NUMERICAL SIMULATION

OF

WELL BLOWOUT

By
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College of Engineering
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Dehradun
May, 2008

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WELL BLOWOUT

A thesis submitted in partial fulfilment of the requirements for the Degree of
Bachelor of Technology
(APPLIED PETROLEUM ENGINEERING)

By

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Under the guidance of

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UNIVERSITY OF PETROLEUM & ENERGY STUDIES

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CERTIFICATE

This is to certify that the work contained in this thesis titled "NUMERICAL SIMULATION OF WELL BLOWOUT" has been carried out by Ankit Mago under my supervision and has not been submitted elsewhere for a degree.

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ABSTRACT

During operations associated with drilling, it is necessary to maintain control over fluids that occur in the pore spaces of formations being penetrated by the well. These fluids can be subjected to extreme pressures and temperatures in situ although these are not pre-requisites for the fluid to cause well control problems.

Failure to maintain control over these fluids can result in a spontaneous and sometimes rapid flow of the fluid into the well bore. The rate of the flow is determined by the degree of imbalance between the well bore and the reservoir pressures combined with the permeability of the reservoir. In its initial stages, such a flow is called as a kick. When such a flow is not controlled and deteriorates in an uncontrolled manner it is called as a blowout.

Blowouts can be very dangerous and are very damaging to the operator. The initial stages of a blowout can be hazardous to the personnel and can cause major damage to the equipment around the well. It can also have an impact on the overlying reservoirs which may become polluted or overly pressurized.

Different methods can be used for controlling a kick. Following methods like Driller's method, Engineer's method, concurrent method, wait on weight method can be used. However the following study concentrates on the application of Driller's method and Wait on Weight method. It also includes the comparison between Driller's method and Wait on weight method. The study ends with a numerical calculation by using wait on weight method for kick removal in a well xyz, drilled by shell E& P.

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ABBREVIATIONS & ACRONYMS

Volumes (m^3 , bbl)

AV	increase in volume of drilling fluid due to weighting material
v_l	volume of p_x drilling fluid above kick at end of phase I
V_x	original volume of gas
V_2	expanded volume of gas
V_{ab}	total volume of annulus
Vg	volume or capacity of the drill string
Vkiek	volume of the kick
V_t	total tank volume increase
X	volume fraction of gas at the well head (gas cut drilling fluid)

Linear capacities (m^3/m, bbl/ft)

c_x	linear capacity of drill collar - open hole annulus
C2	linear capacity of drill pipe - open hole annulus
C3	linear capacity of drill pipe - casing annulus

Depths, heights and lengths (m, ft)

D	depth from surface to bit
D_l	height of p_x drilling fluid below the influx
D_2	height of p_2 drilling fluid below the influx
D_s	depth to casing shoe
h	height of drilling fluid column in Strong-White equation for gas cut drilling fluid
h_b	height of influx when the influx is at bottom. (Must be true vertical height)
h'_b	equivalent height to height of influx at bottom, based only on change in capacity up hole
hjjjf	actual height of influx up hole
h	height of part of p_x drilling fluid in drill pipe - casing annulus

LENGTH (M)

L	length of a section of pipe or annulus
L_{choke}	length of choke line
L_{dc}	length of drill collars
Ldp	length of drill pipe
Ldpoh	length of drill pipe in open hole
Lhwdp	length of heavy wall drill pipe
X	height of pj drilling fluid above influx

Pressures in stages method (kPa, psi)

MAASP	Maximum allowable surface pressure
P	pressure at top of influx at the point of interest
Pann1	closed in annulus pressure at start
Pdp	closed in drill pipe pressure at start
Pd_{p2}	closed in drill pipe pressure at end of first circulation
P_{st}	closed in drill pipe pressure at end of second circulation
P_{sto}	standpipe pressure at the beginning of the first circulation
Pd_{P1}	standpipe pressure at end of phase 1 in first circulation
P_0	formation pressure
P_0^*	pressure at the top of the gas influx when influx is at bottom [= P_0 - P_f]
P_s	Total friction pressure loss
P_{shoe}	formation strength at the casing shoe [= $D_s \rho_f$]
P_{st}	standpipe pressure
$\Delta P_{swab/surge}$	surge and swab pressures

P_{c_1} friction pressure while circulating with original drilling fluid

P_{c_2} friction pressure while circulating with new drilling fluid

P_{choke} choke pressure

P_{dp} closed in drill pipe pressure

P_f pressure exerted by the mass of gas which entered the annulus [$= h_b \rho_{inf}$]

P_{fa} pressure drop due to friction in the annulus

P_{fch} pressure drop due to friction in the choke line

P_{fd} pressure drop due to friction in the drill pipe

P_h hydrostatic head at depth h in Strong-White equation for gas cut drilling fluid

P_0 formation pressure

P_0^* pressure at the top of the gas influx when influx is at bottom [$= P_0 - P_f$]

Gradients (kPa/m, psi/ft)

d^, gradient of weighting material

p drilling fluid gradient

pi initial drilling fluid gradient

p2 gradient of weighted drilling fluid (final weight up in stages method)

Pa/b/c intermediate drilling fluid gradients in well killing by stages with p_2 being the gradient of the final weight up

pp formation strength gradient

Piof gradient of the influx

pinf effective gradient of influx at point of interest

Pm gradient of drilling fluid in the Strong-White equation for gas cut drilling fluid

Other symbols

A	nozzle area (mm^2, in^2)
C	constant in the power-law equation for P_s
d i	outside diameter of pipe (mm, inch)
d_2	diameter of the hole (mm, inch)
f	friction factor
g	acceleration due to gravity (9.80665 m/s^2)
n	index in the power-law equation for P_s
Nx	amount of weighting material to weight up 1 ms or 1 bbl (kg, lbs)
NT	amount of weighting material to weight up total volume of drilling fluid (kg, lbs)
Q	flow rate (pump output) (ms/min, gpm)
T_x	initial absolute temperature of gas (K)
T_2	absolute temperature of gas at point of interest (K)
V	drilling fluid velocity (m/s, ft/min)
V_s	average drilling fluid velocity when calculating surge and swab pressures (m/s, ft/min)
Z_I	initial compressibility factor of gas
Z_2	compressibility factor of gas at point of interest.

INTRODUCTION

During operations associated with drilling, it is necessary to maintain control over the fluids that occur in the pore-spaces of formations being penetrated by the well. These fluids can be subject to extreme pressures and temperatures in-situ although these are not pre-requisites for the fluids to cause well control problems.

Failure to maintain control over these fluids can result in a spontaneous and sometimes rapid flow of the fluid into the well bore. The rate of flow is determined by the degree of imbalance between the well bore and reservoir pressures combined with the permeability of the reservoir. In its initial stages, such a flow is called a kick. When such a flow is not controlled and deteriorates in an uncontrolled manner it is described as a blow-out.

Blow-outs can have a very visible environmental impact and, for that reason alone are very damaging for the Operator. The initial stages of a blow-out can also be very hazardous to personnel and cause major damage to equipment in the vicinity of the well. However, the blow-out can also cause significant damage to the producing reservoir through depletion and creation of preferential gas and water flow paths. It can also have a secondary impact on overlying formations which may become polluted or abnormally pressurized. These factors impact on operations long after the surface environmental impact has been resolved.

- prevention - using primary control techniques and

- control and recovery - if an under-balanced situation does occur; how to control it and regain primary control.

The procedures associated with regaining primary control are called secondary control measures. These aim to regain control with minimum impact to the immediate and long term integrity and productivity of the well. Should these measures fail then more drastic tertiary well control measures may be applied.

1.1 PRIMARY CONTROL

There are four principal causes which may result in or contribute to the loss of primary well control:

- Insufficient fluid density
- Losses
- Swabbing
- Failure to fill the hole properly.

Insufficient density and losses tend to be related to drilling ahead, whilst swabbing and a failure to fill the hole properly tend to occur whilst tripping in and out of the hole with the drill string, casing or other tools.

PRIMARY CONTROL WHILE DRILLING

Whilst drilling ahead, an under-balanced condition will occur if a permeable formation is penetrated which has a pore pressure higher than the hydrostatic pressure of the column of drilling fluid in use, i.e. the density of the drilling fluid is insufficient. Under these conditions primary control can no longer be maintained and secondary control measures will have to be implemented until drilling fluid with a sufficiently high gradient can be circulated into the well under controlled conditions.

Cautionary signals :

Whilst drilling, the following cautionary signals can indicate the possibility of foreign fluid entry to the well bore. In particular:

- gas cut or contaminated fluid at the flow line (this indicates that a hydrocarbon-bearing formation has been penetrated);
- a gradual or sudden increase in penetration rate (although this may be due to various factors, it could indicate that an overpressured formation has been penetrated. When a drilling break occurs, a flow check should be made as quickly as possible);
- an increase in salinity;
- a decrease in circulating pressure.

1.2 SECONDARY WELL CONTROL

PRINCIPLES

Secondary control is the proper use of **blow-out prevention (BOP)** or **pressure control** equipment to regain control of the well in the event that primary control cannot be properly maintained.

The pressure control equipment prevents flow from the well and allows surface pressure to develop in an underbalanced situation. The surface casing pressure will rise to the point where it equals the bottom hole pressure less the hydrostatic head of the fluid in the annulus (where a string of tubulars are in the well) or the hole (where there are no tubulars in the well) . Where a drill string is in the well and pressure control equipment has been installed on it, the drill string surface pressure will rise until it equals the bottom hole pressure less the hydrostatic head of the fluid in the drill string.

Well control equipment permits the well to be closed in and remedial action to be taken, usually in the form of removing any influx of gas, oil or water, and restoring primary control. Where the influx has been caused by the penetration of an overpressured formation this will entail the controlled displacement of the well to drilling fluid with an increased gradient. In the case of swabbing where the kick has been caused by the swabbed-in influx reducing the hydrostatic pressure, it is only necessary to remove the influx under controlled conditions to regain primary control of the well. From the point that the well is closed in until primary control has been reestablished, the first objective of all operations carried out is to maintain bottom hole pressure at, or only slightly above, the formation pore pressure, P_0. Allowing it to drop below P_0 will allow a second influx. If the bottom hole pressure is any higher than P_0 then there is an unnecessary risk of causing damage to the formation. This is one of the basic tenets of well control.

Circulation whilst holding dynamic back pressure via a variable choke is the most common method for removing an influx in a controlled manner. The amount of back pressure, measured by a pressure gauge immediately upstream of the choke (and called the choke pressure or P^) is adjusted such that the bottom hole pressure is maintained at a constant value equal to or just above the formation pore pressure.

Due to the presence of the bit/nozzles it is rare for an influx to enter the drill string and so this conduit to the bottom of the hole, containing a fluid of a known gradient, provides a simple way of monitoring both the dynamic and static bottom hole pressures whilst killing the well in a controlled manner.

1.3 TERTIARY WELL CONTROL

OBJECTIVES

If secondary well control procedures cannot be followed due to equipment failure or hole conditions, certain emergency procedures can be implemented to avoid a total loss of control. In practice this means an internal or external blowout! Such measures, which are usually referred to as Tertiary Well Control have the objective of plugging the open hole section which is the cause of the problem. They therefore generally lead to a partial or complete abandonment of that hole section.

METHODOLOGY

BARYTES PLUGS

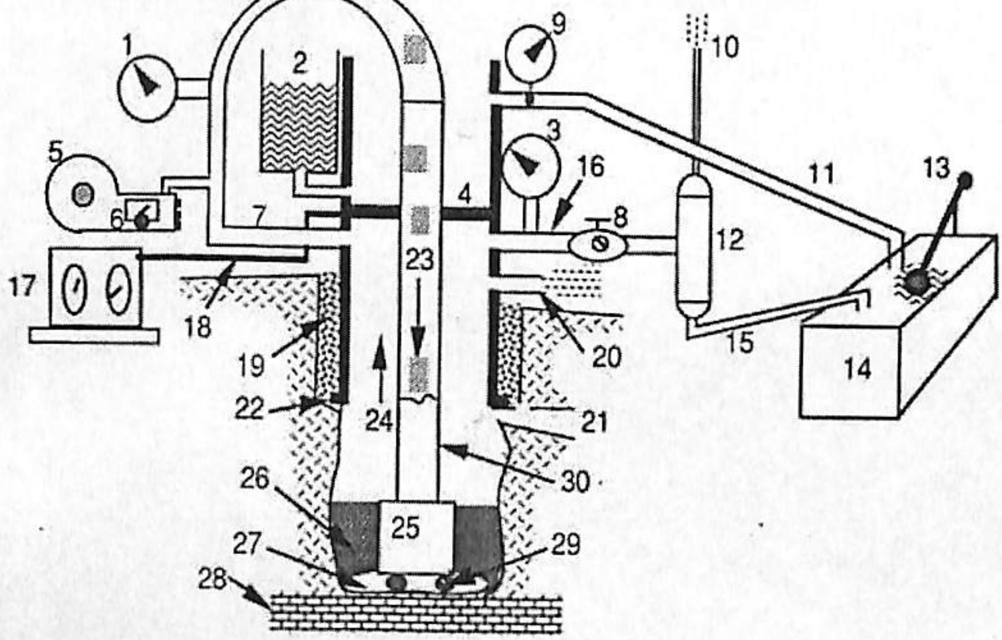
A barytes plug is a slurry of barytes in fresh water or diesel oil which is displaced through the drill string. If possible, the string is then pulled above it. The barytes settles out rapidly and should form an impermeable mass capable of isolating the producing zone. The effectiveness of a barytes plug derives from the high density and fine particle size of the material and its ability to form a tough impermeable barrier. It has the advantages that it can be pumped through the bit and offers a reasonable chance of recovering the drill string. In addition, the plug can be drilled up easily if required.

CEMENT PLUGS

A cement plug can also be used to shut off a down-hole flow. This is really a measure of last resort as it often results in plugging of the string and a subsequent loss of most of the drilling tools. In addition, any cement job is unlikely to be perfect and this can lead to long term problems with cross flow. Once a drill string has been cemented in to a hole section this can be very difficult to remedy.

This method involves displacing a quantity of quick setting (accelerated) cement down the string and into the annulus. The use of quick setting cement reduces the possibility of gas cutting taking place. The cement is usually displaced until pump and choke pressures indicate that a bridge has formed but this will be, to a large extent, guesswork.

CHAPTER 2 : CAUSES OF KICKS & KICK INDICATORS



NUMBER EQUIPMENT

1 standpipe pressure gauge
3 casing pressure gauge
5 mud pump
7 kill line
9 flow line mud flow sensor
11 mud flow line
13 mud pit level sensor
15 separator mud flow line
17 accumulator
19 cement for last casing
21 fracture in formation and loss of mud
22 shoe of last casing
23 kill mud and inside drillpipe
24 drilling mud and drillpipe annulus
25 drill collars
27 drill bit
29 jets in the drill bit

2 hole fill tank
4 blowout preventer rams (or bag)
6 mud pump stroke sensor
8 choke in choke line
10 gas flare and flare line
12 gas mud separator
14 active mud pit
16 choke line
18 bope lines
20 vent line
26 kick fluid and drill collar annulus
28 kicking formation
30 drillpipe

Figure 1: KICK REMOVAL EQUIPMENTS

2.1 CAUSES OF KICKS

GENERAL

The main causes of kicks are:

- Failing to fill the hole properly when tripping
- Swabbing in a kick while tripping out
- Insufficient mud weight
- Abnormal formation pressure
- Lost circulation
- Shallow gas sands
- Excessive drilling rate in gas bearing sands

Currently almost 50% of all blowouts are attributed to a combination of causes (a) and (b). Each of the possible causes are described.

FAILING TO FILL THE HOLE PROPERLY

This is one of the common causes of kicks. If the fluid level in the hole falls, than a reduction of bottom hole pressure must occur since the length of the fluid column has shortened.

As drill pipe and collars are pulled out of the hole, a volume of mud equal to the volume of steel which has been removed, must be added to the hole to keep it full. If this is not done the length of the mud column is reduced, thereby lowering the bottom hole pressure. Once this pressure drops below formation pressure, at any point in the open hole, a kick may occur.

