WELL BLOWOUT: CONDITION MONITORING AND REMEDIAL ACTIONS

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CERTIFICATE

This is to certify that the project report on **"Well Blowout: Condition Monitorig & Remedial Actions"** submitted to UPES, Dehradun by Mr. Aditya Singh & Mr. Manav Thapa in partial fulfillment of the requirements for the degree of Applied Petroleum Engineering in the academic session (2003-2007) has been carried out by them under my supervision & guidance. ~~This work has not been submitted anywhere else for any other degree or diploma.~~

8/5/07

Date: 9/ /

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ABSTRACT

The formations penetrated while drilling into the earth contain fluid under pressure. The borehole being drilled provides a conduit for these fluids stored at great depths and pressures to flow to the surface, posing risk to people, the environment, and equipment. Well control is the continuous process of maintaining formation fluids in check within the earth, and when flowed, done so in a controlled manner. Well control means controlling the flow of formation fluids into a wellbore. Usually this means to prevent the flow of formation fluids during well testing and completions, controlled flow of fluids into the well bore is necessary.

Primary well control is provided by the hydrostatic pressure of the drilling, completion, or workover fluid. During drilling operations, primary well control is practiced between two distinct limits; these being the maximum formation pore pressure gradient and the minimum fracture pressure gradient for each hole section.

The term "secondary" well control is sometimes used to describe those times that control of the well is provided by blowout prevention equipment. Usually this also means that primary control of the well has been lost and well control operations are under way to regain primary control.

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WELL BLOWOUT: CONDITION MONITORING AND REMEDIAL ACTIONS

1. An Introduction

The hydrostatic pressure of the drilling, completion or workover fluid provides primary well control. During drilling operations, primary well control is practiced between two distinct limits; these being the maximum formation pore pressure gradient and the minimum fracture pressure gradient for each hole section. In normal drilling operations, the primary well control is the hydrostatic pressure exerted by the drilling fluid in the well; this pressure can be adjusted to the specific conditions by a variation in the fluid density. Proper well planning requires the hydrostatic head of the drilling fluid to overbalance the formation pressure by a certain safety margin.

The term 'Secondary' well control is used those times that well control is provided by blowout prevention equipment. It also means that primary control of the well has been lost and well control operations are under way to regain primary control. In case of primary control loss resulting from a sudden increase of formation pressure or lost circulation, it becomes necessary to seal off the well by some other means to prevent an uncontrollable flow, or blowout, of formation fluids. The equipment that performs this secondary control function is the blowout preventer (BOP).

BOP's are mounted directly to the wellhead in combinations called the BOP stack. Such a stack will normally contain several of the two basic BOP types: ram and annular. In special situations, a third BOP type-the rotating BOP–can also be used in combination with rams and annular.

2. PRIMARY WELL CONTROL

The hydrostatic pressure of the drilling, completion or workover fluid provides primary well control. During drilling operations, primary well control is practiced between two distinct limits; these being the maximum formation pore pressure gradient and the minimum fracture pressure gradient for each hole section.

2.1 Hydrostatic Pressure

A fluid at rest exerts hydrostatic pressure within the fluid column. It depends upon (1) fluid density; (2) vertical depth of any point of interest.

Oilfield drilling units

$P_h = \rho \times h \times g$

Where,

P_h=hydrostatic pressure
g = gravitational constant
ρ = Fluid density
h= vertical height of fluid column

$P_h = .052 \times MW \times D_{tvd}$

Where,

P_h=hydrostatic pressure (psi)
.052= gravitational constant
MW=mud weight (ppg)
D_{tvd}=true vertical depth (ft)

2.2 Equivalent Mud Weight

Mud weight is used during drilling to ensure that the hydrostatic pressure of the mud column is sufficient to control the formation fluids under pressure within the earth.

