WELL CONTROL PRACTICES

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WELL CONTROL PRACTICES

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CERTIFICATE

This is to certify that the work contained in this thesis titled "Well Control Practices" has been carried out by Bhuvan Rastogi & Rishabh Aggarwal under my supervision and has not been submitted elsewhere for a degree.

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INTRODUCTION-

WELL CONTROL:

Well control is simply balancing or preventing Formation Fluid entering into the well bore by controlling mud hydrostatic pressure

Hydrostatic Pressure = TVD (feet) X Mud density (ppg) X .052 in psi

Hydrostatic Pressure = TVD(mts) X Mud density (gm/cc) /10 IN ksc

It includes all the operations included to keep rectify a kick , steps taken to rectify any situation even a blow out and bring well to the initial slightly overbalanced situation.
Well control is needed to do drilling operations in a safe manner

Various stages of Well Control :

- Primary Control :

  During drilling operations the hydrostatic pressure of drilling fluid is normally kept greater than the pressure of the fluids in the formation. The maintenance of pressure exerted by drilling fluid to hold back the formation pressure sufficiently & continuously is termed as primary well control.

- Secondary Control :

  If pressure in the wellbore fall below the formation pressure, formation fluid (gas/ formation water) enters in the wellbore & the primary control may be temporarily lost. Here secondary well control comes into play, it includes use of equipments such as BOPs, FOSVs, check valves and methods to pump in heavy mud to control kicks.

- Tertiary Control :

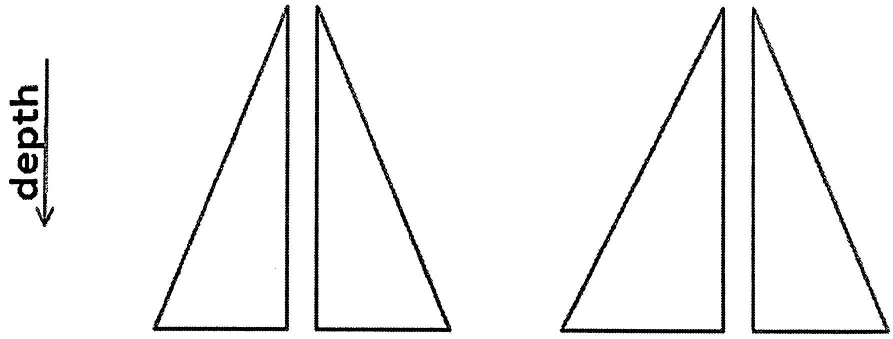
  If secondary well control fails and it leads to a blow out, then tertiary well control comes into play. It involves the techniques used to control a situation of a blowout such as:
  Relief wells
  Dynamic kill
  Barite or gunk plug
  Pump in cement to plug well

Kick :

It is defined as an influx of unwanted flow of formation fluid into the well & can occur at any time the pressure exerted by formation fluid is greater than the BHP being exerted in the wellbore.

Primary well control:

This is maintenance of sufficient hydrostatic head of drilling fluid (H_{mud}) in wellbore to balance the pressure exerted by formation fluids (P_f) of the formation being drilled.
Though generally an excess pressure is maintained over the formation fluid pressure to allow for contingencies. This excess head is known as trip margin or overbalance.



$H_{mud} = P_f$
(ideal pressure maintanance)

$H_{mud} > P_f$
(Overbalanced- generally practiced)

Secondary well control:

When primary measures fails and hydrostatic head falls to a value less than formation fluid pressure (underbalance condition), some influx from formation (kick) will enter the well. If this happens then blow out preventers (BOP) must be closed as soon as possible to reduce further entering of kick and to stop pressures from rising further.
Purpose of secondary control is to rectify such situation by:

1) Allowing the kick fluid to move up and circulate out of the well harmlessly
2) Closing the well and providing a surface pressure to restore the balance between inside and outside pressures of the well

The secondary control includes equipments needed to control the kick i.e. BOPs, FOSV etc. & procedures followed to restore well to slightly overbalanced condition again

Causes Of Kick :

Kicks occur when formation pressure is greater than mud hydrostatic pressure which causes fluid to flow from the formation into the well bore. The main factors which can lead to this condition can be classified as :

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

More than 50 % of kicks occur because of first 2 reasons listed here

a) Improper Hole Fill up on Trips :

While pulling out drill string the mud level decreases by a volume equivalent to the pipe volume. If the borehole does not take the calculated amount of drilling mud, it is assumed that formation fluid has entered the borehole. Therefore while pulling out drill string the wellbore should be filled continuously using trip tank & difference of calculated and actual mud volume should be recorded at regular intervals.
If the hole is not filled to replace the steel volume, the fluid column in the well bore 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 borehole due to combination of these factors the hole should be properly and regularly filled during tripping out operations.

b) Swabbing :

While pulling out the drill string from the bore hole Swab pressures are created. It reduces the BHP. If the reduced BHP becomes less than the formation pressure, a kick may enter the well bore. Factors effecting swab pressures are drill string pulling speed, mud properties, filtration cake, wellbore configuration & effect of balling of bottom hole assembly & bit.

c) Abnormal pressure :

For exploratory drilling, the pressures of formations encountered are not known beforehand. While drilling, the bit can suddenly encounter an abnormal pressure formation. As a result the mud hydrostatic pressure becomes less than the formation pressure and may cause a well kick.

d) Insufficient mud density :

Mud density is the main factor behind hydrostatic pressure of mud at the well bottom, if pressure exerted is less than formation pore pressure the formation may begin to flow into the well bore. Kicks caused by insufficient mud density have an easy solution of drilling with high density mud. The best solution is to maintain mud density slightly greater than the required value to balance formation pressure & to avoid mud loss.

e) Lost Circulation :

Lost circulation is another problem which reduces the hydrostatic pressure. When a kick occurs due to loss of drilling fluid, the problem may become more severe. A large volume of kick fluid may enter the wellbore & mud level increase is observed in mud pits.

f) Gas Cut Mud :

Gas contaminated mud can occasionally cause a kick. As the gas moves to the surface, it expands and reduces the hydrostatic pressure sufficient to allow influx to enter. Although the mud density is reduced considerably at surface, the hydrostatic pressure is not reduced significantly since the most gas expansion occurs near to the surface and not at the bottom part.

Recognition of Kicks

The only time a kick can happen without warning is when drilling offshore and there is no annular connection between the well head and the rig. However, there are many signs that a kick or blowout is occurring. For majority of times the borehole and mud pits are a closed circulating loop system, the addition of any fluid from the formation i.e. kick will result in a change in return flow and a change in the pit volume. Sometimes when surface recognition may be delayed is during lost circulation. The annulus is not full and cannot be filled. When the rate of fluid loss is more than the rate at which fluid can be pumped into the well, it is not possible to monitor the fluid levels. A major influx may occur and it will not be detected at the surface easily. If such an event occurs, the well should be shut in, and the shut-in pressures are monitored. Pipe movement can be made by stripping through the BOP's and the hole can be filled using the choke and kill lines.

Sequence of Events

In most cases, the following distinct series of events can lead to a kick while drilling. Some indications may not occur while others may be happen. Recognition of the changing trends at an early stage will allow remedial action to be taken on time, thus minimizing the potential hazards and costs.

1. The first indication is mostly a **drilling break**. The fast drilling rate may not necessarily indicate an increase in porosity, permeability and pressures. The length of the drilling break depends on the formation characteristics. Regardless of the increase, any significant drilling break should be checked for flow. This is done by:
   (1) picking up the kelly so the kelly bushings are about 10 ft above the rig floor
   (2) stopping the pumps
   (3) observing the fluid level in the annulus to see if the well is flowing.
   If the well is flowing, it should be shut-in and any resultant pressures checked.

2. The next indication of a kick is an **increase in return flowrate** in the flowline. Flow of formation fluid into the wellbore will cause the return flowrate to increase, which will occur shortly after the drilling break. The entering fluid is normally lighter than the mud, so continual influx will lighten the mud column and further reduce BHP. Thus allowing the influx rate to increase. Once flow begins, the rate of increase will be proportional to the depth of penetration into the formation.

3. **Increase in pit volume** may be the because of two separate mechanisms (a) the increased flow rate leads an increase in mud volume, and (b) if the kick contains gas, its expansion in the annulus will increase the flow rate and pit volume.

4. A **pump pressure decrease**, along with a **pump stroke rate increase** becomes noticeable only when the kick fluid has been displaced some distance up the annulus.

5. A reduction in mud density occurs as the kick fluids reach the surface. This reduction is severe with a gas kick, but may be small with a water kick (depending on the mud density). Large amounts of gas can be dissolved in the kick fluids and as the kick fluid reach the surface, high **gas shows** will occur.

Early Warning Signs

They indicate of approaching high pressure formations and well can go underbalance if it is not checked.

- Rate of penetration increases :

  When abnormal pressure formations are encountered, differential pressure & shale density are decreased causing a gradual in ROP.

- Drilling Break :

  When the rate of penetration increases alarmingly, can be due to a sand section which is porous and its fluid is reason for kick.

