from the surface, the tool can also link to a logging while drilling tool, which measures electrical or radioactive properties of the rock being drilled through. This can then be used to steer the bit in relation to rock properties.

Rotary steerable tools can cost over $20,000 a day. Combined with the cost of LWD tools, the system cost can exceed $30,000. Clearly these tools will only be used when the advantages are worth the cost compared with alternative tools. High-cost rigs, complex well paths, long horizontal holes, or a requirement for geosteering all demand this technology.

Navigating to the Target

Two factors are necessary to navigate while drilling. Measurements must be taken and calculations made to work out the position of the wellbore.

Wellbore position surveying tools

All wellbore surveying tools measure the same parameters, but using different equipment. This is called surveying. As previously explained, the two pieces of information measured by the tool are the inclination (the angle between the centerline of the wellbore and vertical) and the azimuth (the direction). The azimuth may be measured with a magnetic compass, in which case the direction relative to magnetic north is converted to grid north. Gyro tools will measure relative to geographic north (the axis of rotation of the earth). The depth at which these measurements are taken is known from the depth of the tool at the time of the survey, so a survey point will show the measured depth, the inclination, and the azimuth. A succession of these points then feeds into calculations to work out the path of the well, as described below.

There are a number of tools that may be used to produce one or more survey points.

1. **Magnetic single shot survey.** Historically, a slim, stainless-steel barrel of around 1½″ diameter contained a magnetic compass unit, an inclinometer, and a camera controlled by a timer. A small film shaped like a disc was loaded into the unit, and the survey barrel was lowered into the well. It could be run on wire, or dropped down the drillstring and fished with wireline, or dropped down the drillstring before pulling out of the hole. The timer would then be set to give enough time for the tool to be run to the right depth. The camera would take a photograph of the compass, which also had a marker on it showing the inclination. Modern units still make the measurements but dispense with the camera and film. A less common unit has a motion sensor that takes the survey two minutes after no motion is sensed.
2. **Magnetic multishot survey.** This tool records a series of surveys as it is pulled out of the hole. Originally the surveys were recorded on to a strip of film, which had to be developed and manually viewed; now the surveys can be recorded in tool memory or data may be transmitted real-time to the surface.
3. **Gyro multishot survey.** Normally run on wireline that transmits information back to the surface, the GMS can take many readings at short distance intervals. The surface computer knows the depth of each survey. The more surveys are taken, the more accurately the well path can be calculated. Gyroscopic tools are an order of magnitude more accurate at reading azimuth than magnetic tools. In addition, there are factors that affect magnetic tools, such as electrical storms and local magnetic anomalies, that can be impossible to completely account for.
4. **Measurement while drilling.** A barrel the size of a drill collar (around 8″ outside diameter) contains instruments that measure direction with magnetic tools and inclination with an inclinometer. This information is transmitted to the surface. The depth of the survey is known, as its position within the drillstring is known.

Wellbore surveying calculations

The well has had several surveys taken, and the measured depth of each is known. Now these results are input into a set of calculations that then show the path of the well.

The surface location is known. What is needed is the vertical depth and N/S-E/W coordinates for each survey point. These can then be plotted to show the view from above and the view from the side from a predetermined direction (see fig. 8–2).

While historically several different calculation methods have been used, one standard used by all eventually evolved. This is called *minimum curvature*. Imagine that two surveys are connected by a perfect arc of known length. The arc length is the difference in the measured depths of the two surveys. How the top and bottom are aligned is shown by the inclination and azimuth of each survey.

This is best explained with an example. Imagine that the surface coordinates are 0, 0 (that is, zero displacement east/west and zero displacement north/south). The inclination is 0° (vertical), and the MD and TVD are both 0. Call this survey number 0.

The next survey, number 1, is at 250 ft and is also 0° inclination. The profile of the well will be relative to north, so although there is no azimuth if the survey is vertical, the input to the calculations will be 000° azimuth. Clearly, it is not necessary to actually calculate this out to know the following:

- MD = 250 ft
- TVD = 250 ft
- E/W coordinate = 0 ft
- N/S coordinate = 0 ft

Survey 2 is at 500 ft measured depth. Inclination is now 3° and azimuth is 000°. This is easy to visualize—a nice curve taking the well north. The calculations show that the position of the well at this survey point is given as follows:

- MD = 500 ft
- TVD = 499.89 ft
- E/W coordinate = 0 ft

- N/S coordinate = 6.54 ft

As would be expected, the vertical depth is now slightly less than the depth along the hole, and there is a small displacement of the well to the north.

Survey 3 is at 750 ft depth. Inclination is now 5° and azimuth is 020°. The well has built some angle and has turned slightly towards the east. The calculated position of this survey point is given as follows:

- MD = 750 ft
- TVD = 749.28 ft
- E/W coordinate = 3.73 ft
- N/S coordinate = 23.33 ft

The assumption behind the calculations is that the well follows a perfect curve between each survey. In reality, this is not the case, and so there is an error between each survey. This error grows as the well is deepened. This error creates a cone-shaped well path, where the well can be anywhere within the cone. This is called the *cone of uncertainty*. If two wells are drilled close together and these cones intersect, a possibility of collision arises. The cone does not necessarily have a round shape if cut through, as the instrument that measures inclination has a different accuracy to the instrument measuring the azimuth. Thus the cone would actually have an elliptical cross section.

There are ways to reduce this error so that the well path is known more accurately. One way to do this is to take more surveys. This shortens the distance between each survey and so will more closely measure the actual well path. Another way is to use gyro-based tools rather than magnetic-based tools to measure azimuth. In practice, MWD tools are used while drilling a section of hole, then casing is run, and a gyro is run inside the casing to give a corrected (and more accurate) path. Gyros centralized inside casings can take readings while moving at very small intervals and so will give a much more accurate survey than MWD tools, which have magnetic sensors and thus in-built azimuth errors, not all of which can be compensated for. MWD tools run in the open hole will not perfectly align the sensors with the centerline of the wellbore (as a hole is not a perfectly even cylinder of fixed diameter). Thus MWD survey measurements will have a significant error that cannot be compensated for. In an inclined hole, the BHA will sag towards the low side of the hole in between stabilizers, and this will give an inclination error in the reading; sag can, however, be calculated.

Multiple wells from a single location

Frequently, several wells are drilled from a single surface installation. This might be a platform offshore, or a small area on land. Having wells close together at the surface provides better project economics, as all the production equipment can be located together.

Once the first well is drilled, the next well may have a risk of colliding with the first well. As subsequent wells are drilled, collision risk increases. One way to visualize this is with a spider plot (fig. 8–10). The grey circles show the eight surface locations of these wells, and each empty circle shows a survey position. This is a view looking from above, as if the wells could be seen below the surface.

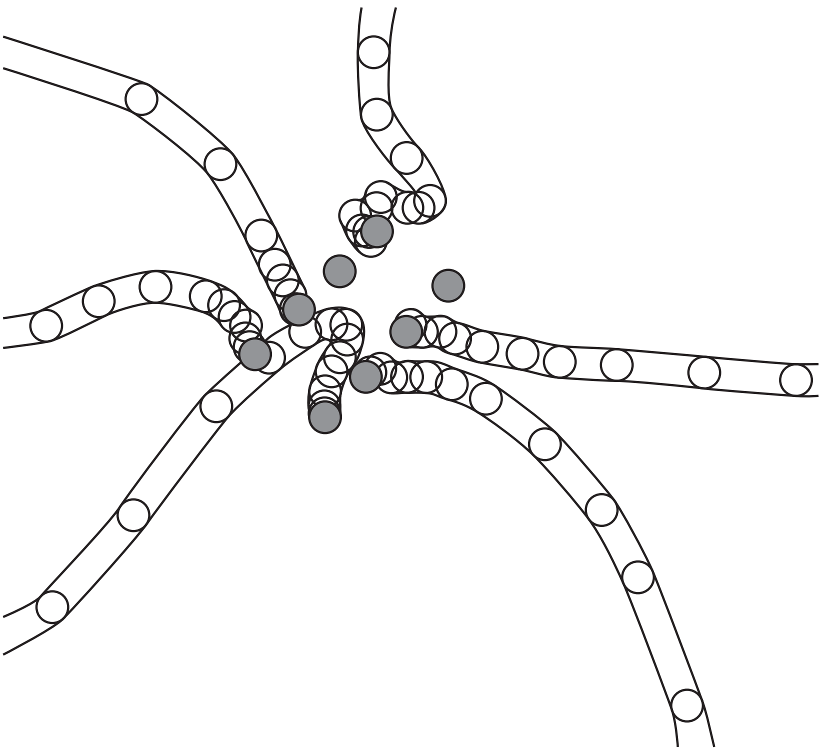


Fig. 8–10. Spider plot showing many wells from one location

Multilateral wells

It is possible to drill a wellbore and, from that "mother" bore, drill several side bores. Multilateral wells are drilled to greatly increase the amount of well exposed to the reservoir. This allows more oil or gas to be produced with lower pressures. As shown in figure 8–11, it can also allow several small reservoirs to be exploited with a single well, which might otherwise be uneconomic if several wells were needed.

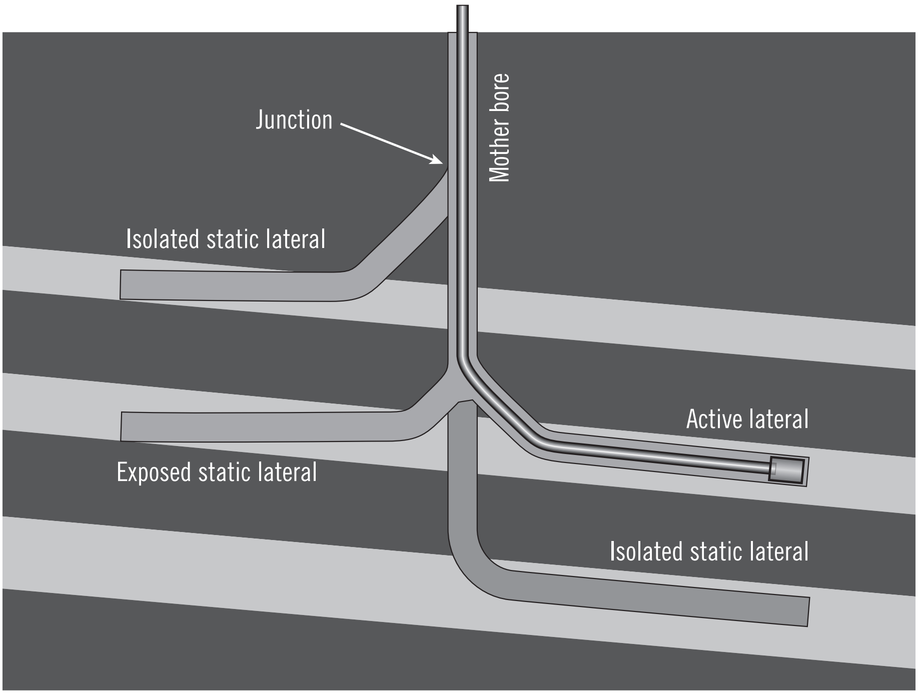


Fig. 8–11. Multilateral well diagram

Geosteering

For most wells, the objective is to drill along a predetermined well path to penetrate one or more defined targets. While the well will not follow the planned well path exactly, it should penetrate each target. However, some wells may be drilled with reference to downhole characteristics that are not accurately known before drilling. Take another look at figure 8–1 at the beginning of this chapter. This illustrates an extended reach well on the Wytch Farm oil field in the South of England. For these very long horizontal wells, it is better to keep the wellbore close to the top of the reservoir without penetrating the roof of the reservoir.

Perhaps a well is required where the horizontal wellbore in the reservoir can be steered to stay very close to the top of the reservoir. The reservoir is sandstone, and the seal rock above it is shale. Shales are naturally (slightly) radioactive, much more so than sandstone. Getting closer to the shale is indicated by increasing radioactivity. The LWD tool measures the radioactivity level, interprets that to give the distance from the shale, and sends steering signals to the rotary steerable tool to increase, hold, or decrease inclination. Rotary steerable tools such as the Schlumberger PowerDrive can be commanded by the LWD tools so that the BHA steers the bit in the reservoir without having to communicate with the surface.

Directional Drilling Problems

Hole cleaning

With a vertical hole, mud flows vertically upwards in the annulus, lifting the cuttings upwards. As the hole angle increases, the cuttings move up partially by lifting and partially by rolling along the low side of the hole. When the hole angle approaches about 45°, cuttings can start to settle on the low side of the hole. As they pile up, it can get hard to remove them. Eventually the pile can become unstable and avalanche down the hole. As long as the pipe is kept rotating while drilling, this stirs up any cuttings beds and moves them back into the moving fluid stream, so sliding the pipe while drilling (especially in high angle or horizontal wells) can lead to serious trouble, as detailed in the following text.

Stuck pipe

If hole cleaning is not adequate, solids will build up in the well. One possible result of this is getting the pipe stuck. If the pipe is stuck on a pile of solids, it will be hard to get free, as the string will likely not be able to move up or down or to rotate. It will be impossible to pump to clear up the hole. The longer pipe does not move, the more the sticking forces will increase.

Wellbore stability

A stable wellbore occurs when the hole stays the same size as the bit that drilled it. An unstable wellbore may get larger all the way round, or it may become larger in one direction than perpendicular to it, or it can become smaller in some formations, such as thick salt. A stable wellbore is desirable because this makes it easier to control direction, run into and pull out of the hole, and cement casing.

Rock strengths and stresses were mentioned in chapter 1. When a hole is drilled away from vertical, the stresses acting on the wellbore wall change in such a way that the difference between the maximum and minimum stress acting on the well becomes greater. The maximum stress increases as the well gets more horizontal. This can make it difficult to keep the wellbore nice and round; parts of the wall will tend to fall off due to the stresses in the wellbore wall. Drilling directional wells then requires special considerations to prevent problems arising from an unstable wellbore.

Logging

Running tools into the hole on wireline starts to get difficult when hole angles get over about 50°. It is worse if the wellbore wall itself is jagged rather than smooth.

Summary

This chapter examined some of the tools and techniques used to drill a well along a defined path. Some of the reasons for drilling directional wells were mentioned, such as to drill many wells from a single surface location or to exploit a reservoir as effectively as possible. Next, the process of kicking off a well was described, and then how to continue to guide the well path after the kickoff, including rotary and motor assemblies.

Horizontal and multilateral wells are more recent developments in directional drilling. These wells show the state that the art has now reached.

Finally, this chapter examined the techniques of surveying the wellbore and the main tools in current use.

9

CASING AND CEMENTING

Overview

An oil or gas well is a pressure vessel, a vertical pipeline thousands of feet long that conducts hydrocarbons from a reservoir to the surface. The integrity of this pressure vessel comes from the steel pipe that lines the wellbore, which is called casing (fig. 9–1). This casing pipe has to maintain integrity for the whole production life of the well, until the day it is finally abandoned. That could be 40 years or more. It is vitally important that the casing itself is properly designed, considering all the forces and environmental factors that it will be subjected to.

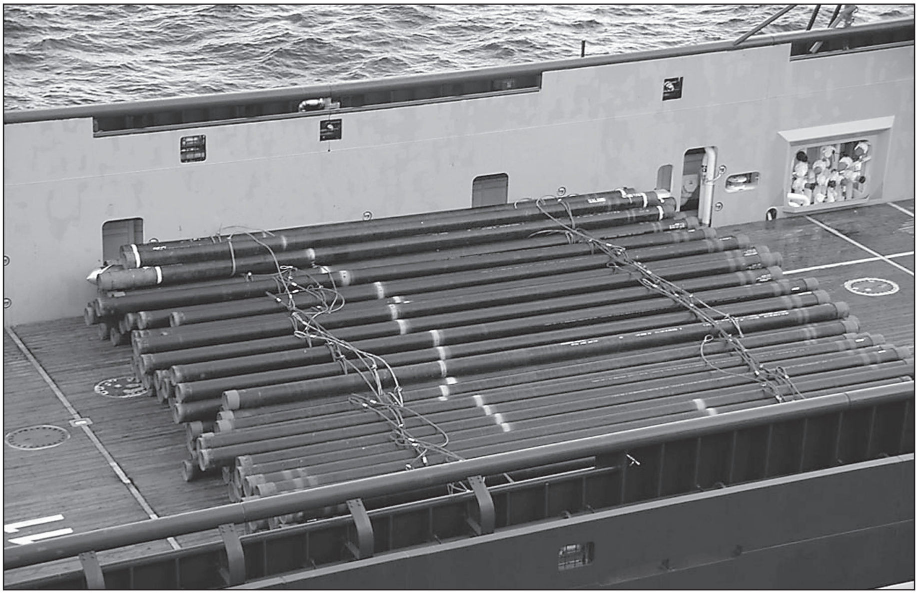


Fig. 9–1. Some 9⅝″ casing ready to offload to a rig

The casing is lowered into the drilled hole and cement is placed between the cement and the hole. The cement has to support the casing (the physical loads) without long-term deterioration. It has to protect the casing from corrosion due to salt water within the formations around it.

The cement must also prevent formation fluids and gases from moving up the annulus outside of the casing, which could be anything from inconvenient to disastrous.

Cement is also used for other purposes during drilling a well. It may seal off zones that allow mud to leak into the formation. It is used to abandon a well by sealing the wellbore to prevent fluids and gases from migrating to the surface. It is often used to seal off the lower part of the well and allow a new hole to be drilled away from the old wellbore.

Casing and cementing will be described so as to impart an understanding of the importance of the casing and cement, how these things are designed, and how they are placed in the well.

Casing Types

Casing provides different functions during drilling, completing, producing, and abandoning a well. In a deeper well, there may be half a dozen different kinds of casing used to perform the necessary functions at different stages of drilling and completing the well.

Conductor pipe

The first casing is usually called the conductor. It may be driven into the ground with a pile driver or it may be cemented inside a drilled hole. The conductor is not set deep into the ground, so there is no strength to hold formation pressures in the event of a kick. The purposes of the conductor are to accomplish the following:

- Conduct drilling fluid returns back up to the rig during drilling surface hole so that a closed circulation system can be established. A closed circulation system is desirable so that mud returns can be treated, drilled solids removed, and the mud reused. (An open circulating system is where the fluid returns from the well are lost, for instance into the sea.)

- Protect unconsolidated surface formations from being eroded away by the drilling fluid.
- Sometimes to support the weight of the wellhead and BOPs.

Figure 9–2 shows a bottom joint of 30″ OD conductor pipe with a drive shoe on the bottom. This shoe has teeth to help to break up the rock as the conductor is hammered into the ground or seabed.

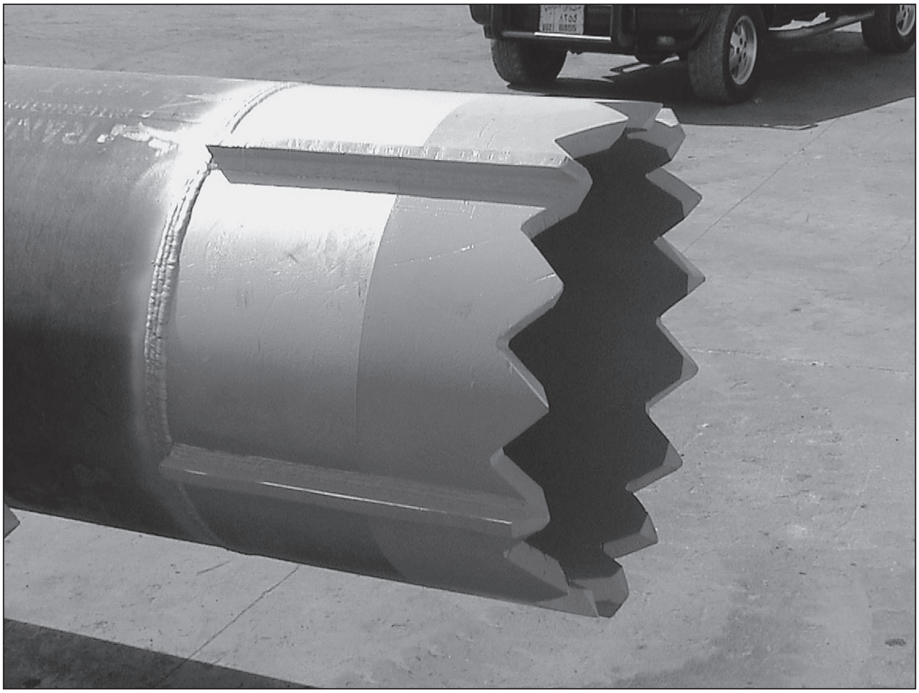


Fig. 9–2. Bottom joint of 30″ diameter casing with the pile drive shoe

Surface casing

The surface casing is the first casing that is set deep enough for the formations at the shoe to withstand pressure from a kicking formation lower down. The purposes of the surface casing are to accomplish the following:

- Allow a BOP to be connected so that the well can be drilled deeper

- Protect freshwater sources close to the surface from pollution by the drilling fluids
- Isolate loose or weak formations that might fall into the wellbore and cause problems

Intermediate casing

A shallow well may not need an intermediate casing; a deep well may need several. The intermediate casings serve as staging posts between the surface casing and the production casing. The primary purposes of the intermediate casings are to accomplish the following:

- Increase the pressure integrity of the well so that it can be safely deepened.
- Protect any directional work done (e.g., kicking off a directional well is often done under surface casing and is then protected by the first intermediate casing).
- Consolidate progress already made.

Intermediate casings are usually between 20″ and 13⅜″ outside diameter.

Production casing

This is the long-term pressure vessel. The production casing houses the completion tubing, through which hydrocarbons will flow from the reservoir to the surface. If the completion tubing were to leak, the production casing must be able to hold the resulting pressure.

Sometimes the production casing is cemented in place with the casing shoe above the reservoir and another hole section drilled. This may then be protected with a liner rather than a string of casing. A liner is effectively a casing that does not extend to the surface but ends somewhere inside the production casing. There are pros and cons to liners.

Advantages of liners include the following:

- **Economics.** The cost of the liner and associated equipment is less than the cost of a full string of casing to the surface.

- **Utility.** The inside diameter of the liner is inevitably less than the ID of the production casing. This allows tools to be run as part of the completion that would be too large to fit inside the liner but that could be set higher up, inside the casing.

Disadvantages to liners include the following:

- **Complexity.** The equipment required to run a liner is much more complex than for a casing, so there is more chance that something will go wrong.
- **Obtaining a good cement job.** Cement volumes tend to be pretty small around liners, so a bit of contamination of the slurry by drilling mud will go a lot further. This was one of the issues with the Deepwater Horizon blowout in the Gulf of Mexico.

If a casing or liner is run through the reservoir and cemented, the casing is perforated using shaped explosive charges (fig. 9–3). These charges create a tunnel through the casing and may continue up to a couple of feet inside the reservoir. If the casing penetrates several hydrocarbon-bearing zones, it would be possible to perforate the lowest zone, flow it until it is depleted, and then cement it off and perforate on a higher zone.

Fig. 9–3. Perforation charges being loaded

Designing the Casing String

When a drilling engineer has to design a set of casings for a well, there are quite a few considerations to be made. First it is necessary to predict all the physical forces that each casing may be subjected to throughout the life of the well (from starting drilling until the well is finally abandoned).

The chemical environment also must be understood; sometimes, corrosive fluids are produced from the reservoir. This will lead to special steel alloys being used, which tend to be expensive and sometimes difficult to handle when running into the hole. When corrosive pore fluids are present in formations penetrated by the well, the outside of the casing can be attacked and corroded. The cement has to form a protective barrier around the casing.

The main casing design considerations are explained in the text that follows.

Tension. Each piece of casing will be in tension from the weight of the casing below it. The tension will therefore increase from the bottom to the top.

Downhole tubulars (casing, tubing, and drillpipe) are specified by weight per foot as well as other attributes. This might seem a strange way to specify a casing, but casing design tables will give, for each casing OD, a choice of weight per foot and also of grade (which is the type of steel alloy used). A common production casing size is 9⅝″ OD, and this comes in weights per foot of 36.0, 40.0, 43.5, 47.0, 53.5, and 58.4. Neglecting buoyancy forces for a moment, the weight of a 10,000 ft string of 9⅝″, 53.5 lb/ft casing would be 535,000 lb, which is over 242 tonnes. A long string of casing can be pretty heavy!

Additional tensile forces are imposed on the casing. In a deviated well where the casing has to bend around, the tensile stress in the outside of the bend is increased (while the tensile stress in the steel on the inside of the bend is decreased). The maximum tension on any element of the casing must be less than the tensile strength of the casing.

Casing is pressure tested after cementing, and this produces a force trying to pull the casing apart—a tensile force. The inside diameter of 9⅝″, 53.5 lb/ft casing is 8.535″, which gives a cross-sectional area of 57.2 in^2. A 3,000 psi pressure test will impose an additional 172,000 lb (78 tonnes) of tensile force on every joint in the casing, in addition to the weight.

The top joint of casing in this case will therefore have to resist 707,000 lb (320 tonnes) of tensile force (again neglecting buoyancy).

Burst. Casings must be able to withstand internal pressure. Internal pressure will come from downhole formation pressures, hydrostatic pressures, and pressure tests.

Collapse. The opposite of internal pressure is where the pressure outside of the casing is higher than the pressure from the fluids inside the casing. It is possible for casing to be squashed flat like a ribbon by external pressure.

Cemented casing is much harder to collapse (takes a much higher pressure) than uncemented casing.

Flowing salt was discussed in chapter 1. Thick salt deposits flow under pressure from the rocks above. Thus salt acts a lot like a hydraulic fluid in these conditions and can impose very high collapse pressures on a string of casing. Two factors then are important when cementing in flowing salts. The casing has to be very strong (thick wall and/or high-strength steel), and the cement around the casing must form a complete sheath. If there are unfilled areas without cement, the salt can flow into that area and place a very high point loading (as opposed to an even loading) on the casing. No casing can resist a high point loading.

Driving forces. Conductor pipes are sometimes driven (hammered in place) by a pile driver into the ground to allow the well to be spudded with a closed circulating system. Conductor is thick-walled pipe (often 1″ or greater wall thickness), so the pipe itself is strong enough to drive. The connections must be selected to be suitable to transmit the heavy shock loads of driving.

Temperature. When a steel casing gets hot, it expands. Where the casing is cemented, this does not cause any problems, but the uncemented pipe between the top of cement and the surface wellhead may buckle as expansion takes place. This can be compensated for by stretching the casing before setting it in the wellhead.

Steel also loses strength as temperature increases. In a deep, hot well, this loss of strength can be significant. At a temperature of 200°C, steel will have lost 19% of its strength. This has to be accounted for when designing casings for high-temperature wells.

Combined axial and internal forces. If a steel tube is in tension, it has an increased resistance to burst and a decreased resistance to collapse. Conversely, if a steel tube is in compression, it has a decreased resistance to burst and an increased resistance to collapse. This is known as the biaxial effect. The industry standard design tables for casing (published by the American Petroleum Institute, API) that give strengths in tension, collapse, and burst also include information on biaxial effects. Generally when designing casing, the increased burst strength due to tension is not allowed for (increasing the safety margin), but decreased collapse resistance due to tension will be accounted for where it is relevant.

Corrosion. When acidic gases such as hydrogen sulfide (H_2S) or carbon dioxide (CO_2) are present with water, steel components can become seriously corroded. This is worse with high temperatures; corrosion rates roughly double for every 32°C increase in temperature. It is also worse with higher pressures and with higher concentrations of corrosive agents. If H_2S, CO_2, and water are all present, corrosion resistance design will require a special study to determine the most cost-effective solution.

Special steels containing nickel or chromium can be used, but these are much more expensive than plain carbon steels. These materials are also softer than carbon steel, and the connections are easily damaged while screwing joints together if they are spun too quickly or if they not exactly aligned while turning.

Hydrogen sulfide is a particular problem for designing casings. Hydrogen can enter the steel crystalline structure and causes hydrogen embrittlement. The steel can break at well below expected failure loads without warning if this has happened. The problem gets worse with higher strength steels and at lower temperatures. Lower temperatures are found at the top of the casing string, where the tensile load is highest. If H_2S is encountered in the well, it is very important that the correct grade of steel is selected so as to avoid hydrogen embrittlement and failure at the exposure temperature of the steel.

Connections. Most failures in casing (around 90%) occur at the connection—the part that screws two joints together. This should not be surprising; an extruded steel pipe is pretty strong, whereas a pipe that has a thread cut on it must have decreased strength against some, if not all, forces (fig. 9–4).

Fig. 9–4. Cutaway casing connection

Particular strain is placed on a connection where the casing is placed in a curved section of wellbore. High tension combined with bending forces and also internal forces place great strength requirements on the connection threads.

Casing and tubing connections might not seal (just contain a thread), or there may be O-ring or elastomer seals incorporated. For gas well service, metal-to-metal seals are normally called for. These work by placing the two metal seal areas in the pin and box in contact just before the connection is fully screwed together. As the joint is torqued up, energy is placed into the seals that causes some elastic deformation and creates a tight seal between the metal faces.

Role of the Cement outside Casing

Casing is cemented in the annulus, either in just the lower part or sometimes in the complete annulus. The cement is designed to meet a variety of needs, including the following:

1. Physically support the weight of the casing.
2. Prevent fluids from migrating upwards inside the cement, or between the cement/formation or casing/cement interfaces.
3. Protect the casing against corrosion.
4. Protect the casing against mobile formations.
5. Allow the production casing to be perforated without the cement shattering under the shock wave.

Mud Removal

One of the most difficult aspects of cementing is to remove all of the drilling fluid from the annulus so that it can be replaced by cement. In an in-gauge hole with well-centralized casing, the chances of achieving full mud removal are good. In an enlarged hole and with the casing not well centralized, the chances are very poor. Great care is needed in designing and executing the job.

Figure 9–5 shows what happens when the casing is not centralized. The cement will preferentially flow to the largest cross-sectional area, leaving mud in the narrow part. The closer the casing is positioned towards the wall, the harder it will be to remove this mud. Several actions can be taken to maximize the chances of full mud removal:

1. Drill a stable, in-gauge hole.
2. Tailor the mud properties before running casing so that the mud is as thin as possible (not viscous).
3. Move the casing (either rotate it or reciprocate it) while pumping cement around. This causes the pipe to move around in the well so that there is not a single area of no flow. Pipe movement is proven to be very beneficial in achieving mud removal.
4. Pump thin (low-viscosity) spacers ahead of the cement. This separates the mud from the cement. The spacers can be tailored to help chemically clean filter cake from the wall and casing, leaving the surfaces water-wet and ready to bond to the cement.
5. Use centralizers to keep the casing in the center of the hole.

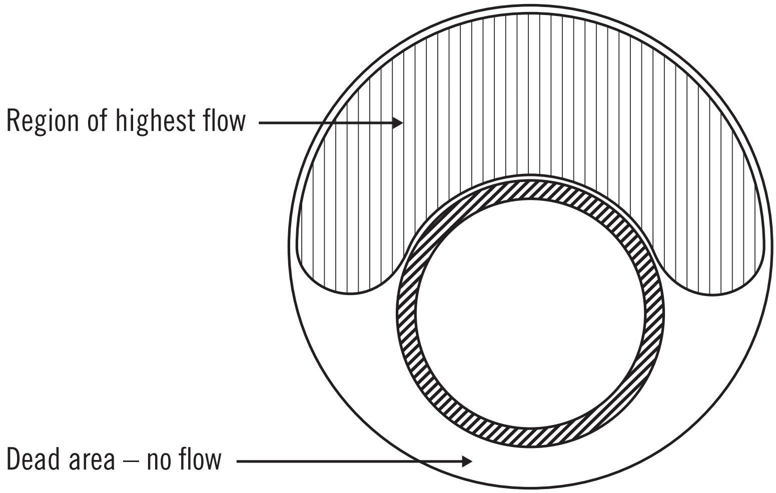


Fig. 9–5. Cement flow around uncentralized casing

It is important that the casing is well centralized, and to ensure this, a tool is fastened to the outside of the casing that pushes the casing off the wall. These tools are called centralizers. A centralizer is made of strips of spring steel, held together at the top and bottom with a steel ring that hinges open so that it can be placed on the pipe (fig. 9–6).

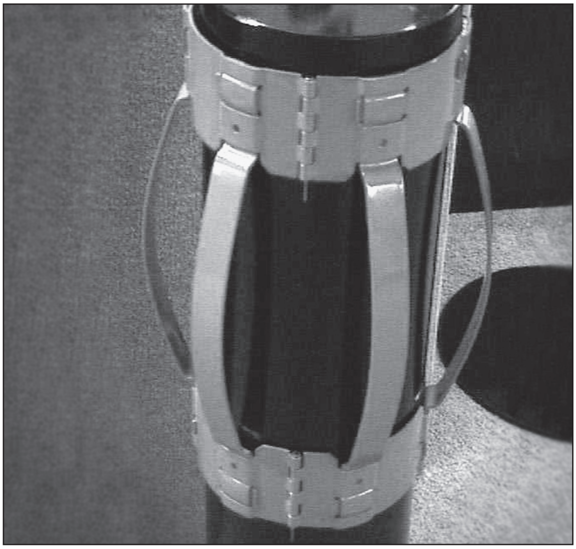


Fig. 9–6. A spring centralizer on casing

Cement

Cementitious material consists of a powder that undergoes chemical reactions when mixed with water. The end result of these reactions is a hard, stonelike material. Cements have been used for centuries (the ancient Egyptians, Greeks, and Romans all used cementitious materials). Modern cement development started with a British patent granted to Joseph Aspdin in 1824, which defined the process used to manufacture cement for building a lighthouse. This cement was called Portland cement because when hard, it looked like stone from the Isle of Portland, used for building.

Portland cement has four principal components: tricalcium silicate (C_3S; about 70%), dicalcium silicate (C_2S; not more than 20%), tricalcium aluminate (C_3A), and tetracalcium aluminoferrite (C_4AF). These chemical compounds are created by mixing raw materials together and firing in a kiln at high temperatures (up to 1,500°C).