Equivalent Mud Weight (**EMW**) = $P_h / (.052 \times D_{tvd})$ **ppg**

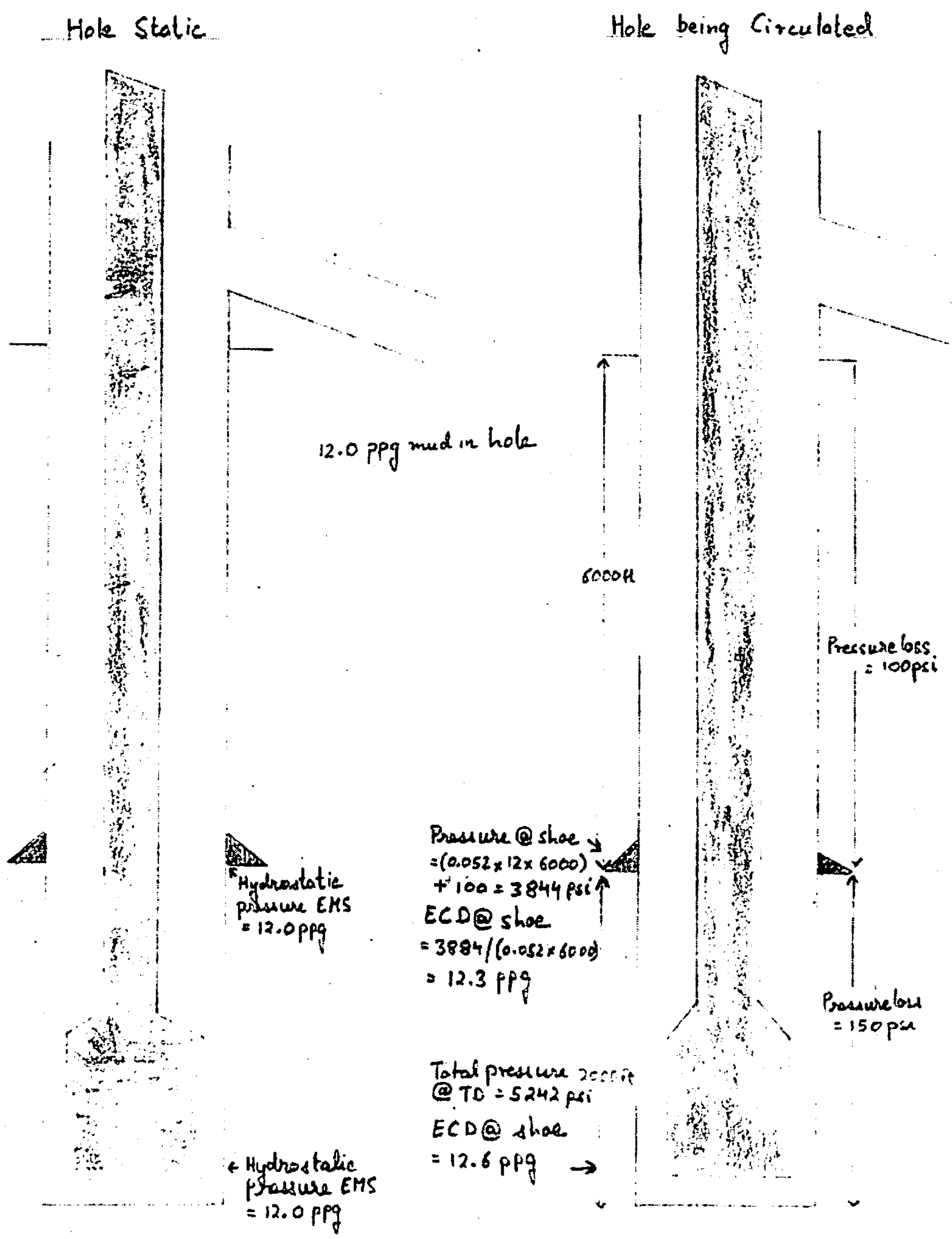
2.3 Circulating Pressure and ECD

The EMW increases due to the frictional pressure resulting from the flow of mud up the annulus. This frictional pressure includes the drill string loss, the loss through the mud motor or bit jets, or other downhole tools, and the annular friction loss. At each point in the well the EMW is increased by a factor reflecting the total frictional pressure above that point. The EMW for the case of annular frictional pressure is known as **equivalent circulating density** or **ECD**

ECD is affected by:

- Length of the drill string
- Mud weight
- Rheology of the drilling mud
- Hydraulic diameter of the components of the circulating system
- Circulating rate

#1



Calculation of Equivalent Circulating Density (ECD)

$$\textbf{ECD (ppg)} = \frac{\text{Annular Pressure Loss (psi)}}{0.052 \times \text{TVD (ft)}} + \text{Mud Density (ppg)}$$

2.4 Surge and Swab Pressures

Surge pressure is the friction pressure loss associated with running pipe into the well and is applied on the formation. **Swab** pressure is the friction pressure loss associated with pulling pipe from the well and is a pressure reduction on the wellbore.

Swab pressure is calculated from the yield point of the mud and, when converted to an EMW term, is usually maintained in the mud weight value to serve as a 'trip margin' safety factor which represents a hydrostatic overbalance and allows for well control during trips.

2.5 Loss of Circulation

Loss of circulation can be caused by:

a) Setting casing too shallow and not gaining sufficient fracture strength for the well to tolerate planned mud weights for that interval.
b) Drilling with excessive overbalance
c) Drilling too fast and the resulting cuttings load the annulus sufficient to cause formation failure.
d) Excessive swab/surge pressures when tripping pipe.
e) Hole packing off due to cuttings build-up or balled-up drilling assemblies.

2.5.1 Curing Loss of Circulation

Loss of circulation can be cured by sealing the lost zone with a plug. **LCM** (loss of circulation material) is pumped after measuring the pump displacement and pipe capacities. The plugs contain cement and therefore it is required that the cement's setting up time should be known. The plug can be placed by various techniques:

a) **Conventional circulation**: Place the plug through open-ended pipe if possible opposite the loss zone. Pump at 1 bbl/min until the losses cease.

b) **Balanced plug**: The basic requirement for balanced plug is that the correct volume of spacer is pumped behind the slurry, to ensure that the hydrostatic pressure in the annulus is balanced with that in the pipe before the pipe is pulled out of the plug.

c) **Non-balanced plug**: If the loss zone is well known, the pipe can be placed approximately 150 ft above it and the slurry displaced to the end of the pipe and the BOP closed. For a downhole mixed plug, pump simultaneously down drillpipe and annulus at 2 bbl/min. For a spotted plug, pump the slurry out of the pipe, and then pump down the annulus only.

2.6 Abnormal Pressure Evaluation

Changes in drilling parameters allow for the detection and estimation of pore pressure values for transition zones.

