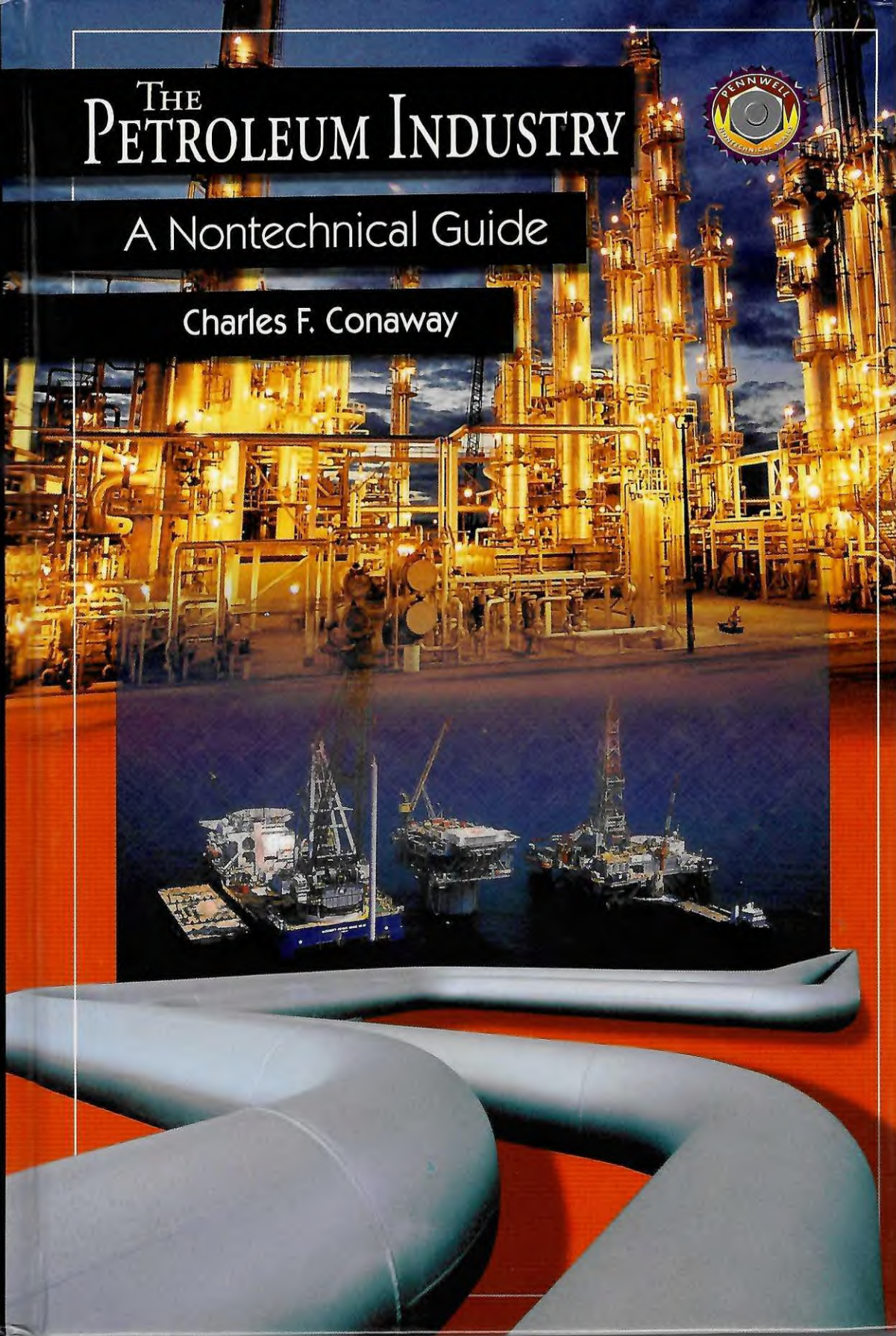


THE PETROLEUM INDUSTRY

A Nontechnical Guide

Charles F. Conaway



Introduction

The mechanics of rotary drilling are quite simple. A rotating bit breaks loose the rock at the bottom of the hole. The rock fragments are then swept away and lifted out of the hole by the mud stream. The practice of rotary drilling is, however, extremely demanding and complex. Some of the reasons for this are

- The difficulty of working at the bottom of a hole three or four miles deep
- Heavy, complex equipment under stress
- Variable rock characteristics
- Reservoir fluids—oil, water, and gas—entering the hole
- Remote areas and hostile environments
- Non-stop operations—24 hours per day, 7 days per week
- Dangerous working conditions
- Environmental hazards
- Pressure to hold down costs

Early Drilling Rigs

Until early this century, oil and gas wells were drilled with cable-tool rigs. The hole was made by spudding, which is making a hole by reciprocating a heavy, chisel-shaped bit suspended on a hemp or steel line (FIGURE 6-1).

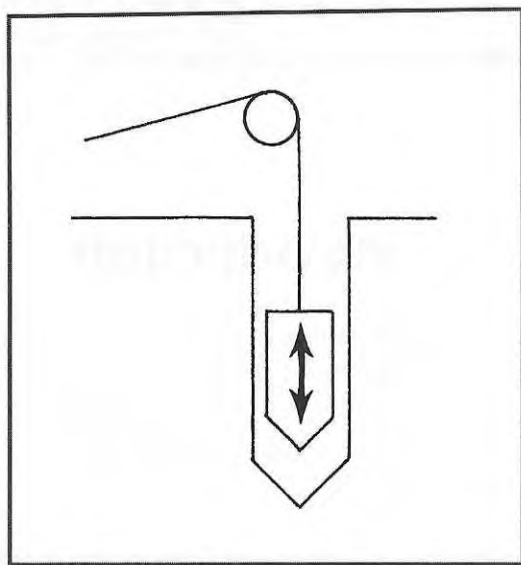


FIG. 6-1 Spudding

The major problem with cable-tools is that there was nothing to prevent oil and gas from blowing out at the surface whenever a reservoir was penetrated. This is wasteful and dangerous, and today would have major environmental repercussions. The rotary drilling system in use today avoids this problem by keeping the hole full of heavy mud that holds back reservoir fluids.

Rotary Drilling System

Drillbits

The only useful work done by a drilling rig takes place at the bottom of the hole where the bit drills the rock. Everything else on a rig—the prime mover, derrick, drawworks, drill pipe, etc.—simply support the bit in this effort.

Drillbits operate in an extremely dirty and hot environment, frequently bounce up and down, and in general are subjected to enormous mechanical stresses. To replace a bit that has become dull or has broken is costly. The entire drill string must be pulled, the bit changed, and the drillstring re-run. In deep holes, this roundtripping can take hours of rig time. The hole can also be lost from pieces of hardened steel left in the hole from a broken bit. It's therefore essential that bits be extraordinarily competent and long-lasting. Fortunately, they are exactly that.

Tricone roller bits. These are the most commonly used bits. Clockwise rotation of the drillstring causes rotation of the three roller-cones, bringing successive teeth to bear vertically on the bottom of the hole. The weight concentrates at the point of the teeth and crushes the rock. The fragments (cuttings) are then swept away by mud jetting out of three downward-facing nozzles (FIGURE 6-2).

