Drilling a Well – An Overview

Drilling operations are procedures performed so that a well bore is drilled until it penetrates a petroleum bearing formation. It is a complex operation developed after years of study and experimentation have provided accepted practices.

Oil and gas wells are drilled through layers of subsurface sedimentary formations. The well is drilled in stages using either one of, or a combination of methods:

1. Straight hole drilling
2. Directional drilling

The well bore becomes smaller as each stage of drilling is completed and that section of hole is cased off with large diameter casing.

The three main stages of the well are:

1. The surface hole
2. The intermediate hole
3. The production hole

As a well is drilled, it naturally deviates from vertical or what is known as a straight hole. If left uncontrolled the deviation can create serious down hole problems. As down hole survey methods developed, these deviations could be determined and techniques developed to control them.

Straight hole drilling applies three basic principles:

1. Stabilization principle
2. Pendulum principle
3. Fulcrum principle

These principles are applied to the design of the drill string assembly to regulate the weight on bit. The assembly will vary depending on the formations being drilled.

There are times when it becomes necessary or more desirable to deliberately deviate the direction of the well. This is known as directional drilling. Specialized tools, in conjunction with varying weights and rotation speeds, influence the drill bit and will change the direction being drilled.

The general routine during the drilling of a well is:

1. The first drill collar and bit are made up and suspended in the rotary table.
2. Additional joints and tools are made up to create a drilling assembly known as a bottom hole assembly or BHA.
3. The Kelly or top drive is attached to perform the drilling operation.
4. As the well is drilled deeper, additional joints of drill pipe are added either from the Mousehole or from the derrick.
5. When the hole is drilled or other problems dictate, the Kelly or top drive is removed.
6. The tubular are pulled out of the hole (POOH) and racked in the derrick for storage by a procedure known as tripping.
7. The drill bit is changed.
8. The sections of pipe are then reassembled and run in the hole (RIH) or tripped in to the bottom of the hole where the drilling resumes.
9. When the hole is drilled down to a predetermined depth, the pipe is removed and a string of casing is run and cemented in place to isolate that section of hole.
10. Once the hole is drilled to its final depth, the well is normally tested to determine if it is viable to produce oil or gas from it and if so then a completion assembly is run into the well.

Drill Pipe

Most drill pipe is steel that is forged into a solid bar and then pierced to produce a seamless tube. The tool joint is a separate piece of metal welded onto the drill pipe and provides threaded ends so that the pipe can be screwed together.

The main factors involved in the design of a drill pipe string are:

- Collapse and burst resistance.
- Tensile strength (Tension).
- Torque (Torsion).
- Resistance against crushing by action of the slips.
- Presence of aggressive fluids (e.g. H_2S and CO_2)/resistance to corrosion.

The forces acting on the tubular of the drill string include:

- Tension, the combined weight of drill collars and drill pipe plus any overpull. An overpull safety margin should be available to pull on a stuck string.
- Torsion, high torque values can be obtained in tight hole conditions. The recommended tool joint make-up torque should be used and not exceed.
- Fatigue in corrosive environment
- Fatigue associated with mechanical notches.
- Cyclic Stress Fatigue, while rotating through crooked holes. Dog leg severity of more than 3deg/30m (3deg/100ft) should be avoided if possible.
- Abrasive Friction
- Vibration, at critical rotary speeds.

Different grades of steel are available to meet different hole requirements, the most common are G105 and S135. G105 is most commonly used in shallow or H_2S environments. S135 is considered a standard for offshore operations. U150 is a relatively new grade that is being used for deepwater operations.

Hard_facing (also called hard banding) of tool joints is performed to limit the degree of circumferential wear produced on the tool joint. Hard facing is proven to be efficient but it also can provide considerable casing wear, leading to a reduction in casing performance properties.

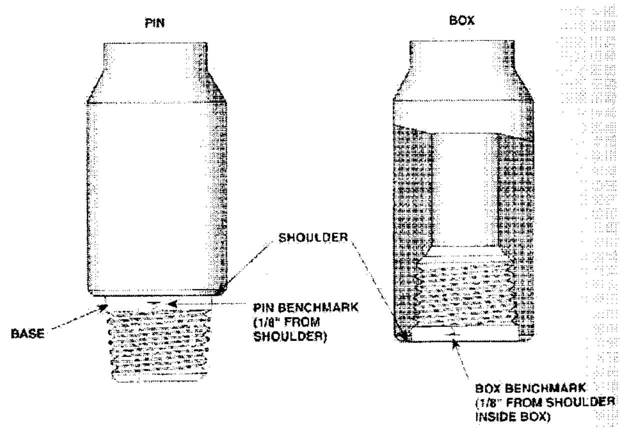
If new hard banded pipe or pipe that has been recently re-hard banded is being used, every effort should be made to run this pipe in the open hole section. This will result in a degree of roughness being taken off the new surface finish and will minimise any adverse impact on casing wear.

The drill pipes are not ordinarily used to put weight on the bit and they are smaller and lighter than the drill collar. In addition, in straight holes drilling, the drill string is suspended in the hole under tension, not compression. It is kept in tension by two opposing forces: the weight of the collar pulling on it from below and the hoist and block pulling from the surface. Keeping the drill string in tension prevents it from bending and buckling and prolongs its life.

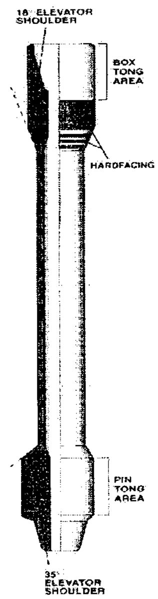
The wall of the tool joint is about 2" thick and about a foot long.

Each tool joint pin and box includes:

- The tong area: it refers to the part of the tool joint to which drilling crews attach the tong that make up or break out the tool joints.
- The elevator shoulder: manufacturers produce tool joints with tapered elevator shoulders so that the pipe can more easily slide past doglegs and curve in the well bore. Normally the shoulder has an 18° taper.



Manufacturers produce some tool joints with hard facing on the joint's exterior. Hard facing may greatly increase the life of a tool joint because an abrasive formation can reduce its size and weaken it.



Drill Pipe Ranges:

Manufacturers make drill pipe in one of three API recommended ranges of length.

Range	Length (ft)	Length (m)
1	18 - 22	5.5 - 6.7
2	27 - 32	8.2 - 9.8
3	38 - 45	11.6 - 13.7

These 3 ranges of length are produced because derrick heights vary and drilling contractor must be able to buy drill pipe lengths that make into stands of a height that fit inside the derrick.

The most common drill pipe in use today in the oil industry is Range 2. Range 1 is now obsolete and has been replaced by lengths of pipe 5ft. to 10ft. long, known as pup joints.

Drill Pipe Grades:

API specifications concern *yield* and *tensile* strengths.

- Minimum yield strength refers to the specific value at which the pipe will permanently distort.
- Minimum tensile strength refers to a specific value at which the pipe will snap or pull apart.

The type of DP needed is based on the conditions expected down hole. Depth being the primary factor. There are 4 API grades:

Strength in PSI	E-75	X-95	G-105	S-135
Minimum yield strength	75,000	95,000	105,000	135,000
Minimum Tensile Strength	100,000	105,000	115,000	145,000

Grades of Pipe: The grade of a pipe is a symbol used for identification.

Grade	Symbol	Minimum Yield
D 55	D	55,000
E 75	E	75,000
X 95	X	95,000
G105	G	105,000
S135	S	135,000
V150	V	150,000
Used	U	

The heavy wall drill pipe (HWDP):

Heavy wall drill pipes, also called heavy-weight drill pipes, are manufactured with walls that are thicker than those in standard drill pipe and fitted with special extra length tool joints.

The extra length of the tool joint allows room for re cutting connections when the original ones are damaged and reduce the rate wear on the OD of the tube by keeping the wall of the tube away from the side of the hole.

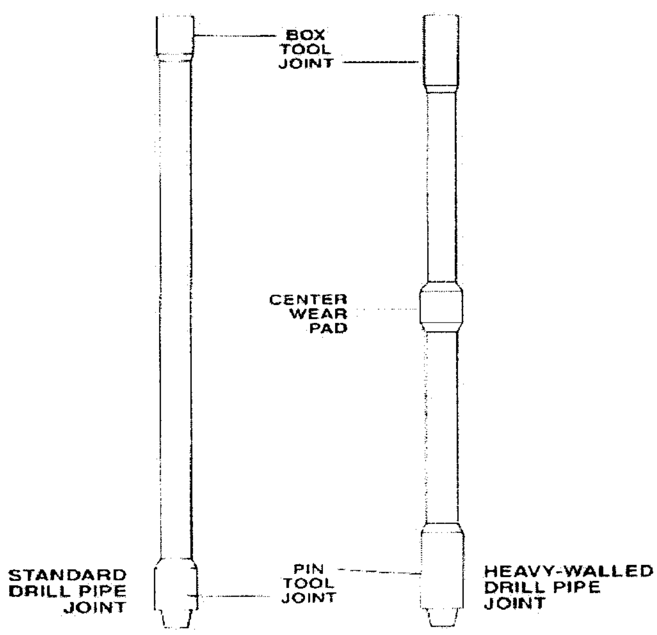
The OD of the tube is also protected from abrasive wear with a center wear pad.

Heavy weight drill pipes are frequently used in the drill stem just above the drill collar, in the transition zone between the stiffer collars and the more limber drill string.

Fatigue failure often occurs in the first few joints above the drill collars. This area of the drill string is referred to as the transition zone.

Decrease the effects of drag and torque. (3 contact points: both tool joints, central upset)

Can be run in compression in certain cases.



Drill Collars

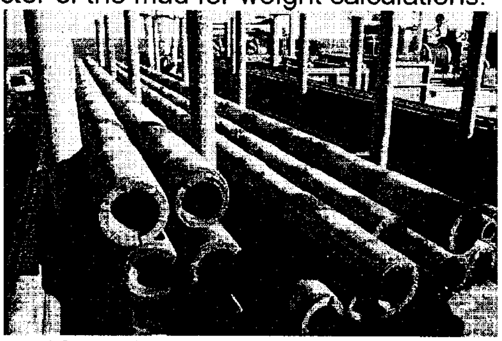
Drill collars are heavy walled metal tubes positioned directly above the bit. Drill collars are used primarily to apply weight to the bit. Their large wall thickness gives them a greater resistance to buckling than drill pipe so they also provide weight to keep the drill string in tension and avoid it from being subjected to buckling forces.

They will be used to provide a pendulum effect that causes the bit to drill a more nearly vertical hole and support and stabilize the bit so that it will drill new hole that is aligned with the hole already drilled.

The lower part of the drill collar section is under compression, therefore subject to buckling. This generates high stresses and potential fatigue failure, particularly at the connections.

Therefore, the drill collars are designed to work in compression and the drill pipes in tension.
However, a safety factor will be kept, commonly 15 to 20% of the weight of the drill collars.

It means that when calculating the amount of D.C.s required to be run with a new bit, the maximum W.O.B. will represent either 80 or 85 % of the weight of the drill collars.
Reminder : Buoyancy factor of the mud for weight calculations.



They range in weight from 16 to 379 pounds per foot. Most of them are round and are 30 or 31 feet long. Well planner determines how many drill collars are needed above the bit by taking into consideration how much weight is needed to drill efficiently and how much each drill collar weighs.

The clearance between drill collars and the wellbore is smaller than with DP, therefore increasing the possibility of differential sticking. Differential sticking is a condition in which the drill stem becomes stuck against the wall of the well bore because of the difference in pressure between the drilling fluid in the well bore and that of a permeable formation.

Some drill collars have spiral grooves machined into the outside surface. These spiral drill collars are used in holes in which the clearance between the drill collar and the wall of the hole is small and in directional drilling where the collars will likely contact the side of the hole.

If it is thought to be a potential problem, spiral drill collars can be used to reduce the contact area with the wellbore and consequently the chance of differential sticking.

Drill Bit

There are two main types of drill bit available.

1. **Roller Cone or Rock Bits**
   These can be sub-divided into Mill Tootherd Bits and Insert Bits

2. **Fixed Head Bits**
   These can be subdivided into Natural Diamond, PDC and Core Bits

Bit Selection

Factors to consider for the bit selection are : Durability, Effectiveness, Nature of Formation.

- **Durability:** We want the bit to last for a reasonable number of rotating hours.

- **Effectiveness**: Is linked with durability, we need a bit that will give the biggest footage.

- **Nature of formation:** We might find changes in the formation, hence we need to find a suitable bit to perform under these conditions.