2.6.1 Drilling Parameters

a. Rate of penetration

As depth increases in normal pore pressure, the penetration rate reduction and increased drilling forces such as WOB, rotary speed and hydraulic bit horsepower represents a clear trend. Changes in these trends allow for the detection of abnormal pore pressure. "Cap rock" can offer very difficult drilling and this in itself is an indication of potential pending overpressure.

b. Corrected d-exponent

The d-exponent is a measurement of the drillability of formation. The original d-exponent neglected the effect of mud weight on ROP and the original d-exponent equation was modified and called the corrected d-exponent or d_c.

$$d = \frac{ROP/60N}{12WOB/10^6B}$$

Where:
d = drillability exponent
ROP = rate of penetration
N= rotary speed
B = bit diameter
WOB=weight on bit

$$d_c = d \times \frac{P_n}{ECD}$$

Where:
P_n = normal formation pore pressure (ppg)
ECD = equivalent circulating density (ppg)

c. Torque and Drag

As the bit enters further into a transition zone, the hydrostatic overbalance becomes less. This causes excess caving from the wellbore and the result in more solids interfering with the bit and the BHA progress. This may result in increased torque and drag. Normal drag from the new hole (vertical hole) usually is on the order of the magnitude of 10000 to 20000 lbs, depending on the hole and BHA geometries. Consistent drag values higher than this may indicate abnormal pressure.

2.6.2 Mud and Mud Logging Parameters

2.6.2.1 Drilling gas

As the well is drilled, formation gas is released into the wellbore and carried to the surface along with the drilling fluids. Gas extraction and detection/ measuring devices, normally installed and maintained by the mud logging company, display the magnitude of the gas as "units".

a. Background gas

Background gas describes the residual gas units measured during routine drilling operations. Shale has very little porosity or ability to hold as much gas as a more porous formation, such as a sand. Therefore, changes in lithology usually results in changes in the magnitude of background gas being displayed at the surface.

b. Connection gas

Whenever the pumps are stopped to allow for a connection, bottomhole pressure is reduced by the ECD. This allows for a small quantity of gas to enter the wellbore. It is indicated by pumping to the surface and display as an increase in gas units appropriate to the bottom-up time. Swabbing can also influence connections gas peaks, as the pipe is raised for a connection.

2.6.3 Chlorides

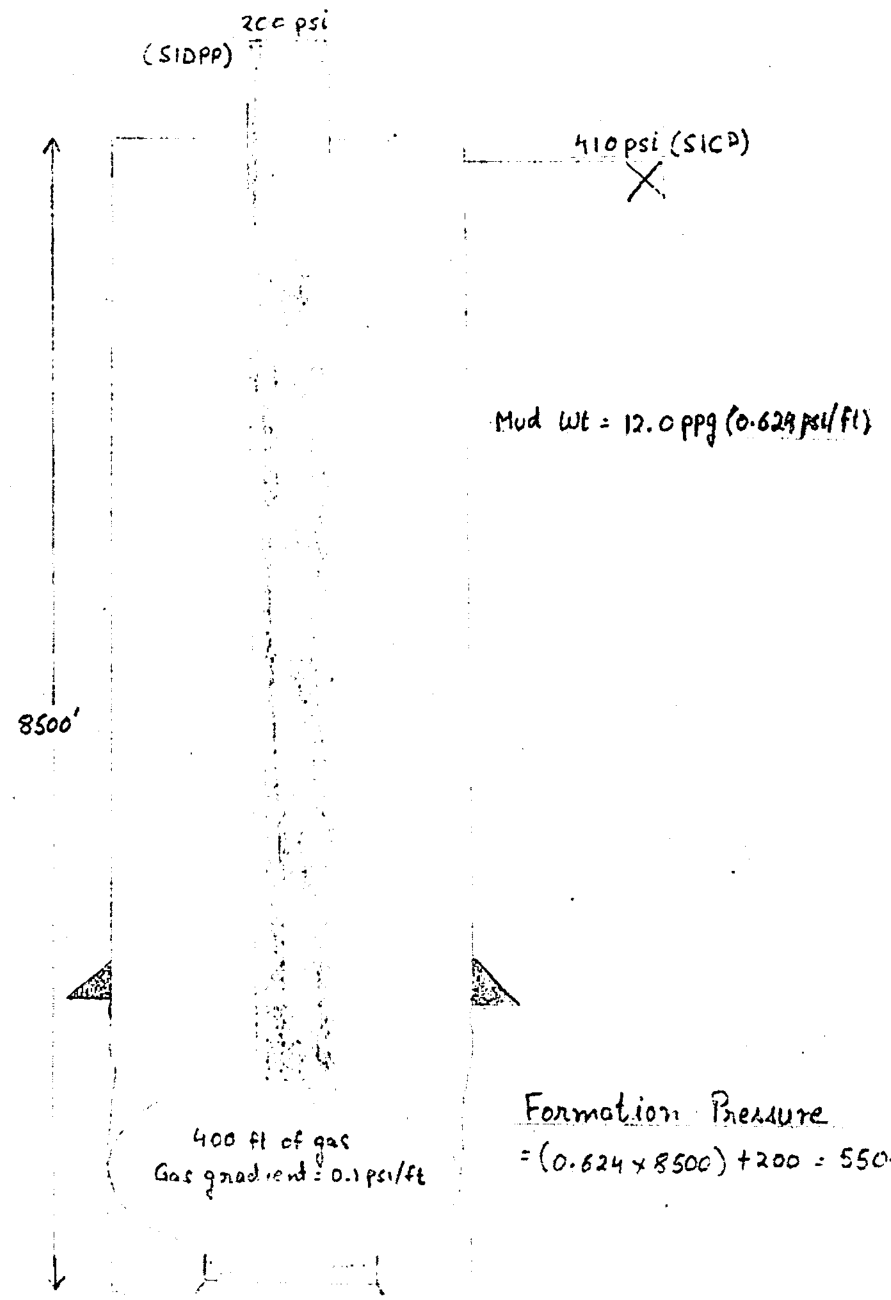
The pore fluids within shale in a sedimentary basin are saline in nature. Thus, chloride content within shale decreases with depth in a normal pressure environment because of compaction. However the shale present within a transition zone is under compacted and contains more pore fluids.