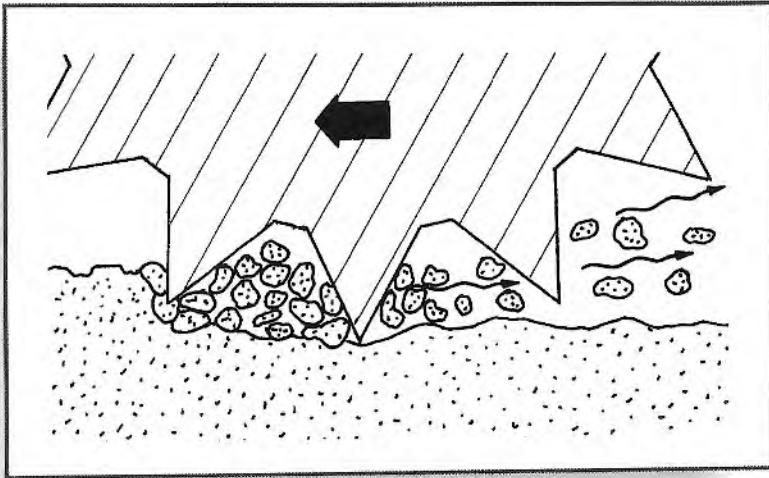


FIG. 6-2 Rock Crushing with Roller Bit

Tricone bits can either have teeth milled from hardened steel as shown in Figure 6-2 or, for harder rock, smaller tungsten carbide teeth inserted in a steel cone, shown in Figure 6-3. When the points of the teeth wear down, the drilling rate slows and the bit must be replaced. Bearing wear can also be a problem.



FIG. 6-3 Tricone Roller Bit with Tungsten Carbide Insert Teeth

PDC (polycrystalline diamond cutter) bits. This is a relatively new bit design that uses very hard polycrystalline diamond wafers on the face of protruding bronze bases (FIGURE 6-4). These are drag bits, which means they have no moving parts. They drill with a shearing action that is particularly effective on the relatively soft formations found in coastal and offshore areas (FIGURE 6-5).

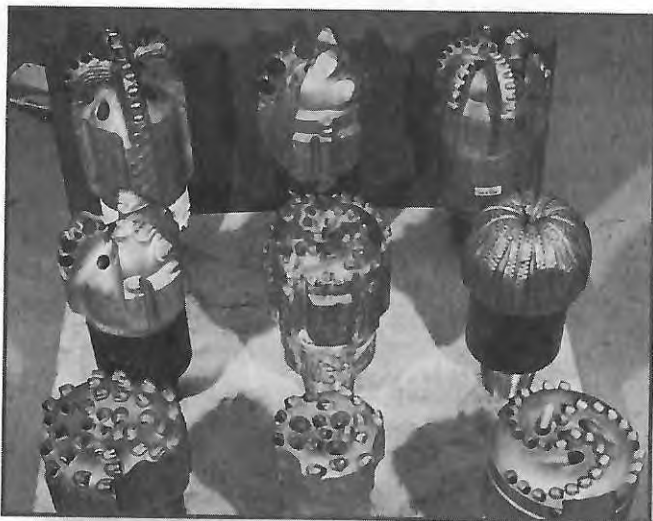


FIG. 6-4 PDC Bits and One Diamond Bit

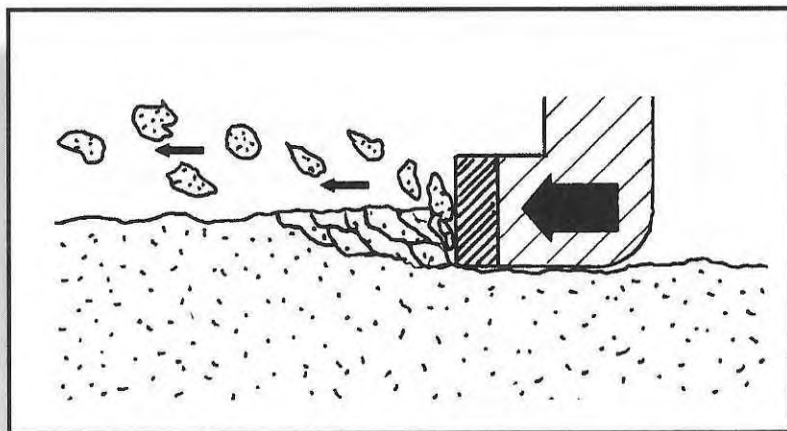


FIG. 6-5 Shearing Action with a PDC Bit

Drillstring

The drillstring is a tube of steel pipe extending from the surface down to the bit. It serves to

- Transmit rotational energy from the surface to the bit
- Conduct the mud stream from the surface to the bit
- Put weight on the bit to maximize penetration rate

The drillstring is made up of 30-foot joints of steel pipe, screwed together. The specialized couplings, called tool joints, have coarse, tapered threads designed to withstand repeated break-outs (unscrewing) and make-ups (screwing together) while retaining tensile strength and sealing ability. Three different pipe configurations are used in the drillstring (FIGURE 6-6):

- **Drill pipe** makes up the bulk of the string. The tool joint is larger in diameter (upset) than is the shank of the joint.
- **Drill collars** are thick-walled joints of drill pipe used to put weight on the bit. Several collars are normally run at the bottom of the string, immediately above the bit. The tool joints are the same diameter (not upset) as the shanks of collars.
- The **kelly** is the topmost joint of drillpipe in the drillstring. It has flattened sides (four or six) used to transfer torque from the rotary system.

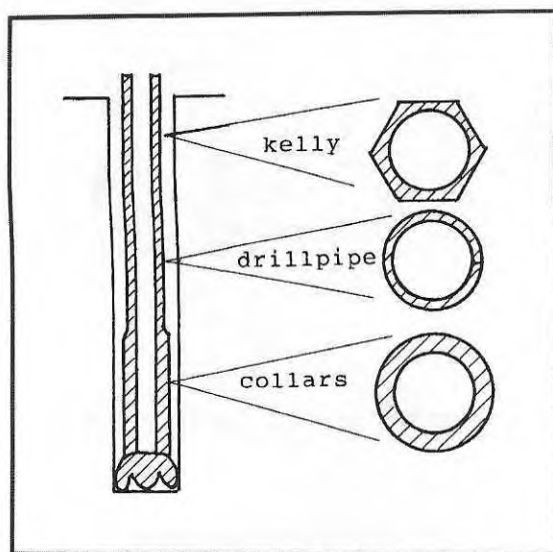


FIG. 6-6 Drillstring Configuration

Hoisting system

By far the heaviest work on a drilling rig is performed by the hoisting system as it runs the drillstring in and out of the hole. The components of the system are:

- The **derrick**, which is tall enough to pull triples (a three-joint "stand" of drillpipe) and strong enough to bear the weight of the entire drillstring.
- The **drilling line** of steel wire rope.
- The **drawworks**, with a large rotating drum that spools in drilling line to raise the load or spools out line to lower the load.
- The **crown block** mounted in the top of the derrick and the traveling block connected to the crown block by the drilling line. Each block is an assembly of multiple pulleys (called "sheaves," but pronounced "shivs") that the drilling line is wrapped around. Taken together, the blocks and drilling line constitute a block and tackle—a device to multiply the lifting capacity of the drilling line. The eight wraps of the line shown

in Figure 6-7 permit eight times the load to be lifted as would be possible with the single line. This mechanical advantage does, however, have a cost. For every foot the traveling block is raised, eight feet of line has to be spooled onto the drum.