- Decrease in Shale density :

  Shale density usually increases with depth but increases in abnormal pressure zones. Any deviation from theoretically established trend line, indicate changes in pore pressure.

- Change in cutting size and shape :

  Cutting from normal pressure zones are small size with rounded edges, but cuttings from abnormal pressure zones are often long with angular edges.

- Change in mud property :

  Mud density and viscosity may increase due to increase in caving and cuttings.

- Increase in flow line temperatures :

  The pressure gradient in abnormal pressure formation is usually higher than normal pressure zones. Also temperature may take sharp increase in transition zones.

Positive Kick Signs

They indicate that the kick has already entered in the well bore.

⇒ Increase in return flow volume (pumps on) :

The first positive sign is increase in flow rate at the flow line with pumps in on condition. The entrance of any fluid into the wellbore causes the flow rate to increase.

⇒ Flowing well (pumps off) :

When the kick is entering the well, it will flow even with pumps off. It is a reliable method checking of a well kick. If well does not flow when the well is shut off & remains static for 2 to 3 mins, then no well kick is entering.

⇒ Pit volume increase :

An increase in pit volume is a positive indication of influx entering into the wellbore & can be easily verified. If an increase in pit volume is seen, shut off the pump and make a flow check, if the well do not flow no kick is entering.

⇒ Decrease in pump pressure :

In case of a kick there is an under balance condition between the fluid in the drill pipe and the mixed column of mud and influx in the annulus. Therefore circulating pressures gradually decrease and unless the pump throttle is changed, pump speed slowly increases

Shut-In Procedures

As soon as 2 or more kick signs are observed, flow check is made. In case of self flow, well is shut-in. shut-in can be done in 2 ways

a) Soft shut-in

b) Hard shut- in

Soft Shut-in:

- A choke is opened before closing BOP, and then gradually closed.
- This is done so that the pressure increase is gradual.
- The water hammering effect is minimized.
- Is slower
- Is done mostly to control a well after blow out, when hammering pressure is very high

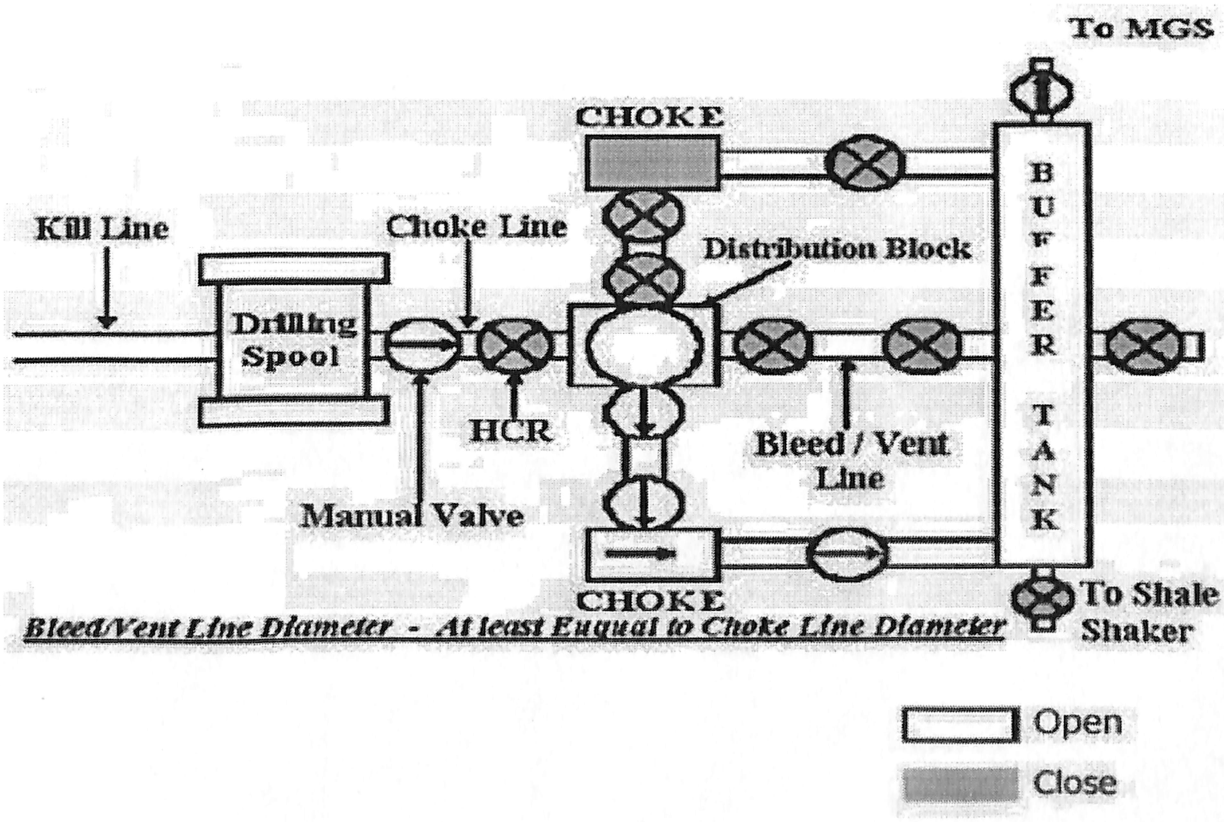
Hard Shut-in:

- BOP is closed when all chokes are closed
- Pressure increase is abrupt.
- Water hammering effect is high.
- Is faster.
- Done when a kick is observed.
- It is preferred for kicks because the more time we waste, more influx enters in well & hammering pressure is not very high initially.

Line up for Soft Shut-In :

Choke or manual valve	:	open
HCR	:	close
Line between HCR & choke	:	open
Remote choke	:	open (partially)
Line from choke to MGS	:	open

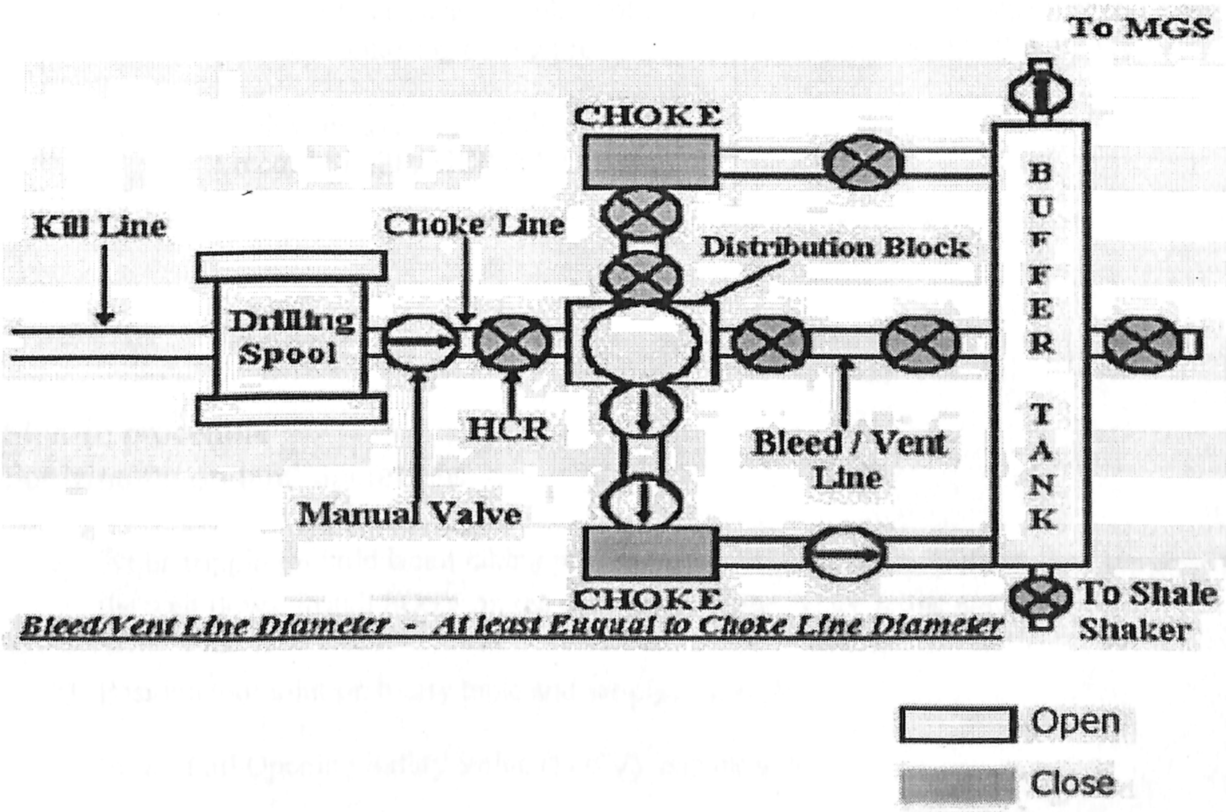
Soft Shut-In



Line up for Hard Shut-In :

Choke or manual valve	:	open
HCR	:	close
Line between HCR & choke	:	open
Remote choke	:	close
Line from choke to MGS	:	open

Hard Shut-In



Following are the common cases encountered and shut-in procedures taken for them.