2.6.4 Shale Density

The bulk density of normally pressured shale increases with depth. Over pressured shale are generally under compacted and thus have increased porosities and lower bulk densities than indicated by a normal trend. When plotted a decrease in the normal trend may indicate abnormal pressure

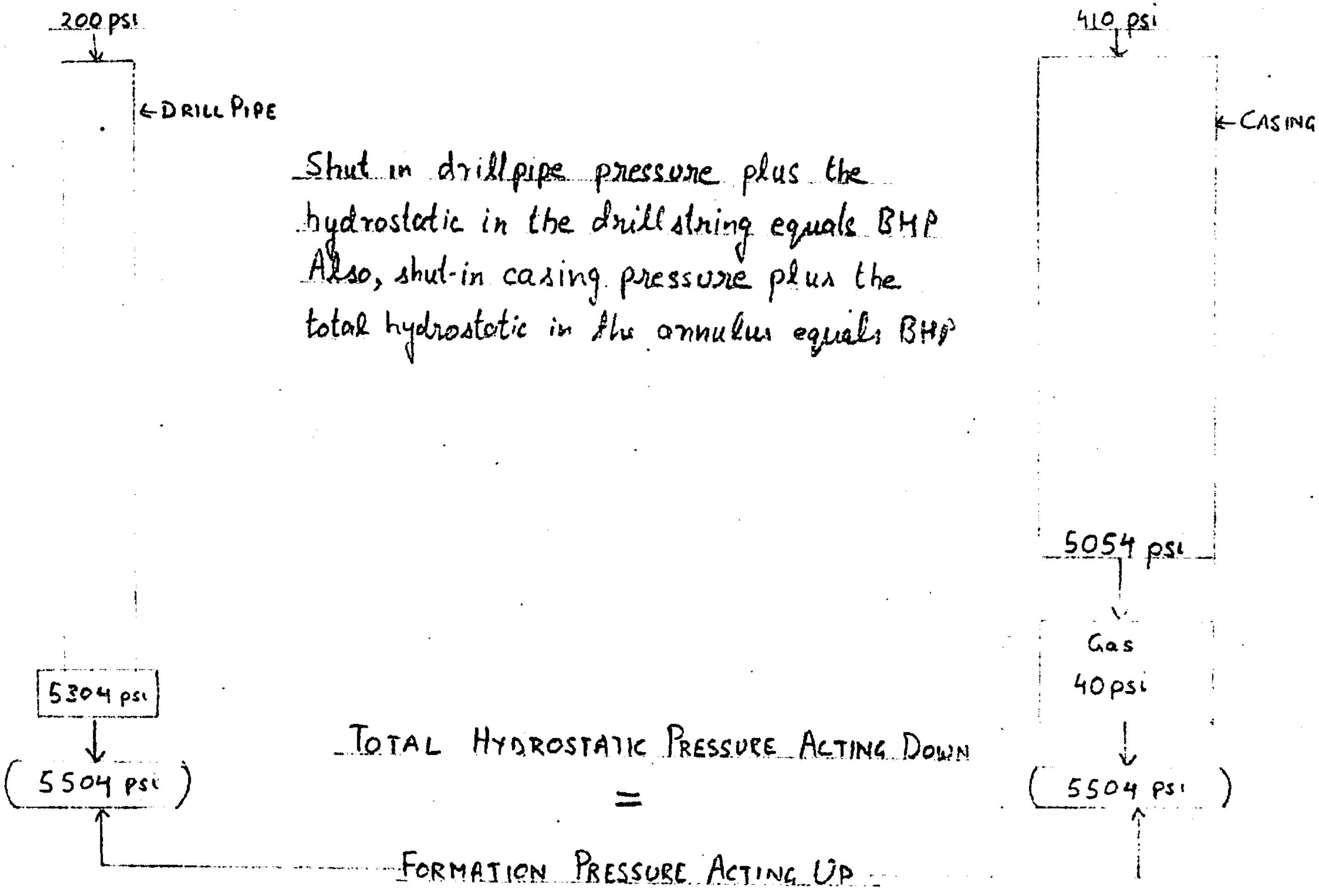
2.6.5 Flowline temperature

Normally as depth increases in the transition zone so does the water content within the shale. Since water is more conductive of heat than the shale matrix, overpressured shale containing more water will have a high temperature gradient across a transition zone. A sharp increase in flowline temperature may indicate abnormal pressure.



Formation Pressure
$= (0.624 \times 8500) + 200 = 5504$ psi

KICK INDUCED PRESSURES AFTER SHUT-IN



Shut in drillpipe pressure plus the hydrostatic in the drillstring equals BHP
Also, shut-in casing pressure plus the total hydrostatic in the annulus equals BHP

TOTAL HYDROSTATIC PRESSURE ACTING DOWN

=

FORMATION PRESSURE ACTING UP

ANALYSIS OF KICK INDUCED PRESSURES AFTER SHUT-IN

Cap rocks are usually very dense and contain little pore fluids. This would be less heat conductive, and a decrease in flowline temperature may indicate a cap rock and pending abnormal formation pressure just below

2.6.6 MWD and LWD

Measurement While Drilling (MWD) and Logging While Drilling (LWD) offer tremendous advantages in pore pressure prediction. Drilling parameters such as WOB and downhole torque provide more accurate data to adjust drilling exponent plots for pressure prediction.