The raw materials are lime, silica, alumina, and iron oxide. Before firing, they are finely ground up and mixed in the correct proportions. After firing, the raw materials have been converted to a material called clinker. After cooling, some gypsum ($CaSO_4 \cdot 2H_2O$) is added (3%–5%), and the mixture is crushed to a powder. This powder is Portland cement.

The chemistry of setting cement is quite complex, and several stages can be identified. However, in general terms, when water is added, the components form hydrated compounds. Crystals are formed that grow and become interlinked. Also in the early stages, materials are dissolved in the water and later on are precipitated as solids. Some water is left trapped in the spaces between the crystals. Cement is porous but should be impermeable because the passages connecting the pores are sufficiently small that movement of water is stopped.

The reaction of hydrating Portland cement is exothermic—it generates heat. This can be a problem in arctic areas when drilling through the permafrost. Special cements are then used that do not freeze and that have a low heat of reaction, while developing sufficient compressive strength to meet the requirements of the set cement.

The American Petroleum Institute established standard specifications for oil well cements. This defined eight different cements, which were classified according to the depths and temperatures at which they could be used. These classes were designated A through H. The specifications state the chemical and physical attributes of the cement. Over time, one class has proven to be the most useful when its properties are chemically modified during mixing. This is API class G cement. It is universally available around the world, and there is a vast amount of experience in using it.

An amount of class G cement powder will require a certain volume of water to hydrate it and make it pumpable. To completely hydrate the cement, 22% water by weight of cement (BWOC) is needed, but this would not make a pumpable slurry. To achieve a pumpable slurry, 44% water BWOC is used, and the "extra" 22% water is held within the set cement matrix. Excess water (above 44% BWOC) will be left as free water after the slurry sets. The point at which the correct amount of water is used to make a pumpable slurry with no free water is known as neat cement.

For API class G cement, the water requirement is 4.96 US gallons for each 94 lb sack, and the resulting slurry weight is 15.8 pounds per gallon (ppg). Free water for normal slurries should be no more than 0.5% of the slurry volume, with 0% for a slurry designed for high-angle or horizontal wells.

Cement Design

Density

Neat class G cement can be modified to suit particular requirements of the well. The most important slurry property is density. As noted above, neat cement slurry weighs 15.8 ppg, which equals a density gradient of 0.822 psi/ft. Normally, casings are cemented with two different slurry densities—a light "lead" slurry and a neat "tail" slurry. This is done for two main reasons:

1. **Hydrostatic pressure.** A long column of neat cement slurry might cause formations downhole to break down due to the high pressure.
2. **Cost.** The light slurry does not require as much cement powder and additives and so is cheaper.

As noted in figure 9–7, if more water than 44% BWOC is used, free water will be left when the slurry sets. Free water must be minimized because this can form channels through the cement that will later on allow fluids to flow. Cement is made lighter (lighter cement is called extended cement) by adding more water. To soak up the excess water, clay is added in sufficient quantity that free water is not left after setting. The clay used is bentonite, and when it is used to lighten a slurry, it is called an extender. Standard cement design tables give the quantities of cement, water, and bentonite needed to mix a slurry of various densities. For instance, to mix 1 (US) gal of slurry using API class G cement, the following mix is required at different weights and is displayed in table 9–1.

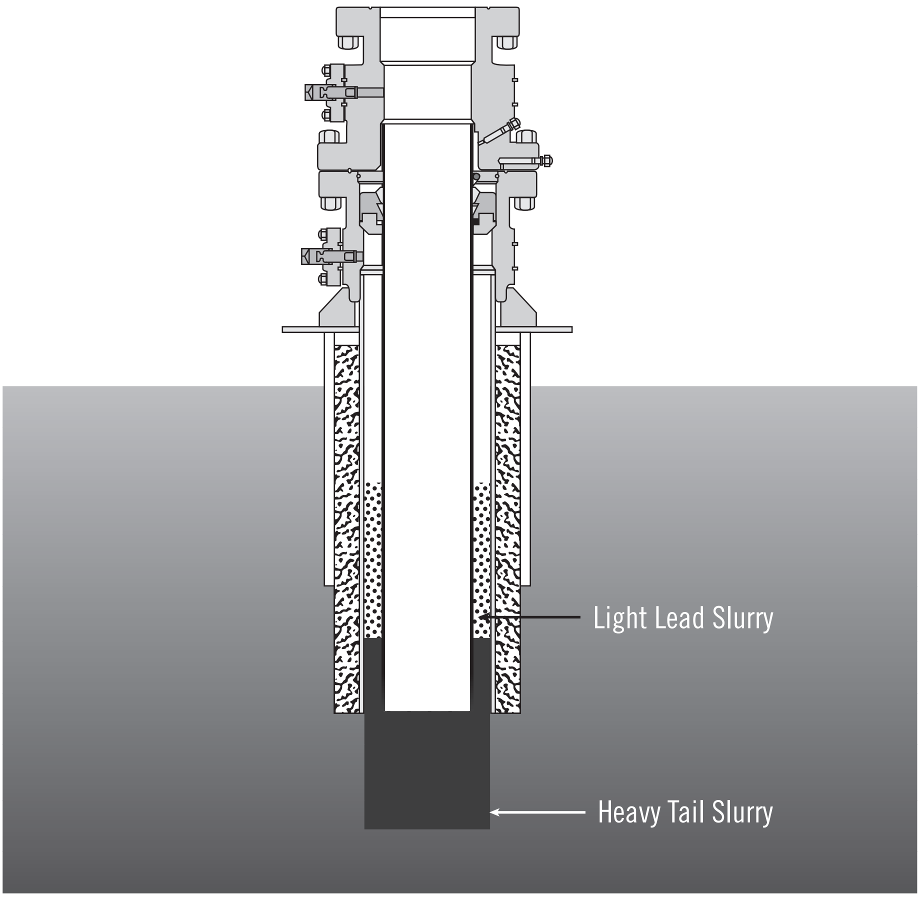


Fig. 9–7. Lead and tail slurry

Table 9–1. The API class G cement mixtures by weight

Slurry weight	Cement required	Water required	Bentonite required
14.2 ppg	8.2 lb	0.66 (US) gal	0.33 lb
13.2 ppg	6.7 lb	0.73 (US) gal	0.54 lb
12.6 ppg	5.6 lb	0.76 (US) gal	0.67 lb

Other materials may also be used as extenders. Hollow glass or ceramic microspheres can be added to neat cement, as can materials with low specific gravity, such as powdered coal or crushed volcanic glass. Cement can also be made into a foam by mixing with nitrogen, which can give very light slurries for weak zones that cannot handle much hydrostatic pressure. Slurries down to 7 ppg (0.364 psi/ft) can be created using foam. This cement would float in water when set.

It may also be necessary to mix up very heavy slurries that are denser than neat cement. In this case, heavy materials such as barite or hematite are added to the slurry.

The lower limit of cement slurry density is dictated by the requirement to always maintain a hydrostatic overbalance on pore fluid pressures while pumping cement around and into place. The upper limit is dictated by the strengths of downhole formations.

Thickening time

The thickening time and compressive strength buildup is dependant on well temperature. Higher temperature gives faster setting and faster strength buildup. The slurry must have sufficient pumpable time to complete the job, with a safety margin in case of problems. Also the thickening time should not be so long that rig operations are unnecessarily delayed while waiting for cement to set. The thickening time is determined in the laboratory using samples of cement, chemicals, and mix water sent in from the rig.

Accelerators or retarders (chemical additives) can be used to lessen or lengthen the pumpable time and will similarly affect the rate of compressive strength buildup.

Compressive strength

To perform the various functions, cement is designed to provide a high compressive strength. A sample of the cement slurry is made up and placed into a 2″ cubic mold. Once the cement is set, this cube is taken out of the mold and placed into a hydraulic press, where it is squashed until it breaks (fig. 9–8). The pressure required to break this cube is measured.

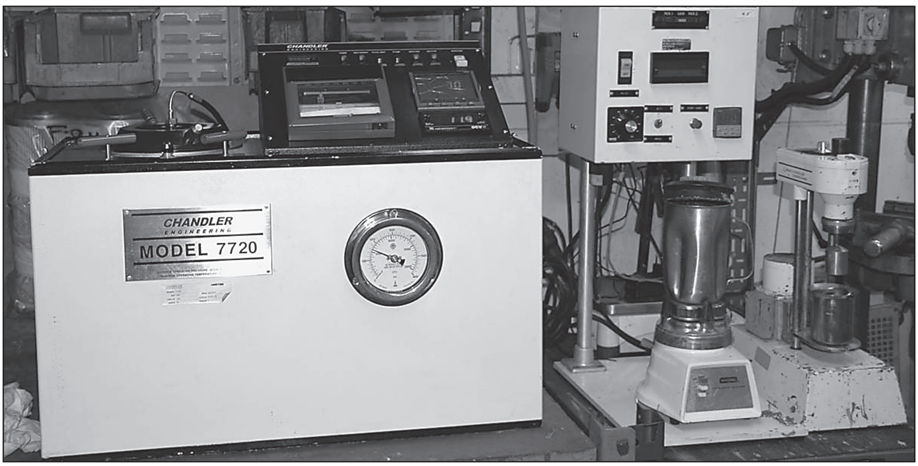


Fig. 9–8. Cement testing lab equipment

A good compressive strength to support the casing is considered to be 500 psi; 2,000 psi is considered the minimum for cement that will be perforated.

Temperature rating

Under static (nonpumping) conditions, the well will have a temperature gradient as the formations get hotter with depth. Normal temperature gradient in sedimentary basins is about 1.4°C per 100 ft of vertical depth. Circulating will decrease the local temperature around the wellbore. Thus at any particular depth, two working temperatures will be relevant to cementing operations: circulating and static.

A temperature log run on wireline some hours after finishing circulating will give the static temperature at the bottom of the well (BHST). The circulating temperature at depth (BHCT) can be calculated by reference to API Specification 10, which contains temperature tables. It is also possible to measure this temperature directly during circulating with logging while drilling tools in the BHA. Of these two temperatures, BHST is relevant to investigating cement stability and compressive strength development with time. Bottomhole circulating temperature is used when calculating pumpable time.

As a rule of thumb, the static temperature at the depth of top of cement should not be less than BHCT used in slurry design. If it is significantly less, it may take an unacceptable length of time to cure. In this case, extra testing should be done at the actual TOC static temperature to see if the cement characteristics are still acceptable.

For deep, hot wells (BHST > 110°C [230°F]), the long-term stability of Portland cement requires the addition of silica flour, usually 35% BWOC. If silica flour is not added, the strength of the set cement will slowly decrease with time.

Rheology

Rheology was covered in some depth in chapter 7 when discussing drilling fluids. The cement slurry rheology is very important because this will affect downhole pressures while pumping cement around the casing and up the annulus. It will also affect mud displacement, mixability, pumpability, and free fall of the slurry down the casing. (When cement slurry is pumped into the casing, the total hydrostatic pressure of the fluids inside the casing is greater than the fluid in the annulus because cement slurry is denser than mud. This leads to a condition whereby the cement will continue to fall down the casing, even if pumping is stopped. With a large cement job, it is possible for this U-tubing effect to cause the cement to fall faster than the pumps can fill the casing behind it, causing a partial vacuum inside the casing. This condition is called free fall.)

Cement slurry rheology is very complex and depends on many factors, such as the following:

- Ratio of solids (cement powder, bentonite, etc.) to water.
- Sizes and shapes of the solids present in the slurry.
- How much energy was used to mix the slurry (affects the distribution of particles and the speed of chemical reactions).
- Flow regime (laminar, turbulent, transitional).
- Time—the cement rheology continuously changes as chemical reactions take place.
- Temperature and pressure—the rheology changes as the cement moves down the well.

Even though tremendous efforts have been made by the industry to completely characterize and explain cement slurry rheology, this work is not yet complete. As with mud rheology, the best model currently available to describe most cement slurry rheologies in the field is the Herschel-Bulkley model.

Chemical additives

All characteristics of the cement can be modified by adding chemicals to the slurry. Some of these additives have already been mentioned, such as bentonite or powdered coal as extenders, barite as a weighting additive, retarders (to slow down the setting speed of the slurry), and accelerators (to make the slurry set faster). Other additives available include the following:

- **Defoamers.** Prevents the slurry from foaming while mixing.
- **Dispersants.** Help to distribute the solid particles present in the slurry.
- **Fluid loss.** Controls loss of filtrate into permeable formations.
- **Lost circulation material.** Inert solid materials to plug off pore spaces at the formation face so as to prevent the loss of whole slurry to the formation.

The use of additives allows one cement type (API class G) to be used for many different wells and in different applications.

Cementing casing in massive salt formations

When cementing in massive salts, the cement forms an essential part of the casing string integrity. Inadequate cement here will make shearing, distortion, or failure of the casing possible as the salt moves. The potential failure modes include the following:

1. Point loading of the casing due to uneven salt closure. The casing can collapse with much less force than would be the case for even loading.
2. Collapse due to overburden pressure being transmitted horizontally by mobile salt.
3. Shearing of the casing due to directional salt flow.
4. Corrosion of the casing, particularly if magnesium salts are present.
5. Long-term degradation of the cement sheath by ionic diffusion into the cement, if the cement is not salt saturated. If the cement sheath degrades, uneven loading may occur, leading to eventual collapse.

The contributing factors to these failures include the following:

- Salt creep may cause hole closure. This occurs faster in bigger holes and is proportional to hole diameter; a 16″ hole will reduce in diameter twice as fast as an 8″ hole.
- Lowered hydrostatic pressures will increase the rate of creep.
- Salt flow may occur due to directional field stresses.
- Leaching (dissolving) of the salt by mud and cement may lead to overgauge hole and slurry chemistry alteration.
- Ionic diffusion of salts into a nonsaturated slurry may occur after setting. Magnesium is particularly detrimental.

The essential objectives are to cement throughout the whole salt body interval to ensure that good cement completely fills the annulus and to prevent long-term degradation due to ion diffusion. There are several things that can be specified in the drilling program to maximize the chance of success.

- **Use a salt-saturated slurry.** If the slurry is unsaturated at downhole temperature, substantial quantities of salt can be leached out by the slurry. This will give an overgauge hole and will significantly affect thickening time, rheology, and compressive strength. Supersaturating a slurry may involve heating the mix water to dissolve more salt. At these saturations, special additives (especially dispersants and fluid loss) are needed.
- **Use a saturated KCl slurry.** Saturated KCl slurries give higher compressive strengths faster than saturated NaCl slurries. Setting time is important (see the next point).
- **Be aware of potential problems with other formations.** Salt-saturated slurries can cause problems against other formations. If exposed long-term to unsaturated formation water, osmotic forces will leach salt out of the cement slurry, which can lead to cement failure. This may or may not be a problem, depending on what formations are exposed where.
- **Use fast setting times.** Once cement starts to set, it holds hydrostatic pressure from above. This reduces pressure on the salt. As pressure is lost, salt creep rate will increase substantially. With long setting times, the salt could creep in enough to touch the casing. As salt does not creep uniformly, the resulting point loading on the casing will quickly collapse or deform it. Even the strongest casing cannot resist such point loadings.
- **Use suitable drilling fluids to minimize leaching out the salt.** Large washouts will lead to the normal problems of mud removal, and this will lead to an incomplete cement sheath. However, using oil- or salt-saturated water muds can give problems, as the hole will close in while drilling.
- **Increase mud densities.** Increased mud density will reduce the rate of creep.

Low-salt slurries have been used successfully in the Gulf of Mexico and other areas. These aim to give fast development of high compressive strengths. These slurries will avoid problems against other formations due to osmosis as mentioned above. However, washouts are still likely, and long-term ion diffusion may be a problem later.

Clearly, cementing against massive salts is a complex problem if the well is to meet its long-term objectives. The success of this cement job starts when drilling through the salt (minimizing leached washouts). Good planning, expert involvement, and attention to every detail, including slurry and spacer design, rig equipment, downhole casing configuration, and cement job supervision and quality control, are vital.

Running and Cementing Casing

After drilling and logging a hole section, casing is lowered into the well. It is cemented in place by pumping cement down the inside, where it exits at the bottom of the casing and comes back up the annulus.

Casing usually comes in lengths of around 40 ft. A special valve called a float shoe is screwed on the bottom joint of the casing. This is made of cement with a plastic valve in the middle, so that it is all drillable with normal drill bits (fig. 9–9). The valve allows fluids to be pumped down through it but does not allow fluids to flow the other way. This keeps the cement slurry in place once pumping stops. Without the float valve, the higher hydrostatic pressure in the annulus would force cement to come back up inside the casing once pressure is released at the surface after cementing. Pressure in the annulus is higher because cement slurry in the annulus is denser than the mud inside the casing.

Fig. 9–9. A float shoe screwed onto 30″ casing

Usually two joints of casing are run above the float shoe. Then another float valve is screwed in place, called a float collar. One purpose of this is that if the valve in the float shoe fails, there is a backup valve in place to stop cement flowing back into the casing. This will happen otherwise, as the cement slurry in the annulus is heavier than the mud inside the casing.

With the float shoe and float collar made up, more joints of casing are screwed on top of the string and lowered into the well. Centralizers are attached as needed due to the hole deviation and condition. Once the casing is all in the well, a hanger can be made up that is used to suspend the casing inside the wellhead. This was explained in chapter 3.

With the casing landed in the wellhead, the next step is to prepare for cementing. A special container is screwed on top of the casing that holds two plugs with rubber fins that fit inside the casing (fig. 9–10).

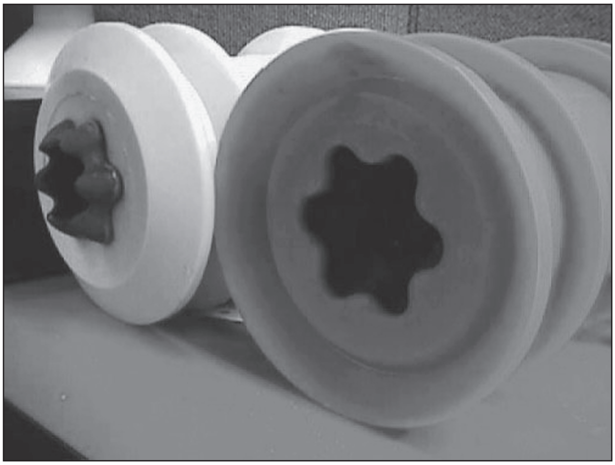


Fig. 9–10. Top and bottom plugs

The bottom plug is hollow, and it has a thin rubber diaphragm at the top. When ready to start pumping cement, the lower releasing pin is drawn out, and cement is directed to the inlet pipe between the two plugs. (The wheels on the cement plug container shown in fig. 9–11 operate the releasing pins.) The bottom plug travels ahead of the cement, separating it from the mud below to minimize contamination of the cement with mud. The fins on the bottom plug, as well as sealing against the inside of the casing, wipe the thin film of mud off the inside of the casing, again to reduce contamination.

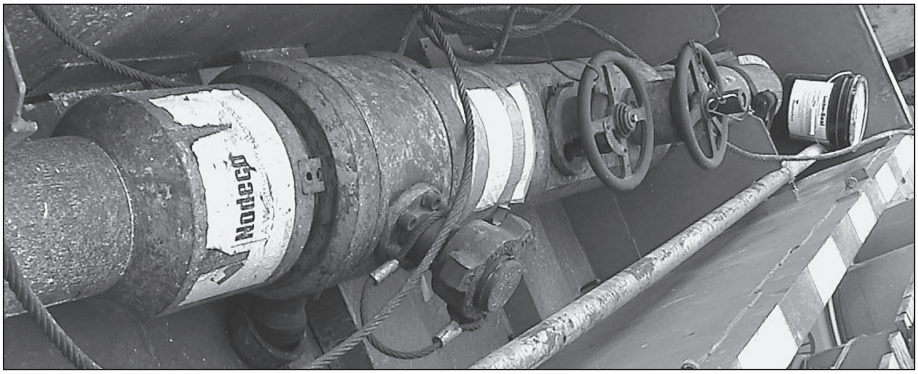


Fig. 9–11. Cement plug container in a shipping basket

Once the correct volume of cement is pumped, the upper releasing pin is withdrawn, and mud is pumped into the upper inlet. Now there is a column of cement moving down the casing, with the bottom plug below and the top plug above.

Eventually the bottom plug hits the float collar. It can move no further down. At this point the rubber membrane ruptures to allow cement to flow through the plug. Cement now flows out of the float shoe and up around the casing.

The pumps are slowed down as the top plug approaches the float collar. Once the top plug lands on top of the bottom plug, it forms a seal. The surface pumping pressure increases, and this shows that the displacement is complete.

Figure 9–12 shows a section of casing cut away to show the float collar valve, with bottom and top plugs in the position they will be in after completing cement displacement.

Normally at this stage, the casing is pressure tested. If for some reason the top plug did not land on the float collar after pumping the correct volume, pumping is stopped, and the casing will have to be pressure tested once the cement has set (fig. 9–12). This involves a small risk of breaking the bond between casing and cement; the casing will expand a little under the test pressure, and when pressure is removed, it will contract again. The cement is not elastic like steel, and instead of moving back with the casing, it is possible that the bond will break. This creates a very small annulus between casing and cement—a microannulus.

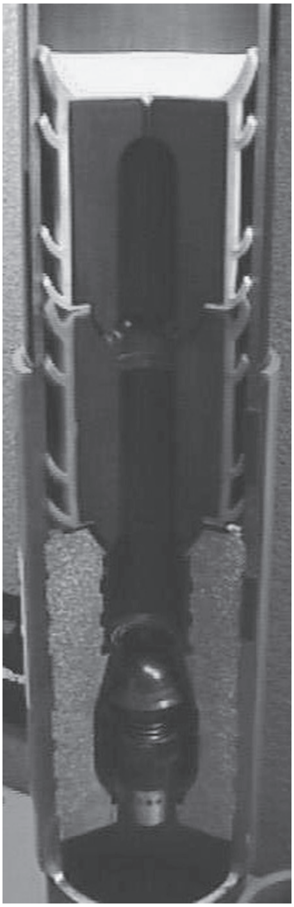


Fig. 9–12. Plugs landed

Cementing Surface Casings

Surface casing is large diameter, so that several more strings of casing can fit inside it and still have a big enough hole through the reservoir to be able to log it and produce from it. Large diameter casing is difficult to handle and to run, especially in any significant wind, unless automated handling equipment is used on the rig. A 40 ft joint of pipe, 20″ in diameter and weighing around 4,000 lb, will be tricky enough to manipulate even in good weather conditions. If the top of the casing is slightly off center, the casing connection thread is likely to become cross-threaded, where the threads on the male end (bottom of the joint of casing) do not quite line up with the threads on the female end (top of the previous joint). The connection can be rotated but the threads become damaged and will not fully make up, so it has to be unscrewed again. The threads may be so badly damaged that both of the casing joints have to be taken off again and replaced. It is not an easy job to run big casings!

Large surface casings do not use the cement plug system. One reason for this is that a large surface hole can become highly enlarged, and it is uncertain how big it really is. These casings are normally cemented all the way up to the surface or seabed. If top and bottom cement plugs are used, the volume of cement has to be known in advance, but for a surface casing, this is not known. The solution is to pump cement until cement returns are seen back at the surface, and then mud can be pumped behind to complete the job. The technique is called stinger cementing and is shown in figure 9–13.

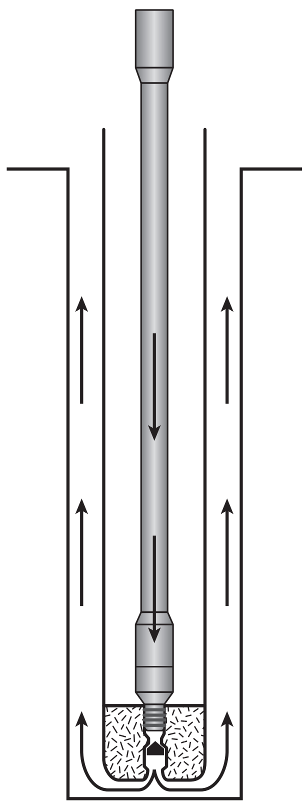


Fig. 9–13. Stinger cement job

The casing is run with a special float shoe on the bottom, called a stab-in float shoe. At the top of the float shoe is a standard-sized (4″ diameter) hole, about 8″ deep. This has a smooth inside.

When the casing shoe is at the correct depth, the top of the casing is held in the rotary table. The rotary table suspends the weight of the casing. Then drillpipe is run inside the casing, with a special seal assembly attached to the bottom of the drillpipe. This stab-in sub locates in a hole on the top of the stab-in float shoe (it “stabs in”) (fig. 9–14), so that a seal is formed between the drillpipe and the casing shoe. Now, mud and cement can be pumped down the drillpipe, out of the float shoe, and up the annulus.

Fig. 9–14. Stab-in sub

With a drillpipe stinger, cement can be pumped down the stinger and up the annulus until cement is seen coming out of the annulus at the surface. Once cement returns are seen at the surface, mud is pumped to push the small volume of cement left in the stinger to the float shoe.

If cement was pumped down the casing without a stinger, at the point that cement starts coming out of the annulus there would still be a huge volume of cement still inside the casing. This cement has to be removed from the inside of the casing by pumping down mud behind it. As a result, a lot of cement is wasted (with surface disposal problems for the large volume of cement). Furthermore, if there is a problem with the cement, it might set up inside the casing and have to be drilled out. This would take a long time and would also be very embarrassing!

Once the cement is displaced into the annulus and the drillpipe stinger is full of mud, the drillpipe can be pulled out of the hole.

Cement Evaluation behind Casing

It is possible to run wireline logs to evaluate the condition of the cement behind the casing. This is done by sending out sound waves from a wireline tool and listening for the returning sound wave a short distance away. As the sound travels up the cement, the frequency and amplitude are affected by the quality of the cement and of the cement casing and cement formation bonds.

A basic cement evaluation log will give an indication of the bonds but not much else. More sophisticated tools can detect the presence of a microannulus, channels in the cement, gas bubbles in the cement, and much more. But of course these tools cost a lot more to use.

Most cement jobs are logged, even if only with the basic tools. In critical cases, especially where problems are suspected, a better analysis of the actual problem is required before any remedial work can be considered.

Other Cement Jobs

Secondary cementing

Cement is pretty versatile stuff, thanks to additives, and this gives many possibilities for using cement to solve a variety of problems. If in a critical cement job a channel is detected in the cement behind the casing, it may be possible to perforate the casing and force cement into the channel under pressure. Repairing a bad primary cement job (primary refers to the first time that the casing was cemented) is called secondary cementing. Unfortunately, secondary cementing is quite tricky and has a low success rate.

The general procedure is that holes are made in the casing using a perforating gun. Drillpipe is run in the hole down to the depth of the perforations. Cement is pumped down the drillstring, where it exits around the perforations. Pressure is then applied to try to force cement to enter the perforations. With a little luck, the cement might plug the channel and the perforations. Forcing cement in under pressure is called squeeze cementing.

A better chance of success comes if the top of cement is just too low, and it is then possible to perforate above the top of cement. Circulation can be established, hopefully, by opening the annulus outside the casing and pumping fluid into the casing. If circulation is possible, cement can be placed by circulation rather than squeezing. It is also possible that bits of formation (cuttings and cavings) have settled around the casing, and this can prevent circulation.

This technique is also used when wells have to be finally abandoned, if for any reason (such as government regulations) some or all of the annuli are required to be filled with cement.

Curing lost circulation

Lost circulation can occur from a variety of causes. This will be discussed in more detail in chapter 13.

If serious lost circulation occurs, cement can be used to cure it. The difficulty is in getting the cement in the right place and keeping it there while it sets.

Cement plugs

A cement plug is a column of cement that is set at some point in the well. Cement plugs serve a variety of purposes.

During well abandonment, cement plugs are set at various points inside the casing to prevent downhole fluids from reaching the surface in the future. Cement plugs are also used to suspend a well (temporarily abandon it), for instance if the well will be completed later on by another rig. In this case, the well will be reentered and the cement plugs drilled out before continuing with completion operations.

If for some reason the lower part of the well is to be redrilled along a separate path, a cement plug may be used both to abandon the lowest section of the original wellbore and to allow the drill bit to depart from the original bore and drill a new one. The main criterion for this kickoff cement plug is that the set cement must have a higher compressive strength than the surrounding rock, or else the bit will drill back along the original hole.

Sometimes, formations exposed in the wellbore can be very unstable. They may be fractured (either naturally or as a result of the drilling operation), or they may react with the drilling fluid in some way. This results in material becoming detached from the wellbore wall and falling into the well. The hole enlarges. This might be cured by setting cement across it to fill the enlarged hole and isolate the troublesome formation; the cement is then drilled through to form a cement-lined hole.

Cement plugs are set by running tubing into the well and pumping cement down the tubing and into the well. The tubing is then withdrawn, leaving behind a column of cement. Setting a successful cement plug the first time is more difficult than achieving a good cement job outside the casing. The annular capacity is larger (because tubing or drillpipe is smaller than casing), so annular velocities are lower. Thus complete removal of the mud is harder to achieve. The slurry must be designed so that once in place, it does not move as the tubing is removed or afterwards while it is still fluid. Contamination of the cement by mud in the well is a real problem, which can be solved by using a special tool on the bottom of the tubing to direct the flow of cement outwards and upwards, instead of straight down as would occur with just plain-ended tubing. Cement plugs require good planning and careful execution to meet the objectives without having to be repeated.

Summary

In this chapter, the major elements of casing design were discussed. The criteria by which a casing design is judged is whether it meets the requirements of the well design at the lowest cost. Casing costs generally account for about 10% of the total cost of the well, so it is a major element in well design.

Cementing of casings was described, with the two techniques (plug cementing and stinger cementing) being covered. The most important cement design parameters were mentioned.

Cement plugs for various purposes were briefly described.

It can be seen that good casing and cement design and execution are critical to the safe and cost-effective drilling and producing of oil and gas wells. Time (and therefore money) spent on design in these areas is never wasted. Engineers involved in well design should receive training to keep them abreast of the latest developments and should have access to the best design tools available (such as computer programs, reference information, and expert advice for difficult cases). They should also have the time to complete a thorough review and design job. Unfortunately, in many cases, not all of these elements are present.

10

EVALUATION

Overview

The term *evaluation* covers several different techniques that together allow different disciplines within the team (drilling, geology, production, reservoir engineers, etc.) to understand the subsurface conditions. Typical information obtained will describe lithology, pore fluids present, wellbore condition, rock structures (bedding planes and faults), and detailed reservoir characteristics (static and flowing).

This chapter will describe the different types of technique available and the type and quality of information possible from each.

Evaluation Techniques

The techniques available can be divided into the following major categories:

1. Physical sampling at the surface (examining drilled cuttings and returned drilling fluids)
2. Physical sampling down hole (taking cores of rock or samples of fluids and recovering them to the surface)
3. Electrical logging (using downhole instruments to measure physical attributes of the formations, casing, and cement)
4. Production testing (flowing hydrocarbons from the reservoir while measuring pressure)

Physical Sampling at the Surface

In the early days of drilling, the main source of information on the formations being drilled through came from examining the drilled cuttings returned to the surface (fig. 10–1). The depth that the sample came from can be estimated (but not known precisely) by recording the time that the sample appeared at the surface and by knowing the time taken to circulate a cutting from the bottom. Subtracting the transit time from the time on the surface then allows the wellsite geologist to work out the bit depth at the time that the cutting was generated and so gain an idea of the depth from which the sample came.

Fig. 10–1. Drilled cuttings at the shale shakers

A solid particle will fall through the drilling fluid in the annulus at a speed that depends on its size, shape, and density relative to the fluid and the viscosity of the fluid. This downward speed is called the *slip velocity.* During circulation, the upward speed of the fluid in the annulus is called the *annular velocity*. The net speed at which a particle will move up the annulus is calculated by subtracting slip velocity from annular velocity. As drilled cuttings from one formation are generated in a variety of sizes and shapes, it follows that their slip velocities will differ too. Samples from one specific depth will arrive at the surface over a period of time and not all at the same time. For this reason, the actual depth of a particular sample is unlikely to be precisely known.

Another source of inaccuracy in sample depth determination is that some cuttings may settle at the side of the hole (in a deviated well) or in an enlarged section of the hole. Later on, pipe movement or an increase in pump speed might disturb these beds of cuttings and allow them to continue upwards. In this case, samples from much higher in the well might suddenly appear at the surface, mixed in with the newer (deeper) cuttings. There is plenty of scope for confusion!

When the bit drills from one formation into a distinctly different formation, there will almost always be a detectable change of rate of penetration or drilling torque if the WOB and RPM are kept the same. The depth at which this ROP or torque change takes place is used to adjust the sample depths for greater accuracy. For instance, if drilling from shale into salt, there will usually be a sudden increase in the rate of penetration. The first samples of salt arriving at the surface should have come from the very top of the salt formation, though mixed in with this sample will be particles of shale still returning up the annulus. The depth of this first salt sample can be assumed to be the depth where the ROP increase was noted.

Drilling mud circulated around the well can also provide valuable information. Pore fluids or gas will enter the mud, even if a kick has not occurred, simply because pore fluids will be released from the drilled cuttings coming up the annulus. This might then cause a detectable change in mud chemistry, for instance by increasing the salinity of the mud. Oil could be easily visible, as shown in figure 10–2.

Just a few types of rocks and minerals make up most of the Earth's crust. All of these are readily identified by simple tests. It is important for the geologist to identify these rocks and minerals in the field without elaborate equipment. Minerals generally occur as small grains making up the rocks. The main attributes that the geologist uses to identify a rock are described next.