- The **drilling hook**, which is attached to the traveling block and supports the load.

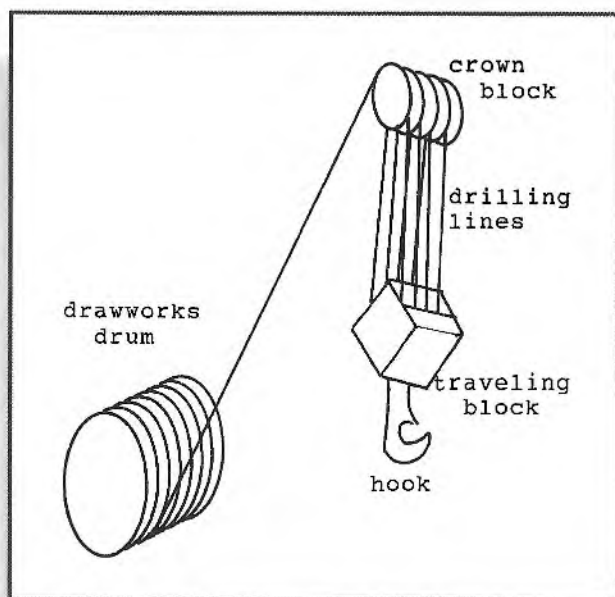


FIG. 6-7 Drilling Rig Hoisting System

Rotating systems

There are three alternative systems used to rotate the drillbit:

1. The **conventional rotating system** is used with most onshore wells and many offshore wells (FIGURE 6-8). The kelly joint, with the rest of the drillstring suspended below it, passes through the kelly bushing and attaches to the swivel hanging from the drilling hook. The rotary table spins the kelly bushing, whose flat-sided hole matches the flat sides of the kelly. This rotates the drillstring and bit.

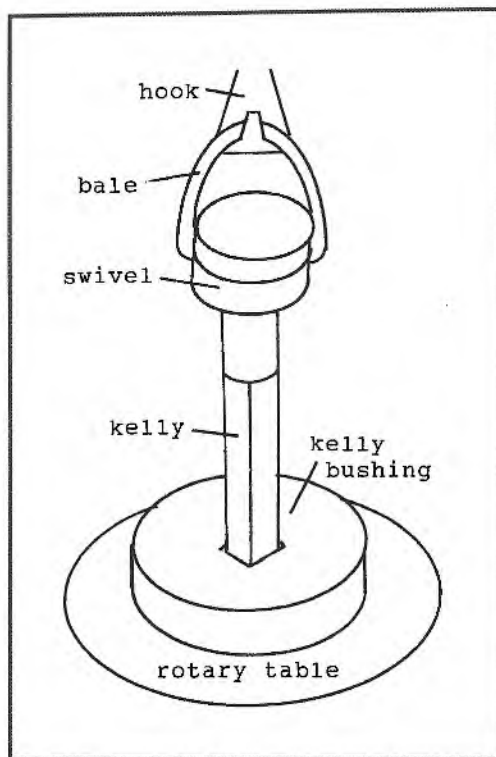


FIG. 6-8 Conventional Rotating System

2. The **power swivel**, or top-drive, is relatively new and finding increasing application, particularly offshore. It uses a hydraulic motor integrated into the swivel to transmit the rotary power. This replaces the kelly, kelly bushing and rotary table. Top-drives have the advantages of permitting circulation and rotation while pulling out of the hole and of adding a full stand of pipe (3 joints) rather than only one joint at a time as the hole deepens.
3. The **down-hole mud motor** is used for directional drilling. The motor is mounted directly above the bit, and is powered by the drilling mud. It turns the bit without rotation of the drillstring.

Mud motors are normally used in the deviated portion of the hole only, with the vertical section drilled conventionally by rotating the drillstring.

Drilling fluids (mud)

In rotary drilling, mud is continuously circulated down the drillstring, out through the nozzles in the bit, then back to the surface through the annulus (space between the drillstring and the hole). The most commonly used mud system is saltwater with numerous additives. Oil-based mud (water in oil emulsion) is also used where its greater stability justifies its greater cost. Various "synthetic" chemical muds, which are extremely expensive, are also used. Their application is offshore wells that require the stability of oil-base mud, but where its use is prevented because disposal of the drill cuttings overboard would cause pollution.

Functions of drilling mud:

- The mud jets forcefully out through the bit nozzles, flushing the drill cuttings away from the bit face. This cleans the rock surface, increasing the bit's penetration rate.
- The mud carries the cuttings up the annulus and out of the hole. To give saltwater mud the necessary lifting ability, it is thickened with clay, called gel.
- The mud lubricates and cools the bit, greatly extending the bit's useful life.
- The mud exerts backpressure on the exposed formations to prevent influx of formation fluids, called a kick, which could lead to a blowout. The density of the mud used therefore depends on the formation pressures anticipated. The density of saltwater mud is increased as needed (called weighting up) by adding pulverized barium sulfate (barite).
- The mud seals off permeable formations to prevent mud loss. In extreme cases such as fractured zones, the formation may absorb the entire mud stream, resulting in lost circulation (no mud returns) which could lead to a blowout. Solid materials, such as shredded paper or cottonseed hulls, are added to the mud to prevent lost circulation.
- The mud reduces friction between the drillstring and the side of the hole.

Mud engineers monitor the mud's characteristics, making changes as needed. For example, if additional gel strength is needed, sacks of dried gel is mixed into the mud stream. If additional weight is needed, sacks of barite or other weight material is added. Since higher gel strength and weight slow the bit's penetration, saltwater mud is frequently diluted with water to maintain the absolute minimum gel strength and weight necessary. It's also common to drill "underbalanced" (having a lighter mud column than would be necessary to hold back reservoir fluids) in situations where there is no possibility of a kick.