LWD offers sonic data, density, porosity, resistivity, conductivity and gamma ray logs. Gamma ray can help pick clean shale section for abnormal pressure detection.

2.6.7 Direct Pressure Measurement

a. Modular Dynamic Test

Modular dynamic test or MDT is a wireline formation tester and is run on electric wire line. It is design to take a sample and to measure formation pressure from permeable zone.

A series of pressure reading can be taken and allowed the formation to be probed for possible permeable zones prior to taking samples.

MDT is of two types: (a) Dual type
(b) Single packer

b. Drill Stem Test (DST)

Whenever Drill Stem Tests are carried out various pressure gauges are run in the hole with the test string. The purpose of the various pressure gauges is to record the downhole pressure during the sequence of flow and shut-in periods that characterizes the DST. The pressure recorded during the test is used to calculate reservoir characteristics such as formation pressure, permeability, skin damage and Productivity Index (PI). Various types of pressure gauges are run in conjunctions with the clocks and recorders.

After DST has been carried out, the test string is pulled and the pressure gauges retrieved for the pressure chart to be read. Analysis of the pressure build up data for the shut-in periods can give accurate estimate of the reservoir pressure.

3. WELL CONTROL PREPARATION

Being prepared for well control operations helps eliminate failure and chances for loss of life, harm to the environment and damage to the rig equipment. Preparation means constantly being focused on personnel, equipment and the progress and state of the wellbore. **Well control is the responsibility of everyone.**

3.1 Personnel

- It is important that personnel be trained in well control principles and procedures.
- Personnel should be aware of warning signs and causes of kick and how to react to them.
- Rig team members should communicate changes in rig parameters to others.

3.2 Equipments

- Blowout prevention equipment should be rated foe anticipated well pressure.
- BOP equipment should be pressure tested on a regular basis.
- Detection equipment should be maintained in good working order.

3.3 Wellbore status

- The casing burst pressure should be known and posted on the rig floor.
- Formation pressure should be determined and mud weight adjusted to ensure a safe overbalance.

3.4 Kick Tolerance

Kick tolerance is the maximum volume of gas kick that can be circulated from the well without causing loss circulation, casing burst, or drill string collapse. The failure mechanism is most often considered to be the last casing shoe although at times casing burst and/or drill string collapse may be possible and should be considered as well.

3.5 Certain important terms in kick circulation

a. **Slow Circulating Rates (SCRs):** Kick should be circulated from the well at a slow rate, typically ½ barrel to 3 bbl/min maximum. This is done to:
   - Minimize pressure exerted on the open hole.
   - Allow choke operator more time to respond to pressure changes
   - Reduce pressure exerted on the well control equipment.

b. **Maximum Allowable Surface Pressure (MASP):** Fracturing mud weight is used to determine the Maximum Allowed Surface Pressure for Leak-Off and Casing Burst

- $MASP_{Leak\ Off}$= 0.052 * (fracturing MW – MW in hole)* TVD of Shoe
- $MASP_{Casing\ burst}$ = 0.7 x Internal Yield Rating of Casing

It is also prudent to know the burst rating of the wellhead and burst and collapse of all tubulars. Also be aware of the fact that tension reduces the collapse rating of tubulars. MASP Casing burst and MASP Leak-off should be posted on the rig floor.

c. Shut in drill Pipe Pressure **(SIDPP)** and Shut in casing Pressure **(SICP)**: When a kick is detected then to circulate it out we need to shut in the drill pipe and the casing annulus so that the things are under control.

SIDPP= Underbalance + HP loss due to influx

SICP= SIDPP + (mud gradient – influx gradient)* vertical height of influx

3.6 Kick Detection and Well Shut In

A kick is the uncontrolled flow of formation fluid into the wellbore. If left uncontrolled, a blowout may occur.

3.6.1 Causes of kicks

Swabbing: Swabbing action occurs whenever pipe is pulled from the well. Swabbing is dependent upon the flow properties of the drilling fluids, the speed at which pipe is pulled, and the hydraulic diameter of the BHA and the annulus.

Improper hole fill during trips: the drop in fluid level when pulling out of the hole can cause hydrostatic pressure to dip below that of the formation. Hole fill should be on a routine and regular basis and trip sheet should be used to record and compare actual fill volumes with calculated pipe displacement.

Insufficient mud weight: The density or weight of the drilling mud is constantly measured during normal operations and maintained to proper point.

Loss of circulations: It can cause the fluid level in the well to drop. This may reduce the well's hydrostatic pressure sufficient to allow kick to occur.

Abnormal pressured formations: Transition zones of increasing formation pressure can occur rapidly, causing mud weight in use to be underbalanced resulting in a kick.

3.6.2 Kick warning signs

Drilling break: One of the first indications that a kick is occurring is sometimes an increase in the penetration rate or drilling break. A drilling break indicates the bit is penetrating a new formation. If the formation has permeability it may contain fluid and be capable of causing a kick.

Increase in flow return rates: Drilling mud is displaced whenever kick fluids enter the wellbore. An increase in flow return rate is the first positive confirmation that a kick is occurring.

Pit gain: A gain in pit volume not caused by surface mud transfer is proof positive that either a kick is occurring or has occurred.

Increase in hook load: An influx may cause an increase in hookload, which is noticeable by the weight indicator. A gas influx replacing the drilling mud will cause in loss of buoyancy and resulting increase in weight.

4. KICK HANDLING PROCEDURES

The following methods are used to displace a kick out of a well

(1) Driller's method
(2) Weight and wait method
(3) Controlling gas migration
(4) Gas lubrication
(5) Stripping
(6) Stack gas clean out for deepwater
(7) Bullheading
(8) Reversing

Of all these methods, only driller's method, weight and wait method, controlling gas migration by volumetric method and bullheading have been described in this report.

