THE FEDERAL UNIVERSITY OF TECHNOLOGY, AKURE

SCHOOL OF ENGINEERING AND ENGINEERING TECHNOLOGY

DEPARTMENT OF MINING ENGINEERING

MNE 403 - OIL AND GAS WELL DRILLING

OIL AND GAS WELL DRILLING

For centuries, oil and gas accumulated in the depths of the earth's crust in rocks, which are porous and permeable. As a result of migration and accumulation through the rock, deposits of reservoirs are formed. The deposits so formed are prospected, explored and developed with the aid of wells. Well or borehole is a cylindrical, vertical or inclined hole drilled or bored in the earth's crust from the surface by means of mechanical tools without admittance of men inside it. The process of well sinking is called drilling. The process of drilling therefore consists of making of hole in a rock using boring tools.

CLASSIFICATION OF BOREHOLES

As a result of the various functions which borehole performs, they are classified as stratigraphic test boreholes, extension (parametric) boreholes, prospecting boreholes, exploratory wells and producing wells.

Stratigraphic Test holes

These holes are to enable the study of the geological structure of the region, which are essential for the formation of oil and gas deposits. During drilling of these holes, efforts are made to reach the crystalline basement, and where deposits occur at a greater depth, drilling is continued as far as drilling rig and the hole sinking technology permits.

During the course of drilling stratigraphic test holes, rock samples (cores) are taken and geophysical investigation are made. It is the results of the drilling that geologists use in the evaluation of the rocks of the region, which are favourable for the accumulation of oil and gas.

The Extension holes

Extension hole furthers the result of the stratigraphic test holes by more drilling in promising areas for oil and gas. A further study is also made of the rock geological structure and assessment of the likelihood of oil and gas deposit is carried out. Cores are usually extracted for study purposes. The result of extension holes study enables better determination of areas which are the most promising for the formation of oil and gas pools and this leads to further study of the area.

The Prospecting holes

Prospecting hole extends the work of the result of the data obtained during extension hole drilling and all other survey studies (geophysical investigation) that might have been carried out. Prospective holes enable verification of the presence or absence of oil and gas accumulation of commercial value. Core sampling is made only within ranges promising productive strata.

The Exploratory wells

Exploratory well is done after oil and gas bearing formation have been proved by prospecting holes. Quantification of oil and gas reserves is carried out and accumulation of all necessary data to schedule programme of developing individual fields are obtained. Coring is made only within limits of productive strata. Trial production operation is carried out and such wells that meet producing criteria are involved in the producing stock of wells. If there are defects impeding the transfer to the producing stock, the exploratory wells in question are either to be conserved or abandoned.

The Producing wells

Producing well is drilled to provide a conduct for the recovery of oil and gas from explored well. Producing wells also include injection, development test observation and pressure observation wells. The injection wells are for the maintenance of the field pressure by injection of water, gas or sometimes air into the reservoir formation. The observation and pressure observation wells are special wells drilled in selected location for the purpose of observing parameters such as fluid levels and pressure changes within the oil reservoir as production proceeds. Development test wells are drilled usually to determine residual quantity of oil and gas remaining in the formation. Cores are taken in productive formation and the oil residual saturation is determined in a laboratory.

Methods of Drilling

There are three basic methods of drilling:

a. Percussive Drilling
b. Rotary Drilling
c. Rotary-Percussive Drilling

Rotary drilling is peculiar to oil and gas well drilling. In rotary drilling, the hole is drilled by a rotating bit to which a downward force is applied. Disintegration of rock is achieved by the concurrent application of pressure, which ensures penetration and torque that guarantees shearing of rock. The bit is connected to the drill string and flushing is achieved with the aid of drilling fluid.

Cuttings from the hole by scrapping or dragging are carried to the surface by drilling mud or gas, which is circulated continuously through the drill pipe. The mud is pumped into the drill pipe at the surface, out through the bit and up the annulus (annular space) between the drill pipe and the walls of the hole.

Rotary drilling is done through a series of devices to press the bit to the rock. It is this force that breaks up the rock and at the same time, the rock bit takes up part of the drill pipe string weight as soon as it touches the bottom of the hole thus building up the necessary axial weight applied on the rock bit.

The borehole drilling process consists of the following repeated operations.

a) running a new rock bit on the drilling string down the well;
b) disintegration of the rock with the bit (mechanical drilling);
c) adding new drill pipe lengths to the string as the borehole is sunk deeper; and
d) pulling the drilling pipe string out of the well to replace worn out bits.

The round-trip operations are labour consuming and energy sapping and this has led to the automation period of rotary drill rigs. Large wrenches are employed for making up or breaking out (tightening or loosening) pipe or casing joints. Air or electrical motors power the wrenches. A pulling and running mechanism is used to swing a drill pipe stand off the center and store it in a specified place on the derrick’s floor, (Figures 1 - 4).

The operation of drilling a well into a potential reservoir interval is the only way to prove the presence of hydrocarbon. Whether a well is drilled onshore or offshore is immaterial to the fundamentals of the process. In an offshore system, the drilling rig is mounted on a structure which may float (a drill ship or semi-submersible rig), or may be permanently or temporarily fixed to the sea bed (platform, jacket, jack-up rig).

The drill hole is built using drill bits and steel casing for lining the drilled sections. The drill bits are lubricated during drilling with drilling mud, which has a composition engineered to provide (a) a density such that a pressure greater than the formation fluid pressure is maintained in the drill hole, (b) that rock cuttings are carried away from the drill bit to the surface, (c) that the drill bit is cooled. The mud may be water-based or oil-based and have components that provide particular properties needed to control the drilling. The main power requirements on a drilling rig are designed to satisfy three major functions, namely power for the hoist, power for the rotary table and power for the mud system.

Drilling Rig Components

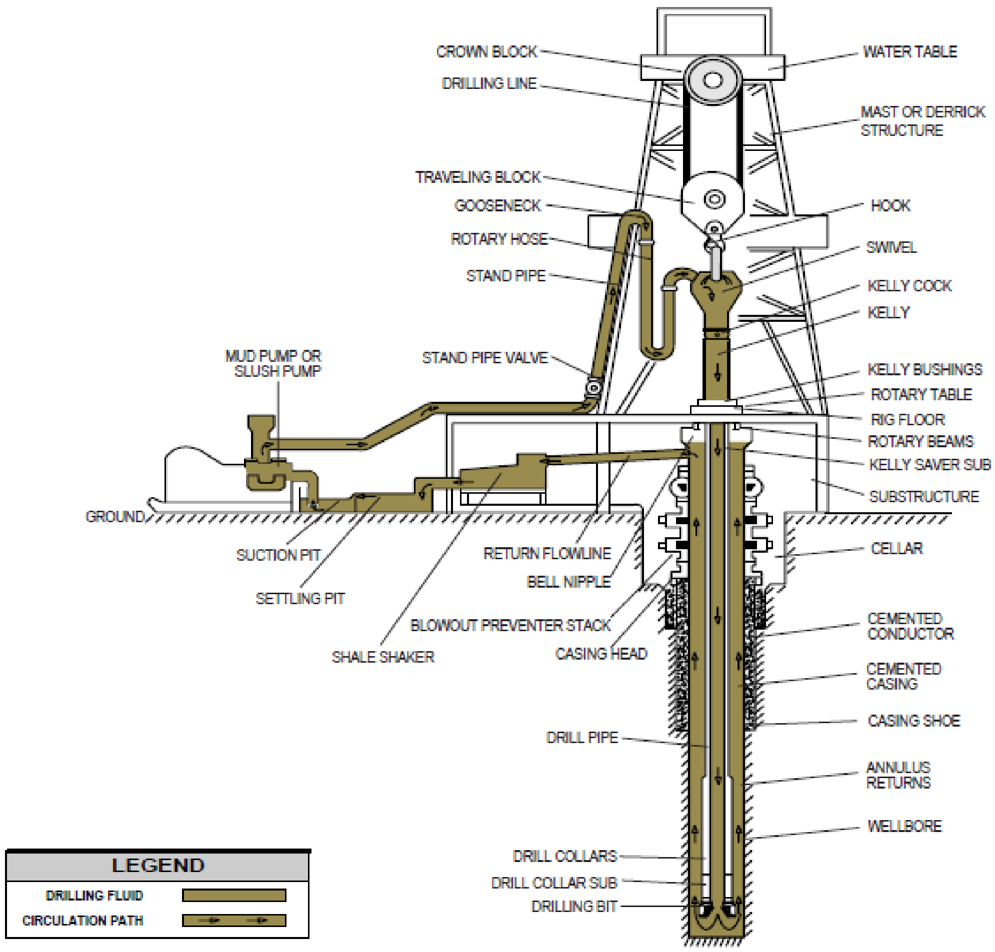


Figure 1: Configuration of a Rotary Drilling

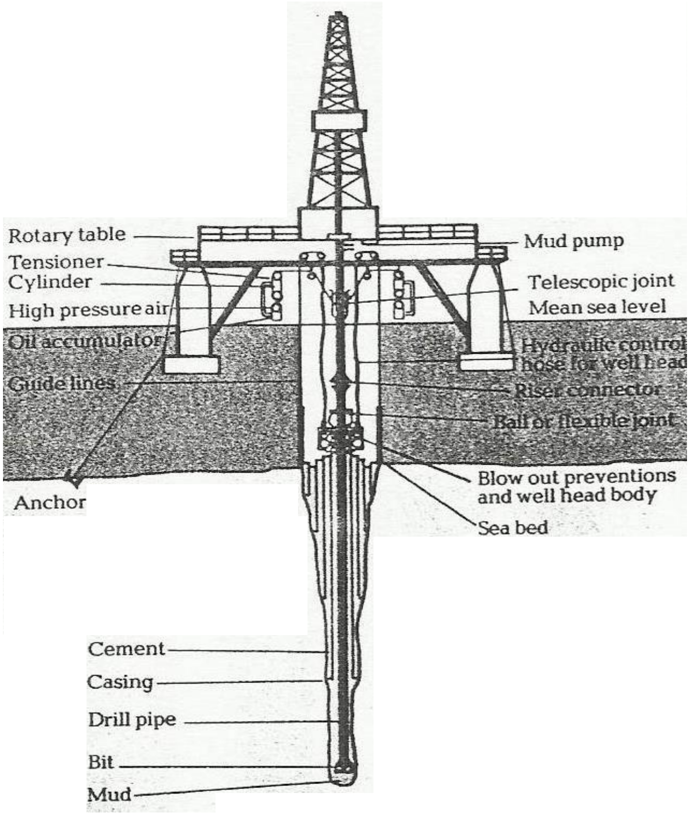


Figure 2: Offshore Drilling Rig Configuration

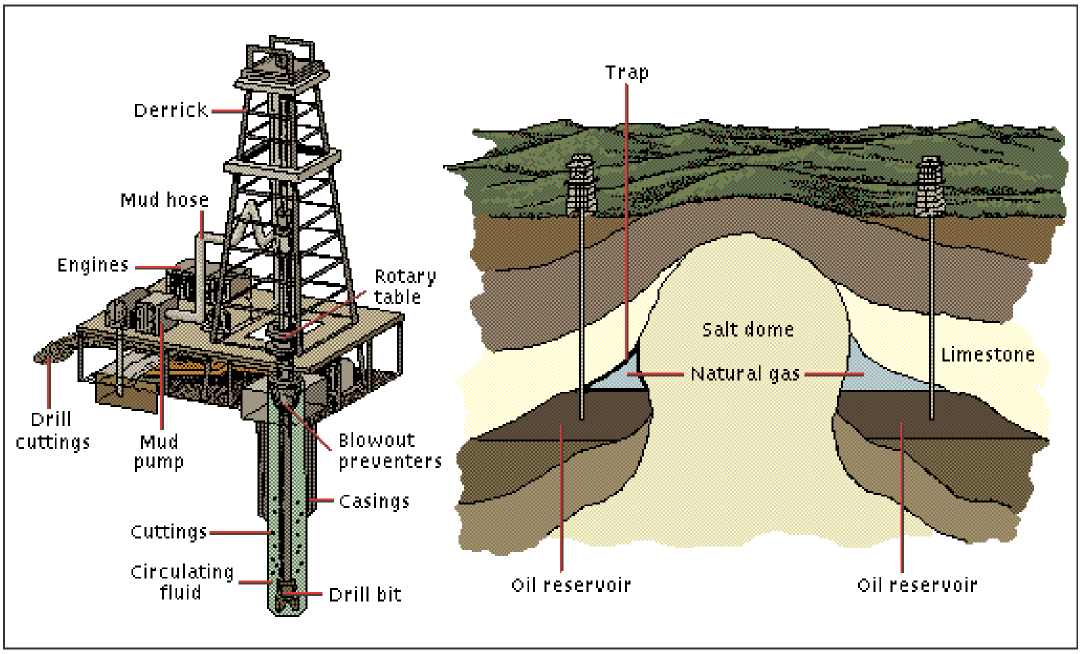


Figure 3: Oil Drill Rig and Reservoir

Figure 4: Offshore Drilling Rig

In Figure 4, anchored in place is a semisubmersible rig having legs filled with air, allowing the production platform to float above the surface of the water.

1. <u>Derrick</u>

The derrick carries the block and tackle system and provides the clearance necessary to the raising and lowering of the drilling string from the well during the drilling operation. It must be of sufficient height and strength to perform its duties in a safe and expedient manner. There are two types of derricks: standard and portable derricks.

(a) <u>Standard derrick</u>

The standard derrick is built in parts; and assembled and dismantled part-by-part at site of well, it is usually transported.

(b) <u>Portable derrick</u>

This is erected as a unit, mounted on trucks and easily moved from locations to locations. Portable derrick is used where there is reduced saving on erection, down time and transportation.

Generally, all derricks are rated according to their ability to withstand

(i) compressive loads

(ii) wind loads

Wind loads are calculated as:

$$P = 0.004V^2$$

where P is the wind load (Ib/ft^2) and V is the wind velocity (mph)

Derrick load:

Derricks load capacities vary from 86,000 - 1,400,0001b depending on steel grade and leg size.

$$F_d = \frac{n + 2}{2} \quad W$$

F_d is the total compressive load on the derrick; n is the number of lines through the traveling block (those supporting W); and W is the hook load.

The derrick load is always greater than the hook load by the factor $\frac{n+2}{n}$ due to the two additional lines draw works and anchor/exerting downward pull.

During hosting, $V_L = nV_{h,}$

where V_L is the velocity of line being spooled at the draw works during hosting; and V_h is the hook velocity.

Choice of derrick

The size of derrick will depend on compressive load and wind load. Size depends on:

a) maximum compressive load anticipated (normally the casing load);

b) maximum wind velocities expected in area of use; and

c) Trip frequenting will normally govern derrick height.

Standard derricks are used in:

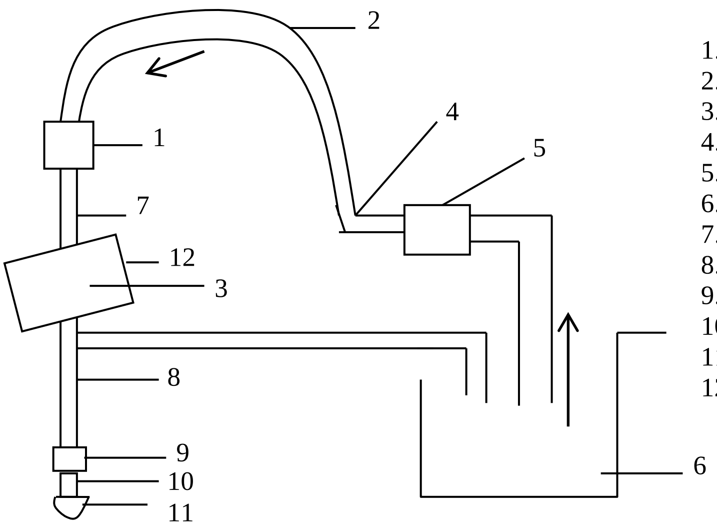
1. Structure where lay down room is not available:
2. Deep wells requiring floor capacity for racking pipe
3. A deep hard area where trip time saving by using a tall derrick may be more than offset moving costs.
4. Any other application where portable and quick rig up time are not of primary consideration.

Mast or Derrick Capacity

The large mast or derrick structures that support the crown block and the entire load carried by, and including, the travelling block and hook, are commonly rated up to 1,400,000 lbs. maximum load capacity. The height of most land exploration masts or derricks does not exceed 150ft. The reason for this height arises from the need to accommodate the travelling block and hook while pulling the drill pipe out of the hole, usually 3 joints at a time. This is called a thimble and is approximately 90ft in length. The length of 3 interconnected joints of drill pipe is called a “stand”. These “stands” are racked in a vertical manner within the mast or derrick structure.

<u>Substructures</u>

The derrick rests on the substructure. It must be built to ensure adequate support for anticipated load including allowance for safety factors. It is essential that the clearance must afford easy access to the blowout preventer. The choice of type is often governed by the soil condition in the area of application.



1. Swivel
2. Drill hoses
3. Blow out Preventer
4. Stand pipe
5. Flush pump
6. Mud
7. Kelley
8. Drill pipe
9. Drill Collar
10. Stabilizer
11. Bit
12. Rotating Table.

Figure 5: Drilling Rig Operating system

2. <u>Draw works (Hoists)</u>

The function of the draw work is very important to the efficiency of any rig; this is as a result of the functions it performs. The draw works are intended for actuating the block and tackle system as a result of which:

(a) the drill string is lowered and pulled up and the casing column descended;

(b) the drill string is held suspended in the course of boring the well and its flushing;

(c) the drill string is advanced as the drill bit penetrates deeper into the rock; and

(d) performs auxiliary work in bringing loads to and moving them away from the well head, screwing and unscrewing pipes (in the absence of power wrenches with an individual drive) and of raising the derrick up into vertical position.

The horsepower and depth rating are usually used to designate draw works. When depth rating is used, the size of drill pipe to which rating relates must be specified.

Draw work horse power can be calculated from $HP = \frac{W\,V_h}{33{,}000} \times \frac{1}{e}$

where W is the hook load, Ib; V_h is the hoisting velocity of traveling block, ft/min (33,000ft-Ib/min per horse power); e is the hook-to-draw works efficiency, usually e = 80 - 90 % depending on the number of lines in use (6 lines = 88%, 8 lines = 84 % etc)

The drawworks (hoist mechanism) provides the means to reel in the drilling line (fast line) onto a large drum as it raises the travelling block, hook and drilling assembly. The drawworks also lets out the drilling line as the drilling assembly is lowered. The drawworks is usually powered by large diesel engines or electric motors and has various gear selections to alter the winch speed of the drum pulling in the drilling line.

