Sudan University of Science and Technology
Collage of Petroleum Engineering
Petroleum Engineering Department

Research Titled:

Well Control using Volumetric Method

التحكم في الآبار باستخدام الطريقة الحجمية

Project Submitted to College of Petroleum Engineering in Partial Fulfillment for the Degree of B-Tech in Petroleum Engineering

Prepared By:

Ashraf Elzeain Shareef Elhassan

Mohammed Awad Elgeed Abd Elaleem

Mohieldeen Mortada Albakri

Yusra Magzoub Ali

Supervisored by:

Ms. Ayah Abdelhai

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الآيـــــــة

بسم الله الرحمن الرحيم

قال تعالى :

﴿ نَزَلَ مِنَ السَّمَاءِ مَاءً فَسَالَتْ أَوْدِيَةٌ بِقَدَرِهَا فَاحْتَمَلَ السَّيْلُ زَبَدًا رَّابِيًا ۚ وَمِمَّا يُوقِدُونَ عَلَيْهِ فِي النَّارِ ابْتِغَاءَ حِلْيَةٍ أَوْ مَتَاعٍ زَبَدٌ مِّثْلُهُ ۚ كَذَٰلِكَ يَضْرِبُ اللَّهُ الْحَقَّ وَالْبَاطِلَ ۚ فَأَمَّا الزَّبَدُ فَيَذْهَبُ جُفَاءً ۖ وَأَمَّا مَا يَنفَعُ النَّاسَ فَيَمْكُثُ فِي الْأَرْضِ ۚ كَذَٰلِكَ يَضْرِبُ اللَّهُ الْأَمْثَالَ (١٧) ﴾

صدق الله العظيم

سورة الرعد الآية (١٧)

DEDICATION

To each of the following in the presence of God and His Messenger.

To the big heart my dear father …. my mother dear..

To those who have demonstrated to me what is the most beautiful in life, my brothers and my sisters.

Finally to any gifts from the sky.

ACKNOWLEDGEMENT

First of all gives thanks to Allah

And a special thanks to supervisor

Ms. ayah abdelhai

&

Mr. Mohammed Abdalkhalig

I can’t forget giving thanks to everyone who helped us and gave new hope to successful.

I'm gratefully acknowledge the financial support of lectures and all staff of Sudan Universities and Technology .

I wish to acknowledge the efforts of the auto work shop staff for their standing beside us the experimental work .

ABSTRACT

The control of wells is a cornerstone of drilling process, Through this study the detailed procedures of bleed and lubricate has been discussed; Calculated volumes of fluid that must be bled from the well during lubricating mean while keeping bottom hole pressure constant, A model to predict the surface pressure has been built, and utilized to find out the maximum number of stands that can be stripped back to bottom without proceeding surface pressure to the working pressure of the weakest component of well head.

The string has been stripped back to bottom safely using volumetric method, prior to circulate kill fluid into well which will return the well control to its primary level. The killing operation is a blend of wait and weight, and volumetric methods. The volumetric has been showed, in means of tools, procedures, and well head pressure monitoring, safe manner.

To mitigate the bad effect of the bull heading, such described methodology has been highly recommended to control the flowing wells.

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Chapter One

Introduction

1.1 Introduction:

The control of the formation pressure , either by ensuring that the borehole pressure is greater than the formation pressure known as (primary control) or by closing BOP valves at surface known (Secondary control) is generally referred to as keeping the pressure in the well under control .

The purpose of well control is to ensure that fluid (oil, gas and water) does not flow in an uncontrolled way from the formation being drilled, into the borehole and eventually to surface. This flow will occur if the pressure in the pore space of the formation being drilled (formation pressure) is greater than the hydrostatic pressure exerted by the column of mud in the wellbore (bore hole pressure) . It is essential that the borehole pressure, due to the column of fluid, exceeds the formation pressure at all times during drilling.

As the well reach to the artificial lift stage, pumps are installed in the well; therefore a frequent process of work over interventions is required to maintain the oil production from the formations. Prior to make any intervention the well must be dead, unless none of the work over activity can be conducted. At this point many methods of non-conventional methods to retrieve the primary well control are rise.

1.2 Problem Statement:

Many of Sudanese Oil Company used to handle the issue of well control when there is no way to circulate the killing fluid, such procedure is suffer from disadvantages, e.g. a great deal of undesirable fluid enters into formation, this makes a highly potential for positive skin factor.

This study aims to return the well to its primary control by using volumetric method, in means of tools, procedures, and well head pressure.

1.3 Objectives:□

1. Review the procedure of bleed and lubricate.
2. Calculate volumes of fluid that must be bled from the well during lubricating.
3. Design a chart to monitor wellhead pressure (casing pressure).

1.4 Scope of Research:

This study is focusing on retrieving the primary well control to a life well and there is no way to commence any full circulation because of the string at the highest portion of the well.

1.5 Lay Out of the Study:

Chapter one

This chapter presents Background of the Research, Statement of the Problem, Objectives of the project and scope of research.

Chapter Two:

This chapter presents Literature Review and Theoretical Background.

Chapter Three:

In this chapter present the methodology of well control.

Chapter Four:

In this chapter, present the result and discussion for design and analysis for well control.

Chapter Five:

This chapter presents conclusions and recommendation.

Chapter Two

Literature Review and Background

2.1 Literature Review:

Davorin Matanovic et.al (1994) to kill a production well means to perform some technical and technological processes for establishing the static hydraulic balance in the well with no additional surface pressures. The standard procedure of the well killing process as adopted in Croatia, is described. Further, the procedures of how to locate the spot where there is a leakage on production equipment and Row to determine the level of fluid in tubing or annulus is explained. Finally, the aim of this paper is also to point out the importance in selection of killing fluids considering a possibility of formation damage.

S.Nishikawa et.al (2001) performed a series of experiments to investigate a procedure for killing sustained casing pressure (SCP) by the bleed –and lubricate method of injecting heavy brine in to the annulus. The procedure involves bleeding fluids from the annulus and lubricating in weighted fluids in order to displace annular fluid with the heavy brine. Three concepts of annular fluid displacement were investigated: brine or mud lubricated into a water-filled annulus, brine into bentonite slurry and immiscible displacement. The experiments showed that annular density increased after many injections of brine into the water-filled annulus and more desirable performance using immiscible fluid. However, the experiment demonstrated an inability to displace drilling mud with brine due to flocculation effect.

A.k wojtanowicz.r.smith(2001) In this study ,aservies of experimenls was performed to in vestigate aprocedure for killing sustained casing pressure (scp) by the bleed –and lubricate method of injecting heavy brine in to the annular the procedure in volves bleeding fluids from the annular and lubricating in weighted fluids in oreder to displaced annular fluid eith the heavy brine .The concept of this method in the annulus the objective of the study was to evaluate theperformace of cyclir injection in view of the efficiency of displacing annulr fluid with injected fluid

Yuan Qiji Zheng Zheng et.al(2012) The paper was aimed at finding out the non-routine well control procedure to deal with the overflow of the well in special operating conditions. Study the well killing technology in four situations. The situation included the well is full of natural gas, lower of the well is liquid column and upper of the well is natural gas, the wellbore blocks and unable establish cycling for containing liquid column, besides the wellbore holds fish where the fish is intact and doesn't block the wellbore, the fish blocks the wellbore or the fish is breakup and blocks the

wellbore. Discuss the principles, steps, calculation procedure and formulas of killing well in volumetric control mode

2.2 Background:

The most important concern when plan to drilling or completion a well is how to management difficulties and danger effect that may be initiated with unexpected release of formation fluids such as water, oil and gas by applying pressure balance concept by using either dense fluid to exert enough balance against formation as the first line of defense or using high efficient equipment's as the second line of defense to reestablish the equivalent pressure.

2.2.1 Pressure Concepts:

When dealing with well control issue many pressure should be differentiated form each other to make a clear realize of the situation.

- **Hydrostatic pressure (P_h):**

Is the pressure exerted by static fluid column (drilling/completion fluid), It varies with the height of the fluid column (depth of the well) and the weight of the fluid. The pressure of the fluid in a well depends on the "True Vertical Depth" which may be less than the "Measured Depth". And can be calculated from the equation (2.1).

$$P_h = 0.052 \, X \, TVD \, X \, Mw \qquad (2.1)$$

Where;

P_h: Hydrostatic pressure (Psi)

TVD: True vertical depth (ft)

Mw: Mud weight (ppg)

- **Pressure Gradient:**

The pressure Gradient is the pressure per vertical depth.

$$PG = P_h/TVD \quad (2.2)$$

Or;

$$PG = 0.052\ x\ MW \quad (2.3)$$

Where:

PG: Pressure Gradient (psi/ft)

- **Formation Pore Pressure:**

Is the pressure exerted by formation fluids (water, oil or gas) contained in the formation pore and can be divided referring to the formation pressure gradient of fluid trapped as:

- ❖ Normal Formation Pressure.
- ❖ Abnormal Formation Pressure.
- ❖ Subnormal Formation Pressure.

- **Bottom Hole Pressure:**

Bottom hole pressure is equal to the sum of all pressures in a well. Generally speaking, bottom hole pressure is the sum of the hydrostatic pressure of the fluid column above the point of interest, plus any surface pressure which may be exerted on the top of the fluid column, and the effect of friction pressure must be added or subtracted depending on the direction of flow. This is expressed mathematically as:

$$BHP = HP + SP \pm FP \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots..(2.4)$$

Where;

BHP = Bottom hole Pressure (psi)

HP = Hydrostatic Pressure (psi).