4.1 Wait & Weight Method

The Wait and Weight Method gets its name from the fact that there is a short "waiting" time while the mud weight is increased or "weighted up" prior to circulating the influx from the hole. The wait and weight method only has application for kicks occurring because the mud weight was underbalanced to the formation pressure.
Generally, the well can be killed in one complete circulation. However, since it is only recommended to use a mud weight that balances formation pressure, additional circulating time will be required to increase the mud weight by a suitable safety factor prior to returning to normal operations. In most cases the Wait and Weight Method will be preferred to the Driller's Method except in deepwater drilling operations. The advantages of the Wait and Weight Method are:

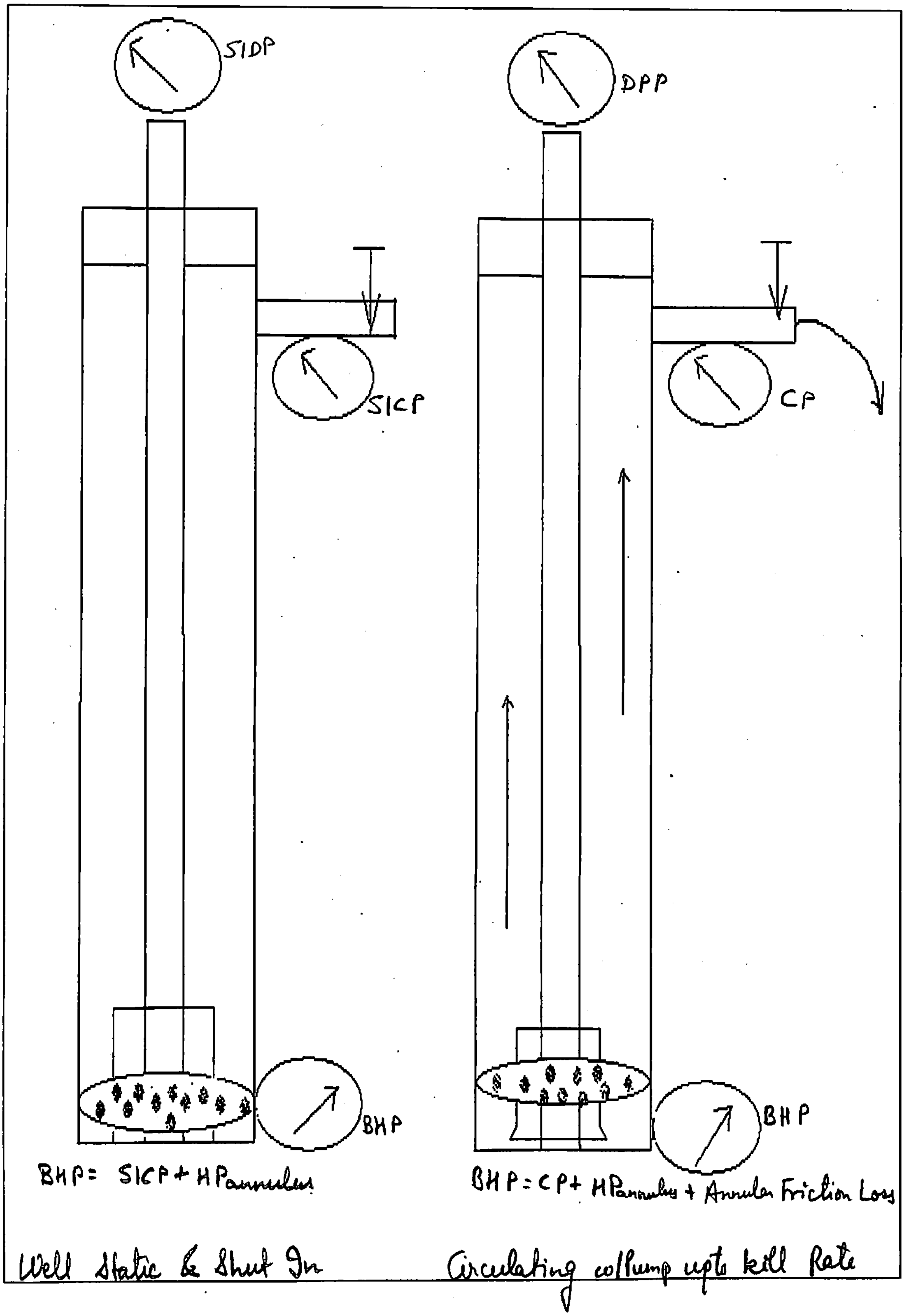
Pressures exerted in the wellbore and on pressure control equipment will be generally lower than if the Driller's Method was used. This difference is mostsignificant if the influx is gas, and for high intensity (large underbalance) kicks.

The maximum pressure exerted on the shoe (or weak point in the openhole) will normally be lower if the Wait and Weight Method is used. The maximum pressure at the shoe will be lower if kill mud starts up the annulus before the top if the influx is displaced to the shoe (or open hole weak point). .

The well will be under pressure for less time.

4.1.1 Preparation Checklist:

- Initiate kick log.
- Post person at choke panel to monitor shut-in pressures for possible gas migration.