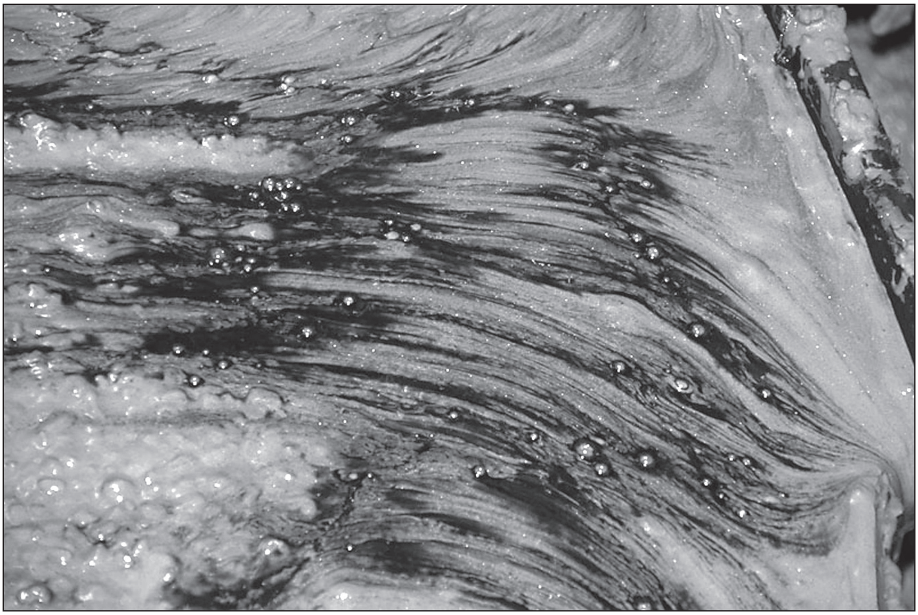


Fig. 10–2. Oil on mud returning from the well

Color. Color is the first property that may be noticed in minerals. Some transparent minerals are shaded different colors by slight impurities such as iron or titanium. Certain types of quartz are good examples of this.

Luster. Luster is the appearance of light reflected from the surface of a mineral. Two typical lusters are metallic and nonmetallic. Nonmetallic lusters have self-descriptive names such as greasy, glassy, silky, and earthy.

Transparency/translucency. A few minerals are transparent in thin sheets, while others are *translucent* (they transmit light but not an image). The majority are *opaque* (do not transmit light).

Crystals shapes and form. The form that a mineral crystal takes can also be diagnostic. Some minerals have characteristic crystals, for example cubes or pyramids, whereas other minerals have no crystal form.

Cleavage. The tendency for some minerals to break along planar surfaces is called *cleavage*. Three aspects of mineral cleavage are the following:

- The number of cleavage surfaces of different directions
- The quality of the surfaces, e.g., poor, excellent, or pitted

- The angle between the surfaces

Hardness. The hardness of a mineral is quantified by Mohs scale, which ranges from 1 to 10. A mineral that is higher on the scale can scratch a mineral that is lower on the scale. The Mohs scale is in order of increasing hardness:

1. Talc
2. Gypsum
3. Calcite
4. Fluorite
5. Apatite
6. Orthoclase
7. Quartz
8. Topaz
9. Corundum
10. Diamond

Saltiness. Tasting can sometimes identify a mineral. (Not recommended with oil-based mud!)

Acid test. A very important test is the application of cold dilute hydrochloric acid to a sample. Calcite and the sedimentary rock limestone made up of predominantly calcite ($CaCO_3$) grains are the only ones that will bubble with dilute acid. Dolomite bubbles slightly, and increased bubbling will be noted if heat is applied.

Swelling properties. Reaction of clays (hydration) to water or dilute acid.

Sorting. Distribution and estimation of grain size.

Roundness. Describes a variety of shapes from very angular to well rounded.

Sphericity. Describes shape from very elongated to very spherical; high sphericity is spherical, and low sphericity is elongated.

Cementation. The degree of cementation and the mineral type. May be well cemented, good cementation, or poor cementation.

Specific gravity (weight). Specific gravity is the relative weight of a mineral compared to the weight of an equal volume of pure water. The average specific gravity (SG) of a rock or mineral would be about 2.5. Metallic ore minerals generally have specific gravities above 3.5. Minerals can be readily recognized from their SG.

Fractures. Some rocks are naturally fractured. Often these fractures will fill up with minerals and can be seen as veins of a different color within the rock.

Fluorescence. Crude oils will fluoresce under ultraviolet light (that is, they will glow, giving off light of a different wavelength than the source light). If a cutting from an oil-bearing formation is exposed to a UV lamp, the fluorescent properties can identify the type of oil present. Different colors of fluorescence indicate different grades of oil. Moving from low to high API gravity, colors seen will be brown (below 15°API), orange, yellow, white, blue-white, and violet (45°API). (The density of an oil is expressed in degrees API. API gravity of 10° is equal to freshwater density [specific gravity of 1]. An API gravity of 45° is equal to a specific gravity of 0.801. The higher the API gravity, the lower the SG, and the more valuable the oil. This is because a lighter oil contains more light hydrocarbon elements, which require less refining to produce petroleum.)

On modern drilling operations, specialist contractors are used to monitor and analyze surface data and samples. This activity is called mud logging.

Mud logging

Mud logging involves taking measurements and samples during drilling. This usually includes the following:

1. Taking samples of cuttings, mud, and formation fluid shows and analyzing them. (A *show* is an indication of hydrocarbons down hole, usually seen by examining drilled cuttings for fluorescence.)
2. Logging and recording all important drilling parameters.
3. Detecting and warning of the presence of problems such as kicks, H_2S, and washouts.
4. Producing analyses and reports.
5. Recording quantities and descriptions of cavings.

A fully computerized unit with readout screens in the drilling supervisor's office is now the norm. It is also possible to transmit this information in real time to the office, where further analysis can be done. With experienced engineers providing round-the-clock cover while drilling, warnings can be provided to the drillers of impending problems (such as pore pressure increases or wellbore instability).

The unit computers record a range of parameters relative to time and depth, and at the end of the well, these are handed over electronically to the operator. Typical recordings will be made of the following:

- Depth in feet or meter intervals
- Drilling rate, both minutes per foot (meter) and feet (meters) per hour
- Weight on bit
- Rotary speed
- Rotary torque
- Pump output
- Pump pressure
- Mud density being pumped into the well and returning from the annulus
- Mud temperature in and out
- Levels of gas dissolved or present in the mud returning from the annulus.

If problems are encountered (such as stuck pipe or a break in the drillstring), this recorded data is very useful in helping to determine the root causes of the problem. Only by knowing the root causes can a strategy be developed to solve the problem and avoid a future recurrence.

Physical Sampling Down Hole

Coring is the act of retrieving a whole sample of the downhole formations for analysis at the surface. Several classifications of coring can be made, such as the following:

- Bottomhole coring

- Explosive sidewall coring
- Rotary sidewall coring

Each of these is described in more detail.

Bottomhole coring

A special drill bit (usually a PDC type but can be diamond) with a hole in the center cuts a doughnut-shaped hole. The column of rock sticking up inside the core bit is protected by an arrangement of tubes. When coring is complete, the coring assembly is pulled out to the surface, and the core itself is held within. This is the most expensive type of coring but gives the most useful sample for analysis (fig. 10–3).

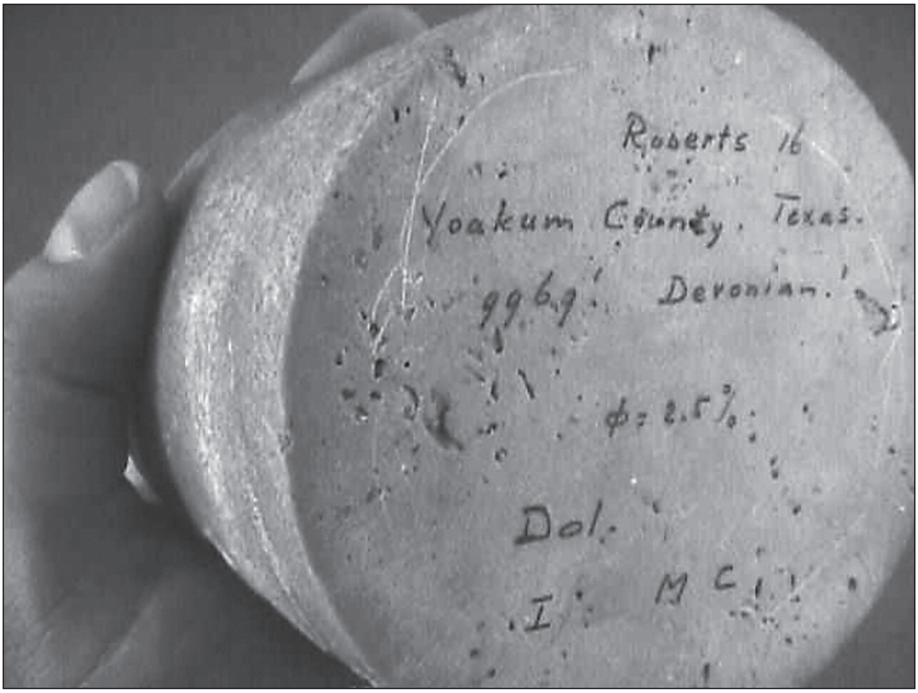


Fig. 10–3. Bottomhole core sample

There are many different bottomhole coring systems available. Choosing between them will depend on the formation being cored (whether complete and well consolidated, unconsolidated, or fractured) and what the hole inclination will be. It also depends on what the desired state is for the recovered core (for instance, it can be kept under downhole pressure if required).

Often on an exploration well, core equipment is kept ready on the rig with an instruction to "core on shows" (stop drilling and go coring if oil is spotted), as well as to core once the potential reservoir is reached.

Recovering a whole piece of formation allows some properties to be measured that cannot be adequately measured by logs (fig. 10–4). Permeability tests can be done using plugs of formation by flowing fluids under pressure through the core plug. Magnetic resonance imaging (MRI) can be used on the core to show the internal structure of the core. Many other useful tests can be carried out on cores, which can justify the cost and difficulty of coring.

Fig. 10–4. PDC core bit

Some of the routinely available coring systems include the following:

- **Sleeve coring.** An outer steel barrel supports the core system. Inside this is an inner sleeve, which may be made of fiberglass, aluminium, or rubber. The inner sleeve supports loose, fractured, or unconsolidated formations. Once at the surface, the core may be kept in the inner sleeve for transporting to the laboratory for analysis. Fiberglass or aluminium sleeves are often sawn into convenient lengths (still with the core inside), with end caps installed to seal the ends, and then are boxed up for transport to the laboratory for analysis.
- **Sponge coring.** An aluminium inner sleeve has a sponge sleeve inside the aluminium tube. The core sits inside the sponge sleeve. When the core is recovered to the surface, any formation fluids that bleed out of the core are absorbed by the sponge where they can be later analyzed.
- **Orientated coring.** A knife blade creates a scratch mark along the core, showing orientation downhole. This can be very important if permeability is highly directional or if the bedding plane directions and inclinations need to be accurately measured.
- **Pressure coring.** After cutting the core, the core barrel is sealed down hole so that when the core reaches the surface, it is still kept at the pressure of its downhole environment. Of course, as the core barrel cools down during recovery, the internal pressures will reduce somewhat, which cannot be avoided. However, if the core contains dissolved gases or very light hydrocarbons, these are kept in solution during recovery. Pressure coring is very expensive. The system is sent to the wellsite inside a standard 40 ft oceangoing container.

Successful coring requires a lot of planning and coordination. The drilling fluid may have to have special physical or chemical attributes to help to avoid contamination of the core and to preserve it as it is pulled out of the well. Surface handling, preservation, and storage are extremely important to ensure that the core is in good condition by the time it arrives at the core analysis laboratory and to recognize and document important information with the core on the rig.

Explosive sidewall coring

A tool is run in the hole on wireline that incorporates hardened hollow steel bullets inside a long steel carrier (fig. 10–5). The bullets are secured to the carrier with two wires. After placing the bullet at the correct depth for a sample, an explosive charge drives the bullet into the wall. The carrier is pulled up on its cable, and this exerts a pull on the wires holding the bullet. With a bit of luck, the bullet will have penetrated to the right depth, the wires will not break, and the bullet and sample will be recovered.

The bullet must be selected for the hardness of formation to be sampled. The wrong choice may lead to the bullet bouncing off the wall (no sample recovered) or overpenetrating (the wire will break before the bullet can be pulled out of the wall).

Fig. 10–5. Explosive sidewall core bullet

Courtesy of Schlumberger.

With explosive sidewall coring, the sample will probably not give useful information on physical structures, such as fractures or bedding planes. The force of the bullet hitting the wall will fragment the formation. Information usefully gained will include porosity and permeability, confirmation of hydrocarbon presence, determination of clay content, and grain density and lithology.

The explosive sidewall coring tool may carry up to 90 sampling bullets. Different bullets can be installed for different formation hardness.

Rotary sidewall coring

A wireline tool has a small core barrel and diamond bit. The core barrel moves out of the side of the tool to contact the formation and starts to turn. It drills into the formation and recovers a standard-sized plug of formation, 0.94″ (2.4 cm) in diameter and up to 1.73″ (4.4 cm) in length. Up to 50 samples can be taken in one trip in the hole, with the samples being stored inside the tool.

The major advantage over explosive sidewall coring is that a relatively undisturbed core sample is recovered. Internal structures and fractures can be seen. One disadvantage of the rotary sidewall coring tool is that the samples are stored in a tube, and if there are any *misruns* (no core recovered), it might be tricky to decide where the cores recovered came from.

Pore fluid sampling and pressure testing

A tool may be run on wireline to a permeable formation of interest. Once on depth, the tool is “set” by extending a probe until it contacts the borehole wall. A seal around the probe isolates the tool from the surrounding drilling fluid.

Once the seal is established, it is possible to measure pore fluid pressure in the formation. Pore fluid samples can be captured.

The data recorded during sample taking may be used to calculate permeability at the point where the probe contacts the formation.

These sampling tools have a nasty tendency to get stuck. To take samples and pressures, the tool is forced against the side of the hole and left in place for a period of time, which can be up to 30 minutes. The early version of this Schlumberger tool was called the Repeat Formation Tester or RFT. In drilling circles, it was known as the Repeat Fishing Tool as it had to be fished out of the hole so often. The current version is called the Modular Dynamics Tester, or MDT; figure 10–6 shows one being prepared to run in the hole.

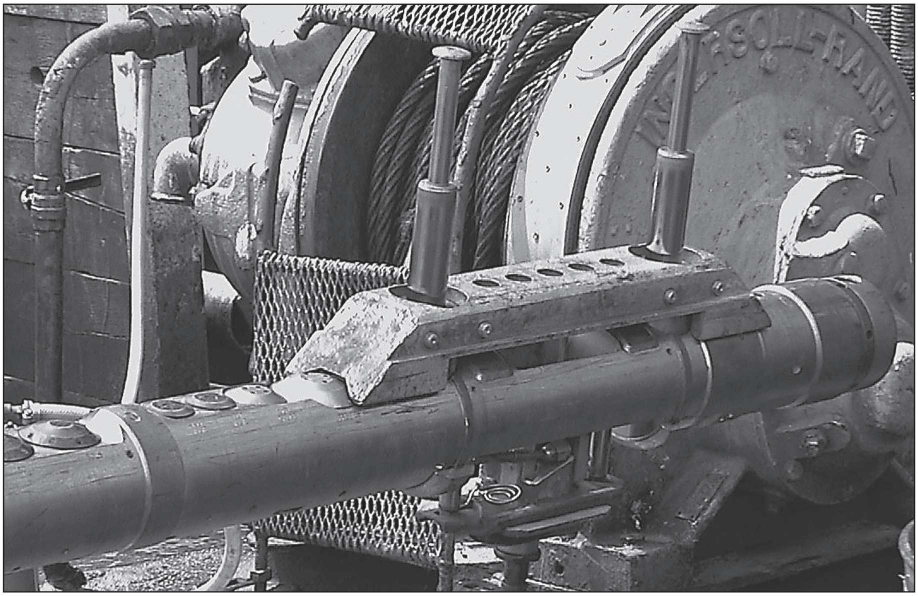


Fig. 10–6. MDT tool being prepared

Electrical Logging

The first electrical log was run in France by Conrad and Marcel Schlumberger in 1927 after they had experimented with measuring electrical properties of the earth's crust. Their electric log measured the electrical potential between the surface of the earth and a probe lowered into a well. This "spontaneous potential" log allowed the identification of different downhole formations by the depths at which the electrical potential was seen to change.

Since that first log, Schlumberger and its competitors have developed many different techniques for measuring downhole physical, chemical, radioactive, and electrical properties. Taken together, these measurements can identify various lithologies, pore fluids, hydrocarbon presence, and other characteristics.

Electric logs are normally run on a special wireline that contains electrical conductors within it. In difficult wellbore conditions (such as high inclination, rough wellbore, or potential sticking conditions), the logging tools can be attached to the bottom of drillpipe or coiled tubing with the electrical cables run inside the pipe. Logging tools are also available that either transmit the information to the surface using pressure pulses in the mud while drilling or can record information within the tool for downloading to a computer at the surface. These will be described in more detail later in this chapter. The operating principles of the various tools still apply, but the tools are run in the hole.

Below are described the major classes of electrical logging tools and the basic operating principles of each.

Resistivity and induction tools

The electrical resistivity of a formation is related to the amount of water contained within the formation (due to the porosity) and the electrical resistivity of the formation water. Most sedimentary rocks do not conduct electricity when no water is present within the rock.

Resistivity logs. Measure resistivity directly by passing a current between electrodes touching the formation. This requires a conducting mud (i.e., water based, not oil or gas based) to work.

Induction logs. Measure formation resistivity indirectly by inducing an electrical flow in the formation using a coil and measuring the induced current with another coil. Induction logs work well in oil-based mud, which resistivity logs do not.

Microresistivity tools. Measure electrical resistance with a very fine resolution at several different places around the circumference of the wellbore. These can produce a color-coded picture of the wellbore with the color varying by resistivity. It is possible to measure the dip of a formation with a microresistivity tool, and as these tools also incorporate a north-sensing tool, the direction that the formation dips can also be measured. Sometimes, fractures can be recognized from the resulting images.

Measuring resistivity helps to locate porous formations, show boundaries between formations, and identify hydrocarbon-bearing zones.

Sonic tools

A pulse of sound is transmitted at the lower end of the tool, and the time it takes the sound to travel a known distance through the rock is measured. Sonic tools can measure formation densities and compressive strengths and can identify formation fractures. Information on permeability can be obtained. When run inside casing, sonic tools can determine the quality of the set cement outside of the casing and can also measure the inside diameter and thickness of the casing, thus identifying areas of casing damage.

Sonic tools give much information of direct interest to the drillers. One such log is shown in figure 10–7. This is a tool used to evaluate the quality of cement after it has set outside casing. The log is depth based on the vertical axis.

In the left track on the log is shown some raw measurements and depth correlation information, such as a gamma ray (GR) log. (GR can be read through steel casing, and this can be used to check that the depths are correct by comparing this log with earlier logs, including a GR track).

In the next track (second from the left) are the sonic velocities and other sonic data.

In the third track is shown a color-coded log indicating directly how good the cement is (different gray-shaded blocks on this monochrome photo). This makes interpretation by nonexperts relatively simple.

Downhole seismic tools can also be included in this group. Hydrophones (very sensitive microphones) listen on the surface while a sound transmitter is lowered into the well. The transmitter is slowly pulled out while it transmits, and the measured sound returns at the surface give a good indication of the sonic properties of the formations between the tool and the surface. This can then be used to improve the interpretation of surface seismic surveys because the transmission time of the sound signal is one-way only. (In a surface seismic survey, sound is transmitted at the surface and the echoes are listened for, so the sound has to travel down and up again. The speed of sound through each formation has to be known or estimated to interpret the surface seismic.)

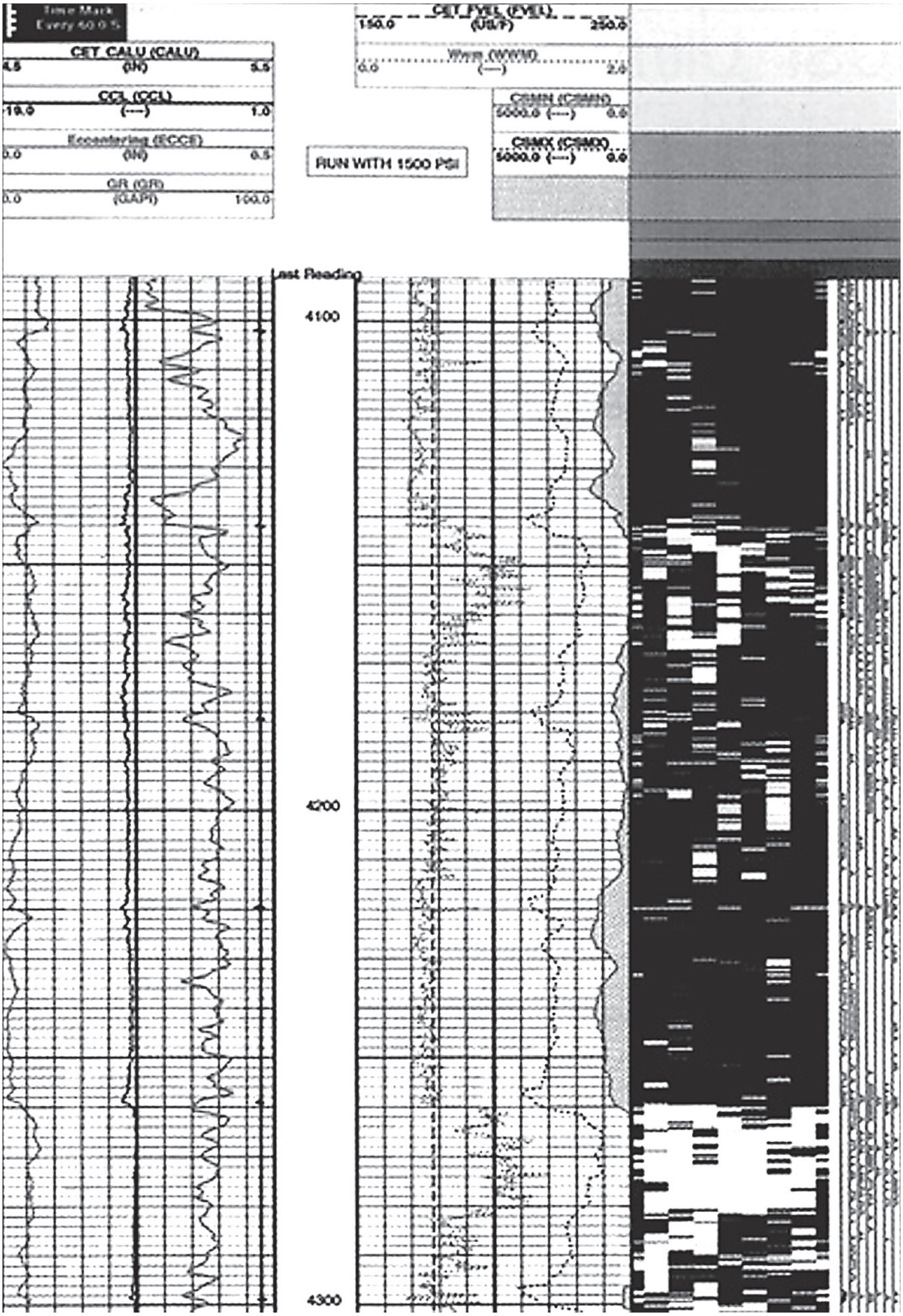


Fig. 10–7. Cement evaluation tool log

Courtesy of Schlumberger.

Radioactivity tools

Radioactivity tools measure the natural radioactivity of the rocks (gamma rays). Some tools can even tell what kind of mineral is responsible for the radioactivity, thus identifying different shale types, for instance. Other radioactive tools bombard the formations with neutrons and measure the response from the formation, which can identify the amount of hydrogen in the formation fluids (which would, for instance, identify the presence of hydrocarbons).

Using tools that contain radioactive sources requires stringent safety precautions to ensure that personnel are not subjected to damaging levels of radiation. Most authorities around the world also mandate that any radioactive sources lost down the hole cannot be abandoned but must be recovered, even if the expense of recovery is very high. Special permission is then needed to abandon it if it cannot be recovered even with great effort.

Mechanical tools

Mechanical tools deploy arms that press against the wellbore and measure the diameter as the tool ascends. These caliper tools may deploy one arm, two arms, or four arms for measuring the open hole. A four-arm caliper is especially useful because it gives a good indication of the wellbore profile. A wellbore may be the same size as the drill bit (in gauge), uniformly enlarged (overgauge), or enlarged more in one direction than another. The type and extent of hole enlargement is an indication of how stable the wellbore is and also of the size and direction of the highest stress in the rock.

A caliper tool also allows the annular volume to be accurately calculated, so that the correct volume of cement can be pumped around the casing.

Special calipers are also used inside casing or tubing strings to evaluate the internal condition (wear, erosion, or other physical damage). These tools contain many caliper arms (15 or more) so as to give a good coverage of the casing ID. One of these tools, the Kinley caliper, is shown in figure 10–9.

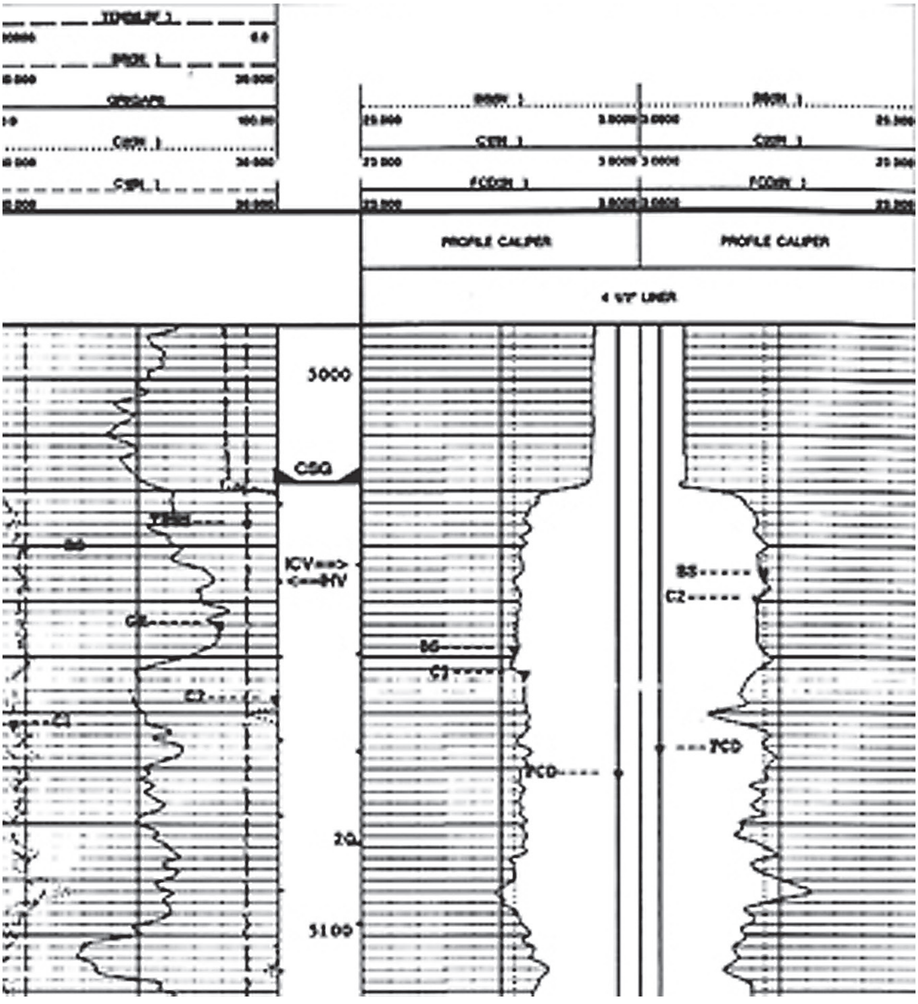


Fig. 10–8. Borehole geometry log

Courtesy of Schlumberger.

If the drillstring becomes stuck, it is important to know at what depth the string is stuck. A tool called a *free-point indicator (FPI)* can be run inside the pipe that anchors itself to the inside of the drillpipe at two places. The driller then applies pull to the pipe, and the small amount of stretch in free pipe can be detected by the FPI tool.

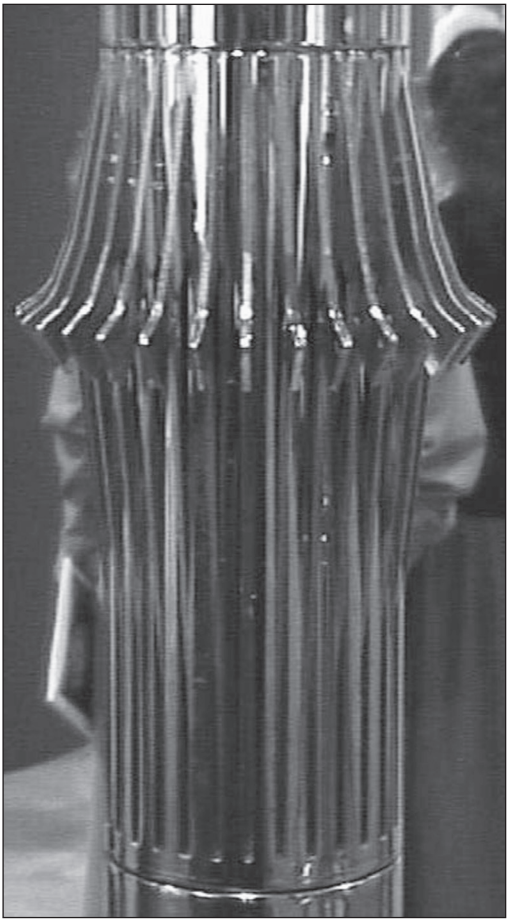


Fig. 10–9. Kinley caliper

The driller then applies torque at the surface, and the small amount of twisting in free pipe can be detected. By moving the tool to different places in the drillpipe, it is possible to detect where the pipe is free in tension and in torsion.

Once the pipe depth is known above which the pipe is free, it is then possible to apply left-hand torque in the string (that is, torque tending to unscrew the pipe). A small explosive charge is set off on wireline as low as possible within the free pipe, and the shock and vibration of this explosion will allow one (or more!) of the drillpipe connections to unscrew. This process is called an *explosive backoff*.

Electrical potential tools

Electrical potential tools, also called *spontaneous potential tools*, measure the voltage arising between a formation down hole and the surface. This was the first kind of log run, as mentioned above.

Temperature log

Temperature logs measure the temperature of the well, which varies with depth. Temperature has a large effect on the setting time of cement, and temperature must be accurately known when designing and testing cement slurries.

The geologists and reservoir engineers will specify what logs they want to run in each hole section, so that they can further identify interesting formation characteristics. The reservoir will have a lot of logs run through it, so that as much as possible can be known about the reservoir and the fluids it contains.

Also the drilling engineers should add their own logging requirements to the program, to ensure that they get the information they need to drill the next wells with greater cost-effectiveness.

Conventional wireline logging

A standard logging cable is a wound wire rope with a diameter of 9/16″. Instead of a rope core in the center of the wire rope, it contains a set of electrical conductors that transmit power to the logging tools and data back to the surface.

On the rig, a *logging unit* consists of a cabin that may be mounted on skids for sending by boat to offshore rigs, or it may be installed on a truck (see fig. 3–20). On a standard unit, the wireline winch contains 25,000 ft to 30,000 ft of cable. Within the logging unit are controls for the winch (to lower tools in and bring them out of the well) and a powerful computer network that analyzes the signals from the tool, displaying the results on screen and printing them out to continuous paper.

The logging unit may have self-contained satellite communications, or it may use the rig communication system to transmit log results back to the operating company. Sometimes, important decisions must be made as soon as possible after logging, and the rig may have to wait for those decisions to be made before operations continue. With total daily operating costs that can exceed six figures in some cases, clearly the time taken to make these decisions must be minimized.

On an exploration well where the hole is drilled solely to obtain information, the logging program for each hole section (and especially in the reservoir) will be extensive. Money invested in logs at this stage allows better decisions to be made when designing and drilling subsequent wells in the field. The logs will also allow any zones bearing hydrocarbons to be identified and to quantify some basic reservoir properties, such as porosity and permeability. The major objective is to identify whether producible hydrocarbons are present in commercially viable quantities. If so, further wells will normally be drilled to extend knowledge of the reservoir before wells are drilled to produce the hydrocarbons. These further wells are called appraisal wells.

If the hole condition is good (stable in-gauge wellbore and no particular hole problems), it is possible to run a log on wireline at inclinations up to 50°. If the hole is badly enlarged in places, has potential sticking problems, or has a higher inclination, other methods of deploying the logging tools have to be considered. These can add greatly to the cost of obtaining logs.

Logging using drillpipe or coiled tubing

If the wellbore passes through some problem sections, but the reservoir is loggable with standard techniques, drillpipe that is open at the lower end can be run to the point where the hole is in good shape (fig. 10–10). Special slim (small-diameter) logging tools can be run on wireline through the drillpipe, exiting at the bottom of the pipe and then logging conventionally. In this case, the drillpipe merely acts as a conduit to get the logging tools past the problem areas. Many wells build up to a high inclination but then drop angle back towards vertical through the reservoir. If the maximum inclination is too high for the tools to slide down the drillpipe, mud can be pumped in at the top to push the tools along the pipe.