Shut In Procedure
For drilling onshore

a) Stop rotary table

b) Pick up Kelly or clear tool joint above rotary table for about 10 ft

c) Stop the pump, check for self flow. If positive close the well as follows :

S. no.	Soft Shut-In	Hard Shut-In
a)	Open HCR valve / manual valve on choke line	Close BOP (Preferably annular preventer)
b)	Close BOP (Preferably annular)	Open HCR valve / manual valve on choke line when choke is in fully closed position
c)	Gradually close adjustable choke while monitoring casing pressure.	Allow pressure to stabilize and then record SIDPP, SICP & Pit Gain
d)	Allow pressure to stabilize and then record SIDPP, SICP & Pit Gain	

Shut-In procedure
For tripping on land operations

a) While tripping if hole is not taking proper amount of drilling mud, make flow checks. If the well flows, install FOSV on the drill string, close FOSV & the annulus.

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

c) Install Full Opening Safety Valve (FOSV) and close it.

d) Close the well as follows

S. no.	Soft Shut-In	Hard Shut-In
a)	Open HCR valve / manual valve on choke line	Close BOP (Preferably annular)
b)	Close BOP (Preferably annular preventer)	Open HCR valve / manual valve on choke line when choke is in fully closed position
c)	Gradually close adjustable choke, monitoring casing pressure.	Make up Kelly and open FOSV
d)	Make up Kelly and open FOSV	Allow pressure to stabilize and then record SIDPP, SICP & Pit Gain
e)	Allow pressure to stabilize and then record SIDPP, SICP & Pit Gain	

Shut-In procedure
When no drill string in well

S. no.	Soft Shut-In	Hard Shut-In
a)	Open HCR valve / manual valve on choke line	Close BOP (Shear or Blind RAM)
b)	Close BOP (Shear or Blind RAM)	Open HCR valve / manual valve on choke line when choke is in full closed position
c)	Gradually close adjustable choke while monitoring casing pressure.	Allow pressure to stabilize and then record SICP & Pit Gain.
d)	Allow pressure to stabilize and then record SICP & Pit Gain.	

Shut In Pressure Interpretation

⇒ Shut-In Drill Pipe Pressure (SIDPP) :

It is the difference between the hydrostatic pressure of drilling fluid and the pressure of formation fluid. When a kick enters during drilling, the drill string remains uncontaminated whereas annulus becomes contaminated with influx. If SIDPP is added to the resultant pressure will be pressure of formation.

Formation pressure – Hydrostatic pressure of drilling mud = SIDPP

SIDPP is used to determine the kill mud weight required to balance the formation pressure.

Kill mud density = {SIDPP(psi) / 0.052 * well TVD} + Original mud density

SIDPP is taken immediately after the closing and for next few minutes. Then its true value is calculated by plotting its graph with time.

⇒ Shut-In Casing Pressure (SICP) :

The shut in pressure of the annulus is called SICP. Since annulus is also filled with influx fluid (oil, gas, water or combination which is not certain) therefore SICP cannot be used to calculate kill mud density as it is not precise.
But it is used in calculation of type of influx that has entered the annulus.
During killing operations casing pressure will allow us to determine the pressure being exerted at various points in well bore & also pressure on BOP equipment and choke lines.

Types Of Influx :

The type of influx can be determined by monitoring amount of the pit gain and shut-in pressures correctly. Having closed a well after a kick, stabilized pressures are recorded and the volume of influx is calculated from the amount of increase in volume at surface in pits.

a) Kick fluid weight of less than 3 ppg shows the fluid is gas.

b) Kick fluid weight between 3 to 9 ppg shows the fluid is mixture of gas, water or oil.

c) Kick fluid weight between 9 to 10 ppg shows the fluid is salt water.

Gas Influx Behavior :

Open Well Migration :

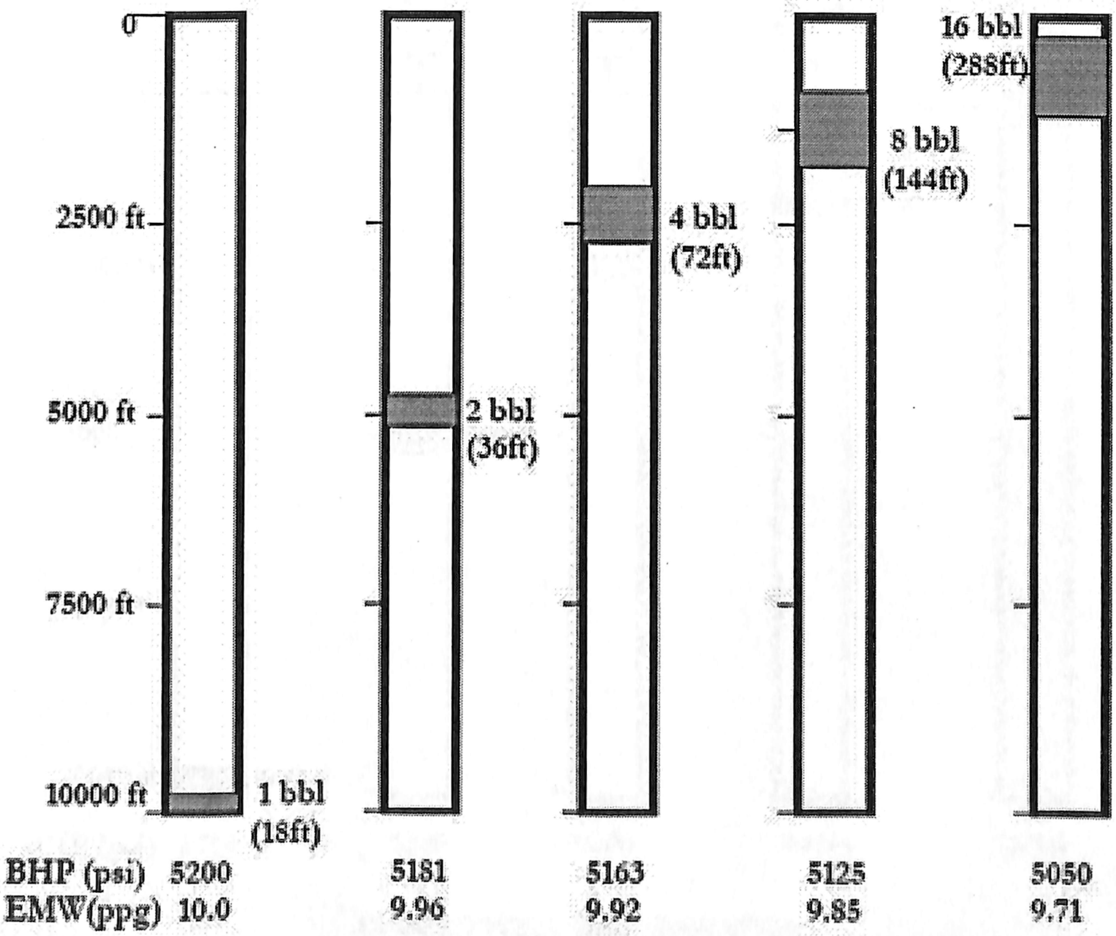
In an open well, gas influx after entering the well bore will start moving up & expanding. The influx will start expanding continuously. This will reduce BHP and a point will be reached when the overbalance on the bottom of the hole is lost. The effect of gas migration in an open well will be as below:

a) Bottom hole pressure reduces.

b) Gas bubble pressure reduces.

c) Pressure below the bubble reduces.

d) Pressure above the bubble remains constant.