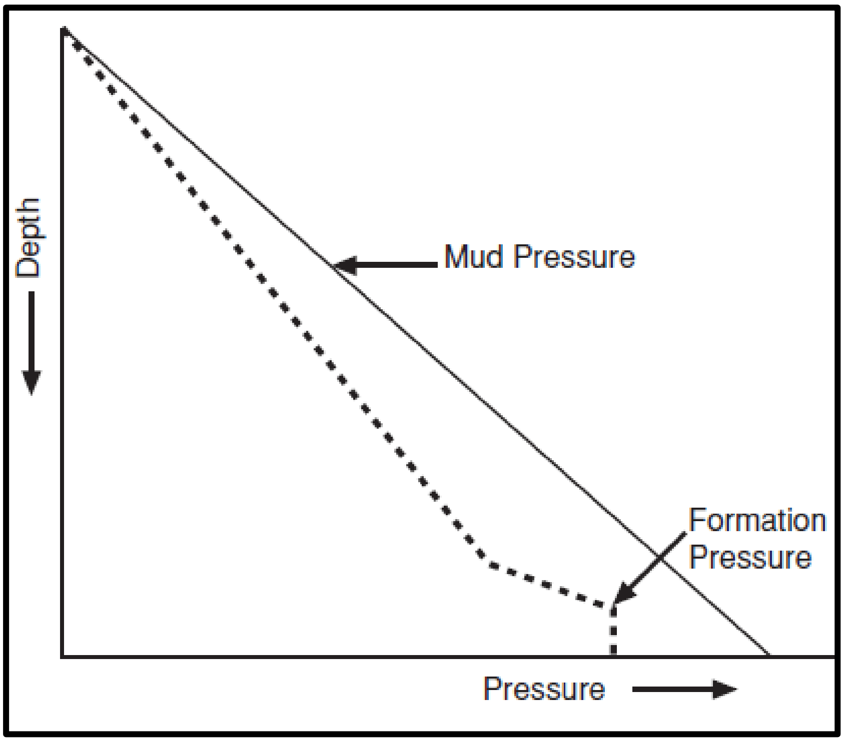
SP = Surface Pressure (psi)

FP = Friction Pressure (psi).

2.2.2 Well Control Levels:

1. Primary Control:

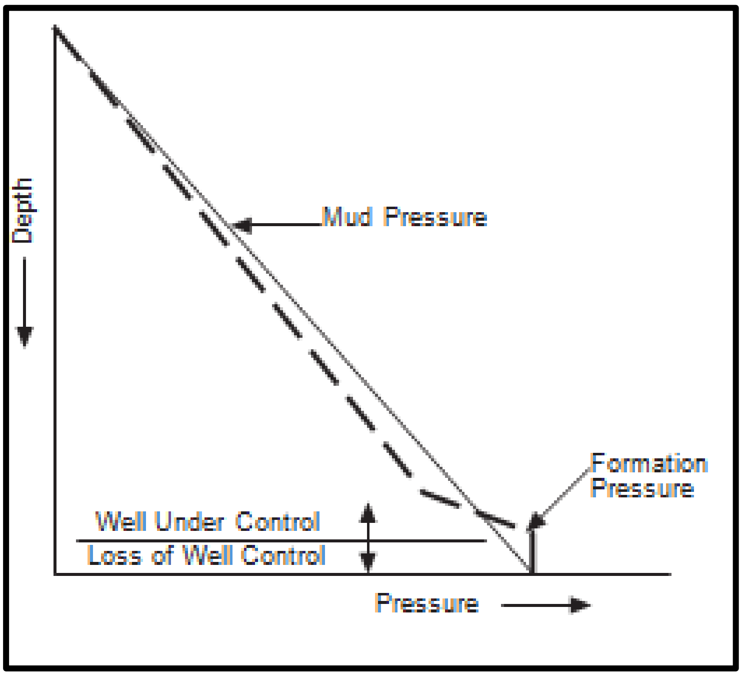
Primary well control is the use of drilling fluid density to provide sufficient pressure to prevent the influx of formation fluid into the wellbore. It is of the utmost importance to ensure that primary well control is maintained at all times. This involves the following: Drilling fluids of adequate density are used, well is kept full of adequate density fluid at all times and changes in: density, volumes and flow rate of drilling fluids from the wellbore are immediately detected and appropriate action taken.



1 (Figure (2.1): Primary Control - Pressure due to mud column exceeds Pore Pressure (Drilling engineering 2001))

2. Secondary control:

Secondary control is required when primary control has failed (e.g. an unexpectedly high pressure formation has been entered) and formation fluids are flowing into the wellbore. The aim of secondary control is to stop the flow of fluids into the wellbore and eventually allow the influx to be circulated to surface and safely discharged, while preventing further influx downhole. The first step in this process is to close the annulus space off at surface, with the BOP valves, to prevent further influx of formation fluids (Figure 2.2). The next step is to circulate heavy mud down the drillstring and up the annulus, to displace the influx and replace the original mud (which allowed the influx in the first place). The second step will require flow the annulus but this is done in a controlled way so that no further influx occurs at the bottom of the borehole. The heavier mud should prevent a further influx of formation fluid when drilling ahead. The well will now be back under primary control.



2 (Figure (2.2): Secondary Control -Influx Controlled by Closing BOP's(Drilling Engineering2001))

3. Tertiary well control:

In the event that secondary control cannot be properly maintained due to hole conditions or equipment failure, certain emergency procedures can be implemented to prevent the loss of control. These procedures are referred to as "Tertiary Control" and usually lead to partial or complete abandonment of the well.

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. However, there are two procedures that are widely used, include: Barite plugs and Cement plugs. (Schlumberger, 1999)

2.2.3 Kick Anatomy:

A kick is an influx, or flow, of formation fluids into the well. The successful detection and handling of kicks is extremely important. Obviously, there are times when it's desirable to have a flow of formation fluids, e.g. when the well is put in production. However, the unplanned kick during completion, workover, or production operations threatens control of the well. We must be prepared for this unplanned kick and ensure that we have a method to control and deal with it.

A kick, if not controlled, can result in a blowout. A blowout is the uncontrolled flow of formation fluids from a well. Blowouts endanger personnel safety and pose a significant threat to an environment. Thus, the single most important step in well control and blowout prevention is to shut the well in when the well kicks.

- **Kick Causes:**

Wells kick when the reservoir pressure of an exposed formation exceeds the wellbore (bottom hole) pressure. During the period of completion, Workover, and production operations there are many procedures which could produce this downhole condition. Some of the most common causes of kicks include:

- ❖ Not keeping the hole full.
- ❖ Lost circulation.
- ❖ Swabbing.
- ❖ Underbalanced pressures.
- ❖ Gas cut mud.
- ❖ Mechanical failures.

a) Not Keeping the Hole Full:

Hydrostatic pressure is the only pressure exerted on exposed perforations. If the hydrostatic pressure in a well drops below the reservoir pressure, the exposed zone will flow into the wellbore. Statistics reveal that most kicks occur on trips, which indicates that the wells were either swabbed or improperly filled during the trip.

When tripping out of the hole, a volume (of steel) is being removed from the well. As the steel is removed, the fluid level (and hydrostatic pressure) in the well drops. If the hydrostatic pressure drops below the reservoir pressure, the exposed zone will flow.

Therefore it is extremely important to fill the hole with fluid while tripping out of the hole.

Normal pressure zone, Common practice is to pump the theoretical fill up volume while pulling out of the well.

b) Lost Circulation:

Loss of circulation leads to a drop of both the fluid level and hydrostatic pressure of a well. If the hydrostatic pressure falls below the reservoir pressure, it is difficult to detect when losses occur during tripping pipe into or out of the hole, large volume of kick fluid may inter the hole before the mud level increase is observed at the surface.

c) Swabbing:

Swabbing is caused by the upward movement of pipe in a well and results in a decrease in bottom hole pressure. In some cases, the bottom hole pressure reduction can be large enough to cause the well to go underbalanced and allow formation fluids inters the wellbore and there are various factors conductive to swab pressure are: (pipe pulling speed, mud properties, filtration cake, annular clearance…etc.)

d) Underbalanced Pressures:

Underbalanced pressure is the condition that occurs when wellbore (bottom hole) pressure is less than the reservoir pressure of an exposed formation. An underbalanced condition is most common on wells that are on production, but can also occur during the course of completion/workover operations. In many fields, completion/workover programs incorporate drill stem tests and underbalanced.

e) Gas Cut Mud:

As the gas is circulated to the surface, it expands and reduces the hydrostatic pressure sufficient to allow to kick to enter.

- **Kick Warning Sign:**
  1. Drilling break
  2. Increase in stroke per minute
  3. Pump pressure decrease
  4. Gas Cutting
  5. Change in cutting shape and size

- ## kick indicators:

Primary (positive) indicators:

Upon recognition of a positive indicator, immediate action should be taken to control the well. The three Positive indicators of a kick are:

- ❖ Increase in pit volume
- ❖ Increase in return flow rate or flow with pumps off
- ❖ Surface pressure with the well shut-in

2.2.4 Well Killing Methods:

Various methods are used to returning the kicked off well to its original circumstance depending on the current situation and the availability of the material.

1. Conventional Methods:

a) wait and weight (One Circulation Method):

The "One circulation Method" ("balanced mud density" or "wait and weight" method):

The procedure used in this method is to circulate out the influx and circulate in the heavier mud simultaneously. The influx is circulated out by pumping kill mud down the drill string displacing the influx up the annulus.