Block and tackle system

The block and tackle system consists of a fixed crown block, traveling tackle block, drilling line connecting stationery and movable pulleys of the crown block and of the tackle block, drilling hook and stings with which loads are suspended from the hook.
One end of the drilling line is fastened with a special device to the base of the derrick block, while the other one, that passes in turn round the pulleys of the crown block, tackle block again round that of the crown block and so on, is connected to the drawworks drum. The weight of the load hung up on the hook is distributed among on lines producing tension therein equaling P/n.

To increase the lifting capacity of the tackle system, a greater number of working lines has to be adopted, which reduces the speed of the load hoisting. In modern drill rigs, the movable part of the tackle system that includes the traveling block and the hook is an integral structure of the hook and block unit.

Crown blocks of drilling outfits differ from one another mainly in the number of rope pulleys and in the number and arrangement of axles on which they are fitted.

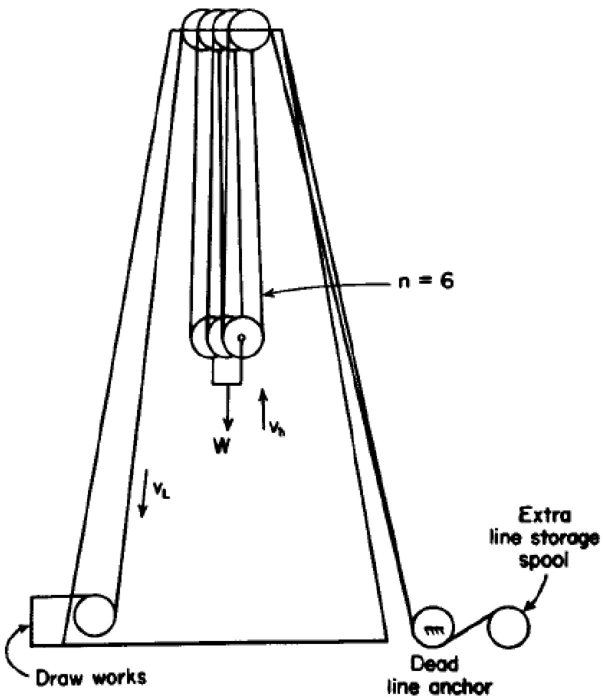


Figure 6: Schematic Block and Tackle Arrangement for Rotary Rig

CALCULATION ON DRAWWORKS

Example

A drilling rig has four lines through the travelling block with a hook-to-drawworks efficiency of 90%. While at a travelling velocity of 20m/min, a hook load of 136,000 kg is being hoisted. Calculate:

(i) the velocity of the line being spoiled at the drawworks;

(ii) the total compressive load; and

(iii) the power of the drawworks.

Solution

(i) $V_L = nV_h = 4 \times 20$ m/min = 80 m/min

(ii) $F_n = \left(\frac{n+2}{n}\right) W = \left(\frac{4+2}{4}\right) 136{,}000 = 204{,}000\ kg$

(iii) $HP = \frac{WV_h}{33{,}000}\ x\ \frac{1}{e} = \frac{136{,}000\ x\ 20}{33{,}000}\ x\ \frac{1}{0.9} = 91.58$

3. Mud pumps

The mud pump circulates the drilling fluid at the desired pressure and volume. Duplex or triplex reciprocating double acting pumps are used. This ensures great capacity with high-pressure heads. Double acting means that each side of the piston works while duplex refers to the number of pistons. The use of the triplex pumps is not so common. Because of non-uniform motion of the pump's piston, the stream of the mud fluid pushed out through the delivery valves and pressure pipeline is of a pulsating nature. The fluctuation of pump delivery (and consequently of pressure) adversely affects the operation of its driving part (variable loads on the bearings, gearings, shafts, piston rods etc); that of the turbo drills, the components of the circulation system and also the stability of the borehole walls. To partially moderate this pulsation, the cranks are displaced (biased) through 90^o relative to one another in duplex pumps and through 120^o in triplex pumps.

The superiority of the piston type pump for drilling service is largely due to the

a) ability to handle fluids containing high percentage of solids, many of which are abrasive;
b) valve clearance which allows passage of large solid particles (typically lost circulation materials) without damage;
c) ease and simplicity of operation and maintenance. Liner's pistons and valves may be replaced in the field by the rig crew; and
d) wide range of volume and pressure available by using different liner and piston sizes.

Pumps are rated by hydraulic horsepower, HP

$$HP = \frac{D^2 \times S \times N \times P}{107{,}000}$$

where D is the liner diameter, in; S is the stroke length, in; N is the revolutions per minute of crack = $\frac{\text{(piston strokes/min)}}{4}$; and P is the discharge pressure, psi

This formula assumes that:

(a) the piston rod area can be neglected and

(b) suction pressure is atmospheric.

The efficiency of drilling operation depends on proper pump selection. The hydraulic power of modern pumps for the sinking of deep wells reaches 1000 KW and more maximum allowable pressure head over 40 MPa.

In the drilling of exploratory or development wells, a very large pump is required to maintain a circulation system. The oilfield pumps used for this purpose are called mud pumps or slush pumps. They are large, positive displacement duplex or triplex pumps. By changing the piston and liner sizes, the piston stroke and the strokes per minute of these pumps can deliver volumes in excess of 1,000 gallon per minute and output pressures over 6,000 psi. The drive units or prime movers for mud pumps are usually diesel engines. Power transmission from the engine to the pump is usually by way of V-belts and grooved pulleys mounted on drive shafts.

4. Prime Movers

Prime mover is any essential component of the rig that provides the required power for the operation of the rig. The bulk of rig power is used for (a) drilling fluid circulation and (b) hoisting.

These functions are not performed simultaneously and so the same engines perform the jobs. The power consumed by circulation system is fairly constant for a period of time but that of hoisting is variable. The prime mover must have the ability to handle highly variable load at rapid acceleration over a wide values of torque and speed range.

Various types of engines are used (steam engines, electric motors, internal combustion engines).

5. The Drill String

The drill string consists of kelly, drill pipe, drill collar etc. The bit load is furnished by heavy-walled, large-diameter drill collar. The cost of production depends on the life span of drill string. These parts are replaced periodically and the parts are expensive. Extra care must be taken to ensure longer life span. Failures of drill string are usually as a result of material fatigue, aggravated by corrosion; and carelessness in care and handling.

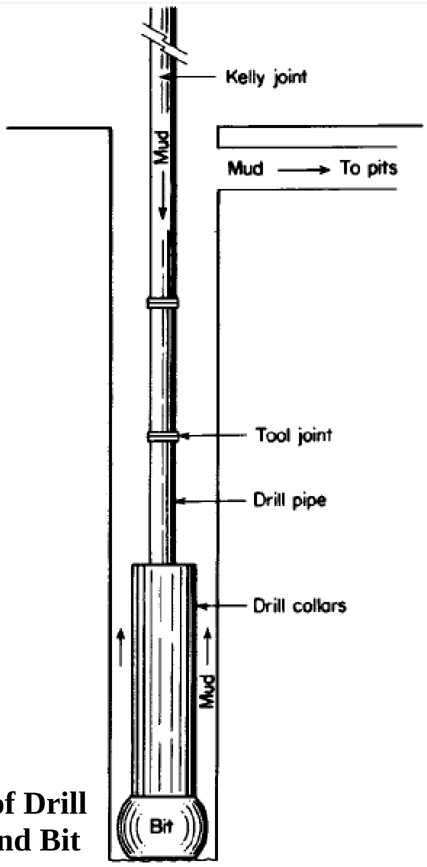


Figure 7: Schematic Diagram of Drill String Components and Bit

Kelly

The basic functions are to allow the rotation of the table to be transmitted to the entire string. There are square, hexagonal or even octagonal kellies. Square kellies have found wide application because of simplicity of fabrication, operation and repair which results in low cost.

The kelly is made from high-grade steel pipe with a square or hexagonal section. It is usually 40ft long for rotary drilling operations on land. The square or hexagonal section fits into a corresponding square or hexagonal hole in the kelly bushing.

The kelly bushing is equipped with drive pins which fit into corresponding holes in the rotary table. When the rotary table is rotated to the right (clockwise), the kelly bushing is turned to the right. This rotates the kelly, which also rotates the attached drill string and rotary bit, to the right rollers in the kelly bushing until another 30ft section or more of hole has been drilled. The whole drill string and kelly are then pulled up until the kelly bushings are picked up out of the rotary table so that the last drill pipe connection can be broken (unscrewed) to insert another length of drill pipe. In this operation, the kelly and kelly bushing are handled together. The threaded connection at the top of the kelly is a left-hand thread as the right-hand rotation applied to the kelly during drilling operations would effectively unscrew right-hand threaded connections above the rotary table.

Kelly Saver Sub

At the top of the drill string is the kelly and it's attached kelly saver sub. The kelly saver sub is a short section of heavy walled, high-grade steel pipe with tool joints box up/pin down. As the name implies, this sub is a protective tool which remains attached to the kelly and is a replacement item when the tool joint pin on the saver sub is worn out or damaged after numerous connections and disconnections to drill pipe.

Swivel

The upper box connection of the kelly cock mates with the pin down connection of the next major piece of equipment, namely the fluid swivel. This extremely important unit supports the weight of the entire drilling assembly on a large, sealed bearing housed in the swivel. This bearing allows the drill string to rotate without rotating the swivel body. The swivel has a fluid inlet through which the circulating drilling fluid is pumped through the bore of the sealed bearing and then into the bore of the kelly and attached drill string. The upper part of the swivel body is equipped with a large, heavy bail through which the hook of the travelling block is passed.

Drill Pipe

The drill pipe serves for achieving the desired depth of borehole and serves as conduct for the drilling fluid. Drill pipes are manufactured from steel or aluminum alloys. With increasing depth of well, it has become necessary to construct drill pipes made of light metal alloys - fabricated of duralumin into whose composition, besides aluminum include Cu, Mn, Zn, and Mg with light admixtures of Fe, Si and Ni. It has smooth inside surface, which reduces hydraulic resistance by 20% as compared to steel drill pipes. The disadvantage is that (a) cannot be used at $T > 150^oC$ since strength is drastically reduced; and (b) cannot be used when drilling fluid has $pH > 10$.

The length, L, is usually between 6 - 11.5m and diameter, d, between 60 -168cm. They are hollow and seamless tubes. The couplings are manufactured separately and they are manufactured to API standards. Drill pipes are specified by its inside diameter, weight (kg per unit length), steel grade and length.

Drill pipe is used above the drill collar section of the drill string. Drill pipe has a thinner wall section than drill collars and is made from high-grade steel pipe. It is equipped with tapered, right-hand threaded tool joints box up/pin down. Drill pipe normally comes in 30ft lengths.

Drill Collars

Drill collars are heavy walled, large outside diameter steel tubes. They enhance the rigidity of the lower part in the drilling shaft above the bit. The drill collar furnishes the compressive load on the bit thereby allowing the lighter drill pipe to remain in tension. As a result, greater penetration with straightens holes and less drill string failures are achieved.

Drill collars are usually 30ft heavy-walled, high-grade steel pipe that have right-hand tapered tool joints in a box up/pin down configuration which is the most common way that oilfield tubulars are used. The number of drill collars required in the drilling assembly will depend on the expected range of weight that will be applied to the drill bit. The required weight on the bit is achieved by letting a certain length of the drill collars act on the bit as a compressive load while the drilling string is turned to the right. The rest of the drill collars and the attached drill pipe above will be kept in tension. The balance point between compression and tension is called the “neutral point” and it appears to be one of the more common points of failure for drill collar tool joints.

Drill Collar Sub

The next piece in the drilling assembly is a short, heavy-walled pipe section with a tool joint box up/box down configuration. This short section of heavy-walled pipe is called a drill collar sub, or substitute, and is made up to the tool joint pin of the drilling bit.

6. Travelling Block and Hook

The travelling block and hook form part of the hoist mechanism which enables the drilling assembly to be lowered into, or pulled out, of the hole. On standard exploration drilling rigs, the travelling block will usually house 6 large pulley wheels, wire or sheaves. The travelling block is strung with interconnecting drilling line, or cable, to the crown block integrated into the top of the mast or derrick structure.

7. <u>Drilling Line</u>

In lowering and pulling operations during drilling, the drilling line is subjected to considerable tensile load as a result of hook load and bending stresses as a result of passing round the rope shelves of the traveling block and crown block. Maximum load occurs during casing operation. Wire made into twisting strands wound round a core impregnated with a lubricant organic material (vegetable and mineral fibred) or shell cable serves as the core of the rope.

<u>Crown Block and Drilling Line</u>

The crown block also has 6 large sheaves and the stringing is accomplished by reeving the drilling line around the sheaves on the travelling block and crown block. One end of the drilling line is anchored at the foot of the mast or derrick structure. This line is known as the “dead” line. The other end of the line is wound onto the cable drum of the hoist mechanism, or drawworks, on the rig floor. This line is the “fast” line. The stringing of the drilling line does not necessarily use all the sheaves of the travelling block and the crown block. The drilling line may use 4, 5 or 6 of the sheaves. The number of sheaves selected will determine if “8-line stringing” (4 sheaves), “10-line stringing” (5 sheaves) or “12-line stringing” (6 sheaves) is being used. The fewer lines used in the stringing means faster hoisting or lowering speeds, but decreases the load
carrying capacity. The more lines used in the stringing means slower hoisting and lowering speeds, but increases the load carrying capacity.

8. <u>Drilling Bits</u>

The basic instrument for breaking of rock during drilling of boreholes is drilling bit. For each type of bit, the mechanical velocity depends on the bluntness of the cutting blades, load on bit, the hardness and plasticity of the rock and quality of flushing water. The mechanical velocity of drilling depends also on the correctness of using the type of bits for the drilling of a particular rock.

For soft rocks, it is necessary to use bit that breaks rocks as a result of cutting or plough because breaking as a result of cutting is most economical.

(a) (b)

Figure 8: Types of Drilling Bit (a) Steel Tooth Bit
(b) Tungsten Carbide Insert Bit

The most common bit used in rotary drilling is the roller cone bit and its most common form is the three-cone, or tri-cone, bit. Each roller cone is equipped with teeth that chip off fragments of the rock as the bit rotates and the roller cones roll over the bottom of the hole. The resulting chips or cuttings have to be cleared from the drilling face. This is accomplished by the circulation of the drilling fluid down through the inside of the bit, and back to the surface in the annulus return. Many improvements have been made to roller cone bits over the years including the introduction of nozzles, or jets that utilize teeth with hardened inserts and larger and better bearings. All of these improvements have been made in order to increase penetration rates and extend the life of the bit.

The bit has a threaded pin up. This connection is threaded for right-hand make up, with the thread being very coarse and rugged, machined on a taper. This form of tool joint is very common in drill pipe, drill collars and drilling assemblies.

Classification of bits by method of action

Bits are divided into four groups:

1. Cut and shear bits - blade bits;
2. Shear and grind bits;
3. Grinding bits; and
4. Wearing bits.

Classification of bits by method of assignment

1. Bits for continuous boring

2. Bits for sample boring

3. Bits for special assignment

Materials for making bits:

Blade and cone bits are made generally from iron, steel, chrome-nickel or nickel-tungsten steel. Also diamond and tungsten carbide tooth bits are used.

Rotary Drill Bits:

1. Drag bits - integral blades, replaceable
2. Rolling cutters - two cone type, three cone type

Percussive Drill Bits:

1. Chisel bits
2. Button bits

They are further subdivided into different designs to better adapt to all kinds of percussive drilling:

(i) Cross bit - four sintered tungsten carbide inserts at right angle.

(ii) X - bit - four sintered tungsten carbide inserts set forming an X.

(iii) Chisel bit - one tungsten carbide insert.

(iv) Cross bit - four sintered tungsten carbide inserts with special rake angle.

(v) Button bit - flat button bit with a number of cylindrical tungsten carbide inserts more common in large sizes, 2.0 - 6.5 ins

Factors influencing the rate of bit penetration:

1. Size and type of drill;
2. Bit size, type and condition;
3. Flushing medium;
4. Rock type and structure;
5. Drill mounting;
6. Lubrication;
7. Thrust; and
8. Rotational speed.

9. Shale Shaker

The purpose of the shale shaker is to separate the cuttings from the drilling fluid so that they are removed from circulation and collected as samples for examination. The "strained" drilling fluid then drops into the settling pit. The settling pit gives the drilling fluid time to drop the very fine particles of and into formation that have become entrained in the drilling fluid. The drilling fluid then passes over a partition in the settling tank the suction pit where it is picked up by the suction pipe of the mud pump, and the circulation cycle starts all over again.

10 Rotary Table

The means to rotate the drilling assembly is provided by the rotary table which is usually powered by a diesel or electric prime mover. A large rotary chain, engaging sprockets mounted on the drive shafts, is the normal means of power transmission from the prime mover to the rotary table. The rotary table itself is a very large, rugged piece of equipment. It is mounted on very large steel beams, called rotary beams, at the rig floor level.

11 Blowout Prevention and Control

Blowout can be described as "an uncontrolled flow of fluids and/or gases from the wellbore to the atmosphere". During well drilling, the hydrostatic pressure exerted by the column of drilling fluid must always exceed the pressure of the fluids and/or gases contained in the formations being penetrated. If this positive pressure differential is not maintained, the formation fluids and gases can enter the wellbore and displace the drilling fluid which can lead to a blowout condition if corrective action is not taken.

The most common reasons for a blowout to occur in open hole sections of the well are:

(a) the drilling fluid column density is lowered by gas bubbles escaping from drilled cuttings or the formation;

(b) formation fluids or gases enter the wellbore as the drilling assembly, acting as a plunger or swab, is pulled out of the hole;

(c) loss of drilling fluid due to a lost circulation zone in the wellbore which reduces the hydrostatic column which, in turn, can allow formation fluids or gases from another zone in the well to enter the wellbore;

(d) failure to fill the hole when pulling out drilling assemblies from the hole. This permits the fluid column to drop in the well, thereby reducing the hydrostatic pressure on the formation penetrated;

(e) an unusually high-pressure zone is encountered and the hydrostatic head of the drilling fluid is simply insufficient to contain the formation fluids or gases.