The holes should be filled, either on a continuous basis with a re-circulating trip tank, or on a regular fill-up schedule. An accurate method of measuring the amount of fluid actually required to fill the hole must be used an accurate record kept of the volume of steel removed. If the volume required to fill the hole is significantly less than the volume of steel known to have been removed, then either:

- Fluid must have entered the hole from the formation, or
- Gas already present in the well bore is expanding.

Note that the volume of steel in a length of drill collars may be anything from five to ten times the volume of steel in the same length of drill pipe. This increased volume of steel fills more of the total available volume in the hole. This means that not only is much mud required to replace each length of drill collars but, if the hole is not filled, the level of mud will drop much further than would be the case with drill pipe.

Two possible arrangements for monitoring mud volume during trips are:

- Mud fill-up line with stroke-counter
- Continuously circulating trip tank.

Mud Fill-Up Line, with Stroke Counter

In this procedure, the hole is 'topped up' at regular intervals using a fill-up line, and the required mud volume is then noted. Typically this will be done after every five stands of drill pipe, and after every stand of drill collars. This may be stretched, depending on circumstances, to one fill-up every ten stands of drill pipe or two stands of drill collars.

The mud volume added may be calculated either by noting the number of pump strokes required from a pump of known displacement, or by pumping mud from a trip-tank, with a direct reading of mud volume available on the drill floor. Ideally the trip tank will be a tall narrow tank, so that a small volume change shows up as a large change in mud level.

The advantage of the fill-up method is that at regular intervals, attention is being drawn to the mud to check hole volumes and a routine is established. Its main possible drawback is that other hole problems or rig requirements may disrupt the trip routine (rhythm) and hence attention from the need to fill up the hole.

Continuous Circulating Trip Tank

The trip tank, can be set to continuous gravity feed, or it can use pump feeding. The advantage of this system is that the hole remains full at all times, and the volumes used can be continuously and accurately maintained.

The main drawback to this system is that the trip tank does not contain enough mud to permit a full trip without refilling. The drill crew should develop a routine of checking the trip tank level frequently and therefore be aware when refilling is required. It is relatively easy for other problems to distract attention from this need, especially when drill collars are being pulled and extra demands placed upon the drill crew.

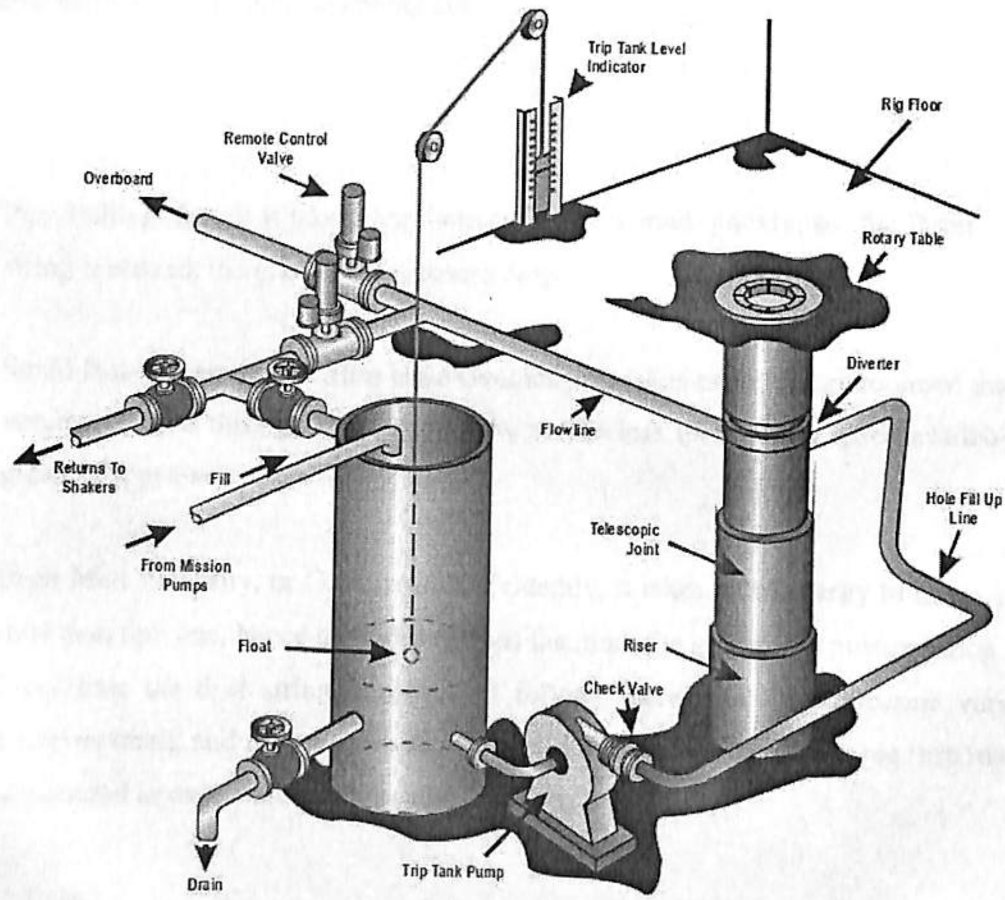


Figure 2 : Continuous Circulating Trip Tank

SWABBING IN A KICK

When the drillstring is pulled up out of the hole during a trip, mud must flow down past it to fill the space left behind. Energy is needed to make the mud move, and this is shown as a pressure drop as the mud flows – a reverse 'annulus pressure loss'. The effect is that the total pressure exerted by the fluid column is reduced slightly.The effect of the bit and bottom hole assembly can be compared with a loosely fitted plunger in a syringe.
Since the pressure drop is related to the energy required to move the mud into place, the principal factors encouraging swabbing are:

a) Pipe Pulling Speed: It takes more energy to move mud quickly, so the faster the string is moved, the greater the pressure drop.

b) Small Hole Clearance, or Slim Hole Geometry: It takes more energy to move the same volume of mud through a smaller space, so the less the annular space available, the greater the pressure drop.

c) High Mud Viscosity, or Gel Strength: Evidently, it takes more energy to move a thick mud than thin one, hence the more viscous the mud, the greater the pressure drop.
Every time the drill string is moved, it follows there must be a pressure variation, however small, and this must be allowed for. The normal overbalance, or 'trip margin', is intended to overcome this potential problem.

The likelihood of swabbing in a kick can be reduced by good drilling practices, including use of an adequate trip margin. These include:

a) Circulating the hole clean before starting a trip.
b) Noting the pressure and position of 'tight-spots' from previous trips.
c) Conditioning mud to as thin a condition as well circumstances permit.
d) Careful observation of pipe pulling speed.

The swabbing-in kick is particularly hazardous since often a brief swabbing episode is followed by normal tripping practice. If the small discrepancy in string displacement volume is not noted at once, it will probably be overlooked thereafter. No other warning sign of the presence of a kick in the well may be seen.

An overall influx of gas, for instance, swabbed into an open annulus, may displace only a very short head of mud. The net decrease in bottom hole pressure is small and likely to be well below the normal range of 'trip margin' overbalance. No further flow of gas will occur into the well and, if the well is shut in, no pressures will show on either drill pipe or casing pressure gauges since the well is still in balance.

If a gas influx has been swabbed in, it will slowly migrate up the Well and expand as it does so. At first this expansion is very slow, and it is unlikely that any significant flow will be seen at the surface unless the influx is very large, or very close to the surface. The greatest swabbing action generally occurs when tripping through a 'fresh drilled' hole. This is because the initial mud filter cake deposited on a new section of hole is soft and thick. It has not been 'wiped' thin by the bit. Particular care should be taken at the start of a trip to ensure that no swabbing occours.

As previously mentioned, bit and stabiliser balling are common causes of swabbing, especially in soft 'gumbo' shales and clays. The best protection here is to circulate 'bottoms up' or until the hole is relatively clean.

The only reliable method of detecting a swabbed-in kick as it occurs is proper hole fill procedure. Once again the trip volumes must be care fully monitored.

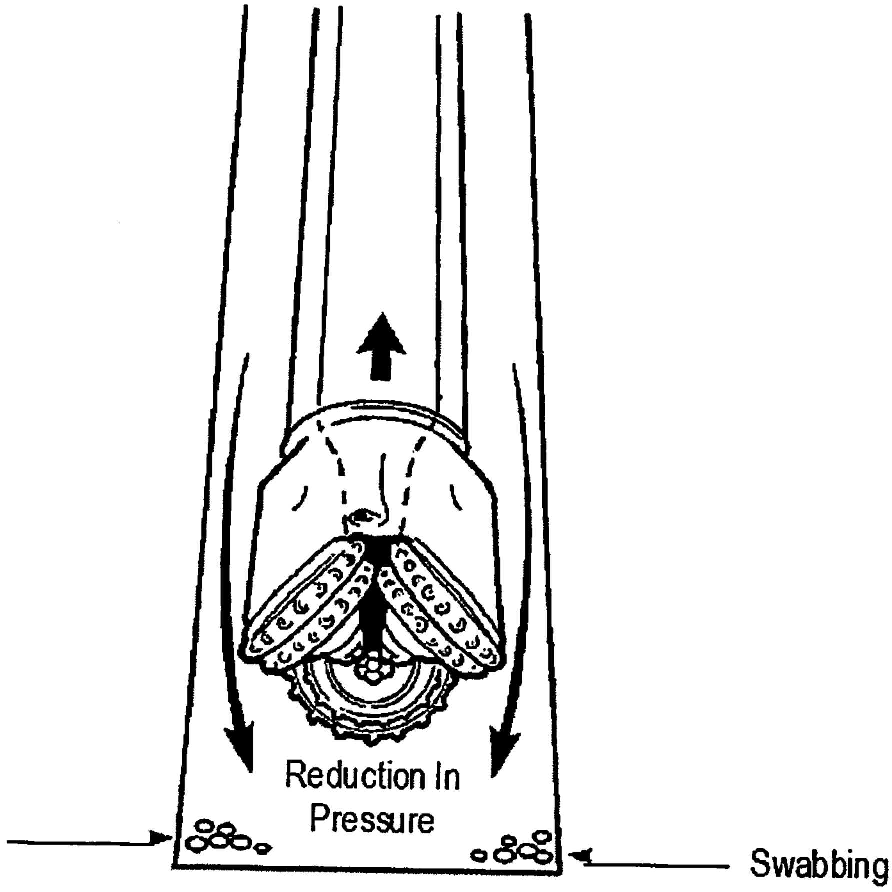


Figure 3 : Swabbing

INSUFFICIENT MUD WEIGHT

The hydrostatic pressure exerted by the column of mud in the hole is the primary means of preventing kicks. Insufficient mud weight can result from penetration of an unexpected, abnormally high-pressure zone, or be due to deliberate underbalance drilling methods in field development wells.

Accidental dilution of the mud with make-up water, in the surface tanks, is a relatively common occurrence, and must be guarded against. With water base muds and fast drilling, it is common to add considerable quantities of water.

If the drilling rate slows, and other problems distract attention from the routine checking of active mud weight, the slow reduction in mud weight may escape notice until it is too late.

In some areas of the world it is necessary to drill whilst taking a continuous small flow of water from aquifers. Great care must be taken here to ensure that excessive dilution does not occur.

ABNORMAL FORMATION PRESSURES

Abnormal pressures and their causes are discussed in the 'Pressures' section. Generally, if a permeable zone containing fluids pressured above the normal gradient for the area is to be penetrated, then appropriate mud weights must be run. Where possible, prediction of likely abnormal pressures should be carried out, both during well planning and during drilling. A number of trends will signal changes in formation pressure.

Sometimes low permeability formations known to be abnormally pressured, such as massive shales, are deliberately drilled under balanced to improve drilling rate. If the permeability is low the formation fluid does not flow at a sufficient rate to be significant before the hole section is completed and cased off. Signs of high formation pressure may be seen in the form of 'sloughing', 'heaving' shales, excess hole fill, and 'pinched' hole sections or tight spots. Providing these effects can be kept under control, the hole may be more rapidly and economically completed using underbalanced drilling techniques.

It may be necessary in such cases to increase mud weight for trips, and care must be taken if permeable sand zones or lenses are encountered. These, being permeable, allow fluid to flow and, if sealed within abnormally pressured rocks, will have abnormal fluid pressure.

LOST CIRCULATION

Kicks can occur when total lost circulation occurs. If the loss of whole mud to natural or artificially induced fractures is sufficiently great, then all returns from the well will cease and the level of mud in the well annulus will drop.

Loss of circulation can occur to cavernous or vugular formations; naturally fractured, pressure depleted or sub-normally pressured zones; fractures induced by excessive pipe running speeds; annulus plugging due to BHA balling or sloughing shales; excessively high annular friction losses; or excessive circulation breaking pressures when mud gel strength is high

When this type of kick occurs, it may rapidly become very severe since a large influx can occur before a rising annulus mud level is seen, for this reason, it is recommended that the annulus should be filled with water to maintain the best possible hydrostatic head in the well. In many cases the mud level only drops a few hundred feet, and the addition of water reduces the underbalance in the well to a minimum. If flow still occurs, it does so at a reduced rate, allowing more time for emergency measures, or well healing procedures, to be carried out.

A note should be kept of the volume of water pumped, to enable an estimate of the maximum pressure the well can take

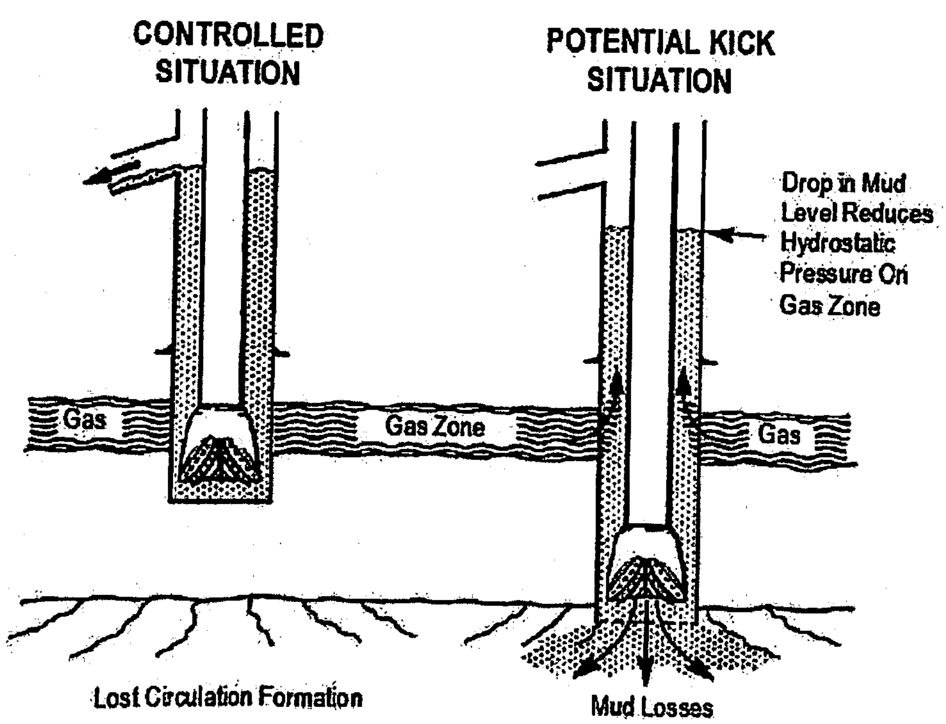


Figure 4 : Kick situation

SHALLOW GAS SANDS

Drilling into shallow gas pockets is one of the most dangerous situations that can be encountered. In a shallow well, gas can travel to the surface very rapidly, giving little warning. While drilling shallow hole, the short surface casing string is set in a relatively weak formation. It is normally necessary to divert the flow rather than shut the well in, risking fracture at the casing shoe and the possibility of gas coming up around the outside of the well.

As the 'bottom-hole' times involved are short, the drill crew should be alert for signs of a kick. The flow sensor may be the only item of equipment able to give an early enough warning of a shallow gas kick in progress which allows the diverter to be put into use. This sensor should be kept working whenever possible. If in doubt shut off the pumps and carry out a flow check. Pit level gains, although a valuable indication, are generally noticed too late. Most shallow gas pockets are found in exploration wildcat wells, through shallow gas-charged sands may be found in field development wells. In latter case the shallow formations have been charged with high pressure gas from deeper zones in nearby wells, which has migrated due to a failure on the previous well. Poor cement jobs, casing failures, inadequate abandonment procedures, downhole blowouts and injection well operations are all possible causes.