The kill mud is pumped into the drill string at a constant pump rate and the pressure on the annulus is controlled on the choke so that the bottom hole pressure does not fall, allowing a further influx to occur.

Advantages:

1. Since heavy mud will usually enter the annulus before the influx reaches surface the annulus pressure will be kept low; thus there is less risk of fracturing the formation at the casing shoe.
2. The maximum annulus pressure will only be exerted on the wellhead for a short time.

3. It is easier to maintain a constant BHP by adjusting the choke.

Disadvantages:

1. It requires longest waiting time prior to circulation
2. In a case where a significant amount of the hole is drilled prior to encountering the kick, the cutting could settle out and plug the annulus.
3. Gas migrations become a problem during waiting period for increasing the mud weight.

b) Driller's Method (Two Circulation Method):

In this method the influx is circulated out from the well after that the kill mud is circulated to control the well.

Advantages:

1. Simple to understand.
2. Minimum calculation.
3. In case of salt water kick ,sand settling around BHA is minimum

Disadvantages:

1. Higher annular pressure.
2. Higher casing shoe pressure in gas kick.
3. Minimum two circulations are required more time on choke operation.

2. Non-Conventional Methods:

These methods are used when the circulation of killing fluid cannot be conducted, mainly consists on bull heading and volumetric methods. The causes that make the circulation is prohibited that either the string is far away from the bottom of the well, this means even if the kill fluid is circulated it cannot return the situation to its original, i.e. primary well control, or the string is at bottom but some blockage is exist.

a) Volumetric Method:

The volumetric method is mostly used in work-over and production operations. In this method the string is usually far away from the bottom.

In order to stop the flowing of the well through the pipe string side; one way valve has to be installed. After that the string is run back to bottom while closing the

BOP, i.e. stripping and snubbing. When the string has been run back to bottom the kill operation is return to the conventional methods.

The reasons for using this method instead of another kill method are based on different variables in the well. Some of them are listed below (Oystein Rossland,2013):

- If the drill string is on its way in the well or out of it, if this is the case an attempt to run it to the bottom with the drill string should be made.
- If there are no drill string in the well.
- If the drill bit or the drill string has been plugged with some kind of debris or lost circulation material (LCM), to open the plugged area explosives can be an alternative.
- Hole collapse can be a reason – this prevents circulation

Advantages:

1. Allow gas migrate mean while expansion.
2. Control bottom hole pressure when no drill pipe in hole.
3. Control bottom hole pressure when pump failure.

Disadvantages:

1. Complicated.
2. Great low fracture pressure.
3. Wearer of ram while stripping.

b) Bull Heading Method:

This method can be achieved when the string is blockage or when it's far away from the bottom of the well, the concept is very easy; the influx will be forced to return to the formation by pumping kill fluid to the well and squeezing all well fluid to the opened formation.

Advantages:

1. Quickly control of blow out.
2. Control of gas expansion.
3. Low cost.

Disadvantages:

1. Positive skin factor

2. May break weak formation
3. May require stimulation

2.2.5 Stripping and Snubbing:

One of the most serious well control problems faced by a drilling representative is being off bottom or out of the hole with a kick in the wellbore. Unfortunately, statistics indicate that most kicks occur on trips, and, as previously stressed, kicks taken with the pipe off bottom (or out of the hole) create a serious complication to conventional well control techniques. When a kick occurs on a trip, or with pipe out of the hole, there are several options available to deal with the kick. Some of these options include:

- Kill the well-off bottom
- Use Volumetric Control if you have a gas kick in the well
- Strip the drill pipe back to bottom
- Strip using Volumetric Control if you have a gas kick in the well
- Snub the drill pipe back in the well

Stripping and snubbing are specialized operations used to trip tubular into or out of a pressurized wellbore through the blowout preventers. Normally, the objective of these operations is to return the pipe to bottom where the well can be conventionally circulated to remove the influx, however, in recent years, many completion/work-over programs have used snubbing techniques to work on wells without killing them.

a) Stripping:

Can be defined as tripping pipe through the blowout preventers when the drill string weight is greater than the net upward force created from wellbore pressures.

$$Stripping\ weight\ = \frac{\pi}{4} \times TJD^2 \times Annular\ pressure + 1000 \qquad (2.5)$$

Where:

T.J.D=Tool joint diameter

String weight=lightest weight string that will stripe without snubbing unit.

(1000lb) is added to compensate for frictional force between pipe and packer element

Stripping using the annular ram preventer:

It is common practice but it is limited to surface pressure of 1500psi and maximum length to be stripped as 1000ft, the following points should be kept in mind while stripping through annular preventer:

1. Drill pipe rubber should be removed.
2. The pressure regulating valve must being good condition.
3. Using closing pressure also was possible.
4. If drill string does not strip –in on its own weight, Additional down ward force will be needed to push the string in the well.

Procedures:

1) Adjust the pressure on the annular preventer until it weeps when the pipe is going in the hole
2) Run the pipe not as term than one foot per second and Maintain the annulus pressure constant with a choke as the pipe goes in the hole.
3) Every stand of pipe should displace mud.
4) If the pressure starts rising between stand sit means gas migration is taking place, use the volumetric correction.

Stripping using the ram blowout preventer:

Procedures:

1) Select the two rams to be used and measure the distance from the rotary table to the top of each one.
2) Reduce the closing pressure on the ram to 500psi, or less.
3) 3 -With the upper ram closed, lower pipe slowly, measuring it until the tool joint is two feet above the upper ram.
4) Stop lowering, close the lower pipe ram.
5) Bleed off the pressure between the ram sand open the upper ram.
6) Lower the pipe, measuring it until the tool joint is between the two rams.
7) Stop the lowering and close the top ram.
8) Pressurize up towel pressure between the rams with the test pump .Open the bottom ram.
9) Continue by going back to step (3).

While doing this, maintain the casing pressure constant by bleeding mud from the choke.

b) Snubbing:

Is defined as forcing pipe through the blowout preventers when the drill string weight is not sufficient to overcome the net upward force created by wellbore pressures.

Often a combination of stripping and snubbing techniques is used to get the drill string to the desired depth. To adequately understand stripping and snubbing, familiarity with the pressures and forces involved in these operations is a must.

Snubbing tools:

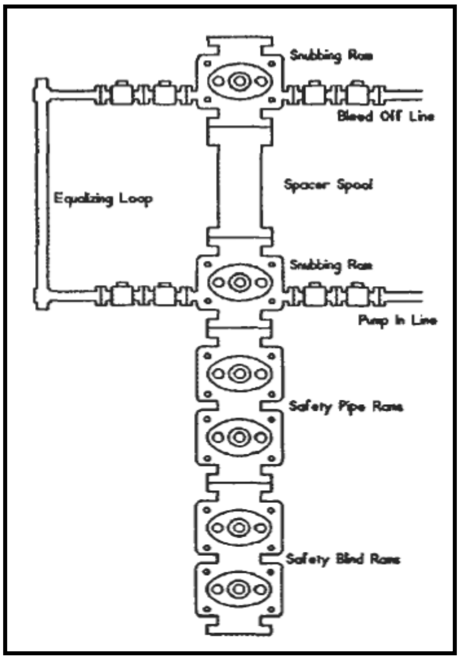
The Snubbing Stack:

There are many acceptable snubbing stack arrangements. The basic snubbing stack is illustrated in (FIG. (2.3) as illustrated, from bottom to top, blind safety rams, the pipe safety rams, the bottom snubbing ram, followed by a spacer spool and the upper snubbing ram.

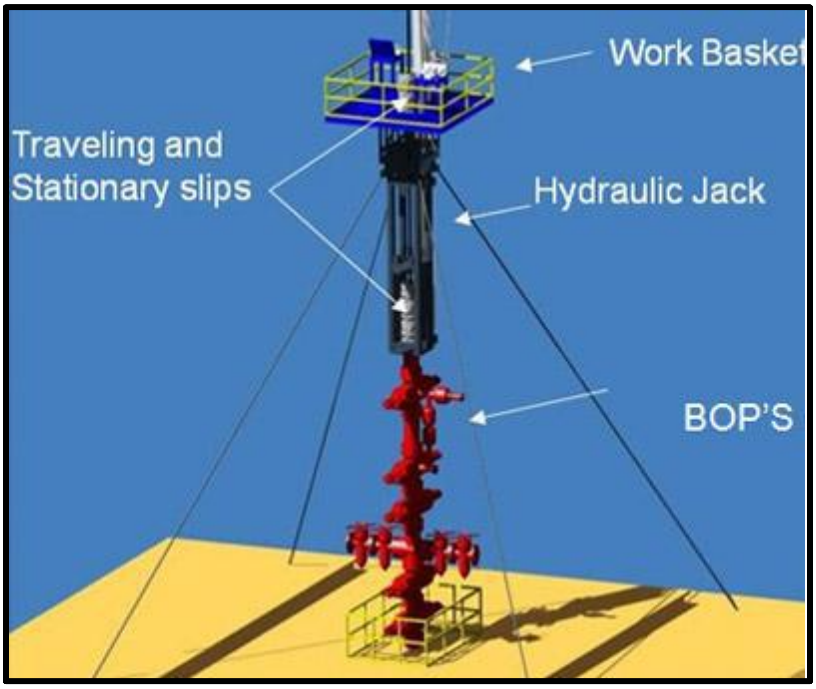
Since a ram preventer should not be operated with a pressure differential across the ram, an equalizing loop is required to equalize the pressure across the snubbing rams during the snubbing operation. The pipe safety ram are used only when the snubbing rams become worn and require changing.