When any of the above conditions occur, the drilling fluid column will be pushed back out of the well slowly at first, but gaining speed rapidly as the column gets lighter and lighter with the entry of more and more formation fluids or gases. The main flow will be out of the annulus, but flow will also come out of the drill pipe if there is no means to shut it off. The blowout preventer is used to close the annular space therefore preventing further loss of fluid from the annulus.

DRILLING FLUIDS

Drilling fluid generally refers to all fluids and includes air, gas, water, oil and muds while drilling mud refers to a suspension of solids in water or oil, or of droplets of one of these liquids dispersed in the other. The two terms are normally used interchangeably. Drilling fluid/mud is circulated into the well during drilling operation to perform various functions that will guarantee speedy, safe and satisfactory completion of the well and their properties can be altered to facilitate these objectives.

FUNCTIONS OF DRILLING FLUIDS

Drilling fluid or mud is a vital component in the rotary drilling process. Most of the problems encountered during the drilling of a well can be directly or indirectly attributed to the mud. Due to the complexities to treating, monitoring and conditioning the mud, an operating company will usually hire a service company to provide a drilling fluid specialist (mud engineer) on the rig.

The cost of the mud and the chemical additives may fairly high (around 10% of the total well cost). Although this may seem expensive, the consequences of not maintaining good mud properties may prove much more expensive in terms of drilling problems.

The main functions of drilling fluid are as follows:

(1) Removal of drill cuttings from the hole

As a bit penetrates the formation, the rock cuttings drilled must be removed; otherwise, the drilling efficiency will decrease. In removing the drill cuttings, there are three separate operations:

i) lifting the cuttings to surface while circulating;

ii) suspension of cuttings while not circulating; and

iii) dropping out of cuttings on surface.

The rate at which cuttings are removed from the hole has a great effect on the drilling efficiency and therefore the rate of penetration. The fluid comes out of the bit nozzle in form of jetting action, cleans the bottom of the hole and carries the cuttings to the surface. To perform this function efficiently, the average annular velocity must be greater than slip velocity. The annular velocity is a function of borehole size and condition, pump output and drill pipe and drill collar sizes. Efficiency of cuttings removal is a direct function of the carrying capacity of the drilling fluid which depends on the following factors (1) density (2) viscosity (3) type of flow (laminar/turbulent i.e. velocity distribution (4) torque (5) size and shape of particles, (6) rotation of drill pipe and (7) ratio of the specific gravity of solids to that of drill pipe fluid.

CALCULATION ON SLIP VELOCITY OF PARTICLES

(A) Laminar Flow

For Spherical cutting: $$V_{LS} = 148\,\frac{dc^2\,(\rho_{S-}\rho_m)}{\mu}$$

For Flat cutting: $$V_{LS} = 57.5\,\frac{dc^2\,(\rho_{S-}\rho_m)}{\mu}$$

where V_{LS} is the maximum or terminal slip velocity of cutting in laminar flow (ft/min);

d_c is the cutting diameter (in);

ρ_m and ρs_m are mud and cutting densities (Ib/gal);

148 and 57.5 are dimensional constant which also include drag coefficient (flat cutting falls about 40% as fast as sphere cutting); and

µ is the mud viscosity (centipoises).

(B) Turbulent Flow

For Spherical cutting: $$V_c = 170\,\sqrt{\frac{d_c\,(\rho_{S-}\,\rho_m)}{\rho_m}}$$

For Flat cutting: $V_c = 133\sqrt{\frac{t_c}{d_c}}\sqrt{\frac{d_c(\rho_s - \rho_m)}{\rho_m}}$

where V_c is the uncorrected slip velocity of cutting in turbulent flow (ft/min);

$\sqrt{\frac{t_c}{d_c}}$ is thickness-to-diameter ratio of cutting;

The value of V_c must be corrected for wall effect.

$$V_{ts} = \frac{V_c}{1 + \frac{d_c}{d_a}}$$

where V_{ts} is the turbulent slip velocity of cutting (ft/min); and

d_a is the hydraulically equivalent diameter of annulus (in).

Conversion:

1 in = 0.025 m

1 Ib = 0.45359 kg

1 gal = 3.7854 litres

<u>Example</u>

1 (a) What is the slip velocity of a 0.50 in diameter sphere under laminar flow using a mud viscosity of 30 cp, mud density of 10 Ib/gal, hole size of 8 ins in diameter, drill pipe of 4.5 ins in diameter and cutting density of 21.7 Ib/gal.

<u>Solution</u>

$$V_{LS} = 148\,\frac{dc^2\,(\rho_s - \rho_m)}{\mu}$$

$$V_{LS} = 148\,\frac{0.5^2(21.7 - 10)}{30} = 14.4\ ft/min$$

(b) What would the maximum falling rate be for the system in turbulent flow ignoring wall effect?

Solution

$$V_c = 170\sqrt{\frac{d_c\,(\rho_s - \rho_m)}{\rho_m}}$$

$$V_c = 170\sqrt{\frac{0.5\,(21.7 - 10)}{10}} = 130\ ft/min$$

(c) What is the turbulent slip velocity corrected for wall effect?

Solution

$$V_{ts} = \frac{V_c}{1 + \frac{d_c}{d_a}}$$

$$V_{ts} = \frac{13o}{1 + \frac{0.5}{3.5}} = 104 \text{ ft/min}$$

(2) Bottom Hole Cleaning

Bottom hole cleaning is a function of the ability of drilling fluid to remove cuttings from the well bore in order to prevent bit balling and floundering. The drilling fluid stream removes rock cuttings generated by the drilling bit action. Consequently, a drilling fluid having maximum carrying capacity at the existing condition provided the most efficient bottom hole cleaning. Inadequate bottom hole cleaning will cause loss in penetration and bit balling and floundering. A balled-up bit is a bit with a mass of sticky finely ground and compacted material firmly attached to it, whereas floundering refers to regrinding of the cuttings by the bit. The deeper the well, the more important bottom hole cleaning becomes.

(3) Controlling the subsurface pressure

Drilling fluids must provide necessary hydrostatic pressure to balance the formation pressure so as to restrict the influx of fluid from the formation into the well bore. An "overbalanced" drilling condition exists when the drilling fluid column pressure exceeds that of the formation pressure. An "under- balanced" condition exists where drilling fluid column is lower than the formation pressure.

To control the subsurface pressure, one needs to understand the different sources of the pressure. Formation pressure originates from the combined weights of the formation solid matrix and the interstitial fluids (oil, gas and/or water) in the rocks overlying the formation of interest.

$$P_f = D\,[(1 - \Phi)\ \gamma_{rm} + \Phi\ \gamma_{if}]$$

where P_f is the formation pressure; D is the depth of the geologic column; Φ is the porosity; γ_{rm} is the specific weight of the rock matrix; γ_{if} is the specific weight of the interstitial fluids occupying the pore spaces.

Pore pressure is the pressure acting on the fluid in the pore spaces of the formation. Normally formation pore pressure is equal to the hydrostatic head of water extending from the top of the water table to the subsurface formation. The hydrostatic pressure (PH) that a column of a drilling fluid exerts at any depth in the hole can be calculated as follows.

PH (psi) = (0.052) x (depth, ft) x (drilling fluid weight, Ib/gal)
= (0.0065) x (depth, ft) x (drilling fluid weight, (Ib/ft^3)
= (0.098) x (depth, ft) x (drilling fluid weight, (gm/cm^3)

This can be represented in the basic equation:

$$P = \gamma D = \rho g D$$

where P is the pressure, Ib/ft^2; γ is the specific weight of fluid in Ib/ft^3; ρ is the density; D is the depth, ft; and g is the acceleration due to gravity.

(4) <u>Cooling and lubricating the drill string</u>

A lot of heat is generated during drilling as a result of friction at the bits and at the points where drill string comes into contact with formation wells. The formation can only absorb small portion of the heat generated due to its physical properties. Large percentage of the heat is conducted away from the point of contact by the circulating fluid up to the surface where it is dissipated. Heat generated makes temperature, T = 500-700^{o}C. Efficient lubrication reduces cost of drilling since life span of drill string is ensured. Excessive torque and drag and differential sticking of pipe is reduced if the drilling fluid possesses sufficient lubricating properties. It will also prolong the service life of the downhole equipment. The composition of based additives of drilling fluid determines the lubricating properties of drilling fluid. Water is the best coolant followed by water-based drilling mud. Oil base drilling fluids are least effective coolant.

(5) <u>Acting as medium for settling out of cuttings in the surface pit</u>

Drilling fluid and cuttings flow from annulus to mud pit. With the aid of different equipment, the cuttings are separated from the fluid and with the aid of pumps, drilling fluid is recirculated.

(6) <u>Forming filter cake on walls of the borehole (permeable formation)</u>

The drilling fluid exhibits a filtration property, which enables filter cakes to be formed on walls of permeable formations. During drilling, filtrate escapes into the formation exposed in the borehole leaving behind filter cakes on the walls of the boreholes. This assists in sealing off the permeable zones.

(7) <u>Prevention of caving-in-of the wall</u>

At a permeable zone in a formation, a tough impermeable cake is formed on the face of a well bore during the drilling of a well. The mud cake is formed by the initial invasion of the liquid phase of the drilling fluid to the permeable zone and deposition of finely divided solids (usually plate like clays) on the face of the formation. This mud cake also helps to strengthen the face of the well bore, thereby preventing caving in. Increasing the colloidal fraction of the drilling fluids and/or chemically treating them can improve the property of the mud cake. It is desirable for the drilling fluid to form an impermeable mud cake quickly thereby reducing the initial filtration loss and cake thickness.

(8) <u>Avoiding damage to productivity of producing formation</u>

It is desirable that the drilling fluid should form an impermeable mud cake quickly. This will reduce the initial filtration loss and reduce the thickness of cake. Higher cake thickness leads to inefficient operation of the drill string during the process of moving in and out of the well bore. When there is great loss of filtrate into formation, considerable damage can be done to producing zone. A proper drilling fluid should be chosen when drilling in productivity zone.

(9) <u>Partial aid in supporting the weight of drill string and casing</u>

The drill string and casing in the borehole are buoyed up by the forces equal to the weight of the displaced up. This results in considerable reduction in the loads, which the surface equipment and structure must support. The buoyant force increases with increasing mud density and reduces the strain on the drill pipe and casing in deep wells.

(10) Reducing casing cost

The filtrate formed on the walls of the well pore reduces the diameter of casing, thereby reducing cost of casing during casing selection.

(11) Preventing corrosion fatigue of drilling pipe

Water-base and oil-emulsion drilling fluids (oil-in-water) may attack the metal surfaces of drill string if not properly treated. The type of corrosion involves is electrochemical or wet corrosion.

Numerous conditions encountered during drilling operations cause corrosion to the drilling equipment. Hydrogen sulfide (H_2S) and carbon dioxide (CO_2) are commonly encountered in drilling deep wells. Hydrogen sulfide reacts with iron at the pipe surface to form iron sulfide (FeS), liberating two hydrogen atoms that permeate steel and lead to corrosion. Carbon dioxide which forms carbonic acid (H_2CO_3) in water, has a similar reaction with steel. Oil base drilling muds are very effective in reducing corrosion to the drilling equipment, because the continuous oil phase prevents the completion of the galvanic cell, which is necessary for corrosion to take place. Certain chemicals, when added to the oil base muds, make the steel surface oil wet and protect against corrosions.

(12) Allowing interpretation of electric logs

A drilling fluid must not adversely affect the formation being drilled so that useful information can be obtained as to the location of producing zones. Drilling mud is subject to instantaneous analysis and this leads to quick information concerning the formation. This instant information becomes more relevant when penetrating overpressure formations, if need be, drilling fluid properties must be sacrificed in order to achieve a more accurate formation evaluation. Coring and core analysis give first-hand information about penetrated formation.

(13) Transmission of the surface available hydraulic horse power to the bit

The successful completion of any well depends on the design of drilling fluid hydraulic well programme. The horsepower generated at the surface is transmitted to the bit through the bit by jet action and this cleans the face of the well. A well-designed hydraulic programme includes pressure loss and mud velocity calculations. These are essential for effective drilling operation.

(14) Suspension of cuttings and weight materials on stopping the circulation

One of the most important requirements of any good drilling fluid is its ability to suspend cuttings and weight materials when circulation is stopped several times for changing of bit (which at times can take many hours), routine maintenance, change of shift etc. If the solids are not kept in suspension during these times, their settling will result in recirculation and deposition of solids on the bit, which becomes stuck.

In order for the mud to have suspension ability, it must (a) possess thixotropic (gelation) properties when the fluid is not in motion, and (b) become fluid again upon agitation. The gelation property can be altered by changing the content of the solids and by adding chemicals. Viscosity and density are other properties that affect cutting suspension. The viscosity affects slip velocity in laminar flow while density affects static suspension since cutting fall is the result of density contrast between solid and liquid.

Mud System

The surface mud system is equipped to:

(a) clean, (b) cool, (c) mix, (d) add chemicals, weight materials etc and (e) remove air or gas from the mud.

To achieve these functions, the following equipment is required:

(i) Shale shaker, (ii) mud tanks, (iii) mud degasser, (iv) desander, (v) desilter,

(vi) mud guns, mechanical mixers or stirrers, and (vii) suction strainer.

The shale shaker separates the bigger drill cuttings; the desander removes solids of size down to 75 microns while desilter removes solids of size down to 30 microns.

CLASSIFICATION OF DRILLING FLUIDS

Drilling fluids normally have such physical and chemical properties that enable their usage under different geological formations. All drilling fluids are classified into three groups: (i) water base (ii) hydrocarbon base and (iii) gaseous base.

The groups are subdivided as follows:

- (i) Water base
  - Fresh water muds
    - 1. simple clay water mixtures
    - 2. chemically treated clay water mixtures
    - 3. calcium treated muds.
  - Salt water muds
- (ii) Hydrocarbon base
  - Emulsion muds
    - 1. oil in water emulsion
    - 2. water-in-oil (inverted) emulsion
  - Oil base muds
- (iii) Gaseous base
  - 1. air
  - 2. natural hydrocarbon gas
  - 3. exhaust gas.

Water-based muds (WBM): They are those drilling fluids in which the continuous phase of the system is water (salt or fresh water). WBM's are those commonly used worldwide.

A fresh Water Mud is the one in which the continuous liquid phase of the system is fresh water.

An Inhibited Mud is the one where the reactivity of the water phase, within the mud system, with active clays, within the formation, is greatly reduced. The distinction between freshwater and inhibited system mud is based on salt concentration (fresh water muds are those having less than 3000 ppm Na^+ ion).

Using Oil Based Muds (OBM) results in fewer problems and cause less formation damage than WBM and they are therefore very popular in certain areas. Oil muds are however more expensive and require more careful handling (pollution control) than WBM. Full-oil muds have a very low water content (< 5%) whereas invert emulsion oil mud have (5-50%) water content.

The use of air as drilling fluid is limited to areas where formations are competent and impermeable (e.g. West Virginia).

The advantages and disadvantages of air drilling in the circulating system are:

Advantages	Disadvantages
(i) Higher penetration rates.	Air cannot support the sides of the borehole.
(ii) Better hole cleaning.	Air cannot exert enough pressure to prevent formation fluids entering the borehole.
(iii) Less formation damages	

Any drilling fluid with specific weight < 781b/ft^3 are regarded as non-weighted drilling fluids since they do not require weighting materials like barite to achieve such weight. Drilling fluids with specific weight > 781b/ ft^3 are classified as weighted drilling fluids. Many deep wells require the use of weighted drilling fluids to provide sufficient hydrostatic head in order to confine formation fluids to their native formations. Water base drilling fluids use barite while oil base drilling fluids use limestone, dolomite and pretreated barite weighting materials.

Composition of Drilling Fluid

a) Water-based muds: They consist of a mixture of a solids, liquids, and chemicals. Some solids (clay) react with the water and chemicals in the mud and are called “active solids”. The activity of these solids must be controlled in order to allow the mud to function properly. The solids, which do not react within the mud, are called “inactive” or inert solids (e.g. Barite). Fresh water is used as the base for most of these muds, but in offshore drilling, salt water is more readily available.
Figure 7 shows the typical composition for a water-based mud.

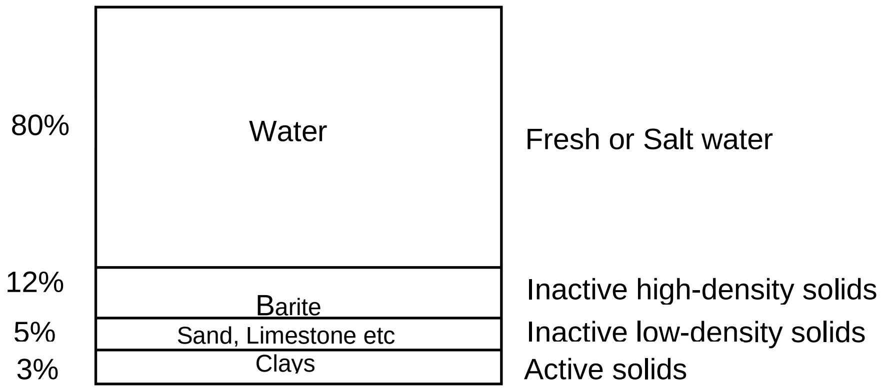


Figure 9: Composition of a Typical Water Based Mud (WBM)

b) Oil- based muds: They are similar in composition to water-based with the exception that the continuous phase is oil. In an invert emulsion mud, water may make-up a large percentage of the volume, but oil is still the continuous phase. The water is dispersed throughout the system as droplets.

Figure 8 shows the typical composition.

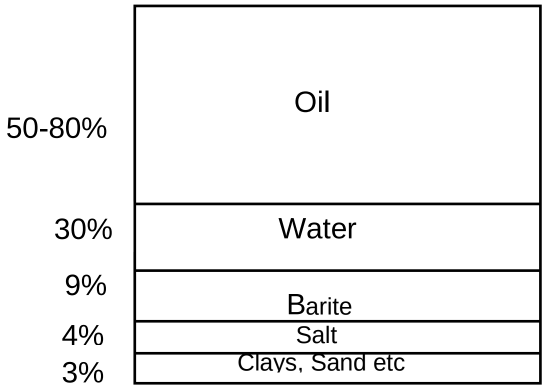


Figure 10: Composition of a typical Oil Based Mud (OBM)

Clay Chemistry

The constituents of clay are called minerals, which can be divided into two broad groups;

a) Expandable (hydrophylic) clays - these will readily absorb water (e.g. montmorillonite)

b) Non-expandable (hydrophobic) clays - these will not readily absorb water (e.g. illite)

Clay minerals have a sandwich like structure usually consisting of three layers, the alternate layers are of silica and alumina. A clay particle usually consists of several sandwiches stacked together like a pack of cards. The chemical composition of montomorillonite differs from that of illite, which accounts for the difference in water absorption.

a) Expandable Clays in Water

The most commonly used clay is Wyoming Bentonite (sodium montmorillonite). In fresh water, the layers absorb water and the chemical bonds holding them together are weakened. This process is known as ‘dispersion’ (i.e. less face-to-face association). Dispersion results in an increase in the number of particles which in turn increases the surface leaving the flat surface of the particles negatively charged while edges are positively charged. It is likely therefore that some plates will tend to form edge-to-edge arrangements. This process is known as ‘flocculation’. There are four arrangements of clay particles shown in Figure 11.