OPEN WELL GAS MIGRATION

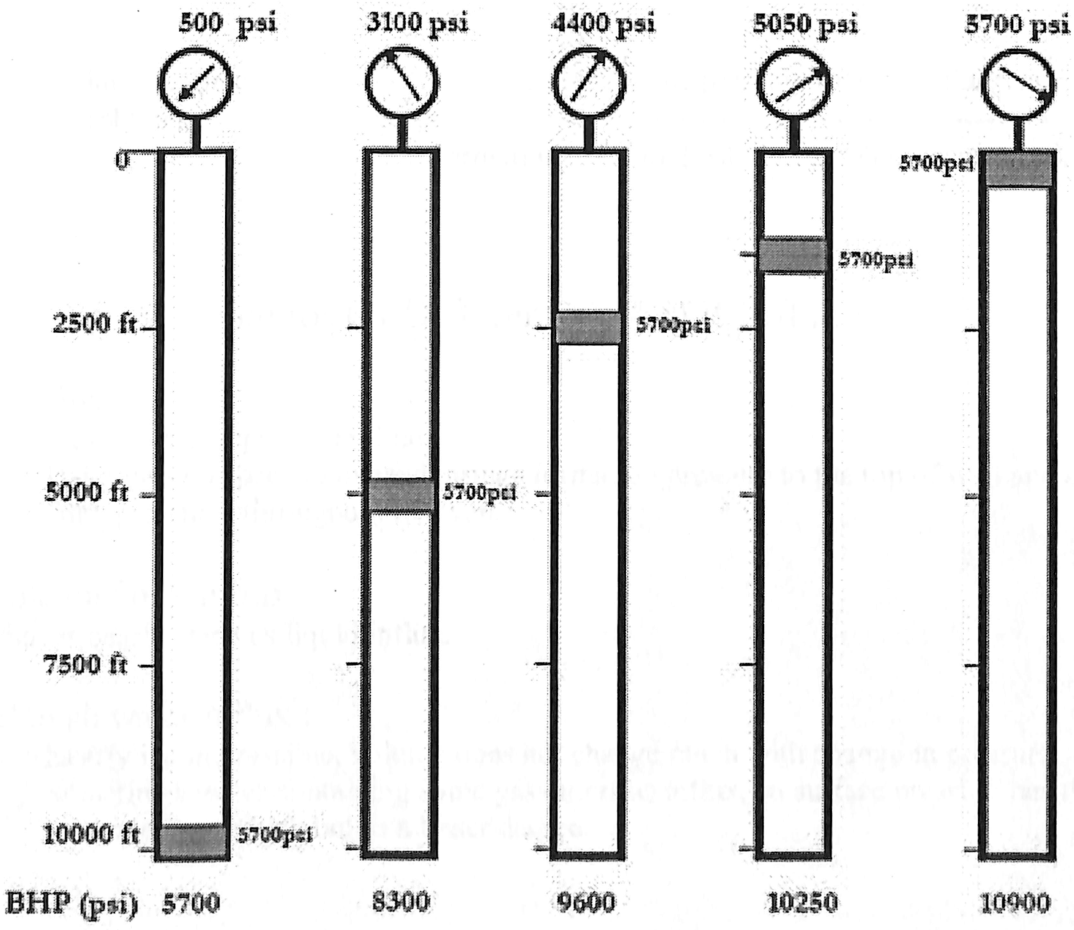
Closed Well Gas Migration :

If gas is to migrate in a well bore that is closed, there will be expansion of gas possible. The gas will carry its initial pressure with it while moving up in the well bore. As a result there will be an increase in both SICP and SIDPP. This causes the well to pressure up in all directions creating extra pressure at the shoe and on the bottom of the wellbore, and the gas bubble pressure remains same. The effect is summarized as below :

a) Gas influx pressure remains same.

b) BHP increases.

c) Pressure at any point in well below or above the influx increases.



CLOSED WELL GAS MIGRATION

Percolation Rate :

In case of close well gas migration the gas bubble pressure remains constant whereas all other pressures keep on increasing. This increase in the pressures is directly proportional to the height which gas percolates up in the well. The Percolation rate of the gas can be calculated as follows:

$$\text{Percolation Rate} = \frac{\text{Increase in drill pipe pressure (psi / hr)}}{\text{Drill fluid density (ppg)} * 0.052}$$

Volume of Bleed To Keep BHP Constant :

When gas migration takes place in a closed well, pressure at every point in the well increases. In order to keep the BHP constant, we must allow the gas to expand freely by bleeding some mud through the choke line. The volume of the mud to be bled can be calculated by the following formula:

$$\text{Volume to Bleed (bbl/hr)} = \frac{\text{Increase in drill pipe pressure (psi/hr)} * \text{Pit gain (bbl)}}{\text{Formation pressure (psi)} - \text{Increase in pressure (psi/hr)}}$$

Properties & Behavior Of Different Types Of Influxes :

Gas influx :

i. Extremely compressible fluid.
ii. If not gets no space to expand, brings formation pressure to the top of well and creates high pressures throughout the well.

Petroleum / oily influx:

It behaves nearly same as liquid influx.

Salt/ fresh water influx :

i. Nearly incompressible, volume does not change much with change in pressure.
ii. Sometimes water containing some gas enters as influx, so surface pressure has the same pattern as a gas kick but to a lesser degree.

Well Killing

The well is killed at Slow Circulation Rates and this rate is called kill speed.

Why Well is killed at Slow Circulating Rate

i. To lessen pressure exerted on open hole

ii. To lessen pressure exerted on surface equipment.

iii. To lessen the time needed to dispose off the kick at surface.

iv. To allow sufficient time for kill mud preparation.

v. To improve volume handled by choke, choke wash-out & better choke adjustments.

When to record Slow Circulating Rate pressure

- At Beginning of each shift
- Whenever there is change in Mud Weight or Bit-Nozzle size or BHA
- At times of pump repair
- After drilling more than 500 feet in a shift

The main principle involved in all well killing is to keep the Bottom Hole Pressure constant.

Initially,

Pump is brought 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 the well bore. To prevent this following procedure is suggested:

i. Bring the pump to kill speed holding casing pressure constant by manipulating the choke.

ii. Do it slowly and gradually in steps (mostly done in steps of 5 SPM)

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

Various kill methods are as follows :

a) Driller's Method

b) Wait and Weight Method

Driller's Method :

i. Killing in 2 circulations

ii. 1st circulation is carried out with original mud (which is already being used) & influx is removed from the wellbore

iii. 2nd circulation is carried out with kill mud (heavier mud) & original mud in well is displaced

Formulae required :

a) Kill mud weight (ppg) = old mud weight (ppg) + $\dfrac{\text{SIDPP(psi)}}{0.052 * \text{TVD (ft)}}$

b) Initial circulating pressure (ICP) = SIDPP (psi) + KRP (psi)

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

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

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

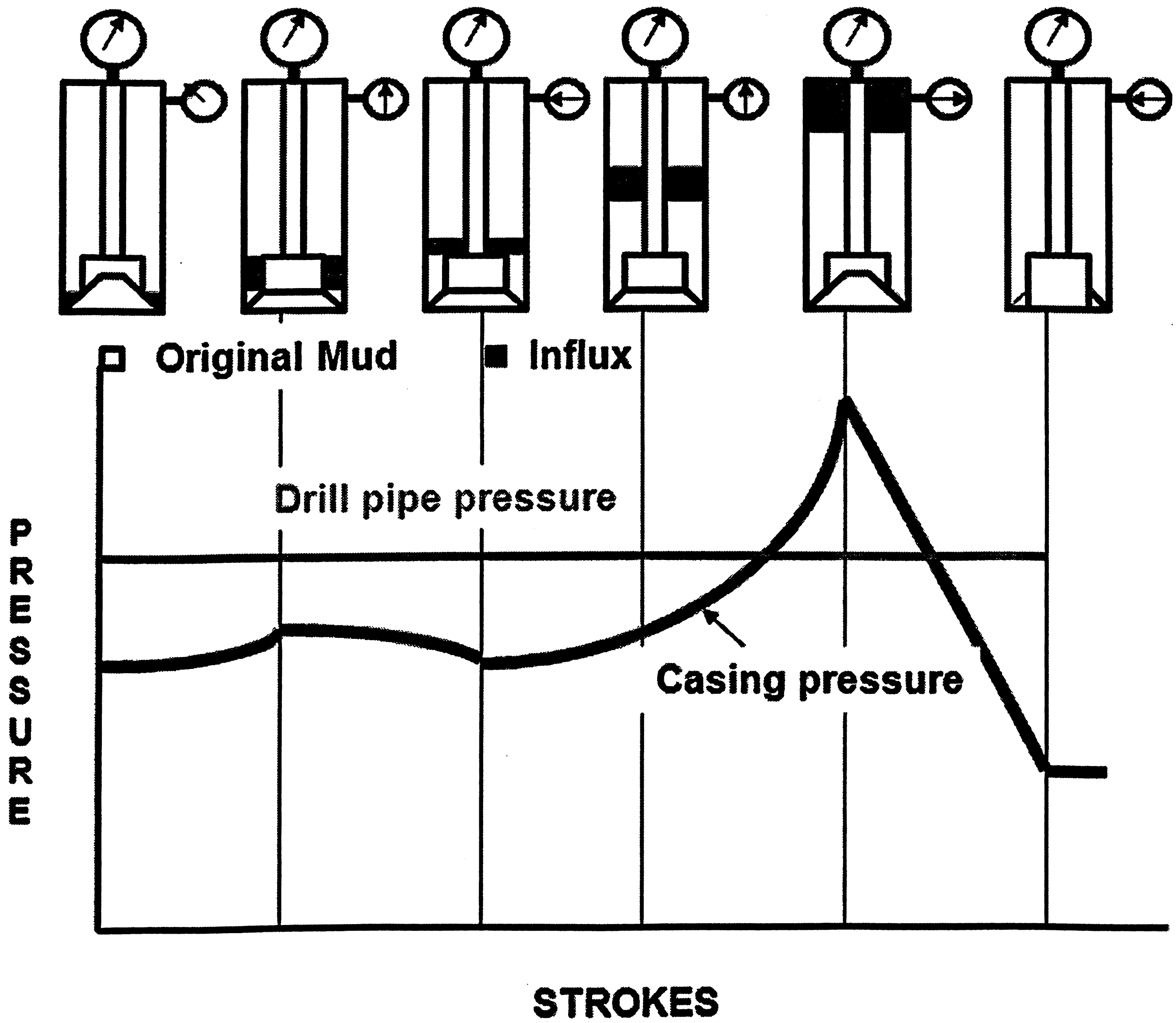
f) Bit to surface strokes = $\dfrac{\text{Annulus volume (bbl)}}{\text{Pump output (bbl/stroke)}}$

Driller's Method : Killing procedure

In this method the well is killed in 2 circulations.

