Well Control

Manual

Bharat PetroResources Limited

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<u>Contents</u>

1.0.0 **Definitions**

1.0.1 **Influx**

The flow of fluids from bottom into the well bore.

1.0.2 **Kick**

Any influx or flow of formation fluid into the well-bore is termed as Kick. It may occur any time during drilling/ initial testing or work-over operation due to formation fluid pressure being greater than the bottom hole pressure.

1.0.3 **Blowout**

If the kick is uncontrolled, the formation fluid will flow to the surface is termed as Blow-out.

1.0.4 **Pore Pressure**

Pore Pressure is the pressure acting on the fluids in the pore spaces in the rock, is known as Formation pressure also. This is the portion of the overburden supported by the formation fluid.

1.0.5 **Hydrostatic pressure**

Pressure exerted by the fluid column at a certain depth is termed as Hydrostatic Pressure.

1.0.6 **Bottom hole pressure (BHP)**
Sum of all pressures that are being exerted at the bottom of the hole and can be written as: BHP = Static pressure + Dynamic pressure

1.0.7 **Fracture Pressure**

The pressure required to initiate a fracture in a sub surface formation. Fracture pressure can be determined by Geo-physical methods; during drilling fracture pressure can be determined by conducting a leak-off test.

1.0.8 **Kill Rate**

Kill rate is reduced circulating rate that is required when circulating out kicks, so that additional pressure to prevent formation flow can be added without exceeding pump liner rating. Kill rate is normally ½ to 1/3 of the normal circulating rate.

1.0.9 **Kill rate pressure**

The pressure measured at drill pipe gauge when the mud pumps are operating at kill rate.

1.0.10 **Maximum allowable annular Surface pressure (MAASP)**

It is maximum allowable surface pressure during well control. Any pressure above this may damage the formation/ casing.

1.0.11 **Primary well control**

Primary well control is the use of drilling fluid density to provide sufficient pressure to prevent the influx of formation fluid into the wellbore.

It is of the utmost importance to ensure that primary well control is maintained at all times. This involves the following:

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

1.0.12 **Secondary well control**

Secondary Control is the proper use of blowout prevention equipment to control the well in the event that primary control cannot be properly maintained. Early recognition of warning signals and rapid shut-in are the key to effective well control. By taking action quickly, the amount of formation fluid that enters the wellbore and the amount of drilling fluid expelled from the annulus is minimized. The size and severity of a kickdepends upon:

e. The degree of underbalance.
f. The formation permeability.
g. The length of time the well remains underbalanced.

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

1.0.13 **Tertiary Well Control:**

Tertiary well control describes the third line of defence. Where the formationcannot be controlled by primary or secondary well control (hydrostatic and equipment). In the event that secondary control cannot be properly maintained due to hole conditions or equipment failure,certain emergency procedures can be implemented to prevent the loss of control. These procedures are referred to as "Tertiary Control" and usually lead to partial or complete abandonment of the well. Unlike primary and secondary control, there are no established tertiary well control procedures that will work in most situations. The procedures to be applied depends on the particular operating conditions which are encountered, and specific recommendations regarding appropriate tertiary control procedures cannot be given until the circumstances leading to the loss of secondary control are established.

An underground blowout for example. However in well control it isnot always used as a qualitative term. 'Unusual well control operations' listed below are considered under this term:-

   a) A kick is taken with the string off bottom.
   b) The drill pipe plugs off during a kill operation.
   c) There is no pipe in the hole.
   d) Hole in drill string.
   e) Lost circulation.
   f) Excessive casing pressure.
   g) Plugged and stuck off bottom.
   h) Gas percolation without gas expansion.

We could also include operations like stripping or snubbing in the hole, or drillingrelief wells. The point to remember is "what is the well status at shut in?" This determines the method of well control. However, there are two procedures that are widely used. These involve the use of:

- Barite plugs

- Cement plugs

1.0.14 Accumulator (BOP Control Unit)

A pressure vessel charged with Nitrogen or other inert gas and used to store hydraulic fluid under pressure for operation of blowout preventers and/or diverter system.

1.0.15 Annular Preventer

A device which can seal around different sizes and shapes object in the well bore or seal an open hole.

1.0.16 Blowout Preventer Stack

The assembly of well control equipment including preventers, spools, valves and nipples connected to the top of the casing head

1.0.16 Choke manifold

The assembly of valves, chokes, gauges and piping to control flow from the annulus and regulate pressure in the drill string/ annulus when the BOPs are closed.

1.0.17 Degasser

A vessel, which utilizes pressure reduction and/or inertia to separate entrained gasses from the liquid phases.

1.0.18 Diverter

A device attached to the well head to close the vertical excess and direct flow into a line away from the rig.

1.0.19 Mud gas separator

a device that removes gas from the returned drilling fluid, when a kick is being circulated out. It is also known as gas buster or poor boy degasser.

1.0.20 Kick tolerance:

Kick tolerance is the volume of the kick at a given pressure which can be safely shut in and circulated out of the well without fracturing the formation.

1.0.21 Underbalanced Drilling (UBD)

Is a drilling process when the hydrostatic head of the drilling fluid has to be kept lower than the formation pressure, with the intention of bringing formation fluid to the surface. It is necessary when formation pressure is sub-hydrostatic and there are every chances of loss circulation, if otherwise drilled with normal drilling fluid. The hydrostatic pressure is maintained by adding natural gas, nitrogen or air to the drilling fluid so that hydrostatic pressure of drilling fluid is lower than the formation pressure.

2.0.0. Causes of kicks

Kicks occur as a result of formation pressure being greater than mud hydrostatic pressure that causes flow of formation fluid into the well bore. The main factors which can lead to this condition can be classified as :

a) Human error
b) Improper hole fill up on trips.
c) Swabbing.
d) Abnormal formation pressure.
e) Insufficient mud density.
f) Lost circulation
g) Gas cut mud

Note; More than 50% of the kicks occur due to first three of the causes listed above.

2.0.1. Improper hole fill up on trips

When the drill string is pulled out, the mud level decreases by a volume equivalent to the steel volume. If the hole does not take the calculated volume of mud, it is assumed a formation fluid has entered the wellbore. This can be ascertained by using Trip Tank during filling up the hole and differences of calculated and actual mud volume be recorded at regular

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intervals. Similarly while running in drill string, trip tank should be used to monitor displacement volume correctly at regular intervals.

If the hole is not filled to replace the steel volume, the fluid column in the wellbore shall go down and reduce the hydrostatic pressure. At the same time the pulling out of drill string causes a reduction in BHP due to swabbing effect. Therefore to avoid the possibility of any formation fluid entering the bore hole due to combination of above two factors the hole should be properly / regularly filled during tripping out.

In the field normally the practice is to fill up the hole either on a regular fill up schedule or to fill up continuously with a re-circulating trip tank. Irrespective of the practice being used an accurate method of measuring the amount of fluid actually being taken by hole should be monitored and an accurate record of actual volume v/s theoretical volume should be kept. If at any stage during pulling-out it is observed that the actual filled in volume is significantly less than volume of steel that has been removed, it means that some formation fluids must have entered the wellbore.

2.0.2. **Swabbing**

During pulling out the drill string from the borehole, swab pressures are created, resulting reduction in bottom hole pressure. If, reduced bottom hole pressure becomes less than the formation pressure, a potential kick may enter the well bore. Various factors conducive to swab pressures are speed of pulling out, mud properties, filtration cake, annular clearance, hole configuration and effect of balling up of BHA & bit.

2.0.3. **Abnormal pressure**

Formation pressures are not known precisely while drilling wild cat or exploratory wells. Sometimes the bit suddenly penetrates an abnormal pressure formation. As a result the mud hydrostatic pressure becomes less

than the formation pressure and may cause a well kick. There are various geological reasons for abnormal pressures.

2.0.4. Insufficient mud density

If a formation is drilled using a mud density that exerts less hydrostatic pressure than the pore pressure, the formation fluid may begin to flow into the well bore. Kicks caused by insufficient mud density can be resolved by drilling with high mud density.