EXCESSIVE DRILLING RATE IN GAS BEARING SANDS

When a formation containing gas is drilled, the mud becomes gas cut due to the breakout gas from the cuttings as they are circulated to the surface. The extent of gas cutting is related to the total gas content of the rock, the permeability of the rock, the rate of penetration and the length of time the cuttings are in the hole (i.e. 'bottom up' time).

The gas in the hole is subjected to normal hydrostatic pressure. As it percolates or is circulated up, the pressure decreases and the gas expands. Small quantities of gas can cause a large reduction in mud weight as measured at the flow-line at surface. The reduction in total hydrostatic head in the well is quite small although the surface effects appears large, as is shown in the graph.

Use of a de-gasser removes gas before the mud is re-circulated around the well. Otherwise the percentage of gas in the mud rises and a progressively greater reduction in hydrostatic head occurs. If very fast penetration is made in a gas-bearing formation, the percentage of gas in the mud is likewise increased and problems may result. The rapid expansion of gas near the surface may cause 'belching' at the bell nipple with a loss of mud from the well and a consequent drop in the hydrostatic pressure. This may induce further 'belching' and lowering of the hydrostatic pressure. This may induce further 'belching' and lowering of the hydrostatic pressure to below that of the formation so that a kick may result. This sequence, once started, rapidly gets out of control.

KICK INDICATORS

GENERAL

There are a number of warning signs and indications, which alert the drill crew to the presence of a kick, or an impending kick. Not all the signs will necessarily be observed in any one instance, though some will be there to provide a 'warning flag' to an alert crew.

Kicks can be divided into two groups:

- POSITIVE INDICATORS OF A KICK IN PROGRESS
- SIGNS OF APPROACHING BALANCE/UNDER BALANCE

The latter may sometimes be referred to as Abnormal Pressure Indicators, however they are not all necessarily linked solely with the presence of abnormal formation pressures.

INDICATIONS THAT A KICK IS IN PROGRESS

1) During Drilling

There are several indications which show that a kick is in progress:

a) FLOW RATE INCREASE.

b) PIT VOLUME INCREASE.

c) PUMP PRESSURE DECREASE/PUMP STROKE INCREASE.

2) During Tripping

The indication of the presence of a kick is:

a) INCORRECT HOLE FILL VOLUME.

If this indication is not noticed at an early stage, it should become progressively more obvious. In the extreme case the hole would eventually stay full, or flow, while pulling out. This may sound ridiculous, but it has occurred.

b) HOLE KEEPS FLOWING BETWEEN STANDS, WHILE RUNNING IN.

The presence of some or all of these indications require that a flow check be carried out to determine whether or not a kick is in progress.

When a kick occurs, the surface pressure required to contain it will depend mainly upon the size of the influx taken into the wellbore. A small kick closed in early means lower pressures being involved through the kill. Furthermore it is easier to deal with a kick which is noticed early and closed in quickly.

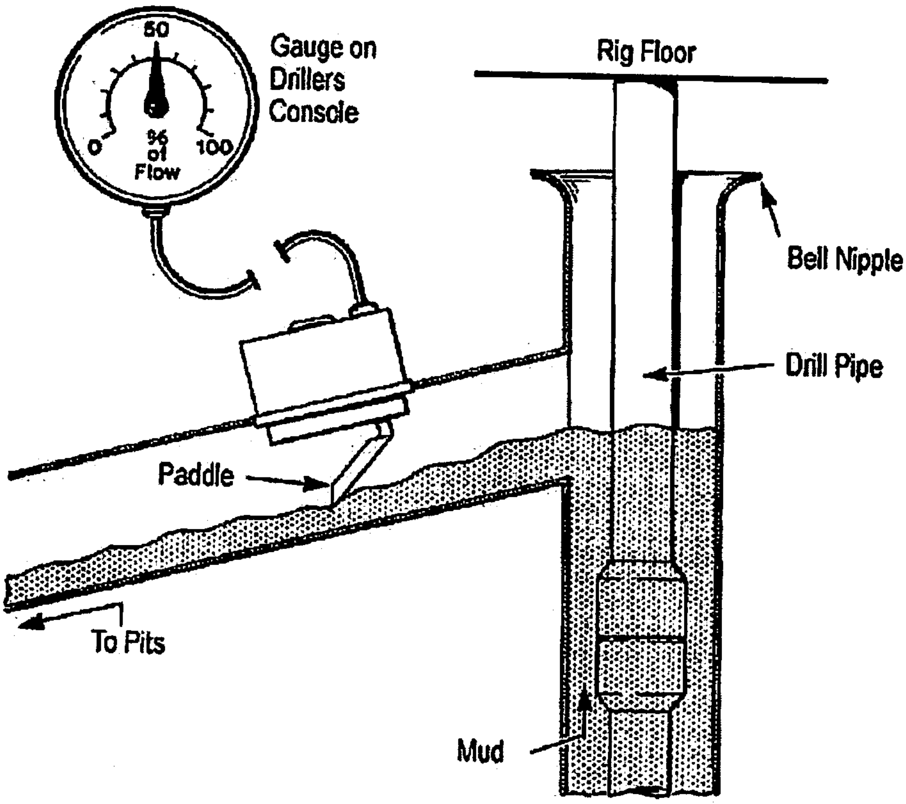


Figure 5 : Flow Rate Check

Pit Volume Increase

Any invasion of formation fluid must result in the expulsion of mud from the well, and this shows up as an increase in surface volume in what is, normally a closed circulating system. As is the case with flowrate, a gain in pit level may be hard, or impossible, to detect when a slow bleed-in of fluid occurs. It is also very easy for other factors to mask a change in pit level. Surface additions to the mud system, or surface withdrawals and dumpings, must be done with the Driller's knowledge. When a continuous addition is being made, for instance seawater ('giving the mud a drink'), the addition rate should be determined and monitored so that any further increase due to a kick can be detected.

The addition of significant amounts of material such as barite also changes the total mud volume. This should be pre-calculated, and again the Driller informed of the likely increase, and over what period such increase will occur.

The continuous use of de-sanders and/or de-silters and mud cleaners on the active system while drilling results in a slow continuous loss of mud. Experience with the particular equipment installed on a rig enables an estimate for the rate of loss to be calculated. Such a continuous loss easily masks small continuous gains. If the driller does not know the equipment is running, he will not be surprised that the mud level is steady, hence he must be notified whenever this equipment is switched on or off.

A continuously recording pit level monitor aids this process considerably, allowing the Driller to see at a glance if any change in pit level, or in the trend of pit level variation, is taking place.

Visual observation of mud pit level, recorded at regular intervals with notes on additions and alterations made is a valuable direct reference to what is happening. The drill crew should be made aware of the importance of maintaining an accurate record of actual pit levels by direct observation and bringing any suspect variation immediately to the Driller's attention.

Floating vessels produce problems in accurate measurement of pit volume, as motion of the vessel varies the mud level at the tank sensors. The use of several floats, or other sensors per pit can reduce this problem to acceptable levels if properly located. The effects of heavy weather provide a considerable masking effect.

Pump Pressure Decrease/Pump Stroke Increase

Invading formation fluid generally reduces the total head of fluid in the annulus. The head of mud in the drillpipe is unaffected, so that there is a tendency for fluid to 'U-tube'. This means that the pump does not have to provide so much energy and this may be seen as a pump pressure reduction. Depending on the rig installation, a small increase in pump rate may also be noted.

The effect is small, and may not be noticeable. The same effects are seen if a washout occurs, so it is necessary to confirm which is taking place, by doing a flow check. The presence of a continuous recording monitor of pump pressure and pump stroke rate on the drill floor means that quite small changes can be seen readily by the Driller.

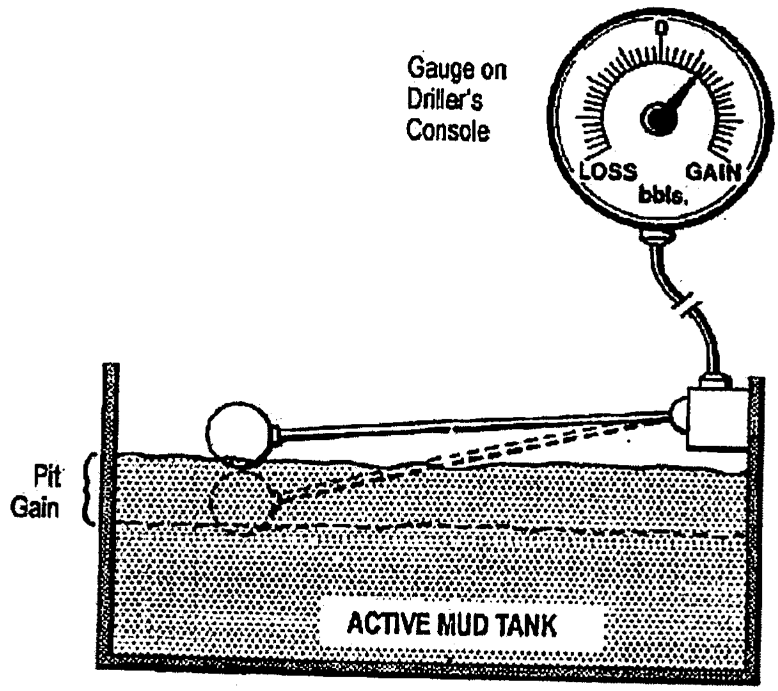


Figure 5 : Pit gain

Drilling Break

A sudden increase in rate of penetration is usually caused by a change in formation type. It may however signal an increase in permeability and a loss of pressure overbalance. Both these effects result in faster drilling.

The drilling break may be spectacular, though most commonly a gradual change is seen. It is rare for the drilling break to indicate a kick is in progress, though it is often a sign that conditions are changing and formation pressure rising, which may lead to a kick.

Incorrect Hole Fill Volume

The importance of ensuring that the correct amount of mud is added to the hole to replace the drillstring as it is removed has already been discussed. Equally it is important to ensure that the correct amount of mud returns from the hole as the drillstring is run back.

Careful monitoring of trip tank volumes, or hole fill up volumes, is essential. If serious doubt exists over a discrepancy, and re-calculation and level checks still show that a discrepancy may exist, the safest response is to close in and check pressures. If none exist then return to bottom and circulate bottoms up before tripping out again.

When the possibility of swabbing is considered high, a short trip of a few stands, or possibly to the last casing shoe and back, may be made, with 'bottoms up' then circulated to determine whether a full trip can be made safely.

It was noted earlier that if an incorrect hole fill is not noticed at first, it becomes progressively more obvious as more material flows into the hole. Also, if the influx is gas, it freely expands as it percolates up the well.

Hole Keeps Flowing Between Stands, While Running In

While running the drillstring into the hole, we expect the well to flow the amount of mud being displaced by the drillpipe metal volume. As a stand of pipe is lowered into the well, the flow of mud from the well commences.

Once the stand is in and the slips set, the flow should subside over a few seconds as the system returns to balance. If the well has not stopped flowing by the time the next stand is ready for running in, it is probable that something is wrong. The well will be observed and shut-in if there is any doubt.

FLOW CHECK PROCEDURE

This confirms that a kick is in progress. If any of the previously mentioned signs occur, either singly or together, a flow check will be carried out to confirm the situation. Pick up the Kelly to clear the bushings, with the pumps on, then shut the pumps off and check for flow.

Normally the well flows for a few seconds before stopping, if it continues to flow, it is likely a kick has occurred.

2.2 INDICATIONS OF APPROACHING BALANCE/RISING FORMATION PRESSURE

Some of the following indications are signs that abnormal formation pressures are being encountered and the formation pressure will eventually balance or exceed the bottom hole pressure exerted by the mud column. Others are simply signs that formation and bottom hole pressures are approaching balance. These are sometimes referred to as secondary indications of a kick.

These indications can be summarized as:

a) Drilling Rate (Sometimes using 'd' exponent trends)
b) Torque and Drag, Fill on Connections
c) Total Gas Levels/Gas Cut Mud
d) Flowline Temperature
e) Mud Flow Properties
f) Mud Salinity
g) Shale Density/Cuttings
h) Heaving Shales
i) Shale Type

Drilling Rate

Given that bit weight, rotary speed, hydraulics and mud properties are held constant while drilling a given formation, the drilling rate is related to differential pressure and bit wear. Normally decreasing trends with depth are expected as the bit wears. Where formation pressure increases, effectively reducing the pressure differential between mud hydrostatic and formation pressure, drilling rate is increased. This increase may be one indication of increasing formation pressure.

Plots of drilling rate versus depth may be maintained at the rig for locating tops of over pressured zones. Mechanical devices are available for measuring both drilling time and/or rate.

Drilling Exponent

Plots of drilling rate versus depth are often difficult to interpret because of changes in drilling rate variables such as WOB, RPM and mud properties In 1966, Jorden and Shirley* developed a normalised rate of penetration equation from data gathered on the Gulf Coast. In their relationship, normalised drilling rate was defined as a function of measured drilling rate, bit weight and size and rotary speed in the equation: in the equation shown below:

$$'d' = \frac{\log(R/60N)}{\log(12W/10^6 D)} \quad (15)$$

R = Rate of penetration, ft/hr
N = Rotary speed, rpm
W = Weight on bit, lbs
D = Bit size, ins

The hydraulics and formation drillability were not included in the equation for normalised drilling rate, since their effects were considered negligible within certain limits. The authors provided correlation's of field measured pressure data and 'd' exponent calculations. They showed that formation pressure could be estimated by first plotting 'd' values in shale versus depth, on semilog paper, and determining a normal trend line of decreasing values with depth in the normally pressured section. Then, by determining the differences between the extrapolated values of 'd' exponent and those calculated from actual data, the correlation was used to estimate the amount of overpressure at any depth.
The method developed with Gulf Coast data has been applied worldwide with moderate success. Since their original work, others have applied a correction for mud weight to obtain a modified drilling exponent.

This is applied in much the same way as the 'd' exponent and sometimes it is plotted as 100/d versus depth, for direct comparison with plots of interval transit time.

Torque and Drag, Fill On Connections

Increases in torque and drag often occur when drilling underbalance through some shale intervals. As the result of this fluid in the shale expands, causing cracking, spalling and sloughing of the shales into the wellbore. This condition can cause a buildup of cuttings in the annulus, excessive fill on connections and trips, a buildup in torque and drag and eventually stuck pipe. Increases in torque and drag can be a good indicator of abnormal pressure, especially if used with other indicators.

Total Gas Levels

A gas detector, or hot wire device, provides a valuable warning signal of an impending kick. Such instruments measure changes in the relative amounts of gas in the mud and cuttings, but do not provide a quantitative value. Increase in the gas content can mean an increase in gas content of the formation being drilled, gas from cavings and/or an underbalanced pressure condition.

In conditions of normal pressure and normal overbalance, background gas should not vary significantly as the hole is drilled. Changes in background levels indicate possible conditions of concern. Increases in the normal background gas indicate the flow of formation gas into the mud or the presence of gas expanding from drilled cuttings.

Connection gas is a measure of gas swabbed into the hole while pulling up for a connection. It is reported in units of gas over normal background gas. Connection gas can be identified by estimating the time to pump mud from bottom and checking the gas detector recording. After the swabbed gas passes the detector, the units should return to the background levels. If not, an underbalance condition could exist.

Connection gas can be eliminated if a sufficiently high overbalance exists, or if pulling speed is reduced and/or if mud properties are adjusted. However, connection gas can be used as an accurate indicator of formation pressure when drilling with close to a balanced pressure. Increasing levels of connection gas are a reliable warning of an underbalanced pressure condition. The relationship of normal gas content readings to the amount of increase can be used as an indicator of the need to increase mud density.

Trip gas is very similar to connection gas except that it is a measure of swabbed gas over an entire trip. Excessive units of trip gas may indicate the need for increasing the trip margin and/or reducing swab pressure.