Aggregation (Face-to-Face) - leads to thicker plates and smaller surface area, this results in a low viscosity fluid. Aggregation may be caused by introducing cations (e.g. Ca ++) to bring the plates together. Lime or gypsum may be added to achieve this effect.

Dispersion - increases the surface area and causes an increase in viscosity. Bentonite does not usually completely disperse in water.

Flocculation - forms a house of card structure, which increases viscosity. The severity of flocculation depends on the force acting on the linked particles. Anything that shrinks the absorbed water film around the particles (e.g., temperature) will increase flocculation.

Deflocculation - reduces the edge-to-face effect. Chemicals called “thinners” are added to achieve this.

b) Non-Expandable Clays in Water

When illite is present in shale cuttings, very little hydration occurs. This is because illite does not exhibit the same tendency to exchange cations as montmorillonite. The methylene blue test is a method of measuring the cation exchange capacity of clays.

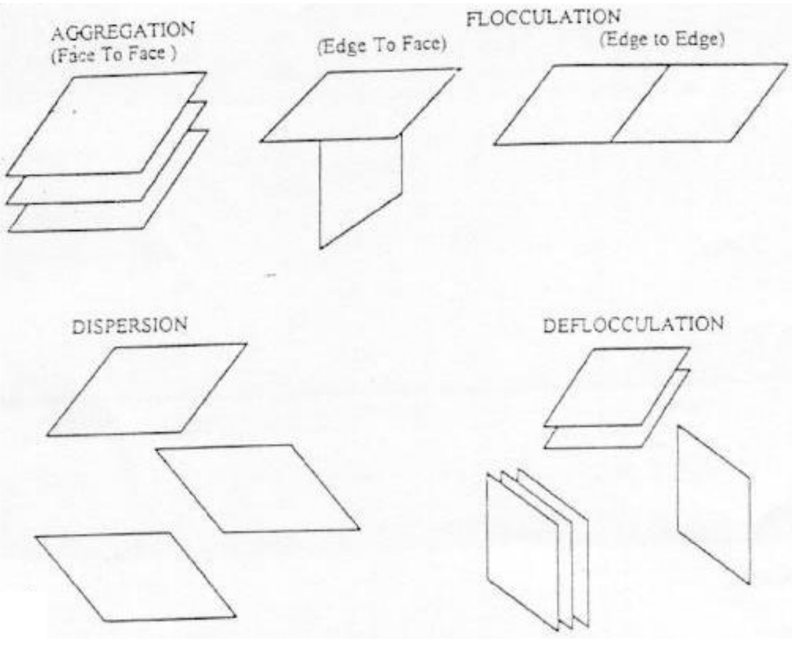


Figure 12: Association of Clay Particles

Mud Programme

In planning a mud programme, the objective is to select a mud which will:

a) allow the target depth to be reached;

b) minimise total well cost; and

c) maximise production from the pay zone.

Many factors have been taken into account. They are:

i) Location of the well: If the well is in a remote location (e.g. offshore) the cost of transporting chemicals may be high. Storage facilities at the rig site must be considered. Environmental aspects may affect the disposal of cuttings or contaminated mud.

ii) Expected lithology: Data from adjacent wells would be useful in predicting any formations that would be troublesome (e.g. unstable shale, highly permeable zones, lost circulation and overpressured zones).

iii) Equipment required: This includes selecting mud pumps of required capacity, solids removal equipment, de-gassers may be necessary, mud mixing equipment.

iv) Mud properties: These must be selected to enable the different formations to be drilled safely and efficiently, and avoid potential drilling problems. It is also important that the producing formations are not damaged by filtrate invasion. Mud weight should be kept between the fracture gradient and the formation gradient.

It is possible that in order to meet all necessary requirements and drill the well as efficient as possible, more than one type of mud is used (e.g. water based mud may be used to a certain hole depth and then, it is replaced by an oil-based mud to drill to total depth). Some mud properties are difficult to predict in advance, so the mud programme has to be flexible to allow alternations and adjustments to be made as the hole is being drilled, (e.g. unexpected hole problems may cause the pH to be increased or the viscosity to be reduced at a certain point.

DRILLING FLUID PROPERTIES

Drilling performance is affected by the following drilling mud properties: specific weight (density), viscosity, gel strength, filtration, sand content, pH values and alkalinity.

a) Mud Density

This is an important parameter, which determines the hydrostatic pressure exerted by the mud column. The most practical instrument for determining the specific weight of drilling fluid is the mud balance. The mud balance is simple and gives an accurate determination of the specific weight of the mud and it's accuracy is not affected by temperature. The control of drilling fluid specific weight is critical to avoid breakdown of formation when heavy drilling fluids are used. This will lead to loss of circulation fluid and at times lead to loss of well or drastic reduction in drilling rate.

A sample of mud is weighed in a mud balance. The cup is completely filled with mud and the lid is placed firmly on top (some mud should escape through the hole in the lid). The balance arm is placed on the base and the rider adjusted until the arm is level. The density can be read directly off the graduated scale at the left-hand side of the rider. Mud densities are usually reported to the nearest 0.1 ppg (lbs per gallon). Other units in common use are lbs/ft^3, psi/1000ft, kg/l and specific gravity (S.G.).

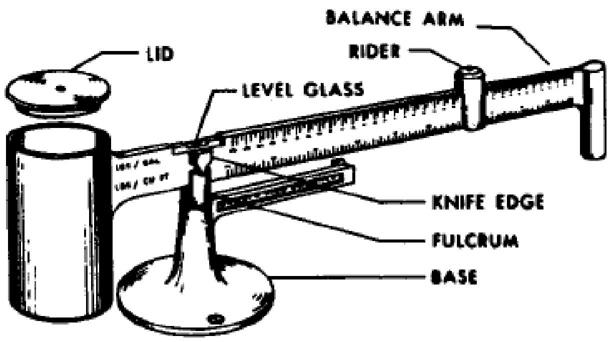


Figure 13: Diagram of Typical Mud Balance

b) Viscosity

In general terms, viscosity is a measure of the liquid's resistance to flow. Two common methods are used on the rig site to measure viscosity namely:

i) Marsh funnel: This is a very quick test, which only gives an indication of viscosity and not an absolute result. The funnel is a standard dimension (12inches long, 6inches diameter at the top, 2inches long tube at the bottom, 3/16inch diameter). A mud sample is poured into the funnel and the time taken for one quart (946 ml) to flow out into a measuring cup is recorded. Fresh water at 75ºF has a funnel viscosity of 26 sec/quart). Since the flow rate varies throughout the test, it cannot give a true viscosity.

Non-Newtonian fluids (i.e. most drilling fluids) exhibit different viscosities at different flow rates. However, the funnel viscosity may be used for checking any radical changes in mud viscosity. Further tests must be carried out before any treatment can be recommended.

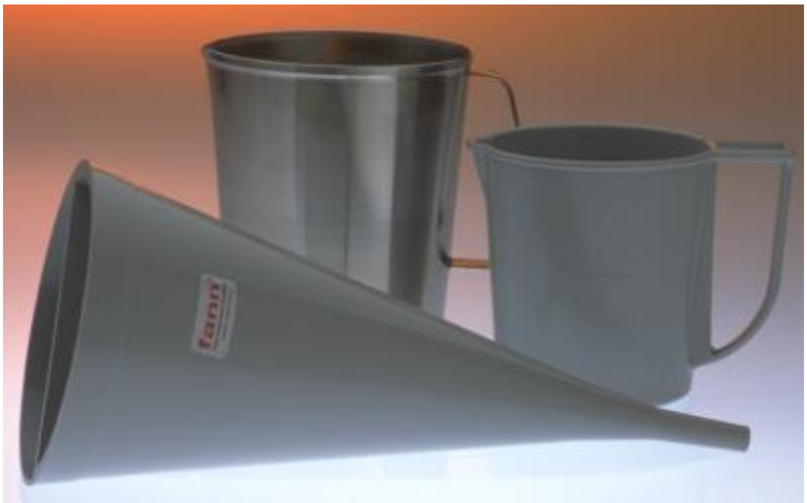


Figure 14: Marsh funnel

ii) Rotational viscometer*:* In this test, a sample of mud is sheared at a constant rate between a rotating outer sleeve and an inner bob. The test is conducted at a range of different speeds, 600 rpm, 300 rpm, 100 rpm etc (laboratory models can operate at 6 different speeds). The standard procedure is to lower the instrument head into the mud sample until the sleeve is immersed up to the scribe line. The rotor speed is set at 600 rpm and after waiting for a steady dial reading, this value is recorded (degrees). The speed is changed to 300 rpm and again the reading is recorded. This is repeated until all required dial readings have been recorded. The results can be plotted as graphs. Assuming that there is a linear relationship between shear stress and shear rate (i.e. Bingham plastic), the following parameters can be calculated from the graph: Plastic Viscosity (PV) and Yield Point (YP).

c) Gel Strength

The property that describes the attractive forces while the mud is static is called gel strength. It can be thought of as the stress required to get the mud moving. The gel strength can be measured using the viscometer. After the mud has remained static for some time (10 secs), the rotor is set as a low speed (3 rpm) and the deflection noted. This is reported as the “initial or 10 second gel”. The same procedure is repeated after the mud remains static for 10 minutes, to determine the “10 minute get”. Both gels are measured in the same units as Yield Point (lbs/100ft^2). Gel strength usually appears on the mud report as two figures (e.g. 15/25. The first being the initial gel and the second is the 10 minute gel.

Thixotropy property is the exhibited by fluids to form a gel structure when allowed to cool and become fluid again after stirring or agitation.

Figure 15: Fann Viscometer

d) Filtration

The wall-building properties of the mud can be measured by means of a filter press. This test measures:

i) the rate at which fluid from a mud sample is forced through a filter under specified temperature and pressure; and

ii) the thickness of the solid residue deposited on the filter paper caused by the loss of fluids.

The instrument consists of a mud cell, pressure assembly and filtering device. The cell is closed at the bottom by a lid, which is fitted with a screen. On top of the screen is placed a filter paper, which is pressed up against an o-ring seal. A graduated cylinder is placed under the screen to collect the filtrate. The pressure of 100 psi is applied for a period of 30 minutes and the volume of filtrate can then be measured (in cm^3). When the pressure is bled-off, the cell can be opened and the filter paper is examined. The thickness of the filter cake is measured in 1/32's of an inch.

e) Sand Content

Sand content determination is not only desirable but imperative since excessive sand may result in the deposition of a hole or may settle in the hole just above the tools when circulation is stopped thus reducing the efficiency of drilling operation or settling of casing. High sand content can increase abrasion of pump parts and pipe connections and consequently increase in cost of production.

The percentage of sand in the mud is measured by using a 200 mesh sieve and a graduated tube. The glass measuring tube is filled with mud up to the scribe line. Water is then added up to the next scribe line. The fluids are mixed by shaking and then poured through the sieve. The sand retained on the sieve should be washed thoroughly to remove the remaining mud. A funnel is fitted to the top of the sieve and the sand is washed into the glass tube by a fine spray of water. After allowing the sand to settle, the sand content can then be read off directly as a percentage.

Measurement is calculated as $\frac{\text{Volume of sand}}{\text{Volume of mud.}} \times 100\%$

Other methods for determining sand content are: (i) elutriation (ii) settling and (iii) infrared sizing. Of these methods, the sieve analysis is the most commonly used because of it's reliability and simplicity.

f) pH

The pH test is a measure of the concentration of hydrogen ions in aqueous solution. In other words, the degree of acidity or alkalinity of drilling fluids is indicated by the pH values. The pH assists in determining the necessary chemical control of mud, it also indicates the presence of contaminants such as cement, gypsum etc which alters the pH value of the mud. pH measurement can be done either by pHydrion paper or by Analytical pH meter. The pH paper will turn to different colours depending on the concentration of hydrogen ions. A standard colour chart can be used to read off the pH to the nearest 0.5 of a unit (on a scale of 0 to 14). With a pH meter, the probe is simply placed in the mud sample and the reading taken after the needle stabilizes. It should be ensured that the probe is washed clean before use. The meter gives a more accurate result to 0.1 of a unit.

g) Alkalinity

Although pH gives an indication of alkalinity, it has been observed that the characteristics of a high pH mud can vary considerably despite constant pH. A further analysis of the mud is usually carried out to assess the alkalinity. The procedure involves taking a small sample, adding phenolphthalein indicator and titrating with acid until the colour changes. The number of ml of acid required per ml of sample is reported as the alkalinity. (Pf = filtrate alkalinity, Pm = mud alkalinity). Another parameter related to Pf and Pm is lime content. This can be calculated from:

Lime Content = 0.26 (Pm - FwPf)

Where Lime content is in lb/bbl and Fw is the volume of fraction of water in the mud.

Factors that affect a good mud job

The following factors affect a good mud job:

(1) mud compatibility with formation;

(2) compatible additives;

(3) good solids removal equipment;

(4) suitable hydraulics;

(5) good mud engineering and drilling practices; and

(6) Other factors - inadequate circulation; poor hole cleaning, inadequate mud density, bad well path, faults etc.

Factors Affecting Penetration Rate

Many factors affect penetration rate. It is worth noting that the fastest on bottom drilling rate does not necessarily result in the lowest cost per foot of drilled hole. Other factors such as accelerated bit wear; equipment failure etc may raise cost.

Some of the more recognizable variables, which affect penetration rate, are the followings:

1. Personnel efficiency

   (a) Competence - (i) experience, (ii) special training

   (b) Psychological factors - (i) company (employee relations),

   (ii) pride in job, and (iii) chance for advancement.

2. Rig efficiency

   (a) State of repair, preventive maintenance, (b) proper size

   (c) Ease of operation, degree of automation city, and power equipment.

3. Formation characteristics

   (a) compressive strength (b) hardness and/or abrasiveness,

   (c) state of underground stress (overburden pressure etc),

   (d) elasticity - brittle or plastic, (e) stickiness or balling tendency

   (f) permeability, (g) fluid content and interstitial pressure, (h) porosity;

   (i) temperature.

4. Mechanical factors

   (a) weight on bit (b) rotational speed (c) bit type

5. Mud properties

   (a) specific weight (b) solid content (c) flow properties (d) fluid loss

   (e) oil content (f) surface tension - wettability.

6. Hydraulic factors – essentially bottom hole cleaning.

3. Formation characteristics:

Generally, penetration rate varies inversely with rock compressive strength. The related property of hardness and abrasiveness affects the bit life. Generally, the rock strength increases with depth, mainly because of increasing overburden pressures. The drilling rate is greater in a porous rock than in a dense rock. Porous zones of the same formation usually have lower compressive strength than the less porous section.

The elastic properties of various formations are greatly influenced by the state of stress at which they exist. The drilling rate is greater in formation with high permeability because pressure across rock chip thickness can be equalized more quickly. The degree of equalization of hydrostatic (drilling fluid column) and formation pressures increases with permeability of the rock. Formations containing incompressible fluids have a quicker response to pressure equalization and will usually drill faster than a formation containing no interstitial fluids or having low pore pressure.

Rock failure becomes more plastic as temperature increases. Rock properties completely govern drilling practices in different geologic areas. Hole size, bit type, drilling fluid selection, and general operating procedures are all dictated by the nature of the rocks to be drilled. Consequently, rock properties are of prime importance with operational procedures being secondary.

4. Mechanical factors:

In all cases, penetration rate is governed by the weight on the bit/or rotary speed, which may be applied. Normally, these limits are imposed by crooked hole, equipment and/or hydraulic consideration.

Bit weight and rotational speed are interrelated. An increase in one usually necessitates a reduction in the other to achieve the minimum wear. The rate of penetration increases with increasing mechanical energy level on a bit (or increasing bit weight and rotational speed).

Increase in bit weight and rotational speed accelerate wear of bit and bearing structures. In soft formations, a doubling of either bit weight or rotational speed will double drilling rate if sufficient bit hydraulic horsepower is available. In hard formations, the weight on the bit has to be sufficient to overcome the compressive strength of the rock. Increase in bit weight and rotational speed will increase the rate of penetration. After the rock compressive strength is exceeded, increasing bit weight by a factor of two doubles or more than doubles the penetration rate.

(a) Bit weight: Research has proved that penetration rate and footage increase when sufficient bit weight is applied to overcome the rock compressive strength. This is expressed in the relationship:

$$R_p = a + bW$$

where Rp is the penetration rate, ft/hr; W is the weight on bit, Ib; a, b = intercept and slope respectively which are dependent on rock properties (bit size and type, drilling fluid properties etc).

This relationship is true if other factors are constant over reasonable ranges of bit loading. It is important that adequate cleaning and cutting removal must be maintained.

(b) Rotational Speed: Most authors have not proved conclusively the dependence of penetration rate on rotational speed. There is no doubt that drilling rate will increase with increase in rotational speed up to a limit. The bit penetration rate is the product of bottom hole sinking length per single revolution multiplied by the total number of revolutions per unit time. The penetration rate does not only depend on rotational speed but also on greater contact. The relationship is:

$$Rp = f(N)^n$$

where f is function; N is the rotary speed, rpm; $n \leq 1$.

Critical rotational speed can be calculated using empirical formula:

$$Nc = \frac{258,000}{L}$$

where Nc is the critical rotational speed at which vibratory effects are maximum, rpm; L is the length of drill string, ft.

Combined Effect of W and N: There are empirical equations relating Rp to bit weight and rotational speed, N

$$Rp = e + fWN^{1/2}$$

where e, f are constants for a given set of conditions.

There must be a balance between the rotational speed and the desired penetration rate when N is too high, the duration of contact between the bit to and the rock gets shorter. A minimum period of time is necessary for removing the broken rock. If N is too high then there will not be sufficient time for cleaning of borehole. When N is too high, intensive wear of roller cutter teeth occurs and consequently the contact pressure of the teeth on the rock decreases. Excess speed causes excess vibration and this can lead to breakdown.