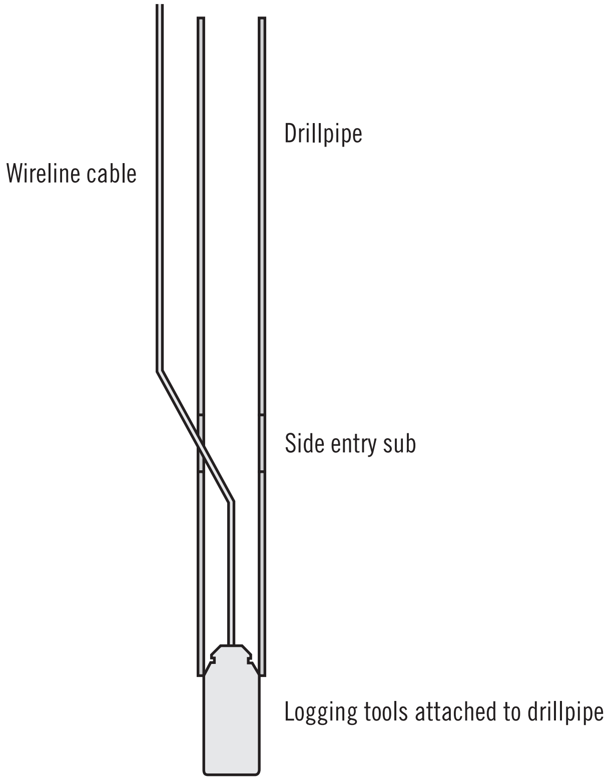


Fig. 10–10. Logging on drillpipe

For more severe conditions where the wellbore through the formations to be logged cannot be logged conventionally, the tools can be physically attached to the bottom of the drillpipe. The pipe, with the logging tools below, is run in the hole for a distance. Wireline is run inside the pipe with a special connector on the bottom, which latches onto the top of the logging tools. A special sub, called a side entry sub, is then used to allow the cable to be run outside the pipe to the surface. Now as the drillpipe and tools are run in and pulled out, the winch operator can pay out or pull in the wire to keep the wire in tension.

Coiled tubing was discussed in chapter 5. Logging tools can be attached to the bottom of coiled tubing, and the electrical wires are run inside the reel of tubing. Coiled tubing has sufficient rigidity that it can often (though not always) push through high-angle and problem hole sections to get the logging tools to the correct depth.

Logging while drilling (LWD)

In the last 20 years or so, logging sensors have been built into drill collars that are robust enough to withstand the heat, shock loadings, and vibration of drilling. These tools record log data while drilling progresses.

Measurement while drilling (MWD) tools were described in chapter 8. If log data is required in real time at the surface, the telemetry system of an MWD tool is used to transmit the data to the surface using mud pressure pulses. This requires that both an LWD tool and an MWD tool are included in the BHA, and a physical connection using electrical wiring is made between the two tools. In a deviated well, it may also be necessary to transmit MWD data so that the bit can be accurately navigated to the target.

LWD tools can also be run in *record mode*, in which data is recorded within a memory module inside the tool. When the tool returns to the surface, this data is downloaded to a computer for analysis and printing. If the telemetry link fails to provide real-time data, the memory should still provide the log data.

LWD tools have developed to the point where the data they provide is accurate and reliable enough to replace many wireline logging tools. The cost of using LWD is then partially offset by the time and cost saving of avoiding wireline logging. LWD can also obtain data in conditions where wireline tools cannot be run. If navigating within the reservoir (say in a horizontal well), the LWD data becomes important to ensure that the wellbore stays in the correct place.

Production Testing

While evaluation of cuttings, mud, drilling parameters, and electrical logs is vital to understand the static reservoir characteristics, the only way to ascertain dynamic reservoir performance is to let the well flow. An exploration well that locates possibly commercial quantities of hydrocarbons is usually tested by flowing it for periods of time and measuring the response (pressure) of the reservoir. This allows the operator to build a model to predict production rates and total hydrocarbon volumes for the reservoir under different operating conditions. The produced hydrocarbons are burned, which is hot, noisy, and often spectacular (fig. 10–11).

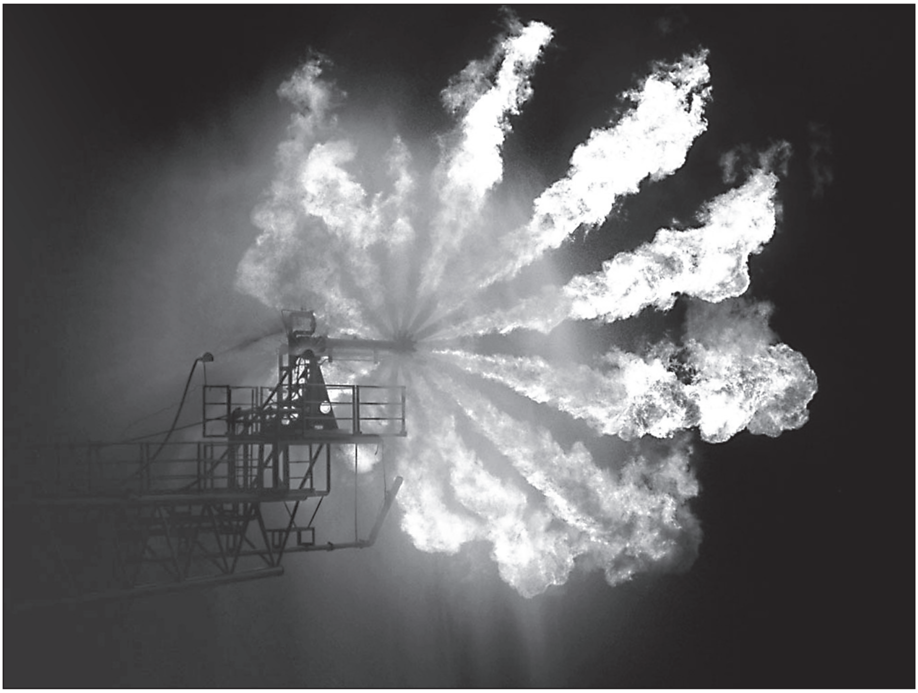


Fig. 10–11. Burning oil from a well test

Modern reservoir testing has evolved from simply seeing how much the well could produce into a sophisticated tool for evaluating the reservoir. Information produced by the test includes the following:

1. Measuring of the rate of flow and the corresponding pressures.
2. Sampling the reservoir fluids and gases.
3. Measuring the reservoir static temperature and pressure.
4. Evaluating the extent of damage done to the reservoir by drilling into it.
5. Identifying internal reservoir boundaries.
6. Measuring the total deliverability of the well (maximum flow rate).
7. Identifying a flow rate at which sand particles start to move into the wellbore.

8. Quantifying the effect of stimulation work done to the well. (As mentioned briefly in chapter 4, *stimulation* refers to work performed on a well in order to increase the production potential [how fast hydrocarbons will flow into the wellbore at a given pressure drop]. Techniques include deliberately fracturing the formation using high pressures and pumping acid to create larger channels.)

A well production test records the downhole pressure response over time to changes in flow rate. Very accurate pressure gauges are placed in the bottom of the well, and the well is allowed to flow through an orifice of fixed size. This orifice is called a *choke*. It will take some time for the flow to stabilize at a steady rate, and once the flow rate is stable, the well will be flowed for a period of time. After that period of time, the well will be shut in, and the pressure inside the well will build up, again over a period of time. These pressures are measured and plotted on a graph of pressure versus time, as shown in figure 10–12.

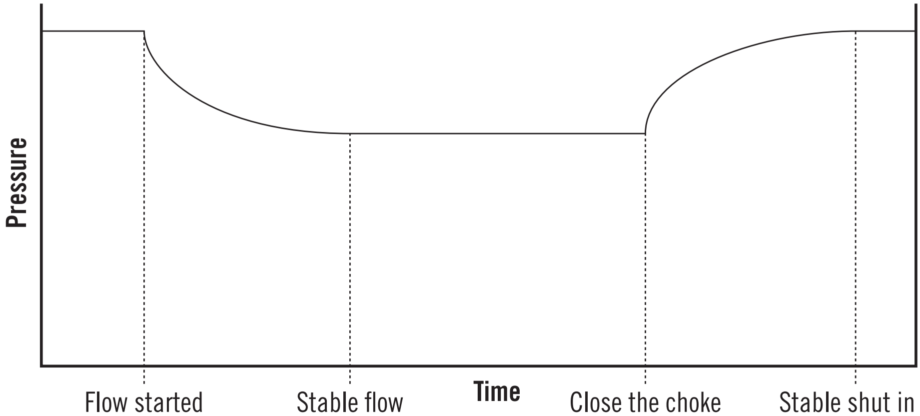


Fig. 10–12. Graph of well pressure vs. time during drawdown

When the well is closed in at the surface, and there is no flow from the reservoir to the well, the pressure in the well equals the pressure in the reservoir. When the well is opened, fluid flows out of the well because the pressure in the well is greater than the pressure inside the test equipment. This leads to a reduction in pressure at the bottom of the hole, and thus there now is lower pressure in the well than in the reservoir. The difference between reservoir and wellbore pressure is called *drawdown*. If there is

2,500 psi in the bottom of the well and 3,000 psi in the formation, the drawdown is 500 psi. The greater the drawdown, the faster the well flows. When the well is first opened up, it takes a little while for the flow and the downhole pressures to stabilize. It is a bit like increasing the throttle setting on a big truck; it takes some time for the truck to settle down at a steady speed.

The time taken for the well to reach a stable drawdown indicates the permeability of the reservoir. The greater the permeability, the faster a stable drawdown is reached. However, analysis of the drawdown data is difficult because the flow rates are not stable until drawdown stabilizes. It is therefore preferred to analyze the buildup curve once the well is shut in again to evaluate permeability and wellbore damage. The faster the pressure in the well builds up to reservoir pressure, the higher the permeability.

If the well is flowing at a stable rate and a sudden change in rate is made (by changing the choke size), a pressure disturbance is created within the reservoir. This disturbance moves like a shock wave away from the wellbore through the reservoir. This shock wave may be reflected off internal disruptions to the reservoir or off the outer boundaries of the reservoir. If it hits a gas cap, the shock wave may simply dissipate. Any reflections can be recognized by a change in the measured pressure once the reflected wave comes back to the wellbore. This type of test is called a *transient test*. Transient testing, made possible by the extreme accuracy of modern gauges and very powerful computers, allows well test interpretations that provide a description of the internal geometry of the reservoir.

To analyze a transient test, two curves are produced of pressure vs. time using log-log axes. One curve simply plots pressure against time (a *pressure curve*), and the other plots the rate of pressure change against time (a *derivative curve*). The shape of the derivative curve identifies features that would be too subtle to be recognized from the pressure curve alone. Early transient curve shapes were compared to a library of curves that were characteristic of various types of reservoir, but using computers, it is possible to compare a vast number of reservoir model shapes to the observed data.

The plot of pressure and derivative curves makes it possible to identify many more reservoir characteristics than was previously possible. Some examples are shown in figure 10–13, in which the lower curve in each graph is the derivative, and the top curve is the pressure.

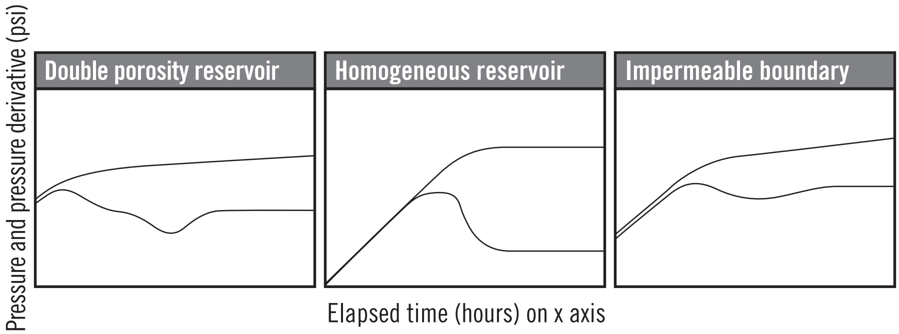


Fig. 10–13. Pressure and derivative curves for different reservoirs

Courtesy of Schlumberger.

Various treatments are available to improve the initial performance of a well. For instance, acid can be used to etch channels in the rock around the wellbore, improving the permeability into the well. A transient test before treatment can be compared with one after treatment to evaluate the effectiveness of the treatment.

Summary

This chapter showed how data from the well is obtained using various methods of sampling and measuring. This data is used to monitor and optimize performance, optimize future drilling activities (well planning and operations), recognize a commercially viable hydrocarbon reservoir, and to optimize exploitation of the reservoir.

In particular, the activities encompassed by mud logging, wireline logging, surface and subsurface sampling, and production well testing were discussed in some detail. The working principles behind different types of electric log were described.

11

WELL CONTROL

Overview

The principles of hydrostatic pressure were described in detail at the end of chapter 1. Also mentioned was the result of drilling into a formation where the pore pressure exceeded mud hydrostatic pressure—a kick may occur, where formation pore fluids enter the wellbore.

This chapter will define well control (primary, secondary, and tertiary). The processes and equipment involved in kick detection and control will be described. Special well control situations (shallow gas, kicks and losses, blowouts, high-pressure, high-temperature wells, and underbalanced drilling) will also be discussed in sufficient detail to impart a basic understanding of the causes, effects, and implications.

Primary, Secondary, and Tertiary Well Control

The term *well control* refers to the control of downhole formation pressures penetrated by the well. There are three distinct well control levels that may occur during drilling operations.

Primary well control

The first line of defense is primary well control, which results from maintaining the density of the drilling fluid such that hydrostatic pressure at all depths where formations are exposed exceeds formation pore pressures:

$$\text{Mud hydrostatic pressure} > \text{Formation pore pressure}$$

The well is planned and drilling operations are controlled with the intention that primary well control is *always* maintained. The exception to this is in underbalanced drilling, which is discussed later in this chapter.

When a kick is taken, primary control has been lost for some reason. There are four main reasons why primary control might be lost during drilling operations:

1. The well penetrates an overpressured zone with a higher formation pressure than mud hydrostatic pressure.
2. A weak downhole formation allows sufficient mud to leave the wellbore that the level of mud in the annulus drops. Since hydrostatic pressure = gradient × depth (of the fluid column), if the top of the column drops, hydrostatic pressure along the wellbore decreases. If it drops far enough, hydrostatic overbalance on a permeable formation exposed somewhere else may be lost, allowing fluids to enter the well.
3. The hole is not properly filled when pulling out of the hole. As steel is pulled out of the well, it has to be replaced by mud. If the driller does not keep the hole full while pulling out, the mud level in the annulus will drop, and hydrostatic pressure will reduce.
4. Swabbing operations may also affect primary control. (Swab pressures were described in chapter 7.) If the drillstring is pulled up with sufficient speed, the reduction in pressure at the bottom can be enough to allow formation fluids to enter the well.

Secondary well control

If primary control is lost and formation fluids start to flow into the well, secondary well control is initiated by closing the blowout preventers to seal off the annulus. This stops mud leaving the well at the surface. As fluid enters the well from the kicking formation, pressure in the well will increase until the total pressure exerted by the mud on the kicking formation equals the formation pore pressure. The pressure exerted by the mud equals mud hydrostatic pressure plus the surface pressure held by the BOP:

$$\text{Mud hydrostatic pressure} + \text{Surface pressure} = \text{Formation pore pressure}$$

Figure 11–1 shows the situation after closing the blowout preventer. Fluid influx has entered the well, the blowout preventer is closed, and the pressures have stabilized. Notice that the influx is in the annulus. The density of all the fluids in the annulus is not known. However, the drillpipe is full of clean mud of known density.

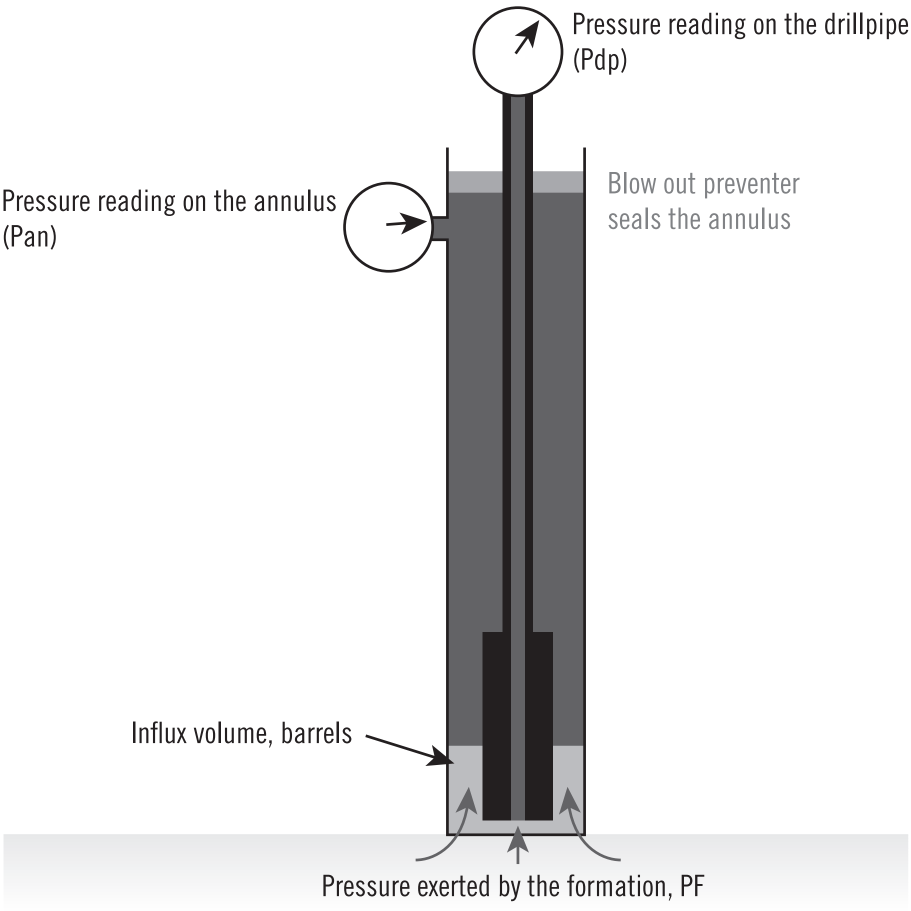


Fig. 11–1. BOP closed on influx

As the mud hydrostatic pressure in the drillpipe and surface pressure are both known, the pressure at the bottom of the well can be calculated.

The objective now is to restore primary control. Two things are necessary to do this:

1. Remove all of the influx out of the well
2. Replace the mud in the well with a fluid that is heavy enough to again exert sufficient hydrostatic pressure to control the downhole formation pressures with the BOP open

Tertiary control

It sometimes happens that the blowout preventer equipment fails or the hole starts to allow fluid to leak away into an underground formation. Secondary control cannot be maintained, and formation fluid again starts to enter the wellbore. This is now a dangerous situation calling for extreme measures to restore control. If control is not restored, the end result is a blowout. Tertiary control has to be applied to try to stop the flow.

Tertiary control involves pumping substances into the wellbore to try to physically stop the flow downhole. This may involve pumping cement (with a high risk of having to abandon the well afterwards). However, there is another method that may be employed, called a barite plug.

A barite plug is set by mixing a heavy slurry of barite in water or diesel oil. It has to be kept moving while mixing and pumping. Once the slurry is in position downhole and pumping stops, the barite rapidly settles out to form an impermeable mass that will hopefully stop the flow of formation fluid. The main risk is that if pumping stops with the slurry inside the pipe, barite will settle out in the pipe and plug the drillstring.

Blowout Preventer Stack

When planning and drilling wells, the assumption is made that *a kick is always possible*. Even if the well is the 100th drilled in the immediate area, primary control can still be lost for some reason. This is why blowout preventers (BOPs) are always used once surface casing has been cemented in place.

The primary function of the BOP is to form a rapid and reliable seal around the drillstring or across the empty hole (if no pipe is in the hole) so as to contain downhole pressures. There are currently two types of preventer available that allow this seal to be formed. Most BOPs contain at least one of each type as the different characteristics of each are useful for different operations.

Bag-type preventer (or annular preventer)

A bag preventer contains a large rubber seal, which is circular if viewed from above and conical if viewed from the side (fig. 11–2). This is held inside a steel chamber. Below the rubber element is a hydraulically operated piston with a matching conical shape on top to fit the rubber underside. As the piston moves up, the rubber element is compressed by the cover above it and pushed inwards by the cone profile. The element can distort to allow it to seal around any smooth object in the wellbore, whether it is a round pipe or tool joint or a square kelly. It can also seal on the open hole, but the level of rubber element distortion necessary will seriously shorten the useful life of the element. The rubber seal, called a packing, is expensive and awkward to replace.

Fig. 11–2. Annular preventer rubber and piston

Apart from sealing on irregular-shaped tubulars, the annular preventer can also be used to allow pipe movement in or out of the well under pressure. Moving pipe in a closed well when the well is under pressure is called *stripping*. This may be useful, for instance, if a kick occurs when little or no pipe is in the hole. In order to kill the well, heavy fluid has to be pumped through the drillstring to the bottom of the hole. If the pipe is not deep enough, more pipe can be added until it is deep enough to kill the well by stripping pipe in through the bag preventer. This is possible because the rubber element can move to accommodate the thicker tool joints moving down through the element.

To strip in, the hydraulic closing pressure on the piston is reduced until a slight amount of mud starts to leak through the seal. This provides some lubrication. Grease is put onto the tool joints, and the pipe is moved downwards slowly to minimize wear on the rubber seal.

Ram-type preventer

The other type of preventer uses a pair of large steel rams that shut under high hydraulic pressure, with great force. These rams are interchangeable and are of different types:

1. **Fixed pipe ram.** The seal is sized to fit one outside diameter only (see fig. 11–3).
2. **Variable bore pipe ram.** The seal element can accommodate a narrow range of diameters, for example 3½″ to 7″. It can only seal on round pipe, not square or hexagonal shapes (see fig. 11–4).
3. **Blind rams.** Blind rams are designed to seal on the open hole.
4. **Blind-shear rams.** Blind-shear rams have blades incorporated that can cut through pipe (though not through drill collars or casing) and can also form a seal when closed.
5. **Casing shear rams.** These are heavy-duty shear rams that do not seal but can cut through heavy pipe, such as casing. These are found in subsea BOP stacks and are used if the rig needs to disconnect from the BOP in an emergency. In this case, the ability to cut whatever pipe is through the BOP is critical. A subsea BOP will also have a set of blind-shear rams that can be closed after the casing shear rams have closed.

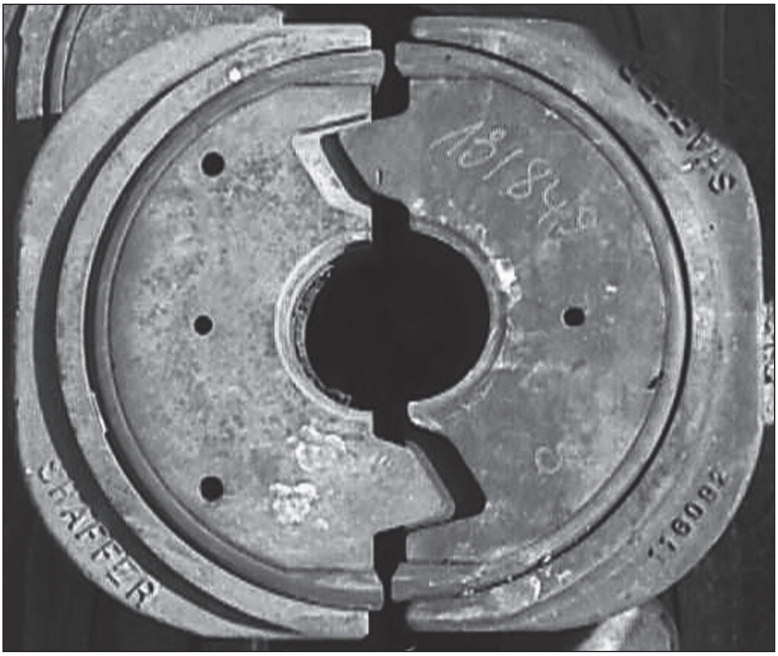


Fig. 11–3. Pair of fixed pipe rams

Fig. 11–4. A variable pipe ram

Normally, a BOP stack would have at least one bag preventer and two ram preventers, as shown in figure 11–5. BOP stacks for deeper wells might have up to four ram preventers and two annular preventers. The ram preventers generally have a higher pressure rating and are always installed below the bag preventers. If only two ram preventers are used, the bottom set will normally be blind-shear rams, and the upper set will be pipe rams. One reason for placing the blind rams on the bottom is that if the pipe rams or annular leaks, it is possible to close the blind rams below and fix the leak above.

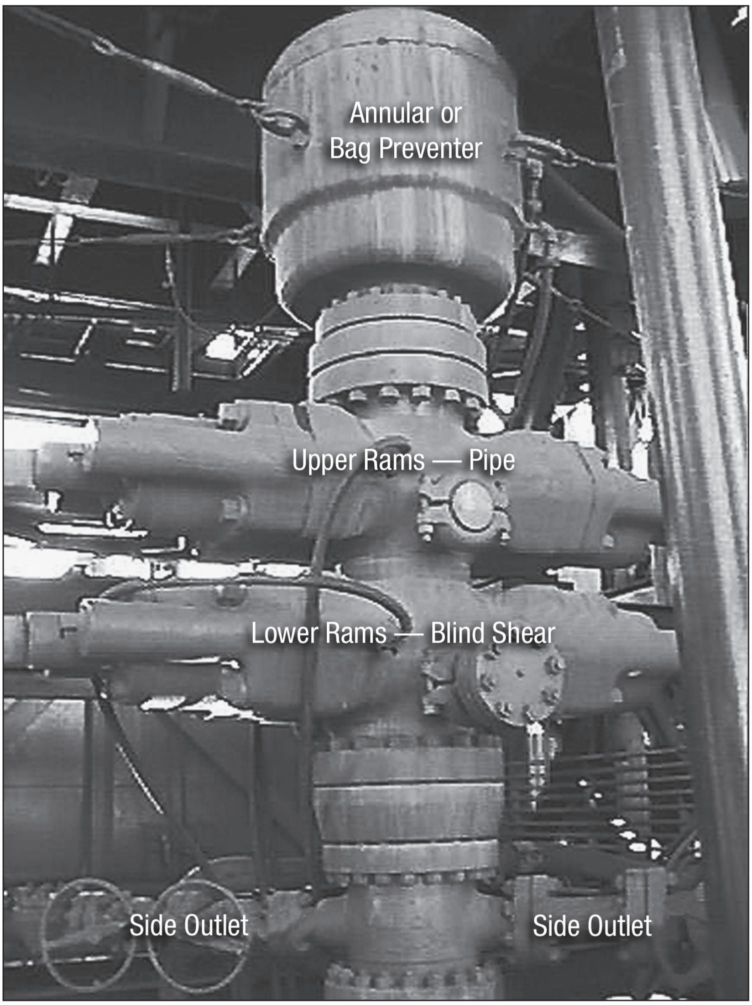


Fig. 11–5. Land rig blowout preventer

Below the rams are pipes that come out to the side. These are called side outlets and are used to allow flow out of or into the annulus during well killing operations.

The side outlets have different names. One side connects to the standpipe manifold to allow flow to be directed into the annulus. This is called the *kill line*. The opposite side connects to a manifold of valves and chokes. This is called the *choke line*, and its purpose is to allow flow out of the annulus to be controlled. Chokes are described below.

Once the driller detects that a kick is in progress, one of the BOP stack preventer units will be closed to seal the annulus of the well.

The pressure at the top of the well (inside the drillpipe and at the top of the annulus) will be recorded. Once the pressures are steady, the formation pore pressure (due to hydrostatic and surface pressure) can be calculated. A plan can then be formulated to kill the well.

Choke valves

There is another vital item that forms part of the BOP equipment. A choke valve allows fluid to flow through it, but it has a variable sized opening. This allows mud to flow out of the annulus but at the same time keeps pressure on the annulus (fig. 11–6).

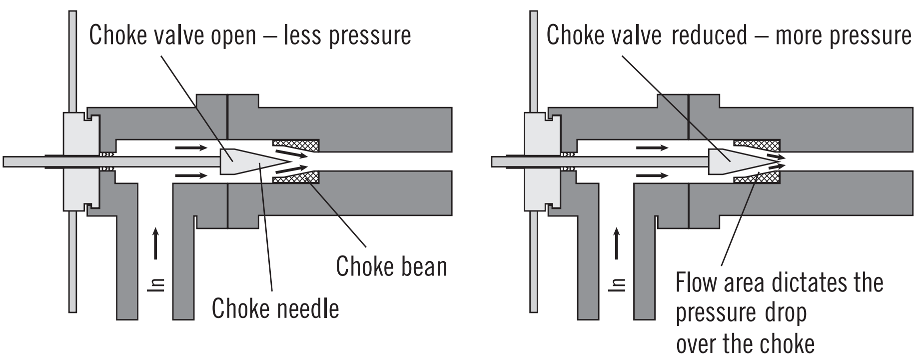


Fig. 11–6. Choke valve—conceptual drawing

The pointed part of the needle moves in and out in respect to the choke bean. As the needle moves in (to the right in the diagram), the gap closes. For a particular flow rate through the choke, this will increase the pressure upstream of the choke. How this is used during killing the well is described later in this chapter.

It would be possible to use a normal valve as a choke. However, mud that contains solids (barite, bentonite, sand, or other drilled particles) is quite abrasive when flowing through a restriction at high pressure. A normal valve would soon erode and fail to hold pressure if it were used to exert pressure on the flowing mud. A choke valve is designed to handle this operation with minimum erosion, by its design and by the use of tungsten carbide internal components. It is still possible for the choke to become eroded during a well killing operation, and so the rig must carry spares of these parts. There must also be valves positioned upstream of the choke that can be closed to allow the choke to be repaired.

BOP control systems

BOP units (bag and ram preventers and some valves) are moved using hydraulic fluid under pressure (fig. 11–7). To provide this pressure, a hydraulic control system is used that contains several elements:

1. A reserve hydraulic fluid tank holding fluid at atmospheric pressure.
2. A set of bottles holding fluid under high pressure (usually 3,000 psi) with pressurized nitrogen.
3. A high-pressure manifold connected to the bottle system.
4. A low-pressure manifold that contains fluid at the working pressure of the ram preventers (usually 1,500 psi).
5. A pressure regulator that feeds fluid from the high-pressure manifold to the low-pressure manifold and that reduces the pressure to the working pressure.
6. A set of valves attached to the low-pressure manifold that can direct working pressure fluid to the rams (to open or to close them) and that directs exhaust fluid back to the reserve hydraulic fluid tank.
7. A valve that controls the opening and closing of the bag preventer.

8. A pressure regulator that feeds fluid from the low-pressure manifold to the bag preventer control valve. Bag preventers operate at a lower pressure than ram preventers (normally about 800 psi), but as the seal element gets worn, higher pressure is required to make the bag seal around pipe. This regulator is also used to lower the closing pressure to the bag preventer if it is desired to strip pipe in through the preventer, as described previously in this chapter.
9. Two sets of pumps to maintain system pressure. One set is driven by compressed air from the rig air system, the other is powered by electricity. This provides some backup in the event of either the rig air or electric system failing. The air-driven pumps give a higher flow rate and generally pressure up the system to around 2,800 psi. The electric pump tops up the system to the full pressure of 3,000 psi at a lower flow rate.

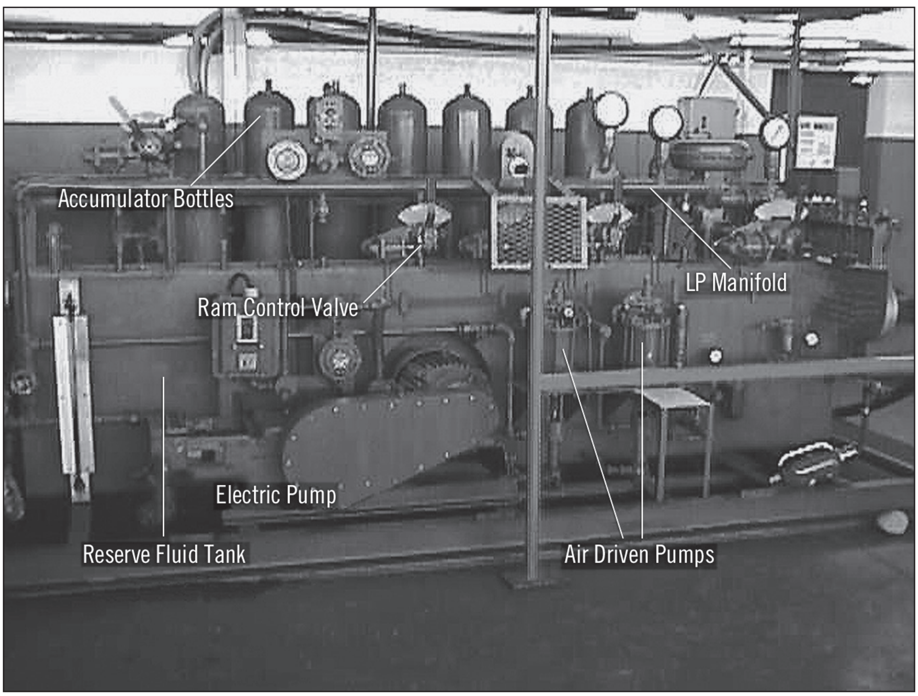


Fig. 11–7. BOP control system, land rig

Subsea BOP systems

On floating rigs, the BOP is attached to the top of the surface casing at the seabed (fig. 11–8). In chapter 4, the process of drilling on a seabed template was discussed, along with the concept of subsea wellheads and BOPs.