2.0.5. Lost circulation

Another factor, which reduces the hydrostatic pressure, which is matter of concern, is lost circulation. The problem may become more severe, when a kick occurs due to lost circulation. A large volume of kick fluid may enter the hole before the mud level increase is observed at the surface. It is a recommended practice to keep the annulus always topped to avoid considerable reduction in BHP when lost circulation is encountered.

2.0.6. Gas cut mud

Gas cut mud may occasionally cause a kick. As the gas is circulated to the surface, it expands and reduces the hydrostatic pressure sufficient to allow a kick to enter. Fortunately, the mud density is reduced considerably at the surface due to gas expansion takes place near surface, resulting hydrostatic pressure is not reduced significantly.

3.0.0 Kick indication

Following are the early warning signs & positive indications for kicks while drilling.

3.0.1   **Early warning signs**

The early warning signs are indications of approaching higher formation pressure which means that the well may go under-balance if no appropriate action is taken. These are as listed below :

i).   **Drilling Break**

The first indication of a possible well kick is a drilling break. There should be a permeable section of reservoir rock for reservoir fluid to enter the well bore. In soft formation, a sand section usually causes a sudden increase in drilling rate. The increase in drilling rate varies.

ii).   **Rate of Penetration (ROP)**

A gradual increase in ROP may be an indication of entering abnormal pressure formations. Similarly weight on bit also changes which can be detected by careful observation.

iii).   **Change in Cutting Size and Shapes**

Cuttings from normal pressure shale are smaller in size with rounded edges and are generally flat. Cuttings drilled from abnormal pressured formation often become long and splintery with angular edges. As differential pressure is reduced due to increase in formation pressure, the cuttings have a tendency to explode off bottom. A change in cutting shape will be observed along with an increase in the amount of cuttings recovered at the surface and this could indicate that formation pressure in the well is increasing.

iv).   **Increase in hook load**

Displacement of drilling fluid by influx will reduce the buoyancy of the drilling fluid, resulting in increase in hook load. However, by the time the change in hook load is noticed, a considerable will already have been taken.

v). Increase in Torque & Drag

The larger cuttings, caused due to above, are piled up around the collars and increase the rotary torque. Increase in rotary torque is a good indication of increasing formation pressure and a potential well kick. Drag & fill up on connections and trips increase when high pressure formations are drilled.

vi). Decrease in Shale Density

Shale density usually increases with depth but decreases in abnormal pressure zones. The density of cuttings can be determined at surface and plotted against depth. A normal trend line is established and any deviation should theoretically indicate changes in pore pressure.

vii). Increase in Chloride Content in Mud Filtrate

Contamination of drilling fluid with considerable volume of saline water from pores may takes place while drilling through high pressure formations. This increases chloride content of the drilling fluid and its filtrate. A higher chloride trend can warn about increase in pore pressure.

viii). Change in Mud Property

As the pressure in the formation increases faster than the mud hydrostatic, more cuttings & caving will dissolve into the mud and increase the viscosity of the mud. Higher changes in mud density trend may warn increase in pore pressure.

ix). Increase in Flow Line Temperature

Increase in Flow Line Temperature also indicates in formation pressure. The temperature gradient in abnormal pressure formation is usually higher than normal formation. The continuous measurement of the mud temperature at

the flow line gives an indication of change in temperature gradient associated with abnormally pressured formation. The temperature may take a sharp increase in transition zones.

x).   Incorrect fill up volume on a trip

Most kicks occur while tripping. Hole fill up volume on a trip must be monitored carefully and a trip sheet filled out.

xi).   Gas cut mud

If a small influx is taken and no pit volume is detectable, the first indication that a kick has occurred may be gas-cut mud at the flow line. However, this may not be conclusive as gas may be from drilled cuttings also.

xii).   Change in 'd'-exponent

Jordan and Shirley developed an equation for normalized penetration rate in which it was defined as a function of measured drilling rate, weight on bit, bit size and rotary speed in the equation as below:

$d = \log (R/60N)/\log (12W/10^3 Db)$

Where,

R = rate of penetration in ft/hr

N = rotary speed rpm

W = weight on bit in 1000 lbs

Db = bit diameter in inches

Since the d-exponent tends to indicate the pressure differential between formation pressure and well bore pressure, mud weight will effect d - exponent. The original calculation should be corrected as follows:

dc = d □×□(MW1 ÷□MW2)

where,

dc = modified d-exponent

MW1 = mud density equivalent of formation fluid at normal pressure condition

MW2 = mud density being used in well

dc values are plotted on a semi log graph paper at every 15 or 30 ft. interval depth to give normal trend line. Abnormal pressure transition zone top is detected at the depth where dc exponent values against shale tend to decrease in comparison to normal values.

3.0.2 **Positive Kick Sign**

Positive kick indicators are different from kick warning signs. They indicate that the kick has already entered the well bore. Any of them indicate regular flow checks.

a) **Increase in Return Flow (Pumps On)**

After the early warning signs the first positive kick sign is increase in flow rate at the flow line with pumps on. Increase in flow rate indicates entrance of any fluid into the well bore.

b) **Flow from Well (Pumps Off)**

Flow check is a reliable method of checking for a well kick by stopping the pump. If the well does not flow when the pump is shut off and remains static for two or three minutes, then no well kick takes place.

c) **Increase in Pit Volume**

An increase in pit volume is obvious & positive indication of flow into the well bore. If an increase in pit volume is observed, shut off the pump and make a flow check which confirms if kick is entering.

d) **Decrease in Pump Pressure and Increase in Pump Stroke**

In case of kick there is under balanced condition between the fluid in the drill pipe and the mixed column of mud and influx in the annulus. Therefore

circulating pressure gradually decreases at constant pump throttle, and pump speed slowly increases.

4.0.0. **Kick while tripping**

The basic requirement to prevent kick while tripping, is that hole must be kept full of mud and the volume of mud required to fill the hole must be equal to the steel displacement of drill string pulled out. The sequence of events to a kick while making a trip-out of hole is :

4.0.1   Hole does not take proper amount of mud. Whenever such situation is noticed the pipe should be run back as far as possible to bottom safely and mud is circulated to clear the hole.

4.0.2   Flow from the flow line

4.0.3   Increase in pit volume

The sequence of events leading to a kick while tripping-in the hole is:

   i).   The hole does not stop flowing during making connection between the stands

   ii). Increase in pit volume

In order to avoid well kicks while tripping, trip schedule must be made and trip tank must be used to monitor the hole fill up (in case of tripping-out) and mud displacement (in case of tripping-in).

5.0.0   **Trip margin**

During pulling out, upward motion of the drill string in the borehole creates a swab pressure. This decreases BHP when pipe is in motion. One way of minimizing this is to use safe tripping speeds and having close monitoring of pipe volume pulled out & mud volume pumped in to keep the hole full. Another practice to tackle the problem is to keep mud weight gradient greater than the formation pressure gradient. The resulting overbalance permits safe tripping and connection operations. This extra mud weight is

called trip margin. For normal drilling operation trip margin is kept 0.2 to 0.3 ppg. However, the swab pressure being a function of yield point (yp) of mud, trip margin can be calculated as follows:-

Trip margin (ppg)= 8.33Yp ÷ 98 (Dh-Dp)

Where

Yp = Yield point of mud in lbs/100 sq.ft

Dh = Hole diameter in inches

Dp = Pipe outside diameter in inches

6.0.0. **Slow circulation rate**

During well control operations, to avoid further entry of formation fluid it is essential to keep BHP minimum equal to formation pressure. This is done by imposing certain calculated backpressure in addition to system pressure losses on the well bore as long as old mud is in the well. Kicks have to be circulated out at slow circulation rates to ensure that the sum of this back pressure and system losses does not exceed the rating of high pressure lines and other rig equipment. Various reasons for circulating out the kicks at slow circulation rates are: -

a) To ensure that the slow circulation pressure plus the shut in drill pipe pressure is a convenient total pressure for the pump and does not exceed the surface line ratings.

b) To allow mud returns to be weighted up and re-circulated within the capabilities of available mud mixing system.

c) To allow longer reaction time for choke adjustments.

d) To allow sufficient time for disposal of kick fluid /de-gassing at the surface.

e) To reduce the annular pressure losses.