Bit Design

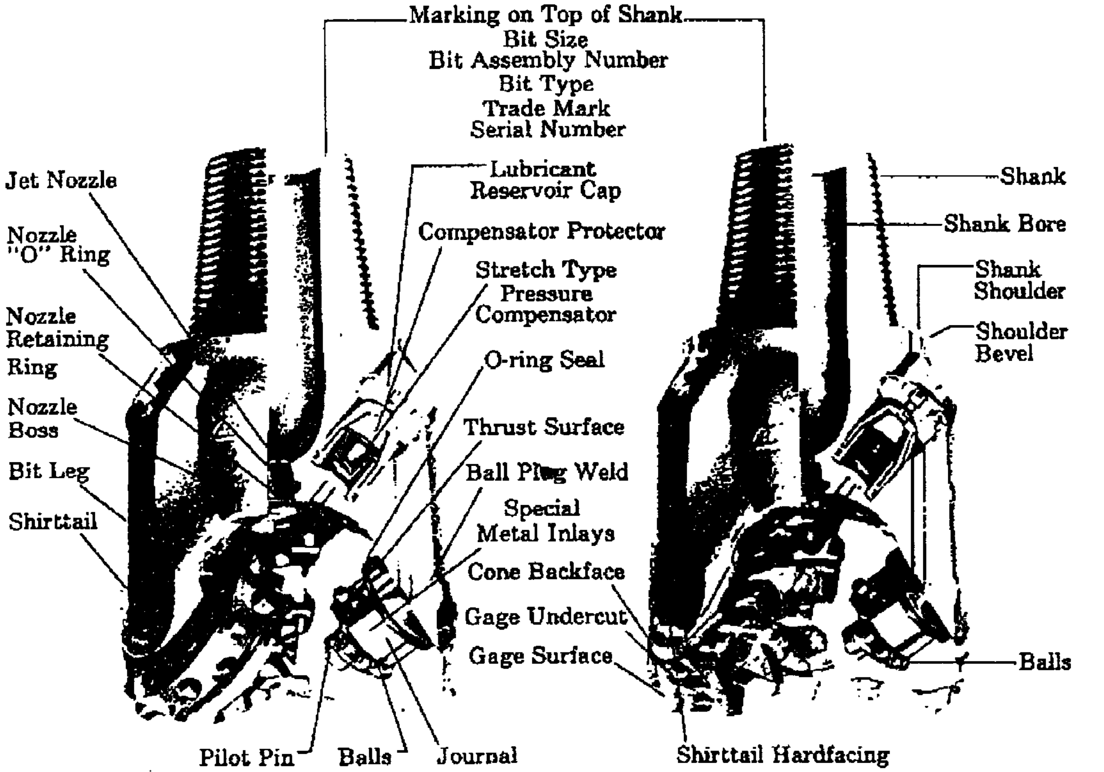
The bit designer will consider different variables:

- Heavy duty bearings
- High resistant cone shell
- Full length cutting teeth

If the designer wants a bit with short teeth, the cone shell can be thicker and the bearings larger.

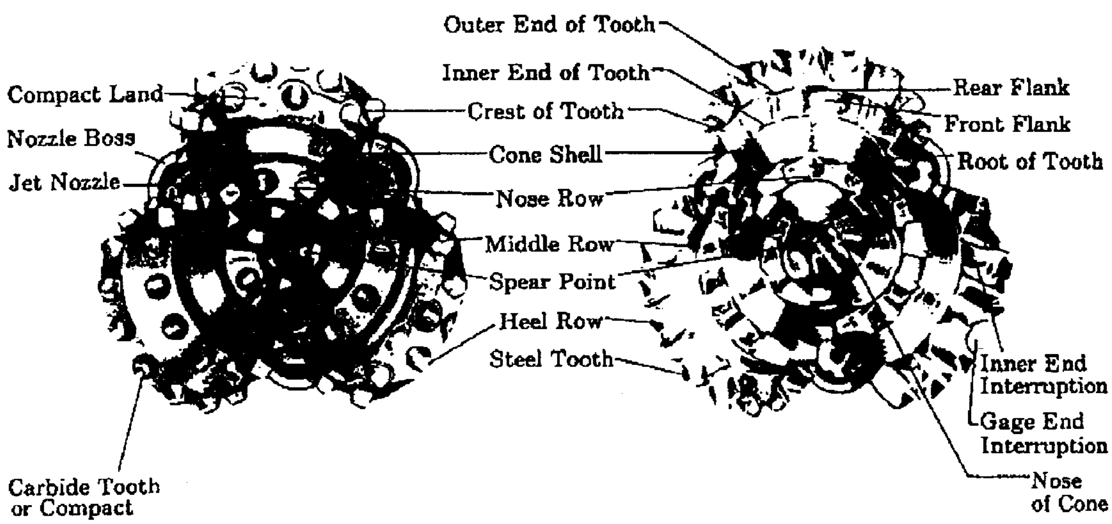
If the designer wants a bit with long teeth, the cone shell must be thinner and the bearings smaller.
At the end, the final product will be a bit which will last for the planned time with no premature failures of one of these elements.

ROCK BIT ELEMENTS



CARBIDE TOOTH BIT
with Sealed Journal Bearings

STEEL TOOTH BIT
with Sealed Journal Bearings



Tripping Procedures

Tripping Procedures to Pull Out Of Hole

1. When it has been decided to stop drilling, the bit is picked up of bottom and the rotation is slowed down.

2. The volume of the annulus is circulated (bottoms up) until the hole is clean while the drill string is reciprocated.

NOTE: If it is noticed that too many cuttings are still coming back to the shale shakers, the circulation will be carried on and in some specific cases a "hole clean" circulation will be performed.

3. The mud weight **"IN"** and **"OUT"** will be checked throughout the circulation.

4. The drilling crew will prepare the IBOPs on the drill floor.
   i.e. Full opening safety valve and gray valve.

5. The trip tank will be filled up and it will be ensured that the electric motor is working properly.

6. The trip sheet will be prepared.

7. The circulation will be stopped, and the trip tank lined up and circulated across the hole.

8. A flow check is performed (15 minutes) with the Kelly or Top Drive still connected.

9. After the flow check, the Kelly or Top Drive is disconnected.

10. The trip starts and the first few stands have to be pulled out slowly and could be pulled out connected if the rig has a top drive.

NOTE: In the open hole the stands are pulled at a steady rate in order to avoid or minimize the swabbing effect created by the stabilizers which, charged with cuttings, will significantly reduce the passageway between the blades and the wall of the hole and, therefore, will tend to work as pistons, emptying the bottom of the hole, leading to a drop of the hydrostatic pressure, and possibly allowing the formation fluid to enter the well bore.

For this reason, the level of the trip tank will be checked at every stand initially.

If a swabbing phenomenon is noticed, the priority will be to go back to bottom and re circulate as long as you are not in a well control situation. Extreme attention and vigilance will be required.

EVERY TIME THE TRIP TANK NEEDS TO BE REFILLED (OR EMPTIED), THE TRIPPING PROCESS SHOULD BE STOPPED TO MAINTAIN CONTROL OF THE VOLUMES.

11. When arriving at the casing shoe, a flow check will be performed (15 minutes), with the IBOP (Kelly valve) stabbed on the string.
12. Then, with the Kelly or Top Drive connected, a slug will be pumped.
13. Disconnect the Kelly or Top Drive and continue to pull out of the hole.

NOTE: The tripping speed can be increased in the cased hole.

14. At the last stand of drill pipe or HWDP pipe below the BOPs, a flow check will be performed (15 minutes).
15. The crew will prepare the cross over for the IBOP.
16. The BHA will be pulled out at a slow speed (because of increased steel volume and low capacities of some trip tank's electric motors).

NOTE: Lifting subs used to handle stands of drill collars should be threaded type subs in order to be able to connect the top drive in case of a well control situation.

Two tongs will be used when making up or breaking out connections to prevent stress and bending of the drill-pipe in the table.

The three flow checks performed at the bottom of the well, at the casing shoe, and prior to pulling BHA out of the hole are a reasonably standard drilling contractor policy. Their duration will be 15 minutes and even more in some particular cases.

Drilling Operations

Bit Break-In

Break-in procedures are extremely important for roller cone bits and vital for fixed cutter bits. New bits can be damaged easily by being started badly and this will reduce bit life often before many metres are drilled.

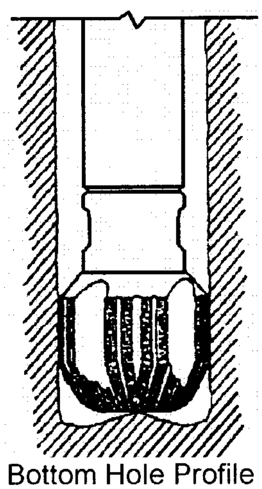
General procedures for all types of bits include:

1. A few feet before reaching bottom begin pumping and rotate the bit (to one-half the on-bottom rotary rate rpm), and slowly lower the bit. Use no more than 500 lbs weight per inch of bit diameter. An increase in torque and bit weight will signal that the bottom has been reached. A crowfoot fixed cutter bit will show an increase in pump pressure.

2. Raise the bit about 6 to 12 inches off bottom while rotating and circulate for five minutes to wash away any fill or junk. Return to bottom and begin drilling with no more than 500 lbs weight per inch of bit diameter. The bit will usually drill-off immediately.

3. If the bit does not drill-off immediately, be patient as a proper break-in is important. Only increase the weight above the 500-pound value if it isn't sufficient to overcome the formation strength.

The bit break-in weights should not be used beyond the drilling of one to two feet of new hole, since the weight is used to get rid of the old hole pattern and to establish a new pattern. The bottomhole pattern left by the previous bit seldom fits the profile of the bit going into the hole.



Bottom Hole Profile

This is because the previous bit had its own particular profile and will be worn in a unique way. Even when following with another bit of the same type or model, the bottomhole pattern will be different between the new bit and the previous bit. The new bit must first drill out the old pattern and establish its own pattern before it can begin to be filly optimised.
Incorrect break-in procedures often lead to severe vibration levels, resulting from low levels of weight applied to the bit. By monitoring the overall levels of axial and torsional events early damage to the bit can be avoided.

Also, lateral vibrations often start when the bit is placed on bottom regardless of bit type. Using the correct break-in procedures can reduce bit whirl. The most effective manner to eliminate bit whirl starting, particularly after a connection follow these directions

1. Set RPM to one half on-bottom target rate.
2. Place the bit back on bottom, slowly increasing the WOB to its target value. Care should be taken when increasing WOB to ensure stick-slip is not initiated prior to increasing RPM.
3. Increase the rotary to the target on-bottom value.

Bottom Balling

The condition known as bottom balling occurs when high bottom hole pressures and a high overbalance pressure are realised. This condition only occurs with non-inhibitive drilling muds.

Slow ROP (1-5m/hr), low drilling torque and a lack of response to drilling parameter changes identify bottom balling. It is also usual for bits to be pulled out of hole with minimal cutting structure wear when bottom balling has occurred.

It is important to control the applied WOB to minimise the possibility of global bailing. If too much WOB is applied, global balling of the bit maybe the result. This will be more likely in low strength shale based formations.

Negative Drilling Breaks

Negative drilling breaks may be encountered when drilling through interbedded sections with varying formation strengths. When negative drilling breaks are encountered, stop drilling, pick up off bottom and eliminate any residual drilling torque. Return to drilling with the same procedure as for the initial start-up of the bit. When the bit profile is established, resume optimum drilling parameters to maximise ROP.

Drilling Abrasive Sandstone

When drilling abrasive sandstone, the drilling parameters should be adjusted to minimise the abrasive potential of the drilling environment. Bit speed should be reduced to the slowest speed possible without inducing torsional vibration. Maintaining a steady drilling torque can monitor this.

The applied WOB should be increased; again care should be taken to avoid initiating torsional vibration. If after increasing WOB drilling torque starts to oscillate then reduce WOB gradually until a steady torque is achieved. Bit HSI should be maximized through abrasive formations, if possible, maximize flow rate to the maximum permissible pump operating pressure.

Surface Indicators

Once the drill rate has been optimised and drilling has commenced, there are several other variables, which should be monitored to ensure this drill rate remains optimised and problems are avoided. Usually changes in the drill rate and drilling problems will show up on several surface indicators, and cross-referencing will help to determine the cause.

The two most important drilling parameters WOB and RPM should be monitored constantly. Their interaction with the following indicators should be noted.

Torque

Torque is usually measured in foot pounds, When diesel or SCR rigs are being used, torque is measured in amperes (amps), which is the amount of electrical power required by the motors to rotate the drillstring. This torque comes from the interaction between the borehole and the bit, BHA and drillpipe.