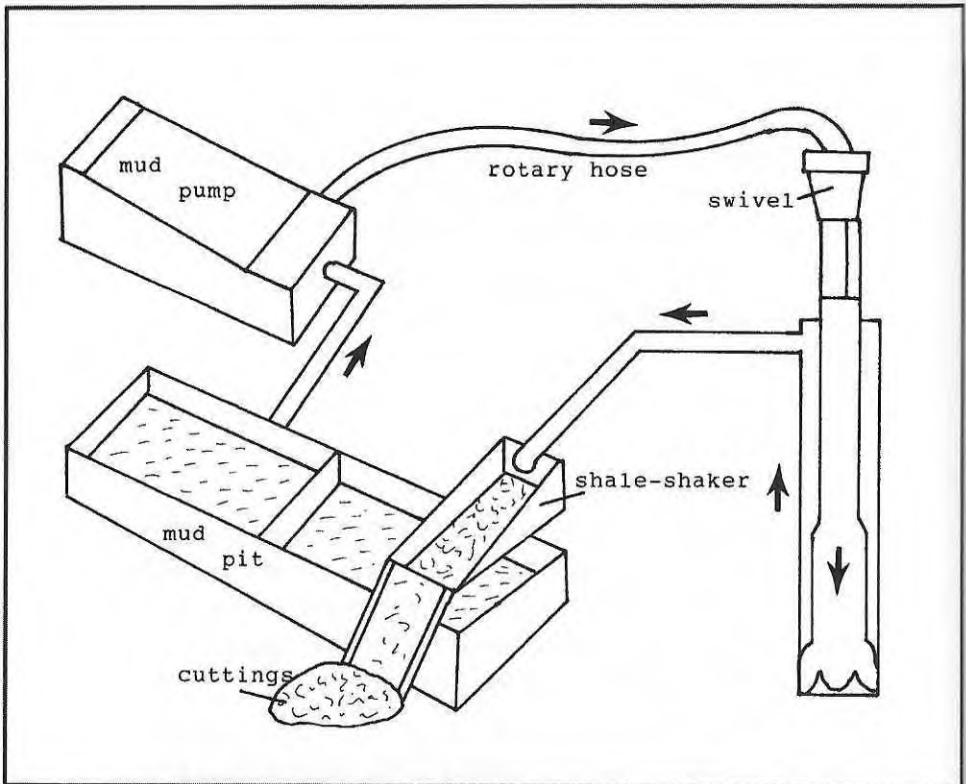


FIG. 6-9 Mud Circulation System

Mud circulation system (FIGURE 6-9):

1. As it comes out of the hole, the mud is diverted to the side before it reaches the rig floor.
2. It falls down through the shale-shaker, which has calibrated mesh that strains out the large cuttings.

3. The mud then drops into the mud pit. Pits are normally constructed of steel, but earthen pits with plastic liners are often used onshore.

Fine-grained solids settle out in the pit. In some situations, mechanical desilters and desanders are used.

4. The mud pump then picks up the solid-free mud out of the far end of the pit.
5. The mud is pumped through the flexible rotary hose to the swivel, then down the drillstring and back up the annulus to complete the circuit.

Pipe handling

The following devices are used to handle the pipe going in and coming out of the hole:

- **Elevators** attached to the hook are used to lift the pipe string. They wrap around the pipe below the tool joint and latch, then lift against the upset shoulder.
- **Slips** are used to hang the string from the rig floor. They wrap around the pipe, wedging it against a recess in the floor. When the string is picked up, the slips come free and can be removed. Slips are normally operated by hand, but power slips are also available (FIGURE 6-10).

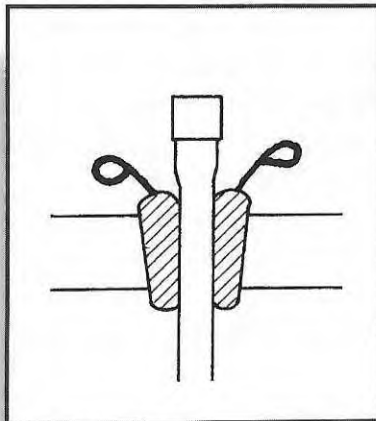


FIG. 6-10 Slips

- **Tongs** are used to make-up and break-out the pipe joints. Power tongs spin the pipe; back-up tongs keep the rest of the string from turning. At times the rotary table is used to spin the pipe.
- The **fingerboard** in the derrick has protruding fingers that hold stacked stands of pipe in place .
- The **rathole** is a hole in the rig floor where the kelly and swivel are stored when they are not in use.
- The **mousehole** is a hole in the rig floor where a joint of pipe is placed prior to being added to the string.

Prime mover

The prime mover is the source of power for the entire rig. Most modern rigs are diesel-electric. Diesel engines drive electric generators that produce direct current to power all the rig's equipment.

Routine Drilling Procedures

Drilling ahead

Most of the rig's time is occupied by drilling ahead, also called "turning to the right" or "making hole." The bit is on bottom drilling, and this continues until the kelly joint is drilled down (upper coupling approaching the rig floor). Another joint of drillpipe is then added, called making a connection, and drilling resumes. When a top drive is used, the entire stand (90') is drilled down, and an entire new stand then added.

While drilling ahead, the driller watches the weight indicator closely, slacking off on the brake to lower the drillstring and keep the proper weight on the bit. He is often alone on the rig floor while the roughnecks are occupied elsewhere with routine maintenance duties.

Making a connection

When the kelly has drilled down:

1. The driller stops the rotary, raises the drillstring off bottom, and shuts down the mud pump
2. The floorhands set the slips and the driller slacks off (lowers) the drillstring until it is suspended from the slips
3. Using tongs, the floorhands break out the kelly from the drillstring
4. The kelly assembly (which includes the kelly, kelly bushing, swivel, and rotary hose) is swung over to the mousehole, stabbed into the joint of drillpipe standing in the mousehole, and the joint is made up
5. The kelly assembly with the new joint attached is picked up, swung over to the drillstring, stabbed, and made up
6. The string is picked up, the slips pulled, the mud pumps started, the bit run to bottom, and rotation resumed

Roundtripping

It's occasionally necessary to come out of the hole with the drillstring to change the bit, add drill collars, etc. and then run back to bottom. This is called "making a roundtrip," and it proceeds as follows:

Tripping out

1. The slips are set, the kelly is broken out, the assembly is set back in the rathole, and the swivel is unlatched from the hook.
2. The elevators attached to the hook are lowered and latched onto the drillstring below the box that is "looking up".
3. The string is picked up the length of a stand (usually three joints) and the slips reset.
4. The floorhands break out the joint, push the pin end of the stand off to the side, and set it down on wooden sills.
5. The derrickman unlatches the elevators and leans the stand back against the fingerboard. The elevators are run back down

to pull another stand and the process repeated until the entire string is racked in the derrick.

Tripping in. The process is reversed to go back into the hole. The derrickman latches the elevators on the stands, the stands are picked up, stabbed, and made up into the string.

The handling of each stand is a complex operation involving many sequential steps, and the sequence needs to be repeated over and over. A rhythm develops, requiring split-second timing between the driller, the floor hands, and the derrickman. It's actually safer to work quickly in this smooth, deft, manner with complete concentration than at a slower pace, allowing the mind to wander.

Automated rigs

There are a number of experimental (and a few commercial) applications under way using rigs with robots handling the pipe, thereby largely eliminating floor hands. This technology is driven by the high injury rates inherent in handling tongs, etc. and may some day result in wholesale automation of drilling.

Well Control

Blowouts

Blowouts, where reservoir fluids blow up the hole and out onto the rig floor, are what drillers worry about most. The force of the escaping fluids can smash tools together, causing a spark that could ignite the fluids and burn up everything in the vicinity. Careful attention is therefore given to well control—keeping reservoir fluids out of the wellbore.

The fluids in porous and permeable rocks are under pressure. When these rocks are drilled, this reservoir pressure will force the fluids into the wellbore unless the reservoir pressure is offset by mud pressure. It is essential to prevent any significant entry into the wellbore by reservoir fluids.