(c) Bit Type: The best bit is that which when utilized with the proper weight, rotational speed, hydraulics, and drilling fluid properties, will achieve the lowest cost per foot of hole drilled. Drilling personnel who are involved in bit selection

should have knowledge of the various basic designs and criteria that differentiate soft formation bit types from hard formation bit types.
Various factors affect bit performance, such as tools geometry (tooth types, wedge angle, spacing, row to row pattern etc), cone offset, number of cones, bearing designs, metallurgical control etc.

5. Mud Properties:

(a) Specific Weight: High specific weight of drilling fluid causes high differential pressure between the hydrostatic pressure and the formation pressure. Overbalance pressure reduces penetration rate. Laboratory and field observations have indicated that penetration rate increases with decreasing difference between drilling fluid column pressure and formation pressure. Rapid removal of cutting from below the bit, which is dependent on specific weight, allows each successive tooth impact to attack rock and this leads to faster drilling.

(b) Solid content: Solids content is related to fluid specific weight and viscosity. Very fine or sub-micron bentonite particles have more detrimental effect on penetration rate than larger particles. It is believed that these small particles plug the minute fractures that are formed by the bit tooth impact. The plugging action delays pressure equalization over the chip thickness, delays chips removal and thereby decreases penetration rate. Perhaps the solid particles cushion the bit tooth rock contact such that a clean, sharp impact is not obtained. It is the opinion of many experts that the percentage of solids in muds exerts a separate and distinct effect on drilling rate.

(c) Flow Properties: The same pumps are normally used for drilling the entire hole. This means that the available hydraulic horsepower must be essentially constant. An increase in yield point and viscosity increases system frictional losses thereby reducing the pressure drop (and velocity), which can be applied across the bit. Chip clearance time is increased and penetration rate decreased.

(d) Filtration: Water may readily enter a permeable rock ahead of the bit so that no pressure differential exists across the thin element being drilled. Low water loss mud's, however, almost instantaneously deposit a tough low permeability filter cake on the whole bottom allowing a definite pressure differential to exist. Low fluid loss desirable from formation damage point of view is undesirable from the standpoint of penetration rate.

Penetration rate is also a function of wettability of rocks as affected by filtrates, due to the presence of surfactants (surface active agents). There are certain electrolytes and surfactants that reduce rock hardness with a resultant 30-60% increase in drilling rate. Increased rock wettability to the filtrate allows the filtrate to fill the micro cracks created by the bit more rapidly and, thus, prevents their healing and increases the penetration rate.

(e) Oil Content: In some formations, penetration rate can be increased by the addition of oil to the water base muds. Oil concentration of 10-15% in drilling fluid help prevent bit balling by hydra table clays and shales in some formations. The oil also lubricated the bottom hole assembly, reduced hole wall friction, and increases effective weight on the bit. Increased bit life means that less non-productive rig time is expended in making trips; thus the over-all penetration rate is increased.

(f) Surface Tension: Russian authors have reported that certain electrolytes and surface active agents act as rock hardness reducers with 30-60% increase in drilling rate being obtained by their proper use. Presumably, these materials act to produce more complete wetting of the rock by the fluid.

6. Hydraulic Factors

Instantaneous and complete removal of cutting is desirable but difficult to achieve but proper application of available hydraulic energy can minimize regrinding and increase penetration rate. Extensive studies of the effects of hydraulic factors have arrived at the following conclusions:

(a) rate of penetration is directly proportional to nozzle velocity (at constant circulation rate);

(b) rate of penetration is directly proportional to circulation volume (at constant nozzle velocity).

The direct proportionalities is as a result of increases in the allowable weight on the bit resulting from better hole cleaning at the higher volumes and velocities. It should be noted that these results applied to soft rocks and drag-type bits. In soft and medium rocks, increases in penetration rate have generally resulted from increased hydraulic horsepower.

In hard rock drilling, the maximum bit weights applied are dependent on equipment considerations rather than on bit balling. Consequently, it appears that increase in nozzle velocity aids drilling rate by minimizing regrinding, with this effect disappearing as soon as no appreciable regrinding occurs. Nozzle velocities above maximum effective value will result in no further increase in penetration rate.

Table 1: Some Mud Additives and Their Uses

S/No	Mud additives	Uses
1.	Organic polymer	To prevent flocculation
2.	Pre-gelatine starch	To reduce filtration properties in salt saturated mud's
3.	Caustic soda	For raising pH
4.	Biocides or modified polysaccharides with fermentation preventives	To avoid bacterial degradation of fluid
5.	Various cellulose preparations	To increase viscosity
6.	Gaur-gum products	To improve suspension and sealing properties
7.	Acrylic polymer (chemical stabilizer compound	To reduce filtration or increase viscosity
8.	Thinners	To reduce viscosity and gel development while not affecting fluid density
9.	Barite	To increase fluid density
10.	Lime	To develop stiff gel for stabilizing loose sand and gravel in borehole
11.	Soda ash	To reduce hardness of water for drilling and to prevent flocculation of bentonite
12.	Surfactants	For cleaning drill bits
13.	Lignosulphonate	To bring down viscosity
14.	Carbomethyl cellulose (CMC)	To control fluid loss and to give colloidal protection

pH Control Additives

Caustic soda, ($NaOH$) is the major additive to keep the pH of the mud high. This is desirable to prevent corrosion and hydrogen embrittlement. The pH of most mud lies between 8.5 and 10.5. Caustic potash (KOH) and lime, $Ca(OH)_2$, may also be used.

Adverse Conditions Affecting Drilling Fluids

Drilling fluid changes during the course of drilling a well as a result of conditions encountered. The drilling fluid is contaminated when drilling through salt domes (NaCl) anhydrite, or gypsum. Drilling weight and viscosity increases as a result of fine solids picked up during drilling.

Salt contaminating occurs as a result of encountered soluble salts: Nacl, KCl, calcium sulphate ($CaSo_4$), and magnesium chloride ($MgCl_2$). This contamination causes increase in viscosity, yield point, gel strength and filtrate loss.

Evaporate formation also supply sodium chloride to drilling fluids. Water base drilling fluids quickly dissolve salt from the formation, resulting in washed out holes. Salt domes causes contamination. Contamination of cement - squeeze cementing, drilling out cement during plug, and running casing. Effect similar to NaCl, KCl - leads to generation of Ca^{++} which affects the clay particles. Introduction of additional hydroxyl ions raises pH of the drilling fluid.

It is essential to test drilling fluid at specified intervals so as to determine changes in drilling fluid composition - type and degree of contamination. Prevention is by using more inert saline and polyvalent drill fluids.

Treatment of monovalent contamination is by:

(1) dilution with fresh water;

(2) addition of chemical thinners, and

(3) conversion to salt-water muds.

Drilling Problems

Drilling problem refers to those well drilling conditions under which normal sinking procedures are impossible. These problems do not include drilling bit failures, failures of drill pipes and troubles with surface equipment.

The following problems are often encountered:

(1) lost circulation (2) sloughing and caving shales

(3) borehole restrictions (4) sticking of drill pipe

(5) oil, gas and water inflows (6) blow out

Eliminating well accidents requires time, materials, labour and equipment all of which increase the cost of drilling. For this reason, the study of the causes of drilling problems and their effective prevention and elimination is one of the priorities of drilling organization and research institutes. These problems can be avoided by (a) proper selection of drilling fluid types, and (b) condition of these fluids in order to maintain good operating properties.

1. Lost circulation

In lost circulation, there is loss of whole fluid into formation. This loss of drilling fluid is classified as lost circulation or lost returns and differs from filter loss in that total drilling fluid or the greater part of it enters the formation. Lost circulation occurs only when the drilling mud column pressure exceeds that of the formation fluid and when the formation permeability is sufficient. Lost circulation may also result from hydraulic fracturing of the formation i.e. it may take place in incompetent formations in which fractures are induced by the hydrostatic pressure of the weighted drilling fluid column.

Lost circulation problems are usually in formations naturally capable of taking drilling fluid because of intrinsic fractures, channels etc. Tissues and fractures are widespread in the crust of the earth, crustal movements produce tension fractures, shearing fractures and compressions. Lost circulation most difficult to eliminate occurs in penetrating badly tissue limestone, dolomites and carbonate rocks.

Lost circulation has the following undesirable effects:

(a) Increase in mud cost because of low returns;

(b) Possibility of blowout due to drop in annular mud level;

(c) No information on the formation being drilled is available since no cuttings are obtained.

Lost circulation that has begun can be eliminated in two ways: First, by reducing the density of the drilling mud i.e by decreasing the drilling mud column pressure. Secondly by artificially decreasing the permeability of the surrounding formation to binder or prevent the penetration of drilling mud into the formation. The first method is used in areas where wells are drilled with clay muds of varying density, the other in areas where wells are drilled with process water. The surrounding formation permeability is reduced by adding inert fillers to the drilling fluid, which penetrate the fissures, and channels, seal them and stop the loss of the hole fluid into the formational voids. Also plugging-back mixtures are pumped into the flow channels of the drilling mud. The method chosen to eliminate lost circulation depends upon the loss rate which is usually evaluated as the amount of drilling mud (m^3) lost into the surrounding formation per hour.

Loss rate: low up to 10-15 m^3/hr; medium up to 40-60m^3/hr; high up to 60m^3/hr.

Low rate lost circulation are eliminated by changing the drilling mud with filling materials such as mice flakes, fine rubber crumbs (1-5) in particle size) aqueous dispersion rubber etc.

Lost returns of medium rate are remedied by forcing quick setting mixtures with filling materials into the affected formation. Mixtures of two cements differing in mineral and chemical composition e.g. oil well cement, alumina cement and Portland cement.

Lost returns of high rate are eliminated by pumping of plug of fillers into the formation with subsequent squeezing of the surrounding formation with cement paste.

Soft plug - mixing clay mud or thick emulsion fluid (90-94% water, 5-9%) diesel oil, 1% emulsifier) with a large volume of filler as possible.

2. Sloughing and Caving

Sloughing and caving in trouble zones occur due to loses of formation small litter stability under the effects of various factors. Holes do not stand up commonly during drilling-in operation in formation crunched by tectonic faults etc. Penetrating such formation through fissures, cracks and channels, the filtrate of drilling fluid weakens the bonds between rock particles and aggregates which then cave into the borehole.

Sloughing occurs in boreholes drilled in sheet clays and other thin-bed fissured formation. Sloughing troubles occur in the same way as do caving in boreholes. Symptons of sloughing and caving in intervals in the borehole are an increased amount of rock fragments lifted by the drilling muds and increase in the drilling mud viscosity; an increase in the mud pump discharge, an increase hook load in pulling the drill pipe string, and bridges in the borehole formed by sloughing and caving which must be drilled out before a new bit can reach the bottom hole face. All clay rocks, argillaceous shale’s included have the tendency to slough.

3. Borehole restriction

Restrictions occur in boreholes because of the flow of plastic formation (salts and clays) under the formation pressure and also due to swelling caused by drilling mud filtrate and thick filter cakes. Restrictions are indicated by an increase in the mud pump discharge pressure while loose filter cakes may cause bridges in the annular space with resistant circulation failure, which can lead to other drilling complications. The prevention of hole restriction is underlain by the use of a drilling mud of proper density and low filter loss accompanied by its enhanced delivery to the borehole. Widening the borehole to normal size eliminates restrictions.

4. Sticking of drill pipe

When the drill collar becomes embedded and stuck in the filter cake you have differential pipe sticking. When filter cake is present, sticking takes place and the pipe becomes motionless. The degree of sticking will depend on the thickness of the filter cake. To avoid sticking, a drilling fluid with low fluid loss (high T & P) and low coefficient of friction (between the pipe and filter cake) should be used. Additives like asphalt, graphite detergents improve the lubrication characteristics of drilling fluid.

5. Gas, Oil and Water in flows

Formation fluid inflows are usually uncontrolled and not only results in gas, oil and energy losses but also cause environmental pollution. Formation oil, gas and water inflows affect the drilling mud properties (density, viscosity, gel strength etc). As a result, the inflow of formation fluids and gas may rise to a dangerous level. One should try to prevent its occurrence. The foremost cause of formation fluid inflow is a well pressure drop below the formation pressure. A drop in drilling mud density and or a mud level drop, which may occur if circulation is lost or the drilling string is lifted without first adding mud, may cause this. In order to prevent gas, oil and water inflows, the drilling mud density should not be allowed to drop below the value specified by the well programme. Measures should be taken during drilling to prevent lost circulation and with drop of the drilling mud level.

6. Blow out

Blowout is accidental escape of oil, gas and water from a well during drilling. Blowout takes place as a result of greater formation pressure than the mud column pressure and this allows the formation fluids to blow out of the hole. When this happens there is danger of explosion and fire. To prevent this blowout preventer is mounted at the wellhead to control the flow from the drill pipe and casing. Proper choice of mud density is essential for prevention of this problem. Low mud pressure is usually caused by too rapid withdrawal of the drill string especially in areas where a very delicate overbalance of formation pressure is necessary.

Blowout Preventer (BOP) stacks are available in various types depending on the number of discharges or the stacks - two, triple, four. Pressures 125 MPa - 50 MPa.

By the aid of Blowout Preventers well pressures are curtailed. The pressure containment equipment prevents uncontrolled discharge of drilling fluids from the hole. When there is a normal or uncontrolled well bore pressures, the BOP stack provides the drillers time for evacuation of personnel and facilities so that corrective action can be taken. The BOP stack also controls the pressures while new drilling fluids are circulated through the well.

WELL COMPLETIONS

Well completion is an important stage of well drilling. Well completion might be said to include drilling-in, well casing and cementing, perforating to gain access to the producing horizon, testing the well for production and finally putting it on stream. Even though all the above can be counted as part of well completion, gaining access to the producing zone is basically referred to as well completion. The basic objective of well completion is to induce the inflow of fluid or gas from the formation into the borehole at a daily rate, which is close to the potential production rate. For fluid to flow from the reservoir into the well, the reservoir pressure, Pr, must be greater than the bottom hole pressure, P_b.

$$P_r > P_b + P_{ad}$$

where P_{ad} is the additional pressure differential needed to overcome the hydraulic resistance which arises in perforation and in filtration channels as the result of the pore space clogging in the bottom hole for a well with fluid height, H, and density, ρ.

For flow. $P_r > Hpg + P_{ad}$

To ensure this equation, H, or P_{ad} needs to be varied, usually P_b is varied by varying density.

Types of Well completion

1. Open hole completion 2. Conventional perforated completions

3. Sand exclusion completion 4. Permanent completion

1. Open Hole Completion

This type of completion refers to cases when the oil string is set on top of pay zone. This method can be used in highly competent formation, which will not slough or cave. It is common in low-pressure limestone areas.

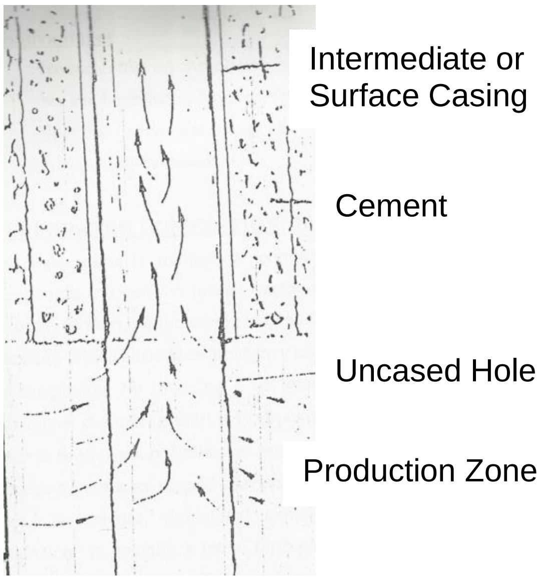


Figure 16: Open Hole Completion

2. Conventional Perforated Completion

The use is restricted to wells in which the oil sting is set through the pay section, cemented and subsequently perforated at the desired interval. This type of completion is very common and feasible in all formation except those in which sand exclusion is a problem. The perforating process is an important factor. Two basic methods are used for perforating the well walls.

(A) Bullet perforating: This is a bullet perforator consisting of multi-barreled firearm which is lowered into a well at a desired level and electrically fired from surface controls.

Penetration of the casing, cement and formation is accomplished by high velocity bullets. It is possible to use single or multiple bullet system.

(B) Jet Perforating: This is achieved by controlled detonation of explosive. Penetration is obtained through the aid of jet's stream of high velocity developed after detonation. The velocity and pressure can be 30,000ft/sec and 3000-5000 MPa respectively.

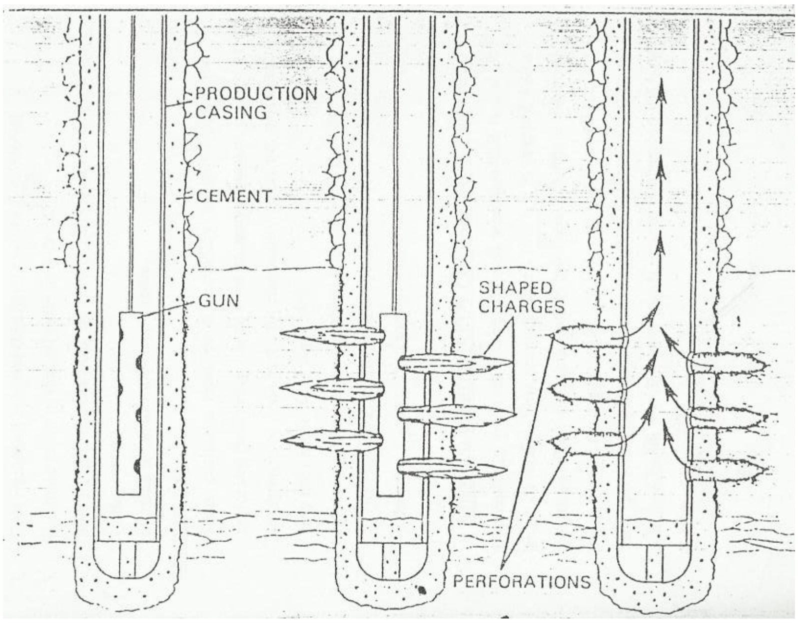


Figure 17: Perforated Completion

Comparison of Bullet and Jet methods

Argument exists about which technique should be used. The generally accepted characteristics of both types are summarized as follows:

(a) Jet

1. Deeper penetration in hard rocks and multiple casing strings.
2. Minimum barring of casing wall.
3. Minimum cement shattering.
4. High temperature range.
5. Available in permanent type completion.