Torque should remain uniform without wide variations through individual formation types, if drilling parameters stay constant.

Irregular Torque

Changes from the mean value(s) may indicate:
- Interbedded formations
- Stabilisers hanging up.
- Keyseats or doglegs.
- Excessive WOB.
- The bit is becoming undergauge.
- Junk in the hole.

Increase in torque maybe due to:
- Higher applied WOB.
- RPM Sensitivity.
- ROP increase.
- Formation change.
- Increasing hole inclination.
- Increasing filter cake.
- The bit becoming undergauge.

Decreases in torque maybe due to:
- Formation change.
- Running on a dislodged pipe protector.
- Cutting structure wear / breakdown.
- Increased RPM reduced WOB.
- Decreasing hole inclination.
- Decreasing filter cake.
- Bit balling

Pump Pressure

Pump pressure is measured in pounds per square inch (psi), with readings being taken at the mud pumps or standpipe.

Constant pump pressure should be the norm once the recommended pressure is reached.

Irregular Pump Pressure

Changes from the recommended value could be:
- Formation or engineering related.

Increases in pump pressure may indicate:
- The annulus is packing-off/ stabilisers balling.
- The bit is globally balling.
- Inadequate hole cleaning.
- A plugged fluid passageway or nozzle.
- A PDM motor is working at a higher torque value.
- Mud rheology changes.

Decreases in pump pressure may indicate
- A washout in the drillstring.
- Lost nozzles.
- Losing circulation
- Aerated drilling fluid.

Pump Strokes

A set number of strokes per minute are necessary to circulate drilling fluid at a predetermined flow rate and pressure. With pump pressure constant, variations in the pump stroke rate can indicate problems.

Increased pump strokes can indicate:
- A washout,
- Losing circulation
- Aerated drilling fluid.

Decreased pump strokes can indicate:
- An annular restriction (pack-off)
- A plugged nozzle.
- Balling bit.

Drill-Off Tests

A drill-off test is designed to determine the most appropriate WOB and RPM to drill a section of hole, using information on formation drillability, bit type and drill rate considerations. This test is a step by step process of altering the drilling parameters to achieve the maximum drill rate.

The test should be performed after a bottom-hole pattern is established and the encountered formation is not expected to change for some time. The test is performed in a passive manner and is used to define a fixed rotary speed and weight-on bit range.

To optimise the WOB range, an active drill-off test can be performed, In both the passive and active drill-off tests, the vibration levels should be monitored. It is inadvisable to use a RPM/WOB combination that produces high vibration levels as well as high ROP, as this combination may result in premature failure of the drill bit or drill-string components.

Passive Drill-Off Test

1. Begin with a moderate RPM and maximum WOB and lock the brake handle down.
2. Allow the bit weight to drill-off by a predetermined increment and record the time taken to drill-off the WOB increment.
3. Continue to monitor the time for each weight increment reduction until the drill rate becomes too slow.
4. Select the weight increment requiring the least amount of time to drill off.
5. Repeat this procedure at different rotary speeds to determine the optimum RPM.

Active Drill-Off Test

Using the RPM and WOB from the passive drill-off test, the active test is used to determine the specific values for the best drill rate. Set the RPM at the best value from the passive drill-off test and for each small weight increment within the optimum WOB range, record the drill rate over five minutes. This will refine and optimise the applied WOB.

For example:

1. Begin by selecting a mid-range WOB and moderate RPM.
2. Maintain the RPM and WOB for five minutes and record the drill rate,
3. Increase the WOB and repeat 1 and 2. Then decrease the WOB and repeat I and 2.
4. Determine the two fastest drill rates and select a WOB between the two drill rates.
5. Using the selected WOB, vary the rotary speed as in 1 and 2, recording the drill rate for each period.
6. Select the RPM between the two best drill rates.

Once drilling has been optimised, the weight on bit should be kept smooth. Continuous weight should be fed to the bit. The 'slack-off/drill-off' approach should be avoided as this will contribute to torsional vibrations leading to premature bit and BHA failure/wear and decreased ROP. Active drill-off tests can be performed independently of the passive test.

Drilling Out Float Equipment

The float equipment should be properly prepared for drilling out. Thread locking compound should be applied to the first four to six casing thread connectors and to the floating equipment threads (float shoe and collar). This will help prevent the shoe joint from backing off during drill out.

The top plug should be released while still pumping cement. This will allow for at least 10 feet of cement to be located above the top plug at the conclusion of pumping. This procedure is referred to as tailing-in.

Maintaining proper operating parameters while drilling out is important to not only protect the bit, but also to prevent damage to the float equipment and casing. Excessive weight and rotation can promote shoe joint failure as well as damage the bit. Higher circulation rates are necessary to remove the drilled-up materials from the bit face.

Plug spinning is a common phenomenon associated with drilling out with both roller cone and fixed cutter bits. If plug spinning is encountered, the WOB should be adjusted accordingly.

Drilling Out with Roller Cone Bits

When drilling out of conventional float equipment with a roller cone bit, a short tooth bit is recommended in order to drill with less torque and possibly eliminate back off of the bottom joints of casing. However, bit selection generally is determined by both the formation below the shoe and the material to be drilled out in the cementing equipment.

The WOB should be 2000 lb. per inch of bit diameter and rotary speed should be 40 to 60 rpm. Mill tooth and insert bits will drill float equipment differently. More WOB maybe necessary when drilling out with an insert bit. The flow rate range is 35 to 50 gpm per inch of bit OD. Frequently raising the drill string several feet while continuing to circulate and rotate will assist in clearing rubber and debris from cones.

Drilling Out with Fixed Cutter Bits

Fixed cutter bits can be used to drill out of float equipment. Special care must be taken in selecting the type of float equipment to be drilled with the fixed cutter bits. All downhole cementing equipment must be made of soft metal, rubber, nylon, plastic, cement or other homogeneous materials. Steel, cast metals and aluminium-inserted plugs can damage the fixed cutter bit.

Plug spinning is a common problem encountered when drilling out with a fixed cutter bit. The use of non-rotating or interlocking plugs is recommended. Another problem is when too much weight is applied; the bit centre punches the rubber plugs, causing the bit to become shrouded in rubber. To prevent this from happening, penetration in the shoe joint should be limited to 2 inches or less before raising the drill string several feet while continuing to circulate and rotate. This will assist in clearing rubber and debris from cones, cutters and fluid courses.

When drilling out operations with fixed cutter bits the aggressiveness of the bit must be limited so excessive and erratic torque do not cause the plugs to spin. If the plugs do begin spinning, slightly increase WOB, which will increase plug/casing interface friction and prevent plugs from spinning, If spinning persists, stop the rotary, apply 2000 lb. and then begin rotary at 50-70 RPM. This will cause the rubber plugs to compress enabling the cutters to get a bite.

The recommended parameters for drilling out with a PDC bit are: WOB should be 2000-4000 lb. (6000lb. maximum) (independent of bit size) Rotary speed should be 50-70 RPM and flow rate should be 50-65 gallons per minute per inch of bit OD.

Drill out procedures recommended for natural diamond, and TSD bits are as follows: WOB should be 1000-3000 lb. per inch of bit diameter, rotary speed should be 60-100 RPM and flow rate should be 25-40 gallons per minute per inch of bit OD.

Conventional type cementing plugs should be avoided when PDC bits are used to drill the plugs, These plugs tend to turn or spin while being drilled with PDC bits. Also the inserts are made of aluminium or cast iron which is detrimental to fixed cutter bits.

Non-rotating type cementing equipment is recommended, however, non-rotating type cementing plugs may also drill slowly if the non-rotating assembly fails during drilling operation.

Lock Down Anti-Rotation plugs tend to perform well. These plugs have huge locking devices that tend to keep the plugs from turning during drilling. A problem with these plugs however, is that they may have too much rubber on the top. Care must be taken to avoid centre punching this type of plug.

When drilling non-rotating type cementing plugs, patience should be exercised. At the start of the drilling operation, WOB should not be too high (2000 -4000 lb.). Excessive WOB may cause the bit to centre punch the plugs, drastically slowing down the drilling operation; RPM should be in the 50-70 range. When rotating off-bottom, RPM should be 60 or less.

Service company personnel who supply the float equipment are the local experts. These people should be contacted to discuss the makeup and materials used in their particular brand of equipment.

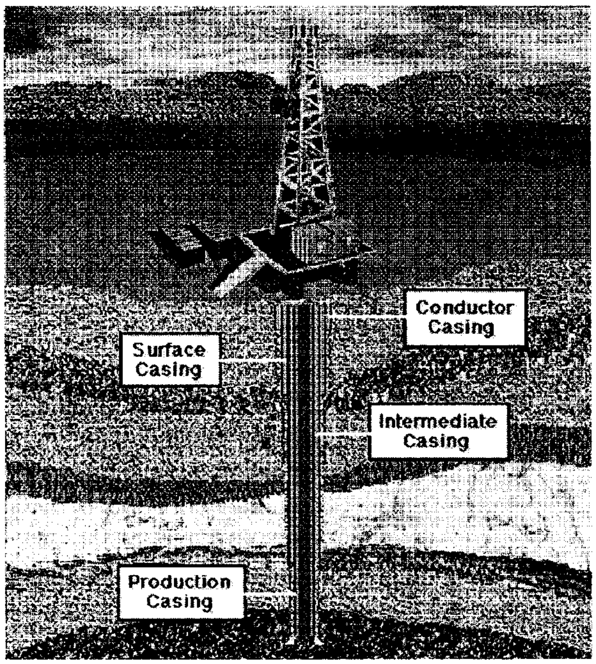
Casing

Functions of Casing

1. Prevent cave-in or washout of the hole
2. Prevent contamination between zones
3. Exclude water from producing formations
4. Confine production to the well bore
5. Provide a means of controlling well pressure
6. Provide a flow path for produced fluids
7. To permit installation of artificial lift equipment

Casing Types

1. Conductor casing
2. Surface casing
3. Intermediate casing
4. Liner casing
5. Production casing



Conductor Casing

The conductor is a short string of pipe that provides surface integrity and ground support for drilling operations.

It can be driven by a pile driver (hammer) or a hole is drilled and the conductor is then run and cemented in place.

Surface Casing

The main functions of the surface casing are:

1. Protect fresh water formations
2. Seals off weal zones
3. Protect the well against blowouts
4. Protect the well from cave-in
5. Apply to state rules and regulations

Intermediate Casing

The main functions of intermediate casing are:

1. Seals off weal zones
2. Seals off high pressure formations
3. Prevents contamination of the drilling fluid

Liner Casing

A liner is an abbreviated or short string of casing used to case an open hole below an existing casing. The casing does not come back to the well head but is hung off in the lower part of the last casing string.

Their installation involves lower cost and requires a relatively short amount of time to run in the hole.

Production casing

Sometimes called the oil string or long string and is frequently the heaviest string in the well.

The production casing separates the reservoir or "pay zone" from all other zones and is the channel to the oil and gas for tubing and other production equipment.

Casing Properties

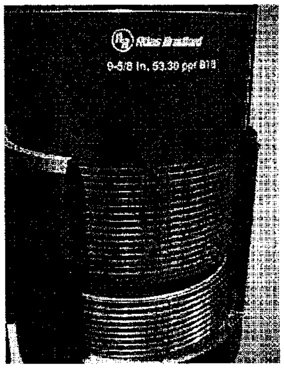
Casing is manufactured to API recommendations and comes in three ranges of length.

Range	Length in Feet
1	16 - 25
2	25 - 34
3	34 – 48

The most common length is range 3 and an average joint length is approximately 40 ft. Shorter lengths are known as pup joints.

Threads and Couplings

As per API recommendations, casing is threaded on each end and furnished with couplings.



There are several different types of thread available for the different applications and strengths. The couplings are usually power tight on to the casing when supplied. Handling tight is defined as tight enough so that a wrench must be used to remove the coupling for cleaning and inspection.

Casing Strength

Casing strings are designed to withstand 3 principal forces:

1. Tension is the force that pulls downward because of the weight of the string.

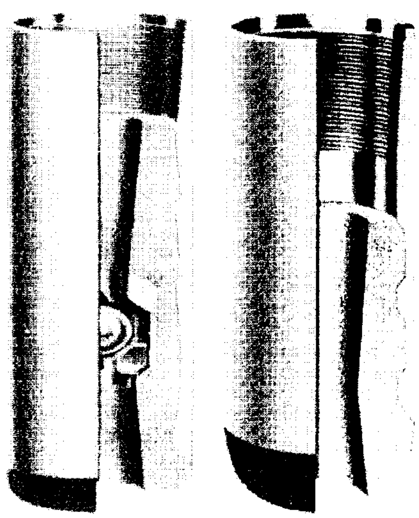
2. Collapse pressure is the external pressure stress that will cause the casing to break down. The problem is minor at surface and greatest at the bottom of the hole and is important in casing selection.