Gas-Cut Mud

The appearance of gas cut mud at the surface usually causes an over-reaction of increasing mud density. Where little or no pit level gain has been recorded, this reaction is probably incorrect. The reduction of bottom hole pressure owing to gas cutting has been shown previously. However due to the compressibility of gas, a fifty percent gas cut of mud at the surface changes the bottom hole pressure at 20,000 feet by only 100 psi. Gas cutting must not be ignored, but regarded as a secondary indicator of a kick.

Flowline Temperature

The temperature gradient in the transition between normal and abnormal pressure zones often increases to about twice the rate of the normal temperature gradient. Increases of the mud temperature at the surface can also indicate the top of an overpressured section. Consideration must be given to circulation times, trip times, connection times, stabilised temperature after tripping, temperature of mud at suction pit, and other factors such as water depth. An increase in flowline temperature when used with other indicators, can show the top of an overpressured section with accuracy.
It is important to note this indicator can be partially or totally masked in offshore drilling from floating vessels by the cooling effect of long lengths of riser and substantial air gaps.

Change in Flow Properties

The presence of formation gas in mud has little or no effect on the chemical and flow properties of a mud. Gas or air will 'froth' or foam the mud at the surface, lowering the surface density and sometimes increasing the viscosity of the mud. As shown in chapter 3, gas does not reduce the bottom hole pressure as much as might be expected.

On the other hand, formation fluids, particularly salt water, which can enter the wellbore, will alter the chemical balance of the mud as well as reduce the density. The result can be a drastic change in chemical and flow properties of the mud. For example, salt water in the mud will cause a drop in pH with a consequent increase in viscosity and fluid loss. The extent of any detrimental effects of contaminants is largely dependent upon the amount of undesirable drilled solids in the mud.

Sometimes the changing flow properties of a mud system can be a reliable warning signal that the well is underbalanced and a kick is imminent. This is only likely to be evident in lightly treated or fresh water mud systems. The inhibitive muds in common North Sea use will often not show any change, being high in salt content themselves.

Mud Salinity

Specific mud characteristics measured in the suction pit are compared with measurements after circulation. Mud resistivity, chloride ion content, pH variations, and other specific ions are closely monitored. Gains or losses of specific ions are correlated to down-hole pressure differentials by proprietary logging methods (Delta Chloride Log) and used in predicting mud weight requirements.

Invasion of the drilling mud by formation water can sometimes be detected by changes in the average density or the salinity of mud returning from the annulus. Depending on the density of the mud, dilution with formation water normally reduces average density. If the density of the invading fluid is close to that of the mud, the density is unaffected but perhaps a change in salinity is apparent. This depends on the salinity contrast between the formation fluid and the mud. Usually formation fluids are more salty than drilling muds and an influx can be detected by marked increases of chloride content of the mud filtrate.

Shale Density/Cuttings

The examination of shale cuttings and/or cores can provide information on formation pressures. Properties of shale such as bulk density, shale type, size, and shape can be related to abnormal pressures.

Several techniques, such as the graduated density column method or the mud balance method, are available to measure the density of shale cuttings recovered at the shaker. Care must be exercised to separate bottom cuttings from upper hole cavings. Also, cuttings must be properly washed and/or scraped to remove the outer layer of a mud contaminated sample. Plots of shale bulk density versus depth are made and the normal trend of increasing density versus depth established. Changes from the normal trend can then be related to changes in formation fluid content, and hence formation fluid pressure.

Shale sections which are drilled underbalance tend to produce larger than normal cuttings, larger volumes than normal, and shapes that are more angular, sharp and splintery in appearance. These effects are due in part to the fact that fluid trapped within pores of the shale at high pressure expands when exposed to the lower mud hydrostatic pressure. Therefore, drilling rates and hole size increases as shale continues to expand, crack, spall and slough into the wellbore, thereby creating larger and different shaped cuttings or cavings. Volume of cuttings increases due to faster penetration rates and increased hole volume caused by sloughing and caving. Close observation of shale on the shaker along with other indicators can provide a basis for determining an underbalanced condition prior to taking a kick.

Heaving Shales

Excessive volumes of shale cuttings on the shaker may be an indication of an underbalanced condition. Shale is usually very porous, but has little or no permeability. Fluids in the pores are subjected to formation pressure, but are not able to flow. However, if a differential pressure exists from the formation to the well bore, such as in the case of abnormal pressure, the fluid pressure causes weakening of the walls of the hole and spalling or heaving of shale into the hole. At the surface an increase in volume of shale cuttings is noted. These cuttings are splintery, angular, and generally larger than normal.

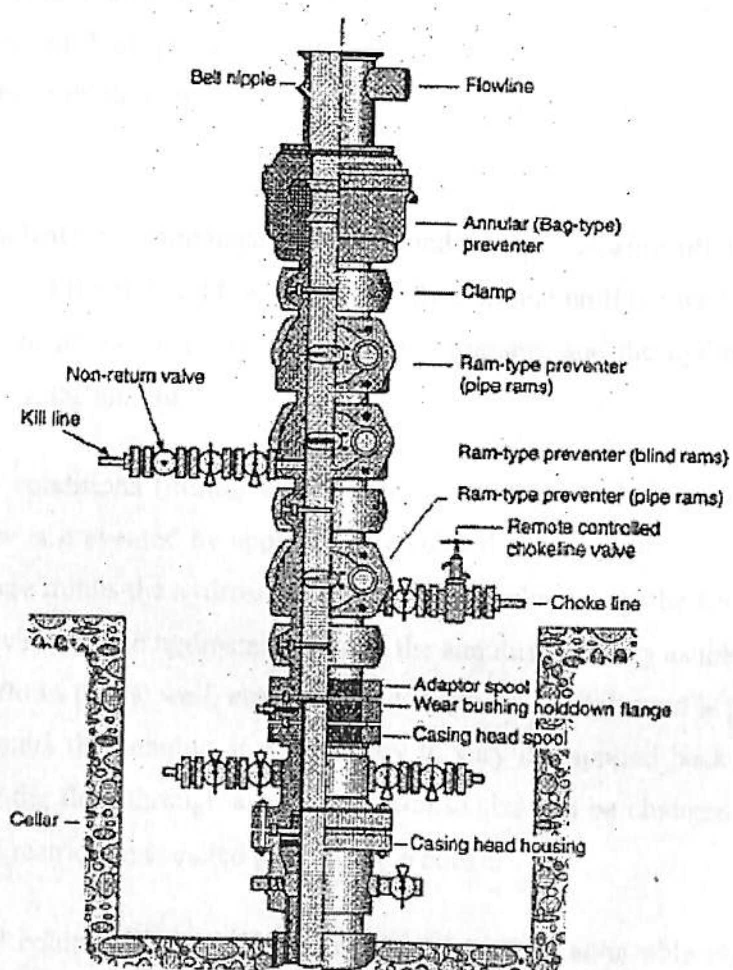
If these conditions persist, the mud hydrostatic pressure is probably too low and a kick will occur while drilling the next permeable formation.

Shale Type

The type of clay mineral of which shales are largely composed varies slowly with increasing depth and the swelling clays, sometimes known as 'gumbos', progressively give way to the non-swelling type. Near the surface the principal clay minerals are calcium and sodium based montmorillonites and illites. With increasing depth of burial these alter slowly – towards the largely potassium based kaolinites.

This change can be determined roughly in a number of ways, of which the Methylene Blue test for clay absorption level determination, and Differential Thermal Analysis for structural water content determination are the best known and most widely used.

CHAPTER 3 : INTRODUCTION TO WELL CONTROL EQUIPMENT



BOP stack set-up

INTRODUCTION

When primary control has been lost and formation fluids enter the well bore, a hydrostatic overbalance is no longer maintained. Instead we have a pressure balance in the annulus between the formation pressure and the sum of the hydrostatic heads of the fluids in the annulus plus viscous friction losses due to flow plus the back pressure applied at the surface. If no, or insufficient, back pressure is applied the rate of flow from formation to well will increase until the friction losses in the annulus enable equilibrium to be reached. The result is a blow out.

This pressure balance is maintained in static conditions by closing off the annulus at the surface by means of the BOPs. Flow will then only continue until the well head pressure has increased to the difference between the formation pressure and the hydrostatic pressure of the fluid column in the annulus.

Under dynamic conditions (during well killing operations) the balance is maintained and additional inflow is prevented by applying a calculated back pressure which is equal to the formation pressure minus the hydrostatic head in the annulus minus the friction losses plus a safety factor. Given that the hydrostatic head in the annulus will vary as the initial volume of formation fluid flows up the well, especially if it is gas, and as kill mud is pumped down the drill pipe and enters the annulus, it is necessary to vary the applied back pressure. This is done by passing the flow through a restriction whose size can be changed in a quantifiable manner. Such a restriction is called an adjustable choke.

The well control equipment on a rig normally contains two adjustable chokes, situated in what is, logically, called a choke manifold.

As well as the choke manifold, the well killing system includes some of the mud treating equipment, and the mud pumps.

This part deals with:

- Choke manifold
- Valves
- Chokes
- High-pressure (HP) lines and hoses

CHOKE MANIFOLD

A choke manifold is an assembly of valves, through which the return flow from the well is routed when the blow-out preventers are closed, with the purpose of applying a calculated back pressure. Choke manifolds may be assembled in a variety of layouts but they will always include at least two adjustable chokes. In some cases this may be one manual choke and one remote controlled choke . The manifold provides alternative flow paths for the fluid so that if necessary chokes can be changed and valves repaired without stopping the flow.

All the high pressure parts of the manifold should have the same working pressure rating as the BOP stack.

The manifold is connected to the hydraulically operated choke line valve and the BOP stack by a high-pressure flexible hose, or alternatively a high pressure steel line. The flexible hose is a specially designed steel armored hose. Ordinary kelly hoses are not considered suitable.

The manifold has to be adequately secured because it may be subjected to violent forces and vibration during certain stages of well killing.

Valve Settings

Of the two choke line valves on or adjacent to the stack, the inner manual valve is kept open, and the second (the remotely controlled hydraulically activated gate valve) kept closed during drilling. All other valves and chokes in the line to the mud/gas separator, are kept open with the exception of the valve immediately upstream of each of the chokes and the second valve in the bypass line after the cross (the centre flow line, the one without a choke).

Wherever two valves are fitted it is standard practice that the second valve is the one operated and the first one used as backup, in case the second one fails.

When two manual chokes are installed either one can be used. When a manual choke and a remote controlled choke are installed, the remote controlled choke is the one normally used, keeping the manual choke as a standby choke. Before taking over the shift the driller should make sure that all the valves on the choke manifold are set as described above.

VALVES

All high pressure valves used on the casing head housing, wellhead spools, drilling spools and in the choke and kill manifold, should have steel seats and full gauge opening.

CHOKES

The choke is normally an adjustable orifice installed in the return line. It is used to restrict the flow area so that the pressure drop of the returns through this line can be regulated while a kick is circulated out.

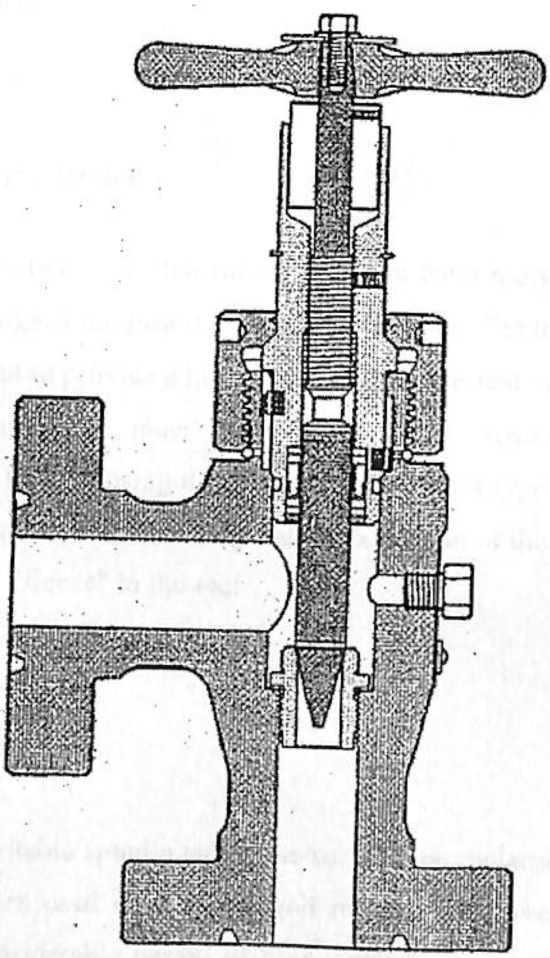


Figure 8 : Manually Operated Choke

Three types of chokes may be encountered in choke manifolds:

- The manual adjustable choke.
- The replaceable fixed choke.
- The remote controlled choke.

MANUAL ADJUSTED CHOKE

The stem and seat area are of tungsten carbide to make them more wear resistant; it must be understood that a choke is not meant to be used as a valve. The tool is designed to create a flow restriction and not to provide a high-pressure seal. Washed out sealing areas are also common. Therefore the choke must be used for initial closing in only and should immediately be backed up by closing the upstream valve. This type of choke should not be left "closed" for long periods of time. Temperature expansion of the needle can damage the seat and the needle may "freeze" in the seat.

FIXED CHOKE

Instead of using an adjustable spindle valve, the seat can be replaced by different sizes of "beans". Such chokes are used only if the well returns will have to be produced at a constant rate over a considerable period of time, such as is common during production tests. Fixed chokes are sometimes referred to as positive chokes.

The choke body in such a set-up is provided with a cap instead of a needle assembly.

REMOTE CONTROLLED CHOKE

Remote controlled chokes are operated from a panel, usually on the rig floor. This operating panel should include:

- a drill pipe pressure gauge
- an annulus pressure gauge
- a pump stroke counter
- a choke selection switch
- a maximum allowable annulus pressure setting regulator (optional)
- a choke control lever
- and throttles for the pumps (optional)

There are different remote controlled chokes, some of which have specific operating characteristics that may affect the well killing operation.

HIGH PRESSURE LINE AND HOSES

HAMMER UNION

The connection between HP equipment is normally a fixed set-up consisting of steel pipes. Only in temporary hook-ups hammer unions.

A union mostly consists of four parts:

- A male sub with convex sealing face.
- A female sub with a concave sealing face, an external square thread and an inner recess for a seal ring.
- A hammer nut with square threads and two or three lugs. A rubber seal ring.

The convex shape of the sub serves for self alignment when making up the union; this improves make up speed and ensures proper seating of the sealing surfaces.

It is important that rig site personnel should inspect both sealing surfaces as well as the rubber seal when making up the connections.

It is also important that the individual parts of the union should be checked for the correct pressure rating (type) before making up. Some of the pressure classes have nuts and female subs which differ only slightly in dimensions e.g. a WECO union type 1502 nut fits a type 1002 female sub, but the threads engage over a small area only. When high pressure is applied the union expands and comes apart.

BOP STACK EQUIPMENT

A BOP stack should have a large enough internal diameter to pass the drilling tools. For the shallow part of the hole a large diameter stack or diverter set-up with low working pressure ratings is required, while for the deeper sections smaller inside diameters, but high working pressure rating are needed.

When all of these qualifications plus the operational characteristics, such as quick operation and reliable sealing, have been incorporated, a blow-out preventer stack has become a heavy, massive piece of equipment.

Although all these items look indestructible, they should be watched carefully and inspections, tests and maintenance executed conscientiously Not seldom was a blow-out the result of damaged or failing BOP equipment.

ANNULAR PREVENTERS

GENERAL

The annular preventer (also called bag type, spherical or universal preventer) is the most versatile piece of equipment on the BOP stack since it can close around casing, drill pipe, drill collars, wireline and even close an open hole. The rubber packing elements of the annular preventers, which allow this flexibility, are also subject to wear and abuse. Treated properly, the packing unit of the annular preventer has a long, reliable life span, but it can be destroyed in a very short time or very few closing cycles by improper use.

The following factors influence the life span of annular preventers:

- The closing pressure as regulated through the control system should be as low as practically possible in order to maximise the life of the packing unit.
- Testing the annular preventer under high test pressures significantly shortens the life of the packing unit.
- Closing the annular preventer without pipe in the hole will shorten the life of the packing unit, especially when high closing pressures are required to achieve this.
- Motion reversal is hard on the packing unit, so pipe should he moved as far as possible in one direction before reversing the direction (long strokes).
- Spare packing units should be stored in a dark, cool room.