When a snubbing ram begins to leak, the upper safety ram is closed and the pressure above the upper safety ram is released through the bleed-off line. The snubbing ram is then repaired. The pump in line can be used to equalize the pressure across the safety ram and the snubbing operation continued.

Since all rams hold pressure from below, an inverted ram must be included below the stack if the snubbing stack is to be tested to pressures greater than well pressure. The essential tools required to conduct the snubbing operations is one way valve and the snubbing unit.(Robert D.Garce, 1994)



3 (FIG.(2.3): Basic Snubbing Stack (Robert D.Garce, 1994))

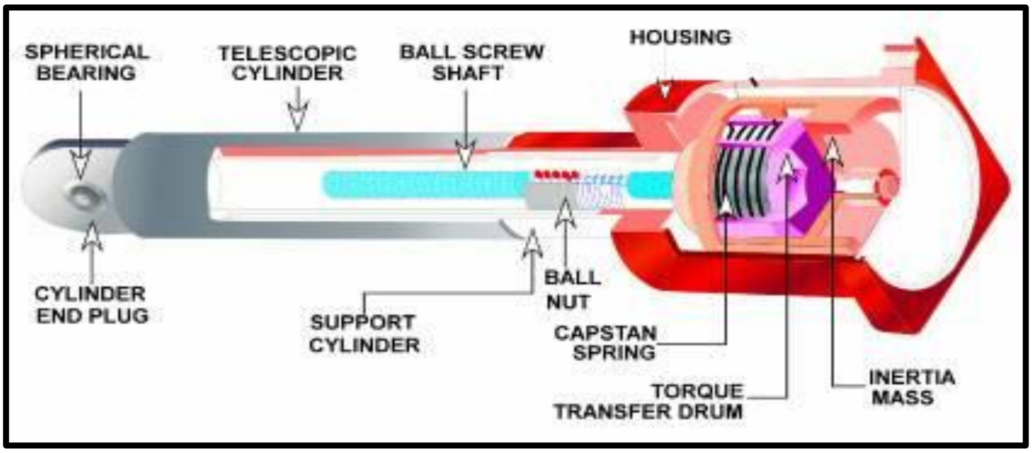


4 (Figure (2.4) snubbing unit.)

Types of snubbing unit:

<u>Mechanical Snubbers</u>

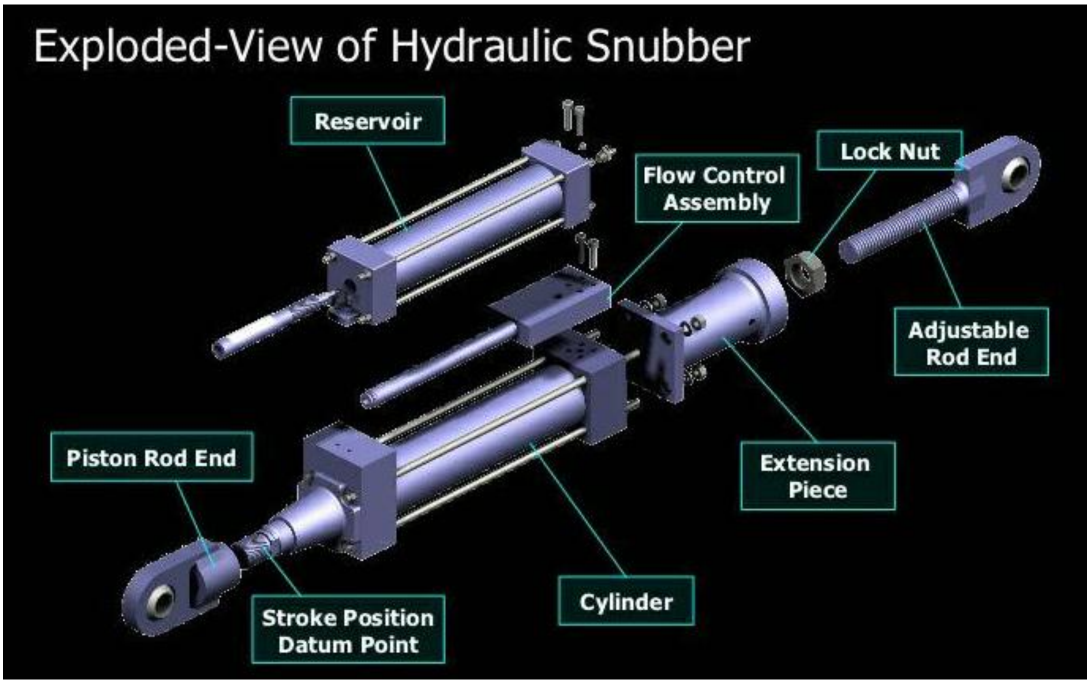
This type of equipment utilizes the rig system to force the pipe in to the hole



5(Fig (2.5) Mechanical Snubbers)

<u>Hydraulic Snubbers</u>

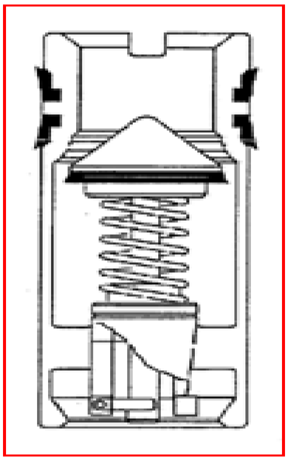
The pipe movement capabilities of the unitary supplied by hydraulic jack. Travelling snubber with slips is connected to a piston that' supplies the force to move pipe in the hole.



6 (Figure (2.6) Hydrant snubber)

<u>Non- return valve:</u>

One way valve component s are used to create a unidirectional flow in advice, they are in fact elastomeric sealing element that allow forward flow and prevent backflow There are different designs. If like low opening pressure and ease of assembly then the first choice would be a duckbill valve. If you need a certain cracking pressure or a low pressure drop at higher flows then an umber valve would be our recommendation.



(FIGURE 2.7) One way valve

2.2.6 Capacity Factors and Displacement:

In well control and in routine drilling operations, frequent calculations of capacity and displacement must be made. A brief review of the mechanics involved is provided below.

The Capacity Factor is defined as the volume of fluid held per foot of container. The container may be a mud pit, an open hole, the inside of a drill string, or an annulus. Capacity factors change as the dimensions of the container change. The internal capacity factor is used to calculate internal drill string volumes, and the annular capacity factor is used to calculate annular volumes. Formulas for calculating these capacity factors are given in equation (2.6)

$$CF = \frac{ID^2}{1029} \qquad (2.6)$$

Where,

CF = Capacity Factor (bbl. /ft.)

ID = Internal pipe diameter (inches)

In the Annular side Capacity Factor can be calculated using equation (2.7):

$$CF = \frac{{D_h}^2 - OD^2}{1029} \qquad (2.7)$$

Where,

D_h = Diameter of hole or inside diameter of larger pipe (inches)

OD= Outside diameter of smaller pipe (inches)

This equation can be used to determine internal and annular capacity factors for several wellbore configurations.

Capacity is the volume of fluid held within a specific container. Internal (drill string) and annular capacities are two of the most important parameters that are calculated in a well control situation.

Capacity is determined by multiplying the height (or length) of the container by its capacity factor.

Displacement is the volume of fluid displaced by placing a solid, such as drill pipe or tubing into a fixed volume of liquid such as drilling mud. Total displacement of drill pipe, casing, tubing, etc. can be determined by multiplying the length of pipe immersed times the displacement factor (bbl. /ft.).

The volume of mud in the hole is always equal to the capacity of the entire hole, minus the displacement of the pipe in the hole (assuming the pipe and annulus are full). The annular capacity between drill string components and the casing or hole can be calculated by subtracting both the capacity and displacement of the drill string component from the capacity of the hole.

Chapter Three

Methodology

3.1 Volumetric Method:

It is necessary to do some volume calculations that are related to the pressure increase in advance of using this method. Fracture pressure is the guide line, and the pressure calculations need to be based on this and one must not exceed it to avoid any losses (Oystein Rossland,2013).

3.1.2Volumetric Killing Procedure:

In this method the bottom hole pressure is maintained relatively constant and slightly in excess of the pore pressure whilst the gas is allowed to expand as it migrates up to the surface.

1) A constant bottom hole pressure is maintained by bleeding off mud, with an equivalent hydrostatic head, equal to the rise in pressure caused by migrating gas. For instance if the choke pressure rises by 100psi, a volume of mud equivalent to the hydrostatic pressure of 100psi is slowly bled off, maintaining constant casing pressure.

Pressure Increment = (safety factor) / 3…………………………………………… (3.1).

Mud Increment = (PI X ACF)/ (MW x 0.052)………….…………….…………. (3.2)

Where:

PI = Pressure Increment (psi).

ACF = Annulus Capacity Factor (bbl/ft).

MW = Mud Weight (ppg).

ROR = DSICP/(FD × 0.052 × T) ……………….………………….……………(3.3)

Where

ROR = Rate of Rise (ft/min)

DSICP = Change in Shut-in Casing Pressure

FD = Fluid Weight (ppg)

T = Time (min)

2) Bleed off in very small increments to allow the pressure to respond by using a manual adjustable choke and diverting the mud into the scaled trip tank.