3. Burst pressure is the internal pressure stress that will cause the casing to burst and split. This problem is at its greatest at the top of the casing string.

Casing Accessories

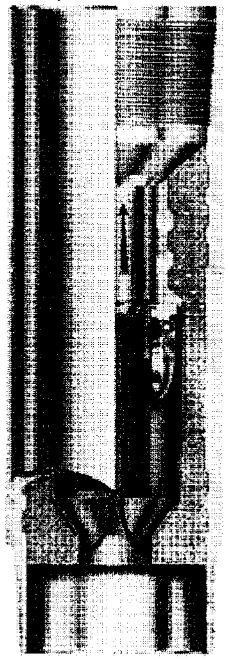
Guide Shoe

Used to guide the casing around obstructions or ledges in the hole. Some are open internally and some are fitted with a one-way check valve or float. This allows fluid to be pumped down the casing but nothing can enter into the casing from the bottom.

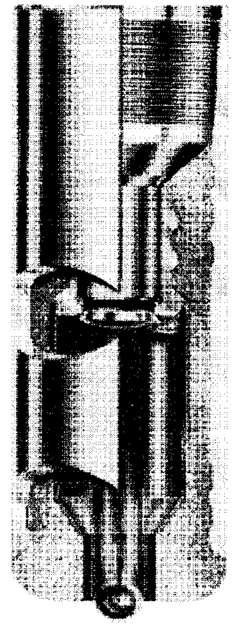


Automatic Fill-up Shoe and Float

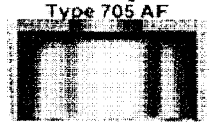
Controls the volume of fluid entering the bottom of the casing. Will reduce surge pressures and reduce the possibilities for lost circulation.



Running In
Type 705 AF



Valve Actuated
Type 505 AF



Running In
Type 705 AF

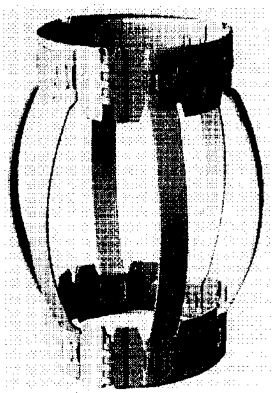
Valve Actuated
Type 505 AF

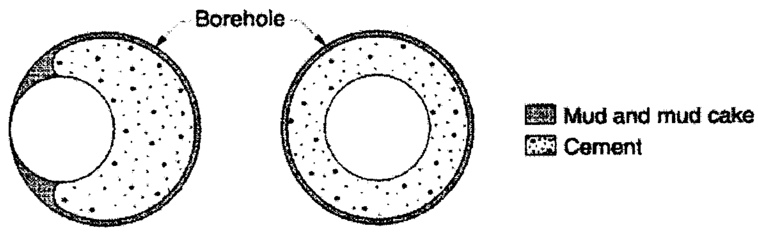
Centralizers

Centralizers are placed on the outside of the casing either while the joints are on the deck or prior to running the joints in the hole. They will centralize the casing in both the open hole and previously cased hole sections.

Casing centralizers have two main functions

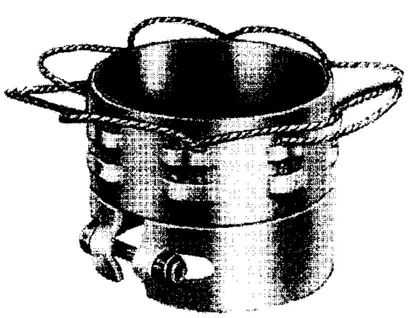
1. To ensure a uniform distribution of cement around the pipe
2. To obtain a complete seal between the casing and the formation



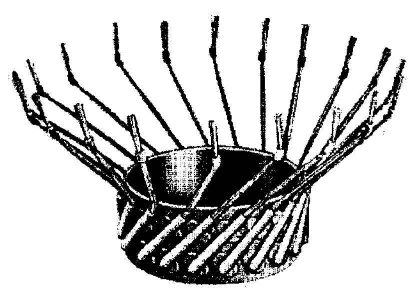


Scratchers

Casing scratches are used to assist In providing a good cement bond with the formation. As the casing is run in the hole, scratches are put on the outside similar to centralizers. As the casing is passing through the open hole section, the scratches help to remove some of the filter cake on the wall of the hole.



Cable Type



Wire Type

CASING EQUIPMENT PREPARATION CHECK LIST

DATE :

9 5/8 CASING EQPT. DESCRIPTION		NOTES AND REMARKS		
		CHECKED		REMARKS
		YES	NO	
DRILL FLOOR EQUIPMENT				
1	CASING BOWL #2			
2	CASING HAND SLIPS			
3	ELEVATOR "SLX" TYPE			
4	SINGLE JOINT ELEVATOR WITH			
	SLINGS AND SWIVEL			
5	ELEVATOR VARCO OR BJ 500 T			
6	CASING SLIPS VARCO OR BJ 500 T			
7	AIR HOSES TO OPERATE no 6			
8	BACK UP TONG WITH JAWS			
9	ADJUSTABLE SLING FOR TONG SUSP.			
10	ELEVATOR BAILS 2 7/8" 134" LONG			
11	SAFETY ROPE FOR V DOOR			
12	FILL UP LINE FOR CASING JOINTS			
13	RUBBER PROTECTORS			
14	LINE FOR PROTECTOR DESCENT			
15	STEPS FOR TONG OPERATOR			
HYDRAULIC EQUIPMENT				
16	HYDRAULIC UNIT			
17	HDYRAULIC CASING TONG			
18	HOSES			
VARIOUS EQUIPMENT				
19	CIRCULATING HEAD			
20	CENTRALIZERS, STOP RINGS			
21	NAILS FOR CENTRALIZERS			
22	PIPE TO BEND THE NAILS			
23	BARYTE TO CLEAN THE THREADS			
24	CLEAN WIRE BRUSH			
25	RAGS			
26	BAKERLOK			
27	CASING DOPE			

NOTE : CHECK THE SENSATOR BEFORE ANY CASING JOB.
GAP = 5/8 "
CHECK THE MUD PUMPS AND SUCTION FILTERS BEFORE ANY CASING JOB

DRILLER'S NAME AND SIGNATURE

Preparation and Inspection before Running

Inspection

New casing should be delivered free of injurious but it is suggested that the individual user familiarize himself with inspection practices specified in the standards and employed by the respective company.

The number of joints delivered to the rig site should be checked against the shipping papers and a casing tally sheet used to list them.

Thread Protectors

All casing, whether new, used, or reconditioned, should always be handled with thread protectors in place.

Casing should be handled at all times on racks or on wooden or metal surfaces free of rocks, sand, or dirt other than normal drilling mud. When lengths of casing are inadvertently dragged in the dirt, the threads should be re-cleaned and serviced .

Rig Equipment

Slip elevators are recommended for long strings. Both spider and elevator slips should be clean and sharp and should fit properly. Slips should be extra long for heavy casing strings. The spider must be level.

Note: Slip and tong marks are injurious. Every possible effort should be made to keep such damage at a minimum by using proper up-to-date equipment.

If Collar-pull elevators are used, the bearing surface should be carefully inspected for:

1. Uneven wear which may produce a side lift on the coupling with danger of it jumping off.
2. Uniform distribution of the load when applied over the bearing face of the coupling.

Spider and elevator slips should be examined and watched to see that all lower together. If they lower unevenly, there is danger of denting the pipe or badly slip-cutting it.

Care must be exercised, particularly when running long casing strings, to insure that the slip bushing or bowl is in good condition. Tongs should be examined for wear on hinge-pins and hinge-surfaces.

The back-up line attachment to the back-up post should be corrected if necessary to be level with the tong in the back-up position, so as to avoid uneven load distribution on the gripping surfaces of the casing.

The length of the back-up line should be such as to cause minimum bending stresses on the casing to allow full stroke movement of the make-up tong.

Pre-running Preparations

Thread Preparation

The following precautions should be taken in the preparation of casing threads for makeup in the casing strings:

Immediately before running, remove thread protectors from both field and coupling ends and clean the threads thoroughly, repeating as additional rows become uncovered.

Carefully inspect the threads. Those found damaged, even slightly, should be laid aside unless satisfactory means are available for correcting thread damage.

The length of each piece of casing shall be measured prior to running. A steel tape calibrated in decimal feet to the nearest 0.01 ft should be used.

The measurement should be made from the outermost face of the coupling or box to the position on the externally threaded end where the coupling or the box stops when the joint is made up power tight.

On round thread joints, this position is to the plane of the vanish point on the pipe; on buttress thread casing, this position is to the base of the triangle stamp on the pipe; and, on extreme line casing, to the shoulder on the externally threaded end. The total of the individual lengths so measured will represent the unloaded length of the casing string.

The actual length under tension in the hole can be obtained by consulting graphs which are prepared for this purpose and which are available in most pipe handbooks.

Check each coupling for makeup. If the standoff is abnormally great, check the coupling for tightness.

Tighten any loose couplings after thoroughly cleaning the threads and applying fresh compound over entire thread surfaces, and before pulling the pipe into the derrick.

Before stabbing, liberally apply thread compound to the entire internally and externally threaded areas.

It is recommended that high-pressure modified thread compound be used, except in special cases where severe conditions are encountered, it is recommended that high pressure silicone thread compound be used.

Place clean thread protector on the field end of the pipe so that the thread will not be damaged while rolling pipe on the rack and pulling into the derrick. Several thread protectors may be cleaned and used repeatedly for this operation.

If a mixed string is to be run, check to determine that appropriate casing will be accessible on the pipe rack when required according to the program.

Connectors that are used as tensile and lifting member should have their thread capacity carefully checked to assure that the connector can safely support the load.

Care should be taken when making up pup joints and connectors to assure that the mating threads are of the same size and type.

Drifting of Casing

It is recommended that each length of the casing be drifted for its entire length with mandrels just before running.

Handling from the Pipe Rack to the Rig Floor

Lower or roll each piece of casing carefully to the walk without dropping.

Avoid hitting casing against any part of derrick or other equipment. Provide a hold-back rope at the V-door opening.

For mixed or unmarked strings, a drift or "jack rabbit" should be run through each length of casing when it is picked up from the catwalk and pulled onto the derrick floor, to avoid running a heavier length or one with a lesser inside diameter than called for in the casing string.

Running Casing

Stabbing

Do not remove thread protector from field end of casing until ready to stab. If necessary, apply thread compound over entire surface of threads just before stabbing.

The brush or utensil used in applying thread compound should be kept free of foreign matter and the compound and the compound should never be thinned.

In stabbing, lower casing carefully to avoid injuring threads. Stab vertically, preferably with assistance of a man on the stabbing board.

If the casing stand tilts to one side after stabbing, lift up, clean, and correct any damaged thread with three-cornered file, then carefully remove any filings and reapply compound over the thread surface.

After stabbing, the casing should be rotated very slowly at first to insure that threads are engaging properly and not cross-threading. If spinning line is used, it should pull close to the coupling.

Make-up, Power Tongs

The use of power tongs for making up casing made desirable the establishment of recommended torque values for each size, weight, and grade of casing. Early studies and test indicated that torque values are affected by a large number of variables, such as: variations in taper, lead, thread height and thread form, surface finish, type of thread compound, length of thread, weight and grade of pipe, etc.

Minimum torque values listed are 75% of optimum values and maximum values listed are 125% of optimum values. All values are rounded to the nearest 10 foot pounds.

These values must necessarily be considered a guide only, due to the very wide variations in torque requirements that can exist for a specific connection. Because of this, it is essential that torque be related to made-up position as outlined in the following:

It is advisable when starting to run casing from each particular mill shipment to make up sufficient joints to determine the torque necessary to provide proper make-up.

Minimum torque should be not less than 75 per cent of the optimum selected. The maximum torque should be not more than 125 per cent of the optimum torque.

The power tong should be provided with a reliable torque gage of know accuracy. In the initial stages of make-up, any irregularities of make-up or in speed of make-up should be observed, since these may be indicative of crossed threads, dirty or damage threads, or other unfavourable conditions.

Continue the make-up, observing both the torque gage and the approximate position of the coupling face with respect to the last scratch position.

The optimum torque values shown in the tabulations have been selected to give optimum make-up under normal conditions and should be considered as satisfactory providing the face of the coupling is flush with the last scratch or within two thread turns plus or minus of the last scratch.