Theoretically speaking, the kill rate or slow circulation rate should be the minimum possible pump speed at which pump can run smoothly without any

knocking. The widely used common practice, for triplex pump, is between 1/2 to 1/3 of pump SPM at the time of drilling.

6.0.1. Recording of slow circulation rate

It should be recorded near to the bottom for each pump at regular intervals and / or when drilling conditions change such as:-

i). At the beginning of each shift.

ii). After change in drilling fluid density.

iii). After change in bit nozzle size or BHA.

iv). After drilling a long section of hole (say 500 ft.) in a shift.

v). After pump fluid end repair.

There are a number of places on the rig where drill pipe pressure gauges are installed such as stand pipe, mud pumps, driller's console, choke & kill manifold and remote choke panel. Slow circulation pressure should be recorded from the gauge that is to be used for well killing operation. So, it should be recorded at remote choke panel, if available on the rig.

7.0.0. Line up for shut in

When one or more positive kick signs are observed, flow check is made. In case of self flow well can be shut-in in two ways:

a) Soft shut-in

b) Hard shut-in

7.0.1. SHUT IN PROCEDURES as per API RP 59

As per following are the shut-in procedures for land/jack-up rigs.

a) **Line up for soft shut-in :**

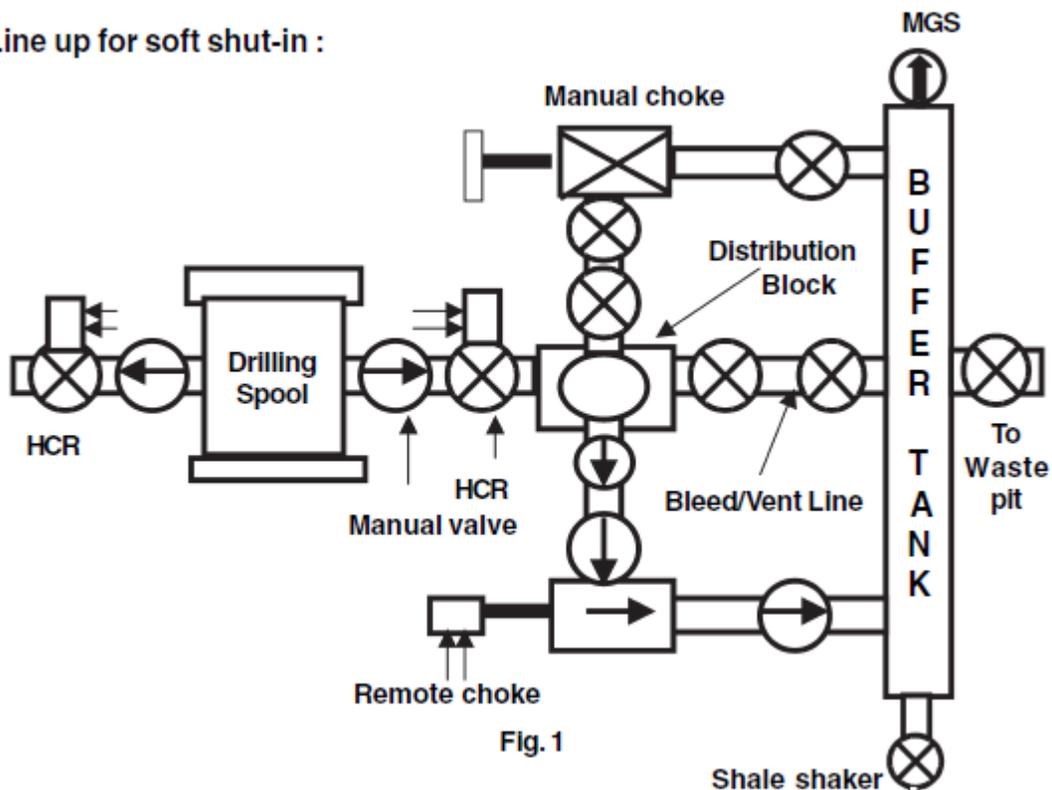Figure 1: Line up for soft shut-in

Line up for soft shut in:

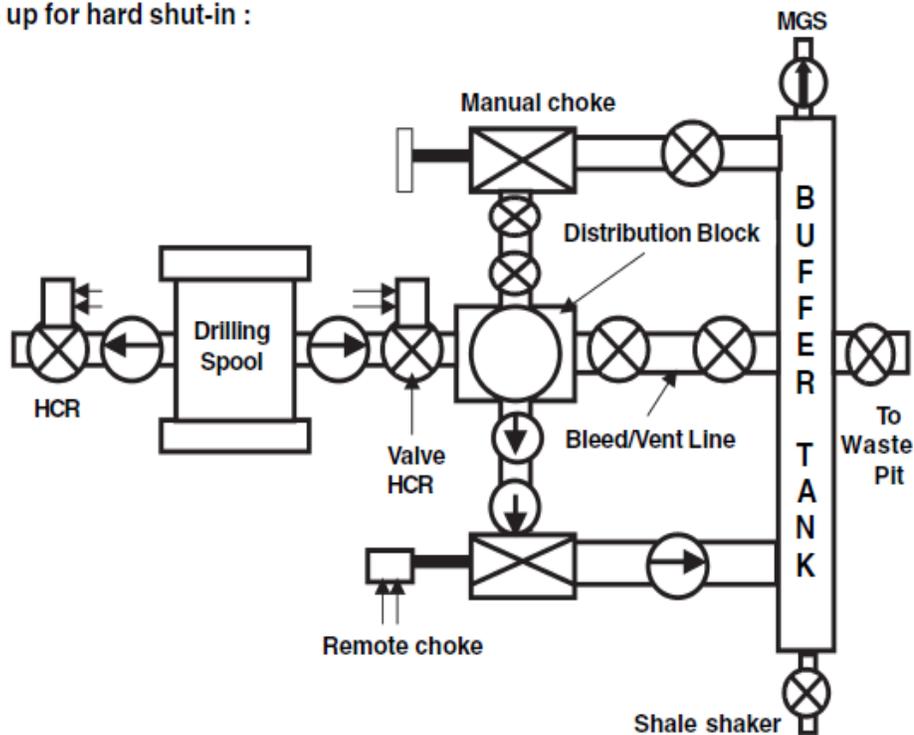|	
Choke line manual valve	: Open
HCR	: Close
Line between HCR & Choke	: Open
Remote choke	: Open (partially)
Line from choke to MGS	: Open

b) Line up for hard shut-in :

Fig. 2

Figure 2 : Line up for hard shut-in

Line-up for hard shut-in

Choke line manual valve	: Open
HCR	: Close
Line between HCR & Choke	: Open
Remote choke	: Close
Line from choke to MGS	: Close

7.0.2. **While Drilling**

1) Stop rotary.

2) Pick up kelly to clear tool joint above rotary table.

3) Stop mud pump, check for self flow. If yes, close the well as follows

Sl.No.	Soft Shut In	Hard Shut In
1	Open hydraulic control valve (HCR valve)/ manual valve on choke line when choke is in fully open position.	Close Blow Out Preventer (Preferably Annular Preventer)
2	Close Blow Out Preventer (Preferably Annular Preventer)	Open HCR / manual valve on choke line when choke is in fully closed position.
3	Gradually close adjustable choke, monitoring casing pressure.	
4	Allow the pressure to stabilise and record SIDPP, SICP and Pit gain.	Allow pressure to stabilise and record SIDPP, SICP and Pit Gain.

7.0.3. **While Tripping**

a) Run in string nearer to bottom as far as possible with safety

b) Position tool joint above rotary table and set pipe on slips.

c) Install full opening safety valve (FOSV) in open position & close it. Following methods are recommended for shut in the well.