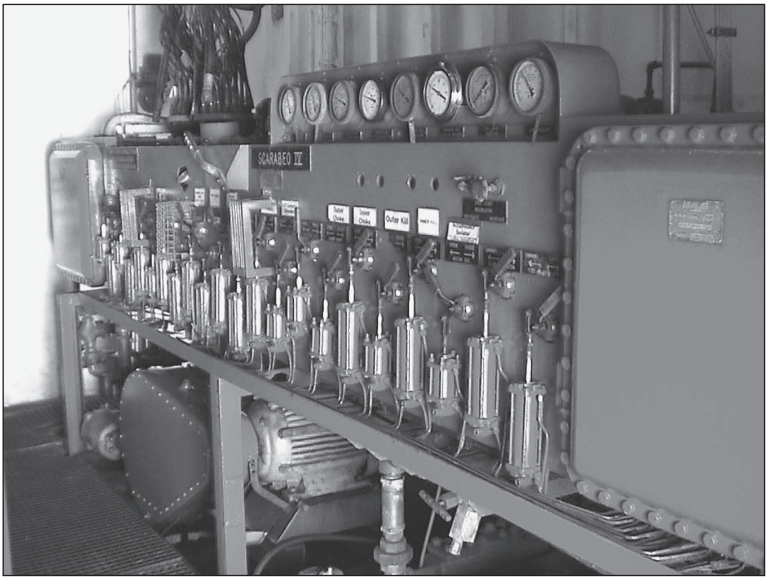


Fig. 11–8. BOP control system, floating rig

A subsea BOP contains extra control systems when compared to a surface BOP (fig. 11–9). The hydraulic control system is also open ended in that hydraulic fluid is exhausted to the sea rather than being returned to the control system. The hydraulic fluid in this case is water mixed with a nontoxic soluble oil so that pollution is avoided.

When drilling with a floating rig, it must be able to move off location away from the well. This might be due to bad weather forcing operations to be suspended, for instance. The BOP system has to be capable of latching to and releasing from the wellhead, so at the bottom of the BOP is a hydraulic latch. Also the riser (described in chapter 4) must be capable of being released, leaving the BOP on the seabed, and so another hydraulic latch is placed here. As floating rigs do move to some extent, the riser and BOP system must accommodate some angular movement of the riser, which is achieved by incorporating a flexible joint below the riser. However, as explained previously, if angular movement exceeds a certain amount (usually around 5°), the rig will disconnect the riser from the BOP to prevent damage.

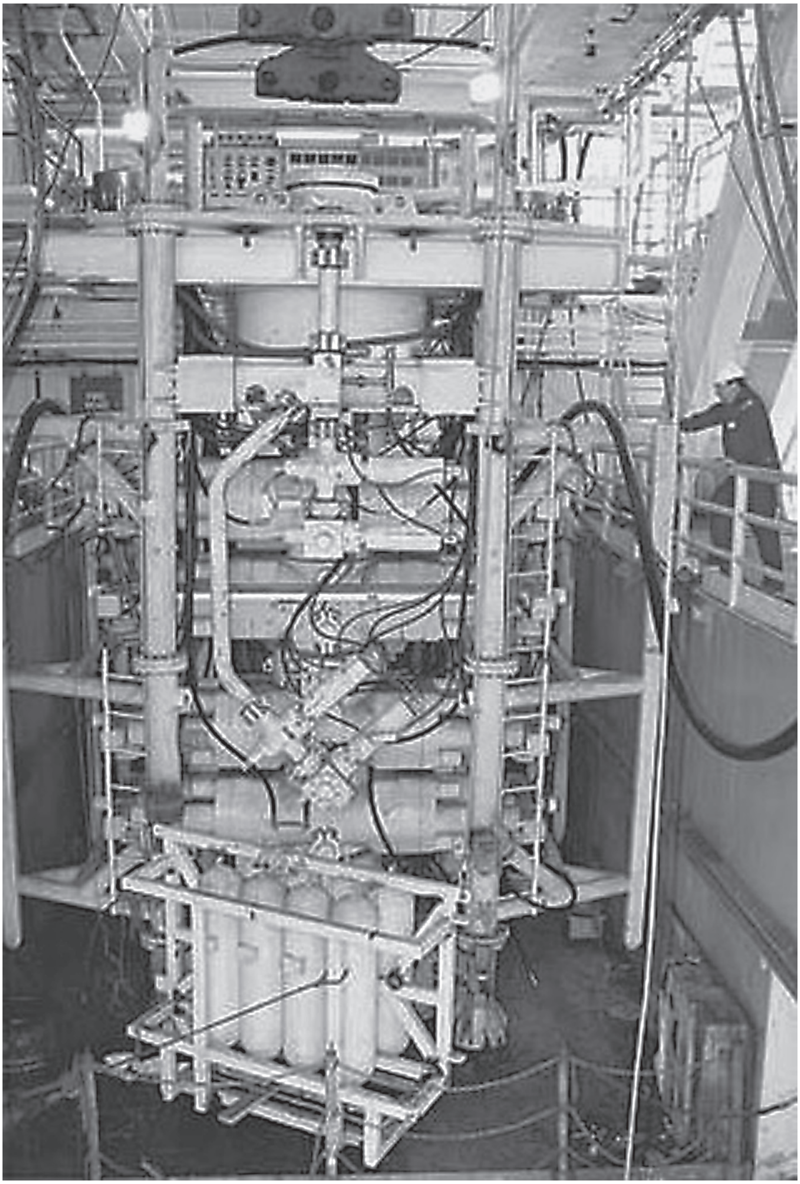


Fig. 11–9. Subsea BOP

Kick Detection Equipment

When a kick occurs, there are warning signs in advance of the actual kick, and if the drillers (backed up by the mud loggers) are alert, they will be ready to take immediate action to close the well once a kick is recognized.

There are two main kick detection systems that give a direct indication of a kick:

1. **The pit volume totalizer.** As described in chapter 5, this system provides a readout showing the total volume of drilling fluid held on the surface. If this total increases, and the increase is not due to the mud engineer adding chemicals or fresh mud to the system, a kick is occurring.
2. **The flow indicator.** This system consists of an instrument attached to a paddle that sits in the flowline from the annulus. This paddle is pushed up by the returning mud stream; the amount it is pushed depends on the flow rate, among other things. If the flow rate should increase, an alarm will sound. If the flow rate out increases but the mud pump speed has not been increased, it is possible that the extra flow out is due to an influx entering the wellbore.

Generally the flow indicator will give the first positive indication of a kick, followed by an increase in the active volume. However, the paddle-type flow indicator is prone to false alarms because of cuttings and other debris that may stick to the paddle or build up underneath it.

If the surface instruments indicate that a kick is in progress while drilling, normally the driller will stop drilling, pick up the drillstring so that the bit is above the bottom of the hole, and stop the pumps. A visual check is then made by looking down through the rotary table, into the bell nipple, at the level of mud in the annulus. If the well is in fact kicking, the mud in the annulus will still be moving upwards even though the pumps are shut down. Having confirmed a kick, the driller will then close the BOP as quickly as possible and will then notify the toolpusher and drilling supervisor in charge of the rig. (Toolpushers and drilling supervisors are the people involved in drilling operations, both on the rig and in the office. A typical organizational setup is described in chapter 12.)

If the permeability of the flowing formation is high, the kick can develop very quickly. A larger drilled hole will also allow influx to flow in faster, but this is compensated for to an extent because the capacity of the hole is greater in a larger hole. It is also possible that if permeability is very low, little or no influx enters the wellbore even though mud hydrostatic is less than formation pore pressure.

Killing the Well

The operations involved in restoring primary control are known as killing the well. In principle it is simple, but in practice, there are many considerations that are required to execute it safely. Problems may occur that have to be recognized and addressed quickly. An example of a well kill will be worked through to describe the main points.

A vertical well is being drilled at 8,000 ft. The bit size is 12¼″, and there are 300 ft of drill collars that have an OD of 8″ and an ID of 3″. Above the drill collars, 5″ diameter drillpipe is in use with an ID of 4.276″. Casing is set at 5,000 ft; this is 13⅜″ OD and 12.615″ ID. The mud in use has a density gradient of 0.5 psi/ft.

A kick is taken, and after closing the BOP, the driller has the following information about the kick:

1. The pressure inside the drillpipe at surface is 500 psi.
2. The pressure on the annulus (inside the BOP) is 600 psi.
3. The active mud system volume has increased by 21 bbl.

In any problem situation, it is best to draw a simple diagram showing the main points. This helps to avoid mistakes. Here is the diagram for this well (see fig. 11–10).

The first thing to notice is that there is a difference between the pressure on the drillpipe and on the annulus. Although the pressure at the bottom of the well is the same, the fluid in the annulus now has a different hydrostatic pressure than the fluid in the drillpipe because pore fluid (21 bbl of it) has entered the wellbore. This is lighter than the mud, so the hydrostatic pressure in the annulus is less (by 100 psi, the difference between drillpipe and annulus pressures).

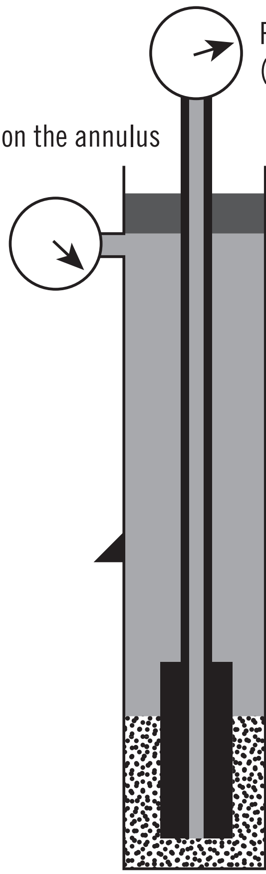


Fig. 11–10. Kicking well situation

If the hole is the same diameter as the drill bit and the influx stays as a single column of fluid (does not mix with the mud), the height of the influx in the annulus can be calculated.

In this case, 21 bbl in a 12¼″ hole with 8″ pipe inside it will have a height of 251 ft. Knowing the height of the influx, knowing how much hydrostatic pressure was lost as a result of this (100 psi), and knowing the mud density, the density of the influx can be calculated.

$$\text{Influx density gradient} = \frac{100 \text{ psi}}{251 \text{ ft}} = 0.102 \text{ psi/ft} \qquad (11.1)$$

This density is consistent with an influx of gas. An oil influx would have a greater density (0.3 to 0.4 psi/ft), and a saltwater influx would be even more (around 0.47 psi/ft). Therefore, the difference in annulus and drillpipe pressures, together with the volume of the influx, allows the probable type of influx to be calculated. It is important in particular to identify whether the influx is gas or not because this affects the well kill operation. Gas is much harder to handle; as it moves up the annulus, its pressure will drop. As the pressure drops, the volume will increase as predicted by Boyle's law. Boyle's law states that for a fixed mass of gas at a fixed temperature, pressure is inversely proportional to volume. If the volume is halved, the pressure will double. If this volume expansion is not allowed to happen, pressures on the well will increase and may exceed rock strength somewhere.

Next, the pressure in the kicking formation can be calculated. Calculations of hydrostatic pressure were covered in chapter 1. As the fluid inside the drillstring should not be contaminated with influx, the drillpipe pressure (P_{dp}) is used to calculate the bottomhole pressure, *BHP*, which equals formation pressure.

$$\text{BHP} = \text{Hydrostatic pressure} + P_{dp} = (0.5 \text{ psi/ft} \times 8{,}000 \text{ ft}) + 500 \text{ psi} = 4{,}500 \text{ psi}$$

To kill the well and restore primary control, a heavier mud must be circulated into the well. To give a hydrostatic pressure of 4,500 psi at 8,000 ft, the kill mud density gradient (ρ_2) can be calculated. (The Greek letter ρ [rho] is used to signify a density gradient; ρ_1 refers to the original mud density, and ρ_2 to the kill mud density.) This calculation is shown in equation (11.2):

$$\rho_2 = \frac{4{,}500 \text{ psi}}{8{,}000 \text{ ft}} = 0.563 \text{ psi/ft} \tag{11.2}$$

While preparations are made to kill the well, the mud engineer can start to add barite to the mud in the active system to increase the density gradient to 0.563 psi/ft. Meanwhile, some more calculations have to be made before the kill can start.

During a well kill operation, the intention is that bottomhole pressure should be kept as close to the formation pressure as possible. If the bottomhole pressure is allowed to drop below pore pressure, it is possible that more influx will enter the well, which will increase the complexity of the operation and increase the risk of problems. If the pressure rises much, a weak formation somewhere in the well might break and allow losses. If that happens, more influx will enter the well and will move into the loss zone. This is called an *internal blowout* and is much more complicated and dangerous than a simple killing operation, so it must be avoided.

The bottomhole pressure during the well kill is controlled by the choke on the annulus. Applying pressure here causes pressure to be applied everywhere in the well, including on the kicking formation.

The bottomhole pressure is monitored during the well kill by watching the pressure on the drillpipe (the pump pressure). The hydrostatic head of the mud in the annulus at any particular stage of the operation is known, and so bottomhole pressure equals pump pressure plus hydrostatic pressure.

During drilling, the driller regularly makes a test of each pump by circulating at a set slow rate and measuring how much pressure is required to circulate around the well at that rate. All mud pumps are tested so that any can be used for killing the well. For purposes of this example, assume that a slow circulating rate (SCR) of 30 strokes per minute was used. The pump outputs 5 gal for every stroke, so at a SCR of 30, the pump output is 150 gal/min. There are 42 US gal in a barrel, so the flow rate is 3.57 bbl/min. At this flow rate, the driller measured a pressure of 500 psi. This is known as the slow circulating pressure, or PC_1.

When heavier mud is pumped into the system, more pressure is required to push this heavier mud around. If the mud is changed to heavier mud, the new pressure (denoted PC_2) can easily be calculated, as shown in equation (11.3):

$$PC_2 = PC_1 \times \frac{\rho_2}{\rho_1} = 500 \times \frac{0.563}{0.5} = 563 \text{ psi} \tag{11.3}$$

This then is the pressure that is required to force the heavier mud to flow around the well. In fact, the pressure required to give flow in the annulus is very small compared to the drillstring, so annular pressure loss is ignored. The assumption is made that PC_1 and PC_2 are the pressures required to give flow through the drillstring and drill bit only.

It can now be said that, ignoring the requirement to maintain bottomhole pressure equal to formation pressure, when circulating starts, the pressure will be 500 psi, and when kill mud reaches the bottom of the well, the circulating pressure will be 563 psi. Once heavy mud is at the bottom, hydrostatic pressure from the mud in the drillstring is sufficient to balance formation pressure. This phase of the kill operation, from starting to pump heavy mud until heavy mud reaches the bottom, is called *phase 1*.

In order to maintain bottomhole pressure equal to formation pressure, extra pressure must be applied (by the choke) during phase 1. Holding pressure on the choke will affect the pressure in the entire system, including the pump pressure. This extra pressure on the pump starts at the original drillpipe pressure (500 psi) and will decrease to zero by the time heavy mud reaches the bit. In a vertical well, this decrease is linear; for each barrel pumped, the extra pressure will reduce by the same amount. The volume inside the drillstring is known; it works out to be 139 bbl.

The initial circulating pressure equals the slow circulating rate pressure plus the shut-in drillpipe pressure. Initial circulating pressure therefore is 500 psi + 500 psi = 1,000 psi. Final circulating pressure is PC_2.

A table and graph of pump strokes against pump pressure for phase 1 is then constructed (see fig. 11–11).

Pump pressure	1000	956	913	869	825	781	738	694	650	606	563
Strokes pumped	0	117	234	351	468	585	702	819	936	1053	1170
Barrels pumped	0	14	28	42	56	70	84	98	111	125	139

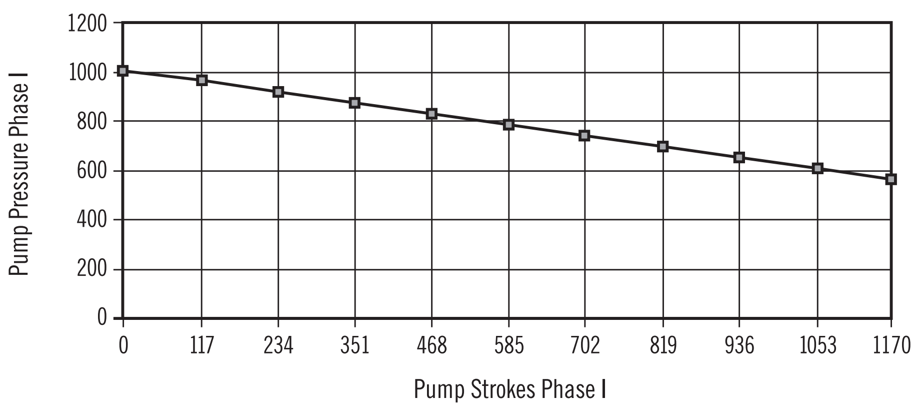


Fig. 11–11. Vertical well kill phase 1 graph

When the surface active system mud is weighted up to ρ_2, the kill can begin. One person controls the choke valve and can see both drillpipe and annulus gauges. As the pumps start and flow begins, the pressure on the annulus will start to rise. The choke is now opened to keep the choke pressure equal to the shut-in choke pressure of 600 psi, and this is maintained while the pump speed is slowly increased to 30 strokes a minute. Once the pump is at the correct speed, the choke operator needs to watch both choke and drillpipe gauges. Using the table or graph above, the choke setting is adjusted to keep the pump pressure correct. At this stage, pump pressure will naturally fall as heavy mud moves down the drillstring, and only slight choke adjustments are needed.

At the end of phase 1, the pump pressure is then kept constant for the rest of the killing operation (in this case at 563 psi). The choke setting will change as the gas moves up the wellbore. As the gas moves up and expands in accordance with Boyle's law, it will push out more mud than enters the well. This reduces the hydrostatic pressure in the annulus, and so choke pressure has to be increased to compensate. Choke pressure will reach a maximum once the top of the gas reaches the choke and then will decrease rapidly as mud replaces gas leaving the annulus.

Once the kill operation is complete, the pumps are stopped. If no pressure remains on drillpipe or annulus, the BOP is opened. A visual check is made to ensure that the well is not flowing with the pumps off. If all is well, drilling can now be resumed, although in practice, in order to get the mud into proper shape for drilling, another full circulation is generally required.

There are other techniques for killing a well, depending on the circumstances. The technique outlined in this example is called *wait and weight* or the *balanced method*. Other methods not described here are drillers, volumetric, combined volumetric and stripping, and bullheading.

Shallow Gas

Shallow gas was discussed in chapter 3. The emphasis on shallow gas is prevention. If shallow gas is encountered and the well flows, the chances of stopping it are remote.

Instead of a BOP designed to close in the well, a diverter is used during drilling (fig. 11–12). This is comprised of a large bag preventer, underneath which are two large side outlets (up to 12″ diameter) with some kind of full opening valve system. Once the well starts to flow, the side outlet facing downwind is opened, and the bag preventer is closed. Flow from the well gets diverted downwind, away from the rig.

Fig. 11–12. Diverter with large-diameter side outlets

Photo courtesy of Schlumberger.

Dynamic kill

Dynamic killing is a method for stopping an influx by increasing annular pressure losses (that is, the pressure required to force mud to flow in the annulus). This pressure increase comes from pumping fluid as fast as possible into the well.

Dynamic killing of a shallow gas flow is unlikely to be successful except in rather narrow circumstances. To have any chance of working, a dynamic kill must have the following:

1. **Very high flow rates.** The maximum pump output on most rigs will be insufficient.
2. **Small hole diameter.** Once the blowout is established, large volumes of formation solids are blown out of the well so that the hole rapidly enlarges. This means also that an attempt to dynamically kill the well must be made within seconds of a flow being identified.
3. **Small annular clearance.** If large-diameter drill collars and drillpipe are used, this reduces annular clearance and hence increases the annular pressure loss.
4. **Increased drilling fluid density and viscosity.** Surface holes are generally drilled with low-density fluids because the formations drilled are weak. Using high-density, highly viscous fluid would increase the risk of mud losses into the formation. It is even possible to cause formations to fracture by using high-density drilling fluid. This implies that a tank of heavy, viscous kill mud must be kept ready to pump at maximum rate as soon as the need is identified.

If a dynamic kill is the chosen method of killing a shallow gas blowout, this must be planned in advance to address each of these elements if there is to be any realistic prospect of success. Crew training is vital, as is implementing equipment and procedures to detect and respond to an influx as early as possible.

Ultimately if the well is not killed quickly and the blowout develops, the chance of equipment failure is high. The extremely erosive nature of the flow (gas plus formation solids being an effective sandblaster) means that sooner or later, holes will appear in the diverter system, allowing the flow to enter the rig. H_2S is sometimes encountered in shallow gas flows, which presents an immediate and serious threat to life. It is to be hoped that the accumulation of shallow gas is small, and after a short while, it depletes, and the flow stops. It is also possible that chunks of rock coming up the wellbore get stuck and form a bridge, stopping the flow.

Shallow gas on floating rigs

The best place to be if a shallow gas flow occurs is watching from a safe distance upwind! The second best place to be is on a floating rig, drilling with returns to the seabed.

Surface hole on floating rigs is normally drilled without returns to the rig. After cementing conductor pipe in the seabed, the next BHA is run into the conductor using guidance from subsea video cameras. Mud and cutting returns from the annulus exit into the sea. If a shallow gas flow occurs, and if this presents a danger to the rig (gas appearing on the sea surface close to the rig), the driller drops the drillstring, and the rig moves away.

Sometimes on floating rigs, returns are taken back up to the rig. This might be the case in deeper water, or if government regulations prohibit cuttings being exhausted to the sea. It is possible to use a subsea diverter, which is deployed on top of the conductor on the seabed. If the well flows, the diverter bag preventer closes to stop the gas being channelled up to the rig by the riser pipe, and the gas exhausts to the seabed. Shear rams should be run as part of the diverter system so that the rig can easily disconnect the riser from the diverter and move off location.

Special Well Control Considerations

There are, of course, some circumstances where well control becomes quite complex. Some of these circumstances are briefly described so as to give familiarity with the terms and a basic understanding of what is meant.

High-angle/horizontal well killing

The example discussed previously in this chapter assumed that the well was vertical. If the well in fact is drilled at a high angle, killing the well while maintaining a constant bottomhole pressure is a bit different. In this case, the driller's method of killing the well may be more appropriate. In this method, the well is killed in two circulations. No calculations are required for the first circulation; normal density mud is used to simply circulate out the influx. Pump pressure is held constant at PC_1 by manipulating the choke for the whole of the first circulation. Once the influx is out, if the pumps are stopped and the choke is closed, the pressure on both drillpipe and annulus should be the same and equal to the original shut-in drillpipe pressure.

For the second circulation, the only calculation required is the density of the kill mud, ρ_2. During phase 1, the choke pressure is held constant at a pressure equal to the shut-in pressure at the end of the first circulation. Pump pressure will decrease during phase 1 as heavy mud replaces light mud in the drillpipe. Once phase 1 is complete, attention is switched to the pump pressure gauge, and pump pressure is now held constant by manipulating the choke until heavy mud returns are seen from the annulus.

If a balanced kill is used, the phase 1 graph is a bit more complicated to follow, as it is not a straight line. This is illustrated in figure 11–13. However, as phase 1 proceeds, the pump pressure will tend to follow the line fairly closely with only small adjustments to the choke.

In a horizontal well, the cause of the kick is unlikely to be drilling into an overpressured zone. It may be a swabbed kick or some other cause. In this case, heavy mud is not required; it is just necessary to circulate out the influx while holding pressure over the chokes.

Pump pressure	1000	956	913	869	825	806	788	769	750	738	731
Strokes pumped	0	117	234	351	468	585	702	819	936	1053	1170
Barrels pumped	0	14	28	42	56	70	84	98	111	125	139

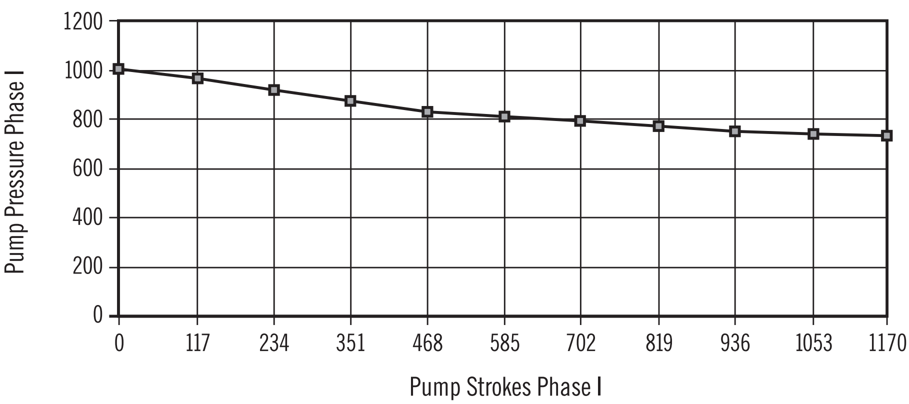


Fig. 11–13. Deviated well kill phase 1 graph

High-pressure, high-temperature (HPHT) wells

As most of the shallow, easily exploitable oilfields have probably been found, the exploration for hydrocarbons has moved to remote areas and also to deeper prospects in mature areas. This has made HPHT wells much more common over the last few years. An *HPHT well* is defined as a well where wellhead pressure could exceed 10,000 psi and where the undisturbed bottomhole temperature exceeds 150°C. Though definitions in the industry do vary a little, this gives an idea of the scale of the problem.

From a well control point of view, hole sections that meet the HPHT definition require extensive planning, careful training of drill crews, and special equipment to detect and handle kicks.

Kick tolerance was mentioned in chapter 3. In HPHT wells, the formation fracture gradient and pore pressure gradient are often fairly close together, meaning the kick tolerance will be small. Therefore, very sensitive kick detection systems are necessary, together with crew training and regular drills to ensure that at the first sign of a kick, the well is closed in quickly (without visually checking for a flow). The well is then watched for any buildup of pressure.

Another problem in HPHT wells is that oil-based muds are often preferred due to temperature limitations of some water-based systems. Gas at high pressure (above around 6,000 psi) is completely soluble in oil muds, so a gas influx can enter the well as a liquid. A small volume can enter undetected. However, as this travels up the annulus and the pressure reduces (because the hydrostatic head of fluid above it reduces), the gas can suddenly come out of solution and expand to many times its liquid volume. The result would be a very rapid increase in flow detected at the surface and a large volume of gas to circulate out when killing the well. Under these circumstances, the kicking formation probably gave a continuous slow stream of dissolved gas into the mud so that all of the mud between the kicking formation and the point where gas comes out of solution is contaminated. More gas will come out of solution during the well kill.

Special seals are required for the BOPs that can handle the high temperatures at which they have to operate. Also, as gas moves through the chokes, it experiences rapid expansion due to the reduction from high pressure down to atmospheric pressure. As gas expands, it cools down, and it is possible for the temperature downstream of the chokes to be well below freezing point. This requires consideration of low-temperature steel strength and brittleness in the choke manifold. The normal working pressure of the choke manifold might have to be derated by 50% or more.

When gas in the presence of water cools down and reduces pressure, icelike compounds called *hydrates* may be formed. Hydrates can plug lines during well killing, which presents a serious problem because it stops the killing operation. Hydrate formation can be prevented by injecting glycol into the choke manifold, so part of the preparation for HPHT drilling must include provision of an injection facility for glycol.

Relief wells

When a blowout occurs, the rig is likely to be damaged or even destroyed. It is also possible that the blowout will damage the wellhead in a way that makes it impossible to enter the well from the top in order to kill it. Under such circumstances, the only way to actually kill the well is to drill another wellbore to intercept the blowing well. As explained previously, the wellbore used to intercept the blowing well is called a relief well.

The process of drilling a relief well requires fine directional drilling control and an accurate knowledge of the path of the blowing well. The relief well will be spudded from about 300 m (1,000 ft) away. It will deviate so as to come alongside the blowing well, following it from a few meters away and alongside the last casing that was set above the section of the well that is blowing out. Wireline ranging tools run in the relief well will detect the metal casing in the blowing well and confirm the azimuth and direction to it. These tools work within a range of about 15 m. Casing will be run and cemented at a similar depth to the casing on the blowing well, so as to get the maximum strength below the casing shoe, ready to drill the intercept.

With the two wellbores parallel and the casing shoes at a similar depth, the final hole section is drilled. The drillstring in the blowing well provides the means to use the ranging tools to find the well. (If there is no drillstring in the well, the relief well will be drilled to intercept the casing and has to drill or mill through it.) It is nudged towards the blowing well with an intercept angle of around 10° and carefully guided until the interception is made. Once the relief well intercepts the blowing well, heavy kill mud may be pumped down the relief well and into the blowing well to kill it.

Underbalanced drilling

When a reservoir rock is penetrated by the drill bit, damage almost inevitably occurs at the exposed rock face. The major cause of this damage is the interaction between the drilling fluid and the formation. The higher the overbalance, the greater the pressure tending to force mud into the formation, and the greater the damage. If this overbalance can be eliminated, so can much or all of the damage from drilling.

Normally, operations are conducted so that an overbalance always exists—primary well control is maintained. However, using special equipment, drilling fluids, and operating techniques, it is possible to drill with the mud hydrostatic pressure below the formation pore pressure. This means also that the formation fluids will continually flow into the well while drilling.

On top of the blowout preventer is added a special tool, called a *rotating control head* (fig. 11–14).

Fig. 11–14. Rotating control head

Photo Courtesy of Williams Tool Company Inc., Arkansas.

This seals on the drillpipe while allowing rotation and movement of the drillstring. It is necessary to do this so that the actual pressure at the bottom of the hole (drilling fluid hydrostatic pressure + surface pressure) can be controlled.

Horizontal oil wells are drilled in the Austin Chalk in Texas that produce so much oil during drilling that the wells are paid for by the time they are finished.

Certification of Personnel for Well Control

Most government authorities worldwide now require supervisory staff on drilling operations to be demonstrably competent in basic well control techniques. This requirement is most often met by taking a course and passing a test, which incorporates both theoretical training and testing and practical training and testing, using a simulator. The certificate is only valid for two years, and consequently regular training and retesting has to be completed.

Many personnel nowadays will only encounter a few kicks throughout an entire career, unless they drill many exploration wells. As with any skill, if it is not regularly practiced, the skills get rusty with time. While having a current well control certificate does not guarantee an ability to handle a well control incident calmly and properly, it should demonstrate that the knowledge and ability exist.

Summary

This chapter described the three levels of well control (primary, secondary, and tertiary). Well control equipment was covered in some detail, including blowout preventers and control systems, chokes, and kick detection equipment. Next an example was given of a kick and killing the well, with the necessary calculations. Some special well control situations were described in sufficient detail to give a basic understanding of the terms used. Finally, current requirements for certification of personnel were included.

12

MANAGING DRILLING OPERATIONS

Overview

A typical drilling operation can vary in cost between around $30,000 per day for a small land rig in an established area to over $1,000,000 a day for a modern offshore rig in a remote area. Deepwater exploration wells in frontier areas can cost over $100,000,000. How these activities are managed has a large impact on the return on investment (ROI) for the operator. Almost every drilling decision ultimately has an ROI basis: What is the most cost-effective way to achieve the well objectives?

This chapter will describe the traditional chain of command and will also examine some of the contractual models used in drilling companies. Cost estimating and tracking is very important and will be looked at in some detail. Logistics is a vital component in any drilling campaign, and some of the considerations for logistics are included.

What happens if a major incident occurs is quite interesting, and this, too, is described.

Personnel Involved in Drilling Operations

Figure 12–1 is an example organization chart showing the typical command hierarchy in a traditional drilling operation. It is useful to understand the various titles, roles, and responsibilities of the various positions.

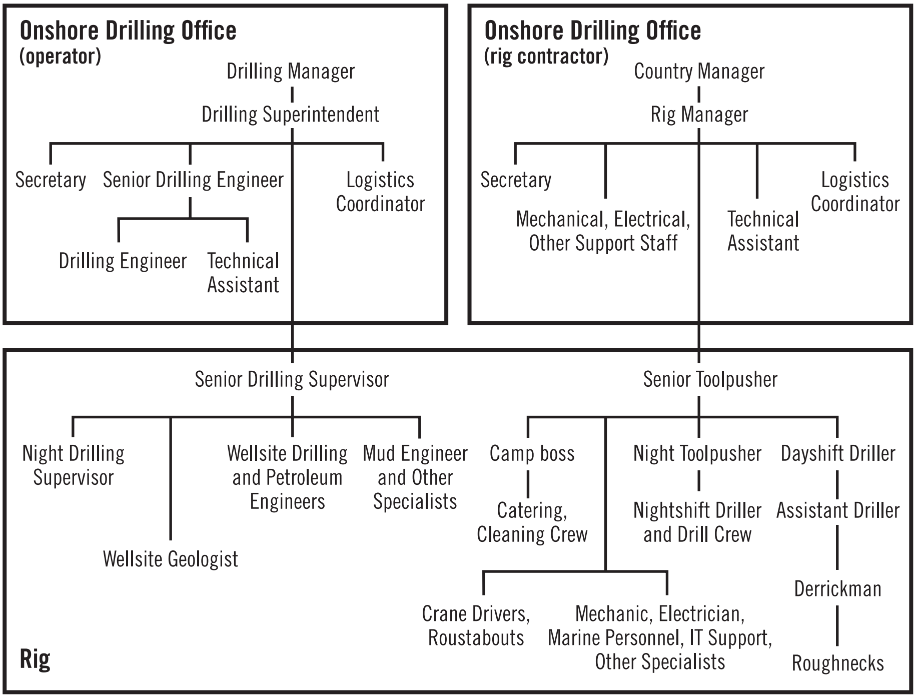


Fig. 12–1. Typical organization structure

Oil company/operator

Operations manager. Generally responsible for all operational matters to do with drilling and production-related activities. Will most often take overall command of the incident response team in the event of a major incident such as explosion or blowout.

Drilling manager. The top drilling position in the country in most oil companies. The drilling manager will report to the operations manager. Responsibilities include the day-to-day running of the drilling department, liaising with government authorities, overseeing the work of the senior drilling engineers, and acting as the ultimate technical decision maker for problems or disputes. In the event of a major incident, the drilling manager will join the incident response team and will be responsible for technical decisions to bring the incident under control. May deputize for the operations manager.

Drilling superintendent. In a larger organization with several rigs operating, there may be one or more drilling superintendents, reporting to the drilling manager. The drilling superintendent is the main point of contact between the wellsite drilling supervisor and the office. One drilling superintendent may be responsible for a number of rigs. This is the person who will also communicate frequently with the drilling contractor rig manager.