If several threads remain exposed when the optimum torque is reached, apply additional torque up to the maximum torque. If the standoff (distance from face of coupling to the last scratch) is greater than three thread turns when the maximum torque is reached, the joint should be treated as a questionable joint.

Make-up torque values for buttress thread casing connections should be determined by carefully noting the torque required to make up each of several connections to the base of the triangle, then using the torque value thus established, make up balance of the pipe of that particular weight and grade in the string.

Make-up, Conventional Tongs

When conventional tongs are used for casing make-up, tighten with tongs to proper degree of tightness.

The joint should be made up beyond the hand-tight position at least 3 turns for sizes 4-1/2 through 7 inch, and at least 3-1/2 turns for sizes 7-5/8 inch and larger, except 9-5/8 inch and 10-3/4 inch grade P-110 and 20 inch grade J-55 and K-55 which should be made up 4 turns beyond hand-tight position. When using a spinning line it is necessary to compare hand tightness with spin-up tightness.

In order to do this, make up the first few joint to the hand tight position, then back off and spin up joints to the spin-up tight position. Compare relative position of these two make-ups and use this information to determine when the joint is made up the recommended number of turns beyond hand tight.

Questionable Make-up

Joints that are questionable as to their proper tightness should be unscrewed and the casing laid down for inspection and repair. When this is done, the mating coupling should be carefully inspected for damaged threads.

If casing has a tendency to wobble unduly at its upper end when making up, indicating that the thread may not be in line with the axis of the casing, the speed of rotation should be decreased to prevent galling of threads.

If wobbling should persist despite reduced rotational speed, the casing should be laid down for inspection. Serious consideration should be given before using such casing in a position in the string when a heavy tensile load is imposed.

In making up the field joint it is possible for the coupling to make up slightly on the mill end. This does not indicate that the coupling on the mill end is too loose, but simply that the field end has reached the tightness with which the coupling was screwed on at the mill.

Lowering Casing

Casing strings should be picked up and lowered carefully, and care exercised in setting slips to avoid shock loads.

Dropping a string even a short distance may loosen couplings at the bottom of the string. Care should be exercised to prevent setting casing down on bottom, or otherwise placing it in compression because of the danger of buckling, particularly in that part of the well where hole enlargement has occurred.

Definite instructions should be available as to the design of the casing string, including the proper location of the various grades of steel, weights of casing, and types of joint. Care should be exercised to run the string in exactly the order in which it was designed.

If any length cannot be clearly identified, it should be laid aside until its grade, weight, and the type of joint can be positively established.

To facilitate running and to assure adequate hydrostatic head to contain reservoir pressures, the casing should be periodically filled with mud while being run. A number of things govern the frequency with which filling should be accomplished: weight of pipe in the hole, mud weight, reservoir pressure, etc. In most cases, filling every 6-10 lengths should suffice.

In no case should too infrequent filling jeopardize the hydrostatic balance of reservoir pressure. Filling should be done with mud of the proper weight, using a conveniently located hose of adequate size to expedite the filling operation. A quick-opening/closing plug valve on the mud hose will facilitate the operation and prevent overflow.

If rubber hose is used, it is recommended that the quick-closing valve be mounted where the hose is connected to the mud lines rather that at the outlet end of the hose. It is also recommended that at least one other discharge connection be left open on the mud system to prevent build-up of excessive pressure when the quick closing valve is closed while pump is still running.

A copper nipple at the end of the mud hose may be used to prevent damaging of the coupling threads during the filling operation.

Note: The foregoing mud fill-up practice will be unnecessary if automatic fill-up casing shoes and collars are used.

Casing Landing Procedure

Definite instructions should be provided for the proper string tension, also on the proper landing procedure after the cement has set. The purpose is to avoid critical stresses or excessive and unsafe tensile stresses at any time during the life of

the well. In arriving at the proper tension and landing procedure, consideration should be given to all factors such as well temperature and pressure, temperature developed due to cement hydration, mud temperature and changes of temperature during producing operations.

The adequacy of the original tension safety factor of the string as designed will influence the landing procedure and should be considered.

If after due consideration it is not considered necessary to develop special land procedure instructions (and this probably applies to a very large majority of the wells drilled), then the procedure should be followed of landing the casing in the casing head at exactly the position in which it was hanging when the cement plug reached its lowest point or "as cemented"

Causes of Casing Problems

General

The more common causes of casing troubles are as follows:

1. Improper selection for depth and pressures encountered.
2. Insufficient inspection of each length of casing or of field-shop threads.
3. Abuse in mill, transportation, and field handling.
4. Non-observance of good rules in running and pulling casing.
5. Improper cutting of field-shop threads.

6. The use of poorly manufactured couplings for replacements and additions.

7. Improper care in storage.

8. Excessive torque of casing to force it through tight places in the hole.

9. Pulling too hard on string (to free it). This may loosen the couplings at the top of the string. They should be retightened with tongs before finally setting the string.

10. Rotary drilling inside casing. Setting the casing with improper tension after cementing is one of the greatest contributing causes of such failures.

11. Wire-line cutting, by swabbing or cable-tool drilling.

12. Buckling of casing in an enlarged, washed-out un-cemented cavity if too much tension released in landing.

13. Dropping a string, even a very short distance.

14. Leaky joints, under external or internal pressure, are a common trouble, this may be due to:

    a. Improper thread compound.
    b. Under-torqueing.
    c. Dirty threads.
    d. Galled threads, due to dirt, careless stabbing, damaged threads, too rapid spinning, over-torqueing, or wobbling during spinning or torqueing operations.
    e. Improper cutting of field-shop threads.
    f. Pulling too hard on string.
    g. Dropping string.
    h. Excessive making and breaking.
    i. Torqueing too high on casing, especially on breaking out. This gives a bending effect
    that tends to gall the threads.
    j. Improper joint make-up at mill.
    k. Casing out-of-roundness.
    l. Improper landing practices which produce stresses in the threaded joint in excess of the yield point.

Cementing

Cementing operations are generally divided into two main processes:

1. Primary Cementing

The main functions of primary cementing are:
1. To restrict fluid movement between formations and the surface
2. To provide support for the casing
3. To prevent pollution of fresshwater formations
4. To prevent casing corrosion

2. Secondary Cementing

Secondary cementing is considered as a remedial operation for problems down hole. The two main operations of secondary cementing are:

1. Squeeze cementing for:
   - Repair of casing leaks
   - Shut off bottom water in a producing zone
   - Abandonment of a depleted zone

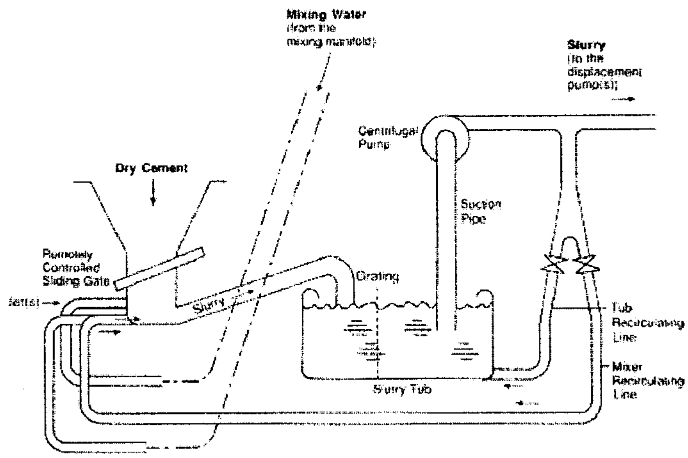
2. Plug back cementing for:
   - Sealing off a dry zone
   - Shut off a depleted formation so that the production can be taken from a higher zone

Mixing Cement

Dry cement is mixed with water to form what is known as a "slurry". The purest water available should be used although sea water could be used but will increase the early strength of the cement.

Cement Mixer

The recirculating mixer is the most commonly used system for cement mixing because it produces a smooth and homogenous cement slurry due to the process of mixing the wet cement with recirculated slurry.



Slurry Density

Slurry density will be checked with a pressurized mud balance and also with an automatic density recorder in the mixing tank.

Density will be carefully monitored and controlled because:

1. It indicates the volume of the slurry
2. It is a direct indication of the water to cement ratio that affects hydration
3. Lost Circulation may be a factor

Cement Additives

Additives are used with basic cements in order to:

1. Alter the setting time
2. Change the slurry density
3. Lower the water loss
4. Improve flow properties

Pumping Cement

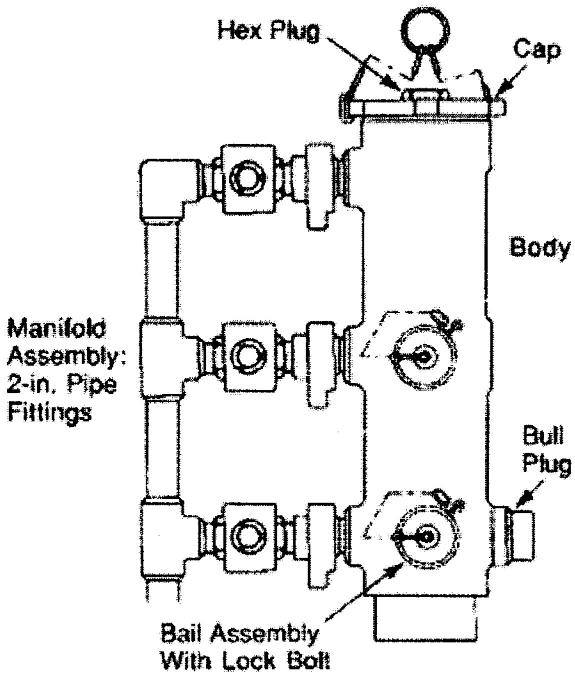
Water is usually used as preflush to provide a spacer between the drilling mud and the cement slurry.

It will:

1. Assist in removal of some of the filter cake
2. Reduce cement contamination
3. Be put in turbulent flow at low rate
4. Will be easy to obtain

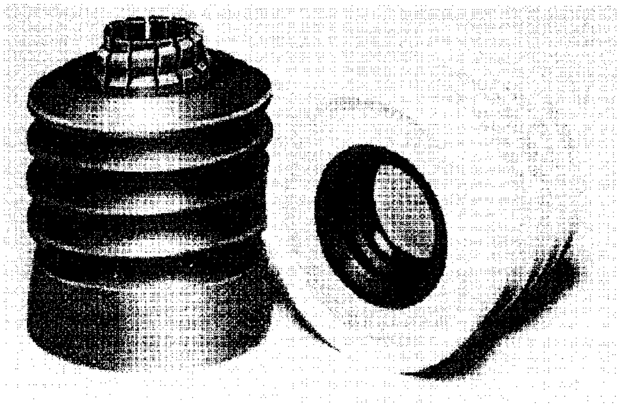
Cement Head

The cement head or plug container is made up on the top joint of casing and provides a way to circulate cement and to load the plugs.