Sl.No.	Soft Shut In	Hard Shut In
1	Open hydraulic control valve (HCR valve)/ manual valve on choke line when choke is in fully open position.	Close Blow Out Preventer (Preferably Annular Preventer)
2	Close Blow Out Preventer (Preferably	Open HCR / manual valve on

	Annular Preventer)	choke line when choke is in fully closed position.
3	Gradually close adjustable choke, monitoring casing pressure.	
4	Make up Kelly and open FOSV	Make up Kelly and open FOSV
5	Allow the pressure to stabilise and record SIDPP, SICP and Pit gain.	Allow pressure to stabilise and record SIDPP, SICP and Pit Gain.

7.0.4. **While String is Out of Hole**

Sl.No.	Soft Shut In	Hard Shut In
1	Open HCR valve on choke line.	Close shear or blind ram.
2	Close shear or blind ram.	Open HCR valve on choke line.
3	Close choke.	Close choke.
4	Record SICP and pit gain.	Record SICP and pit gain.

8.0.0. **Shut in pressure interpretation**

8.0.1 **Shut-in Drill Pipe Pressure (SIDPP)**

SIDPP is the difference between formation pressure and mud hydrostatic head when a kick enters the hole. SIDPP is used to determine the kill mud weight required to balance the formation pressure by using the equation given below

$$\text{Kill Mud Density (ppg)} = \text{original mud density (ppg)} + \frac{\text{SIDPP(psi)}}{0.052 \times \text{Well TVD(ft)}}$$

The shut in drill pipe pressure should be read & recorded from the gauge on the choke control panel. Since true SIDPP is determined for the calculation of kill mud density, it is recommended to read and record the SIDPP immediately after the closure and subsequently after every 3-5 minutes.

The recorded values of SIDPP should be tabulated/ plotted to ascertain the true value of SIDPP. Once the well is closed initially the SIDPP starts increasing till the BHP becomes equal to the formation pressure. The time taken for stabilization depends upon the permeability of the formation. SIDPP may further increase but at a slower rate if the influx is gas/gas mixture.

8.0.2   **Shut-in Casing Pressure (SICP)**

SICP, the shut in pressure on the annulus side is the difference between the combined fluid hydrostatic pressures and formation fluid pressure. Since annulus is contaminated with formation fluid (Oil, gas, salt water or combinations) therefore SICP can not be used to calculate kill mud density however it is used to determine kind of influx which has entered the well bore. During kill operation casing pressure will allow us to determine the pressure being exerted at various points in the well bore and also pressures on the BOP equipment and choke lines.

Example

A well was shut in after a kick, given below are the tabulated values of SIDPP and SICP. Find out the stabilized value of SIDPP.

Time	SIDPP(psi)	SICP(psi)
0915	150	175
0920	250	295
0925	325	395
0930	380	475

0935	440	545
0940	445	550
0945	455	560
0950	470	575
0955	490	595

Note : Pressure recording should be done at every two minutes interval.

Solution

As evident from tabulated values, SICP is increasing faster than SIDPP up-to 0935 hrs but later both the pressures are rising by same amount. This shows that the pressures have stabilized at 0935 hrs and subsequently due to close well gas migration both the pressures are rising by same amount. Therefore the value recorded at 0935 hrs i.e. 440 psi is the true SIDPP. The proper recognition of stabilized value of SIDPP is very important as this value is used for the calculation of kill mud weight and formation pressure.

Example

A well was shut in after a kick, given below are the tabulated values of SIDPP and SICP. Find out the stabilized value of SIDPP.

Time	SIDPP(psi)	SICP(psi)
1100	100	250
1105	200	370
1110	290	470
1115	370	560
1120	450	650
1125	450	650
1130	450	650
1135	450	650
1140	455	655
1145	460	660
1150	465	670

Solution

As is evident from tabulated values, SIDPP and SICP were increasing considerably up to 1120 hrs & later there is no change in the pressures up to 1135 hrs Therefore the value recorded at 1120 hrs i.e. 450 psi is the stabilized value of SIDPP. Further increase in both the pressures is due to closed well gas migration.

Equipment and Instrumentation

To maintain control of the well when well head pressures develop, requirements are:

- A means of closing the well

- A means of pumping into the well and controlling the release of fluids and gases.

- A level of instrumentation, with back up, which will enable evaluation and monitoring of pressures during this critical operation.

9.0.1   Well heads

Well head provides a means of landing and sealing around casing strings and supporting the BOP stack. Their pressure integrity is vital to well control, the rated working pressure exceeding the maximum expected surface pressure. They must also have sufficient strength to support subsequently installed casing and tubing strings as well as the BOP stack.

9.0.2   BOP Equipment

BOP must have the capacity to close-in the well, with or without tubular in the hole and also provide means of stripping in or out of the hole, or shearing the pipe if necessary.

9.0.2.1   Ram Preventers

Ram type BOPs are controlled by hydraulically operated double acting pistons. One set of rams designed to close around each size of pipe in the hole, must be included in the stack. The ram packing, which provides the seal, is an oil resistant alstomer bonded to steel.

I). Pipe rams: These are designed to close around a specific size of pipe, and must be changed to suit the OD of the string in the hole at the time.

II). Variable pipe rams: These are available to cover a specific range of pipe sizes.

III). Blind/ Shear ram: These will cut drill pipe and seal the well, or close the well in as blind rams. The pipe must be spaced out such that the rams do not close against a tool joint.

9.0.2.2   Annular preventers:

These have internally rainforced, doughnut/ Spherical shaped elastomer packing ring. They are designed to close and seal over the open hole, or any diameter/shape of tubular in hole. The other big advantage is that the drill pipe can be reciprocated/ rotated with the well shut in, if necessary, and the pipe can be stripped in or out of the hole.

9.0.2.3   Pressure gauges:

Accurate read out of pump pressure and choke pressure is required to control the blow out. Gauges of lower rating must be installed, so that relatively low pressure can be accurately measured.

9.0.2.4   Stripping tank:

Should stripping be necessary, it is essential to be able to accurately measure small volume mud bled from the well to an accuracy of at least half a barrel.

9.0.2.5 **Diverter Equipment and Control system Standard RP-174)**

A Diverter system is a large, low pressure annular preventer with large diameter discharge lines to divert well fluids from the rig. If shallow gas is encountered, it is possible to deplete it through the diverter to provide sufficient time to evacuate the rig floor. A Diverter system is used during top hole drilling, where other BOP system can not be used to control shallow gas. Shutting the well in will cause the formation to break down, with the possibility of gas blowing up the outside of the casing. It allows routing of the flow away from the rig to protect persons and equipment. Components of Diverter system include- annular sealing device, vent outlet, vent lines, valves and control system.

9.0.3 **Recommended practice of Diverter system:**

I). The friction loss should not exceed the diverter system rated working pressure, place undue pressure on the well bore and/or exceed other equipment's design pressure etc

II). To minimize back pressure on well bore while diverting well fluids. Diverter piping should be adequately sized.

III). Vent line shold be 8" or above

IV). Diverter lines should be straight as far as possible, properly anchored and sloping down to avoid blockage of the lines with cuttings.

V). The diverter and the mud return should be separate lines.

VI). Diverter valves should be full opening type either pneumatic or hydraulic or mechanical.

VII). The diverter control system may be self contained or integral part of the BOP control system.

VIII). The diverter control system should be capable of operating from two or more locations- one to be located near the driller's console.

IX). Control system of the diverter should be capable of closing the diverter within maximum 45 seconds and simultaneously opening of the valves in the diverter lines.

9.0.4 **Procedures for diverter operation:**

Where shallow casing strings or conductor pipe are set, fracture gradientswill be low. It may be impossible to close the BOP on a shallow gas kick without breaking down the formation at the shoe. If a shallow gas kick istaken while drilling top hole then the kick should be diverted.Drilling shallow sand too fast can result in large volumes of gas cut mud inthe annulus and cause the well to flow, also fast drilling can load up theannulus increasing the mud density leading to lost circulation and if the levelin annulus drops far enough then well may flow. When drilling top hole a diverter should be installed and it is good practiceto leave the diverter installed until 13 3/8" casing has been run. An automaticdiverter system should first:-

I). Open an alternative flow path to overboard lines.