Senior drilling engineer (SDE). This position has different titles in different companies but most people will understand the title even if it is different in their company. Responsibilities include assisting the drilling superintendent; well planning; daily analysis of drilling activities; liaising with various service companies; ensuring tools, equipment, and personnel are organized to be on the rig when needed; cost estimating and tracking; supervising the work of more junior staff members; daily liaison with service companies involved in the operation; and evaluating tenders for services.

Logistics coordinator. May report to the drilling manager or SDE. Responsible for all activities related to obtaining, storing, and shipping equipment and personnel to the wellsite and back. Coordinates land, sea, and air transports. Supervises the storage yards. Monitors rental equipment to ensure it is returned promptly when finished.

Drilling engineer (DE). Reports to the senior drilling engineer. Responsible for technical work on drilling programs, such as technical evaluations and engineering studies. Other work as directed by the senior drilling engineer.

Technical assistant. Works with the drilling engineer to help compile reports, locate information, filing, etc.

Senior drilling supervisor (DS). Often called the "company man" (even though women also work in this position). The most senior representative of the operator at the wellsite. Responsible for coordinating all drilling-related activities, using the drilling program as guidance but making changes as necessary for a safe and efficient operation. Instructs the rig crews via the toolpusher. Ensures that safe practices are maintained. Manages the various contractors on hire to the operator (e.g., mud engineer, mud loggers, directional drillers, etc.). Any operator personnel at the wellsite must report to and coordinate their work with the drilling supervisor, even if they are not "drilling" personnel (such as the wellsite geologist). The drilling supervisor discusses the ongoing program with the toolpusher, and the two coordinate the workload. The drilling supervisor should not instruct the drill crews directly but only through the toolpusher or night toolpusher. This is important because the drill crews report to the toolpusher and not the drilling supervisor. Furthermore, unsafe situations may be created if the drilling supervisor and driller are both unaware of some other planned activity initiated by the toolpusher (such as maintenance work on certain equipment).

Night drilling supervisor. In some areas, it is usual to have an assistant to the drilling supervisor who will be on shift during the night (usually 6 p.m. to 6 a.m.). In the past, this position did not exist, and in some areas, it still is not used. For critical operations during the night, the drilling supervisor will usually wish to be present, but as long as things are proceeding according to plan, the night drilling supervisor will normally be responsible for overall supervision.

The night DS will often prepare the daily drilling report, ready for the drilling supervisor to check and send in the morning. On most operations, the daily drilling report is transmitted to the operator's drilling office by about 6:30 a.m.

On a high-cost operation, the night drilling supervisor may well be an experienced senior drilling supervisor, working on the night shift.

Wellsite drilling engineer/petroleum engineer (WSDE/WSPE). Often the two terms *drilling engineer* and *petroleum engineer* are interchangeable. Sometimes there is no WSDE or WSPE on the rig. Supports the drilling supervisor in the daily activities. Often a training role to gain practical experience.

Wellsite geologist. Monitors the work of the mud loggers (if present on the rig). Keeps a record of the geology encountered. Witnesses the work of the wireline loggers. Will sometimes determine the correct setting depth for casing strings.

Mud engineer. An employee of the drilling fluids contractor. Responsible for building and maintaining the mud system as per the program. Tests the mud properties frequently and reports on the results to the drilling supervisor and to the mud contractor office onshore.

Other contractor personnel. There are many operations that may require the services of other personnel, either employed by the operator or by service companies contracted to the operator. These personnel will report to the drilling supervisor and will have responsibility for their own equipment and area of expertise.

Drilling contractor. The drilling contractor owns the rig and employs the regular supervisors and crews working on the rig. The rigsite personnel will almost always work an equal-time system; a week or a month on the rig followed by the same time off. This requires two sets of supervisors (toolpushers, night toolpushers, camp boss, etc.) and four complete crews, two of which will be on the rig at any time (drill crews [driller and below], radio operator, cooks, crane drivers, etc.).

Rig superintendent. Similar level of responsibility to the operator counterpart (senior drilling engineer). May be responsible for one or more rigs.

Toolpusher. The person in overall command of the rig. In some offshore areas (such as the North Sea), the toolpusher may also be designated as the offshore installation manager (OIM), with certain legal responsibilities similar to that of a captain at sea. (With floating rigs, whether anchored in position or not, there is often a qualified marine captain who is the OIM.)

Night toolpusher. Usually works 6 p.m. to 6 a.m. Often deals with much of the paperwork and ensures that the store is kept with sufficient spares, chemicals, etc. for upcoming operations.

Camp boss. In charge of accommodation and catering.

Radio operator. Usually two on the rig at any one time to provide 24-hour radio cover.

Driller. In charge of a crew of five or six people, the drillers usually work 12-hour shifts (midnight to noon, noon to midnight) on the drill floor. The on-shift driller is the most critical person on the rig. The decisions that the driller makes and how the driller reacts to problems has a huge influence on the final outcome.

Assistant driller (AD). Helps the driller by preparing tools and equipment; completes some of the paperwork; and ensures maintenance and repair work to drilling equipment is done, involving the mechanic or electrician as necessary.

Derrickman. Works up in the derrick when tripping into or out of the hole. Responsible for the mud pits and mud pump during drilling.

Roughnecks. Work on the drill floor as directed by the driller, AD, or derrickman.

Crane drivers. In charge of a crew of roustabouts working on the rig decks. Apart from operating the cranes, handles other tasks around the rig (off the drill floor) as directed by the driller or toolpusher. Work 12-hour shifts to provide 24-hour cover.

Roustabouts. Wellsite laborers, working for the crane driver (or sometimes for a roustabout foreman). Normally people who work for a drilling contractor start their life at the wellsite as a roustabout.

Contract Types

There are now many different types of rig contracts. Innovative contracts have been created that attempt to maximize the operator's return on investment by aligning the needs of the operator and contractors.

Two of the earliest types of contract were footage and turnkey. These two types of contracts give the contractor a pretty free hand in how the well is drilled with little or no involvement by the operator.

In a *footage contract*, the drilling contractor is paid per foot of hole drilled and cased. The incentive to the contractor is to drill as fast as possible without any regard for the "quality" of the hole. Also there is a very strong incentive to take short cuts that expose people to safety risks, as well as potentially endangering the rig and the environment. Everything takes second place to drilling as fast as possible.

A *turnkey contract* pays the contractor for completing the well and handing it over, ready to "turn it on," as suggested by its name. As with a footage contract, the incentive on the contractor is to drill and complete the well as fast as possible.

In the pure versions of these two contract models, serious damage to the reservoir is likely (or more accurately, inevitable). The return on investment for the operator is low because the productivity of the well is low, due to the damage to the reservoir.

For many years the most common contract model has been a dayrate contract. It is still commonly used. With a *dayrate contract*, the drilling contractor is paid a daily rate for the rig, and the contractor has little or no say in how the well is drilled. The operator designs the well, writes the drilling program, and supervises the work at the wellsite. This allows the operator control over the quality of the well. However, the incentive to the contractor is to take as long as possible to drill the well.

In the mid- to late 1980s, incentive contracts started to be commonly used. With *incentive contracts*, a dayrate contract is still in place, but the contractor gains an incentive to organize the work well so as to finish the well faster. Now the objectives of the contractor and the operator start to be aligned—they share the same objectives. How well the objectives are aligned depends entirely on how the incentive portion is structured.

In a dayrate contract, the operator usually contracts separately for all of the other services required. To drill a well might involve 30 different contracts for the provision of services ranging from aircraft to wellsite supervision. However, it is also possible that the drilling contractor provides some of these services under the rig contract, reducing the number of contracts and services that the operator has to manage.

One of the drawbacks to this type of dayrate contract has been that each time a drilling campaign for exploration or development wells was planned, a complete set of tenders was issued, which then had to be evaluated. The evaluation in most cases was based primarily on cost comparisons, with little regard for the quality of services provided. This can lead to below-optimum performance, and in some cases (drilling fluids being a prime example), reduced production potential of the well and a seriously reduced ROI from what was possible. The more forward-looking operating companies such as Shell now take a longer view and form long-term contractual relationships that can give greater benefits to both parties—a win-win relationship.

In the early 1990s, Shell developed a contracting strategy called Drilling in the Nineties (DITN). The basis of this strategy was that most of the drilling activity could be contracted out to a favored or lead contractor by contract strategies that rewarded the contractor for taking on board a large share of the responsibility for planning and drilling wells. One necessary feature of this is that contracts are long term.

From Shell's DITN strategy lead, other operators started to look into similar contracting strategies. One development of this was *integrated service provider contracts*, whereby one company with all of the required capabilities (some in house, some subcontracted) would effectively manage complete projects. In the highest extreme, an ISP might manage a field development project from initial surveying, exploration, and development drilling through production and final abandonment. Several major international contractors emerged with the capability to offer these complete services, with Schlumberger, Halliburton, and Baker Hughes INTEQ among the largest. These multibillion-dollar groups compete for quite a large business pie. They develop capabilities in drilling engineering by recruiting experienced drilling engineers and drilling supervisors (most of whom previously worked for the operators) and by training the engineers and supervisors of the future.

There is one potential danger for the operators in this development. It is very important to their future business that they do not lose the capability to plan and supervise drilling themselves. If the operators lose this capability, they will also lose the capability to manage the risks involved in drilling wells. The major risks are those associated with events such as a blowout, environmental damage, or damage to the reservoir. Whatever type of contract is in place, the operator cannot delegate those responsibilities. Unless a core of experienced people is retained, the operator must put place its future business in the hands of the contractors.

Incentive Schemes

The purpose of an incentive scheme is to somehow change the way people work so as to meet particular objectives. There are various possible features to an incentive scheme, such as the following:

1. **Safety.** It is important that safety is not compromised to meet operational objectives. Some schemes have the typical unimaginative approach, something like, "If anybody has an accident, everybody loses part (or all) of their bonus." This does not make people work more safely. All it does is put a lot of pressure on people to not report accidents. It is, of course, inherently unfair to all those people who were not in any position to prevent or mitigate the accident, such as people off shift or working on a different part of the rig. And once the earned bonus is taken away, the result is a disincentive to giving good performance.

2. **Lump sums for flat-time operations.** A *flat-time operation* is one where the depth of the well is not increased. Figure 3–7 showed an example time-depth curve. The one given in figure 12–2 shows the actual vs. planned time-depth curve for a well in the Gulf of Suez. The horizontal parts of the graph (*flat time*) relate to operations such as running casing or nippling up and testing BOPs. Time marches on, but the well gets no deeper, so the line is horizontal. Instead of staying on day rate, the contractor could agree to complete some of these operations for a lump sum. This gives the contractor an incentive to plan and execute this part of the job efficiently, and it limits the cost to the operator if the contractor has a problem or equipment failure.

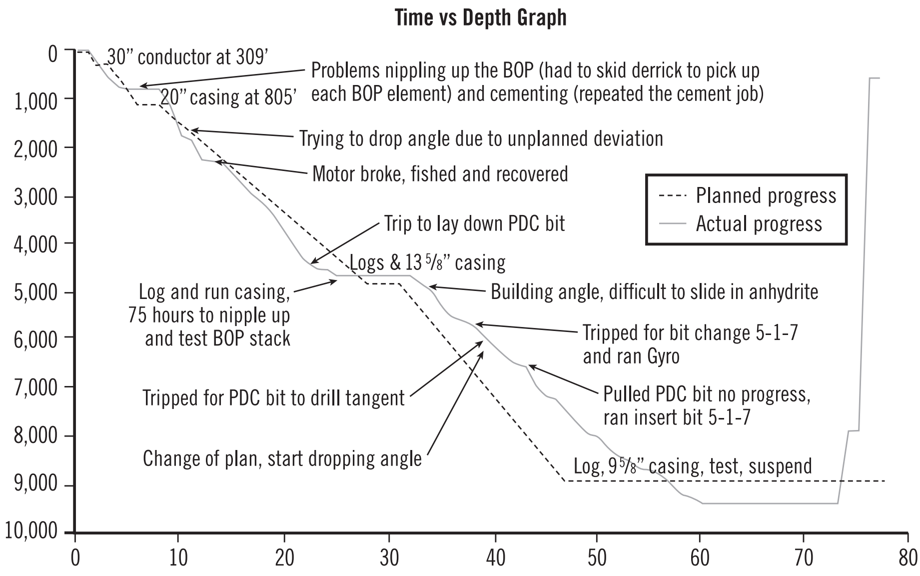


Fig. 12–2. Time-depth graph

3. **Meeting specific targets.** A target could be any performance-related objective that can be measured, such as cost at total depth or time to total depth.
4. **Percentage of well cost saved.** The well could have an agreed target cost, and for every dollar saved against that cost, the contractor earns a percentage.

For an incentive scheme to work well, it should include the following attributes:

- **It must be simple.** The people working for a bonus have to understand how to earn that bonus (what performance is required) and how much will be earned for any particular standard of performance. Some schemes are so complicated that it requires a computer spreadsheet to work out who gets what.
- **It must be easy to measure.** Ideally, anybody covered by the scheme should be able to read the daily reports or look at the time-depth curve (showing actual as well as predicted performance) and work out what is in it for him or her.
- **It must be fair.** If there are penalties for accidents, they should only apply to those people who were in a position to prevent or mitigate the accident and failed to do so. While bonus schemes generally reward the contractor company, the people doing the actual work should earn a fair share of the bonus.
- **It must be paid quickly.** If the bonus is not paid for a long time, people become disenchanted with the scheme and with the operator. This acts as a disincentive.

Some schemes have a reward and a penalty; others have only reward elements.

Decision Making at the Wellsite

The division of responsibility between the drilling supervisor and the toolpusher must always be clear. This is vital not only for operational efficiency when making decisions but also to ensure safe working. With a dayrate contract plus an incentive scheme, some operational decisions must devolve to the toolpusher. The actual division will therefore depend on the contractual provisions.

A special case is decisions made during a major incident (one involving a risk of injury or damage to the rig or to the environment). In some areas, these responsibilities are proscribed by law (for instance, the offshore installation manager has legally defined responsibilities that cannot be delegated to another person).

These areas of responsibility must be defined before operations begin. All supervisory staff (whether operator, contractor, or service company) must understand and follow the procedures laid down.

On a typical dayrate operation, the drilling supervisor will set out a daily program of work for the next 24 hours. This is then discussed with the toolpusher so as to ensure that the contractor has some input and is able to flag up any conflicts. For instance, the drilling supervisor may plan to test the blowout preventer on a test stump in readiness for nippling up the BOP later on. However, the toolpusher may be aware of some equipment problem that prevents the test from occurring until a later time. (A *test stump* is a "false" wellhead spool to which the BOP can be connected and tested. Once the BOP is then nippled up on the actual wellhead, only the last connection needs to be tested. This can save a considerable amount of rig time.)

It is good practice for the main supervisory staff on the rig to meet at least once a day to discuss the upcoming program.

Decision Making in the Office

Each day, usually sometime around 6:30 a.m., the drilling supervisor transmits a daily drilling report back to the office. Previously this was by telex, but now computerized reporting systems are the norm. With high-cost operations, data from the rig can be constantly streamed to a real-time data center, where it can be analyzed by specialists in different disciplines. This data also can be monitored in the drilling office.

In a typical drilling office that has several rigs working, a morning meeting is held, chaired by the drilling manager. Each drilling superintendent describes briefly the operations on the rig, any problems that have occurred or are expected, and other relevant points. This is a good forum where others in the meeting may give advice. It also keeps everybody updated on what everybody else is doing. People from other departments or sometimes from the drilling contractor or service companies might attend, though this is not usually the case.

Although the drilling superintendent responsible for a rig works office hours, the rig can contact the responsible drilling superintendent (DSupt) any time if problems occur.

The daily drilling report, either in full or an abbreviated version, is usually distributed to other departments, or other companies who are partners in the well, so as to keep them informed of progress and problems.

Interfacing with Service Companies

Unless an integrated service provider is used to provide all of the various third-party services, the DSupt has to manage and coordinate the activities of up to 30 companies that may be involved in drilling a well. Much of the DSupt's time will be taken up with these management activities.

Of particular importance are the vendors providing drilling fluid and cement for the well. If the same company is not providing both services. the DSupt has to ensure that there are no incompatibility problems between mud and cement.

The service company representatives (salesmen) do provide a valuable service to the DSupt. It is impossible for one person to keep up-to-date on all new developments in all service areas. By allowing time to meet with the representatives, the DSupt can become aware of new tools, techniques, or services that may help to improve drilling performance. Often with new developments, the DSupt can negotiate quite a good deal as new developments need plenty of field applications before they become generally accepted. A DSupt who is willing to try new things will overall return better performance than those who do not, as long as two simple criteria are met:

1. The new development has a reasonable chance of working, after a careful evaluation of the potential benefits and drawbacks.
2. The cost of the development not working is not too high.

For instance, perhaps a drillbit manufacturer comes up with a new drillbit design. A deal can be made that guarantees the performance of the bit. The payment to the bit vendor is related to the bit performance. The bit vendor will want to ensure that the bit is likely to succeed, not only because of the payment for the bit, but also because any failures in the field will make it harder to sell the bit to other companies. These deals can be quite attractive for both parties, and if the new bit works better than the anticipated performance of the bit it is replacing, the drilling costs are reduced.

Estimating the Well Cost

Early on in the well planning process, the drilling engineer has to make an estimate of how much the well might cost. With a development well, there will be a wealth of offset well data that will allow a reasonably accurate estimate, as long as the basic design elements of the well are known. Exploration wells are a different ball game because there is much less information available and many more unknowns. These unknowns are handled in the cost estimates as contingencies.

The reason for completing a cost estimate so early on in the process rather than after the drilling program is complete (when a proper accurate estimate can be made) is that the well has to be budgeted for in advance. A document known as an *approval for expenditure* or *AFE* must be signed off by senior management.

A computer spreadsheet is an excellent tool for creating cost estimates. Once drilling starts, estimated costs can be replaced with actual costs to give a continually updated forecast of the likely final well cost. In the event that the likely cost will exceed the AFE amount, an AFE amendment should be sought to cover the additional cost.

Well costs can be divided into several categories. Each cost element generally has a code to allow it to be tracked later on (see fig. 12–3).

Fixed costs

Fixed costs are the same however long the well takes to drill or however deep it is drilled. Typical fixed costs relate to moving the rig on location, moving it off after the well is complete, and surveying the well location.

Time-dependent costs

A large proportion of the total cost of the well comes from the time it takes to drill the well. If problems occur, time-dependent costs escalate rapidly. On a dayrate contract, the largest time-dependent cost will be the rig itself. Other time-dependent costs will include equipment on daily rental, personnel, vessels, helicopters, fuel, water, shore base, and dock fees. On an offshore well in deep water, the rig might cost $500,000 a day, but the other time-dependent costs might bring the total operational daily cost to twice that amount.

Well cost estimate - level 2

Well :	Exploration Well 1		**Date :**	18-Jun-99				
Reporter :	Steve Devereux							
A/C no.	**Description**	**Cost rates**			**Cost Estimate**			
		Rig Move	Drill/Suspd	Compl/Test	Rig Moves	Drill/Suspd	Compl/Test	Total
					3.0 days	29.9 days	8.0 days	40.9 days
						2900 m	2900 m	
TIME DEPENDENT ($/day)								
87201	Rig Rate	24,000	25,000	25,000	72,000	748,688	200,000	1,020,688
87415	Vessels	7,000	7,000	7,000	21,000	209,633	56,000	286,633
87230	Additional (catering etc)		400	600		11,979	4,800	16,779
87530	Cement serv. & pers.		508	508		15,213	4,064	19,277
87524	Mud logging		600			17,969		17,969
	Conductor driving equipmt		2,000			10,000		10,000
87665	Dock fees & base overheads	4,400	4,400	4,400	13,200	131,769		144,969
87551	Rental tools		700			20,963		20,963
87554	Consultants on rig	1,400	1,400	1,400	4,200	41,927		46,127
87551	Anderdrift survey tool to 2450m		500			5,700		5,700
87506	ROV mob; drill 26", set 20"	2,100	2,100	2,100	6,300	4,201		10,501
87554	Water	5	5	5	15	150	40	205
87554	Fuel (incl rig and vessels)	500	500	500	1,500	14,974	4,000	20,474
	TOTAL		**45,113**		**118,215**	**1,233,164**	**268,904**	**1,620,283**
DEPTH DEPENDENT ($/m)								
87545	Deviation survey (gyros, MMS)		5			14,500		14,500
87315	Mud and chemicals					226,509		226,509
87330	Solids control consumables		2			5,800		5,800
87320	Cement and chemicals					25,924	1,620	27,544
87301	Bits					133,920		133,920
86201	Casing and accessories					889,610	46,005	935,615
86201	Completion			30			87,000	87,000
	TOTAL					**1,296,263**	**134,625**	**1,430,888**
FIXED COSTS ($)								
87110	Site survey	100,000			100,000			100,000
87220	Rig positioning	25,000			25,000			25,000
87220	Rig Mob/Demob							
87220	Boats Mob/Demob	48,000			48,000			48,000
87548	Casing crews & equipment		20,000	5,000		20,000	5,000	25,000
87509	Electric logging		498,886			498,886		498,886
87509	Cased hole logging and perf.		17,498	77,382		17,498	77,382	94,880
87554	Well Testing			100,000			100,000	100,000
86211	Wellhead		50,000			50,000		50,000
87554	Insurance	20,000			20,000			20,000
	Fishing & Abandon services		10,250			10,250		10,250
	Well planning		40,000			40,000		40,000
	TOTAL				**193,000**	**636,634**	**182,382**	**1,012,016**
SUPPORT COSTS ($/day)								
87554	Drilling Office overhead	2,500	2,500	2,500	7,500	74,869	20,000	102,369
87665	Office Sup't consultant	1,000	1,000	1,000	3,000	29,948	8,000	40,948
87554	Other drilling expenses	50	50	50	150	1,497	400	2,047
87420	Air transport	5,000	5,000	5,000	15,000	149,738	40,000	204,738
	TOTAL				**25,650**	**256,051**	**68,400**	**350,101**
	GENERAL TOTAL	**8,550**	**8,550**	**8,550**	**336,865**	**3,422,112**	**654,311**	**4,413,288**
	TOTAL							**$4,413,288**

Fig. 12–3. Well cost estimate with cost codes

Depth-dependent costs

Depth-dependent costs will increase as the well deepens. Typical depth-dependent costs relate to casings, cement, completion tubings, drilling fluid, and drill bits. These might form up to one-third of the total well cost, unless problems occur that substantially increase the time-dependent costs.

Support costs (overheads)

Overheads are the costs that are incurred by the office and other off-rig activities. Examples include engineering work, such as data analysis or studies, and support staff, such as secretaries, as well as a proportion of the cost of the office. Some of these costs are time dependent and some are fixed costs.

Contingency costs

There are some problems that can be expected to occur, with a small or large probability that any particular problem will actually occur. The cost of each event—the *contingency cost*—is the probability of its occurrence multiplied by the cost if it actually does occur. Say that in a particular hole section, offset data predicts that mud losses might occur. If the cost of those losses might be $50,000 and the likelihood of losses is 10%, the contingency cost is $5,000. An example estimate of contingency costs is given in figure 12–4.

Accuracy of the estimate

There is one other element to the cost estimate. The accuracy of the estimate (the confidence in the final figure) must be given. If good offset data is available, the accuracy generally will be that the final cost should be within 10% of the estimate, or, exceptionally, 5%. For an exploration well, the accuracy will be considerably less—25% would be a reasonable assumption.

Well cost estimate - level 2					
Well:	Exploration Well 1				
Reporter:	Steve Devereux		Date:	18-Jun-99	
		Total cost of all events =			$ 1,602,564
Contingencies		Total contingency cost =			$ 586,630
Problem	Probability, %	Rig days	Other costs	Total cost	Contingency cost
Problems running 20" casing into hole	25	2		$ 107,326	$ 26,832
Hole instability in 17 1/2" hole	25	5	$	$ 268,315	$ 67,079
Hole instability in 12 1/4" hole	25	5	$	$ 268,315	$ 67,079
Kick in 12 1/4" section	25	2	$	$ 107,326	$ 26,832
Kick in 8 1/2" section	25	2	$	$ 107,326	$ 26,832
Losses in 6" section	50	3	$	$ 160,989	$ 80,495
Set 5" liner & TD in 4 1/2"	50	7	$ 100,000	$ 475,641	$ 237,821
Logging problems	50	2		$ 107,326	$ 53,663

Fig. 12–4. Contingency cost estimate

For the final total estimated cost, all of the previously mentioned categories are added up. This is felt to be the likely cost. To arrive at the maximum cost, the total is multiplied by the accuracy factor. For a total of $5,000,000 and an accuracy of 10%, the maximum cost of the well should not exceed $5,500,000. This is the amount that the AFE should approve (fig. 12–5).

Logistics

Logistics is the art and science of getting people and materials to the rig and back again afterwards. Without effective logistics, the well will not get drilled. Logistical problems increase with the distance from the point of supply and with the remoteness of the location. Some special situations, such as in remote mountainous or heavily forested areas, might mandate the use of a rig that is totally moved and supplied by helicopter.

As well as moving supplies, their whereabouts must be monitored. Many drilling operations (if not all) now use computerized inventory and monitoring systems that allow close tracking to be maintained.

Well cost estimate - level 2

By: Steve Devereux

BUDGET TITLE Exploration Well 1

Notes 1. Assumes well logged, tested and abandoned.
2. Mob/Demob costs **are not included.**

DATE 18-Jun-99

VALUE of this estimate	**$4,999,918**	
Dry Hole cost of well	**$4,345,607**	($654,311 less than total)
Contingency included	**$ 586,630**	(Equivalent to 12% of the total estimate)
Accuracy of estimate	**15%**	(Maximum anticipated cost $5,749,906)

1) SUMMARY

This well cost estimate covers the drilling, logging, testing and abandonment of the Exploration well.

2) ESTIMATES

Well time estimate:		
Rig move, jack up, preload	at 50 m	2.0 days
Drive 30" conductor	at 200 m	2.0 days
NU diverter		1.0 days
Drill 26" hole	at 1000 m	2.0 days
20" surface casing		1.2 days
17.5" hole	at 1700 m	2.0 days
13 3/8" casing		1.2 days
12.25" hole	at 2450 m	4.0 days
9 5/8" casing		1.2 days
8 1/2" hole	at 2900 m	4.0 days
7" liner		2.0 days
TD logging		3.1 days
Testing		6.0 days
Abandon well		3.0 days
Release rig		1.0 days
Weather downtime 5%		1.7 days
Rig downtime 10%		3.6 days
TOTAL:		**40.9 days**

Well cost estimate (see attached for details) :	
Rig move :	$ 336,865
Drill, Log, Suspend:	$ 3,422,112
Compl & Test:	$ 654,311
TOTAL Base Estimate	**$4,413,288**
Contingency	$ 586,630
TOTAL with contingency	**$4,999,918**

Fig. 12–5. Final cost estimate summary

Some materials have restrictions as to how they can be moved: explosives; toxic, corrosive, or flammable chemicals; and radioactive materials all require special precautions and may not be transported by helicopter.

Each chemical is accompanied by a form when it is transported. This form is known as the *material safety data sheet (MSDS)*. The MSDS identifies the chemical and its dangerous properties, lists any special handling or storage procedures, and states what first-aid procedures to use if somebody is exposed to it.

One of the early considerations in a drilling campaign has to be whether the infrastructure exists to supply the rig. This may mean building roads, heliports, harbor facilities, and storage areas. As these things take time, any deficiencies in the infrastructure must be known about early enough to remedy them.

Handling Major Incidents

Before operations commence, there must be an incident response team in place. The role of this team is to assemble in a predefined location in the event that a major emergency takes place, such as a fire or explosion, blowout, or structural failure of the rig. The team members and the specific role of each is defined.

All responsible operators and drilling contractors have a room set aside that can be rapidly set up with all of the necessary facilities for the team to function. These facilities will include communications (such as Internet, phones, fax, radios, etc.), a log board that is used to keep a visible log of events, and diagrams of the rig and other facilities. Also included are the contact details for all the emergency services and other operators who may be able to assist. There will be sufficient desks and chairs for the whole team to work, plus representatives of the emergency services who be present to coordinate their services directly with the team, such as police, coast guard, or fire brigade.

Training of team members is important. If the team is to function well together, they must train together for the event. There are companies that specialize in putting together realistic simulations of major events, and it is surprising how much pressure can be placed on the team members in these simulations. It is good if a couple of days a year can be put aside for such training.

When a major incident occurs, the rig supervisor (usually the contractor toolpusher or OIM) will assume the position of on-scene commander and initiate a procedure to call out the response team. The team will assemble in the incident room, and the first person there will start the log board, noting times and events. As more team members arrive, they will be able to see the log board and get a quick view of the situation. It is very important that the team members allow the on-scene commander to get on with handling the incident at the wellsite by giving support and coordination of resources, rather than by trying to pull the strings from onshore (which they do not have the legal right to do). The people on the rig are (or should be) qualified and competent to react properly to the situation, and they are certainly in the best position to assess what is happening. That is also where legal responsibility rests. However, the experienced operations staff present in the incident room will be able to look at the data coming in and advise the rig on alternative scenarios that, in the heat of the incident, the wellsite staff might have overlooked.

The response team will communicate with the emergency services, government authorities, and the media. Handling the media is an important consideration, and it is much better if one person is assigned to keep the media briefed without releasing names or unconfirmed data. Once the media sniff an incident (and they will find out about it surprisingly quickly), they will be all over the place, trying to get any small detail. Information such as names or numbers of casualties must never be given over an open communications channel, as these will be monitored by the media and others. If casualties are involved, the police will take over the task of informing relatives, as well as gathering information for later investigation.

Once the incident is under control, the investigation of the causes and chain of events begins. The police will want to visit the scene of any casualties (serious injuries or fatalities), and they generally have the power to demand that the scene not be disturbed more than is necessary to secure the rig and prevent further damage or problems. If major pollution has resulted, the cleanup might take some time and cost a lot. The aftermath can take some time to get through. As much as possible must be learned to reduce the chances of any recurrence.

Summary

This chapter looked at a variety of subjects relating to the management of drilling operations. Job titles and responsibilities, contracts, incentive schemes, and cost estimating were covered. Logistics and responding to a major incident were described.

13

DRILLING PROBLEMS AND SOLUTIONS

Overview

There are various common problems that might occur during drilling, and there are some uncommon ones, too. This chapter will describe the most commonly encountered drilling problems caused by downhole conditions (as opposed to events such as surface equipment failure).

When any problem is encountered, the drilling staff *must* identify the root causes of the problem before a proper response to solve the problem can be formulated. If the root causes are incorrectly identified, it is unlikely that the correct response will be made, and the problem might remain unsolved. It can even make the situation worse. Identifying the root causes of problems covered in this chapter will be described, along with possible responses.

Lost Circulation

As mentioned in chapter 3, lost circulation occurs in varying degrees. Losses up to 30 barrels an hour (bbl/hr) would be called *seepage losses*. This condition is usually caused by drilling through very permeable formations where the mud cannot form an effective filter cake.

Between 30 and 60 bbl/hr of mud lost per hour would be called *moderate losses*. Again, this is likely to be caused by high-permeability formations and an ineffective filter cake. It could also be caused by faults that do not seal but allow mud to enter into the fault system.

Downhole mud losses of more than 60 bbl/hr are categorized as *serious losses*. This level of losses is unlikely to be caused by high-permeability formations. Potential causes include nonsealing faults or fracture systems.

If the mud losses are so severe that no returns at all are seen at the surface, the term *total losses* would be used to describe the situation. Potential causes include nonsealing faults or fracture systems, and drilling into formations that contain large caverns (also called *vugs*).

Losses occur because both of the following conditions are present:

- The drilling fluid hydrostatic pressure is higher than the problem formation pore pressure.
- There is a path that allows the mud to flow into the formation and away from the wellbore.

Preventing and curing losses addresses one or both of these two factors; the goal is to reduce overbalance and plug off the pathways.

In discussing lost circulation, it is convenient to categorize the problem according to situations in which the losses occur.

Losses while drilling surface hole

Losses in surface hole have two common causes:

- Very permeable formations (often unconsolidated sands) that allow whole mud to seep through the pore spaces (fig. 13–1). Commonly, losses ranging from seepage to moderate might be caused by this. Total losses into permeable formations are unlikely.
- Fractures (either existing or more likely created by the drilling process) that allow mud to leave the wellbore. Severe or total losses are likely with fractures.

Losses into a permeable formation might be cured by pumping lost circulation material (LCM) mixed into some mud into the well. LCM is bulky, lightweight plugging material that blocks the pores in the formation taking the fluid. Materials used for LCM include clay, sawdust, mica (a stable, nonhydrateable clay mineral with large, flat, platelike crystals) and ground nut shells. Usually some mud would be placed in a separate tank (probably about 100 bbl), and a mix of LCM types mixed in. The drill bit will be pulled up the well until it is somewhere close above the top of the permeable formation, and the LCM mud is pumped to the zone and left for a while. It is hoped that the LCM will create a nice plaster of material at the exposed face of the formation. Sometimes it works, and sometimes it does not.