SIDP
SICP
BHP
BHP= SICP+ HPannulus
Well Static & Shut In
DPP
CP
BHP
BHP=CP+ HPannulus + Annular Friction Loss
Circulating w/Pump upto kill Rate

- Work pipe, yes or no.
- Minimize annular closing pressure with no leakage (surface stacks only). .
- Toolpusher walk-around to assure well and equipment status. Check annular preventer, standpipe manifold valves, pump relief valves, casing valves, choke and overboard lines for possible leaks.
- Also check for broaching to the surface for offshore rigs.
- Complete well control kill sheet.
- Check that barite supply is sufficient. Suction pit should be separate from return pit if possible.
- Ensure that there is clear communication between driller and choke operator.
- Begin kill operations.

4.1.2 Implementation of Wait and Weight Method

It is necessary to perform several calculations prior to initiating circulation. These are as follows:

a) Determine a suitable circulation rate.

The upper limit for the circulation rate is generally set by the maximum rate that barite can be mixed into the mud to maintain the required mud weight increase.

Max circulation rate (bpm) = Barite delivery rate (Ib/min) / Barite required to weight up mud (Ib/bbl)

b) Calculate the Kill Weight Mud (KWM)

The kill weight mud is the mud weight required to exactly balance the kick zone pressure.

Kill Weight Mud (ppg) = Original Weight Mud (OWM) + SIDPP/ (0.052 x TVD)

Calculate the drillstring and annulus volumes. The drill string and annular volumes need be known to determine where the influx and kill weight mud is within the circulation path during the well kill. This data is usually obtained from the completed kill sheet.

d) Calculate the Initial Circulating Pressure (ICP)

The Initial Circulating Pressure should be calculated in order to estimate the circulating pressure that will be required to maintain constant bottomhole pressure at the start of circulation. The ICP recorded after the pump has been brought up to speed should be the sum of the shut-in drillpipe pressure and the Slow Circulating Pressure (SCR) at the chosen rate.

ICP = SIDPP + SCR

d) Calculate the Final Circulating Pressure (FCP)

As the drillpipe is displaced with kill weight mud. the circulating standpipe pressure must be reduced to take into account the increased hydrostatic pressure of the mud in the pipe. The standpipe pressure must also compensate for the increase in friction pressure due to pumping a heavier weight mud.

Once the drillpipe has been completely displaced with KMW, the static drillpipe pressure should be zero.

The required circulating standpipe pressure at this point is just the SCR pressure adjusted for the KWM.

Final Circulating Pressure (FCP) = SCR x (KWM/OWM*)*

e) Calculate Circulating Pressure at Major Angle Changes along Well Path

Additional circulating pressure checkpoints will be calculated for horizontal and/or extended reach type wells. These checkpoints will reflect the correct hydrostatic kill of underbalance as the Kill Weight Mud reaches depths of major angle changes along the well path. Each Kick-Off Point (KOP) and corresponding End-of-Build (EOB) will represent a change in the linearity relationship of circulating pressure vs. depth or pump strokes from the initial Circulating Pressure to the Final Circulating Pressure.

$KOP1_{cp}$= ICP + [((FCP -SPP) x $KOP1_{md}$)/TMD) – ((SIDPP x $KOP1_{vd}$)/TVD)]

$EOB1_{cp}$ = ICP + ((FCP -SPP) x EOB 1_{md})/TMD) – ((SIDPP x $EOB1_{vd}$)/TVD)]

Where:
KOP_{cp} -Circulating pressure when Kill Weight Mud reaches the Kick-Off Point of interest (1,2,3... etc.)
EOB_{cp} - Circulating pressure when KWM reaches the End-of-Build for corresponding KOP.
KOP_{md}- Kick-Off Point measured depth. .
KOP_{vd} - Kick-Off Point vertical depth.
EOB_{md}- End-of-Build measured depth.
EOB_{vd} - End-of-Build vertical depth.
ICP – Initial Circulating Pressure
FCP -Final Circulating Pressure
SPP –Slow Pump Pressure
TMD –Total Measured Depth.
TVD – Total Vertical Depth
SIDPP -Shut -in Drillpipe Pressure

f) Determine the pump strokes required to circulate the KWM to critical points downhole

At all times during circulation it is important to know the position of the influx in the wellbore and the position of the Kill Weight Mud. The key points during the circulation are:

- When the kill weight mud reaches a kick off point or major directional change.
- When the kill weight mud reaches the bit.
- When the kill influx reaches the shoe.
- When the influx reaches the choke.

g) Construct a Circulating Drillpipe Pressure vs. Pump Strokes Schedule

To ensure that the drillpipe pressure is adjusted correctly as the kill weight mud is circulated down the drillstring, a pressure schedule should be made and referenced during the well kill. The Initial Circulating Pressure should be noted corresponding to zero pump strokes and the Final Circulating Pressure noted at Strokes to Bit value. The KOP and EOB pressures should be indicated at corresponding pump strokes as well. The circulating pressures and pump strokes should be scaled linearly between each pressure point of interest.

For a low angle(«30 degrees) or straight hole well, the schedule would be linear between ICP and FCP and linear from zero pump strokes to Strokes to Bit value. A kill sheet would have all the pertinent info discussed here and should be used for an actual well kill.