II). Close shaker valve and trip tank valve.

III). Close diverter annular around drill pipe.

IV). If there are two overboard lines then the upwind valve should bemanually closed.

If any indication of flow is observed while drilling top hole, close diverter immediately as the gas will reach surface in a very short time and it isinadvisable to attempt a flow check

Suggested diverting procedure in the event of a shallow gas kick.

a) Maintain maximum pump rate and commence pumping
   kill mud if available.

b) Space out so that the lower safety valve is above the drill floor.

c) With diverter line open close shaker valve and diverter packer.

d) Shut down all nonessential equipment, if there is an indication of gas onrig floor or cellar area then activate deluge systems.

e) On a land rigs monitor area near the cellar and around for evidence of gas breakingout around conductor.

f) If mud reserves run out then continue pumping with sea-water.

g) While drilling top hole a float should be run. This will prevent gasentering drill string if a kick is taken while making a connection. It willalso stop backflow through the drill string on connections.

h) Alert the personnel on the rig.

i) Take all precautions to prevent fire by putting off all naked flames and unnecessary electrical system.

10.0.0 **Well killing procedure**

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

  i).   Driller's Method
  ii).   Wait and Weight Method
  iii).   Concurrent Method
  iv).   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 i.e. volumetric method is a non-circulating method in which the influx is brought out & heavy mud is placed in the well bore without circulation.

10.0.1 **Bringing the pump to kill speed (Slow Circulation Speed)**

It 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 well bore. To prevent this, following procedure is suggested.

1) Bring the pump to kill speed slowly holding casing pressure constant by manipulating the choke.

2) When the pump is at the desired kill speed, follow the pressure schedule according to the kill method being used.

10.0.2 **Driller's Method**

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

i). In first circulation the influx is removed from the well bore using original mud density.

ii). In second circulation the kill mud replaces the original mud and restores the primary control of the well.

Formulae Required

1) $\text{Kill Mud Density (ppg)} = \text{original mud density (ppg)} + \frac{\text{SIDPP(psi)}}{0.052 \times \text{Well TVD(ft)}}$

2) Initial Circulating Pressure (ICP) = SIDPP(psi) + SCP (psi)

3) $\text{Final Circulating Pressure (FCP)} = \frac{\text{Kill mud weight (ppg)} \times \text{SCP(psi)}}{\text{Original mud weight(ppg)}}$

4) Surface to Bit = Drill string volume (bbl) ÷ Pump output (bbl/stroke

5) Bit to Shoe = Open hole annulus volume (bbl) ÷ Pump output (bbl/stroke)

6) Bit to Surface = Annulus volume (bbl) ÷ Pump output (bbl/stroke)

10.0.2.1 **Killing Procedure (Drillers Method)**

In this method the well is killed in two circulations.

1) First Circulation

a). Bring the pump up to kill speed in steps of 5 SPM, gradually opening the choke holding casing pressure constant.

b). When the pump is up to kill speed, maintain drill pipe pressure constant.

c). Circulate out the influx from the well maintaining drill pipe pressure constant.

d). When the influx is out, stop the pump reducing the pump speed in steps of 5 SPM, 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 well bore. Whereas if SICP is more than original SIDPP, it indicates that some influx is still in the well bore.

2) Second Circulation

a). Line up suction with kill mud.

b). Bring the pump up to kill speed in steps of 5 SPM, gradually opening the choke holding casing pressure constant.

c). When the pump is at kill speed, pump kill mud from surface to bit, maintaining   casing pressure const.

d). Pump kill mud from bit to surface, maintaining drill pipe pressure constant equal to FCP.

e). 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

Pressure profile of drill pipe pressure and casing pressure in first cycle of Drillers method is given on next page
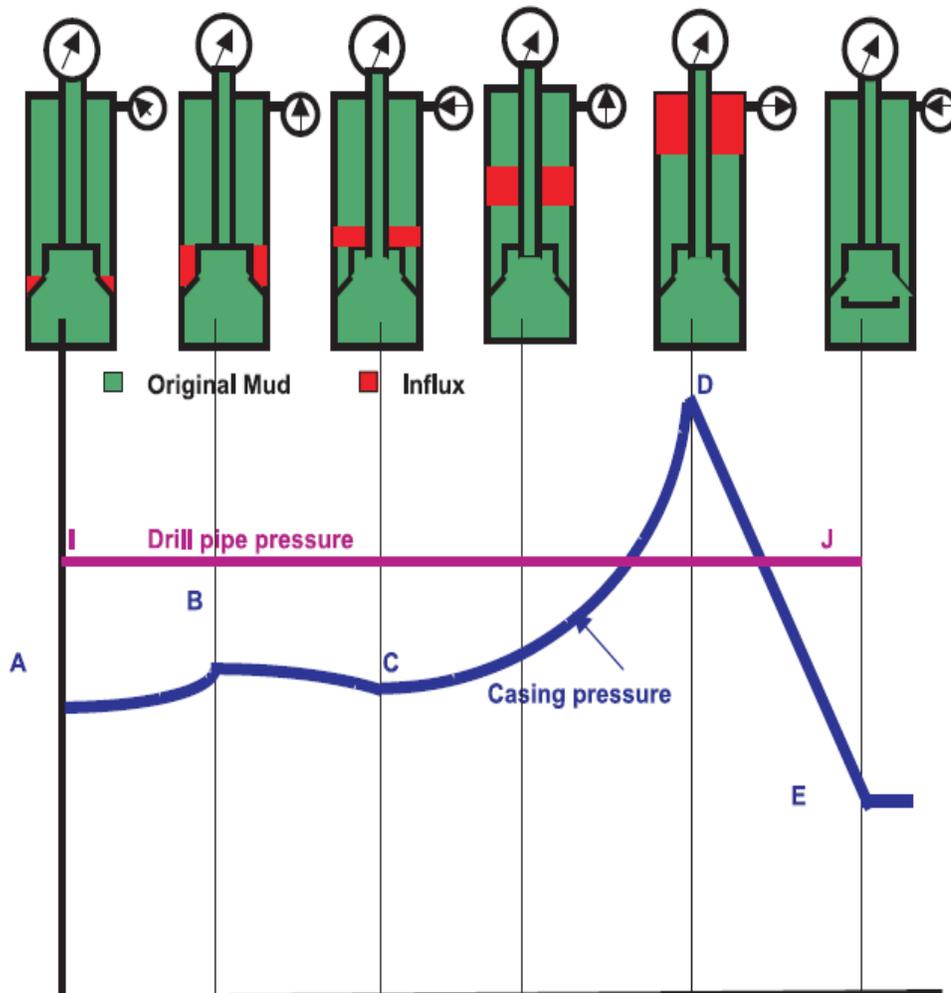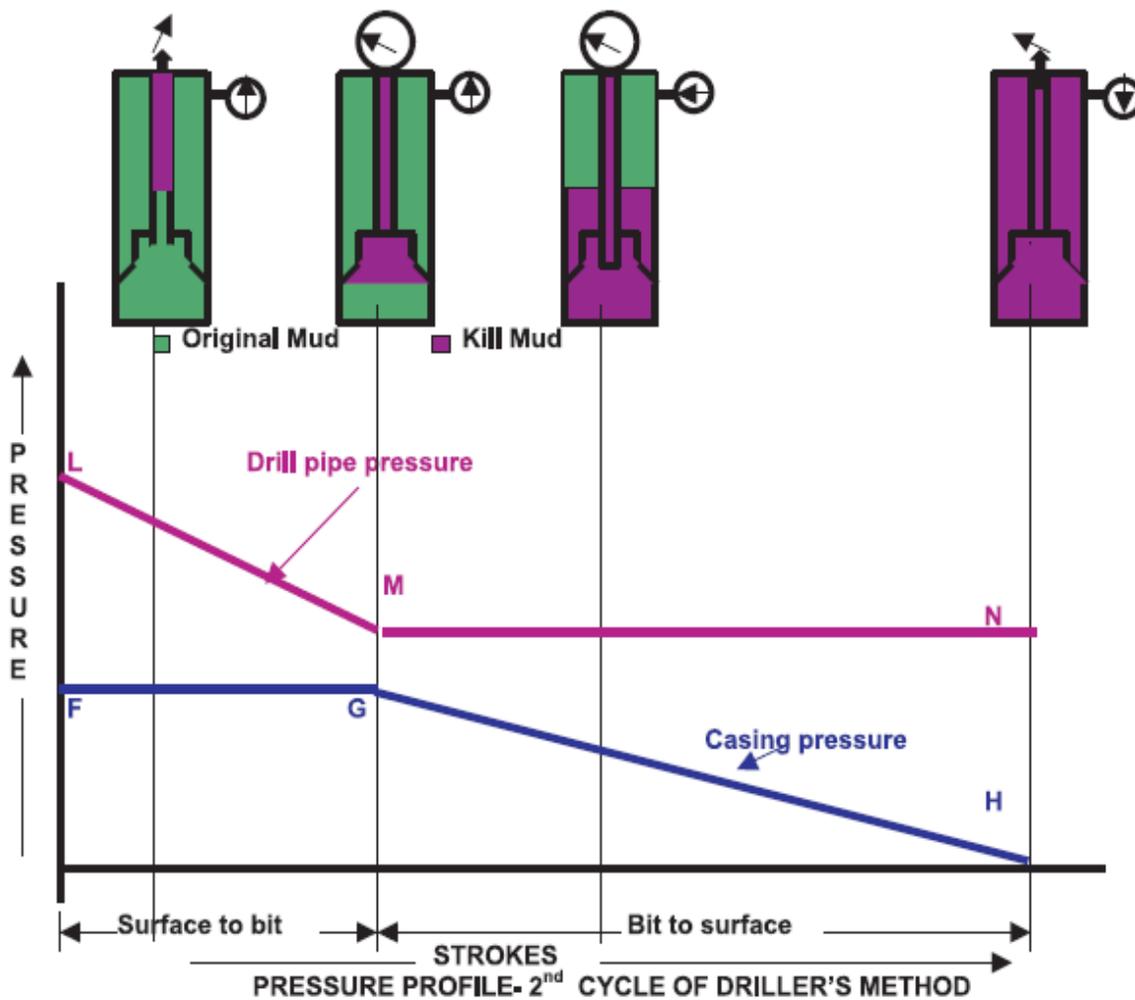
Figure 3: Pressure Profile- 1st Cycle of Drillers Method