Closing time of annular preventers

The main disadvantage of the annular preventer is the time required to close it. The annular preventer takes three to ten times the volume of fluid to close, compared to a set of rams, and therefore requires a longer closing time. Even though current regulations specify a 38 mm (1V2") minimum diameter hydraulic control line, many surface stacks may still have hydraulic lines to the annular preventer that are smaller, or have a restriction in them which prevents rapid closing. Raising the closing pressure does not help as much as using larger lines and fittings. In addition it increases the wear on the packing unit. The small lines and/or restrictions make the packing unit movement inflexible when trying to strip, and cause excessive packing unit wear during stripping operations, especially when tool joints are passing through it.

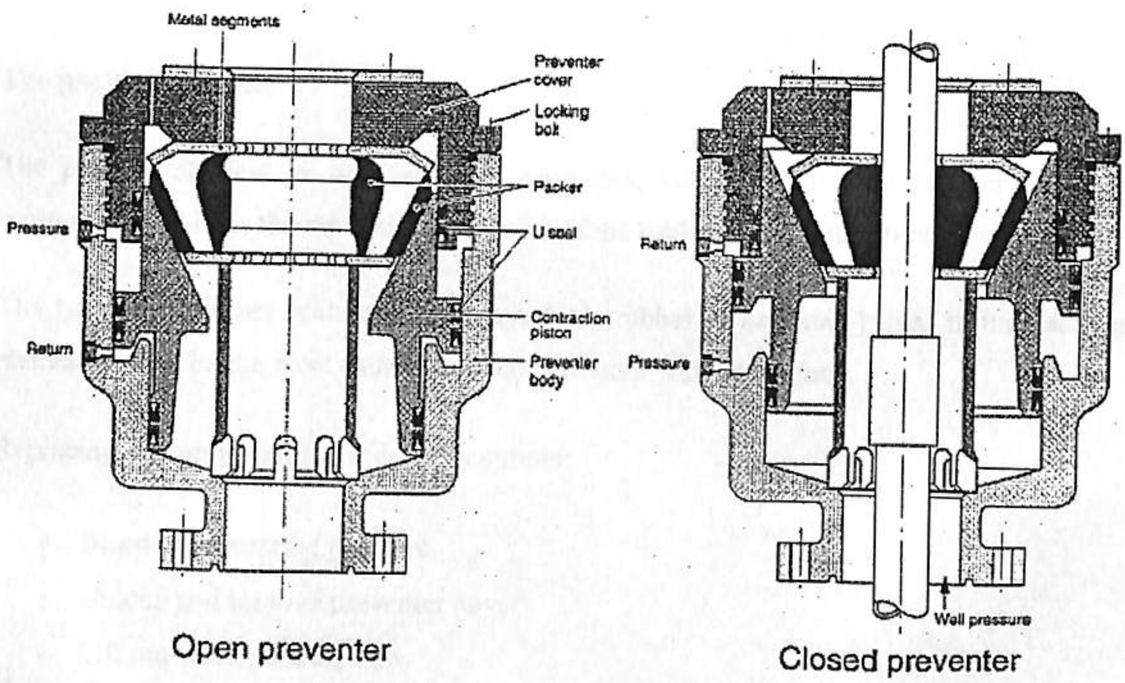


Figure 9 : Annular Preventer

The regulator valve used to regulate the annular preventer closing pressure, should allow fluid passage back through it if the line pressure increases. That way the packing unit can open against the closing pressure while stripping a tool joint. It is very important to see to it that this regulator is in good shape, that there are no check valves ahead of it (often present in the four-way valve), or that it has been replaced by a plain regulator.

The arrangement where a small accumulator bottle (surge bottle) is placed in the closing line of the annular preventer, to allow for hydraulic fluid movement when stripping, is very desirable from the viewpoint of reducing packing unit wear. This arrangement is recommended for all surface and subsurface stacks.

The packing element I

The packing element or unit has steel segments, vulcanized into the rubber body, to reinforce it and limit the amount of extrusion of the rubber when it is activated.

The type of elastomer (natural rubber, synthetic rubber or neoprene) used in the packing element should be the most suitable for the particular well conditions.

Replacing a worn packing unit is fairly simple:

- Bleed off operating pressure.
- Unlock and remove preventer cover.
- Lift out worn packing unit.
- Check seals on head and piston.
- Drop in new packing unit, and replace and lock cover.

Should the packing unit have to be replaced while pipe is in the hole, the packing unit has to be cut with a knife between two steel segments, preferably at 90° to the lifting eye bolt holes.

Packing unit type	Identification		Operating temperature range	Drilling fluid compatibility
	Colour	code		
Natural rubber	Black	NR	-30°C to 105°C	Waterbased
Nitrile rubber	Red band	NBR	-6°C to 85°C	Oil based / oil additive
Neoprene rubber	Green band	CR	-30°C to 75°C	Oil based

TABLE 1: PACKING UNIT TYPE

RAM TYPE PREVENTERS

GENERAL

The ram type blow-out preventer is the result of some seventy years of development. It is an extremely rugged and reliable piece of equipment. The normal preventer consists of a ram head with extrudable packer material for sealing and a pipe centring wedge. The RAM head sits on a piston rod, which connects it to the hydraulic chambers seals.

Rams can be famished to fit any size of pipe. Stainless steel rams, offset rams for multiple completions, as well as shear rams for cutting off pipe in case of emergency, are available.

Generally the closing pressure is less than 10,350 kPa/1,500 psi. There are however high pressure ram preventers, notably from Hydril, which require pressures in excess of 13,100 kPa/1,900 psi. The manufacturers' data should be consulted for more details.

Pipe rams.

BOP pipe rams must form a seal around the pipe and against each other, to seal off well pressure. Ram packing elements are self feeding and contain a reserve of material in order to assure seal life under wear conditions. They should however be inspected regularly for wear.

Pipe rams are made to close around a certain size pipe. They should not be closed on open hole with full closing pressure (10,350 kPa or 1,500 psi), as the packer will be damaged by extrusion. If pipe rams are to be function tested on an open hole, it would be better to close them with reduced operating pressure (2,950 kPa or 500 psi) to avoid damage to the ram packing and also possible damage to the ram face.

When stripping or moving pipe through the rams, there is less wear to the packer element if the closing pressure is reduced to the minimum value sufficient to effect a seal. This practice is accepted only if sufficient backup rams are available. Stripping through rams is not in the scope of this course.

Shearing blind rams

Shearing blind rams (SBRs) are rams with blades integral to the body. Under normal operating conditions they are used as blind rams. If emergency conditions make it necessary to shear the drill pipe, the closing shear rams will cut the pipe and seal the well bore, regardless of whether the lower section of the cut pipe is suspended on the lower pipe rams or dropped. If the fish is not dropped, the lower shear ram will bend the cut pipe over a shoulder and away from the front face of the lower shear ram which then seals against the packer in the upper shear ram.

The recommended shearing procedure is:

- Raise the bit off the bottom and position drill pipe in the preventer so that the tool joint is definitely not located in the shear ram cavity.
- To ensure proper alignment for shearing, a set of pipe rams may be closed before the shear rams are activated. Also, if the string is not to fall down the hole after being sheared a string may first be landed on a closed and locked pair of pipe rams some 750 mm (30") below the shear rams. The tool joint and upset portion of the drill pipe must be below the lower edge of the shear ram cavity to ensure that the pipe is sheared successfully.
- Close the shear blind rams with 20,700 kPa (3,000 psi) operating pressure.

The maximum pipe sizes that can be cut with shear blind rams are limited by preventer size, blade width and operating system capacity. Typical performances are:

- A 179-5 mm (7Vie") bore BOP can shear up to 101*6 mm (4") OD pipe.
- A 279-4 mm (11") bore BOP can shear up to 127 mm (5") OD pipe .
- A 346 mm (135/8") bore BOP can shear up to 139-7 mm (5V2") OD pipe.

BOPs with a larger bore are not as limited in blade width or operating system capacity and it is possible to shear larger OD pipes with them, even though the SBRs were designed to shear standard drill pipes only.

Variable rams

The variable bore ram extends the versatility of the BOP. It allows a single set of rams to seal on several different sizes of pipe or even on the hexagonal kelly. For example, the variable rams for a 163/4" bore BOP can seal on diameters from 88-9 to 177*8 mm (3V2" to 7").

Variable bore rams eliminate the need to change rams when different diameter drill strings are used. This can save a round trip with a subsea BOP stack. One set of variable rams in a stack can provide backup for two different sizes of standard pipe rams. The string cannot however be hung off on variable rams.

Secondary sealing

Ram preventers (with a rated WP of 34,500 kPa/5,000 psi or higher) are provided with a supply of secondary rod sealant or packing, and a mechanism to force this sealant into place when the primary rod seal is no longer effective. This secondary sealant should not be used routinely (and in some cases it should be removed when testing the primary seal).

LOCKING

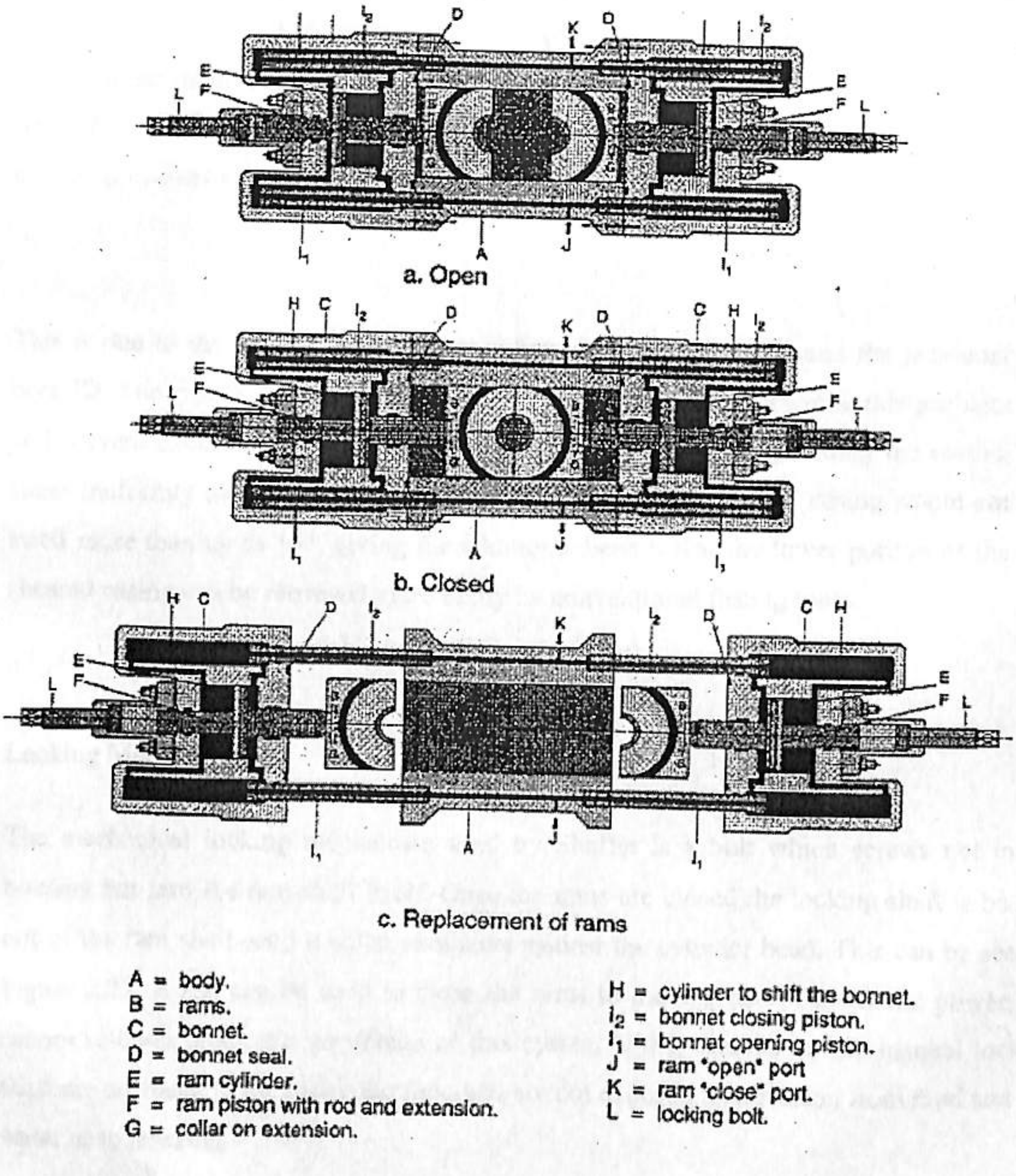
When a well has to be closed in for a long period, or when the drill string is to be landed on the rams, then these rams have to be locked by a locking mechanism.

On surface BOPs this is usually by means of bolts that are manually operated via extension rods to which handwheels can be attached. The handwheels must be well accessible and easy to operate. Should there be a total power failure or a long period without activity the manual lock bolts can be used to close the rams. In such a case a check should be made that the opening pressure has been bled off!

Opening and closing ratios

Earn type preventers have specially designed opening and closing ratios. These are the ratios between the well pressures and the operating pressures needed to open or close the rams. Closing ratios are generally of the order of seven to one. That means that a BOP having a closing ratio of seven to one would require a closing pressure of 3,450 kPa/500 psi to close the rams when the well bore pressure is 24,150 kPa/3,500 psi. Opening ratios are much lower because the well bore pressure acts behind the ram to oppose opening. Opening ratios of two to one are common.

- **Open position.** Hydraulic pressure is supplied via port J to the ram side of the ram pistons E. The closing fluid returns via port K.
- **Closed position** . Hydraulic pressure is supplied via port K to the locking bolt side of the ram pistons E. The opening fluid returns then via port J.
- **Replacement of rams** . The ram closing pressure on port K also serves to open the bonnets to give access to the rams. When the bonnet bolts are unscrewed and closing pressure is applied, hydraulic fluid pushes the rams inward and at the same time moves the bonnets away from the preventer body. Even though the rams move inward the bonnet stroke is sufficient to bring the rams out of the preventer bore.



A = body.
B = rams.
C = bonnet.
D = bonnet seal.
E = ram cylinder.
F = ram piston with rod and extension.
G = collar on extension.
H = cylinder to shift the bonnet.
I_2 = bonnet closing piston.
I_1 = bonnet opening piston.
J = ram "open" port
K = ram "close" port.
L = locking bolt.

Figure 10 : RAM TYPE "U" BOP UNIT

Casing shear rams

Conventional shear rams are designed to crush the pipe and then shear the flattened mass. That presents a problem when large diameter pipe has to be cut. If an attempt was made to cut 133/s" casing, for example,in an 183/4" bore preventer using conventional shear rams, the pipe would not be cut but be crushed and jammed in the bore of the preventer. In addition there may be severe damage to the shear ram blade and the preventer cavity.

This is due to the lack of available space between the casing OD and the preventer bore ID. The type V rams of Shaffer have cutting blades that overcome this problem and prevent excessive flattening of the casing during shear by spreading the cutting stress uniformly over the casing circumference. For instance 133/8" casing would not swell more than up to 15", giving the additional benefit that the lower portion of the sheared casing can be retrieved more easily by conventional fishing tools.

Locking Mechanism

The mechanical locking mechanism used by Shaffer is a bolt which screws not into a housing but into the ram shaft itself. Once the rams are closed the locking shaft is backed out of the ram shaft until a collar shoulders against the cylinder head. This can be seen in Figure 2.32. It too can be used to close the rams in the absence of hydraulic power, but cannot re-open them. An advantage of this system is that threads on the manual locking shaft are enclosed in the hydraulic fluid and are not exposed to corrosion from mud and salt water or to freezing.

Shaffer call their sub-sea system "Poslock". Poslock operators automatically lock the rams each time they are closed. This eliminates the additional complication and cost of a second hydraulic function for locking the rams. It also simplifies the emergency operation, because the rams are both closed and locked just by activating the close function.