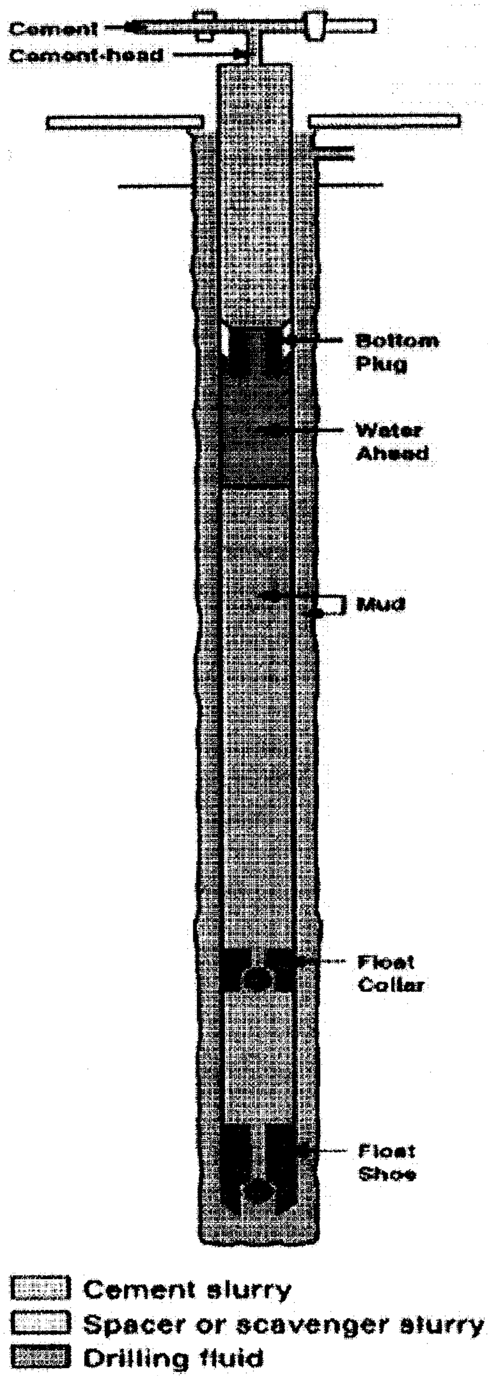


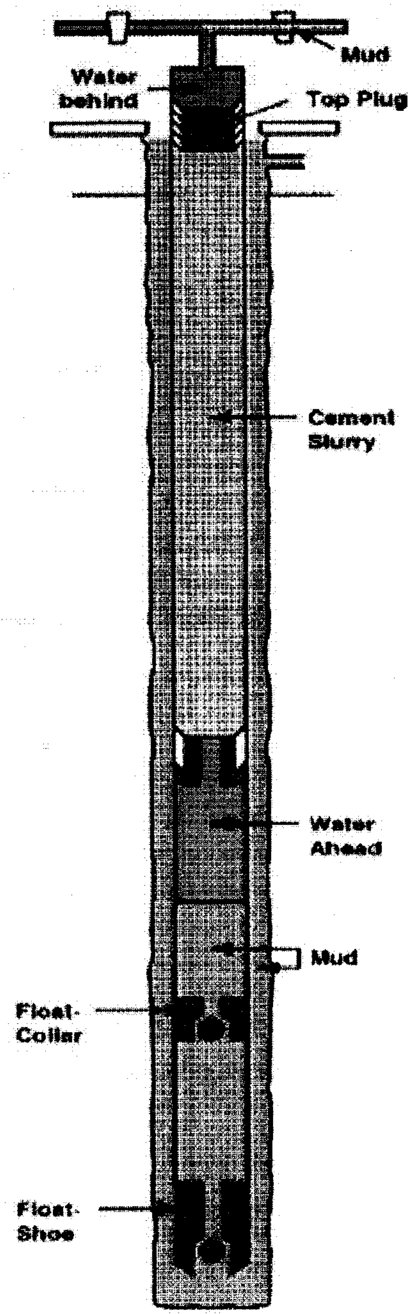
Cement Plugs

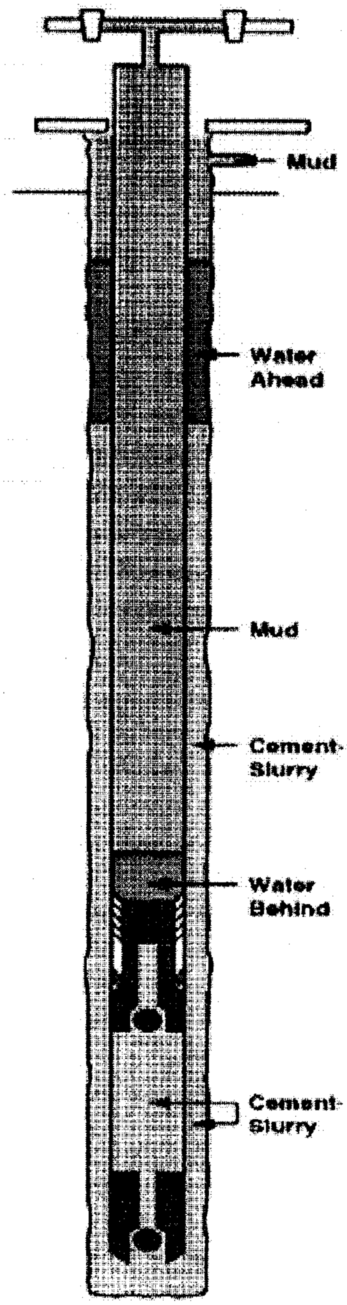
The cement plugs will assist in wiping mud from the inside of the casing but their main function will be to separate the cement from the drilling fluid to avoid contamination.

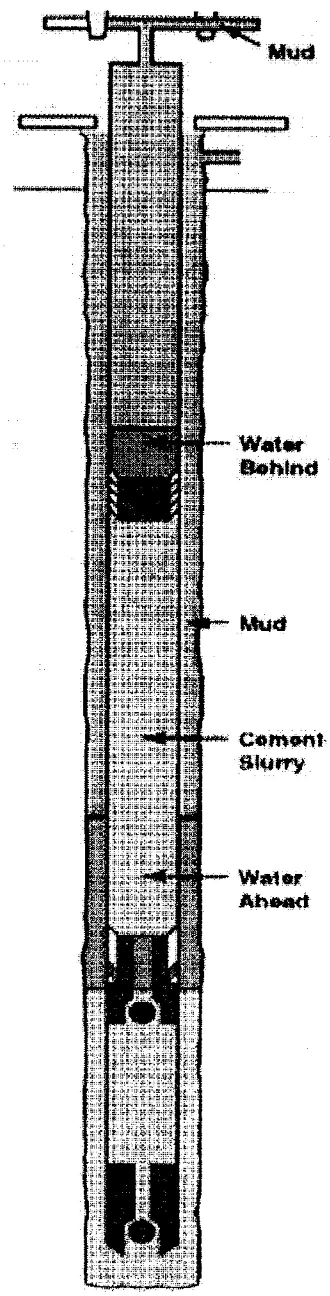


Cementing Sequence






Mud
Water
Ahead
Mud
Cement-
Slurry
Water
Behind
Cement-
Slurry


Mud
Water
Behind
Mud
Cement
Slurry
Water
Ahead

Cement Job

The operator should pump the cement at the highest rate possible and with no delays.

When the bottom plug reaches the float collar, the pressure increases and ruptures the diaphragm, allowing the cement to go down and in to the annular space between the casing and the hole.

The top plug is more solid and can withstand higher pressures.

When it seats or "bumps", the pump pressure will increase. At this time the cement job is complete. The pressure should be bled off so that the casing does not "bulge" before the cement sets dry

After Cementing

The operator generally decides the beginning of waiting on cement time (WOC) and will normally start drilling out the shoe after about 12 hours.

If there is a concern about the height of the cement it can be solved by cement bond logs or temperature survey as cement gives off heat as it sets.

Well Control Principles

Primary Well Control

Primary well control is the use of fluid density to provide sufficient hydrostatic pressure.

- Drilling and completion fluids of adequate density are used.
- Well is kept full of adequate density fluid at all times.
- Active volumes are continuously monitored, especially during tripping.
- Changes in density, volumes and flow rate of drilling fluids from the wellbore are immediately detected and appropriate action taken.

Causes of Kicks

There are 5 major causes for the loss of primary well control:

1. Failure To Fill The Hole Properly While Tripping

As the drill string is pulled from the hole, the mud level drops due to the volume of pipe being removed.

As the mud level drops the hydrostatic pressure may be reduced enough to lose primary well control allowing formation fluids to enter the wellbore.

2. Swabbing

The hydrostatic pressure in the wellbore will always be reduced to some extent when the drill string or any downhole tools are being pulled from the hole.

The reduction in hydrostatic pressure should not be such that primary control is lost.

Swabbing is caused by one or more of the following:

- High pulling speeds.
- Mud properties with high viscosity and high gels.
- Tight annulus BHA-hole clearance, or restricted annulus clearance

3. Lost Circulation

When lost circulation occurs, the drilling fluid level will drop and a reduction in hydrostatic pressure in the wellbore may cause the loss of primary well control.

Loss of circulation may result from one or more of the following:

- Cavernous or vugular formations.
- Naturally fractured, pressure depleted or sub-normally pressured zones.
- Fractures induced by excessive pipe running speeds.
- A restricted annulus due to balling of BHA or sloughing shales

- Excessively high annular friction losses.
- Excessive pressures caused by breaking circulation when mud gel strength is high.
- Mechanical failure (casing, riser, etc.)

4. Insufficient Mud Weight

When the hydrostatic pressure due to drilling fluid density is less than formation pressure of a permeable zone, formation fluids will enter the well bore.

This may occur due to the following:

- Drilling into an abnormal pressure zone.
- Dilution of the drilling fluid.
- Reduction in drilling fluid density due to influx of formation fluids, in particular gas.
- Settling of weighted material.
- Failures to displace riser to kill mud after circulating out a kick.
- Pumping long column of low weight spacer while cementing.
- After cementing while WOC. Cement loses hydrostatic pressure as is starts to set.

5. Loss Of Riser Drilling Fluid Column

On floating unit operations, the loss of the drilling fluid column in the riser may result in a reduction of hydrostatic pressure in the well bore and may cause the loss of primary well control.

This loss of riser hydrostatic column could be due to:

- Accidental disconnects.
- Riser damage.
- Displacement of riser with seawater.

Secondary Well Control

Secondary Control is the proper use of blowout prevention equipment to control the well in the event that primary control cannot be properly maintained.

Early recognition of warning signals and rapid shut-in are the key to effective well control. By taking action quickly, the amount of formation fluid that enters the wellbore and the amount of drilling fluid expelled from the annulus is minimized.

The size and severity of a kick depends upon:

- The degree of underbalance.
- The formation permeability and productivity.
- The length of time the well remains underbalanced.

Smaller kicks provide lower choke or annulus pressure both upon initial closure and later when the kick is circulated to the choke.

Tertiary Well Control

In the event that secondary control cannot be properly maintained due to hole conditions or equipment failure, certain emergency procedures can be implemented to prevent the loss of control.

These procedures are referred to as "Tertiary Control" and usually lead to partial or complete abandonment of the well.

The procedures to be applied depends on the particular operating conditions which are encountered, and specific recommendations regarding appropriate tertiary control procedures cannot be given until the circumstances leading to the loss of secondary control are established.

However, there are two procedures that are widely used. These involve the use of:

1. Barite plugs
2. Cement plugs

Barite Plugs

A barite plug is slurry of barite in fresh water or diesel oil which is spotted in the hole to form a barite bridge that will seal the blowout and allow control of the well to be re-established.

The plug is displaced through the drillstring and, if conditions allow, the string is pulled up to a safe point above the plug. The barite settles out rapidly to form an impermeable mass capable of shutting off high rates of flow. The effectiveness of a barite plug derives from the high density and fine particle size of the barite and its ability to form a tough impermeable barrier.
A barite plug has the following advantages:

It can be pumped through the bit and offers a reasonable chance of recovering the drillstring.
The material required is normally available at the rig site.
The plug can be drilled easily if required.

The main disadvantage is the risk of settling and consequent plugging of the drillstring if pumping is stopped before the slurry has been completely displaced.

Cement Plugs

A cement plug can be used to shut off a downhole flow. However, this generally involves abandonment of the well and loss of most of the drilling tools.

Cement plugs are set by pumping a quantity of quick setting (accelerated) cement into the annulus via the drillstring.

The cement is usually displaced until the pump and choke pressures indicate that a bridge has formed.

Quick setting cement reduces the possibility of gas cutting.

If a cement plug has to be set off bottom with mud below it, then consideration should be given to spotting a slug of viscous mud below the zone to be plugged.

This precaution should be considered in long or deviated holes or when the cement slurry is substantially heavier than the mud.

Setting a cement plug offers little chance of recovering the drillstring. It is also likely that the string will become plugged after pumping the cement, precluding any second attempt if the first should not succeed.

Cement plugging should be regarded as the final option.

Detecting a Kick

A kick cannot occur without a warning sign or variation when drilling with "returns to surface."

A kick occurs when the hydrostatic pressure of the mud column in the well is less than the formation pressure (i.e., an underbalance), if the formation can produce formation fluids.

Whereas drilling breaks, mud contamination, etc., are cautionary signals, a kick provides a positive indicator that formation fluid is entering the wellbore.

The pit level/volume indicators and flow line sensors must be regularly calibrated, according to the calibration procedures, so that high and low level alarms can be set as closely together as practical. By doing this, any gains or losses can be identified quickly.

Kick Detection While Drilling

1. Increase in Relative Flow
The first positive indicator that a kick is occurring is an increase in the return flow rate while the pumps are running at constant output.

2. Decrease in pump pressure and corresponding increase in the pump strokes.

3. Flow with pumps off.
Flow out of the flow line with the pumps shut off is a positive indicator that a kick is in progress. The check for flow can, however, be masked by mud U-tubing or if a slug has been pumped before tripping. Drainage of return lines can also be a factor in flow checks.
Rig movement on a floating drilling rig makes it more difficult to recognize the kick indicators.
It is important that surface equipment reliably detect small increases in the return flow rate.

4. Increase in Pit Volume
A gain in pit volume not caused by, mud additions, mud transfer from different pits, start and stop of mud solids control equipment, or the start and stop of degassing equipment, is a positive indicator that a kick is occurring.

Monitoring and recording of the active pit volume must be done on a continuous basis.