3) Repeat this process until the influx has migrated up to the BOP.
4) When the gas is at the BOP stack, lubricate mud into the well. The lubrication
5) procedure will replace the influx with mud, as the gas is bleed off at the choke.
6) Pump mud into the casing until pump pressure reaches the predetermined limit and
7) stop the pump.
8) Leave the well shut-in for a time to allow gas to migrate through the lubricated mud.
9) Bleed gas from the well until the surface pressure is reduced by the exact amount equal to the hydrostatic pressure of the fluid volume lubricated into the well.
10) Route returns via the mud gas separator and monitor. If a significant quantity of mud is returned, bleeding should be stopped, and further time allowed for the gas to migrate through the lubricated mud.
11) It is unlikely that all the gas will rise to surface as a discrete bubble and it will be mixed through the mud, therefore, will take a considerable length of time to be completed.

3.1.3The operating steps of killing with volumetric control mode:

(1) Adjust the wellhead pressure, and the wellhead pressure is the reference value during the Killing process.

(2) Inject kill fluid Δ V, and record the injected time, the amount of injected kill fluid, the Injected pressure

(3) Observe and record the change of SIP.

(4) Air discharge after injected kill fluid drops to the bottom. Shut in well after the wellhead Pressure down to base pressure, record the time of air discharge, the mutative value of pressure During the air discharge process, the volume of discharged liquid.

(5) Repeat the above process, until Pa = 0

3.1.4Volumetric method calculations:

The basic concept to establish volumetric method calculation is to keep bottom hole pressure equal to the hydrostatic pressure and back pressure created by well control elements.

BHP = Hp + Sp ……………………………………..………………..……. (3.4)

Where:

BHP: bottom hole project.

Hp : Hydrostatic pressure

Sp : surface pressure.

P.choke : Pann + Ps + Pw …………………………………….….…………..(3.5)

Where:

Pann: Initial SICP

Ps: Built in safety margin prior to volumetric well control commencing.

Recommended safety margin according to operating company policy.

Pw: = Working margin for volumetric well control

Allow the casing pressure to increase to P.choke (psi),when casing pressure is at P.choke bleed off at choke a volume of mud equal to the working pressure margin.

Casing pressure must be kept constant at Pchoke during this operation. After working pressure margin of mud equivalent has been bled off at choke allow the gas to migrate unexpanded until a further pressure margin of overbalance is attained. Bleed off (working pressure margin Pw) equivalent mud at choke and repeat procedure until gas is at choke.

3.1.5.CALCULATIONS FOR MUD VOLUME TO BLEED FOR PW:

Volume to bleed around drill pipe:

Dp = Pw X Dp/OH Csg Cap /mud gradient………….….………..…….........(3.6)

Volume to bleed around drill collar:

Dc = Pw X Dp/Dcs Cap /mud gradient ……………..……..….………..…..…..(3.7)

ACF = (ID2- OD2)/1029 ……………………………………....……..…......(3.8)

Where:

ACF: annular capacity factor

ID : inside diameter.

OD : outside diameter

after Kick and volumetric

Pit volume = bleed volume + total volume in tank…………………………………...…(3.9)

Pf = SICP +(P hyd mud + P hyd gas)ann ……………………………………….(3.10)

BHP = SICP +Ph ……………………………………………………………..….(3.11)

P hyd mud : hydrostatic pressure of original mud in the annulus

P hyd gas : hydrostatic pressure of influx

3.2 Engineer's Method:

Many equations are used to accomplish kill operation.

$$P_f = P_h + SIDPP \tag{3.1}$$

$$\rho_K = \frac{P_f}{0.052 \times TVD} \tag{3.2}$$

$$ICP = SCR + SIDPP \tag{3.3}$$

$$FCP = ICP * \frac{\rho_K}{\rho_m} \tag{3.4}$$

Where;

SIDPP = shut in drill pipe pressure, psi.

ρ_K = Kill mud weight, ppg.

ICP = initial circulation pressure. Psi

SCR = slow circulation rate,

ρ_m = current mud, ppg.

FCP = final circulation pressure, psi.

2.2 Engineer's Method Stages:

Phase I (displacing drill string to kill mud)

As the kill mud is pumped at a constant rate down the drill string the choke is opened. The choke should be adjusted to keep the standpipe pressure decreasing according to the pressure vs. time plot discussed above. In fact the pressure is reduced in steps by maintaining the standpipe pressure constant for a period of time and opening the choke to allow the pressure to drop in regular increments. Once the heavy mud completely fills the drill string the standpipe pressure should become equal to P_{C_2}.

The pressure on the annulus usually increases during phase I due to the reduction in hydrostatic pressure caused by gas expansion in the annulus.

Phase II (pumping heavy mud into the annulus until influx reaches the choke)

During this stage of the operation the choke is adjusted to keep the standpipe pressure constant (i.e. standpipe pressure = P_{c2}). The annulus pressure will vary more significantly than in phase I due to two effects:

a) The increased in hydrostatic pressure due to the heavy mud entering the annulus will tend to reduce Pann.

b) If the influx is gas, the expansion of the gas will tend to increase P_{ann} since some of the annular column of mud is being replaced by gas, leading to a decrease in hydrostatic pressure in the annulus.

Phase III (all the influx removed from the annulus)

As the influx is allowed to escape, the hydrostatic pressure in the annulus will increase due to more heavy mud being pumped through the bit to replace the influx. Therefore, P_{ann} will reduce significantly.

If the influx is gas this reduction may be very severe and cause vibrations which may damage the surface equipment (choke lines and choke manifold should be well secured). As in phase II the standpipe pressure should remain constant

Phase IV: (stage between all the influx being expelled and heavy mud reaching Surface)

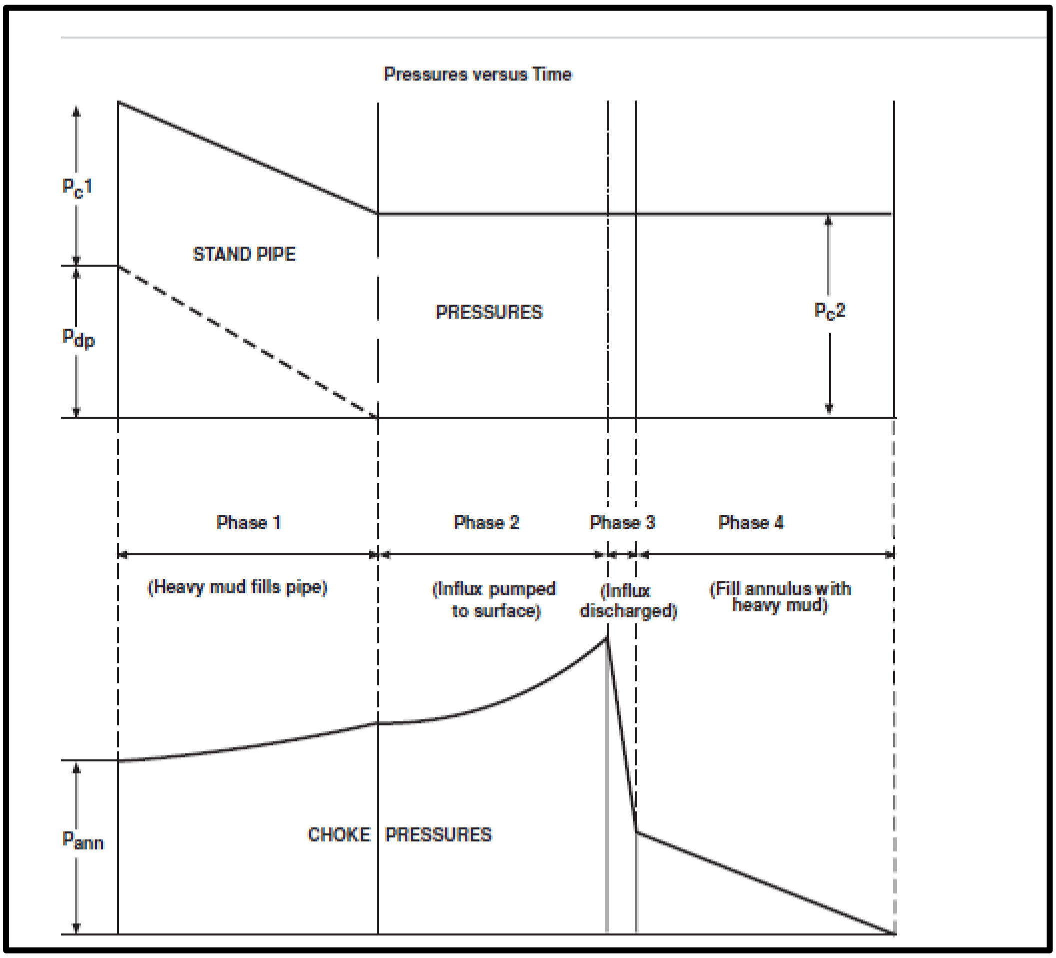
During this phase all the original mud is circulated out of the annulus and is the annulus is completely full of heavy mud.

If the mud weight has been calculated correctly, the annulus pressure will be equal to 0 (zero), and the choke should be fully open.

The standpipe pressure should be equal to P_{c2}.

To check that the well is finally dead the pumps can be stopped and the choke closed. The pressures on the drill pipe and the annulus should be 0 (zero). If the pressures are not zero continue circulating the heavy weight mud. When the well is dead, open the annular preventer, circulate, and condition the mud prior to resuming normal operations.

For all killing methods there are some parameters should be estimated;



8 (Figure (3.1): Summary of standpipe and annulus pressure during the "one circulation" method (Drilling engineering 2001))

Chapter Four

Results and Discussion

XX well is a producer well; the decision has been made to repair the faulty pump. The procedure is to make a wiper trip using 7” casing scraper to depth 2000 meter, the run in hole was perfect. But at the pull out of the hole the driller forget to fill the hole, before finish the pull out the well start flowing, the well had been secured and following observation are recorded.