When closing hydraulic pressure is applied, the complete piston assembly moves inward and pushes the rams into the well bore. As the piston reaches the fully closed position, the locking segments slide toward the piston O.D. over the locking shoulder because the locking cone is forced inward by the closing hydraulic pressure.

The locking cone holds the locking segments in position and is prevented by a spring from vibrating outward if the hydraulic closing pressure is removed.

DIVERTERS

If a kick is taken when the conductor is set in incompetent formation, the well will not be shut-in, but diverted instead. A surface diverter system, consisting of an annular preventer and vent lines, allows the flow to be directed to a safe area, preferably down wind, away from the rig and personnel.

Vent lines should be as large (304*8 mm/12" minimum) and as straight as practical, so as to minimise back pressure, erosion and the risk of plugging by formation debris. The lines should be adequately braced to absorb severe shock loading; sections likely to suffer erosion, such as bends, should be reinforced. There should be no restriction to the bore and any valves in the lines should be full opening ball valves.

To prevent the well being inadvertently shut in, any valves in the vent line should be designed to automatically open when the diverter element is closed. The minimum working pressure of a large bore diverter line system should be 3,450 kPa (500 psi); the hydraulic operating line should have a 38*1 mm (1V2^{W}) diameter, this allows hydraulic control systems to close diverters smaller than a large volume of hydraulic operating fluid , stored tinder high pressure in the accumulator, delivers the hydraulic energy required to close and open the BOPs and the remotely operated valves.

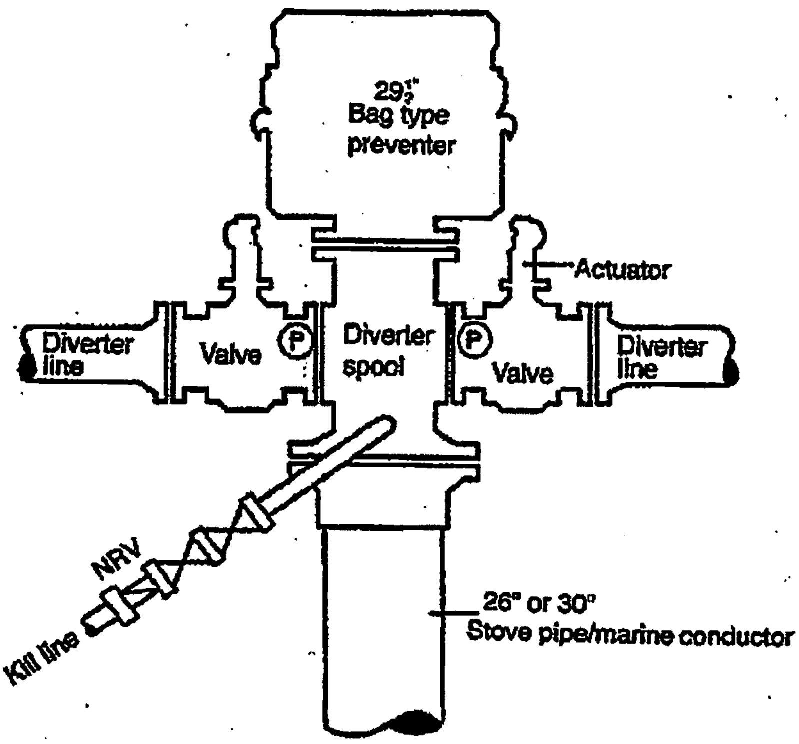
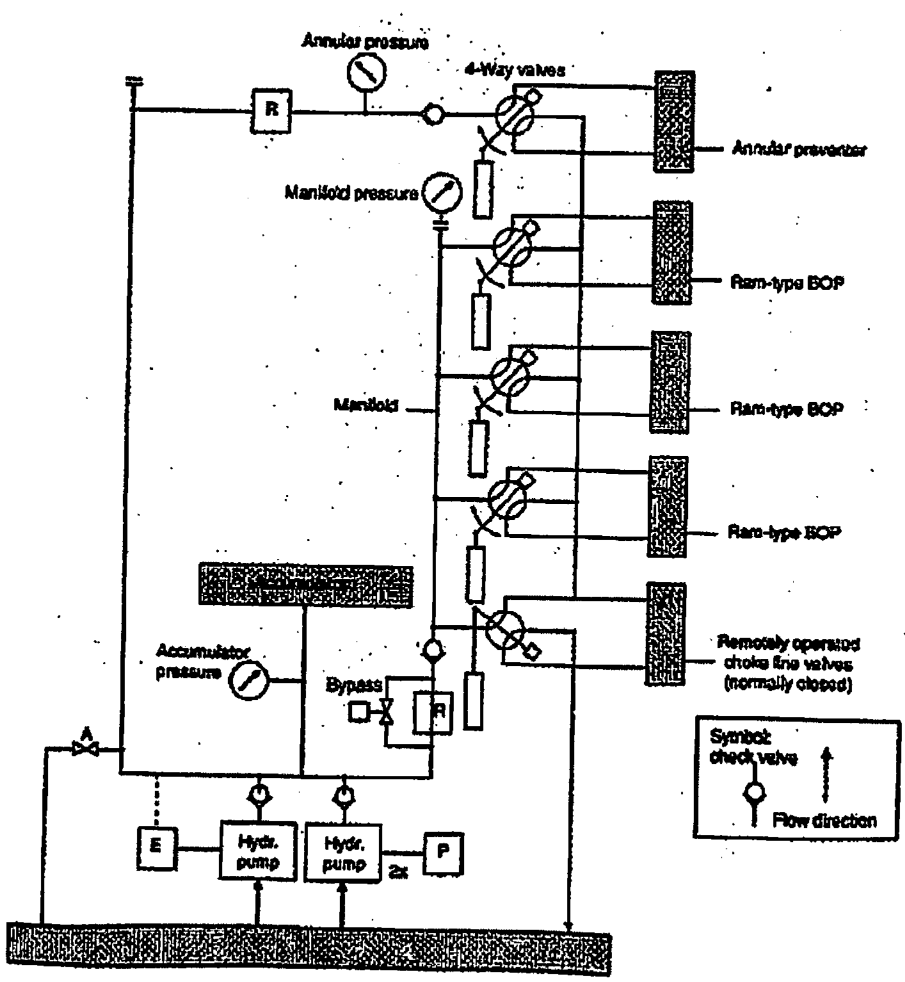


Figure 11 : Diverter System for Surface Stack

Figure 12 : SIMPLIFIED DIAGRAM OF KOOMEY UNIT



ACCUMULATOR CAPACITY

The hydraulic energy required to operate the BOPs is stored in a number of accumulator bottles which contain either a bladder type diaphragm or a piston to separate the nitrogen from the hydraulic fluid.

Without recharging, the accumulator capacity shall be adequate for closing and opening all preventers and closing again the annular preventer and one ram type preventer, and holding them closed against the rated working pressures of the preventers record the highest anticipated surface pressure, whichever value prevails). The required accumulator capacity can be calculated from the total usable fluid volume used to carry out the above-mentioned opening/closing functions, thereby not dropping the operating pressure below the recommended minimum value. The total usable fluid volume is based on Boyle's law.

HYDRAULIC LINES

The connections between the hydraulic unit and the preventers should consist of HP fire resistant hoses or steel pipe and joints.

To prevent oil losses and to keep the hoses or pipes full of oil during rig move, self-closing couplings are used.

SELF CLOSING COUPLING

Each coupling half is provided with a spring loaded check valve. As long as the connection is disengaged the valves remain closed, and the oil is trapped.

Once the connection has been engaged the pins on the check valves open the check valves to allow free flow of the liquid.

ADDITIONAL WELL CONTROL EQUIPMENT

INTRODUCTION

As long as the kelly or top drive is connected to the drill string the drill pipe can be shut off by one or more kelly cocks, also called drill pipe safety valves.

Should there be a kick during tripping, additional inside pipe shutoff tools are required to prevent a blow-out through the string. The following equipment is required as additional well control tools:

- Two lower kelly cocks, for each size of drill pipe in use, should be available. One of these is intended for use below the kelly or top drive during drilling operations and the other should be on the drilling floor in the "open" position. The latter should be complete with removable handles for easy stabbing and connecting.
- Subs, for connecting the kelly cock to the drill collars in use, should be available on the drilling floor.
- Two drop-in type back-pressure valves, to match the seating subs fitted in the drill string, must be available. The drop-in valves must be able to pass the smallest bore in the drill string above the seating sub, including the kelly cock.

Instead of a drop-in type back-pressure valve (dart valve) a float valve can be installed in the drill string just above the bit.

- A "Gray-type" inside BOP, with the appropriate connections for the drill string in use, should be on the drilling floor ready for immediate use at all times.
- A 69,000 kPa (10,000 psi) WP, 50.8 mm (2") or 76.2 mm (3") rotating type circulating head with correct bottom subs for the drill string sizes in use should be available on the drilling floor.
- A left hand threaded upper kelly cock should be installed and in good operating condition at all times. A test sub for testing the kelly and kelly cocks should be available on site.

KELLY COCK

UPPER KELLY COCK

The top valve above a kelly is often an Omsco kelly cock and the bottom valve is often a Hydril orTLW. kelly cock. Both remain open during normal operation. They are manually operated valves and are opened or closed by a key wrench or with a spanner.

The Omsco kelly cock at the top of the kelly only maintains pressure from below after it is closed. This kelly cock is used when the kelly is for example almost down, the string stuck and the swivel or hose starts to leak during a well kill.

LOWER KELLY COCK

The valve body of the Hydril kelly guard is made of one single piece which means that it is not necessary to break any tightened connections when a seat or ball has to be renewed. It is only half the weight of a standard kelly cock and is therefore much easier to handle. The simplicity and reduced weight of this type of valve have led to it being used more and more as a stab-in valve.

INSIDE BOPS

THREE TYPE OF INSIDE BOPs ARE

- Gray valve
- Drop-in cheek valve
- Float sub (bit sub)

All these valves are check valves closing with flow from below but free to pump through from above. They are shown in the accompanying figures

The Gray valve is stored on the rig floor and is kept in the open position by a valve rod and a valve release screw.

If the well starts flowing while tripping the drill pipe must be closed in first. When there is a light flow the Gray valve can be installed directly on the drill pipe. However, with strong back flow the force of the flowing mud.

MUD/GAS SEPARATOR

In critical situations, when circulating out a gas kick, a mixture of gas and drilling fluid may be ejected from the well at high rates - as a foam, as gas and as slugs of more-or-less gas free liquid in rapid (and chaotic) succession. In the absence of efficient separation of the gas and liquid phases a substantial quantity of drilling fluid may be lost at surface, forcing a suspension of well killing activities while fresh supplies of fluid are made up. This is a hazard to be avoided if at all possible.

The required separation is provided by the "mud/gas separator", which is designed to provide rapid venting of gas and recovery of the bulk of the drilling fluid, It is standard equipment on drilling units and has the advantages of being robust and simple in operation.

The main design features are:

- Adequate height and diameter.
- Internal baffling to aid gas break-out.
- Fluid seal by U-tube into the trip tank or dip tube.
- Gas vent outlet of adequate diameter and length.
- Liquid outlet to be large diameter

The mud/gas separator is designed to cope with a range of conditions, since drilling fluid properties may vary widely, as will the characteristics and behaviour of the kick fluids. The type of drilling fluid and the particular conditions existing within the well bore will also considerably affect the environment within which the separator has to operate.

FLUID SEAL

If gas pressure in the separator overcomes the hydrostatic pressure of the fluid in the U-tube trap at the separator bottom, gas will blow through into the shaker room. The U-tube or liquid outlet system should be arranged to provide a minimum U-tube height of at least 10 feet. This, with fluid of say 0*52 psi/ft, will support a back pressure of 5 psi. The liquid outlet line is recommended to be at least *8"* ID, although 12" is advised to improve the handling of high viscosity contaminated drilling fluid flows. Some combinations of drilling fluid types and well fluids can produce very high viscosity and significant gellation.

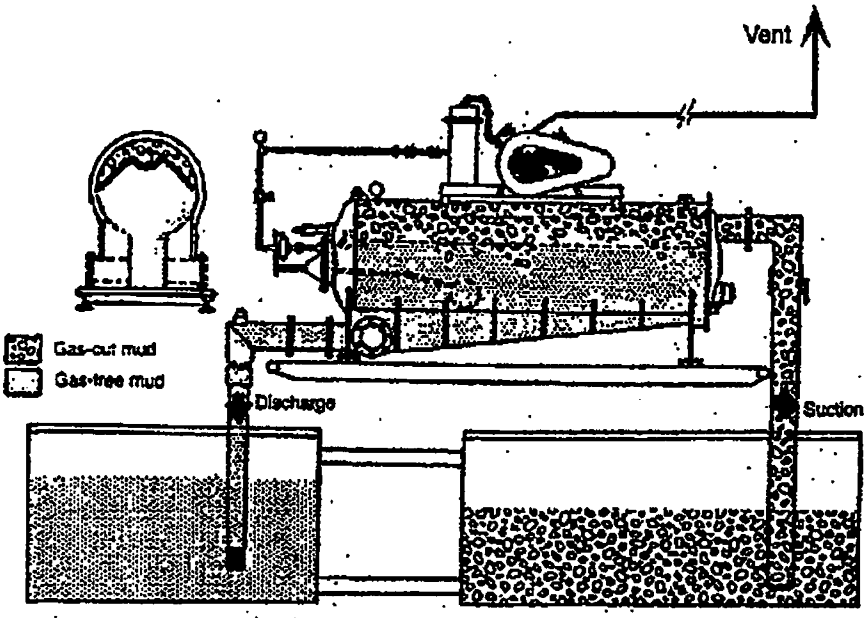
VENT UNIT

The derrick gas vent line should be of large diameter, with as few bends as possible, to minimise back pressures. *8"* ID lines are strongly recommended. It has been common practice in the past to use thick walled line pipe for these derrick vents. This seems unnecessary, given the pressures involved, and reduces the internal dimensions, limiting the capacity of the degasser vent line.

VACUUM DEGASSER

Virtually all the gas which is entrained in the drilling fluid can be removed by circulating it through a degasser which is held at a partial vacuum. In this equipment gas-cut drilling fluid is picked up from the shakers tank and pulled through the degasser vessel by a jet pump. The small vacuum pump mounted on top of the vessel removes the freed gas and freely vents these gases to the atmosphere.

The most commonly used degasser, that of Swaco, has a large contact area with the drilling fluid flowing over a corrugated baffle plate. The vent line from the degasser should preferably not be connected the vent line of the mud/gas separator, but if connected, a check valve must be inserted between these two vent lines.



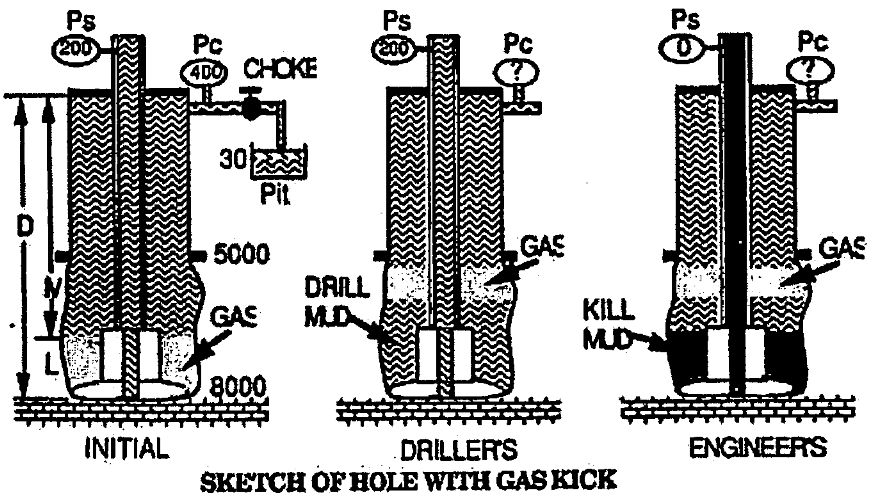


Figure 14 : Sketch of Hole With Gas Kick

WELL KILLING METHODS

The main principle involved in all well killing methods is to keep bottom hole pressure constant. The various kill methods are as follows:

- **Driller's Method**
- **Wait and Weight Method**
- **Concurrent Method**
- **Volumetric Method**

In the first three methods the influx is circulated out and the heavy mud is pumped in the well keeping the bottom hole pressure constant. The fourth method Volumetric method is a non circulating method in which the influx is brought out & heavy mud is placed in the well bore without circulation.