(b) Bullet

1. Equal to superior penetration in soft to medium rock.
2. Maximum fracturing of cement and soft rocks.

3. Completely selective firing available.
4. Controlled penetration by bullet selection where needed.
5. High powered, large, cheaper, diameter gun available if needed.

Accurate depth measurements are essential to any perforating job. The collar and radioactivity log are used to get correct depth.

The main objective of perforated completion is to obtain productivity as near to that of an uncased hole as possible, while still enjoying the advantages of casing. The principal factors to consider are:

(a) perforation diameter (b) perforation density (number or holes per metre, 16-20)

(c) depth of penetration (radial dist).

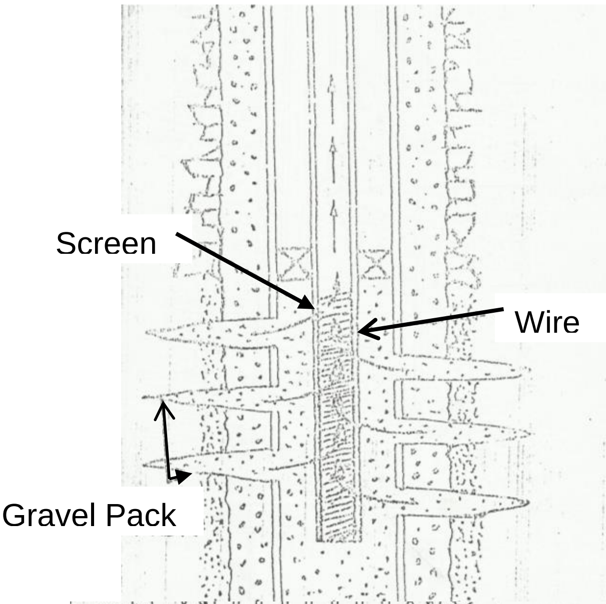
Open hole Vs Perforated completion

The open hole method is initially cheaper, since perforating costs are eliminated. Contamination by cement is or can be avoided. But perforated completion offers a much higher degree of control over the pay section - interval can be perforated and tested as desired. Hydraulic fracturing is more successful in perforated completion. Productivity ratios of perforated wells were about 50% higher than those of similar open hole completions. Perforated completion preferable in low pressure or thin water drives pay areas.

3. Sand Exclusion Completion

The basic difference with other types of well completion method is that sand must be excluded from the produced oil. Sand production, if unchecked, can cause corrosion of equipment and well bore; and flow string plugging to the extent that well operation becomes uneconomical. Sand production is sensitive to the rate of fluid production. At very low rates, little or no sand may be produced, while at high rates large quantities will be carried along in the production stream. Screening is the most common method used for excluding sand. These techniques include (a) Use of slotted or screen line (b) Packing of the hole with aggregates such as gravel.

The basic requirement of these methods is that the openings through which the produced fluids flow must be of proper size to cause the formation sand to form a stable bridge and thereby excluded. Hence, the size of sand must be known, this can be obtained from special barrels. The maximum opening size which will exclude given sand is determined from screen analysis. It is extremely important that the sand face be free of mud cake before the liner is set, to prevent plugging. Either using clay-free completion fluids or washing the well with salt water before hanging the liner commonly accomplishes this.



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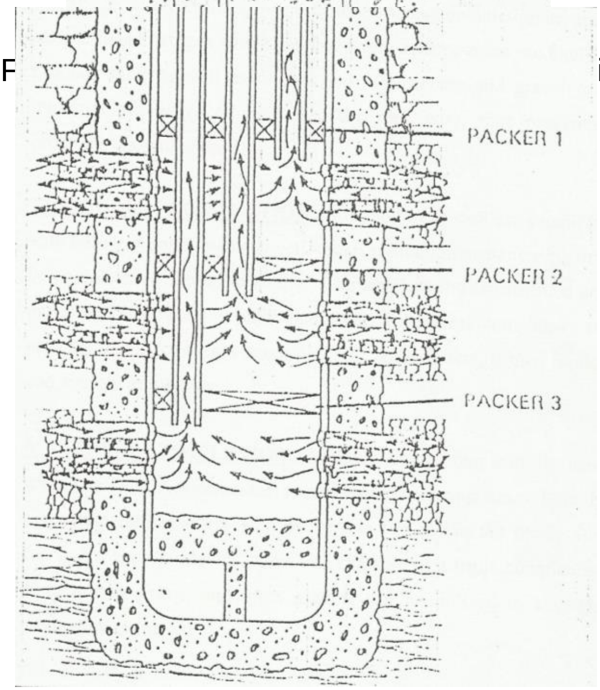

Figure 19: Multiple Completion

4. Permanent Completion

A permanent type completion is one in which the tubing is run and the wellhead is assembled only once in the life of the well. Perforating, squeeze cementing, gravel packing or other completion or remedial work is performed with special, small diameter tools capable of being run inside the tubing. This method is economical and at times saving up to 75% is achieved.

Coring and Core Analysis

Analyses of rock samples yield data basic to the evaluation of the productive potential of a hydrocarbon reservoir. Due of the size of rock cuttings, only qualitative information is obtained from them. Coring techniques enable us to obtain large reservoir rock samples from the bottom during drilling or from the sides of the bore hole after drilling for use for both qualitative and quantitative analyses.

General Coring Methods and Equipment

Two basic methods are used: (a) Bottom coring - coring at the time of drilling (b) Side wall coring - coring after drilling.

Bottom Coring

All bottom-coring methods utilize some type of open center bit, which cuts as doughnuts shaped hole leaving a cylindrical plug or core in the center. As drilling progresses, this central plug rises inside a hollow tube or core barrel above the bit where it is captured and subsequently raised to the surface.

Bottom coring can be classified according to the type of equipment used:

1. Conventional coring

(a) conventional core head (other than diamond)

(b) diamond core head

2. Wireline Retrievable Coring

Conventional coring equipment requires that the entire drill string be pulled to retrieve the core. This disadvantage is compensated with the advantage that large cores, 3 - 5 ins diameter and 30-55 ft long may be obtained. The 3½ ins diameter core is probably the most common. There are different types of core barrels in use from different manufacturers. The core barrels used with diamond heads are generally longer than those used with conventional hands 55 ft as compared with 30 ft.

Diamond bits cost much more but will drill more total footage and when worn out may be returned to their supplier for salvage. The core recovery with diamond heads is generally higher than with conventional heads particularly in hard rock areas. Rate of penetration may, however, be lower in soft formations than that of the rolling cutter heads.

Wireline coring:

It denotes the method whereby the core (and inner barrel) may be retrieved without pulling the drill string. This is accomplished with an overshot run down the drill pipe on a wireline. The diamond heads for this technique have smaller openings but the core barrels used are similar to conventional types. Cores obtained from this method are small: 1⅛ - 1¾ in diameter, L= 10 - 20ft. The main advantage of this method is the saving in trip time. This is beneficial in deep wells.

Sidewall Coring

It is often desirable to obtain core samples from a particular zone or zones already drilled. This is achieved with the aid of a hollow bullet which is fired from the surface electrically from a panel. A flexible steel cable retrieves the bullet and its contained core, (d = ¾ - l in). Sidewall coring is widely applied in soft rock areas where hole conditions are not conducive to drill stem testing. The zones to be sampled are normally selected from electric logs.

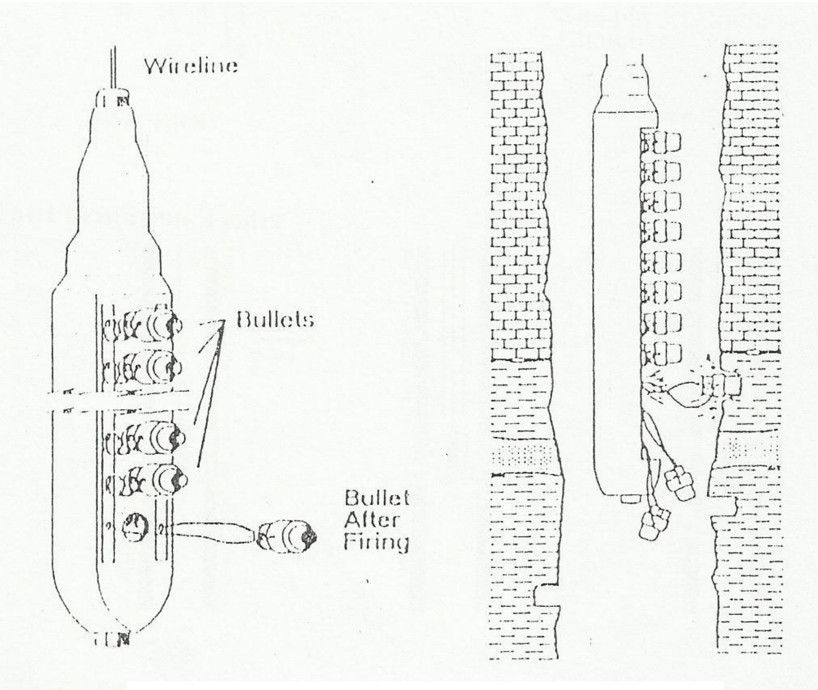

Figure 20: Percussion Sidewall Coring

Handling and Sampling of Core Recovery

Coring is done for quantitative analysis of the physical properties and fluid content of the recovered core. Absolute care is essential to guarantee that the core reaches the laboratory in the best possible condition. The following procedures are recommended for handling and sampling:

(a) Field sampling

1. Field check list - Log sheet to keep records of depths of interval cored, coring time for each foot, lithologic description of the core, sample number and depth, fractures and other notable features of the core, and type and properties of drilling fluid.
2. Removal of core from core barrel and handling prior to preservation. Removal in segments.
3. Wiping clean with dry rags (not washed). Laid on pipe rack and marked from top to bottom measured with a tape.
4. Frequency of sampling - For whole core analysis - All are recovered from any section to be studied and analyzed. For conventional core analysis - one sample per foot is ordinarily taken to define net productive thickness, transitional zones, and contents. For sidewall core analysis, sample frequency is normally beyond the control of the core analysis.

(b) Preservation of core

For fluid content analysis, preservation to guarantee in-situ fluid content is essential during transportation to the laboratory done by freezing with dry ice or plastic bags can be used. Sidewall cores can be stored in bottles.

(c) Core handling in Laboratory

Cores placed in order of depth and sample number if frozen – defreeze - wiped clean and an ultraviolet examination and a vaguely (microscopic) description are made and recorded. A detail notation of fractures and logs is also made at this time.

Routine Core Analysis

Determines (a) Porosity (b) Permeability (c) Fluid saturation

Uses of Core Analysis Data

(a) Determination of type of fluid to be produced oil and or gas;

(b) Rate of production,

(c) Total amount of fluid to be produced.

CALCULATION ON ROUTINE CORE ANALYSIS

Porosity, permeability and level of fluid saturation in the rock samples

Porosity:

$$\text{Porosity, } \phi = \frac{V_b - V_s}{V_b} = \frac{V_p}{V_b} \quad \%$$

where V_b is bulk volume; V_s is solid volume and V_p is pores volume

Porosity by saturation method;

$$V_p = \frac{w_s - w_d}{\rho_L}$$

$$\text{Grain volume, } V_s = \frac{w_d}{\rho_L}$$

where w_s is weight of sample when saturated;

w_d is weight of sample when dried;

ρ_L is density of liquid used for the saturation;

ρ_s is density of solid.

Permeability: by Darcy's equation

$$V = \frac{k \, . \, dp}{\mu \, . \, dl}$$

where V is the apparent flow velocity, μ is the viscosity, k is the permeability and

$\frac{dp}{dl}$ is the pressure gradient in the direction of flow

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

where k is the permeability, q is the discharge (cm^3/sec), A is the crossectional area,

μ is the viscosity, L is the length and ΔP is pressure differential.

Fluid Saturation:

$$S_w = \frac{V_w}{V_p}; \quad S_o = \frac{V_o}{V_p}; \quad S_g = \frac{V_g}{V_p}$$

$$V_p = V_w + V_o + V_g$$

S_o, S_w, S_g are oil, water and gas saturation respectively.

V_o, V_w, V_g are oil, water and gas volume in the rock respectively.

Example

Given the following data on a core sample, compute the porosity and oil, water and gas saturation:

Sample weight as received from field = 53.50 gm (W_b)

Water volume recovered during extraction = 1.50 cm^3 (V_w)

Sample weight after extraction and drying = 51.05 gm (W_d)

Density of core oil = 0.85 gm/cm^3 (ρ_o)

Bulk volume of sample = 23.60 cm^3 (V_b)

Grain density of sample = 2.63 gm/cm^3 (ρ_s)

Solution

(i) Porosity, $\phi = \frac{V_b - V_s}{V_b} = \frac{V_p}{V_b}$ %

but $V_s = \frac{w_d}{\rho_L} = \frac{51.05}{2.63} = 19.4 \text{ cm}^3$

$$\phi = \frac{23.60 - 19.4}{23.60} = \frac{4.2}{23.60} = 0.178 \text{ or } 17.8\%$$

$$S_w = \frac{V_w}{V_p}$$

but $V_p = V_b - V_s = 23.60 - 19.4 = 4.2 \text{ cm}^3$

$$S_w = \frac{V_w}{V_p} = \frac{1.50}{4.2} = 0.357 \text{ or } 35.7\%$$

$$S_o = \frac{V_o}{V_p}$$

but $V_o = \frac{W_o}{\rho_o}$

note $W_b = W_d + W_w + W_o$

$W_o = W_b - W_d - W_w$

$W_w = \rho_w V_w = 1 \text{x } 1.5 = 1.5 \text{ gm}$

therefore $W_o = 53.50 - 51.05 - 1.50 = 0.95 \text{ gm}$

$$V_o = \frac{W_o}{\rho_o} = \frac{0.95}{0.85} = 1.12 \text{ cm}^3$$

$$S_o = \frac{V_o}{V_p} = \frac{1.12}{4.2} = 0.267 \text{ or } 26.7\%$$

$S_g = 1 - S_w - S_o$ note $1 = S_g + S_w + S_o$

$= 1 – 0.357 – 0.267$

$= 0.37$ or 37%

Formation Damage

Permeability alteration occurs around the well bore as a result of drilling and completion operations. This alteration that is unfavorable makes the permeability of the altered zone to be less than that of the virgin reservoir rock. This alteration is called formation damage and this has a considerable effect on the productivity of a well.

Formation damage is caused by the invasion of foreign fluids and/or solids into the exposed section adjacent to the well bore. Generally, the drilling mud is the main source of such contaminants. One of the functions of a drilling mud is the control of encountered subsurface pressures. In carrying out this function the mud column pressure must exceed that of the formation. In doing this, drilling mud is filtered into the formation in accordance with the filtration characteristics of the mud in use.

Causes:

(i) Liquid Invasion

The susceptibility of a particular formation to damage by foreign fluids is largely dependent on its clay content. Dirty sands (those with high clay content) are generally quite sensitive to the filtrate from fresh water base mud which brings about the hydration and swelling of interstitial clay particles. Saline filtrates cause less of this kind of trouble and may in fact reduce particle size and increase oil permeability in some cases.

Fluid invasion can also have the following effects:

1. emulsification with formation fluids, resulting in highly viscous mixtures and capillary blocking by insular bubbles (the latter is commonly called

the Jamin effect).

2. precipitation of solids insoluble salts and asphatic or wax particles.
3. reduction of relative permeability to gas by the presence of a third immiscible fluid.
4. reduction of relative permeability to oil due to an increased irreducible water saturation. This is a common, auxiliary consequence of clay swelling and results from pore size reduction.

There is no uniformity in the effects, which a particular fluid has on a specific formation. Each case is somewhat unique from a formation damage standpoint, the best damage prevention rule is to use drilling and completion fluids as much like the formation fluids as possible. In general, it is best to use lease crude oil, other oils, salt water, and finally fresh water in that order. The use of gas or aerated liquid mud often alleviates the problem in those areas where their usage is feasible.

(ii) Solid Invasion

The invasion of solid particles may be a considerable source of formation damage. For solids to enter into a rock the solid particles must naturally be smaller than the pore openings. An extreme case of whole mud invasion is the loss circulation. Permeability decreases as a result of solid invasion are due to:

1. Plugging of internal pores by solid particles and
2. reduction of effect pore radius with consequent increase in interstitial water content and reduction in effective permeability to oil or gas.

The depth of invasion is less than that of the filtrate up to 12in. The severity of damage decreases with distance from the well bore.

Methods for appraising and preventing formation damage

Damage effects	**Practical preventive measures**
1. Foreign fluid invasion	
(a) Clay swelling.	Use of additives which will reduce filtration losses
(b) Emulsification.	Reduce pressure differential against formation to lowest safe value.
(c) Precipitation of solids.	Air and / or gas drilling may eliminate the problem in areas where applicable.
(d) Rock alteration movement	Use of fluids which are compatible with

of interstitial fluids.	formation and its contents, if possible, i.e lease crude, formation water, saline or oil base muds.
(e) reduction in relative permeability due to introduction of third phase.	Minimize exposure fume as much as possible.
2. Foreign solid invasion	
(a) Size reduction or plugging of internal pores by intruding solids	Addition of properly sized colloidal solids which rapidly form an efficient bridge
(b) Increased interstitial water content and consequently reduction in oil or gas permeability	Also items (1b, c, e) above

Practically speaking, the cost of the preventive measures should not exceed the benefits obtained. Some formation damage will almost always occur during well completion, regardless of the preventive measures applied.

Oil Well Casing

To preclude the rock forming the well walls from caving in, a casing (string) consisting of metal case pipes with threaded joints or pipes welded together, is lowered into the borehole. As the borehole is sunk deeper, the casing is moved nearer to the bottom hole and is lengthened (built up) as required with a ripe added to the casing string at a time. As the casing string becomes longer, its advance towards the bottom hole grows more and more difficult and then comes a time when it becomes impossible to bridge the casing string any further impossible even by using special driving tools. The lowered casing is then left in the borehole, another casing string is put down inside the first one, and the borehole is sunk deeper with a bit of a smaller diameter etc. 3rd casing even smaller diameters. The process continues until the designed depth has been reached. In this way the well diameter grows smaller and smaller as the borehole is sunk deeper.