- Formation depth = 1800 m
- Casing pressure =700 psi
- Oil gravity = 36° API
- String bottom at = 300 m
- Average length stand = 18.98 m
- Annulus capacity = 0.0131703 m^3/m
- Tubing capacity =0.00454 m^3/m
- Close and displacement = 0.062071 m^3/m
- Working pressure for weakest component of well head 3000 psi.

To ensure safe operational data we have calculate the following parameter to be followed up completely.

4.1 The Volume of Fluid to be bled per Stand:

One of the most important parameter while stripe back to bottom is the volume that must be bled per stand, can be calculated from;

Vol. per stand = stand length * closed end displacement

$$=18.98 * 0.062071 = 1.17\ m^3, or\ 7.34\ bbl$$

The capacity of the closed end displacement is used because when the one way valve is installed to the string; no fluid will pass into the pipe string. This volume must be bled among stripe one stand, if more volume bled the bottom hole pressure will decrease allowing to more influx, if less this means the surface pressure will be more than planed and more than well head rated pressure and farther more the pressure exerted to the formation will be more. The crew should be alerted to circulate at this point exactly as shown in the chart below.

1 (Table 4.1) Volumetric Kill Sheet

	VOLUMETRIC CONTROL WORKSHEET						
ell:X	Rig:	date&time:		sheet no:			
mud weight in hole							
hydrostatic pressure per barrel of …0.845…..SG mud in 3 1/2" X 8 1/2" annulus ……..psi/bbl							
hydrostatic pressure per barrel of ……. SG mud in 3 1/2.. X ..8 1/2… annulus……………psi/ft							
hydrostatic pressure per barrel of ………mud in ……….. X ………… hole							
hydrostatic pressure per barrel of ………mud in ……….. X ………… hole …………………..psi/ft							
overbalance margin	200	operating margin		200 Psi			
Number Of stands	Operations	chocke monitor pressure(psi)	change in monitor pressure(psi)	hydrostatic of mud bled/lubricate(psi)	overbalance (psi)	volume of mud lubricated (bbl)	total volume of mud (bbl)
16	well shutt in	700	0	0	0	0	0
	influx migration	750	50	0	200	0	0
	influx migration	800	50	0	250	0	0
17	bleed mud at chock	800	0	-50	200	7.4	7.4
	influx migration	850	50	0	250	0	7.4
18	bleed mud at chock	850	0	-50	200	7.4	14.8
	influx migration	900	50	0	250	0	14.8
19	bleed mud at chock	900	0	-50	200	7.4	22.2
	influx migration	950	50	0	250	0	22.2
20	bleed mud at chock	950	0	-50	200	7.4	29.6
	influx migration	1000	50	0	250	0	29.6
21	bleed mud at chock	1000	0	-50	200	7.4	37
	influx migration	1050	50	0	250	0	37
22	bleed mud at chock	1050	0	-50	200	7.4	44.4

	influx migration	1100	50	0	250	0	44.4
23	bleed mud at chock	1100	0	-50	200	7.4	51.8
	influx migration	1150	50	0	250	0	51.8
24	bleed mud at chock	1150	0	-50	200	7.4	59.2
	influx migration	1200	50	0	250	0	59.2
25	bleed mud at chock	1200	0	-50	200	7.4	66.6
	influx migration	1250	50	0	250	0	66.6
26	bleed mud at chock	1250	0	-50	200	7.4	74
	influx migration	1300	50	0	250	0	74
27	bleed mud at chock	1300	0	-50	200	7.4	81.4
	influx migration	1350	50	0	250	0	81.4
28	bleed mud at chock	1350	0	-50	200	7.4	88.8
	influx migration	1400	50	0	250	0	88.8
29	bleed mud at chock	1400	0	-50	200	7.4	96.2
	influx migration	1450	50	0	250	0	96.2
30	bleed mud at chock	1450	0	-50	200	7.4	103.6
	influx migration	1500	50	0	250	0	103.6
31	bleed mud at chock	1500	0	-50	200	7.4	111
	influx migration	1550	50	0	250	0	111
32	bleed mud at chock	1550	0	-50	200	7.4	118.4
	influx migration	1600	50	0	250	0	118.4
33	bleed mud at chock	1600	0	-50	200	7.4	125.8
	influx migration	1650	50	0	250	0	125.8
34	bleed mud at chock	1650	0	-50	200	7.4	133.2
	influx migration	1700	50	0	250	0	133.2
35	bleed mud at chock	1700	0	-50	200	7.4	140.6
	influx migration	1750	50	0	250	0	140.6
36	bleed mud at chock	1750	0	-50	200	7.4	148

	influx migration	1800	50	0	250	0	148
37	bleed mud at chock	1800	0	-50	200	7.4	155.4
	influx migration	1850	50	0	250	0	155.4
38	bleed mud at chock	1850	0	-50	200	7.4	162.8
	influx migration	1900	50	0	300	0	162.8
39	bleed mud at chock	1900	50	-50	350	7.4	170.2
	influx migration	1950	0	0	250	0	170.2
40	bleed mud at chock	1950	50	-50	300	7.4	177.6
	influx migration	2000	50	0	300	0	177.6
41	bleed mud at chock	2000	0	-50	300	7.4	185
	influx migration	2050	50	0	300	0	185
42	bleed mud at chock	2050	0	-50	200	7.4	192.4
	influx migration	2100	50	0	250	0	192.4
43	bleed mud at chock	2100	0	-50	200	7.4	199.8
	influx migration	2150	50	0	250	0	199.8
44	bleed mud at chock	2150	0	0	200	7.4	207.2
	influx migration	2200	50	0	250	0	207.2
45	bleed mud at chock	2200	0	-50	200	7.4	214.6
	influx migration	2250	50	0	250	0	214.6
46	bleed mud at chock	2250	0	-50	200	7.4	222
	influx migration	2300	50	0	250	0	222
47	bleed mud at chock	2300	0	-50	200	7.4	229.4
	influx migration	2350	50	0	250	0	229.4
48	bleed mud at chock	2350	0	-50	200	7.4	236.8
	influx migration	2400	50	0	250	0	236.8
49	bleed mud at chock	2400	0	0	200	7.4	244.2
	influx migration	2450	50	0	250	0	244.2
50	bleed mud at chock	2450	0	-50	200	7.4	251.6

	influx migration	2500	50	0	250	0	251.6
51	bleed mud at chock	2500	0	-50	200	7.4	259
	influx migration	2550	50	0	250	0	259
52	bleed mud at chock	2550	0	-50	200	7.4	266.4
	influx migration	2600	50	0	250	0	266.4
53	bleed mud at chock	2600	0	-50	200	7.4	273.8
	influx migration	2650	50	0	250	0	273.8
54	bleed mud at chock	2650	0	-50	200	7.4	281.2
	influx migration	2700	50	0	250	0	281.2
55	bleed mud at chock	2700	0	-50	200	7.4	288.6
	influx migration	2750	50	0	250	0	288.6
56	bleed mud at chock	2750	0	-50	200	7.4	296
	influx migration	2800	50	0	250	0	296
57	bleed mud at chock	2800	0	-50	200	7.4	303.4
	influx migration	2850	50	0	250	0	303.4
58	bleed mud at chock	2850	0	0	200	7.4	310.8
	influx migration	2900	50	0	250	0	310.8
59	bleed mud at chock	2900	0	-50	200	7.4	318.2
	influx migration	2950	50	0	250	0	318.2
60	bleed mud at chock	2950	0	-50	200	7.4	325.6
	influx migration	3000	50	0	250	0	325.6
61	bleed mud at chock	3000	0	-50	200	7.4	333
	stop stripping	3050	50	0	250	0	333
62		3050	0	-50	200	7.4	340.4

mud in tank before stripping = bbl.