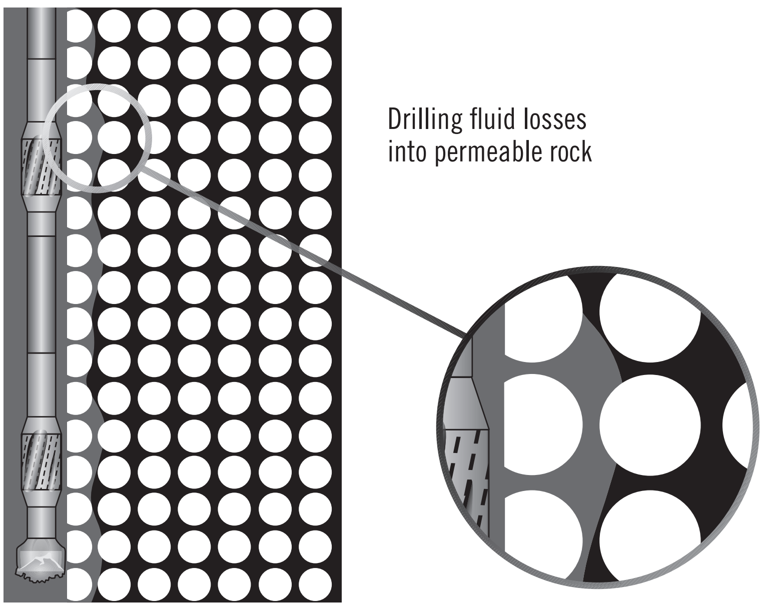


Fig. 13–1. Losses into high-permeability sandstone

As well as attempting to plug the formation face, the pressure exerted on the formation must be minimized. There are several techniques available to achieve this:

1. Reduce the density of the drilling fluid itself. Spud mud, commonly used to drill surface hole, is usually a simple mix of bentonite (which has a low specific gravity) and water. The bentonite disperses in the mud, and the individual clay crystals, which are platelike, can form a good filter cake on permeable formations, unless the formation is coarse. Bentonite also imparts viscosity to the mud. This is called an *unweighted mud* because

no weighting materials such as barite are added. The density could be further reduced by the following:

a. Mixing the mud with fresh water rather than sea water, if the supply situation permits. Sea water has a higher density than fresh water.

b. Aerating the mud using compressed nitrogen injected at the standpipe. (Aerated muds are discussed in chapter 7.)

2. Reduce the density of the drilling fluid when it is contaminated with cuttings, which it will be in the annulus while drilling. Several methods may be easily employed:

   a. Increase the viscosity of the mud at the shear rates present in the annulus so that the mud lifts out cuttings more efficiently. Polymers (such as starches) can be added to do this.

   b. Drill more slowly by applying less weight on the bit, so that cuttings contaminate the mud at a lower rate. This is called *controlled drilling* because the ROP is controlled at a level below which the bit could potentially drill if the drilling parameters were optimized to drill as fast as possible. This also tends to generate smaller cuttings, which are more easily lifted up with the mud flow.

   c. Increase the circulation rate. This lifts out cuttings more quickly. It will also increase the annular pressure losses slightly, but this effect is very small due to the large-diameter, shallow hole typically drilled for surface casing. In most cases, the reduction in contaminated mud density causes a greater drop in bottomhole pressure than the increased annular pressure loss.

   d. From time to time, pump around a pill of highly viscous mud to try to clean out any cuttings not moving out of the well.

3. Reduce the height of the mud column. On an offshore rig, surface hole might be drilled with fluid returns to the seabed, rather than trying to create a closed circulating system to bring fluid to the rig. It is also possible to weld a remotely controlled large-diameter valve on the riser close to the sea surface. If losses are taken, the valve can be opened, and returns exit at sea level. If the well flows, this valve is closed at the same time as the diverter.

Slots can also be cut into the conductor pipe and positioned just above the seabed (fig. 13–2).

While using these techniques, maintaining primary well control and monitoring for potential kicks must not be compromised. The risks are different for an exploration well than for a development well.

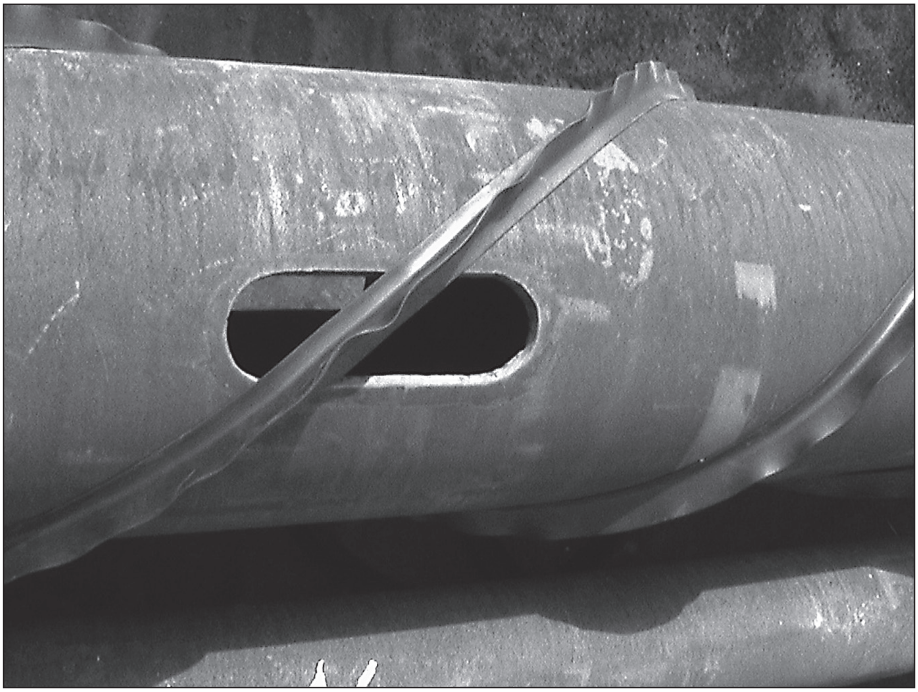


Fig. 13–2. Slotted conductor

Fractures are a real cause for worry. If the fracture extends to surface, the rig itself might collapse if the strength of the ground underneath is compromised due to the fractures and the lubricating effect of mud in the fractures.

These surface hole losses *must be cured*, and the only effective way is by pumping cement into the well and ensuring that the cement sets in the fractures close to the wellbore. The procedure for placing cement in the right location while it sets is described later.

If a small-diameter pilot hole is drilled and later opened up to a larger hole, the losses situation can be controlled much more easily. The mud flows faster in a small pilot hole annulus, lifting cuttings out faster. The physical area of the wellbore wall is smaller, and thus there is less area from which the mud can escape. When the hole is opened up, the ROP is controlled at a rate that prevents excess loading in the annulus by cuttings.

On platform wells, if all of the conductors are set before drilling begins, it is possible for losses to become established between the well being drilled and an adjacent conductor. The distance through the rock can be very short (a few meters). (See figure 4–1 to see how close together the wells can be when drilled from a platform or template.) The other very real danger here is that if shallow gas is penetrated by the well, gas might channel through the rock and flow up and out via an adjacent conductor that forms a perfect conduit to just below the platform and without any diverter set on it. In this situation, conductor depths may be staggered to increase the distance between conductor shoes. It is also very good practice to set around 50 ft of cement in the bottom of each conductor before starting to drill the first well.

Losses in normally pressured, deeper formations

These formations may be unconsolidated, naturally fractured, or fractured by the drilling operation. The formations also may be consolidated but highly permeable, with pore sizes too large for the mud solids to plaster. The loss zone can be anywhere in the open hole, not necessarily the formation just drilled into.

Several factors can contribute to the mud loss, such as annulus loaded with cuttings, high equivalent circulating density (ECD), excessive mud density, insufficient mud viscosity, and high water loss (low solids content to plaster the wall and plug off high-permeability formations). Other contributing factors could be excessive surge pressures, breaking the formation during a formation integrity test, or closing in the well after a kick.

It is necessary to identify the type of loss zone and the mechanism causing the losses to start. Knowing the depth and type of loss zone will help formulate a strategy to cure the losses.

In general, several techniques should be useful in *most* loss situations deeper in the well in smaller holes. Given in the order in which that they should be attempted, these are as follows:

1. Decrease circulation rate for lower circulating pressures and drill with controlled parameters to minimize annulus loading with solids, which makes the fluid in the annulus heavier. The losses may well decrease over a period of time (a few minutes to a few hours). The severity of the loss may dictate whether this is acceptable; for instance, with losses of over 60 bbl/hr using expensive mud, the cost may be too high. Restricted replacement mud supply may also preclude this, such as desert drilling with limited water available. However, the circulation rate must be sufficient to lift cuttings out of the well, or stuck pipe with cuttings in the wellbore becomes likely.
2. Reduce mud density if possible by diluting the mud and maximizing the use of solids control equipment.
3. Pump a 100 bbl lost circulation material pill with mixed fine, medium, and coarse LCM. Place it across and above the loss zone and observe the well. When the well becomes static, start circulation cautiously, monitoring the active volume, and resume drilling.
4. Add solids (LCM) to the whole active volume of mud to increase plastering characteristics.
5. Severe or total losses can sometimes be cured by drilling ahead slowly with reduced weight on bit. It is only an option if there is a plentiful supply of water (such as on an offshore rig) and mud chemicals.

Drilling with no returns is called *blind drilling*. It should not be attempted if there is any chance of hydrocarbons being penetrated. The circulation rate must be sufficiently high to lift cuttings away from the BHA and up to the loss zone, where they may plug off the large pore spaces or fractures. A general lower limit for annular velocity for blind drilling is 50 ft/min.

Further action may include setting a barite plug (as described in chapter 11), diesel oil bentonite plug, or cement plug (described later in this chapter); setting an extra casing string; or plugging back and sidetracking if the severity of the situation warrants it and if that might bypass the loss zone. Aerated mud techniques as described in chapter 7 might also be applicable, but these must be planned well in advance.

Losses in heavily fractured or cavernous formations

Some formations contain very large fractures (typical of limestone reservoirs) or large caverns. When the bit penetrates one of these spaces, total losses are likely to start immediately—a good sign that this type of formation has been penetrated.

One option may be to drill blind with water if the area is well known, or to drill with foamed mud if not. Casing is set as soon as possible after drilling right through the loss zone (drilling far enough to give a reasonable column of cement above the casing shoe).

Another option is the careful spotting of large volumes of cement as described later. If done correctly, this will work to plug off fractures or caverns around the wellbore. Drilling further after this cement cure can open up more fractures, which could lead to one or more repeats until the fractured zone has been completely drilled through.

Diesel oil bentonite (DOB) plug

DOB plugs are also known as *gunk plugs*. They work by holding bentonite clay in suspension in diesel oil until the plug is in place downhole, and then arranging for water to hydrate the bentonite. The bentonite hydrates rapidly, becoming extremely viscous. They can be successful in shutting off flow in an underground blowout, especially if the flow is water.

A DOB plug will not maintain strength indefinitely. Cement should be spotted to give a permanent seal once the plug has worked. The main potential problem with the DOB plug is that it will set up inside the drillstring if it contacts any water. A good diesel spacer ahead and behind are essential to prevent this.

To place the plug, 150 lb of bentonite are mixed for each barrel of diesel. Normally, a DOB plug will be between 30 bbl and 150 bbl in size. There must be no water present in the mixing pit or in the pump lines.

About 10 bbl of diesel is pumped as a spacer ahead, followed by the DOB slurry, and then another 10 bbl of diesel behind. Fresh water is pumped behind the diesel. The plug is pumped down the drillstring to the loss zone. As the water behind exits the drill bit, the larger annular capacity allows the water to mix with the DOB slurry. Any water already present in the loss zone will also mix with the slurry, hydrating the bentonite. Water can be pumped ahead of the first diesel spacer if desired (e.g., if oil mud is in use), in which case the diesel spacer ahead might be increased in volume.

Curing total losses with cement

The best lost circulation material for severe to total losses is cement. There are two keys to success that the procedure must aim for:

1. Sufficient cement must be placed in the loss zone immediately around the wellbore.
2. The cement must not move away from the near-wellbore zone while it sets.

Many times, a small volume of cement is used, and the subsequent actions almost guarantee that the cement will move away from the wellbore after placing. Here is an outline procedure that has worked well in the field:

1. Drill right through the loss zone so that it is completely penetrated first, if it is possible and if it can be done safely.
2. Position drillpipe just above the top of the loss zone.
3. Pump a large quantity of lightweight extended cement slurry (about 200 bbl).
4. Pump a large quantity of neat cement, which ideally incorporates polypropylene fibers in the slurry (about 100 bbl or so). The slurry should be designed so that the compressive strength when set will be less than the formation compressive strength. This is to avoid the drill bit from drilling an unintended sidetrack away from the wellbore. If the fibers plug off against the formation face, that is fine—it will prevent the earlier slurry from moving away from the wellbore.

5. Pump mud behind the cement. The volume of mud pumped should be some barrels less than the total drillpipe capacity so that a bit of cement is left in the pipe (about 5 bbl). If mud returns to the surface during this part of the job, it indicates that the fibers are plugging off the channels leaving the wellbore (a good sign).
6. Pull out about 200 ft of the drillpipe without putting any mud into the hole. Normally, mud is pumped into the annulus when pipe is pulled out to ensure primary well control is maintained (as described in chapter 11). While pulling out, the cement remaining in the drillpipe will drop out of the bottom.
7. Pull out another 300 ft or so of pipe. Pump a measured amount of fluid into the annulus while pulling out, but *no more than is needed to replace the volume of steel removed.* It is better to pump too little than too much so as to avoid chasing cement away from the near-wellbore zone.
8. Wait until the cement should be hard, and then top up the well with mud. Pull out the drillpipe, run in with a drilling assembly, and drill out the cement. While the procedure will vary a little depending on the actual situation, this procedure gives a high probability of success the first time. Cement floods the spaces around the well and is allowed to stay there and set.

Stuck Pipe

The drillstring can be said to be *stuck* when it cannot be pulled all the way out of the hole without exceeding the maximum allowable pull on the pipe. Within that definition, it may or may not be possible to circulate; pipe movement downwards below the stuck point may or may not be possible, and pipe rotation also might or might not be possible.

Most cases of stuck pipe (over 90%) are avoidable with good supervision. Pipe rarely gets stuck with no advance warning signs. If the conditions are present to make stuck pipe possible, the drilling supervisor and drillers must stay on the ball and take suitable precautions to prevent it from occurring.

If pipe does get stuck in such a way that no pipe movement at all is possible, the immediate actions will usually determine the outcome (getting free vs. staying stuck). Sticking forces increase with time, so it is very important to analyze the situation and take immediate action to get unstuck.

Stuck pipe may be classified into categories according to the main cause of sticking.

Sticking mechanisms for stuck pipe

Causes of stuck pipe can be classified into three basic categories:

1. **Geometry.** This relates to dimensional problems in the wellbore. Circulation is usually possible; the problem will be seen with the string moving, and only in one direction.
2. **Solids.** This relates to solid particles in the hole. Circulation may be restricted or impossible, and hole cleaning may have been inadequate. This usually occurs when pulling out of the hole.
3. **Differential sticking.** This relates to mud overbalance over a permeable formation.

Each of these will be examined in turn.

Geometry-related stuck pipe

There are several different root causes of geometry-related stuck pipe (fig. 13–3).

If the wellbore is undergauge for any reason, full gauge tools such as the drill bit or stabilizers can get stuck if moved into the undergauge part of the hole. Several causes are possible for an undergauge hole. These include drilling with an undergauge bit, thick filtercake buildup on a permeable formation, and mobile formations (squeezing salt or shale that moves in to the wellbore with time).

In deviated wells, it is possible for a keyseat to form. Where the drillstring (OD of 5”) presses against the inside of the bend in the wellbore, it can wear a groove into the formation. If this groove becomes deep enough, when the pipe is pulled out of the hole, the drillpipe will slide inside the groove. However, the top of the BHA cannot move through the groove, having a larger OD. The result is that the pipe becomes stuck at the top of the BHA. Full circulation will be possible. If the BHA was not pulled too hard into the keyseat, it might be possible to move the drillstring down.

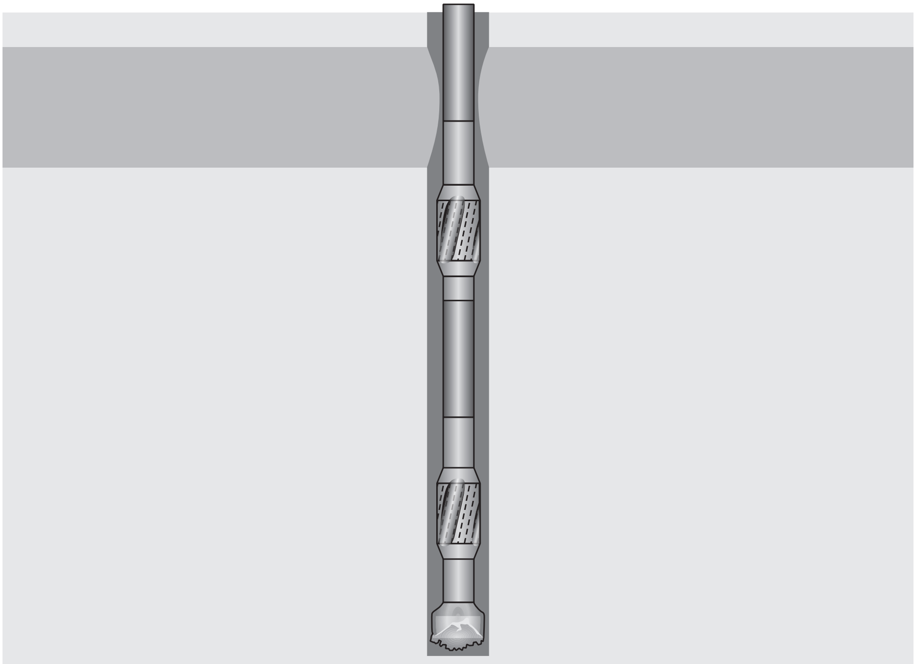


Fig. 13–3. Geometry-related stuck pipe

Keyseats can be avoided by limiting the dogleg severity of the buildup section, limiting the number of rotating hours against the bend before it is cased, and limiting the drillstring tension while drilling below the bend. A tool known as a *string reamer* can be placed in the drillpipe above the bend, this tool enlarges the groove as it moves downwards during drilling. A keyseat reamer can also be run at the top of the BHA, which allows the keyseat to be dressed out by rotating while pulling out of the hole. It takes extra time and is a bit tricky, so it is preferable to use a string reamer, if possible.

If a section of the hole was drilled with an assembly that caused a dogleg to form (such as a build or steerable motor assembly), problems can occur if a more highly stabilized assembly is run straight into the same section. It is a geometry-related problem. It is necessary to ream in first with the new BHA. Reaming is like drilling but instead of rotating on bottom, the bit drills on its gauge area only to smooth out the curved section and enlarge it slightly. The work that the bit does is monitored by watching—and limiting—the torque required to turn the drillstring.

Where hard and soft layers of formation alternate, the soft parts can enlarge more than the harder formations. Ledges form. It is possible for the pipe to get stuck at changes of diameter, such as on the bit, on stabilizers, or at the top of the BHA.

Solids-related stuck pipe

Solids particles in the annulus can cause the pipe to get stuck (fig. 13–4). Mostly, these solid particles will be drilled cuttings or wellbore cavings. However, there are other possibilities. Solids-related problems normally occur when pulling pipe out of the hole, or if the pipe is left in one place without any circulation. In most cases, circulation will not be possible because the solid particles will block off the annulus. If circulation is impossible due to solids, the hole is said to be *packed off*. This stuck pipe situation is the most difficult to cure, but most of the time, it is luckily not difficult to avoid.

Before the drillstring is pulled out after drilling, circulation should continue after drilling stops for long enough to lift all the cuttings to the surface. This is not always as straightforward as it sounds. In inclined wellbore sections, cuttings move upwards by a combination of lifting (vertically upwards movement) and rolling along the low side of the hole. As inclination increases, more rolling and less lifting takes place; in a horizontal well, the vertical lift component is zero. Making solids roll along the hole takes more energy (higher flow rates) than lifting them. Also, as inclination increases, the drillpipe will tend to rest on the low side of the hole. This reduces the flow rate along the bottom, as the flow will preferentially go to the largest available area—above the drillpipe. Under these conditions, cuttings beds form easily and are not easily moved if the drillstring is not rotated (when drilling with a directional motor). Modern rotary steerable tools avoid this.

Fig. 13–4. Hydrated clays sticking to a drill collar

Stable cuttings beds can form in inclinations over about 60°, especially if the hole is overgauge in places. At lower inclinations, any cuttings bed will get only so large and then will avalanche down the hole. Stable cuttings beds sit there nice and quietly until the BHA is tripped out of the hole. As the larger BHA encounters the bed, it ploughs into the pile of solids and can get stuck. If the pipe is packed off with solids, the prognosis is bad. To cure the problem, circulation must be reestablished, but this is often impossible.

Another source of solids in the well is reactive formations. This is overwhelmingly a problem with shales. Formations can become unstable due to adverse reactions with the mud physical or chemical properties. Two instability modes are possible. The first possibility is that the shale hydrates, becomes plastic and sticky, and falls into the wellbore. The second possibility is that the hydrostatic pressure exerted by the mud is insufficient to hold the formation together, and slivers of shale fall off into the well as cavings (mentioned in chapter 3). This also can occur when drilling in overpressured shales. The pore pressure might even be higher than the mud hydrostatic pressure, but the well does not kick due to the very low permeability of shale, and high levels of cavings result. Even if the annulus is clean of cuttings at the start of a trip out of the hole, reactive formations can cause material to fall in during the trip and stick the pipe. The warning signs are that the force needed to pull the drillstring out does not decrease as rapidly as would be expected as steel is removed from the hole. If this occurs, the driller must stop pulling out and circulate the hole clean again.

In shallow, unconsolidated sands, tophole collapse might occur. The hydrostatic pressure must be able to support the formation, but if there is not a good filter cake and losses occur, there is little difference in pressure between the formation around the wellbore and mud hydrostatic pressure. The sand simply falls into the well. (This problem can be demonstrated by trying to dig a deep hole on a beach.) The mud must have good plastering characteristics so that a firm filter cake is formed, allowing the mud hydrostatic to hold the sand back.

Sometimes, formations are fractured. This can happen especially with brittle shales, coal, and limestone. Mud gets into the fractures, and this lubricates the fracture faces as well as changing the pressure regime near the wellbore. Pieces of formation fall off (fracture cavings). Cavings from fractured formations can be identified by their size, shape, and presence of fracture faces that may be visible.

Junk in the hole can also fall into this category. If something is lost down the hole, either because of something breaking or by something falling through the rotary table, stuck pipe may result.

Cement that is not fully set is known as *green cement*. If a cement plug was set in the hole and the driller runs into it with the bit while it is still green, the pipe can become plugged or can get stuck in the cement.

Differentially stuck pipe

Differentially stuck pipe is far less common today than 15 or 20 years ago (fig. 13–5). The knowledge of the mechanisms involved, better muds, more use of stabilized BHAs, and better awareness of drill crews has relegated differential sticking to a minority of cases of stuck pipe. Interestingly, many people immediately assume differential sticking when a problem occurs and have to be convinced that something else might be the cause.

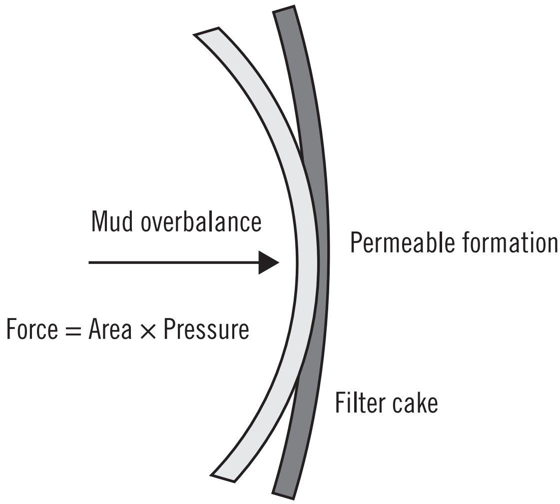


Fig. 13–5. Differential sticking

There are four conditions related to differential sticking, all of which must be present for it to occur. These are as follows:

- The presence of a permeable zone covered with wall cake
- Static overbalance on the formation
- Contact between the wall and drillstring
- A stationary string

With wall contact and over a period of time (seconds to minutes), the stationary tubular pushes into the filter cake. This establishes a contact area over which differential pressure may act. Larger diameter tubulars form greater contact areas and therefore are more likely to get stuck. Circulation will be possible, but there can be no pipe movement until the pipe is freed.

The force required to pull the tubular free is proportional to both the differential pressure and to the contact area. If this force exceeds the allowable pull on the pipe, the differential pressure must be reduced or the filter cake thickness (and therefore the contact area) must be reduced. Casing is a particular problem, due to the large-diameter, smooth pipe giving lots of good contact area with the formation.

To prevent differentially stuck pipe, the mud should be tailored so that it forms a thin, tough and nonsticky filter cake. Overbalance should be minimized, commensurate with maintaining primary well control. Stabilizers can be run to hold the large-diameter drill collars off the wall. Drill collars can be used that have spiral grooves cut into them, which reduces the contact area. Finally, whenever the BHA is opposite a permeable formation, the time it spends static (neither reciprocating nor rotating) should be minimized.

Sometimes, the drillstring or casing will get stuck by another mechanism elsewhere in the hole and then will become differentially stuck if the conditions exist.

Once pipe becomes differentially stuck, chemicals can be pumped down the drillstring and over the sticking formation to dehydrate and shrink the filter cake. Reducing overbalance is more tricky, first because of the well control implications and second because reducing mud hydrostatic significantly can have a highly destabilizing effect on some shales. The other action that can be taken is to pull and jar on the pipe. This is described next.

Jars and jarring

Steel as a material is quite elastic. *Elasticity* is a property of a material whereby a force applied to the object causes it to deform, and when the force is removed, the object reverts to its original dimensions. Springs are made of steel precisely because it is an elastic material. If more than a certain force is applied, the material stretches permanently; this force is called the *elastic limit*. If even more force is applied, the material will break; this force is called the *ultimate tensile strength*. Chapter 5 discussed how these limits affect the design of the drillstring.

When the drillstring is held in tension, it has stretched to a certain extent. How much it has stretched is measured by the strain. Strain is simply the amount that the pipe has stretched divided by the original length. So if a 10,000 ft pipe stretches by 5 ft, the strain will equal 0.0005.

The energy that is used in creating this strain is stored in the pipe and is called the *strain energy*.

A catapult works by using rubber strips to store strain energy. A stone is placed in the catapult pouch, pulled back (to store energy), and let go. The stored energy pulls the pouch and stone, accelerating it forwards. The initial acceleration is fast (because the pull on the pouch is greatest), and the acceleration reduces as the stone moves forward. When the rubber becomes slack, the stone stops accelerating and has reached its maximum speed.

A drillstring and jar is like a downhole catapult. The jar is a tubular tool that is placed high up in the bottomhole assembly. It can open and close just like a bicycle pump. However, there is a mechanism inside the jar that stops the tool from opening until some condition is satisfied. The condition might be that a certain amount of pull must be applied to the jar, or that a period of time has to elapse after placing the jar in tension. Once the condition is satisfied, the jar opens a certain amount, typically around 2 ft, and will not open further.

One or two drill collars are placed above the jar. The rest of the BHA stays below the jar. If the pipe gets stuck (below the jar), strain energy is applied to the drillstring by pulling upwards on it. The jar suddenly opens, which allows the strain energy stored in the drillstring to accelerate the heavy drill collars above the jar upwards. When the jar is completely open, the weight of the drill collars moving quickly upwards exerts a hammer blow on the jar and everything below it. In the catapult analogy, the drill collars above the jar are equivalent to the stone that gets catapulted.

A jar is almost always run as part of a drilling bottomhole assembly. Drilling jars are very robust so as to withstand many hours of rotating, vibration, high internal pressure, and changes in pressure and temperature. Fishing assemblies also incorporate jars.

Fishing

Sometimes, something gets into the hole that needs to be recovered. For instance, a spanner might drop down the rotary table or part of the drillstring might break. These items prevent normal operations from continuing. The item that must be removed from the well is called a *fish*, and activities to remove the fish are termed *fishing*. There are four main causes for fish in the hole:

1. If there is a failure somewhere in the pipe in the hole that causes a break, the lower part of the string will drop into the hole.
2. If stuck pipe cannot be freed, it has to be cut or unscrewed downhole.
3. Something falls into the well.
4. Sometimes wells are worked over; they may require that the existing completion is replaced with another completion. Often the completion tubing has to be cut downhole and recovered in pieces.

There are five classes of tool that can be used to remove a fish or junk from the hole. The choice of which one to use will depend on the circumstances. The five classes are each briefly described.

Outside catch tools

If the junk has a round profile at the top, the preferred tool will normally be an outside catch tool. These tools are pushed over the top of the fish. When the fishing tool is moved upwards, it grips the fish and allows force to be applied.

There are two types of outside catch tool that are commonly available: the overshot and the die collar.

An overshot is very simple, strong, and versatile. It consists of a steel barrel inside of which is a wedge-shaped profile machined on the inside diameter. Fitting into this profile is a spiral element, called a *grapple*. The grapple has a wedge-shaped outer profile that fits the ID of the outer barrel, as can be seen in figure 13–6. On the grapple ID are hardened steel teeth that grip the fish. As pull is applied to the tool, the wedge shapes cause the grapple to close, and thus the more tension that is applied to the tool, the tighter the grapple grips the fish.

Of all the fishing tools available, the overshot is overwhelmingly preferred to catch anything tubular shaped, due to the following:

- It can exert a tremendous pull on the fish. A jar can be placed above the overshot so that hammer blows can be applied to the fish through the overshot.

- It can be unlatched down hole if the fish cannot move. Latching and unlatching does not damage the top of the fish significantly.
- As it is hollow down the middle, logging tools and explosives can be run on wireline into the fish.
- If the fish is not plugged off, it is possible to circulate down the overshot and through the fish—a major advantage.

Fig. 13–6. Cutaway of an overshot

A *die collar* is a tubular piece of steel (fig. 13–7). Inside it has a slightly conical profile facing downwards. Threads are cut into this profile. To latch onto the fish, the die collar is lowered over the fish and a little weight applied. By rotating the drillstring to the right, these threads cut into the top of the fish and grip it. However, once the die collar is on the fish, it cannot be removed. It is not as strong as the overshot, so if it is jarred on, it will likely pull off the fish.

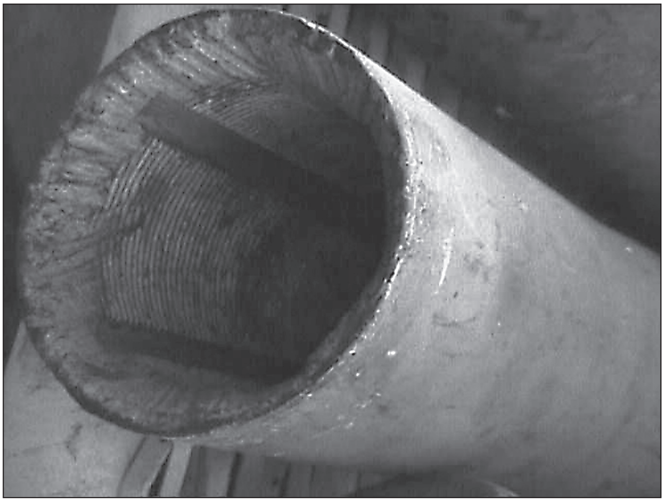


Fig. 13–7. Die collar

Inside catch tools

Sometimes, a tubular fish has a large outside diameter, which prevents an overshot from going over it. Casing is a good example. For these fish, the fishing tool must grip on the inside diameter. There are two types of tool commonly available: the releasing spear and the taper tap.

The releasing spear works like an overshot in reverse. It has a mandrel down the middle that has a conical profile outside. Steel slip elements fit around this mandrel with teeth on the outside. As force is applied, the mandrel profile pushes outwards on the slip elements, so that the more tension is applied, the more the slips grip. As with an overshot, it can be released downhole.

The taper tap works like a die collar in reverse. It has a slightly wedge-shaped section of bar below, which has threads cut on to the profile. The tap is lowered into the inside diameter, some weight is set down, and the tap is rotated. The threads cut into the top ID of the fish to grip it. The taper tap is not very strong and as with the die collar, it cannot be unlatched once on the fish.

Washover and basket tools

Within this class of tool there are three types: the fishing magnet, tools that use fluid movement to catch small bits of junk, and tools that use a barrel to go over bits of junk and then close below the junk.

A fishing magnet can be either a permanent magnet run on drillpipe or it can be an electromagnet run on wireline. Fishing magnets are useful only for small pieces of ferrous junk.

Tools that use fluid movement include the jet junk retriever (fig. 13–8). With the tool at the bottom of the hole, a ball is dropped that diverts flow around the outside of the tool and back up inside the end. Spring-loaded fingers allow small bits of junk (such as a drillbit cone) to enter the end of the barrel and are held in place by the fingers closing below the junk.

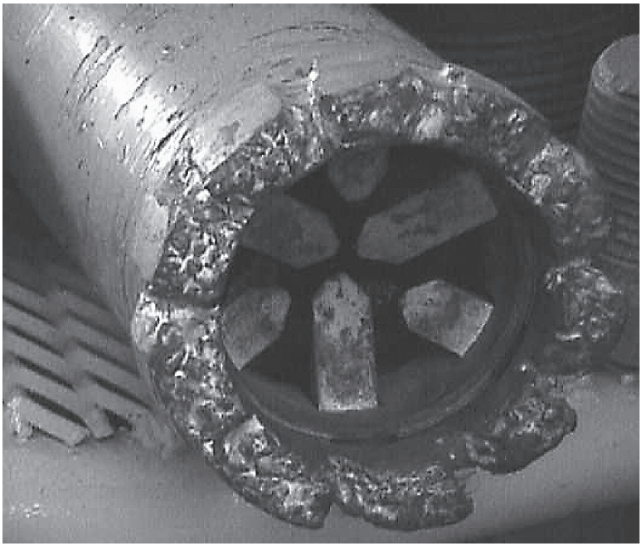


Fig. 13–8. Jet junk retriever

In general, tools that use a barrel to go over the fish are called *washover tools*.

Washover tools are available with a milling shoe on the bottom (which can cut some rock at the bottom as well as mill on junk) and with spring-loaded catch fingers inside. This is used to go over the junk and to catch it inside the barrel.