5. Variation in Pump Speed and Pressure
An influx of formation fluid into the wellbore may cause a variation in the pump output.

A decrease in pump pressure combined with an increase in pump speed may occur when low-density formation fluids flow into the annulus causing a "U-tube" effect.

Changes in the pump speed and pressure may not mean there is a kick in the well bore. It may be an indication of pump problems, washout in the string, washed nozzles, etc.

When there is a change in pump speed and pressure, a flow check will be conducted.

6. Well Flowing During a Connection
An influx may occur during a connection due to the reduction in bottom hole pressure as the pumps are shut down (reduction of ECD) and the pipe pulled off bottom (swabbing).

If the well flows only during a connection, it is likely that the influx flow rate will be slow initially, resulting in only a small pit gain.

Checking for flow during a connection is important, because if a close to balance situation is developing, it is most likely to show initially during a connection.

The first signs are likely to be increasing connection gases.

The detection of a small pit gain during a connection is complicated by mud volume in the flow line returning to the pit after the pumps have been shut down (drain back).

7. Drilling Break

A drilling break is an increase in the rate of penetration and is often the first indication that a kick may occur.

A drilling break is an indication of a change in formation characteristics.

Any change in formation can be a factor for the cause of a kick. Increases in formation porosity, permeability and, most important, pore pressure will usually cause an increase in the penetration rate.

Sometimes circulating bottoms up may be advisable before continuing to drill ahead even if a flow check is negative, e.g., HTHP wells, transition zones, or reservoir intervals.

Flow into the well may not be noticeable during a flow check, e.g., the mud in the hole under balances a tight formation.

If low gravity formation fluids enter the wellbore during drilling, the hydrostatic pressure in the annulus will decrease rapidly as more influx enters and when the influx expands as it is circulated up the hole. As a result, rapid influx flow rates can quickly develop, although the initial influx flow rate might have been very low.

The length of formation exposed also has direct bearing on the rate of flow into the well. The greater the length of formation exposed, the larger the flow rate.

All drilling breaks will be flow checked.

8. Change of Drilling Fluid Properties

Accurate and frequent checks of the mud weight and continuous monitoring of the gas content of the mud returning from the hole must be made.

Reduction in drilling fluid density due to formation fluids.

A flow line show observed when gas cut or fluid contaminated mud is returning from the well, does not necessarily mean the well is kicking.

Flow line shows can be:
Drilled shows.
Swabbed shows.
High pressure - low volume shows.

Gas cut mud may have much less density than the mud going in the hole, however, this does not mean that the bottom hole pressure is reduced significantly.

Reduced mud weights can occur during drilling for many reasons. The main reasons are:

Reduction due to formation fluids.
Reduction due to gas cutting.
Settling of weighting material.

9. Increase in Hookload
An increase in Hookload although theoretically possible is not a reliable method of detecting a kick especially in a deviated hole.

When an influx displaces the drilling fluid in the wellbore there will be a reduction in the buoyancy of the drill string, because the influx is lighter than the drilling fluid. A reduction in the buoyancy will be seen on the surface as an increase in the Hookload.

Normally if this indicator is seen, a serious kick has occurred and other, more reliable indicators should have been noticed.

Kick Detection While Tripping

Before tripping the mud should be conditioned to ensure tripping will not cause excessive swab and surge pressures all gas and cuttings have been circulated out and the mud weight is always adequately overbalanced.

The swab and surge pressures and maximum pipe speed will be calculated so as not to break down the formations.

Before every trip, the trip tank, or calibrated tank will be lined up and a trip sheet will be filled out.

The trip sheet will show the expected hole fill volumes as the pipe is pulled out of the hole.

Flow into the wellbore will cause improper hole fill-up. If this is observed, a flow check will be conducted.

If the flow check is positive then the well will be shut-in.

A negative flow check at this point is not necessarily confirmation that an influx has not occurred. It is possible, that the well will not flow even if an influx has been swabbed in.

Every effort must be made to ensure that significant swab pressures are avoided during a trip. The first 10 stands are usually the most critical.

As pipe is tripped out of the hole, the actual hole fill volumes will be entered.

If the hole is taking less mud than expected it is an indication that an influx has been swabbed into the hole. If a successful trip was made the previous time, then the previous trip sheet will be a good guide to expected hole fill values.

If the hole will not take the correct volume of mud, the pipe will be run immediately back to bottom and bottoms up circulated. When circulating mud, consider bringing the last 2500 feet of annulus volume below the BOP stack through an open choke (especially in HPHT wells).

Any deviation from expected hole fill volumes will be investigated

Kick Containment

When a well kicks, it should be shut-in within the shortest possible time. By taking action quickly, the amount of formation fluid that enters the well bore and the amount of drilling fluid expelled from the annulus is minimized.

The size and severity of a kick depends upon:

- The degree of underbalance.
- The formation permeability.
- The length of time the well remains underbalanced.

Any suspected influx must be shut-in as fast as possible. The preferred method is the hard shut-in. The procedure for shutting-in the well will be rehearsed so that it can be done fast and without mistakes. Drills will be conducted and recorded on the IADC drilling report.

The Driller, or the person on the brake, has sole responsibility to take the initial steps in a potential well control situation. He has the authority to shut the well in whenever an indication of an influx or kick exists. False alarms should be treated as good kick drills.

Clearly written, detailed instructions on the shut-in policy will be available to the Driller. Notices displaying the shut-in procedure will be posted on the drill floor.

When a positive indication of a kick is observed (or if there is any doubt), such as a sudden increase in flow or an increase in the pit level is noted, the well will be shut-in immediately without conducting a flow check.

Shut In Procedures

Surface BOPs while Drilling

Stop rotation.

Pick up the string to shut-in position.

Stop the pumps and flow check; if well flows:

Close annular and open remote control choke line valve (HCR).

Notify the Toolpusher and OIM, who will notify the Operator representative.

Check space out and close pipe rams and ram locks.

Bleed off pressure between pipe rams and annular (if possible).

Record annulus and drill pipe pressure and pit gain.

Subsea BOPs while Drilling

Stop rotation.

Pick up the string to shut-in position.

Stop the pumps and flow check; if well flows:

Close the annular preventer (upper preferred) with 1500 psi control pressure, and immediately open choke outlet valves on the BOP stack.

Notify the Toolpusher and OIM, who will notify the Operator representative.

Confirm the space out and close the designated hang off rams with reduced pressure, reduce the annular pressure, slack off and land drill string on the rams.

Increase the manifold pressure back to 1500 psi. Engage ram locks.

Bleed off pressure between pipe rams and annular, if possible, and open annular.

Adjust the Drill String Compensator to support the drill string weight to the BOP plus 20,000 lbs. Set the DSC at mid stroke.

Commence recording the shut-in drill pipe and casing pressures.

Confirm the gain in pit volume.

Monitor riser for flow.

Surface BOPs while Tripping

Set the slips at suitable height.

Install full opening safety valve and close same.

Close annular and open HCR valve on choke line.

Notify Toolpusher and OIM, who will notify the Operator representative.

Make up the Kelly or Top Drive (insert pup joint between safety valve and Top Drive) and open the safety valve.

Record annulus and drillpipe pressures and pit gain.

Prepare to strip back to bottom.

Subsea BOPs while Tripping

Set the slips at suitable height.

Stab, hand tighten and close the fully opening safety valve .

Close the annular preventer (upper preferred), and immediately open choke outlet valves on the BOP stack.

Notify the Toolpusher and OIM, who will notify the Operator representative.

Make up the Kelly or Top Drive and open the safety valve. (insert a pup joint or single between the Top Drive and the safety valve).

Open the Drill String Compensator (DSC).

Confirm the space out and close the designated hang off rams with reduced pressure, reduce the annular pressure, slack off and land drill string on the rams. Increase the manifold pressure back to 1500 psi. Engage ram locks.

Bleed off the pressure trapped between the annular and rams, if possible.

Adjust the DSC to support the drill string weight to the BOP plus 20,000 lbs. Set the DSC at mid stroke.

Commence recording the shut-in drill pipe and casing pressures.

Confirm the gain in the trip tank volume.

Monitor riser for flow and prepare for stripping operation.

Stuck Pipe

Stuck pipe can be a very time consuming and expensive problem.

Stuck pipe is generally divided into two categories:

1. Formation related
2. Mechanical and wellbore geometry related

Solids Induced Pack-off

Packing Off - First Actions

1. At the first signs of the drill string torqueing up and trying to pack-off, the pump strokes should be reduced by half. This will minimise pressure trapped should the hole pack-off. Excessive pressure applied to a pack-off will aggravate the situation. If the hole cleans up, return flow to the normal rate.

2. If the string packs off, immediately stop the pumps and bleed down the standpipe pressure [NB not possible with a non-ported float valve]. When bleeding pressure down from under a pack-off, control the rate so as not to "U" tube solids into the drill string in case they plug the string.

3. Leave low pressure (<500 psi) trapped below the pack-off. This will act as an indicator that the situation is improving should the pressure bleed off.

4. Holding a maximum of 500 psi on the standpipe and with the string hanging at its free rotating weight, start cycling the drill string up to maximum make-up torque. At this stage do not work the string up or down.

5. Continue cycling the torque, watching for pressure bleed off and returns at the shakers. If bleed off or partial circulation occurs, slowly increase pump strokes to maintain a maximum of 500 psi standpipe pressure. If circulation improves continue to increase the pump strokes.

6. If circulation cannot be regained, work the pipe between free up and free down weight. DO NOT APPLY EXCESSIVE PULLS AND SET DOWN WEIGHTS AS THIS WILL AGGRAVATE THE SITUATION (50k lb max). Whilst working the string continue to cycle the torque to stall out and maintain a maximum of 500 psi standpipe pressure.

7. DO NOT ATTEMPT TO FIRE THE JARS IN EITHER DIRECTION.

8. If circulation cannot be established increase the standpipe pressure in stages up to 1500 psi and continue to work the pipe and apply torque.

9. If the pipe is not free once full circulation is established, commence jarring operations in the opposite direction to the last pipe movement. Once the pipe is free rotate and clean the hole prior to continuing the trip.

Unconsolidated formations

An unconsolidated formation falls into the well bore because it is loosely packed with little or no bonding between particles, pebbles or boulders.

The collapse of the formation is caused by removing the supporting rock as the well is drilled. This is very similar to digging a hole in sand on the beach, the faster you dig the faster the hole collapses.

It happens in a well bore when little or no filter cake is present. The un-bonded formation (sand, gravel, small river bed boulders etc.) cannot be supported by hydrostatic overbalance as the fluid simply flows into the formation. Sand or gravel then falls into the hole and packs off the drill string. The effect can be a gradual increase in drag over a number of metres, or can be sudden.

This mechanism is normally associated with shallow formations. Examples are shallow river bed structures at about 500m in the central North Sea and in surface hole sections of land wells. This mechanism normally occurs while drilling shallow unconsolidated formations.

Mobile Formations

The mobile formation squeezes into the well bore because it is being compressed by the overburden forces. Mobile formations behave in a plastic manner, deforming under pressure.

The deformation results in a decrease in the well bore size, causing problems running BHA's, logging tools and casing. A deformation occurs because the mud weight is not sufficient to prevent the formation squeezing into the well bore.

Fractured & Faulted Formations

A natural fracture system in the rock can often be found near faults. Rock near faults can be broken into large or small pieces. If they are loose they can fall into the well bore and jam the string in the hole. Even if the pieces are bonded together, impacts from the BHA due to drill string vibration can cause the formation to fall into the well bore.

This type of sticking is particularly unusual in that stuck pipe can occur while drilling. When this has happened in the past, the first sign of a problem has been the string torquing up and sticking. There is a risk of sticking in fractured / faulted formation when drilling through a fault and when drilling through fractured limestone formations.

Naturally Over-Pressured Shale Collapse

A naturally over-pressured shale is one with a natural pore pressure greater than the normal hydrostatic pressure gradient.

Naturally over-pressured shales are most commonly caused by geological phenomena such as under-compaction, naturally removed overburden (i.e: weathering) and uplift. Using insufficient mud weight in these formations will cause the hole to become unstable and collapse.

Induced Over-Pressured Shale Collapse

Induced over-pressure shale occurs when the shale assumes the hydrostatic pressure of the well bore fluids after a number of days exposure to that pressure. When this is followed by no increase or a reduction in hydrostatic pressure in the well bore, the shale, which now has a higher internal pressure than the well bore, collapses in a similar manner to naturally over-pressured shale.

Reactive Formations

A water sensitive shale is drilled with less inhibition than is required. The shale absorbs the water and swells into the well bore. The reaction is 'time dependent', as the chemical reaction takes time to occur. However, the time can range from hours to days.