Mud pressure reflects the hydrostatic head of the column of mud in the hole above the formation. That is, the downward force of the column of mud. Pressure is expressed in pounds per square inch (psi), which means the weight pressing on one square inch of area.

Mud pressure increases with the depth of the hole and with the density of the mud. For example, the mud pressure at the bottom of a 7000 foot hole filled with mud having a density of 10 pounds per gallon can be calculated as follows (FIGURE 6-11):

1. Convert the gallons to cubic feet.

$$\frac{10 \text{ lbs / gal}}{7.48 \text{ gal / ft}^3} = 74.8 \text{ lbs / ft}^3$$

2. Divide by 144 to get the weight of each 12" by 1" by 1" column within the cubic foot. This is the hydrostatic gradient—the increase of mud pressure per foot of depth.

$$74.8 \div 144 = 0.515 \text{ psi (lbs/in}^2\text{)}$$

3. Multiply the per-foot hydrostatic gradient by the depth to get the mud pressure at the bottom of the hole.

$$0.515 \times 7000 = 3605 \text{ psi}$$

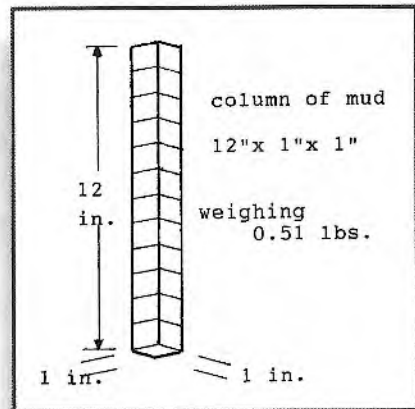


FIG. 6-11 Hydrostatic Gradient

If the reservoir pressure in this example was 3500 psi, the hole would be overbalanced, meaning that the mud pressure exceeds the reservoir pressure. The pressure differential from the wellbore into the formation would cause some mud filtrate to invade the formation. The solids from the mud filter out on the face of the formation, forming a filter cake. If the reservoir pressure

were higher than the mud pressure, say 4000 psi, this under-balance would cause formation fluids to enter the wellbore. If oil or gas enter the wellbore—a kick—aggressive action must be taken quickly to prevent a blowout.

Anatomy of a blowout

1. An underbalanced condition exists, permitting oil or gas to enter the wellbore.
2. The oil and gas displaces mud in the annulus. Since the oil and gas are lighter than the displaced mud, the mud column becomes even lighter. This accelerates the rate of fluid influx.
3. As a gas kick rises up the annulus, the mud column above it becomes shorter, which reduces pressure on the gas. This causes the gas to expand, which displaces more mud and further accelerates the progress of the kick.
4. The kick reaches the surface and blows out through the rig floor. The blowout often ignites, burning the crew and destroying the rig.

Preventing blowouts

Every effort must be made to anticipate the reservoir pressures that will be encountered, and to design the mud program to handle those pressures. This is relatively easy to do in development drilling where the local pressure regime is well known from earlier wells. It is much more difficult when drilling wildcat wells.

It might seem that the best approach to blowout prevention would be to drill the entire hole with mud so heavy that there would be no chance of a kick getting started. This is, however, not practical because heavy mud significantly retards the bit's penetration rate. The practice is therefore to drill the non-permeable sections of the hole somewhat under-balanced, then to weight up for the permeable zones.

The crew must stay alert during drilling to detect the following early signs of a kick developing. These are generally quite subtle and easy to overlook.

- Mud returns cut with oil, gas, or water
- An increased penetration rate caused by underbalance

- A gain in mud pit level from mud displaced by the kick
- A change in the rate of mud return; increasing rate could signal a kick; decreasing rate could signal lost circulation
- A decrease in mud-pump discharge pressure from the lighter mud column
- An increase in drillstring weight; since gas- or oil-cut mud is less dense, it exerts less buoyancy on the drillstring

If a kick is detected early, the mud can be weighted up and the kick circulated out of the hole with little difficulty. When a kick is gaining momentum with the possibility of blowing out, it may be necessary to close the blowout preventer (BOP).

The BOP is a safety valve at the top of the hole, just underneath the rig floor. When activated, the BOP closes and seals off the well, preventing it from blowing out. BOPs are equipped with alternative sets of rams. One set closes around the drillpipe to seal off the annulus. Another set seals off the entire hole when the drillstring is out of the hole. A third set can cut through the drillpipe and seal it off.

Controlling a blowout

The art and science of capping blowouts was significantly advanced by dealing with the hundreds of Kuwaiti wells blown up in the Gulf War.

Capping procedure

1. Working under a cooling spray of water, workers clear away obstructions and debris from around the well before the fire is extinguished. If this isn't done, the fire will re-ignite from the hot metal. There is no urgency to put the fire out because it protects the workers by burning off the oil and gas. This is particularly true when the wellstream includes poison hydrogen sulfide gas.
2. Explosives are suspended over the well with a crane line and detonated. The explosion momentarily consumes all the oxygen, which puts out the fire.

3. If a stub of undamaged pipe remains at the top of the hole, it is prepared to have a valve slipped down over it. This usually involves sawing off the pipe to get below the damage.
4. An open valve equipped with gripping devices is swung over the wellstream with the crane, lowered down over the pipe stub, and secured. The valve is then closed and the well is under control.
5. If there is no pipe available to hold the valve, a relief well must be drilled. A rig is set up off to the side and drills a directional hole that penetrates the formation very near to the original well. Water or cement is then pumped down the relief well to kill the blowout (FIGURE 6-12).

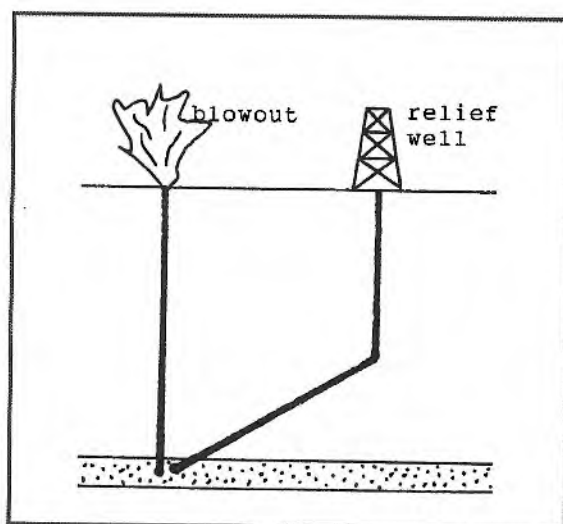


FIG. 6-12 Relief Well

Stuck pipe

Getting the drillstring stuck in the hole is a constant concern for drillers. It happens quite often, almost routinely, but is normally resolved without serious consequences. In some cases, however, a portion of the hole has to be abandoned.