According to Gatlin, the general functions of casing strings are to:

1. furnish a permanent borehole of precisely known diameter through which subsequent drilling completion, and producing operations may be completion, and producing operations may be conducted;

2. allow segregation of formation behind the pipe, which prevents inter formation flow and permits production from a specific zone; and
3. afford a means of attaching the necessary surface valves and connections to control and handle the produced fluids.

There are four principal types of casing strings, which are classified according to the primary functions of the string and the drilling conditions.

These types are as follows:

1. <u>The conductor casing</u>

It is a surface pipe used to seal off the near surface water, prevent the caving and sloughing of the walls of the hole, and as a conductor and of the drilling/mud through loose unconsolidated shallow layers of soil to the level of the mud rough of the circulation system. This is the first casing pit in the well. It is shortest in length and largest in diameter. L = 4 - 5m, but in certain areas, they are run to L = 40m or more. At offshore wells, they may be run to depths 40 - 75m (below the sea bottom) to isolate the borehole and fix upper loose deposits.

2. <u>The conductor (surface string)</u>

It protects the freshwater sands, preventing their contamination, and provides a means of controlling unstable rocks, varies widely, runs up to 150 - 400m.

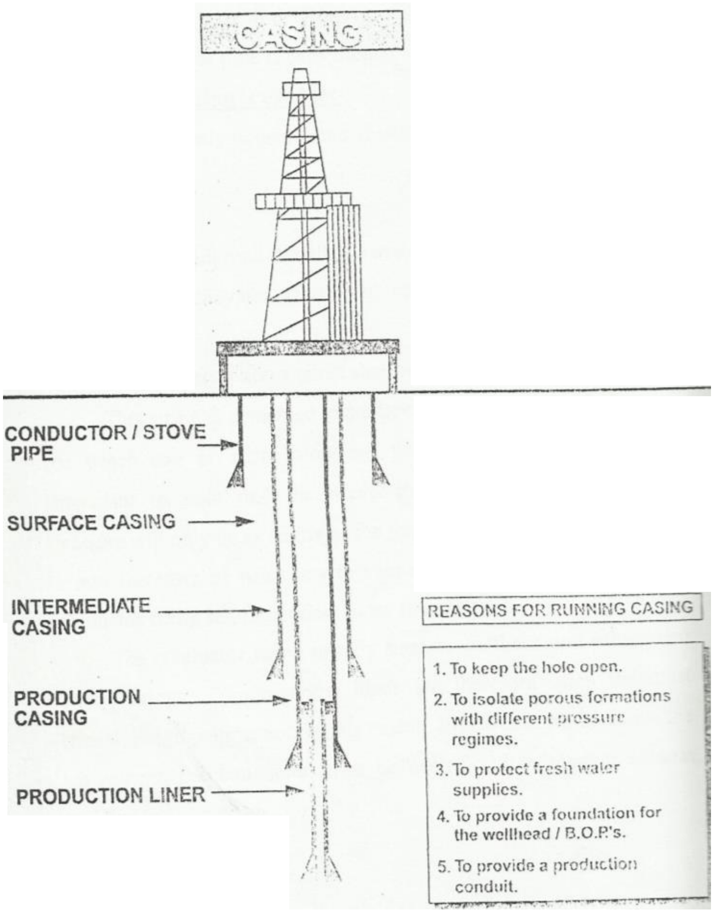

Figure 21: Well Casing

3. Intermediate string - is used for lining the wells and performs the following functions:

(a) isolate lost circulation zones and high-pressure formation areas.

(b) overlap formations having a tendency of caving in and plastic deformations under the overburden rock pressure.

(c) drilling in formations with unequal pressures in which in certain situations some lost circulations occurs within some shale.

(d) drilling in heavy saline deposits where the borehole suffers from caving due to salt dissolution in the drilling mud. A well may contain several intermediate casing. The number used depends on depth and geologic conditions in specific area.

(4) The Production (Oil) Strings

It is the last casing string lowered in a well. It is also the longest and of the smallest diameter casing. It's functions are to set casing just above or through the oil or gas producing zone with subsequent well operation, and to test penetrated formations for oil, gas and water influxes. The setting in of the entire casing strings of different diameters and lengths form the basis of the well program. The term "well" program refers to such data as the bit size and the borehole diameter, number and length of casing string, their strength values, and the annular cement top behind each string.

Strength - Casing is graded on the basis of its minimum individual yield strength. Lengths of casing pipes are usually joined by means of threaded couplings. The mechanical properties should comply with the data in table.

Table 2: Steel Strength Group

Description	S	D	K	E	L	M	R
Ultimate strength MP_a	550	650	700	750	800	900	1100
Yield strength MP_a	320	380	500	550	650	750	950

The casing pipes fabricated of steels, strength groups K, E, L, M and R are subject to thermal treatment at the pipe rolling plant. Each steel casing pipe must contain a stamp stating, the nominal diameter (mm), pipe no, steel strength group, thread length, wall thickness (mm) manufactures trade and year and month of manufacture.

Loading - The casing string is an intricate industrial structure. When it is set in a hole, it is subjected to several significant forces deferring in value and character of load. Casing string is subjected to:

1. Tension loading due to its own weight tends to pull the casing apart, and it lowers its resistance, to external pressure.
2. Axial dynamic loads while the casing string movement is not yet in a steady of state (with acceleration or deceleration).
3. Axial loads because of an excess pressure and temperature in the course of casing string cementing and well operation.
4. Axial loads due to friction of the casing string against the borehole walls during its lowering down.
5. Compression loads caused by part of the string weight when it bear against the bottom-hole face
6. External and internal excess pressure
7. Bending loads arising in crooked holes.

In strength calculations of casing strings, three most essential forces must be taken into account, which result from a longitudinal or axial loading on the casing due to its own weight, and the external and the internal pressure. To compensate for the other loads imposed on the casing string, the axial tension loading is calculated without taking into consideration the weight loss due to buoyancy. In most counties there are casing standards.

Casing is designed taking into consideration economic selection of grades and weights of casing which will withstand without failure the above listed forces to which the casing is subjected. The forces are not uniform throughout the depth of the borehole but vary with depth, combination of grades of casing can be used. This means that expensive grades and weight can be reserved for critical areas of borehole and this will lead to impressive saving on money and material.

Effects of external pressure

When casing is lowered into borehole, the outside pressure may be greater that the inside pressure as result of formation pressure and fluid pressure in between the casing and bore well. When the external pressure is greater than the internal pressure there is tendency for the casing to collapse. If the collapse is preceded by permanent deformation, the casing is said to have experienced plastic failure, but if under elastic deformation, failure is said to be elastic. The ability of casing to withstand external pressure without experiencing plastic or elastic failure is called collapse resistance.

From investigation of past researches, it has been concluded that collapse resistance is determined by

(1) the ratio of pipe diameter to wall thickness,

(2) the characteristics of the material of construction; and

(3) the axial tension or axial compression to which the casing is subjected.

As a result of long time detailed study, API has adopted the following formula for calculation of allowable collapse pressure for failure in the elastic range for (D/t values less than 43.5)

$$Pc = 0.75 \frac{(86670 - 1386)}{D/t}$$

For failure in the plastic range (for D/t values greater than 43.5)

$$Pc = 0.75 \frac{(50,210,000)}{(D/t)^3}$$

for grades H-40, J 55, M 80 and P-110, for failure in the plastic range and for D/t of 14

$$Pc = 0.75 \times 2Ya \frac{(D/t - 1)}{(D/t)^2}$$

for failure in the plastic range and for D/t = 14 and to the point at which the curve for elastic failure intersect the elastic curve

$$Pc = 0.75 \times Ya \left\{ \frac{2.503}{(D/t)} - 0.046 \right\}$$

for failure in the elastic range

$$Pc = 0.75 \left\{ \frac{62.6 \times 10^6}{(D/t) \left\{ (d/t)-1^2 \right\}} \right\}$$

In all the above equations

Pc = minimum collapse pressure, ib/in^2

D = nominal outside diameter, in

T = nominal wall thickness in average yield stress, in

Table 3: API Casing

Grade	Minimum Yield Strength (psi)	Maximum Yield Strength (psi)	Minimum Tensile Strength (psi)
H40	40,000	80,000	60,000
J55	55,000	80,000	70-95,000
K55	55,000	80,000	70-95,000
N80	80,000	110,000	100,000
L80	80,000	95,000	100,000
C90	90,000	105,000	100,000
C95	95,000	110,000	105,000
P110	110,000	140,000	125,000
Q125	125,000	150,000	135,000

Effects of Internal Pressure

During the entry of formation fluid into casing, casing is often subjected to high internal pressure. In the lower section of casing string, the external pressure is greater than the internal pressure. In upper portion, external pressure is negligible since formation pressure due to formation fluid is not significant. Any appreciable internal pressure due to flow of fluid or from surface pump will lead to excess internal pressure with resulting tendency for failure - bursting.

Internal yield pressures are calculated for all grades of casing by means of equation.

P_i = $0.875\ (2Y_m t/D)$

P_i = minimum internal yield pressure

Y_m = specified minimum yield strength ib/in^2

T = nominal wall thickness

D = nominal outside diameter

Selection of casing sizes

The controlling factor in the selection of casing size is the outside diameter of the production string. Blum stated the following considerations in the determination of this factor:

1. Drilling cost - As the well diameter increases so will the cost of drilling and completion. The cost of large diameter holes should be balanced against expected economic advantages.
2. Method of production - A well may flow naturally in its early history but later may required pumping. The hole should be large enough to accommodate necessary production requirement.
3. Production rates - Rate is an important factor only where it is high enough to cause appreciable pressure drop in the production tubing.
4. Possibilities of multizone completion - Hole sizes should be large enough to handle equipment for multizone completion, if this is a reasonable possibility.
5. No of intermediate strings - If the expected drilling conditions necessitate one or more intermediate strings, the maximum size of the production string will be limited.
6. Nature of the fluid produced - The factor is important primarily because it affects the choice of production equipment, and in turn, the down-hole equipment and accessories limit the minimum hole size.
7. Rig limitation - Normally, the selection of rig depends on size and depth of the hole to be drilled. There are cases, however, when rig selection is limited in a given area. In those cases, sizes of hole and casing are determined by rig capabilities.
8. Work-over - If experience indicates that remedial work is commonly needed, hole size should be enough to accommodate the necessary equipment.
9. Availability of casing - Shortage of casing has in many instances been the determining factor in establishing production string size.
10. Common practice - Even after careful consideration of the above actors, the experience of others in given areas and situations should be studied before final determination of the casing size.
11. Type of well (exploratory or development) - In an explored well, the prime purpose of drilling is to prove up the existence of commercial zones.

CALCULATION ON CASING

Example

A grade H-40 oil well casing has an internal yield pressure of 7.0 MPa and a nominal wall thickness of 20 mm. If the specified minimum yield strength of the casing is 50 MPa, determine the nominal outside diameter of the casing.

Solution

$P_i = 0.875\ (2\ \gamma_m\ \frac{t}{D})$

$7.0 = 0.875\ (2\ x\ 50\ x\ \frac{0.02}{D})$

D = 0.25 m

Oil Well Cementing

Cementing is the process of filling predesigned interval of the well with a suspension of binding material (cement) that is capable of hardening in the quiescent state to form tough impermeable zone.

The cement used to cement oil wells is not too different from the cement as a component in ordinary concrete. Basically, Portland cement that usually contains special materials to give it the necessary characteristics to make it suitable for cementing a particular well is used. High temperature, which are sometimes found in oil wells, make cement set (harden) faster than normal. Thus, adding retarder (a material that slows down the setting time of cement) makes it possible to successfully cement high temperature wells.

Functions

Cementing is used to:

(1) seal off formation with troublesome zones,

(2) allow deeper drilling and help prevent blowouts,

(3) form cement bridges isolating the bottom part of the borehole say, for drilling a new hole

(4) fix casing and the walls of the borehole;

(5) prevent loss of circulating fluids;

(6) protect the casing pipes against corrosion due to formation fluids and gases;

(7) preserve natural permeabilities and porosities of formation; and

(8) perform other less important functions.

Plugging materials

Plugging materials are hydraulic products i.e. they harden to a gel mass when mixed with water, thus forming hard impermeable stone.

Depending upon the kind of binding materials, plugging materials are classified into:

(1) Portland - cement base plugging material
(2) blast - furnace slag-base plugging material
(3) limestone - base plugging material
(4) other plugging materials (Salite-siliceous and others)

Only the first two plugging materials i.e. the Portland cements base and Slag-base plugging materials are used to cement borehole.

Depending upon their additives, the plugging materials and their slurries are divided into sane fibron, pozzolan, sulfate – resistant expanding, weighted and lightened cements.

Today, the nomenclatures of the Portland cement and slag-base plugging material include:

1. Oil-well Portland cements for cold and hot wells, the former for well temperature of up to 50^oC and the latter for temperature of up to 100^oC. The density of the slurry is 1.88g/cm^3
2. Lightened cements for preparing slurries, have a density 1.4 - 1.6g/cm^3 based on plugging. Portland cements or a slag-sand mixture (90 - 140^0C) the light weight additives being mud powder or milled pumice stone, Tripoli earth and others.
3. Weighted cements for preparing slurries with a density not less than 2.155g/cm^3 based on plugging. Portland cements for temperature corresponding to cold and hot cements and also based on a slag-sand mixture for 90^0 – 140^0C, the weighting additives being magnetite, barite etc.
4. Heat-resistant slag-sand cements for well temperature of 90^0C – 140^oC and 140 – 180^oC low-hygroscopic (usage as scrubbing) plugging cements.

Portland cement is a powder of a definite mineralogical composition. The principal calcareous raw materials blended and used in cement manufacture are: 60-67%Ca0, 17-25%SiO_2, 8% Al_2O_3 and others.

CALCULATION ON CEMENTATION

<u>Example</u>

In a single stage cementing operation, a 273 mm diameter casing string is lowered down the borehole to depth of 2000 m, the borehole diameter is 320 mm, the pipe outside diameter is 273 mm, the pipe inside diameter is 255 mm, the annular cement level is 1500 m, drilling mud density is 1350 kg/m^3, density of cement slurry is 1860 kg/m^3, float collar is set at 20 m height, mixing truck is the 35MN-30 type.

Calculate:

(i) the amount of dry cement to prepare the required amount of cement slurry if water content ratio "m" is 1:2;

(ii) the amount of dry cement needed including cement loss in mixing if factor accounting for cement loss is 1.5;

(iii) the volume of water required to prepare the calculated amount of cement slurry; and

(iv) the number of trucks required for the operation (take k_1 and k_2 as 1.15 and 1.05 respectively.

Solution

Volume of cement, $V_c = \frac{\pi}{4}[k_1(D^2 - d_1^2) + H_c + d_2^2\ h]$

$V_c = 0.785[1.15(0.320^2\text{-}0.273^2)1500 + 0.255^2\text{x}20]$

$V_c = 38.4\ m^3$

(i) The amount of dry cement, $G_c = V_c\, \rho_c \left(\frac{1}{1+m}\right)$

$$G_c = 38.4\ x\ 1.86\left(\frac{1}{1+0.5}\right) = 47.6t$$

(ii) The amount of cement including loss at mixing

$$G_c^1 = k^2\ G_c = 1.05 \text{ x } 47.6 = 50\text{t}$$

(iii) Volume of water required, $V_w = 0.5\ G_c^1 = 0.5 \text{ x } 50 = 25\ m^3$

(iv) No of trucks, $n = \frac{G_c^1}{truck\ capacity} = \frac{50}{30} = 1.6 \cong 2\ trucks$

DIRECTIONAL DRILLING

Directional drilling is defined by the API as the art science and technology involving the intentional deflection of a wellbore in a specific direction in order to reach a predetermined objective below the surface of the earth.

Usually, oil well drilling crew tries to drill the hole as straight as possible. However, at times it is desirable to deflect the hole from vertical and drill on a slant. Perhaps the most dramatic example of slant or directional drilling is on drilling platform. There a platform is erected over the drilling site, and several wells are drilled from this single platform without having to move it. Only the first hole drilled into the reservoir may be vertical, every subsequent well may be drilled vertically to a certain depth, then kicked off (deflected) directionally so that the bottom of the hole ends up perhaps hundreds of meters away from its starting point on the surface.

Directional drilling involves the use of some rather interesting downhole tools and techniques. For example, some means of kicking the hole off vertical must be used. This might be accomplished with a “bent sub” and a “downhole motor”. A “sub” (short for substitute) is a special device that is threaded so that it can be attached to or made up in the drill string. A “bend sub” is simply a short piece of pipe threaded on both ends that has a bend in the middle. The “bend” has an angle of from 1-3 degrees. A “downhole motor” is a tool shaped like a piece of pipe that has turbine blades (a turbine is like a series of electric fan blades stacked on top of each other on a shaft) or it can be multicurve steel shaft that turns inside an elliptically shaped opening in a housing. In practice, the bit is made up in the bottom of the “downhole motor” and the “bent sub” on the top. This assembly is tripped into the hole as usual.
When the tool reaches bottom, it must be oriented (pointed in the direction necessary to get the hole to go in the desired direction). To orient the tool, various types of compasses or directional gyroscopes, coupled with photographic or electronic readout devices, are employed. Once the tool is oriented, drilling begins. However, the drilling string is not rotated. Instead, drilling mud flowing through the directional motor causes the turbine blades to turn, or the multicurve shaft to turn, which causes the bit to rotate. Because of the “bent sub”, the hole starts off at an angle, a relatively small angle (1-3 degrees) at first but the angle is increased as drilling progresses up to almost 90 degrees from vertical if necessary. Periodically, the hole is surveyed, that is, using the compass or an electronic readout device, its direction and angle of deflection are checked. The angle and direction of the hole are carefully maintained until total depth is reached and the pay zone is penetrated.