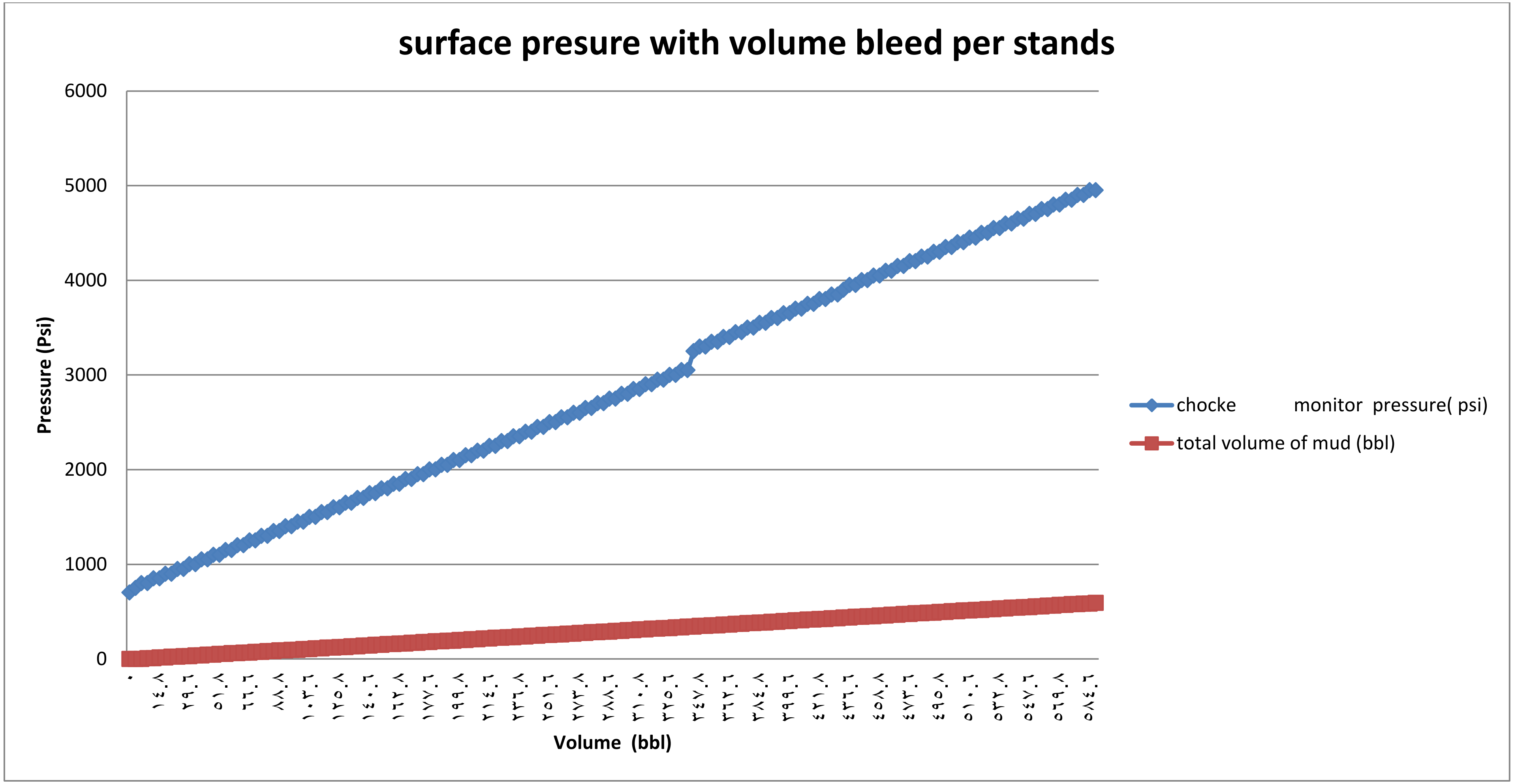
Bottom hole Pressure = Hydrostatic Pressure + Surface Pressure

Pa = 700 psi

Ps = 100 +50 = 150
psi
P f =(TVD X0.052 X Mw) + SICP
Choke = Pann + Ps + Pw ,700+50 +50 =800psi
Shoe Fracture Pressure = (TVD shoe x Shoe Test x 0.052)

PI = Sf /3

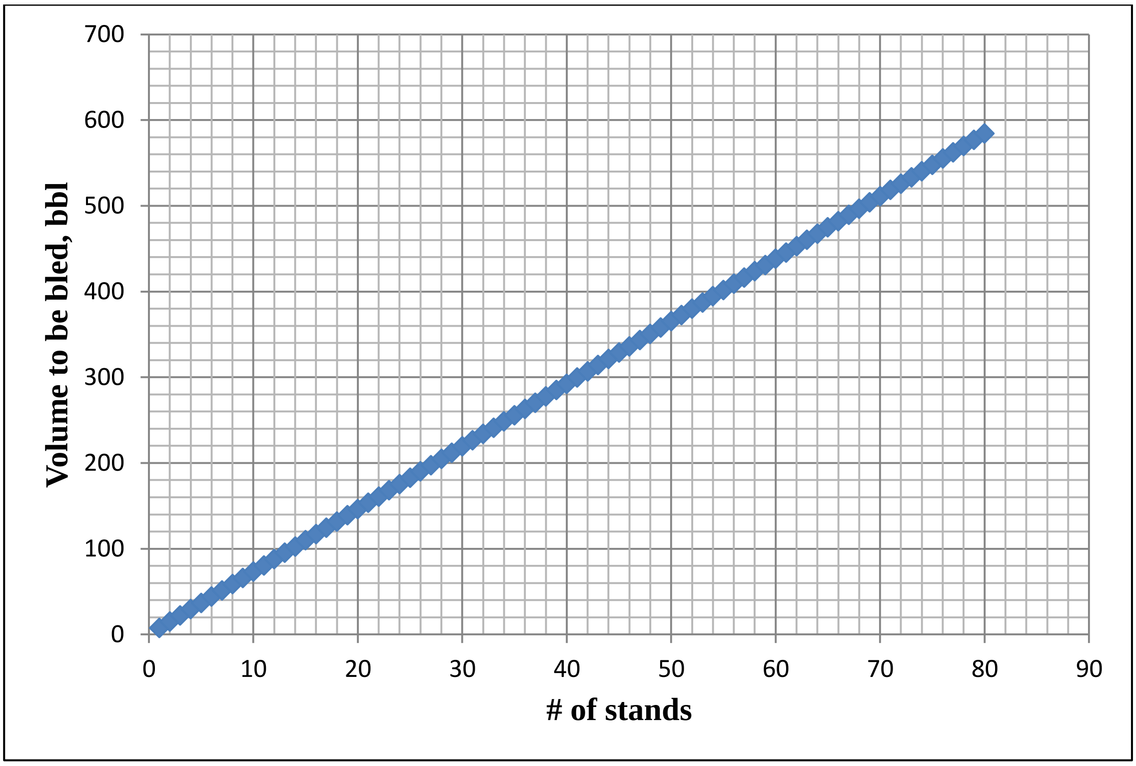
mud increment = (PI* Ann Cap Factor)/(Mw*0.052)

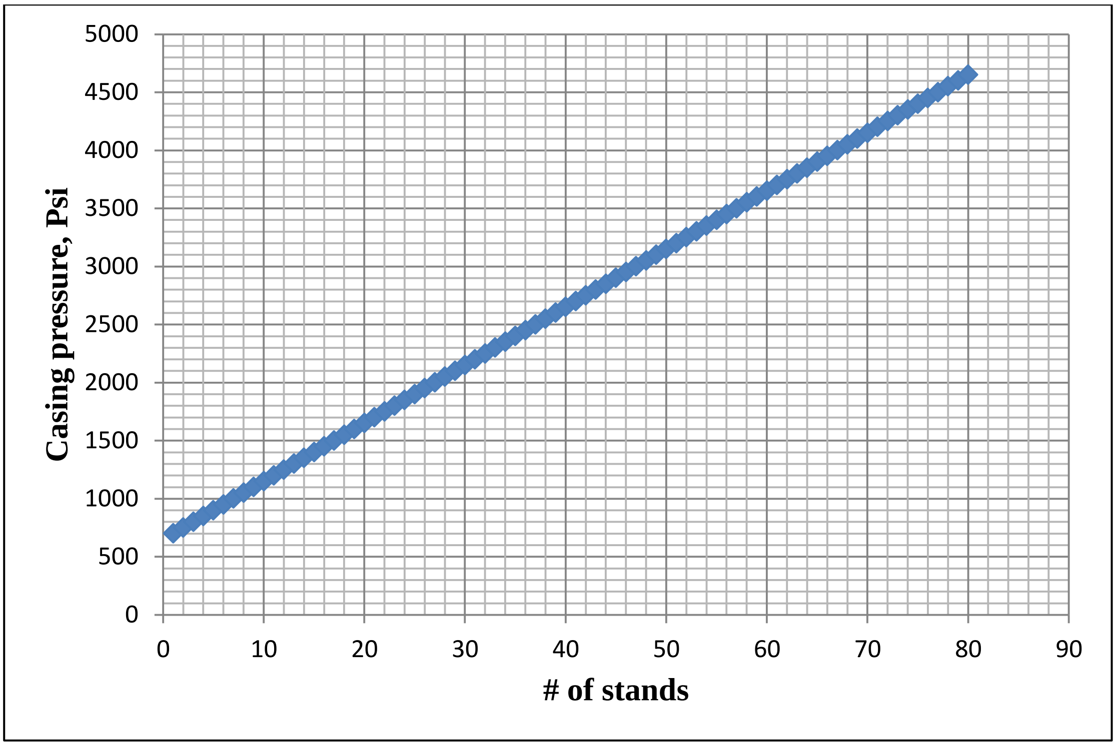


(Fig4.1) surface pressure vs volume bleed per stands

The total stands that must be stripped back to bottom is $(1800 - 300) / 18.98$ which is equal to 80 stands (approximate to nearest bigger number), the number of stands can be plotted against the volume has to be bled, and versus the anticipated casing pressure, this will give a very important clue for the supervisors that the workers did a bad or an excellent practice. Table (1) show pressure increase influx migration up to the surface choke.

Figures (1.) and (2.) show the volume to be bled and the casing surface pressure while the stripe back to bottom process.





[10](Fig (4.2.) Casing pressure vs. number of stands..)

It is clear as the number of stands being increased as the bled volume increase in same manner the casing pressure. The maximum casing pressure is 4650 psi, as the working pressure of the weakest component of well head is less than 4650 psi, i.e. 3000 psi. This will make another challenge to mitigate the risk of failure of the well head while stripping operation as shown in chart ( ), thus the maximum number of stands to be stripped back to bottom safely without making any failure to the well head component is 46 stands. After that there must be a break circulation utilizing the kill fluid to ensure that the surface pressure is less than working pressure of the weakest component of well head.