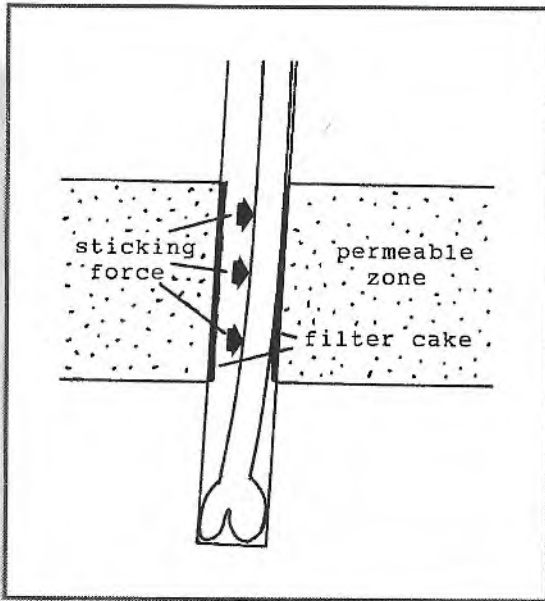


FIG. 6-13 Differential Sticking

Differential sticking. Differential sticking is probably the most common cause of stuck pipe. It is a major problem when drilling softer, unconsolidated formations typical of continental margins (FIGURE 6-13).

When a permeable formation is penetrated while drilling overbalanced, some of the liquid in the mud is forced out into the formation, leaving behind the mud solids as a filtercake on the formation face. Differential sticking occurs if the pipe remains motionless in the hole for a short period of time—such as while making a connection. The pipe rests on the side of the hole, pressing through the filter-cake and contacting the formation face. It becomes differentially stuck when the filter-cake build-up blocks communication of mud-column pressure to the area where the pipe contacts the formation. The pressure in the contact area then drops toward the formation pressure. This creates a pressure differential between the mud column pressure on the inside of the hole and formation pressure on the bottom side. The differential presses the pipe against the side of the hole with such force that it cannot be moved.

Avoiding differential sticking. While overbalanced, the pipe must be kept moving, either reciprocating or rotating, so that differential pressure doesn't

build up. It's also helpful to use low filtrate-loss mud to minimize filter-cake thickness.

Hole caving. Several conditions can cause the side of the hole to cave in and, in severe cases, cause the pipe to stick (FIGURE 6-14):

- Some shales absorb mud filtrate, swell up, and slough into the hole.
- Large quantities of material from uncemented or fractured formations can fall into the hole.
- The weight of the overlying rock can extrude salt and plastic shale formations into the wellbore.

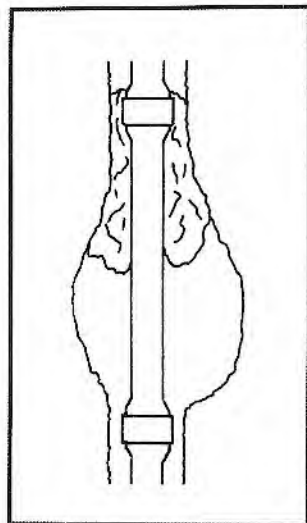


FIG. 6-14 Pipe Stuck by Formation Caving

Freeing stuck pipe

1. When differentially stuck, the first approach may be to reduce mud weight and eliminate the overbalance that caused the problem. This is only possible when there is no concern about a permeable zone kicking. If this is unsuccessful, and if mud circulation is still possible, a "pill" of a few barrels of refined oil or mudcake solvent can be circulated down the pipe and up the annulus until its "spotted" over the stuck area. Tension and torque are kept on the pipe for a considerable period to see if it will free up.
2. If still stuck, the next approach may be to run a free-point indicator down the drillstring by wireline. Tension is pulled on the drillstring and the free-point indicator locates the point below which the pipe is not in tension. This is where the pipe is stuck.

A light explosive is run down the inside of the pipe and detonated immediately above the free-point. The purpose is

to “rattle” (loosen) a coupling so that it can be unscrewed. The string is then carefully rotated counterclockwise to break out the rattled coupling. The string is pulled, leaving the fish (bit and lower part of the drillstring) in the hole.

A set of jars (device that delivers sharp blows) is added, the string is re-run and stabbed back into the fish. The jars are activated, perhaps repeatedly, to deliver upward hammerblows to the fish. In most cases, it is quickly dislodged and recovered.

3. If jarring fails, a wash pipe may be run to wash over the outside of the fish, removing the material that is causing it to stick.

Twist-offs

Drillpipe failures, called twist-offs, sometimes occur from metal fatigue during routine drilling operations. Fishing operations are then required as follows:

1. The condition of the portion of the fish that is looking up must be determined before a strategy for latching on to it can be devised. The piece of parted pipe that was recovered provides a great deal of information about the condition of the piece looking up, but sometimes it is necessary to run an impression block. This has a flat bottom of soft metal that is bumped down on top of the fish. The fish indents the soft metal, providing a picture of its degree of distortion and raggedness. The impression block also shows whether the fish is standing up straight in the hole or is leaning over against the side.
2. It may be necessary to dress-off (clean up) the fish so that the fishing tools can get over or into it. This involves running mills with tungsten carbide surfaces for grinding steel. If an over-shot (fishing tool that fits over, or swallows, the fish) is to be used, a mill that grinds down over the outside of the fish is run. If a spear (fishing tool that fits down inside the fish) is to be run, a tapered mill is used to penetrate inside the fish (FIGURE 6-15).
3. When the fish has been dressed, the fishing tools and jars are run on the drillstring. If the fish is standing up, clear of the

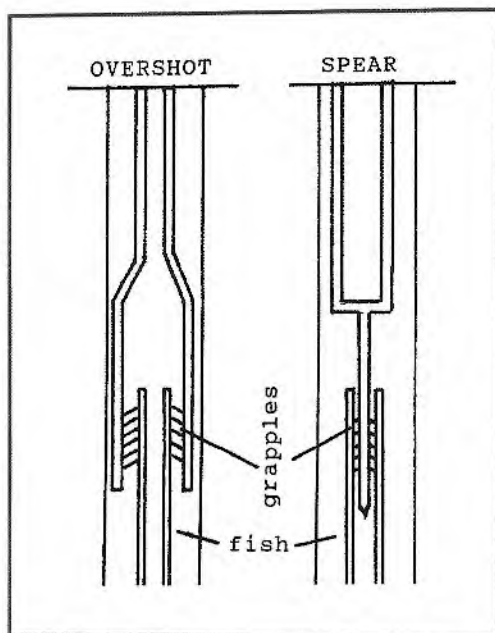


FIG. 6-15 Fishing Tools

side of the hole, overshots can be run. They are preferred to spears because it's difficult to unlatch spears if the fish can't be moved. This can result in a bigger fish.

4. The fishing tools, either overshots or spears, have multiple grapples that grip the fish securely. The jars are then activated and hopefully dislodge the fish.

Directional Drilling

Directional drilling was developed when the industry moved offshore several decades ago. Whereas an onshore rig can easily be moved to a new location to drill another vertical well, in offshore waters the horizontal space needed to support the rig must be created by erecting a platform. In deep waters, the cost of a platform is so great that it is not feasible to build one for each well. Directional drilling technology was therefore developed to drill multiple wells from the same platform, but with the wells having dispersed bottom-hole locations.

Directional wells drilled from off-shore platforms typically have S-shaped profiles. They start out vertically, then kick off at an angle until the lateral displacement (called reach) is attained, then return to vertical until the reservoir is penetrated (FIGURE 6-16).