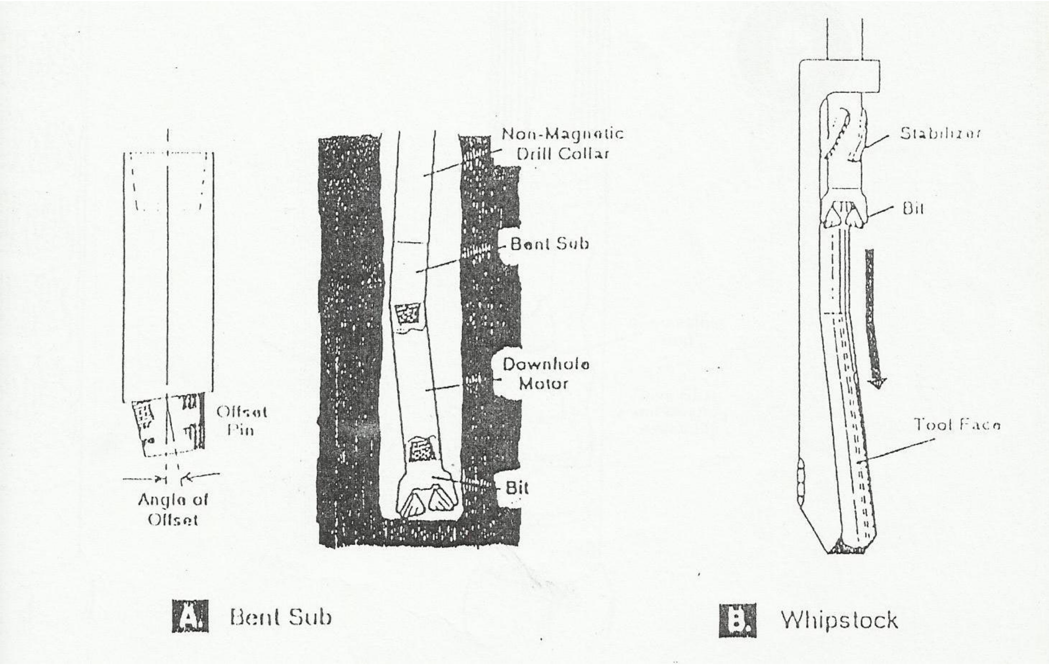

Figure 22: Kick-off Tools for Hole Deviation

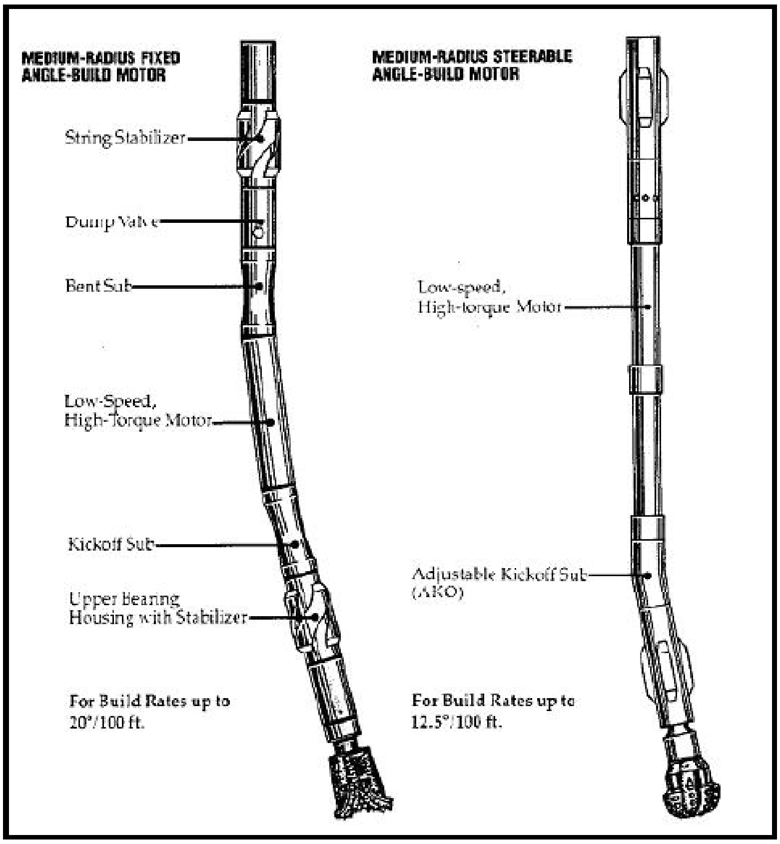

Figure 23: Downhole Motor Configuration for Directional

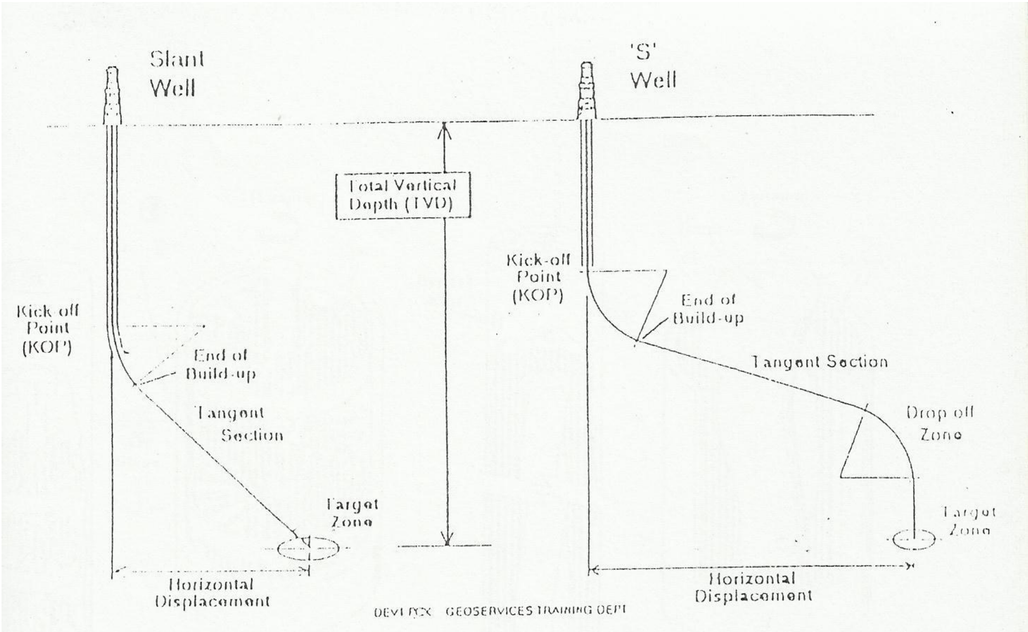

Figure 24: Nomenclatures for Directional Wellbores

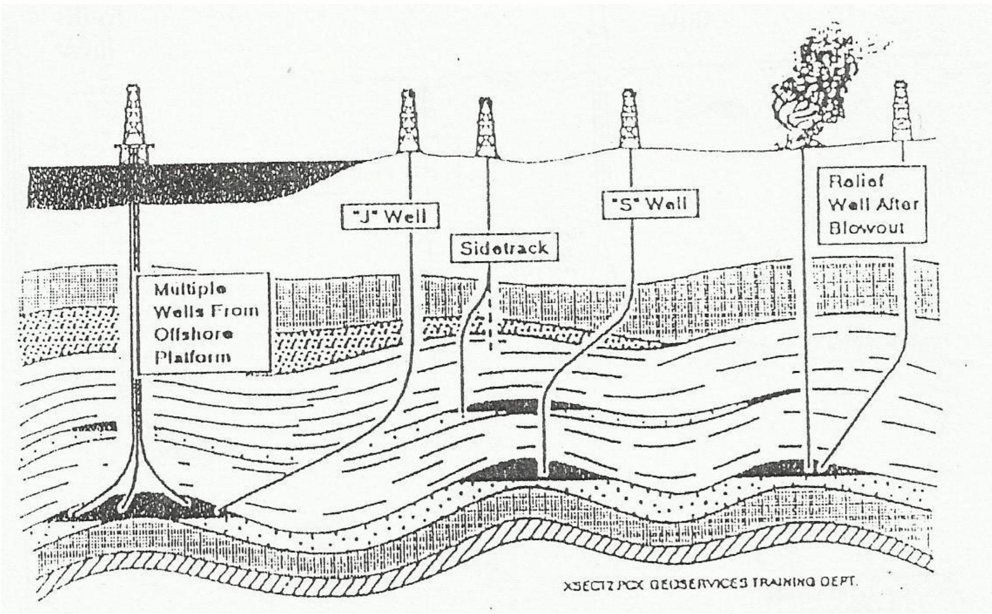

Figure 25: Types of Directional Wells

Types of Directional Wells

There are four basic types of directional wells. Most wells can be categorized by one of the four basic types or a combination thereof.

Type I well (Figure 26) is often called a build and hold. The Type 1 well is drilled vertically from the surface to kickoff point at a relatively shallow depth. At that point, the well is steadily and smoothly deflected until a maximum angle and the desired direction are achieved. Then, casing is run and cemented if desired. The established angle and direction are maintained while drilling to the target depth. One or more strings of casing can be run if necessary. Usually this method is employed when drilling shallow wells with single producing zones.

Type II well (Figure 27) is often called an “S” curve. It is similar to the Type I because the well is deflected at a relatively shallow depth, and surface casing is frequently (but not always) run through the build curve. The angle and direction are maintained until a specified depth and horizontal departure has been reached. Then, the angle is steadily and smoothly dropped until the well is near vertical. Intermediate casing is usually run through the section of the hole where the angle was dropped. Drilling continues in the vertical hole below the intermediate casing to the target. Type II wells are generally used where multiple pay zones are encountered. Also, after the well has been returned to vertical, directional drilling services are no longer required. Since most of the directional drilling is done in the shallower portions of the hole where trips are shorter and penetration rates are higher, the overall cost of the well is reduced. A disadvantage of the Type II is that it will generate more torque and drag for the same horizontal departure.

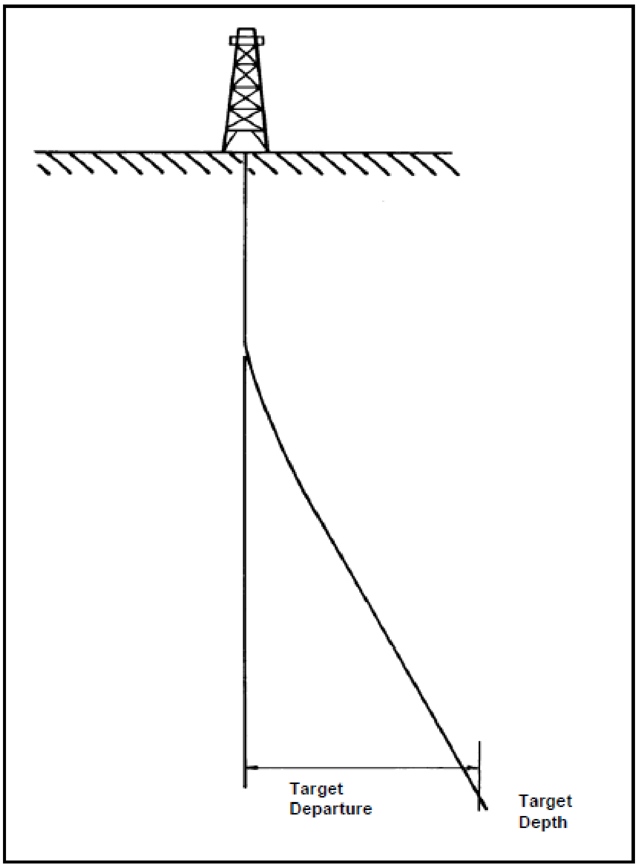

Figure 26: Basic Hole Pattern for a Type I Well

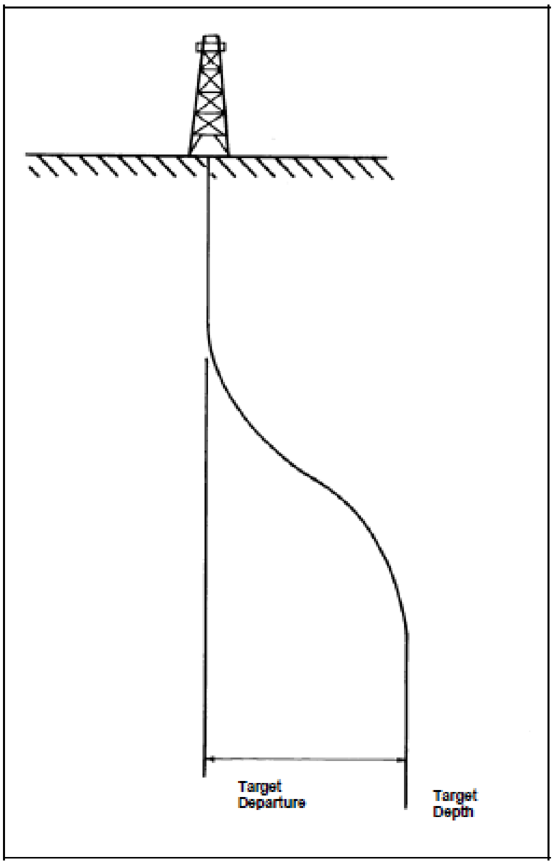

Figure 27: Basic Hole Pattern for a Type II Well

Type III well (Figure 28) is a continues build to target. It is similar to the Type I well except the kickoff point is at a deeper depth, and surface casing is set prior to deflecting the well. The well is deflected at the kickoff point, and inclination is continually built through the target interval. The inclinations are usually high and the horizontal departure low. This type of well is generally used for multiple sand zones, fault drilling, salt dome drilling, and stratigraphic tests. It is not used very often.

Type IV well (Figure 29) can be categorized as horizontal or extended reach wells. Design of these wells can vary significantly, but they will have high inclinations and large horizontal departures. Horizontal wells will have an inclination greater than 80°.

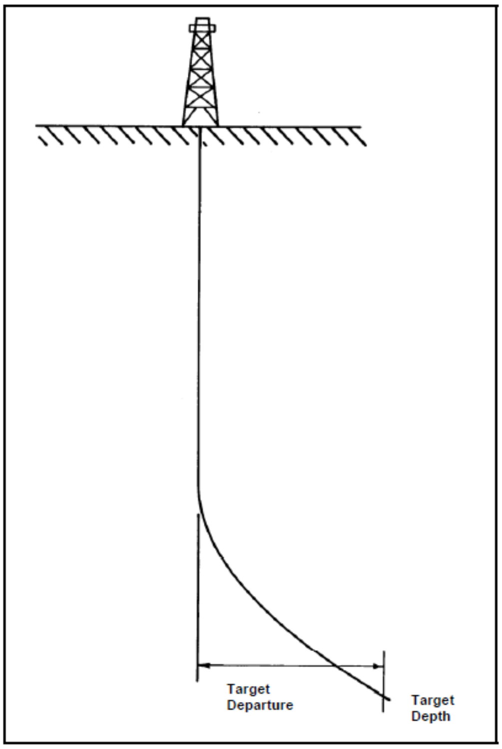

Figure 28: Basic Hole Pattern for a Type III

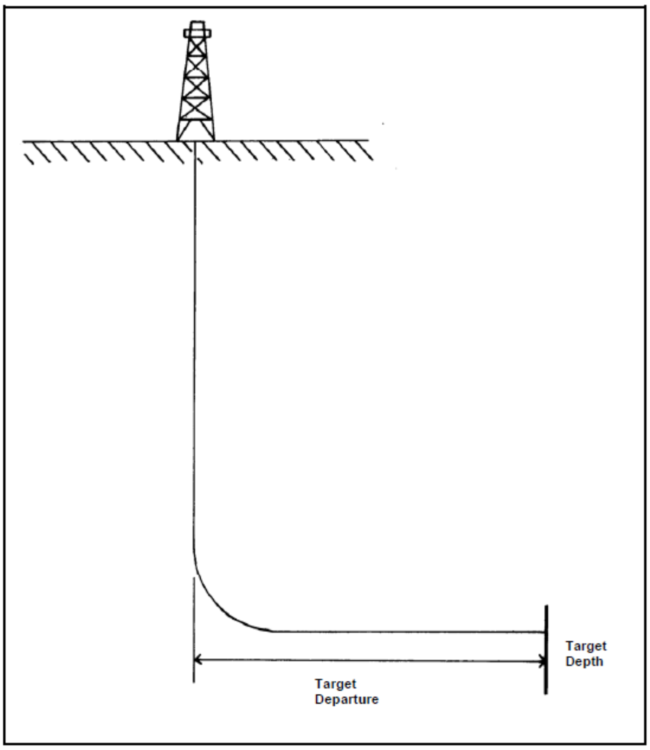

Figure 29: Basic Hole Pattern for a Type IV

Uses of directional drilling

Sidetracking is one of the primary uses for directional drilling. Sidetracking is an operation which deflects the borehole by starting a new hole at any point above the bottom of the old hole. The primary reason for sidetracking is to bypass a fish which has been lost in the hole; however, there are several other reasons for sidetracking. A sidetrack can be performed so that the bottom of the hole can intersect a producing formation at a more favourable position such as up dip above the oil-water contact. A well can be sidetracked to alleviate problems associated with water or gas coning. A sidetrack can be performed in an old well to move the location of the bottom of the hole from a depleted portion of the reservoir to a portion that is productive, such as, across a fault or permeability barrier. Sidetracking an exploration well can lead to a better geologic understanding of an area especially where the geology is complicated. Sidetracking and directional drilling can be more economical than multiple exploration wells if the upper portion of the well is expensive to drill.

In horizontal wells, it is a common practice to sidetrack existing vertical wells most frequently utilizing the short radius method. A whipstock is set inside the casing and the well sidetracked. Then the formation is drilled horizontally to increase productivity. Multiple sidetracks can be drilled from the same well, which are termed multilaterals.

Most often, a sidetrack is accomplished by setting a cement plug in the hole and dressing off the plug to a depth at which the sidetrack will commence. The sidetrack can be either "blind" or "oriented". In a blind sidetrack, the direction of the sidetrack is not specified and is not considered a directional well. In either case, a deflecting tool is used to drill out the old hole and start a new hole.

Fishing

A fish is a piece of equipment, a tool, or a part or all of the drill string lost or stuck in the hole. Small pieces, such as a bit cone, a wrench, or any other relatively small, non-drillable item, are called junk. Whenever there is junk or a fish in the hole, it must be removed or fished out so that drilling operations can continue.

A number of ingenious tools and techniques have been developed to retrieve a fish. For example, an overshot can be run into the fish and set around the outside of it. Grapples in the overshot latch onto the fish firmly and then the overshot and attached fish are pulled out of the hole.

Another fishing tool is a spear. Unlike an overshot, which goes over the outside of the fish, a spear goes inside. It grips the inside of the fish and allows it to be retrieved. Other fishing tools include powerful magnets and baskets through which mud can be circulated, both of which are useful for retrieving junk from the hole.

Special mills are available that allow the jagged top of a fish to be better attached. Since two fishing jobs are seldom alike, various other fishing tools have been designed to meet the unique requirements of the rig fisherman.

Reading Materials

[1]Mitchell B. (1974). Oil Well Drilling Engineering Handbook. USA Library of Congress, USA. p. 600.

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