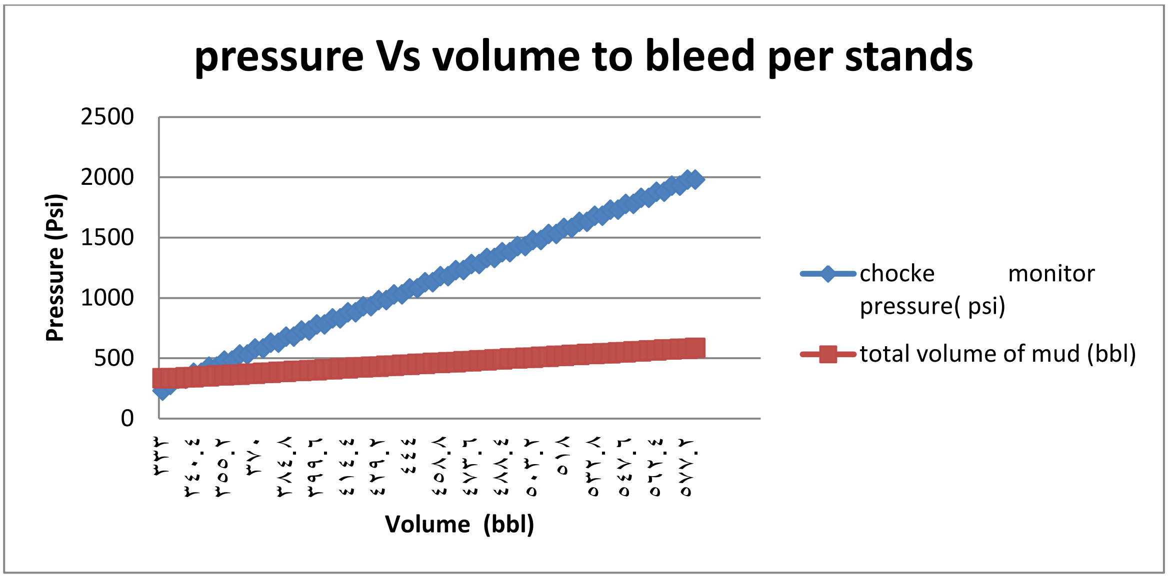
To make this formation pressure and kill fluid density have to be calculated;

Formation pressure $= P_h + P_{csg} = 0.052 * 1800 * 3.28 * 7.037 + 700 = 2861\ psi$

Kill mud weight $= \frac{P_f}{0.052*TVD} = \frac{2861}{0.052*1800*3.28} = 9.4\ ppg$

The New casing pressure will be equal to the formation pressure minus the hydrostatic pressure of kill fluid plus the original fluid (Oil),

$$New\ CSG\ pressure = P_f - 0.052 * \left((300 + 46 * 18.98) * 3.28 * 9.4 + (1800 - 300 - 46 * 18.98) * 3.28 * 7.037\right) = 228\ psi$$



11 (Fig 4.3) pressure Vs volume to bleed per stands

At this stage the strip operation can be safely resumed

1. Total volume to be bled:

This parameter is just for supervision point of view, as the string has been stripped back to bottom a certain volume must be bled, usually the measuring in the trip tank, it can be re-zero or evacuated.

Total volume = (formation depth – bottom of string)* closed end displacement

$$= (1800 - 300) * 0.062071 = 93.11\ m^3 = 585\ bbl$$

As well as the volume to be bled per stand, the total volume to be bled must be as planed if more means another influx enters the well, if less volume has been bled the well is pressurized by the non-bleed volume.

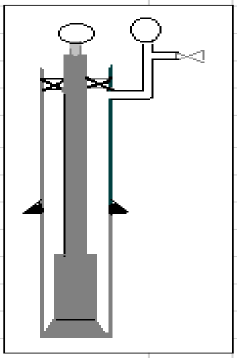
After the string is stripped back to bottom successfully, the circulation can be established therefore a conventional method can be used, we have chosen the engineer method, because of the time that taken to stripe back to bottom can be utilized to mix a kill fluid, moreover the casing pressure, if the operation proceed smoothly, will be the same. Hence the casing and drill pipe pressures are equal, the following parameter are easy to calculate.

For the schedule of pressures the kill sheet is utilized to calculate volumes and pressure charts.

Surface BOP (Vertical Well) Kill Sheet - API Units

Date : 17-Oct

Formation Strength Data :-				**Current Well Data:**			
Surface Leak-off Presure:-	(A)		psi	Mud Data:			
Mud Weight:-	(B)		ppg	Weight	7.037	ppg	
Maximum Allowable Mud Weight:-				Gradient		psi/ft	
(B) + (A) / shoe True Vertical Depth *0.052 =	(C)	0	ppg	**Casing Shoe Data:**			
Initial MAASP =				Size	7	inch	
[(C) - Current Mud Weight] x Shoe TVD x 0.052 =			psi	M.D	5609	ft	
Pump No. 1 Displacement	Pump No. 2 Displacement			T.V.D	5906	ft	
0.109 bbls/stroke	bbls/stroke						



Slow Pump Rate Data :		**Dynamic Pressure Loss (PL)**				Hole Data :-		
		Pump NO.1				Size		inch
40	spm	450	psi		psi	M.D	5906	ft
	spm		psi		psi	T.V.D	5906	ft

Pre-Volume Data:	Length ft.		Capacity bbls/ft		Volume bbls		Pump strokes		Time minutes	
Drill pipe	5906	x	0.0087	=	51.38					
Heavy Wall Drill pipe	0	x	0	=	0.00		Volume / Pump Displacement		Pump Strokes / Slow Pump Rate	
Drill Collars	0	x	0	=	0.00					
Drill String Volume				(D)	53.38	bbl	(E) 490	stks	12.2	min
DC x Open Hole	0	x	0	=	0.00					
DP / HWDP x Open Hole	5906	x	0.0252	=	148.83					
Open Hole Volume				(F)	148.83	bbl	1365	stks	34.1	min
DP x Casing	5609	x	0.083	=(G)	465.55	bbl	4271	stks	106.8	min
Total Annuulus Volume			(F+G) = (H)		614.38	bbl	5636	stks	140.9	min
Total Well System Volume			(D+H) = (I)		667.76	bbl	6126	stks	153.2	min
Active Surface Volume			(J)		7.00	bbl		stks		
Total Active Fluid System			(I+J)			bbl		stks		

Kick Data							
SIDPP	550	psi	SICP	700	psi	Pit Gain	20 bbls

Kill Mud Weight KMW	Current Mud Weight + SIDPP / TVD x 0.052	**Pf/(0.052 xTVD)**	9.4	ppg
Kill Mud Gradient KMG	Current Mud Gradient + SIDPP / TVD		0.4888	psi/ft
Initial Circulating pressure ICP	Dynamic Pressure Loss + SIDPP		1000	psi
Final Circulating pressure FCP	Kill Mud Weight / Current Mud Weight x Dynamic Pressure Loss		601	psi

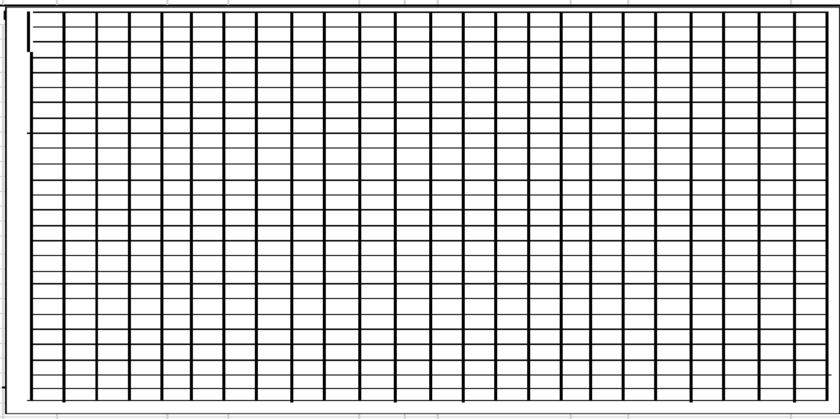
(K) = ICP - FCP	399	psi	(K) x 100 / (E) =	81	psi/100 strokes

Static

Strokes	Pressure
0	1000
100	919
200	837
300	756
400	674
490	601

ICP

FCP



Strokes →

closed end displacement = length of tubular(ft) stripped x closed end capacity(bbl) /ann cap =(5906 -3799) x 0.119= 251

influx hight = displacement/ ann cap =251/0.0252 =9934 ft(this mean all the kill fluid displaced by influx) and the well back to its original condition(density = 7.037 , SICP = 700 psi , Pf = 2862 psi)

Ph = .052 x5906x7.037 = 2161 psi

Pf = Ph+ Ps = 2161 + 700 = 2862

KMw = 2862/(0.052 x5906) =9.4 ppg

ICP =Pf - Ph =2862 - 2161 = 701 psi

Chapter five

Conclusion and Recommendations

5.1Conclusion

- From the data collected, shown the well X has started to flow during pulling out of the hole.
- Using volumetric method to control the well and strip tubing to the bottom.
- Surface pressure increases and may cause blow out due to exceeding of the wellhead rated pressure, this problem solved by stop striping and using conventional well control (wait and weight).
- Surface pressure control by increasing hydrostatic head and back to normal stripping.
- Strip back completely to the bottom and circulate using a kill mud weight until the well-controlled and operation back to normal.

5.2 Recommendations:

- From the previous well X study we find that the most important issues is to used volumetric control method as the first choice when conventional method can't be applied to control formation fluids flow, than to used bull heading method because bull heading will cause positive skin factor and may require stimulation which will increase over all well cost and reduce well productivity.
- For most of Sudanese oil field to use the volumetric method, its more safe, cheaper and simple.
- It's recommended because it can accurately monitoring through bleeded volume in the scaled tank.
- Any time after commence stripping operation can change to circulation method to avoid pressure limitation for the surface equipment and casing burst pressure.

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