Hole Cleaning

In deviated wells cuttings and cavings settle to the low side of the hole and form layers called solids beds or cuttings beds. The BHA becomes stuck in the solids bed.

OR

Cuttings and cavings slide down the annulus when the pumps are turned off and pack-off the drill string. Avalanching can also occur while the pumps are on. Good hole cleaning means removal of sufficient solids from the well bore to allow the reasonably unhindered passage of the drill string and the casing.

There are several main reasons for solids not being cleaned out of the well bore.

These are:
□Low annular flow rate.
Inappropriate mud properties.
Insufficient circulation time.
Inadequate mechanical agitation.

Tectonically Stressed Formations

Well bore instability is caused when highly stressed formations are drilled and there exists a significant difference between the near well bore stress and the restraining pressure provided by the drilling fluid density.

Tectonic stresses build up in areas where rock is being compressed or stretched due to movement of the earth's crust. The rock in these areas is being buckled by the pressure of moving tectonic plates.

When a hole is drilled in an area of high tectonic stresses the rock around the well bore will collapse into the well bore and produce splintery cavings similar to those produced by over-pressured shale. In the tectonic stress case the hydrostatic pressure required to stabilise the well bore may be much higher than the fracture pressure of the other exposed formations

Differential Sticking

Differential sticking occurs when the drill string is held against the well bore by a force. This force is created by the imbalance of the hydrostatic pressure in the well bore and the pore pressure of a permeable formation. When the hydrostatic pressure is greater than the pore pressure the difference is called the overbalance. The resultant force of the overbalance acting on an area of drill string is the force that sticks the string.

This mechanism normally occurs:
1) With a stationary or very slow moving string.
2) When contact exists between the drill string and well bore.
3) When an overbalance is present.
4) Across a permeable formation.
5) In a thick filter cake.

Mechanical & Well Bore Geometry

Other Stuck Pipe Types - First Action
Guidelines for freeing stuck pipe other than Pack-offs and Differential sticking.
a) Ensure circulation is maintained.
b) If the string became stuck while moving up, (apply torque) jar down.
c) If the string became stuck while moving down, do not apply torque and Jar up.
d) Jarring operations should start with light loading (50k lbs) and then systematically increased to maximum load over a one hour period. Stop or reduce circulation when; a) cocking the jars to fire up and b) jarring down. Pump pressure will increase jar blow when jarring up, so full circulation is beneficial (beware of maximum load at the jar).
e) If jarring is unsuccessful consider acid pills, if conditions permit.

Key Seating

Key seating is caused by the drill pipe rotating against the bore hole wall at the same point and wearing a groove or key seat in the wall. When the drill string is tripped, the tool joints or the BHA are pulled into the key seat and become jammed. Key seating can also occur at the casing shoe if a groove is worn in the casing.

This mechanism normally occurs:
· At abrupt changes in angle or direction in medium-soft to medium-hard formation.
· Where high side wall forces and string rotation exist.
· While pulling out of the hole.
· After long drilling hours with no wiper trips through the dogleg section.

Undergauge Hole

Drilling hard abrasive rock wears the bit and the stabiliser gauge and results in a smaller than gauge hole. When a subsequent in-gauge bit is run, it encounters resistance due to the undergauge section of hole. If the string is run into the hole quickly without reaming, the bit can jam in the undergauge hole section.

This mechanism normally occurs:
· After running a new bit.
· After coring
· When a PDC bit is run after a roller cone bit
· When drilling abrasive formations

Junk

Debris that has fallen into the hole from surface or from downhole equipment, which falls down the well bore and jams the drill string.

This mechanism usually occurs:
· Due to poor housekeeping on the rig floor.
· The hole cover not being installed.
· Downhole equipment failure.

Ledges and Doglegs

___**Ledge**: The well bore passes through rock of varying types and ledges develop at the interfaces between layers of differing hardness.

___**Doglegs**: While drilling a well bore, the characteristics of the rock cause the bit to be deflected and can result in a change in direction. Likewise when drilling with a directional BHA, sudden changes in angle can cause a kink in the well bore direction. Sharp deviations in wellbore direction are called doglegs.

This mechanism usually occurs:
· When an unsuitable BHA is run.
· After a change in BHA.
· Prognosed hard soft interbedded formations.
· Prognosed fractured / faulted formations.
· After direction changes.
· While POOH.

Collapsed Casing / Tubing
Casing collapses either if pressure conditions exceed its original rated collapse pressure or the original collapse pressure rating of the casing is no longer valid due to casing wear and/or corrosion. Casing wear due to friction or corrosion decreases the effective collapse pressure rating of the casing, through decreased wall thickness. Collapse is often discovered when the BHA is run into the hole and hangs up inside the casing.

This mechanism can occur when:
· The collapse pressure of the casing is exceeded during a pressure test where an annulus leak is occurring. The collapse pressure of the casing may be less than expected, due to casing wear.
· The casing fluid is evacuated, causing the casing to collapse.
· The casing is buckled due to aggressive running procedures.

Cement Blocks
The drill string becomes jammed in the hole by cement blocks falling around the string.

This mechanism normally occurs when :
· Hard cement becomes unstable around the casing shoe, open hole squeeze plugs and kick-off plugs.

Green Cement
When the drill string is inadvertently run into cement, the cement can flash set. The top of the cement may be higher than prognosed. The increase in pressure generated by the surge of the BHA causes the cement to flash set.

Circulation is attempted with the bottom of the drill string in soft cement. The increase in pressure causes the cement to flash set. A high penetration rate is used when cleaning out recently set cement, below which is un-set cement which flash sets.

This mechanism normally occurs:
· While running into the hole to dress off cement.

Hydrogen Sulphide

Hydrogen Sulfide, also known as H_2S, is a toxic, colorless, combustible gas that is formed by the decomposition of organic plant and animal life by bacteria and has the distinct odor of rotten eggs at low concentrations. Hydrogen Sulphide can be found in oil and gas refining and production, sewers, pulp mills, underground water and a variety of industrial processes.

It is heavier than air and forms explosive mixtures, with air, between ~~5.9~~4.3% (LEL) and ~~22.2~~46% (UEL) by volume.

Prolonged exposure to Hydrogen Sulfide has a tendency to dull the olfactory nerve, your sense of smell. The sense of smell can be lost in 2 to 15 minutes of exposure to low concentrations and lost in 60 seconds at higher levels.

Thus a person exposed to Hydrogen Sulphide may think the proportion of the gas is decreasing, when it may actually be increasing.

Susceptibility to H_2S poisoning varies according to the number of exposures by an individual. A second exposure is more dangerous than the first, and so on.

Hydrogen Sulphide is more poisonous than Carbon Monoxide, but its characteristic odor of rotten eggs in low concentrations can make its presence easy to detect.

One-tenth of 1% (0.1 percent! or 1000 ppm) may cause instantaneous death, and unconsciousness may result from exposure to 0.02% (2 hundredths of a percent, 200 ppm).

This gas is very irritating to the eyes and throat, and as its concentration increases, It also tends to destroy the sense of smell.

H_2S poisons a person by building up in the blood stream the same as carbon monoxide does, but H_2S is as toxic as Hydrogen Cyanide and is between 5 to 6 times more toxic than Carbon Monoxide.

The after effects of being intoxicated with this gas are serious, similar to those of carbon Monoxide. They last for long periods of time and may have permanent effects. Should the concentration be high enough, death follows rapidly after the victim has lost consciousness.

This toxic gas paralyzes the nerve centers in the brain which control breathing. As a result, the lungs are unable to function and the individual is asphyxiated.

Hydrogen Sulphide in low concentrations is easily recognized by its characteristic foul odour similar to rotten eggs.

However continued exposure will temporarily eliminate one's ability to smell the gas. The effect usually misleads the worker into thinking the danger has passed; often with tragic results.

The acute effect of H_2S on the body is twofold. It acts as an irritant to eyes, nose, throat and lungs and it acts as an internal poison causing unconsciousness by paralysis of the respiratory system.

Properties of H_2S

Color	Colorless
Odor	Very offensive, commonly referred to as odour of rotten eggs
Vapor density	1.189 (Air=1.0) H2S is heavier than air
Explosive limits	4.3 to 46 percent by volume in air
Auto ignition temp	260 degrees C
Flammability	Forms explosive mixture with air or oxygen
Water solubility	2.9 percent (2.9g/100 ml water at 20 degrees C)

Effects of H_2S (10,000 parts per million = 1 percent)

1 ppm	Can be smelled.
10 ppm	Occupational Exposure Limit (OEL) for 8 hours (Alberta)
15 ppm	OEL allowable for 15 minutes of exposure.
20 ppm	Ceiling OEL. At this level workers must wear appropriate breathing apparatus.
100 ppm	Loss of sense of smell in 2 to 15 minutes. Possible headache, nausea, throat irritation.
200 ppm	Sense of smell lost rapidly. Burns eyes and throat.
300 ppm	Immediately Dangerous to Life and Health (IDLH) level. Positive pressure breathing apparatus required.

500 ppm Loss of reasoning and balance. Respiratory disturbances in 2 to 15 minutes.

700 ppm............... Immediate unconsciousness. Death will result if not rescued promptly.

1000 ppm.............Causes immediate unconsciousness. Causes seizures, loss of control of bowel and bladder. Breathing will stop and death will result if not rescued promptly. Immediate resuscitation needed.

Gas Detectors

To determine the presence of H_2S in your work area, one of the following means of detection should be used:

1. Gas Detector Tubes

The concentration of H_2S is indicated by the length of the discoloration when a set volume of air is drawn through the detector tube. There are several reliable types of detector tubes available, but correct interpretation of the results requires a trained and experienced operator.

2. Continuous Monitors

In larger plants and during critical drilling and well servicing operations a system is used where potentially hazardous areas are sampled by strategically located sensors. An alarm system is activated by any sensor and will give warning when the H_2S concentration rises above preset limits for the area sampled

3. Personal Monitors

Battery operated H_2S monitors can be carried or worn by individual workers to indicate the concentration of H_2S to which they are being exposed.

4. Portable Monitors

Used for testing for gas enriched areas on the rig. Mainly used when performing confined space entry operations.

Familiarize yourself with the detection equipment used on your worksite. Learn its proper operation. Maintain and operate it according to manufacturer's specifications. Your life may depend on it!

Rescue & First Aid

Do Not become a victim yourself. Ask yourself (**THINK**) *"Is it safe for you and me to attempt a rescue without proper respiratory PPE?"* Unfortunately many would be rescuers become victims adding to the gravity of the situation and possibly overwhelming the medical resources available.

It is VITALLY IMPORTANT that everyone working around or near H_2S have a good working knowledge of artificial respiration (rescue breathing).

Training in C.P.R. (cardio-pulmonary resuscitation) would be a strongly recommended addition to a worker's knowledge and skill in first aid.

It is important when workers use respiratory protective equipment for rescue that they are aware of the limitations of each type of equipment.

Regular practice and training in rescue are necessary to provide appropriate rescue capability on the worksite.

Protection from H_2S

When you are in any area where H_2S is a potential hazard, you must wear approved personal protective and respiratory protective equipment.

Selection of Respiratory Protective Equipment must be in accordance with the General Safety Regulations.

Two Common Types of Respiratory Protection

1. Self-Contained Breathing Apparatus

This type of apparatus supplies compressed air from a cylinder worn on the back to a full face piece. This apparatus must be of the type that maintains positive pressure in the facepiece.

The cylinder must be rated to supply air for at least 30 minute. Heavy physical work will consume air more quickly. ***Note:*** A physically fit, well trained and experienced Fire Fighter (Rescuer) may be able to make a "30 minute" bottle last 30 minutes. In most individuals with you should only expect 15 – 20 minute of service from these bottles.

All self-contained breathing apparatus must be equipped with an "Low Air Pressure" alarm in accordance with the General Safety Regulations. Typically, this alarm signals the user that there is only 5 minutes of usable air remaining. *Remember the above note!*

2. Supplied Air Breathing Apparatus

This apparatus supplies respirable air from cylinders, or a compressor in a remote location, via a hose to a full face piece. This apparatus must be of a type that maintains positive pressure in the face piece.

An emergency escape bottle must be worn with this type of equipment in case of an interruption of supplied air. This is a requirement of the General Safety Regulation Sections.

The emergency escape bottle is for escape purposes only and must never be used alone to carry out work in an H_2S environment.

Note: Workers using respiratory protective equipment of either type, must be clean shaven.

ALWAYS PUT ON RESPIRATORY PROTECTION BEFORE ATTEMPTING ANY RESCUE.
YOU COULD BECOME A VICTIM!