BRINGING THE PUMP TO KILL SPEED ON SURFACE is important to understand the start up procedure, irrespective of kill method, for bringing the pump up to kill speed . Pump should be brought to kill speed patiently. During this period if the casing pressure is allowed to increase it can cause formation breakdown or if the casing pressure is allowed to decrease it can cause entry of more influx into wellbore. To prevent this, following procedure is suggested.

- Bring the pump to kill speed holding casing pressure constant by manipulating choke.
- When the pump is at the desired kill speed follow the pressure schedule according to the kill method being used.

Note : While bringing the pump to kill speed keeping casing pressure constant , there might be slight reduction in bottom hole pressure due to expansion of gas but this is compensated by the annular pressure losses.

DRILLER'S METHOD

In Driller's method the killing of a well is accomplished in two circulations

- In first circulation the influx is removed from the well bore using original mud density.
- In second circulation the kill mud replaces the original mud and restores the primary control of the well.

Formulae required :

a) Kill Mud Weight (ppg) $= \text{Old Mud Weight (ppg)} + \dfrac{\text{SIDPP (psi)}}{0.052 \times \text{TVD (ft)}}$

b) Initial Circulating Pressure (ICP) = SIDPP(psi) + KRP (psi)

c) Final Circulating Pressure (FCP) $= \dfrac{\text{Kill mud weight (ppg)}}{\text{Original mud weight (ppg)}} \times \text{KRP(psi)}$

d) Surface to bit Strokes $= \dfrac{\text{Drill string volume(bbl)}}{\text{Pump output (bbl/stroke)}}$

e) Bit to shoe Strokes $= \dfrac{\text{Open hole annulus volume (bbl)}}{\text{Pump output (bbl/stroke)}}$

f) Bit to surface Strokes $= \dfrac{\text{Annulus Volume (bbl)}}{\text{Pump output (bbl/stroke)}}$

KILLING PROCEDURE (Drillers Method)

In this method the well is killed in two circulations.

First Circulation

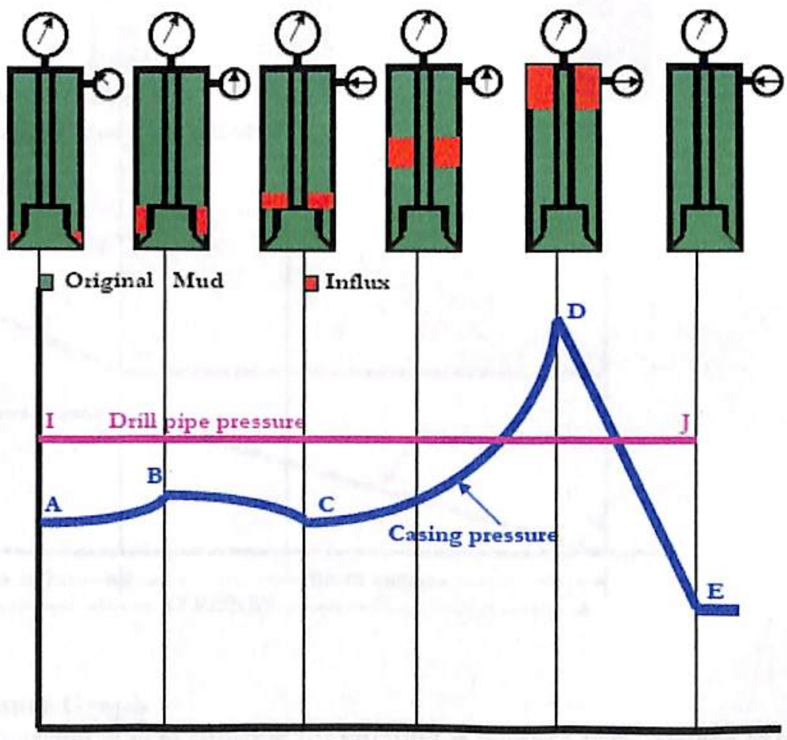
- Bring the pump up to kill speed in steps of 5 SPM, gradually opening the choke holding casing pressure constant.
- When the pump is up to kill speed, maintain drill pipe pressure constant .
- Circulate out the influx from the well maintaining drill pipe pressure constant.
- When the influx is out, stop the pump reducing the pump speed in steps of 5SPM , gradually closing the choke, maintaining casing pressure constant. Record pressure, SIDPP and SICP should be equal to original SIDPP.

Note : In case recorded SIDPP & SICP are equal but more than original SIDPP value, it indicates trapped pressure in wellbore. Whereas if SICP is more than original SIDPP, it indicates that some influx is still in the wellbore.

Second Circulation

- Line up suction with kill mud.
- Bring the pump up to kill speed in steps of 5 SPM, gradually opening the choke, holding casing pressure constant.
- When the pump is at kill speed, pump kill mud from surface to bit, maintaining casing pressure constant.
- Pump kill mud from bit to surface, maintaining drill pipe pressure constant equal to FCP.
- When the kill mud reaches surface, stop the pump reducing the pump in steps of 5 SPM , gradually closing the choke maintaining casing pressure constant.

Record pressures, SIDPP and SICP both should be equal to zero.
Open & observe the well. Add trip margin before resuming normal operation.



PRESSURE PROFILE- 1st CYCLE OF DRILLER'S METHOD

Casing Pressure Graph

A-B Casing pressure rises as influx expands in drill collar annulus.

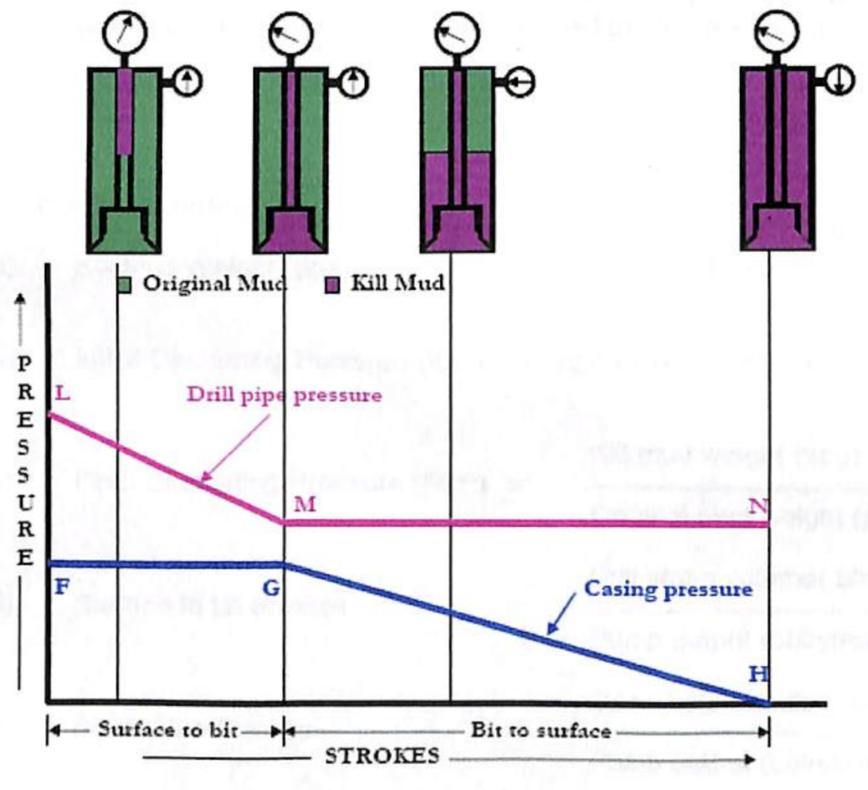
B-C Casing pressure decreases as influx crosses over from drill collar annulus to drill pipe annulus & losses height.

C -D Casing pressure again rises as influx now expands in drill pipe annulus and it becomes maximum when influx reaches surface at point 'D' on the graph.

D-E Casing pressure reduces sharply as influx is removed from the wellbore.

Drill Pipe Pressure Graph

I-J Drill pipe pressure is held constant till the influx is removed from the wellbore.



Casing Pressure Graph

F-G Casing pressure is held constant till kill mud is pumped from surface to bit.

G-H Casing pressure reduces to zero as kill mud is pumped from bit to surface.

Drill Pipe Graph

L-M Drill pipe pressure reduces as kill mud is pumped from surface to bit. During this period SIDPP drops & becomes zero whereas KRP increases to FCP value.

On the whole drill pipe pressure reduces from ICP to FCP.

M-N Drill pipe pressure is held constant as the kill mud is pumped from bit to surface.

WAIT AND WEIGHT METHOD

- In Wait and Weight method well is killed in one circulation using kill mud.
- In this method operations are delayed (wait) once the well is shut in, while a sufficient volume of kill (weight) mud has been prepared. As the kill mud is pumped to the bit the hydrostatic pressure in the Drill Pipe increases, this causes the drill pipe pressure to fall. At the same time, influx which is on its way up the annulus expands continuously and gains volume / height, thereby causing the hydrostatic pressure in annulus to fall and casing pressure to rise. Because of this, for maintaining BHP constant a calculated step down plan for the drill pipe pressure must be used while pumping the kill mud from surface to the bit.

Formulae required :

a) Kill Mud Weight (ppg) $= \text{Old Mud Weight (ppg)} + \dfrac{\text{SIDPP (psi)}}{0.052 \times \text{TVD (ft)}}$

b) Initial Circulating Pressure (ICP) $= \text{SIDPP(psi)} + \text{KRP (psi)}$

c) Final Circulating Pressure (FCP) $= \dfrac{\text{Kill mud weight (ppg)}}{\text{Original mud weight (ppg)}} \times \text{KRP(psi)}$

d) Surface to bit Strokes $= \dfrac{\text{Drill string volume(bbl)}}{\text{Pump output (bbl/stroke)}}$

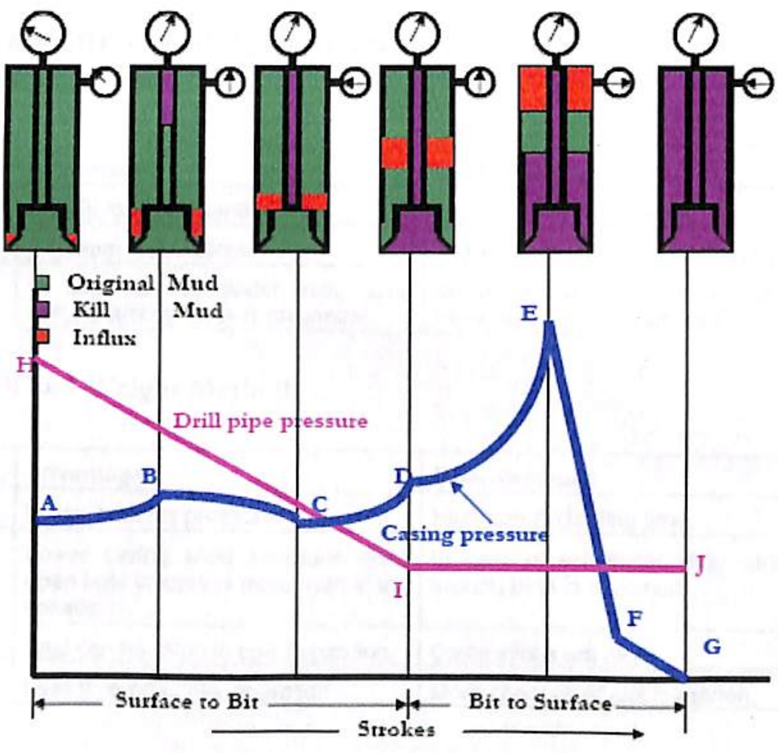
e) Bit to shoe Strokes $= \dfrac{\text{Open hole annulus volume (bbl)}}{\text{Pump output (bbl/stroke)}}$

f) Bit to surface Strokes $= \dfrac{\text{Annulus Volume (bbl)}}{\text{Pump output (bbl/stroke)}}$

g) Pressure drop / 100 strokes $= \dfrac{\text{ICP} - \text{FCP}}{\text{Surface to bit strokes}} \times 100$

Killing Procedure (Wait and Weight Method)

- Line up suction with kill mud.
- Bring the pump up to kill speed in steps of 5 SPM, gradually opening the choke, holding casing pressure constant.
- When the pump is at kill speed, pump kill mud from surface to bit, maintaining drill pipe pressure as per step down schedule(during this step drill pipe pressure will fall from ICP to FCP).
- Pump kill mud from bit to surface, maintaining drill pipe pressure constant equal to FCP.
- When the kill mud reaches surface, stop the pump reducing the pump speed in steps of 5 SPM , gradually closing the choke maintaining casing pressure constant. Record pressures, SIDPP and SICP both should be equal to zero. Open & observe the well. Add trip margin before resuming normal operation .



PRESSURE PROFILE- WAIT & WEIGHT METHOD

Casing Pressure Graph

A-B Casing pressure rises as influx expands in drill collar annulus.
B-C Casing pressure decreases as influx crosses over from drill collar annulus to drill pipe annulus & losses height.
C-D Casing pressure again rises as influx now expands in drill pipe annulus.
D -E Casing pressure continues to increase but initially at a slower rate as at this stage kill mud starts entering the annulus, later on casing pressure increases at a faster due to rapid expansion of gas.
E-F Casing pressure reduces sharply as influx is removed from the wellbore.
F-G Casing pressure further reduces as original mud is replaced by kill mud.

Drill Pipe Pressure Graph

H-I Drill pipe reduces from ICP to FCP as kill mud is pumped from surface to bit.
I- J Drill pipe pressure is held constant at FCP as kill mud is pumped from bit to surface.

COMPARISON OF METHODS

Driller's Method

	Advantages	Disadvantages
1.	Simple to understand	Higher annulus pressure
2.	Minimum calculations	Higher casing shoe pressure in gas kick.
3.	In case of salt water kick, sand settling around BHA is minimum.	Minimum two circulations are required. More time on choke operation.

Wait and Weight Method

	Advantages	Disadvantages
1.	Lower annulus pressure.	High non circulating time.
2.	Lower casing shoe pressure when open hole volume is more than string volume.	In case of salt water kick, sand settling around BHA is maximum.
3.	Well can be killed in one circulation.	Calculations are more.
4.	Less time on choke operation.	More chances of gas migration.

PRESSURE BEHAVIOUR AT DIFFERENT POINTS DURING WELL KILLING

Pressure behaviour at different points of annulus during the process of well killing can be analysed by an example discussed below. For the purpose of understanding, the annular hydrostatic has been divided in two parts i.e hydrostatic pressure below & above the casing shoe. The well is shut-in & the killing has started with influx at bottom, it is assumed that while killing the well the BHP has been kept constant equal to formation pressure i.e 1200 psi.