⇒ First Circulation.

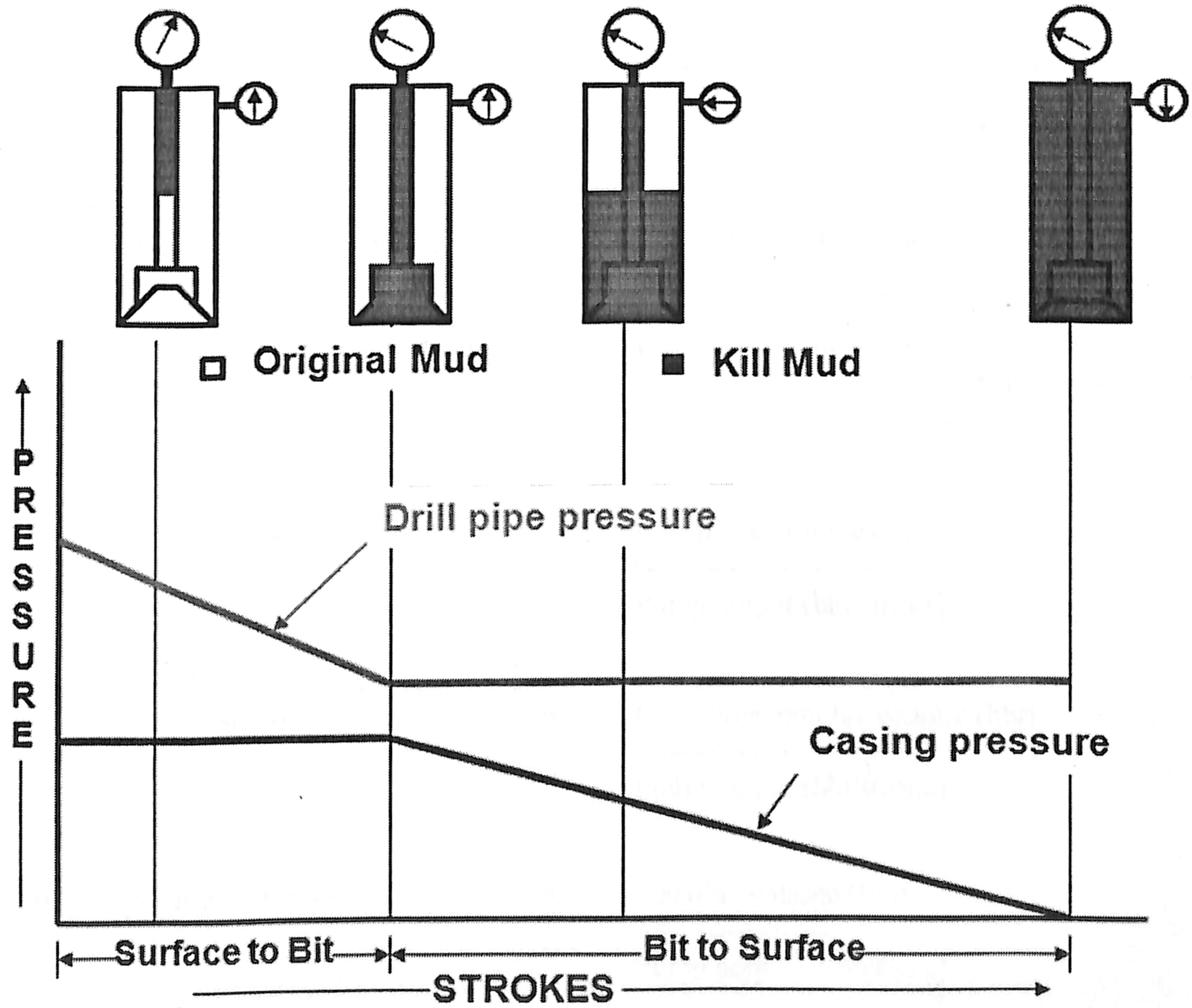
- Bring the pump to kill speed in steps of 5 SPM, hold casing pressure constant & gradually open the choke.
- When the pump reaches the kill speed, maintain drill pipe pressure constant.
- Circulate out kick influx from the well maintaining drill pipe pressure constant.
- When the influx is out, stop the pump by reducing speed in steps of 5 SPM, to finally close the choke, maintaining casing pressure constant. Record pressures, SIDPP & SICP



Pressure profile of 1st cycle : Driller's Method

⇒ Second Circulation.

- Do calculations of mud weight of kill mud, volume needed etc.
- Prepare kill mud.
- Bring the pump to kill speed in steps of 5 SPM, hold casing pressure constant & gradually open the choke.
- When the pump reaches 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 speed in steps of 5 SPM., gradually closing the choke maintaining casing pressure constant.
- Record pressures, SIDPP & SICP should be zero now. Open and observe the well. Add trip margin before resuming the normal operation.



Pressure profile of 2nd cycle : Driller's Method

Wait & Weight Method :

i. In Wait & Weight method the well is killed using kill mud in single circulation.

ii. In this method the operations are delayed (wait) once the well is shut-in, while a sufficient amount volume of kill (weight) mud has been prepared.

iii. As the kill mud is pumped to the bit the hydrostatic pressure in the drill pipe increases continuously, this decreases the drill pipe pressure at the surface. At the same time, influx the annulus expands gaining volume and height, hence causing the hydrostatic pressure in annulus to fall and increasing casing pressure. 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 bit.

Formulae required :

a) Kill mud weight (ppg) = old mud weight (ppg) + $\dfrac{\text{SIDPP(psi)}}{0.052 * \text{TVD (ft)}}$

b) Initial circulating pressure (ICP) = SIDPP (psi) + KRP (psi)

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

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

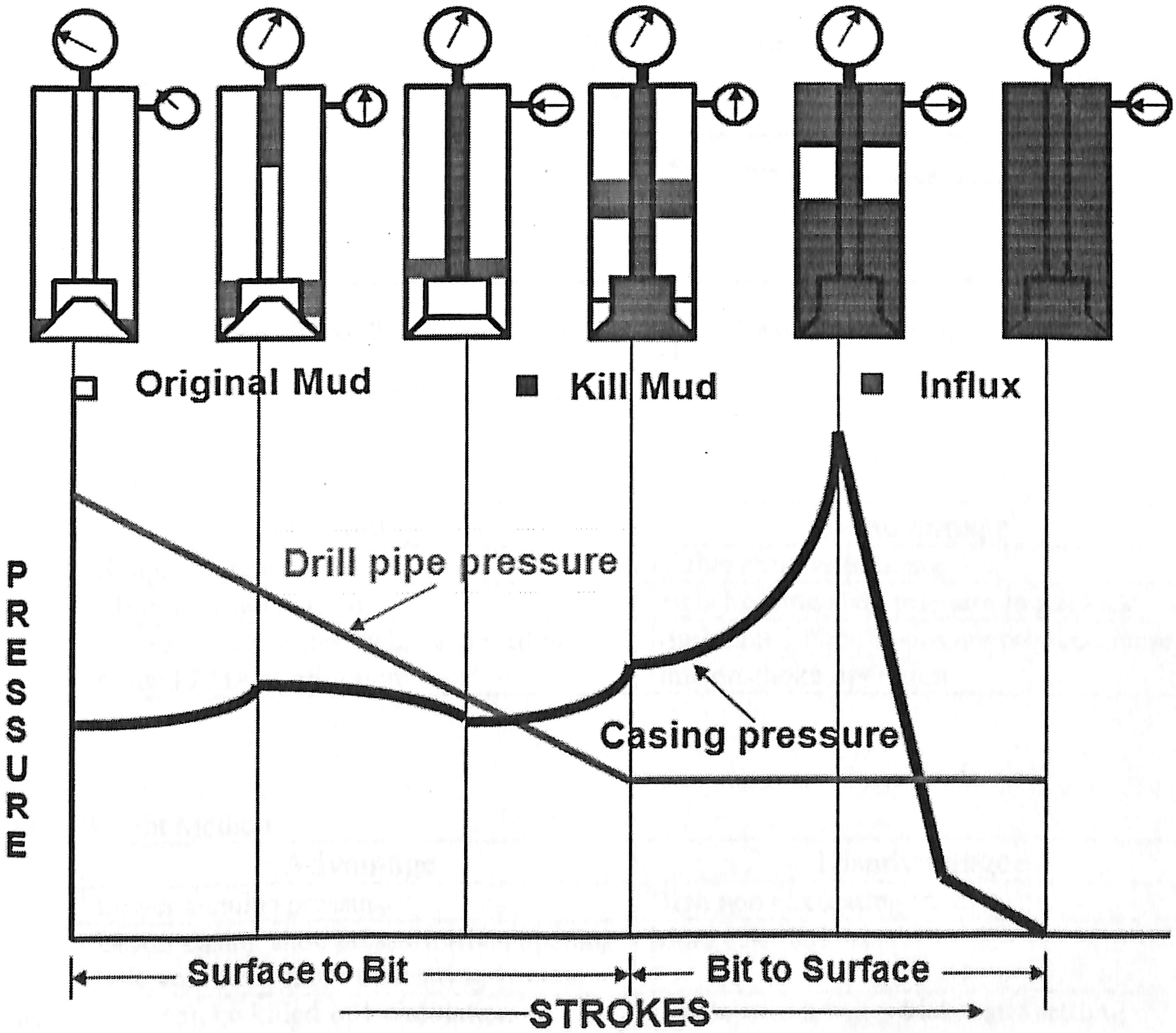
e) Bit to shoe strokes = $\dfrac{\text{Open hole annulus volume (bbl)}}{\text{Pump output (bbl/stroke)}}$