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

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

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

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

Drill Pipe Pressure Graph

i). I - J Drill pipe pressure is held constant till the influx is removed from the well bore.

Original Mud   Kill Mud

PRESSURE

Drill pipe pressure

Casing pressure

Surface to bit   Bit to surface

STROKES

PRESSURE PROFILE- 2nd CYCLE OF DRILLER'S METHOD

Casing Pressure Graph

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

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

Drill Pipe Graph

a). 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.

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

10.0.3 **Wait and Weight Method**

1) In Wait and Weight method well is killed in one circulation using kill mud.

2) In this method, operations are delayed (wait) once the well is shut in, while a sufficient volume of kill (weight) mud is being prepared. As the kill mud moves from surface 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

i). $\text{Kill Mud Density (ppg)} = \text{original mud density (ppg)} + \frac{\text{SIDPP(psi)}}{0.052 \times \text{Well TVD(ft)}}$

ii). Initial Circulating Pressure (ICP) = SIDPP(psi) + KRP (psi)

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

iv). Surface to Bit Strokes = Drill string volume (bbl) ÷ Pump output (bbl/stroke)

v). Bit to Shoe Strokes = Open hole annulus volume (bbl) ÷ Pump output (bbl/stroke)

vi).   Bit to Surface Strokes = Annulus volume (bbl) ÷ Pump output (bbl/stroke)

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

10.0.3.1 **Killing Procedure (Wait and Weight Method)**

i).   Line up suction with kill mud.

ii).   Bring the pump up to kill speed in steps of 5 SPM, gradually opening the choke, holding casing pressure constant.

iii).   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).

iv).   Pump kill mud from bit to surface, maintaining drill pipe pressure constant equal to FCP.

v).   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.

vi).   Open & observe the well. Add trip margin before resuming normal operation.

10.0.3.2 **Comparison of methods**

a).   **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.

b). 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

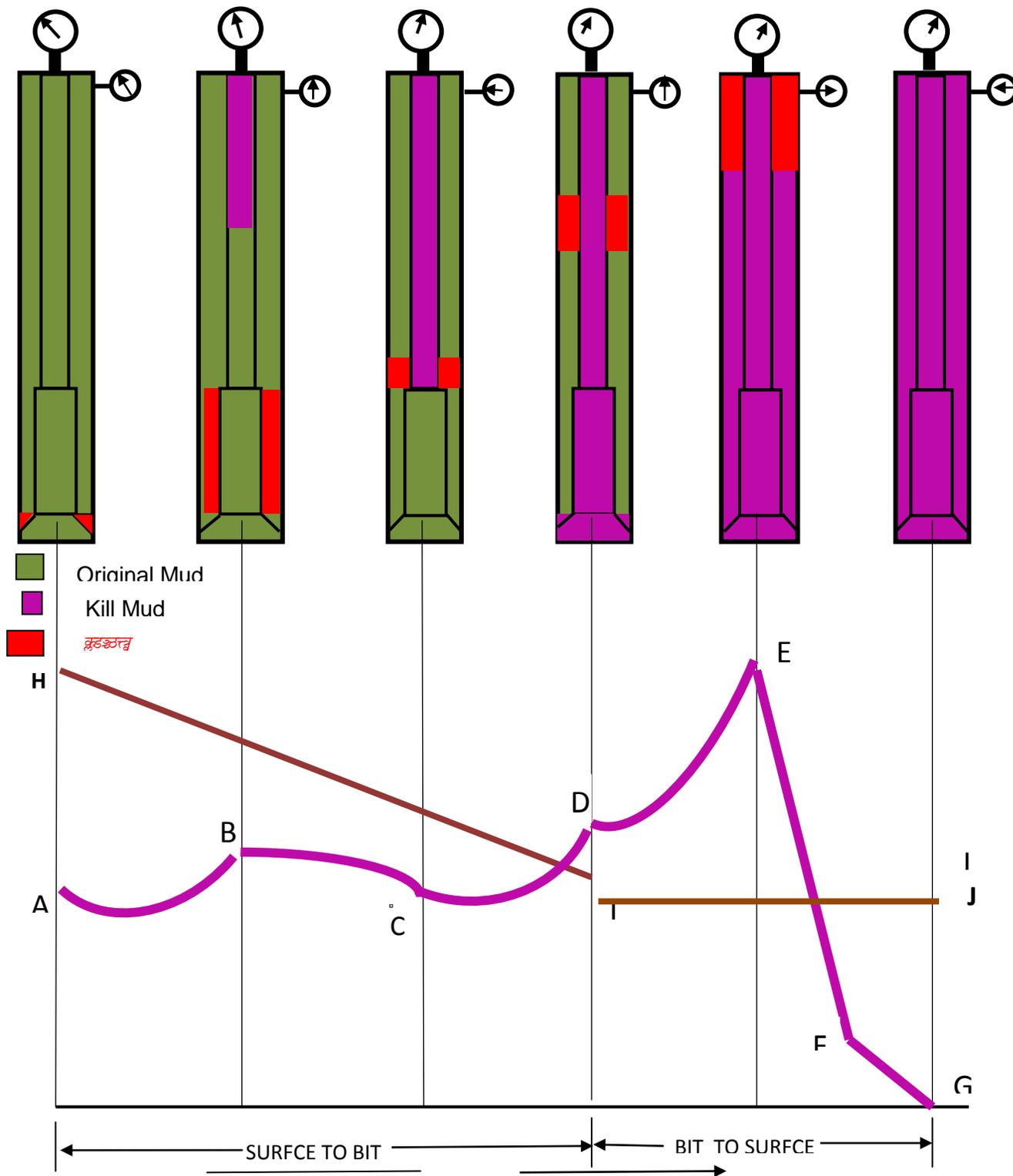**Pressure Profile- Wait & Weight Method**

Figure 5: Pressure Profile- 1st Cycle of Drillers

Casing Pressure Graph

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

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

iii). C- D Casing pressure again rises as influx now expands in drill pipe annulus.

iv).   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.

v).   E- F Casing pressure reduces sharply as influx is removed from the well bore.

vi).   F- G Casing pressure further reduces as original mud is replaced by kill mud.