A simple washover tool can be made on the rig from a piece of small-diameter casing or liner. This tool is set on bottom, weight is applied, and the string is rotated. This causes the fingers to bend and twist so as to close the fingers below the bits of junk. It is useful for catching rock bit cones or other small bits that are lying on the bottom of the hole.

Drilling, milling, and smashing junk

In surface holes where formations are soft, smaller bits of loose junk can be drilled with a steel tooth bit. Often what happens is that the bits of junk get pushed into the side of the hole and are never seen again. Steel tooth bits are also capable of breaking up small bits of junk—no other drill bit can do this.

Mills can be used when junk is in the hole. Mills work well on junk that is not loose—that is, it is cemented in place or otherwise prevented from rolling around. Rolling junk can damage the mill, although mills can deal with this kind of junk also. It might take more than one mill to do the job.

Mills used for cutting up junk (and especially junk that might be loose) have chips of tungsten carbide brazed to the bottom of a steel body to cut as in figure 13–9.

Fig. 13–9. Flat-bottomed mill

Explosives can also be run on wireline or pipe to break up junk, which can then be dealt with using a washover tool or a drill or mill. The explosive used is a shaped charge, designed so that the force is projected downwards onto the junk.

Fishing for wireline and logging tools

Finally, wireline sometimes breaks, resulting in a tricky fishing job. Wireline is fished with a spear that has barbs on the side. The spear is run into the top of the wire and rotated. The barbs catch on the wire and cause the wire to wrap around the spear so that it can be pulled out.

If a logging tool gets stuck, the best way to fish it is by stripping over the wire. The wire is cut at the surface and is fed through a special tool that latches onto a profile at the top of the logging tool. This fishing tool is then run in the hole over the wire so that the wire guides the fishing tool to the logging tool. It is a slow job because each stand of pipe has to have the wire fed through it before it can be connected to the string at the rotary table.

Economics of fishing

Fishing is an expensive activity because normal operations cannot continue until the situation is resolved. If the fish cannot be recovered, the alternatives are as follows:

- Place cement on top of the fish and drill a sidetrack around it.
- Finish the well early (if enough of the original objectives can be achieved in the shallower wellbore).
- Abandon the well (either drill another well or abandon the project).

These alternative courses of action have a cost attached to them. There comes a point when fishing should be discontinued and the best alternative pursued. This is an economic decision.

Fishing jobs have the best chance of success on the first attempt. If the first attempt fails, it is only worth trying again if, in the process of the first attempt, something was learned that would improve the chances of success on the second attempt. The longer a fish stays in the hole, the harder it becomes to recover it. This is because hole conditions deteriorate with time, sticking forces will increase with time, and as more attempts are made, the more the fish itself might become damaged or worn.

Fishing considerations for radioactive sources

If radioactive materials are contained in the fish, many governments mandate that they must be recovered even if the cost is very high. In this case, fishing can only be abandoned if certain rules are met (which will change with the area and government involved), after having exhausted all possibilities to recover the fish.

Some logging tools containing radioactive sources that are run on drillpipe are designed so that the source itself can be recovered. A special tool is run on wireline into the drillstring where it can latch onto the source container and pull it back to the surface.

Summary

This chapter looked at some of the commonly encountered downhole problems, such as lost circulation, stuck pipe, and fishing operations. When these problems occur, the root causes plus the current status of the well must be established before an effective strategy, specifically targeted to solve the problem, can be formulated.

14

SAFETY AND ENVIRONMENTAL ISSUES

Overview

Management of safety is of fundamental importance to the oil industry. Over the years, systems have been developed to ensure a safe working environment for the people who work at the wellsite. Equipment, training, practices, and procedures are used to reduce risk to a level that is considered as low as reasonably practical (ALARP). In addition, many governments have become involved as a result of incidents that have occurred. In some cases, such as the *Piper Alpha* disaster in the UK North Sea, a single incident is so serious that public inquiries are held, which can lead to major changes in the legal requirements that govern the industry. The 2010 BP Macondo disaster in the Gulf of Mexico will have a similar effect. Macondo resulted from a chain of human errors, any one of which could have broken the chain and prevented the disaster.

Ultimately, the safety of a person working at the wellsite is also very much the individual's own responsibility—not to work unsafely nor allow others to do so and to alert supervisors to any unsafe conditions encountered. However, the systems must be in place that lead to a safe environment and that allow people to be effectively trained to work within those systems (fig. 14–1). The actions and attitudes of management must ensure that people are not encouraged—or intimidated—to work unsafely.

An important trend since the new millennium is the development of highly automated systems that can replace human muscle power and keep people away from heavy and powerful tools that can cause injury if things go wrong.

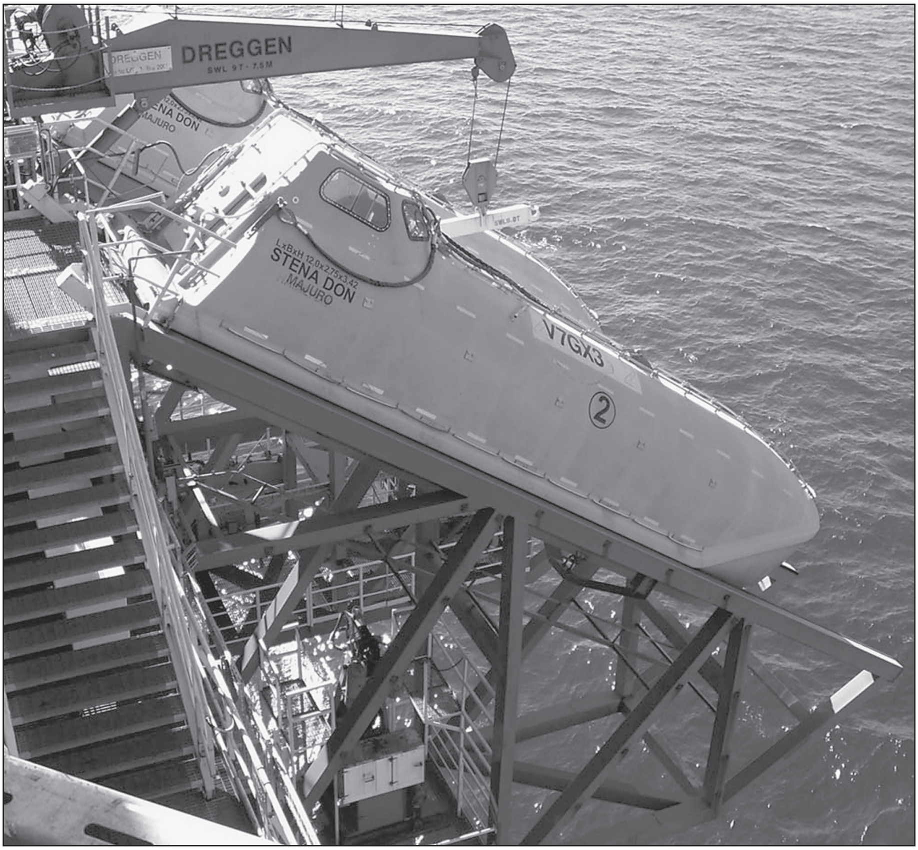


Fig. 14–1. Lifeboat on a semisubmersible rig

Safety Meetings

Meetings are an essential part of the safety regime on any rig. They are used to ensure good communication among everybody on the wellsite. There are several different types of safety meetings that are regularly held, as outlined below.

Prespud meetings

Once the drilling program is finalized and before the rig starts to drill, there will be a prespud meeting held in some suitable venue, such as a conference center or training facility. All of the contractors (including the drilling contractor) will be represented at this meeting, which is generally chaired by the senior drilling engineer responsible for planning and supervising the operation from the office. The well design and drilling program will be discussed, and as part of this, any potential hazards will be flagged up. Potential risks must be managed, preferably by avoiding them altogether. If a problem does occur, procedures must be in place with a preplanned strategy to minimize its impact and to allow recovery from its effects as safely and efficiently as possible. Recognizing and managing risks is one of the primary responsibilities of everybody involved in the operation, and the prespud meeting is probably the earliest forum where all concerned can come together to discuss these risks.

On the rig, before the well is spudded, a similar prespud meeting will be held with the drill crews and rig supervisors, chaired by the drilling supervisor. This ensures that everybody is aware of the potential risks and how they will be addressed. The meeting is also a forum for feedback—a lot of practical experience will be represented in the room, and good suggestions often result.

Weekly safety meeting

Every rig operated by a responsible company has weekly safety meetings that all personnel are expected to attend. These meetings generally take between 30 and 60 minutes. Items to be discussed will typically include the following:

- Any incidents or accidents that have taken place on the rig.
- Any incidents or accidents on other rigs that may be particularly relevant to the rig.
- Suggestions from the participants to improve safety on the rig.
- Status of any ongoing work that has a bearing on safety.
- Any STOP cards that have been handed in can be discussed and the lessons learned emphasized. (STOP cards are discussed later in this chapter.)
- Rig safety statistics.

Minutes of these meetings are recorded and sent to the office, as well as being posted on the rig notice board.

Daily operations meeting

On many rigs, a daily meeting is held in the morning to discuss work for the day. Generally, the attendees might include the toolpusher, drilling supervisor, driller, mechanic, and electrician. While enjoying a cup of fresh coffee and donuts, the anticipated program over the next 24 hours will be reviewed. Any planned maintenance or repair work will be coordinated so that normal rig operations are affected as little as possible, and the risk of something conflicting is reduced.

Pretour meeting

Before starting their 12-hour shift, the driller will call together the drill and deck crews. The work program for the shift will be discussed and any special considerations noted. This allows the new shift to start work knowing what the overall plan is, what hazardous operations might be coming up, and what equipment needs to be prepared.

Prejob safety meeting

Before starting any nonroutine work, the on-shift driller will call a safety meeting of all the people who will be involved in the work. As the driller has overall responsibility for the safe execution of drillfloor operations, it is important that he or she runs the meeting.

Here is an actual checklist for a prejob safety meeting for running casing. Present at this meeting would be the drill and deck crews and any contractors involved in running the casing. The toolpusher and drilling supervisor might also be present.

Prejob Safety Meeting for Running Casing

1. A good safe job is required; work efficiently without rushing.
2. All the correct safety equipment is to be used: safety belts at height, etc. There will be no exceptions.
3. The on-shift driller has overall responsibility for the job. Any problems are to be reported to him.

4. Watch out for pinch points: fingers or hands getting trapped between moving and stationary equipment, such as casing coming up to the drill floor.
5. Keep the drill floor reasonably clean to prevent tripping and slipping hazards.
6. No one is to use the V-door stairs when a joint of pipe is being moved between the catwalk and the drill floor or being picked up by the single joint elevators.
7. When you change shift, make sure you hand over your job to your relief, and then stop and watch that person working for a few minutes to make sure the job is being done properly.
8. Any unsafe conditions must be corrected immediately. Watch out for ropes on the V-door and stabbing board getting worn and change in good time. Keep an eye on lifting slings and strops.
9. Joints of casing must have clamp-on protectors in place on the pin end before picking up the V-door. If one drops off, the rig crew must be told straight away and the pin examined before running.
10. It must be possible to circulate the casing in case of a well control situation or if the casing has to be washed past a tight spot. The crossover from casing to the high-pressure pump line must be kept on the drill floor ready to use.
11. The personnel working on the stabbing board must be rotated out every couple of hours, and they must also get adequate rest.
12. Highlight any special procedures, hazards, etc. with the crews.
13. Invite questions or comments from the crew.

Newcomers on the Rig

When people arrive at an offshore rig, they usually sit through a briefing about the rig (fig. 14–2). They will probably see a video about the rig showing the rig layout, lifeboat locations, etc. The video will demonstrate the various alarm sounds, what they mean, and what actions are to be taken on hearing them. They will also be told when the weekly safety meeting will be held and that they must attend if they are on the rig at that time.

Fig. 14–2. Helicopter landing on an offshore rig

They will be assigned a cabin and a bed (even if they are only day tripping) and told which lifeboat to use in an emergency.

If they are new to the rig, they will sometimes be given a distinctive green hard hat. This marks them out so that everybody else knows that they are not familiar with the rig. On an offshore rig, an experienced crew member will take care of the newcomer and show them around.

Training and Certification

Safety training is an essential part of any safety regime. Courses will be organized by the drilling contractor and by the operator for rig personnel to attend during their time off the rig (fig. 14–3). Some of these courses have to be repeated at regular intervals, such as the well control certificates mentioned in chapter 11.

Survival and firefighting is covered usually in a five-day course and teaches how to escape from a submerged helicopter, deploy and enter life rafts and lifeboats, and how to fight various types of fires.

Fig. 14–3. Eyewash station, positioned around the rig

This is a practical course; attendees are strapped into a mock helicopter cabin that is ditched into a pool and turned upside down. Divers are in the water to assist anybody who has real problems. In the mock cabin, all the windows are out and the door is open, but even for somebody who is at home under the water, it can be a little stressful. It is easy to see that in a real ditching and especially in rough water, if the chopper turned over and sank straight away, someone would have a real problem getting out. One thing that would aid escape would be to carry a mask and snorkel. As any diver will know, human eyes do not focus when submerged in water, but wearing a mask allows proper vision (though everything will appear bigger because of the refractive index of water). It would also be worth carrying a diving knife, which has a thick, strong blade and can be used as a lever. However, attitudes in some places will make it hard or impossible to carry such a "weapon" in the cabin. In the opinion of the author, carrying something that can significantly increase one's chances of survival in an emergency should not be discouraged.

In most developed areas, it is also necessary to have a medical certificate. These certificates are valid for 5 years up to age 40, and for 3 years after that.

If hydrogen sulfide (H_2S) might be present in the well, a one- or two-day course will be organized. This will teach or remind attendees about the characteristics of the gas, what to do in an H_2S emergency, how to use the self-contained breathing apparatus (SCBA) and escape sets, and how to work in an H_2S environment (as opposed to escaping through it). (An *SCBA set* is comprised of a compressed air bottle on a harness, a full face mask, and a demand valve.)

If other characteristics of the well demand it, customized training courses may be arranged. An example would be drilling a high-pressure, high-temperature well.

Drills

It is all very well to attend courses once in a couple of years, but any skill gets rusty if not practiced regularly. Drills give personnel the chance to practice what to do in various situations. Drills are held regularly on the rig to simulate a variety of potential problems.

Fire drills

The fire alarm is sounded and the designated fire teams are sent to an area of the rig. There, they will deploy fire hoses and perhaps rescue one or more "victims." Meanwhile, anybody not on duty on the drill floor or in other areas will report to a defined muster point on the rig, where they will be marked off against the persons on board (POB) list. (A *POB list* gives the names of everyone on board, along with their company and assigned room and lifeboat. It is always kept up-to-date and is sent into the office daily.)

The medic will prepare the rig hospital for casualties.

Abandon rig drill

An abandon rig drill may be done as part of the fire drill. The toolpusher or OIM will change the fire alarm to the abandon rig alarm, and everybody at the muster point will get into the lifeboats.

Kick drill (also called a *pit drill*)

The toolpusher or drilling supervisor will cause an indication to the driller that the active pit level is increasing (there are several ways to achieve this). The driller is expected to stop drilling and make a flow check. Once a flow check is under way, the driller will be told that this is a drill, and he or she is to simulate closing the BOP. The reaction time of the driller and crew will be noted.

Trip drill

While tripping in or out of the hole, the toolpusher or drilling supervisor will tell the driller to assume that the well is flowing. The driller will lower the drillstring so that the crew can place a valve on top of the drillpipe. This valve is closed, then the BOP is closed, and the well secured. The total time from initiating the drill to securing the well will be noted.

A drill crew can expect either a trip drill or a kick drill each week, without any prior notice.

H_2S drill

If working on a well where H_2S might be present, H_2S drills will be held regularly. The alarm will sound, and personnel will either don an SCBA set (if working) or will take an escape set and report to the upwind muster point.

Permit to Work Systems

A permit to work (PTW) system ensures that nonroutine work is carried out safely and without conflicting with other work going on around the rig. A permit is signed by the OIM or toolpusher; sometimes the drilling supervisor will countersign the permit.

The permit will contain the conditions under which the work must take place, any safety precautions required, how long the permit is valid for, and any other relevant information. Once the work is complete, the permit is returned to the OIM and closed.

Permits are generally issued for hot work, tank entry, overwater work, and electrical work.

Hot work. *Hot work* refers to any welding, cutting, or grinding that will be done in an area that could potentially experience an explosive atmosphere. Typically this will be anywhere outside of the welder's workshop or accommodation. The hot work permit will call for gas detection tests to be done before the job and perhaps at intervals during the job, along with any special firefighting precautions (such as keeping an extinguisher or hose ready at the job site).

Tank entry. If somebody has to enter a tank or enclosed space, the permit will call for the atmosphere to be tested to ensure it is breathable. It is likely that the person entering an enclosed space must wear breathing apparatus. A safety monitor will stay outside the tank, probably with a radio transmitter, and if the person in the tank requires assistance, this monitor will call for help first and then take appropriate action to help.

Over water work. If somebody has to work over the water except on properly constructed walkways, several precautions will be taken. A safety harness with a line attached to the rig structure will be required, as will a flotation vest. A safety monitor will stand by with a radio. The standby boat will be called and will stay down current of the rig for as long as the work continues.

Electrical work. Where electrical equipment will be worked on outside of the electrician's workshop, a work permit is needed. This permit will show how the equipment is to be electrically isolated from the supply plus any other precautions that may be required.

Safety Alerts

Various agencies (governments and companies) issue notices to the industry to publicize incidents or accidents. The purpose of disseminating safety alerts is that lessons can be learned which may prevent a future occurrence of a similar incident.

While government agencies disseminate safety alerts freely, companies are rather more reluctant to place this information in the public domain. If a company identifies an incident that occurred on its rig or operation, it might lead to bad publicity. It would be preferable if instead of merely disseminating this information within the company, the responsible government authority could issue the safety alert but disguise the source of the incident. The objective of disseminating the alert can be achieved without identifying the rig and well on which the incident occurred.

Equipment Certification

Certification by a responsible and recognized authority assures users that a particular piece of equipment is fit for purpose. Of especial interest are items involved in lifting (such as slings, shackles, wire ropes, and lifting frames) and pressure vessels (such as gas cylinders, pressurized storage tanks, and high-pressure lines). If these fail, the likelihood of serious injuries or fatalities is quite high.

Lifting equipment generally is tested every three or six months. Slings on a rig are often color coded with paint; if a sling does not have the current color painted on it, it should not be used.

Pressure vessels bear a metal plate that an inspector will stamp after visually inspecting the tank and applying test pressure to it. Many people do not appreciate the effect of a pressure vessel bursting with low pressure on it. Only a few pounds per square inch of pressure is enough to exert a force on tank plates that will cause large pieces to fly off with enough force to kill.

Electrical equipment carries a rating that signifies whether or not it can be used in potentially explosive atmospheres. A drilling rig (or production station) is divided into zones according to the likelihood of an explosive atmosphere being present. A zone 1 area is likely to experience an explosive atmosphere in normal daily operations. A zone 2 area may experience an explosive atmosphere if abnormal events take place, and a zone 3 area is unlikely to be exposed to an explosive atmosphere. Outside of the accommodation, most areas of the rig will be rated zone 2, and so the electrical equipment used (including switches, motors, and power tools) must be appropriately certified.

Safety Equipment

Safety equipment can be divided into two groups—personal protective equipment (PPE) and other safety equipment.

Personal protective equipment

On most rigs, everybody working outside of the accommodation or workshops must wear safety boots (with steel toes), a hard hat, and safety glasses. Some companies also demand that approved flame-resistant overalls be worn.

For specialist tasks such as those performed by welders, floormen, and derrickmen, other items of PPE will be issued that relate to the task at hand. Such items would include welding gloves and goggles, work gloves, and safety harnesses (fig. 14–4).

For personnel who must be exposed to chemicals while mixing mud or cement, PPE may include rubber gloves, rubber safety boots, rubber aprons, goggles, and breathing masks.

Other safety equipment

Also available at various places around the rig will be equipment that is available to be used if a problem occurs. In areas where toxic or corrosive chemicals are stored or mixed, eyewash stations must be placed where they can be easily reached. These must be regularly checked to ensure that the water containers are full, rubbish is not piled up on top of or around the stations, and they are in good condition overall. Showers might also be placed in chemical storage areas.

Fire extinguishers, hoses, and axes will be placed at strategic positions.

Fig. 14–4. Man working high in the derrick (note the safety harness)

Safety notices and barriers alert rig personnel to particular hazards, such as high-pressure lines.

Temporary barriers are erected to keep nonessential personnel away from temporary hazards, such as high-pressure testing.

STOP

The DuPont company some years ago designed a program to reduce accidents and incidents in its factories. This program is called STOP, and it has been implemented on many rigs.

The idea behind STOP is that if somebody witnesses an unsafe act (some action that may lead to an accident), they should do the following:

1. Inform the person doing the unsafe act that they should stop doing it. This must be done in a nonconfrontational manner.
2. Fill in a card that describes the unsafe act but does not name the person doing it. The person filling in the card can optionally put his or her name on the card but is not obliged to do so.
3. Somebody will be responsible for collecting the STOP cards and seeing what lessons can be learned.
4. The lessons learned are disseminated at the weekly safety meetings. If a number of STOP cards show a recurrent theme, the safety manager may decide that the problem may be widespread and some extra action is warranted, such as arranging training courses or writing articles in newsletters.

STOP has proved to be very effective in reducing serious incidents. Its use is quite widespread in the industry.

Minimizing Discharge and Spills

The oil industry gets a lot of bad press about discharges of substances into the environment. While this type of criticism would have been fair enough 10 years ago, it is now very different in most places. Discharges from rigs owned by responsible companies are tightly controlled, and modern rigs have systems designed and built into the rig to minimize any discharge from the rig that does not meet strict standards of cleanliness.

In areas where no special environmental considerations apply, some discharges can be made without adversely affecting the environment. In sensitive areas, solid and liquid wastes can be disposed of in other ways.

Offshore rigs

Solid waste from rigs includes drilled cuttings. Where water-based muds are used, these cuttings can often be safely discharged overboard where they simply pile up on the seabed. In sensitive areas where even clean cuttings (that is, without any hydrocarbons present on them) might damage the environment, cuttings can be disposed of in other ways, as can cuttings with oil on them. First, they can be collected in containers and shipped to land for disposal in a landfill. Second, they can be ground up into a slurry and injected into one of the casing annuli, if suitable formations are exposed to that annulus that allow this injection. Food waste is generally ground up so that it will pass through a coarse mesh and dumped overboard, but again, in sensitive areas, this can be shipped to land.

Sewage can be treated so that it can be safely discharged overboard without pollution.

Liquid discharges can be somewhat trickier due to the volumes involved. Water-based muds and cements can usually be discharged overboard, as no lasting harm will result. Oil-based muds based on mineral oils are not discharged but are stored and often recycled, resulting in savings to the operator.

Scrap steel, rope, plastic containers, medical waste, and other rubbish are not discharged but are returned to the shore base for responsible disposal.

Onshore rigs

As part of location preparation, land rig locations have waste pits dug. One of these waste pits—the largest—is positioned next to the mud tanks. Drilled cuttings and mud are dumped into this pit. It is a good idea to dig a large U-shaped pit and to dump mud and cuttings at one end. At the other end of the U, the liquid that drains off can be sucked out. Sometimes it can be recycled into the mud system (as it is full of expensive chemicals), and this is pretty useful in arid regions where water supply is expensive. Alternatively, it can be sucked into a tanker and disposed of or processed elsewhere.

After the well has finished, the pit is allowed to dry out. This can take several weeks, even in the desert. Once it has dried, the pit is recovered with the originally extracted earth and the site is restored. In many cases the wellhead can be visited, and it is difficult to tell where the waste pits used to be.

Sewage pits are also dug and pipes are run from the accommodations to this pit. As with the rig waste pit, this is allowed to dry out before being covered over and the site restored.

Inadvertent spills

Sometimes an accident or incident will occur that places large volumes of polluting fluids into the environment. This may be crude oil, rig fuel, oil-based mud, or some other liquid pollutant. This will initiate a preplanned spill response that may involve other operators in the area, the coast guard, and other public agencies and various contractors.

In many areas, the operators active in the area get together and share the cost of a spill response team. Equipment is stored in areas where response vessels can quickly load up and head out to the area. This equipment will include booms (to contain the spill), pumps, tanks, and chemicals.

To have all this equipment standing by costs quite a lot of money. Hopefully, it will never be needed, but nevertheless it is part of the operators' responsibility to be prepared.

Environmental Impact Studies

Even in areas that are not especially sensitive, many operators carry out studies to gauge the impact of their operations on the flora, fauna, and aquatic life around the operation. This assessment will cover not only the result of normal operations but also what would happen if an oil spill occurred. The effects of prevailing winds and currents will be studied to see which areas would be at greatest risk of a landfall so that contingency plans can be drafted.

In sensitive areas, public enquiries might be held so that the public can understand the operator's plans and can comment and raise concerns.

There are sometimes alternative courses of action that can reduce the environmental impact of an operation. BP drilled record-breaking horizontal wells to exploit a reservoir offshore by drilling from land on the south coast of England. These wells had thousands of feet of horizontal wellbore successfully drilled from a land rig, which avoided using an offshore rig or creating artificial islands (which was one of the alternatives studied when the field was discovered). Much attention was paid to the environmental impact of the various alternatives, and the result was a successful exploitation of the field without upsetting anybody.

Severe Weather—Suspension of Operations

Severe weather can create significant danger for rig crews. In areas prone to hurricanes and tornadoes, such as the Gulf of Mexico at certain times of the year, close attention is paid to the possible courses that such storms might take. When it becomes possible for a rig to be hit by one of these storms, the well is secured and the rig abandoned.

In other areas, other problems might prevail, such as sandstorms. The judgment of the drilling supervisor must be used to ensure that operations are suspended before weather conditions get so dangerous that the likelihood of an incident increases significantly.

Summary

Safety management is as important as managing any other aspect of the operation. Every responsible manager and supervisor in this industry wishes to see everyone return home safely to their families at the end of their time on the rig. Most companies have very clear policies and statements that ensure that everybody concerned knows that unsafe practices will not be tolerated.

This chapter set out many of the safety concerns that result from operating drilling rigs. Equipment, training, practices, and procedures are used to reduce risk to a level that is as low as reasonably practical.

There is no longer room in this industry for anybody who does not take safety and environmental protection seriously.

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GETTING WORK IN THE DRILLING INDUSTRY

Overview

The drilling industry is fascinating. It is technologically advanced, operates worldwide in every type of territory, and has enormous capital expenditures. The people who work in the industry are, in general, paid well. They can travel frequently and find themselves with greater responsibilities at younger ages than is the case in other industries. In many positions, they have almost half the year free to do as they please, while living where they want to live. What's not to like? Well, employment in the drilling industry requires someone who is willing to work very hard, sometimes with long days and nights, do whatever is needed to get the job done, study, and serve an apprenticeship. I qualified as an aeronautical engineer in 1978, and when I joined the drilling industry in 1979, found myself doing hard manual labor on a drilling rig in Holland, starting on the bottom rung of the ladder.

This chapter will set out some of the pathways into the industry for those interested in joining the select group of people who succeed in it.

Happily, women are increasingly getting involved in the drilling industry, and the industry is better for it.

Financial Health Warning

As in all walks of life, there are people who prey on inexperience and hope for victims to rip off. I have seen Web sites that guarantee to get someone an oilfield job in 90 days, once some "refundable" fee has been paid. Or someone from an agency promises to help a person get a job if a fee is paid to their agency. It is a con—there can be no such guarantees. Never pay anyone money to register for work or pay for a plane ticket to start a job. If something looks too good to be true, it usually is! Be careful.

Types of Employers

Operators

The operators are the companies that profit from selling oil and gas. Operators can be huge (Exxon, Shell, or BP), medium-sized (Devon, Tullow, or Cairn), or small, of course. The larger operators will typically recruit people who have a technical degree or engineering background and will train them to become the drilling engineers and managers of the future. The medium-sized ones may recruit people with a good technical degree and some drilling experience. The small operators will not have the resources to train people and will generally look for experienced people in the disciplines they need. So, job seekers without experience in the field should avoid the smaller operators and not waste everyone's time.

Young people planning their career paths should check out the Web sites of some of the larger operators or contact the HR departments directly to find out about entry requirements and to help decide an appropriate academic path.

Sometimes the larger operators send recruiters into universities. They are looking to make contact with those doing technical degrees who show good results. Shell and BP (and probably others) run scholarship programs in which those sponsored get some money while at a university to help cover the cost of their education. For those who are serious about their studies and can demonstrate good grades, it is worth applying for these scholarships.

Some experienced drilling hands with a drilling contractor background make the switch to working for operators, usually as drilling supervisors at the wellsite.

Drilling contractors

These companies provide drilling rigs to the operators. The larger ones may recruit a small number of university graduates to follow a training program, but in general, a high school education or some experience in an engineering environment would be of interest.

Those with modest educational achievements interested in working on the rigs should do some homework first by checking out the different contractors. (One such Web site is for the International Association of Drilling Contractors, www.iadc.org.) The next step is to determine where the nearest oilfield center of activity is (Houston, Aberdeen, Stavanger, Singapore, Perth, Calgary, Rio, or Cape Town, for instance) where there is a concentration of oilfield organizations. Once those companies with offices in the region are located, a job seeker can make a list and check out the corporate Web sites to see if they offer information about what kind of people they might recruit.

There are some training centers that run courses for people starting to work offshore, and information may be obtained by searching the Internet for “Roustabout course.” A prospective employee might consider funding himself on one of these courses, and having obtained that training, apply to the drilling contractors in the area. This offers an advantage over others who just fire off letters to try to get a job without any preparation. This also reduces the risk for the contractor in trying out a new employee. Before a new employee would go onto a rig, he would otherwise have to be sent on this type of course anyway. A person can compensate to some extent for modest academic achievement if he can demonstrate willingness to do that bit extra and to make a financial commitment to his effort to enter the industry.

Working for a drilling contractor offers a path to work up from the bottom to the top. However, an employee will be judged on how hard he works, how well he gets on with others, and how willing he is to put himself out. People who moan a lot are more likely to simply not progress upwards. In this business, an employee on a rig might have his plans changed if fog prevents the chopper flying in to pick him up. This is just part of the job, and someone who cannot handle those things should find a different industry to work in.

Service companies

There is a vast array of different services that are required to drill a well, and thousands of companies worldwide that provide those services. Some of these service companies are huge and highly technically advanced (Schlumberger, www.slb.com, for instance). The companies to which a person applies will depend very much on that individual's educational achievements and work experience. For those who lack high academic achievements, there are still plenty of service companies that might be willing to take on an employee and start him off at the bottom, as long as he gives them reason to believe that he would be worth their investment of time and money.

A good starting point is Wikipedia, searching for the page "List of Oilfield Service Companies," which provides names and links to other Wikipedia pages with more information on each company. The reader of this book will have an idea of what each of these companies does and how they fit into the overall picture.

Some Drilling-Related Job Definitions

Rotation on the rig is usually equal time: work 28 days, go off for 28 days, or 14 days on/off, 21 days, etc. Different schedules are possible. Working half the year is a pretty good way to balance work and life. It also means an employee does not have to live where he works.

Drilling-related employment glossary

assistant driller. Reports to the driller, gets equipment prepared for upcoming operations. Relieves the driller for coffee, meal, or bathroom breaks.

cementing engineer. Calculates the requirements for pumping cement, supervises the cement job. Usually has a chemical background or a lot of experience working for a cementing company.

company rep, company man, or drilling supervisor. Titles change, but this is the person who represents the operator on the rig. Makes sure that the program is followed safely and efficiently. Signs the daily activity reports that the contractor and service companies use for invoicing. Usually has many years of drilling experience, including time spent as a driller. While some are employed as staff, many work as consultants for a daily rate.

derrickman. Works high up in the derrick, racking pipe when tripping out of the hole (see fig. 14–4). When the rig is not tripping pipe, the derrickman generally looks after the mud pumps. One step up from a **roughneck**.

driller. In charge of a drill crew, usually working a shift that is 12 hours on, 12 hours off.

drilling engineer. Usually works for an operator, or sometimes for a contractor or a specialist service company providing drilling engineering services to operators. Plans wells, works on casing design, and may work in an office or at the wellsite. May eventually advance to drilling manager.

logging engineer. In charge of a logging crew, running electric logs. Will have a degree plus specific training from the logging company.

offshore installation manager (OIM). On a marine rig, the OIM has similar legal responsibilities as the captain of a ship.

mud engineer. Looks after the drilling and completion fluids on the rig. Usually has a chemical background or education or a lot of experience working for a mud company.

mud logger. Works in a rigsite laboratory, monitoring drilling parameters, cuttings coming from the well, and any gas or oil coming back. Usually has a geological qualification.

roughneck. Works on the rig floor as part of the drill crew or helps out wherever needed for the derrickman. Would often be a promotion up from roustabout.

roustabout. Rig laborer, bottom of the drilling ladder. Works off the drill floor, usually for a roustabout foreman or crane operator.

subsea engineer. Looks after the subsea blowout preventer on a floating rig. May have worked as a driller and then specialized in subsea equipment.

toolpusher. The contractor employee in charge of the rig.

Take a look at the jobs on www.drillers.com to get an idea of the variety of work available.

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QUICKLY LEARN THE BASICS OF DRILLING TECHNOLOGY IN ONE TEXT!

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ABOUT THE AUTHOR

Steve Devereux started in the drilling business in 1979 and has worked as an independent consultant since 1988, functioning in all drilling roles up to Operations Manager. He has worked in about 30 countries in all kinds of environments and most kinds of rigs. He is an experienced oilfield trainer and mentor and a Chartered Engineer. Devereux is also the author of PennWell's *Practical Well Planning and Drilling Manual* (1998). He's a keen aerobatic pilot and lives in France.

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