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

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

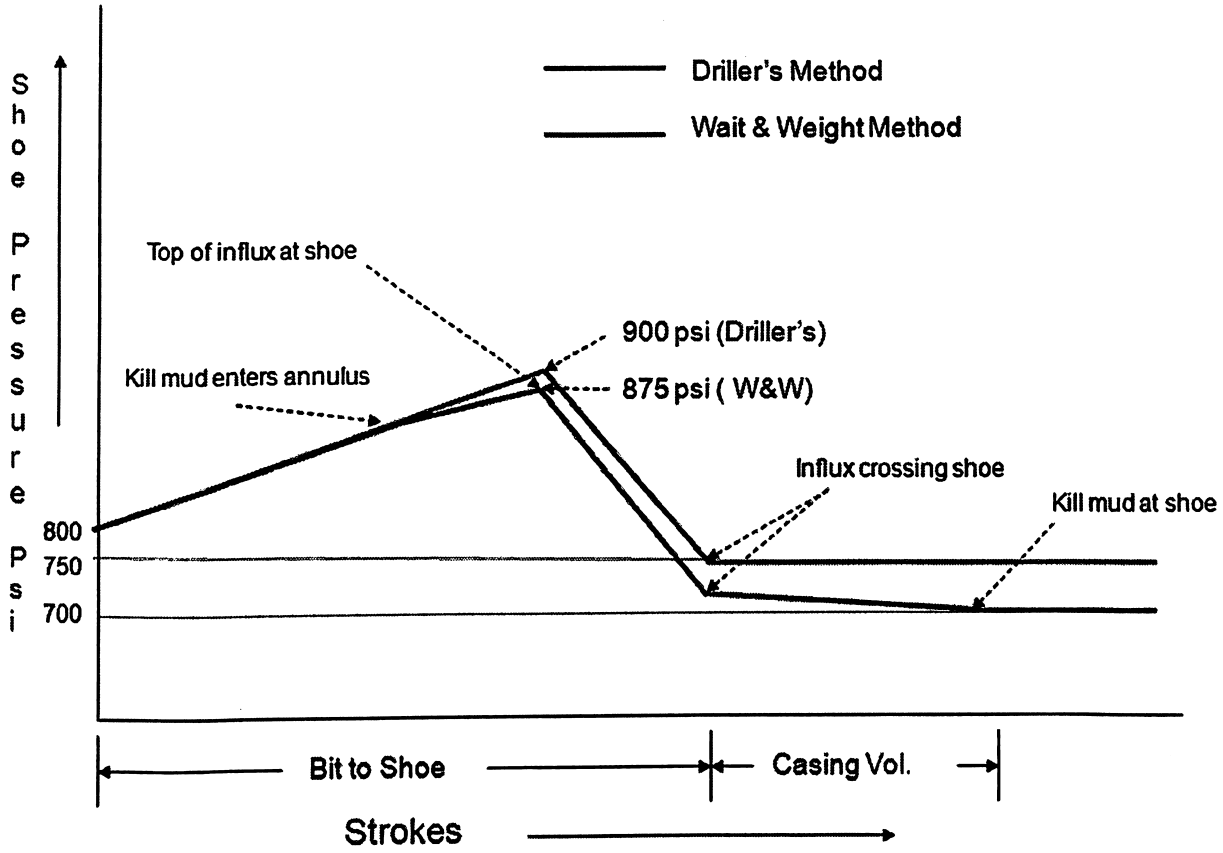
Wait & Weight method: Killing procedure :

- Line up suction with kill mud.
- Bring the pump to kill speed by gradually decreasing in steps of 5 SPM, gradually opening the choke, holding casing pressure constant.
- When the pump is at kill speed, pump the 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 at FCP.
- When the kill mud reaches surface, stop the pump reducing the speed in steps of 5 SPM., gradually closing the choke maintaining casing pressure constant.
- Record SIDPP & SICP, they should be zero now. Open and observe the well. Add trip margin before resuming normal operation



Pressure Profile : Wait & Weight Method

Comparison of Methods



Driller's Method

	Advantage	Disadvantage
i)	Simple 2 understand	Higher annular pressure
ii)	Minimum calculations	Higher casing shoe pressure in gas kick
iii)	In case of salt water kick, sand settling around BHA is minimum	Minimum 2 circulations are required more time on choke operation

Wait & Weight Method

	Advantage	Disadvantage
i)	Lower annulus pressure	High non circulating time
ii)	Lower casing shoe pressure when opening hole volume is more than string volume	More calculations
iii)	Well can be killed in 1 circulation	In case of salt water kick, sand settling around BHA is maximum
iv)	Less time in choke operation	More chances of gas migration

Considerations for Well Control in Horizontal Wells

The basic well control parameters and procedures like causes of kick, positive signs, well shut-in and killing procedures etc. are same for both vertical and horizontal wells, but due to non vertical sections of horizontal wells there exist some differences.

⇒ Influx Volumes

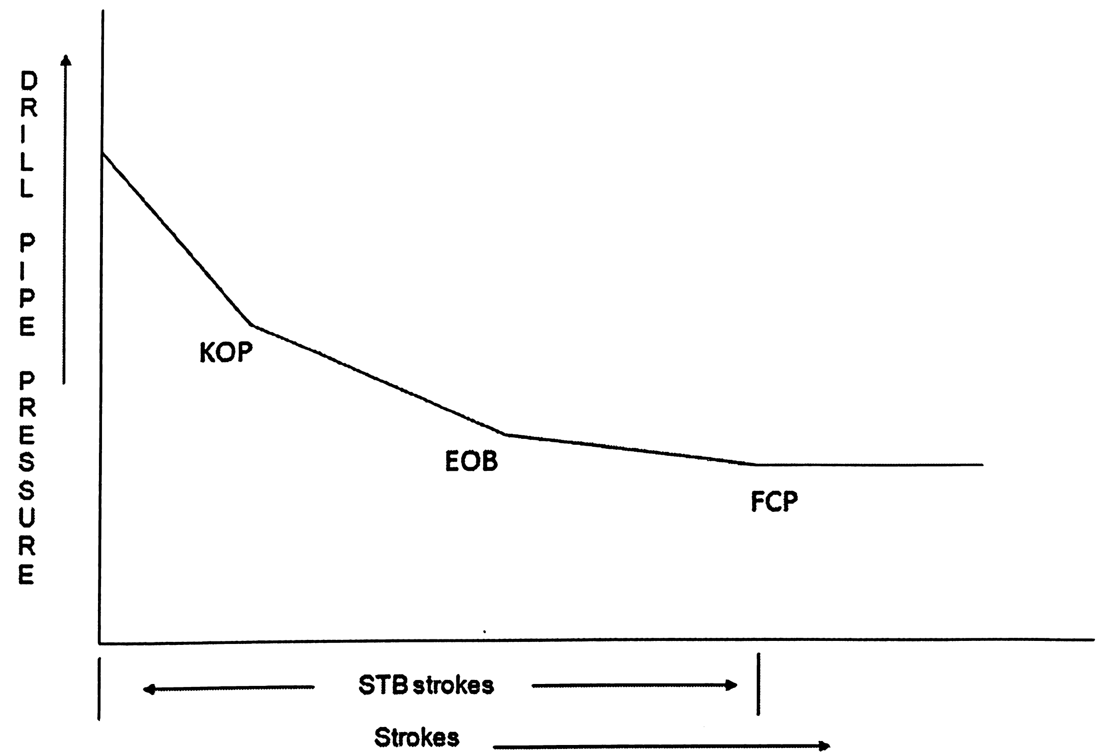
For the difference between formation pressure and mud hydrostatics and for the same duration in which the well is underbalance, the kick influx volumes can be higher for horizontal wells as compared to vertical ones. This is due to the fact that horizontal wells expose more productive formation on the well bore & therefore the rate at which the influx enters the wellbore is considerably higher. this shall result in high pressures at the casing shoe, which may lead to an underground blowout.