Drill Pipe Pressure Graph

i).   H- I Drill pipe reduces from ICP to FCP as kill mud is pumped from surface to bit.

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

10.0.4 **Volumetric Method**

The volumetric method is a non-circulating killing method used for removing gas influx when there is little or no drill pipe in the hole, a wash out in the string or when the hole can not be circulated. It works equally well for a situation where the well is closed-in and waiting on orders or equipment or for stripping in or out of hole. In this method the influx is brought up to the surface by means of migration & controlled expansion. This process involves bleeding of calculated volume of mud at the surface till the influx reaches the surface, thereby allowing the casing pressure to increase to maintain BHP

constant. After the gas influx is brought to the surface in this manner of controlled expansion, the calculated volume of mud is pumped in to the well & gas influx is bled thereby allowing the casing pressure to decrease while maintaining BHP constant.

The basis of the volumetric method is that each barrel of mud contributes a certain pressure to the bottom of the hole. This may be measured as psi/bbl. This term of psi/bbl must be co-ordinated with pit volume or trip tank volume so that the number of barrels can be read directly.

A record of casing pressure is kept, if the casing pressure rises mud can be bled from the well according to the psi/bbl value calculated to maintain a constant bottom hole pressure. The volumetric method works by bleeding off (or adding) mud because the BHP is the sum of the casing pressure & the pressure exerted by the mud column.

The Volumetric method of well control should not be equated with classic well killing methods. Volumetric method is used to control BHP within limits by coordinating the increase (because of gas migration) or decrease (because of bleeding of gas) in annulus surface pressure with the corresponding decrease or increase in annular hydrostatic pressure (by decreasing or increasing height / weight of mud column in the annulus).

Volumetric method is implemented mainly in two steps namely the bleeding" and "lubrication" process. In the bleeding process the gas influx is allowed to migrate in the annulus and thereby causing an increase in the annular surface pressure as well as the BHP. The goal of maintaining the BHP constant is achieved through corresponding reduction in annular hydrostatic pressure by bleeding calculated volume of mud, which in turns reduces the mud column height in the annulus and allows the gas to expand. The bleeding process has to be repeated several times till the gas reaches the surface.

Once the gas is at the surface the process of lubrication starts. In lubrication process annular hydrostatic pressure is increased by injecting a calculated volume of same or heavy mud through kill line while the BHP is maintained constant by bleeding gas through choke and reducing surface pressure by the same amount. The process may be repeated several times till all the gas influx is fully removed from the annulus and the annular surface pressure is brought down to zero or at a level wherein tripping /stripping of the bit to the bottom or removing/ replacing of choked or damaged string becomes feasible. Once the bit is at the bottom, the well can be killed / circulated with appropriate kill weight mud.

10.0.4.1 **Volumetric Kill Calculations**

Example

Well TVD = 12,000 ft

Influx = 25 bbl

Mud weight = 10.5 ppg

Annular volume = 0.047 bbl/ft (8 1/2" □□5")

SICP = 500 psi

SIDPP = 0 psi

As indicated by SIDPP value (0 psi) the bit nozzles are plugged, therefore the well has to be killed by Volumetric method.

Calculations

a) **For Bleeding Process**

Let the incremental increase in casing pressure would be 100 psi

Mud Gradient = 0.052 ×10.5 = 0.546 psi/ft

Height of mud column for 1 psi of Hydrostatic pressure = 1 /0.546 ft

Height of mud column for 100 psi of Hydrostatic pressure = 100 / 0.546 ft
=183'

Volume of Mud for 100 psi hydrostatic pressure = 183 x 0.047= 8.6 bbl

10.0.4.2 **For Lubrication Process**

Calculation of kill mud weight for lubrication

$$KMW = OMW + \frac{SIDPP}{0.52 \times TVD}$$

As the SIDPP may not be known SICP may be taken in place of SIDPP. But if the value of SICP is very high then SIDPP can be calculated by assuming some gas gradient by the following formula :-

$$Influx\ gradient = Mud\ Weight \times 0.052 - \frac{SICP - SIDPP}{Height\ of\ influx}$$

Since kill mud is to be placed only in the top section of the well which is being occupied by gas, the height of gas column is to be calculated.

Total pit gain = Initial pit gain + Total amount of mud bled

= 30 bbl + 100 bbl (say) = 130 bbl

$$Height\ of\ gas\ column\ when\ gas\ is\ at\ the\ surface = \frac{130}{0.047} = 2766\ ft$$

$$KMW = 10.5 + \frac{500}{0.052 \times 2766} = 13.98\ ppg$$

Kill mud gradient = 13.98 × 0.052 = 0.727 psi/ft

Height of kill mud column for 1 psi of Hydrostatic pressure = 1 / 0.727 ft

Height of kill mud column for 100 psi of Hydrostatic pressure 100/0.727= 137.5 ft

Volume of kill Mud for 100 psi hydrostatic pressure = 137.55×0.047=6.46 bbl=

6.5(App)

10.0.4.3 **Killing Procedure (Volumetric Method)**

Volumetric killing is accomplished in two steps, namely 'Bleeding' & 'Lubrication'.

I). Bleeding

a) Allow the casing pressure to increase to 650 psi, this causes the BHP to increase by 150 psi, don't start bleeding now (this 150 psi may be kept as safety margin).

b) Allow the Casing pressure to increase by another 100 psi to 750 psi, this causes the BHP to increase by 250psi. Since it is planned to keep only 150 psi extra pressure at the bottom as safety margin, we can now reduce 100 psi of BHP by bleeding 6.46 bbl of mud. While bleeding mud the surface casing pressure should not be allowed to reduce more than 100 psi which may require the bleeding to be completed in number of steps.

c) Allow the pressure to increase by another 100 psi to 850 psi and bleed 6.46 bbl of mud in the same way.

d) This procedure should be repeated until gas reaches surface. Thereafter, Lubrication technique is to be used for reducing the casing pressure.
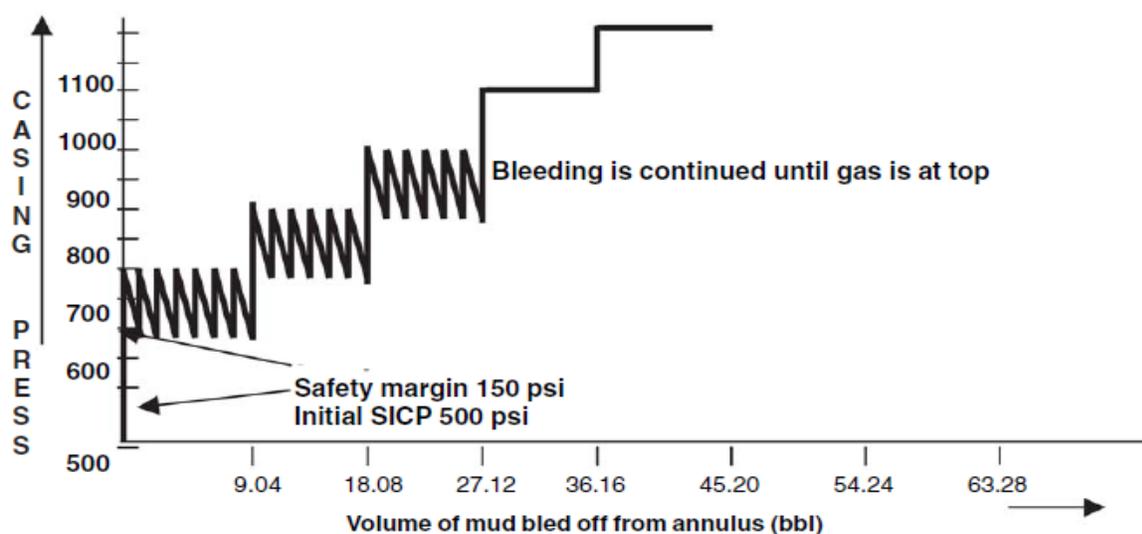