Bent-sub assembly

The bottom-hole assembly (BHA) used for directional drilling incorporates a downhole mud motor with a bent sub that forces the bit to the side of the hole, thus building angle (FIGURE 6-17). When the motor operates, it rotates the bit while the drillstring remains stationary. This permits directional control. Using a magnetic insert in the bent sub, the BHA can be precisely oriented with respect to azimuth (North, East, etc.). The inclination of the borehole is also surveyed regularly. With these two pieces of information, the bottom-hole location is continuously calculated and the well can be accurately steered to its target. Devices can also be placed in the BHA, immediately above the bit, to sense azimuth and inclination, and continuously transmit the information to the surface via pulses in the mud column.

Since more horsepower can normally be brought to bear on the bit by conventional drillstring rotation than by using the mud motor, the initial vertical section of hole is usually drilled conventionally, with the mud motor installed when kick-off depth is reached. Once the required kick-off angle has been built with the motor, the straight, diagonal leg of the hole is drilled using both the motor and drillstring rotation. The motor is then used to build angle back to the vertical, and drillstring rotation is resumed to finish the final vertical section.

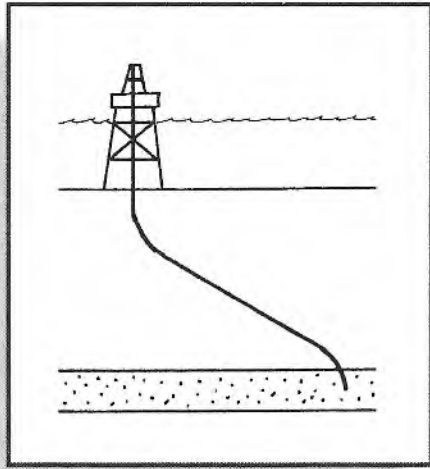


FIG. 6-16 Directional Drilling

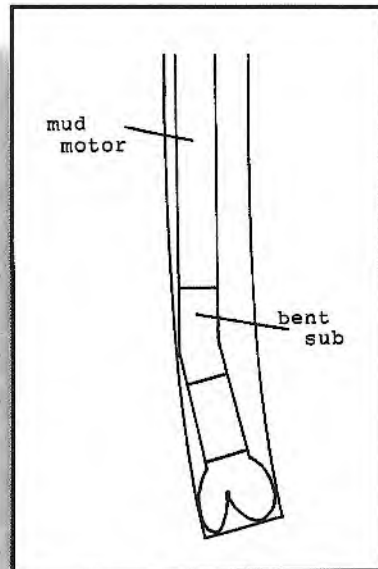


FIG. 6-17 Bent-Sub Assembly

Horizontal drilling

Directional wells are sometimes drilled to penetrate the reservoir at a very shallow angle or are drilled horizontally for some distance within the reservoir. To date, the usual reason to drill horizontally is to expose more of a low-permeability reservoir to the wellbore so that production rate is increased. Any low-permeability reservoir is a potential target for horizontal drilling, but it works particularly well in low-permeability reservoirs with vertical fractures that can be connected by the horizontal borehole. This is the case with the Austin Chalk development in Texas—the most intensively horizontal drilled reservoir in the world.

Horizontal drilling is developing rapidly and the cost is coming down, but it still is considerably more expensive than conventional drilling. Horizontal wells are therefore a small fraction of the total wells drilled, with the technology reserved for special cases such as:

- In the North Sea, the large, expensive platforms that were set to develop giant fields are now being used to drill horizontal wells to develop small fields in the vicinity that would otherwise be uneconomic.
- Reservoirs with thin oil columns are often troubled with bottom water “coning” upward and covering the perforations so that only water is produced. Horizontal wells, by distributing the pressure drop across a broad area, have been found effective in preventing coning.

The tools and procedures used in steering the bit along a horizontal trajectory are not greatly different from those used in conventional directional drilling. Bent subs with downhole motors are used with drill collars for stiffness and weight and with stabilizers (large diameter drill collars that contact the side of the hole) to act as pivot points (FIGURE 6-18).

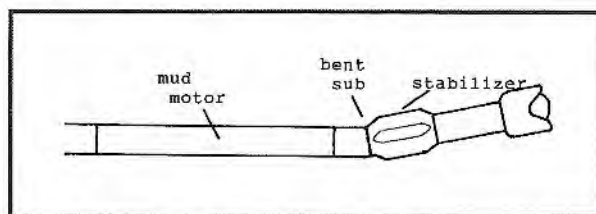


FIG. 6-18 Stabilizer Assembly for Horizontal Drilling

Laterals. Horizontal drilling technology is increasingly being used to drill short lateral extensions from the same borehole (FIGURE 6-19). Some of the applications for laterals are

- Replacing an original completion that has been damaged
- Increasing a well's production rate from a tight formation by using opposed multiple laterals to achieve greater access to the formation
- Completing a well in multiple zones using stacked multiple laterals

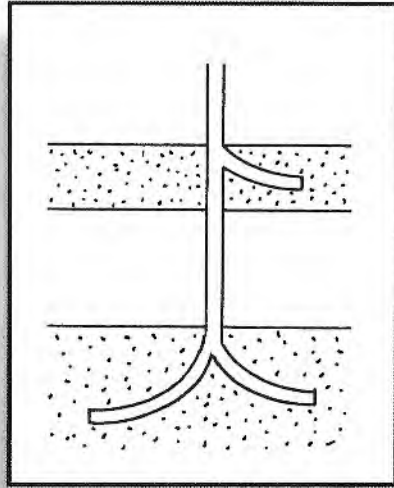


Fig. 6-19 Multiple Laterals

Drilling Rig Conveyances

The drilling rig itself is essentially the same anywhere in the world, whether onshore or offshore. It's the delivery system, which moves and supports the rig while drilling, that changes greatly with the circumstances.

Land rigs

Jackknife rigs. The jackknife rig is used to drill most land wells. To move the rig, the mast is lowered (jackknifed) and the entire rig is broken down into pieces small enough for transport by truck.

The drilling floor is usually elevated, with the BOP stack fitting between the ground and the floor. The practice of digging a cellar for the BOPs with the rig floor at ground level has largely been discontinued. It was expensive and the cellar could collect poisonous hydrogen sulfide gas.

If the drilling location is on dry ground, its preparation often involves only leveling it with a bulldozer and lining earthen pits with plastic. In some cases gravel, shell or other hard material needs to be added. If the location is

Note that in all three examples above, the measurement error is in the purchaser's favor, working against the producer. In the U.S. particularly, but also in many places around the world, custody-transfer meter runs are owned and maintained by the purchaser. It's clear, however, that the producer must actively oversee meter maintenance to protect his interests.

Equipment Systems

The primary activity in surface processing facilities is separating the produced fluids into streams of oil, gas, and water for sale and disposal. This separation is accomplished largely by gravity segregation, drawing the lighter gas drawn off the top of vessels, the heavier water off the bottom, with only the oil remaining. High-gravity, low-viscosity crude oil normally separates easily from water, but lower gravity, higher viscosity crudes often form emulsions that complicate separation.