⇒ Shut-In Pressures

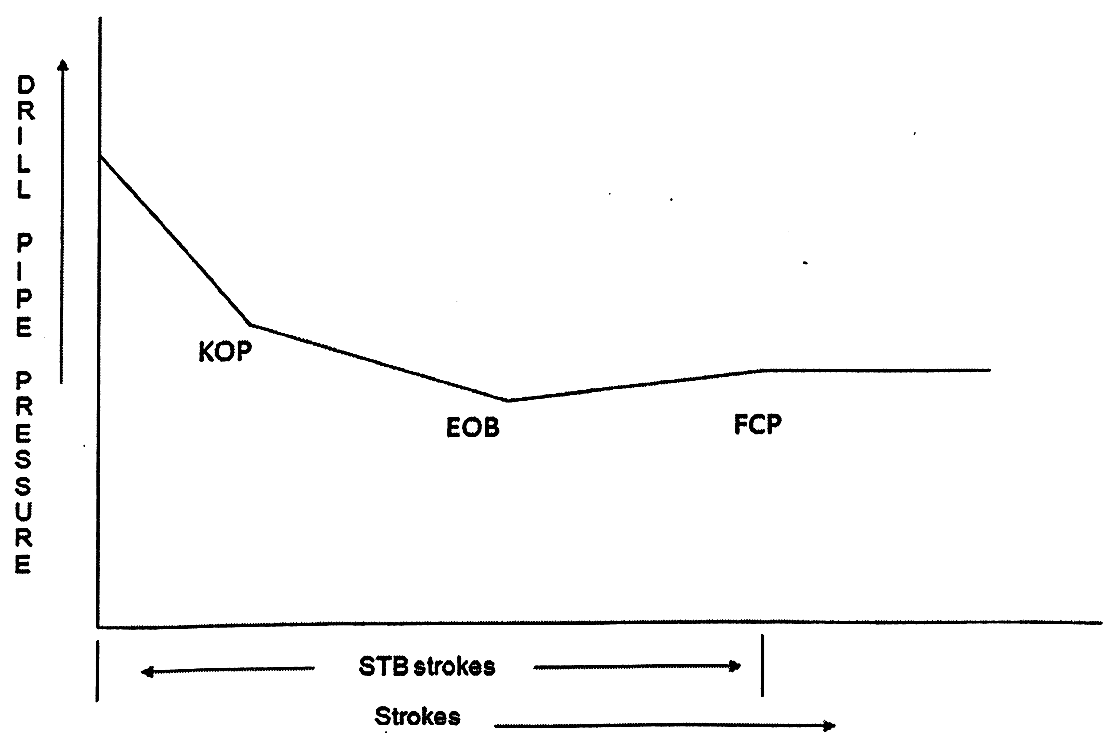
In a well kick situation during drilling, if the influx is in horizontal section then the then the stabilized SIDPP & SICP shall be same, whereas in vertical well there shall be difference in 2 shut in pressures.
In case of a swabbed-in kick in a horizontal well, both SIDPP & SICP shall be zero as long as the influx is in horizontal section, whereas in case of a vertical well under similar conditions both the pressures shall be equal and more than zero.

⇒ Well Killing Procedures

While using Wait & Weight Method in a vertical well the drill pipe pressure drops linearly as kill mud goes down the bit. Whereas in case of a horizontal well, the drill pipe pressure schedule will be different as the build and horizontal section shall not have same linear pressure decrease as in vertical well. Lost circulation may occur due to overbalance situation if a linear drill pipe pressure schedule is followed.
During killing in horizontal wells, the gas removal is not very effective as the gas has the tendency to get segregated to the top side of the hole especially due to annular velocities while killing at slow pump rates. Due to this reason, more circulation time may be required than calculated. This problem can also be dealt by killing at high pump rates, in cases where possibility of loss circulation is not anticipated.
While drilling a horizontal well there is a possibility to come across several faults which may be having same pore pressures, hence loss circulation often occurs in faults where pore pressure is less than the BHP.



Step Down Schedule for Highly Deviated Wells



Step Down Schedule for a Horizontal Well

Tertiary well control:

In case where secondary control cannot be maintained certain emergency procedures can be followed. These procedures are called "tertiary control", these usually end up in partial or complete abandonment of the well.
There is no set procedure that will work in all situations, procedure vary with the situation encountered.
However there are 3 basic procedures which are mainly followed:

1) Barite plugs
2) Cement plugs
3) Relief wells

When secondary well control fails it leads to blow out:

Blow Out :

It is an uncontrolled flow of formation fluid from well. It can occur at the surface or subsurface from the well bore. A blow out is a result of an uncontrolled kick.
Blow out are mainly of two types:

Blowout on surface:

Most common type. More hazardous to environment. This happens when kick enters and is not controlled influx fluid moves up with high velocity, influx fluids consist of gas and oil which due to heat evolved from friction may catch fire. This leads to blow off of whole surface assembly and severe harm to man, machine and environment.
Thus blow outs must be avoided at all costs.

Underground Blow out:

An underground blowout is defined as the situation when the flow of fluids is from one zone to another. More commonly an underground blow out can also happen by a lack of pressure response on the annulus while pumping on the drill pipe or by a lack of pressure while pumping. An underground blow out can be a very dangerous and a destructive situation to face and control. Underground blowouts are more destructive and more challenging than surface blowouts. The volume of influx flow is not known nor its composition. Further, the conditions prevailing in the wellbore and the tubulars in contact with the blowouts are also not known descriptively.
If an underground blow out is within 3500 to 4100 feet of the surface then the flow may fracture to the surface outside the casing. The potential for cratering is high and the crater could be anywhere. The most destructive position of the crater can be when it is just below the rig or platform and it can result in destruction of entire rigs and production platforms.

Barite Plugs:

A barite plug is slurry of barite in fresh water or diesel oil which is pumped in the well to form barite bridge that can seal the blowout hence allowing control of the well to be established. The plug is pumped through the drill pipe and the string is pulled up to a safe point above the plug if possible. The barite settles down rapidly to form an impermeable mass capable of shutting high pressure and flow rates.

The efficiency of barite plug depends on high density and fine particle size of the barite also on its ability to form a tough impermeable barrier.

To be effective, the barite slurry should have the following properties:

i. Its viscosity and yield point should be low to ensure rapid settling rate.
ii. Clay content should be less
iii. The slurry should be of high density of around 3ppg higher than the density of mud.
iv. The fluid loss coefficient must be high to allow rapid dehydration of slurry. High fluid loss can sometimes cause borehole to slough and bridge itself.

Barite plug has the many advantages:

i. It can be pumped through the bit and gives a good chance to recover the drill string.
ii. The material needed is normally available at the site.
iii. The plug can be drilled easily to continue operations when needed in later stages

Cement plug:

A cement plug is used to shut down a down hole flow. However, it mostly leads to abandonment of the well and loss of major drilling tools. Cement plugs are set by pumping a certain amount of quick setting cement in annulus. The cement is displaced until the pump and choke pressures show that a bridge has been made.

Setting a cement plug usually don't provide option of recovering drillstring. It is also possible that the string will be plugged after pumping in cement slurry. Hence, cement plugging should be used as the final option.

Case Study…

On well no.KL#648 KLRR of Ahmedabad Asset ONGC experienced a kick, following were the steps taken at site :

- Rotary table was stopped and well was checked for self flow, which was positive
- Well was closed using Cameron 5" Pipe Ram preventer.
- Hard shut-in method was used.
- SIDPP, SICP & Pit gain were recorded

SIDPP	600 psi
SICP	645 psi
Pit Gain	9 bbl

- Mud of Specific gravity 1.6 was made and well was killed using wait and weight method in 1 circulation.

Well Data :

Location	KL#648 (KLRR)		
Lease	Kalol		
Operator	ONGC		
Rig No.	John # 18		
Type of BOP	Ram +Annular (a Cameron double Ram- pipe and blind & a Shaffer Annular type)		
Type of well	development		
Category of well	Inclined (High angle) (proposed angle at end : 80°)		
Objective	To develop KVII pay zone as oil producer		
Well profile	L type		
Target depth	1731 m		
Kick off point	975.2m		
Drill Pipe	size – 5"	weight – 9.5 ppf	grade – G&S
Casing	size – 9 5/8"	make – Jindal	

Pump Data :

No. of pumps	2
Pump Manufacturer	Honghua HHF
Type	Triplex
Stroke Length	10"
Slow pump rate	60 SPM

Bit Data :

SRR	
Size	8 ½"
IADC code	117
Manufacturer	Smith
Type	XR+C

Mud Record (original mud) :

Type of mud	KCl – PHPA polymer mud
Sp. Gravity	1.3
Tunnel viscosity	45 cp
PV/YP	22/50
Gel strength	14/21
Fluid loss	4.2
PH	8.5
Solids	14%
Sand	21%

Relevant data at time of kick :

Drilled depth	MD	1620m (5315ft)	TVD	1442m (4731ft)
Casing Shoe depth	MD	1437m (4714ft)	TVD	1368m (4488ft)
KOP	MD	975.2m (3199.4ft)	TVD	975.2m (3199.4ft)
Original Mud Wt.	1.3 Sp. Gravity (10.82ppg)			
Slow pump rate	60 SPM with 300 psi pressure loss			
SIDPP	600 psi			
SICP	645 psi			
Pit gain	9 bbl			

In ONGC, due to lack of labor Kill Sheet is not prepared, hence I tried to make it

Formulas and Conversions used :