Stage A: Well is shut – in
BHP =Hydrostatic Pressure below shoe+ Hydrostatic Pressure above shoe+ SICP
BHP = 400 + 600 + 200 = 1200 psi
P re s s u re at shoe = 600+200 = 800 psi

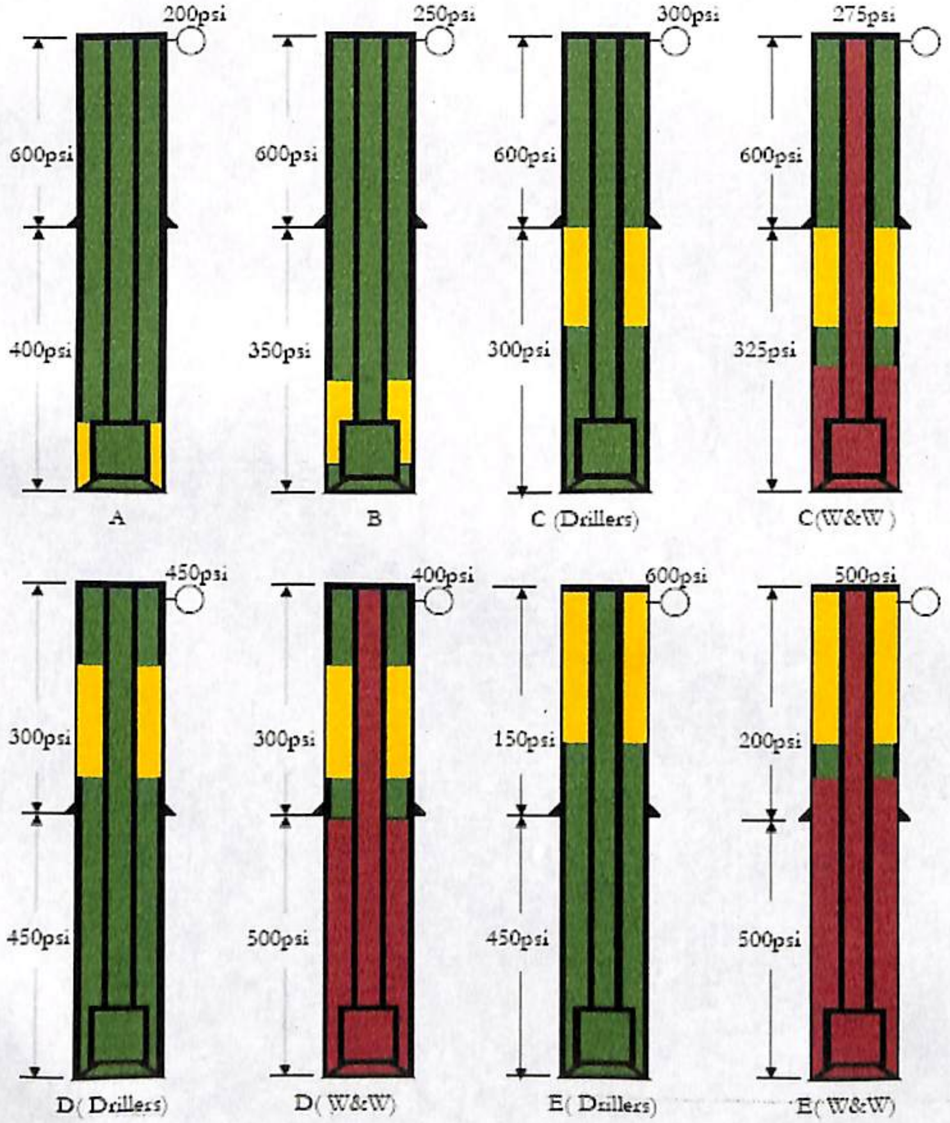
Stage B : Well killing in progress
As there will be expansion of gas so hydrostatic pressure below the shoe reduces (suppose now it is 350 psi).
BHP = Hydrostatic Pr. below shoe + Hydrostatic Pr. above shoe + Casing Pr
= 350 + 600 + Casing Pressure = 1200 psi
Therefore, Casing pressure = 1200-(350+600) = 250 psi
Pressure at shoe=250 +600 = 850 psi

Stage C : Top of Influx at Shoe
As there will be further expansion of gas so hydrostatic pressure below shoe will reduce further (suppose now it is 300 psi).
BHP = Hydrostatic Pr. below shoe + Hydrostatic Pr. above shoe + Casing Pr.
= 300 + 600 + Casing Pressure = 1200 psi
Therefore, Casing pressure = 1200-(300+600) = 300 psi
Pressure at shoe=300 +600 = 900 psi (maximum pressure at casing shoe)

Comparing Driller's Method with Wait & Weight Method.

If we are killing the well by W& W method then there will be some kill mud in annulus, provided open hole volume is more than drill string volume. In that case hydrostatic pressure below shoe will be more than 300 psi (suppose now it is 325 psi).
BHP = Hydrostatic Pr. below shoe + Hydrostatic Pr. above shoe + Casing Pr
= 325 + 600 + Casing Pressure = 1200 psi
Therefore, Casing pressure for Wait & Weight Method = 1200-(325+600) = 275psi P ressure at shoe for wait & weight method =275 +600 = 875 psi(maximum pressure at casing shoe)

Figure 17 :
DIAGRAMATIC REPRESENTATION
DIFFERENCE B/W DRILLERS & W/W METHOD



Stage D : Influx in casing

In case of Driller's Method now annulus below shoe is full of original mud. If werefer to first condition when influx was at stage A, the hydrostatic pressure below shoe was 400 psi when it comprised of original mud and influx. So now hydrostatic pressure below shoe will be more than 400 psi since influx has been displaced inside the casing (suppose now it is 450 psi).

Hydrostatic pressure above shoe = 300 psi
(since, now the influx has entered the casing the hydrostatic above shoe has reduced considerably to 300 psi)
BHP = Hydrostatic Pr. below shoe + Hydrostatic Pr. above shoe + Casing Pr.
BHP = 450 + 300 + Casing Pressure = 1200 psi

Therefore, Casing pressure for drillers method = 1200-(450+300) = 450 psi
Pressure at shoe for driller's method =300 +450 = 750 psi

In case of **wait & weight method** annulus below shoe is now full of kill mud, whereas in case of driller's method at this stage annulus below shoe was full of original mud, because for driller's method the pressure below shoe was 450 psi, so in case of wait & weight method pressure below shoe will be more than 450 psi(suppose it is 500 psi).
BHP = 500 + 300 + Casing Pressure = 1200 psi

Therefore, Casing pressure for wait & weight method = 1200-(500+300) = 400 psi
Pressure at shoe for wait & weight method =300 +400 = 700 psi

Stage E : Influx at surface
Due to further expansion of gas there will be further reduction of hydrostatic head above shoe(Suppose it has reduced to 150psi for drillers method).

i) drillers method
BHP = Hydrostatic Pr. below shoe + Hydrostatic Pr. above shoe + Casing Pr.
BHP = 450 + 150 + Casing Pressure = 1200 psi
Therefore, Casing pressure for **drillers method** = 1200-(450+150) = 600psi
Pressure at shoe for **drillers method** =150 +600 = 750 psi

ii) wait & weight method
BHP = Hydrostatic Pr. below shoe + Hydrostatic Pr. above shoe + Casing Pr.
BHP = 500+ 200 + Casing Pressure = 1200 psi
In this case the hydrostatic pressure above the shoe will be more as compared to that of driller's method, because of entry of kill mud in this section (say 200 psi)
Therefore, Casing pressure for **w & w method** = 1200-(500+200) = 500psi
Pressure at shoe for **wait & weight method** =200 +500 = 700 psi

Above information is tabulated below:

Stage	Method	Hyd. Pressure Below shoe	Hyd. Pressure above shoe	Casing Pressure	BHP	Pressure at shoe
A	Both Methods	400	600	200	1200	800
B	Both Methods	350	600	250	1200	850
C	Driller's Method	300	600	300	1200	900
	W& W Method	*325*	*600*	*275*	1200	*875*
D	Driller's Method	450	300	450	1200	750
	W& W Method	*500*	*300*	*400*	1200	*700*
E	Driller's Method	450	150	600	1200	750
	W& W Method	*500*	*200*	*500*	1200	*700*

Following conclusions are drawn :

a) Pressure at surface is increasing and it will be maximum when top of influx is at surface.

b) Maximum pressure at surface is more in case of driller's method as compared to wait & weight method.

c) Maximum pressure at shoe is less in case of wait & weight method if open hole volume is more than drill string volume.

d) Pressure at any points above the bubble increases.

e) Pressure at any point below the bubble is constant for drillers method. For wait & weight method pressure at any point below bubble remains constant so long there is no kill mud in annulus. Once kill mud starts entering in to the annulus the pressure at any point below the bubble starts falling and it will continue to fall till the kill mud reaches that point. There after pressure at that point become constant.

f) Pressure of influx decreases due to expansion of gas.

g) Pressure at shoe increases as influx rises up in the annulus, becomes maximum when top of influx is at shoe thereafter as influx enters the shoe the pressure at shoe decreases & becomes constant once hydrostatic pressure below the shoe becomes constant.

After the influx has entered the shoe & hydrostatic below the shoe has become constant, the pressure at shoe will be less as compared to the shoe pressure at the time of initial shut-in.

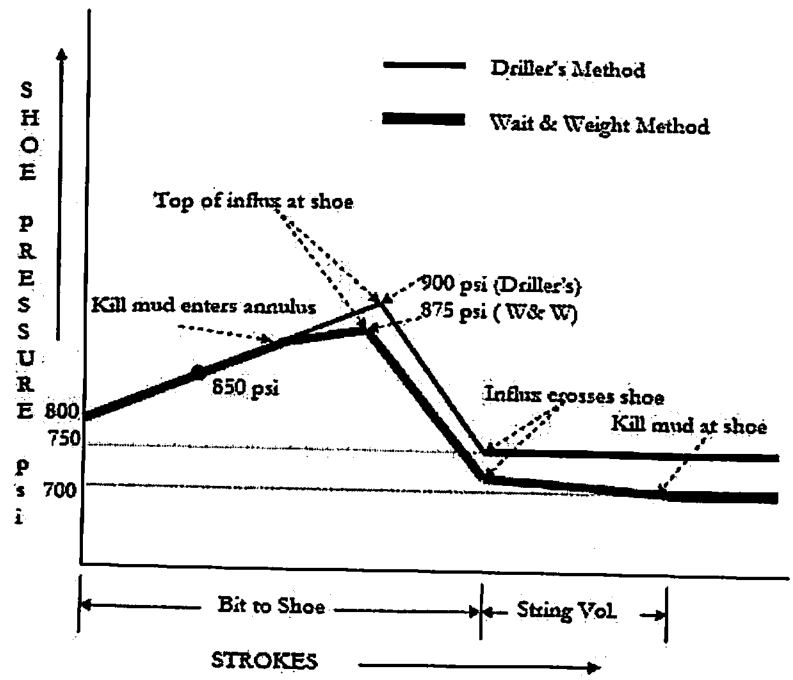


Figure 18 : CASING SHOE PRESSURE PROFILE

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CONCLUSION

The Driller's Method was the first and most popular displacement procedure. The required calculations are not difficult. One disadvantage of the Driller's Method is that at least two circulations are required to control the well

The Wait and Weight Method is slightly more complicated but offers some distinct advantages. First, the well is killed in half the time. Modern mud-mixing facilities permit barite to be mixed at rates up to 600 sacks per hour with dual mixing systems; therefore, time required to weight up the suction pit is minimized and kill rate is not penalized. The Wait and Weight Method results in kill mud in the well sooner and that is always an advantage. In addition, as discussed and illustrated in this report, the annulus pressures are lower when the Wait and Weight Method is used. Also the method is cost effective.

The primary disadvantage is the potential for errors and problems while displacing the kill-weight mud to the bit. With the Driller's Method, the procedure can be stopped and started easily. Stopping and starting when using the Wait and Weight Method is not as easy, especially during the period that the kill-weight mud is being displaced to the bit. It is not uncommon that good drilling men get confused during displacement using the Wait and Weight Method.

In view of all considerations, the Wait and Weight Method is the preferred technique

NOMENCLATURE.

1. P_{fs} = formation strength gradient at shoe.
2. P_o = formation pressure gradient.
3. P_{df} = drilling fluid gradient
4. P_{info} = original influx gradient.
5. D_{hv} = true vertical depth of hole.
6. D_{sv} = true vertical depth of shoe.
7. V_{info} = original influx volume.
8. V_{infs} = influx volume at shoe.
9. H_{inf} = Height of influx on bottom.
10. H_{ufaan} = Height of influx at shoe, alonghole
11. $Av\,cap_{agvs}$ = Average annular capacity (shoe)
12. $Av\,cap_{btw}$ = Average annular capacity (bottom)
13. θ_{btm} = hole angle at bottom.
14. θ_s = hole angle at shoe.

DATA :

Hole diameter, d_2 = 8.5 inch.

Depth to bit, D = 10,000 ft

Volume of influx, V_{inf} = 25 bbl.

Tank Volume = 400 bbl

closed in drill pipe pressure, P_{dp} = 1610 psi

Closed in annular pressure, P_{ann} = 1920 psi

Initial drilling fluid gradient, P_1 = 0.519 psi/ft

formation strength gradient, P_f = 0.850 psi/ft

Pump output, θ at 30 strokes/min - 125 gpm

P_G - 340 psi.

CASING		GRADE. (K55)
weight	-	40 lbs/ft
Inner dia	-	8.835 inch
outer dia	-	9.625 inch
length	-	6800 ft.

DRILL PIPE		GRADE E.
weight	-	19.5 lbs/ft.
Inner dia	-	4.276 inch
outer dia	-	5 inch.

HWDP		GRADE E.
weight	-	50 lbs/ft
Inner dia	-	3 inch
outer dia	-	5 inch
length	-	1,100 ft.

DRILL COLLARS

weight - 96.02 lbs/ft

I.D - $2\frac{13}{16}$ inch

O.D - $6\frac{3}{8}$ inch

length - 600 ft.

Calculating the formation pressure when bit is at the bottom of the hole:

Formation pressure = Hydrostatic head of fluid in drill string + closed in drill pipe pressure.

$P_o = \Delta P_1 + P_{dp}$

$= 3000 \times 11.78 + 10,980$

$= 46,320$ KPa.

$= 10,000 \times 0.519 + 1,610$ psi

$= 6800$ psi

Calculating Height of Influx - Bottom.

Δ capacity of annulus opposite drill collars $= 600 \times 0.0307$ bbl

$= 18.42$ bbl.

Δ volume of influx above drill collar

$= 25 - 18.42$

$= 6.58$ bbl

Δ Height of this = $6.58 / 0.459 = 143$ ft

Total height of Influx $= 600 + 143 = 743$

- Calculating gradient of Influx (ρ influx)

Formation pressure = hydrostatic head of fluid in drill string + hydrostatic head of influx + Closed in annular pressu

$$P_0 = X\rho_1 + h_b \rho_{inf} + P_{ann}.$$

$$P_0 = D\rho_1 + P_{dp} \Rightarrow X\rho_1 + h_b \rho_{inf} + P_{ann}$$

$$= D\rho_1 + P_{dp}$$

Rearranging $h_b \rho_{inf} = D\rho_1 + P_{dp} - P_{ann} - X\rho_1.$

Dividing through h_b

$$\rho_{inf} = \rho_1 + \frac{(P_{dp} - P_{ann})}{h_b}$$

- since $(D - X = h_b)$

- $P_{dp} < P_{ann}$ $\quad \therefore \rho_{inf} = \rho_1 - \frac{(P_{ann} - P_{d}}{h_b}$

$$= 0.519 - \frac{1,920 - 161}{743}$$

$$= 0.10 \text{ psi/ft.}$$

So influx can be assumed to be gas.

* Drill string contents:

capacity of drill pipe + capacity of HWDP + capacity of DC's

= Total drill string

= $8{,}300 \times 17.5 \times 10^{-3} + 1100 \times 8.70 \times 10^{-3} + 600 \times 7.68 \times 10^{-3}$

= 159.43 bbls.

* Now, calculating annular content;

Total annular capacity = capacity of DC/OH annulus + capacity of DP/OH annulus + capacity of DP/casing annulus

$= 18.42 + 2600 \times 0.0459 + 6899 \times 0.5155$

= 493.1 bbl.

Calculating the required density of weighted drilling fluid:

{ hydrostatic head of ρ_2 fluid = formation Pressure }

To balance formation pressure.

$\Delta P_2 = P_0$

$P_0 = \Delta P_1 + P_{dp}$.

Thus for balance = $\Delta P_2 = \Delta P_1 + P_{dp}$

∴ density of new drilling fluid

$\rho_2 = \rho_1 + P_{dp}/D$.

$= 0.519 + \frac{1610}{10{,}000} = 0.680$ psi/ft.

Calculating amount of weighted material required (N)

Tank volume + capacity of drill string + capacity annulus = total volume.

$\therefore$ 400 + 161.63 + 493.1 = 1052.5 bbls

for barytes with a density of 262.3 lbs/ft

$$= 1052.5 \times \frac{1472.8 \times (\rho_2 - \rho_1)}{1.822 - \rho_2}$$

$= 218537$ bbl.

$\rho_1 = 0.519$

$\rho_2 = 0.680$.

Calculating volume increase

$$\Delta V = \frac{218537}{262.3 \times 5.615} = 148.4 \text{ bbls.}$$