Fig 6 : Mud Bleeding Process

II). **Lubrication**

The lubrication technique is used to Kill the well / reduce the casing pressure when gas is at the surface so that other operation such as tripping / stripping can be performed.

a) Slowly pump the calculated volume of mud (6.46 bbl) which shall give 100 psi equivalent hydrostatic pressure into the annulus. Allow the mud to fall through the gas. This is a slow process, but can be speeded up by using a low yield point mud.

b) Bleed gas from the annulus until the surface pressure is reduced by 100 psi or the amount equal to the hydrostatic pressure of the mud pumped in. In no case mud is to be bled off.

c) Repeat the process until all of the gas has been bled off and the well is killed or the desired surface pressure is reached.

Note: During the pumping and gas bleeding process, it will usually be necessary to decrease the volume of mud pumped before gas is bled off particularly near the end of the operation. This is because the annular volume occupied by the gas decreases with each pump & bleed sequence. Watch the pumping pressure closely and when it reaches 50-100 psi above the shut in casing pressure, stop pumping. Measure the volume of mud pumped, calculate the hydrostatic pressure of that volume in the annulus and bleed sufficient gas to drop the casing pressure by the amount of hydrostatic pressure plus any increment of trapped pressure because of pumping operation.

Volume and Pressures during Top Kill

(Assuming maximum surface pressure of 1900 psi at the end of bleeding operation)

Volume to lubricate, bbl (cumulative)	Pressure to Bleed (psi)	Remaining casing (psi)
0	0	1900
6.46	100	1800
12.92	100	1700
19.38	100	1600
25.84	100	1500
32.30	100	1400
38.76	100	1300
45.22	100	1200
51.68	100	1100
58.14	100	1000
64.60	100	900
71.06	100	800
77.52	100	700
83.98	100	600
90.44	100	500
96.90	100	400
103.36	100	300
109.82	100	200
116.28	100	100
122.74	100	0

11.0.0 **Well Control Complications:**

11.0.1 **MAASP Limitations**

The MAASP (Maximum allowable annular surface pressure) is calculated from Formation integrity test. If the top of the influx is past the open hole weak point, assumed to be the casing shoe, the surface pressure can be allowed to exceed the calculated MAASP. This is because FIT was carried out with the annulus full of mud. Any lighter fluids in the well above the weak

point will increase the MAASP. If surface pressure exceeds the MAASP while the influx is still below the shoe, then:

I). Either the choke pressure is maintained to hold bottom hole pressure constant, exceeding the MAASP and risking an underground blowout.

II). Or the choke pressure is reduced and limited to MAASP. This option risks allowing a further influx into the well and creating a worse situation.

The second option will be taken if there is a high risk of underground blowout developing and that the influx is likely to breakout around the casing endangering personnel and the rig; or if it is known that the kick zone has a low permeability and there is little chance of taking a high volume of influx.

11.0.1 **Plugged bit nozzle:**

A bit nozzle plugging while circulating out a kick will result an increase in drill pipe pressure, while the choke pressure remains constant. If the problem is identified and choke is opened in an attempt to reduce the drill pipe pressure, the resulting drop in bottom hole pressure may allow a further influx into the hole. If the nozzle plug can not be cleared with increase in pump pressure, the string must be perforated as close as possible near to the bit nozzle to establish circulation

11.0.2 **Choke washout:**

As the choke starts to wash out, choke has to be controlled to maintain the annulus pressure. This may happen due to lost circulation also, which can be confirmed by observing the pit volume. If ir becomes unmanageable by controlling the choke, flow should be diverted to second choke and replace the wash out choke.

11.0.3 **Plugged choke:**

Choke may plug, if annulus is full of cuttings, and a slower rate must be used to kill the well. Choke and drill pipe pressure will increase together in such case. If opening the chock fails to clear it, the pump must be stopped

and flow diverted to second chock. The excess pressure must be bled, before restarting the pump, from the well at the choke.

11.0.4 **Pump failure:**

If the pump is washed out, drill pipe pressure likely to become erratic and both drill pipe and casing pressure will drop. The pump will be stopped and the well shut in. killing operation will then continue with the second rig pump or the cement pump if necessary, while the washed out pump is repaired.

11.0.5 **Hole in drill string:**

A washout in drill string is indicated by a decrease in drill pipe pressure while the choke pressure remains unchanged. If the washout is severe and it occurs in the early stage of well killing operation, it may be necessary to strip out of the hole to look for it. If it occurs as the influx is further up the annulus, it may be possible to continue operation. The well must be shut in and the position of the washout identified before any further action is taken.

11.0.6 **Stuck pipe:**

If the pipe becomes stuck on bottom through differential sticking, well control operation can continue as normal. The situation become worst, if pipe got stuck due to hole pack-off. If, attempts to free the pipe fail, back off the string at free point. Depending on the shut in pressure after backing off, attempt can be made to kill the well or pump cement plug.

12.0.0 **Special techniques in well control**

12.0.1 **Bullheading**

When a kick is controlled by pumping into the well from surface, this procedure is known as Bullheading. It is basically forcing a kick back into the formation. It may be necessary when a very large influx has been taken and displacement by conventional method would cause excessive surface pressures. On a high pressure well, bullheading may be necessary when a gas kick is taken due to limitations of the poor boy degasser. The speed at

which the kick may be circulated out without overloading the poor boy degasser and displacing the fluid seal may be too slow to be practical. It is also a method to consider when a kick is taken with no pipe in the hole, or the pipe too far off bottom to strip back into the hole. It also can be used in areas where the influx is likely to contain unacceptable level of H2S.

12.0.1   **Barite plugs**

A barite plug is a heavy weight slug of mud mixed to the maximum possible weight and spotted above the kick zone. It is often used ti kill an underground blowout, where the formation is flowing into a weaker zone further up the hole. The density and volume of the plug should be sufficient to control the kick zone and the rate at which it is pumped into place should exceed the influx rate such that it is not blown up the annulus before sufficient volume is in place to kill the kick.

Barite plugs are often mixed with a view to settling out on bottom, forming a solid plug. However, the rate of settling of barite in the annus is considered too slow to help the kill and additional problem of barite settling at surface, especially when mixing a large plug, can cause problem. The plug should be mixed as thin as practically possible to assist in pumping, but if barite settles out in the drill string and plug the nozzles, then the well control problem is further complicated.

If it is apparent that the well is still flowing after the first attempt, a large volume plug pumped at a faster rate if possible, should be tried. Once the plug is in place and the well is not flowing, pull above the plug and monitor surface pressures. It may be possible to open the BOP and circulate normally. Consideration then should be given as to whether the loss zone can be sealed with a cement plug or if it is necessary to run the casing.

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Annexure-1

As per Company requirment, the following certification are required by Rig Personnel on board: -

A. Enquest Petro Solutions (Requirement for PMC)

1. Day Drilling Supervisor

Must possess valid well control certificate (IWCF)

2. Night Drilling Supervisor

Must possess valid well control certificate (IWCF)

B. Rig Personnel on board (Requirement for Drilling Contractor)

1. Tool Pusher

Must possess valid well control certificate (IWCF), Supervisor level

2. Tour Pusher/Night Tool Pusher

Must possess valid well control certificate (IWCF), Supervisor level

3. Driller

Must possess valid well control certificate (IWCF) / IADC well cap.