Flow lines

The produced fluids flow from the wellhead to central treating facilities through a flowline. The fluids are driven down the line and through the treating facilities by wellhead pressure, either natural or generated by artificial lift equipment.

On land, it's not unusual for as many as 50 wells to be served by a single tank battery (central treating facility). Flowlines are typically made of small diameter steel pipe, either welded or screwed. They may either be buried or laid on the surface. Coiled polyethylene is sometimes used in low-pressure applications. The lines radiate inward from all directions and some may be over a mile (5280') in length.

Fields in shallow, protected waters that are developed with dispersed vertical wells and a central facilities platform use flowlines similar to those on land. They may be laid on the seafloor or buried to avoid being hooked by dragging ship anchors.

On deepwater offshore platforms that support multiple trees for directional wells, the flow lines are only a few feet long—just enough to reach from the trees on the cellar deck to the valve manifold on the top deck.

Piping manifolds

Whether on land or offshore, all flowlines come together at the “manifold”—the first segment of the central processing train. This piping and valving station switches the flow from any well or group of wells into any one of multiple “headers” (FIGURE 11-7).

The typical system has a production header leading to the production treating system and a test header leading to the test system. One well at a time is switched into the test header while all the other wells are switched through the production header.

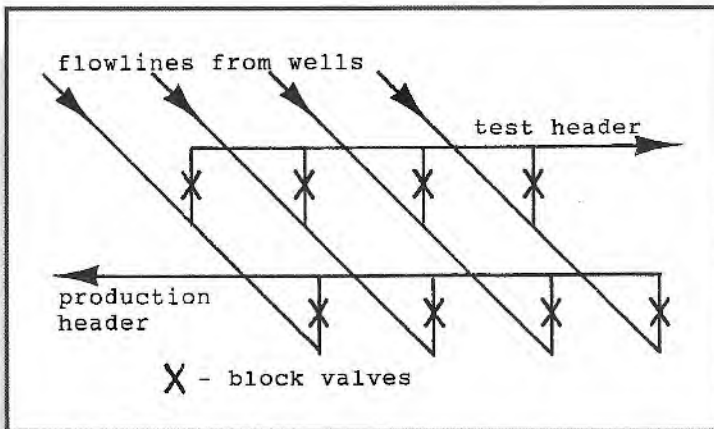


FIG. 11-7 Piping Manifold

Gas separators

The first pressure vessel the fluid enters at the central facility is the gas separator, usually called “the separator.” It separates the free gas from the liquid. Since the gas occupies many times the liquid volume, this sharply reduces the size of downstream facilities needed. Most separators are two-phase, separating the gas phase from the liquid phase, which includes both water and oil (FIGURE 11-8). Three-phase separators that divide the production into three streams—oil, water and gas—are sometimes used with high-gravity oils that readily separate from the water.

Vertical separators are used for low-volume operations, while horizontal separators are typically used in high-volume, high-GOR applications.

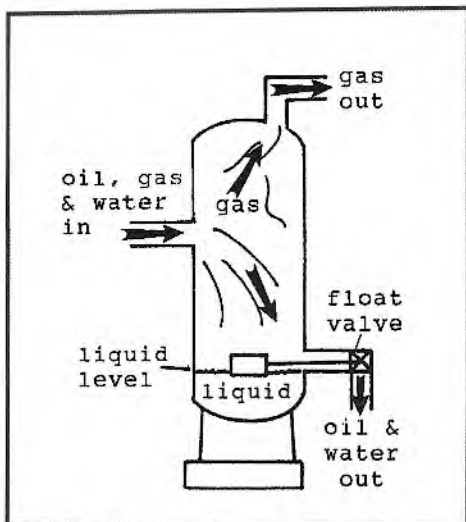


FIG. 11-8 Vertical Two-phase Gas Separator

The sequence of events in a gas separator is as follows:

1. The oil, gas, and water enter midway up the vessel.
2. Since the gas is lighter than the liquid, it rises upward and exits through the top of the vessel.
3. The liquid drops to the bottom of the vessel and accumulates. When the liquid level rises to a pre-determined point, the dump valve opens, dumping liquid. The valve closes when the liquid level reaches the bottom setting.

Free-water knockouts

Free-water knockouts (FWKs) are installed downstream from the separator when the wells produce a large volume of free water (water not tied up in an emulsion).

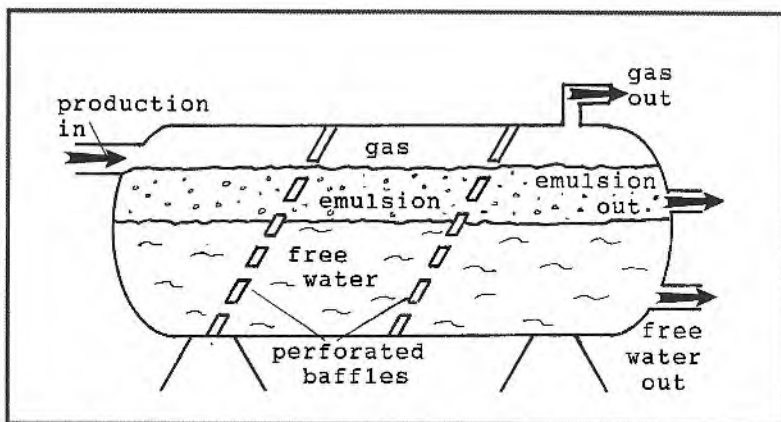


FIG. 11-9 Horizontal Free-water Knockout

Knockouts are large, usually horizontal, pressure vessels providing adequate retention time for free water to drop out of the emulsion. The free water is drawn out of the base of the vessel, the emulsion outlet is midway up the vessel, and any remaining gas is drawn off the top (FIGURE 11-9).

Emulsion-breaking facilities

Emulsions are mixtures of two insoluble liquids with small quantities of one of the liquids in small, discrete droplets dispersed throughout the other, continuous liquid. Oilfield emulsions are usually water-in-oil (the water is dispersed and the oil is continuous) and are often quite stable.

Produced water is considered a contaminant of crude oils, so purchasers accept only traces of S&W (sediment and water). Breaking emulsions to remove S&W is therefore a major production problem, particularly onshore where crudes are typically more viscous, and therefore more emulsion-prone. Emulsion problems increase in cold weather because the oil viscosity increases, tightening the emulsions.

Oilfield emulsions are broken in the surface facilities by several processes:

- **Applying heat.** Heat reduces oil viscosity and coalesces small water droplets into bigger ones. Both effects help the water to settle to the bottom of the treating vessel.
- **Injecting detergent-type chemicals.** Which weaken the surface tension between the oil and water, helping water coalescence.
- **Applying an electric potential.** When applied across the emulsion electrically charges the water droplets, causing them to coalesce.
- **Retention.** Wash tanks, or gunbarrels, are large tanks used to provide a great deal of quiet retention time for the water to settle out of the crude and be drawn off the bottom.

Produced fluids enter most wash tanks through flumes designed to reduce turbulence in the tank. The clean oil spills over to stock tanks through an outlet near the top of the wash tank, the free water is drawn off the bottom. The incoming fluid may or may not have been heated, depending on how tight the emulsion is (FIGURE 11-10).