1 meter	=	3.2808 feet
Sp. Gravity * 8.33	=	ppg (pound per galleon)
Volume between 2 pipes (bbl/ft)	=	$\dfrac{\{ OD_{(inches)} \}^2 - \{ ID_{(inches)} \}^2}{1024}$
Maximum Allowable Mud Weight (ppg)	=	Mud Wt (LOT) + $\dfrac{\text{Surface Leak off pressure}}{\text{Shoe TVD} * 0.052}$
Maximum Allowable Annular Surface Pressure (MAASP)	=	{Max Allowable MW – Current MW} *Shoe TVD * 0.052
Kill mud weight (ppg)	=	old mud weight (ppg) + $\dfrac{\text{SIDPP(psi)}}{0.052 * \text{TVD (ft)}}$
Initial circulating pressure (ICP)	=	SIDPP (psi) + KRP (psi)
Final Circulating Pressure (FCP)	=	$\dfrac{\text{Kill mud weight (ppg)}}{\text{Original mud weight (ppg)}} * \text{KRP (psi)}$
Dynamic Pressure Loss at KOP at KOP	=	$PL + [\ \{FCP - PL\} * \dfrac{KOP_{MD}}{TD_{MD}}\ ]$
Remaining SIDPP at KOP (psi)	=	$SIDPP - [\{KMW - OMW\} * 0.052 * KOP_{TVD}]$
Circulating Pressure at KOP (KOP_{CP})	=	PL_{KOP} (psi) + $SIDPP_{KOP}$ (psi)

$$\text{Surface to bit strokes} = \frac{\text{drill string volume (bbl)}}{\text{Pump output (bbl/stroke)}}$$

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

$$\text{Bit to surface strokes} = \frac{\text{Annulus volume (bbl)}}{\text{Pump output (bbl/stroke)}}$$

$$\text{Pressure drop / 100 strokes} = \frac{\text{ICP} - \text{FCP}}{\text{Surface to Bit strokes}} * 100$$

Surface BOP (Deviated Well) Kill Sheet

Formation Strength Data :

LOT data :
Surface Leak off Pressure : 1120 psi
Mud Weight : 10.4 ppg

Maximum Allowable Mud Wt. =

$$10.4 + \frac{1120}{4488(TVD_{Shoe}) * 0.052} = 15.2 \text{ ppg}$$

Initial MAASP =
[{15.2 – 10.82} * 4488(TVD $_{Shoe}$) * 0.052 = 1022.2 psi

Pump 1 Displacement	Pump 2 Displacement
0.127 bbl/stroke	

Slow Pump Rate Data	(PL) Dynamic Press Loss	
	Pump 1	Pump 2
60 SPM	300 psi	

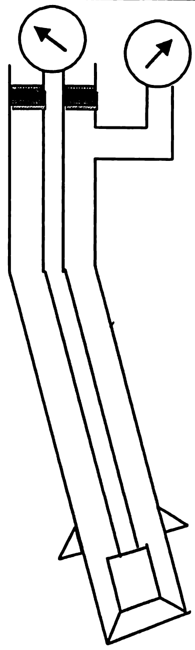
Current Well Data :

Mud Data :
(OMW) 10.82 ppg

Deviation Data :
KOP MD 3199.4ft
KOP TVD 3199.4ft

Casing Shoe Data :
Size 9 5/8"
MD 4714ft
TVD 4488ft

Hole Data :
Size 8 ½"
MD 5315ft
TVD 4731ft



Pre-Recorded Volume Data	**Length (ft)**	**Capacity (bbl/ft)**	**volume (bbl)**	**Pump (stks)**	**Time (minutes)**
DP- Surface to KOP	3199.4	* 0.0178	= 56.94	448	
DP- KOP to BHA	1725.6	* 0.0178	= 30.71	242	
HWDP	210	* 0.0087	= 1.827	14	
Drill Collar	180	* 0.0061	= 1.098	9	
Drill String Volume			**= 90.575**	**713**	**12**
DC * Open Hole	180	* 0.0323	= 5.81		
DP / HWDP	421	* 0.0459	= 19.32		
Open Hole Volume			**= 25.13**	**198**	
DP * Casing	4714	* 0.0515	= 242.77	1912	
Total Annulus Volume			**= 267.9**	**2110**	**35**
Total Well System Volume			**=358.4**	**2823**	**47**

Surface BOP (Deviated Well) Kill Sheet

Kick Data :

SIDPP 600 psi SICP Pit Gain

Kill Mud Weight
KMW

$$10.82\,(OMW) + \frac{600\,(SIDPP)}{0.052 * 4731\,(TVD)} = 13.25\text{ ppg}$$

Initial Circulating Pressure
ICP

$$300\,(PL) + 600\,(SIDPP) = 900\text{ psi}$$

Final Circulating Pressure
FCP

$$\frac{13.25\,(KMW)}{10.82\,(OMW)} * 300\,(PL) = 367.37\text{ psi}$$

Dynamic Pressure Loss
at KOP

$$300(PL) + [\{\,367.37(FCP) - 300(PL)\,\} * \frac{3199.4(KOP_{MD})}{5315(TD_{MD})} = 340.55\text{psi}$$

Remaining SIDPP at KOP

$$600(SIDPP) - [\{\,13.25(KMW)-10.82(OMW)\,\} * 0.052 * 3199.4(KOP_{TVD}) = 195.72$$

Circulating Pressure at KOP

$$340.55(PL_{KOP}) + 195.72(SIDPP_{KOP}) = 536.27$$

ICP – KOP = 900 – 536.27 = 363.27

$$\frac{363.27 * 100}{484(stks_{\text{SURFACE to KOP}})} = 81.1\text{ psi/100stks}$$

KOP – FCP = 536.27 – 367.37 = 168.9

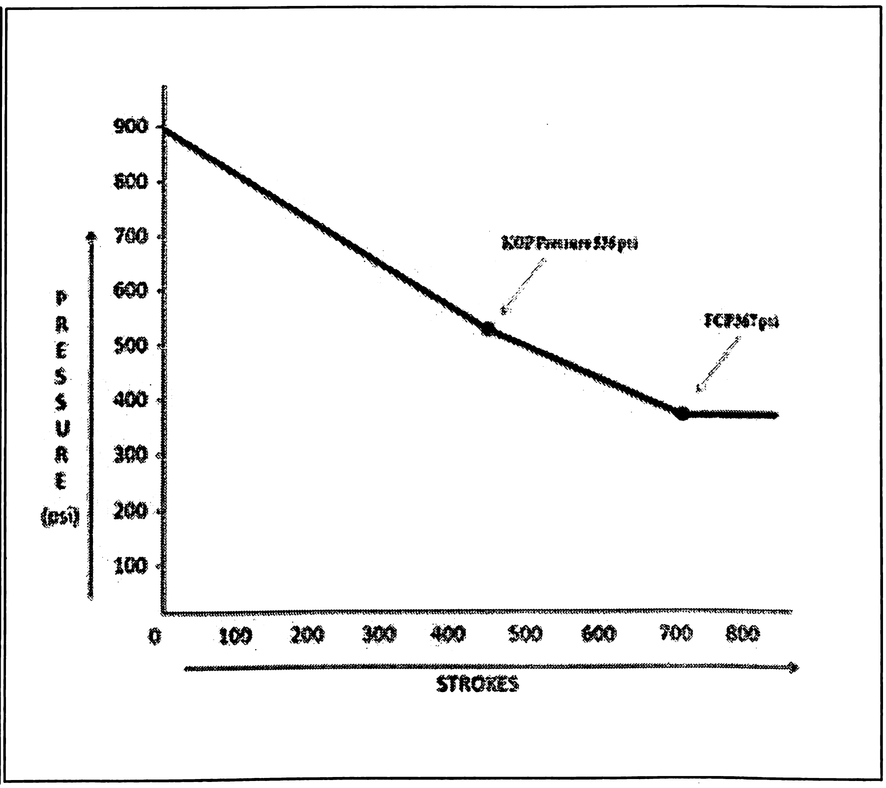
$$\frac{168.9 * 100}{265(stks_{\text{KOP to BHA}})} = 63.7\text{ psi/100stks}$$

Result:

Final pressure profile:

Surface BOP (Deviated Well) Kill Sheet

Strokes	Pressure
00	900
100	818.9
200	737.8
300	656.7
400	575.6
448	536.27
500	503.14
600	434.45
700	375.75
713	367.37



Conclusion:

Kick at well no.KL#648 KLRR of Ahmedabad Asset ONGC was killed by using 13.2 ppg mud, using Wait & Weight method in 1 circulation.
The following result was observed.

Surface BOP (Deviated Well) Kill Sheet

Strokes Surface to Bit	=	713	Strokes
Strokes Bit to Shoe	=	198	Strokes
Strokes Bit to Surface	=	2110	Strokes
Kill Mud Weight	=	13.25	ppg
Initial Circulating Pressure	=	900	psi
Final Circulating Pressure	=	367.37	psi
MAASP with original mud weight	=	1022.2	psi
MAASP with Kill Mud	=	455.08	psi
Time for complete Circulation	=	47	mins
Circulating Pressure at KOP	=	536.27	psi
Pressure Drop/100 Strokes up to KOP	=	81.1	psi/100stks
Pressure Drop/100 Strokes from KOP to Bit	=	63.7	psi/100stks