4.1.3 The Well Kill Procedure Using the Wait and Weight Method.

- Bring the pump up to kill speed.
- Line up pump to the drillpipe and route returns through the choke manifold to the mud gas separator.
- Zero the stroke counter on the choke panel and at driller's console.
- Circulate the influx from the well maintaining constant bottom hole pressure.
- As the drillpipe is displaced with kill weight mud, the standpipe pressure should be stepped down in accordance with the circulating schedule. Once the kill weight mud has reached the bit or end of the drillstring, the drillpipe pressure should be held constant at the FCP for the remainder of the well kill.
- If the influx is gas, the drillpipe pressure will tend to drop as the influx expands as it is circulated up hole (this will not occur if the influx is water). The casing gauge reading can assist the choke operator when making small adjustments to the choke to affect small pressure changes on the drillpipe gauge. That is, if the drillpipe pressure gauge is noted to be 50 psi too low,the choke can be closed slightly to raise the casing pressure by 50 psi and then wait and see if the drillpipe pressure corresponds accordingly.
- There is about a second per thousand foot time delay from the time the choke is manipulated until the affect is noted by a change if) drillpipe pressure. The casing gauge pressure will indicate the same change immediately.

WELL-CONTROL KILL SHEET

PRE-RECORDED DATA

Pre Recorded Drillstring Info

Lengths (FT)	Capacities (BBL/FT)
Drillpipe #1 14765 5½"	0.0218
Drill pipe #2 or Heavyweight 720 5"	0.0178
BHA Collars DC 900	0.0089
360	0.0061

Pre Recorded Annular Info

Lengths (FT)	Capacities (BBL/FT)
Csg Casing 11551	0.0414
720	0.0459
BHA XDH 900	0.0459
360	0.0292

Pump Output

#1 Pump output (bbl/stk) 0.087

#2 Pump output (bbl/stk) 0.087

Strokes to Kill Well

345 ÷ 0.087 = 3966
Drillstring Volume ÷ Pump output = Surface to bit strokes

591 ÷ 0.087 = 6793
Annular Volume ÷ Pump output = Bottoms up Strokes

Total strokes to kill well 11 0489

Strokes to Kick Off Points

Drillstring Volume to KOP ÷ Pump Output = NA STKS to KOP

Drillstring Volume to EOB ÷ Pump Output = STKS to EOB

DRILLSTRING VOLUME (BBLS)

Length x Capacity (bbl/ft) = Volume

14765 x 0.0218 = 322

720 x

900 x

360 x

And For Total Drillstring Volume

DRILLSTRING VOLUME TO KOPS

And For Drill-String Volume to KOP

And for Drillstring Volume to EOB

ANNULAR VOLUME (BBLS)

(1) Casing by Drillstring

11551 x 0.0414 = 478

x =

x =

(2) Openhole by Drillstring

x =

x =

x =

(3) Choke line (Subsea Only)

And for total Annular Volume

RISER VOLUME (BBLS)

Riser length x Capacity

SUBSEA PUMP START UP SCHEDULE

SICP | Choke Line Friction psi | Casing/Choke psi

CLPF @ Stks/min

SICP | Choke line friction psi | Casing Choke psi

CLPF @ Stks/min

SICP | Choke line friction psi | Casing Choke psi

CLPF @ Stks/min

Well Name: Ahd #7 Date: 01/01/2007

WELL CONTROL KILL SHEET Rig: Dalma MR4 Time: 03:30 Am

(a) Well Information

14.4	Original Mud Weight (OMW)	Total Measured Depth (TMD)	16745
16745	Total Vertical Depth (TVD)	KOP Vertical Depth (KOPv)	NA
NA	KOP Measured Depth (KOPm)	Strokes to KOP	NA
NA	EOB Vertical Depth (EOBv)	Stroke to EOB	NA
NA	EOB Measured Depth (EOBm)	Strokes to bit	

870 @ 30

Slow Pump Pressure (SPP) @ Slow Circulation Rate (SCR)

(b) Kick Information

260	430	430	28
SIDPP	SICP	SIKM (kill Monitor)	Pit gain

(c) Calculations

Kill mud Weight (KMW) $= OMW + \frac{SIDPP}{(0.052 \times TVD)}$ 14.7

Initial Circulating Pressure (ICP)

ICP = SIDPP + Slow Pump Pressure 1130

Final Circulating Pressure (FCP)

FCP = SPP x (KMW / OMW) 888

Circulating Pressure at KOP and EOB sections NA (CP@KOP₁) NA (CP@KOP₂)

$KOP(i) = ICP + \left(\frac{(FCP - SPP) \times KOP(i)_{md}}{TMD} - \frac{SIDPP \times KOP(i)_{vd}}{TVD}\right)$

NA (CP@EOB₁) NA (CP@EOB₂)

$EOB(i) = ICP + \left(\frac{(FCP - SPP) \times EOB(i)_{md}}{TMD} - \frac{SIDPP \times EOB(i)_{vd}}{TVD}\right)$

(d) Subsea Info

Water Depth	3140	
Choke line Friction psi		SPM
CLFP (up both choke and kill lines)	310	30 SPM

(e) DP Pressure Schedule

	Strokes	DP psi	
	0	1130	ICP
1	397	1106	
2	793	1082	
3	1190	1057	
Stks to KOP	1586	1033	CP @KOP
1	1983	1009	
2	2379	985	
3	2776	961	
Stks to EOB	3172	936	CP @EOB
1	3569	912	
2	3966	888	
3			
Stks to bit	3966	888	FCP

4.2 Driller's Method

The calculations discussed for the Wait and Weight method need be made for the Driller's method as well. For induced kicks that do not require a mud weight increase to kill the well, the circulating pressure versus pump strokes may not be necessary.

The Driller's method requires circulating the influx from the well prior to circulating Kill Weight Mud. The Initial Circulating Pressure (ICP) will be maintained constant throughout the first circulation, since the mud weight is not changed.

4.2.1 Preparation Checklist

- Initiate Kick Log (monitor and record shut-.in pressures in two-minute increments. Continue to record pressures, volumes and pump strokes throughout the well control incident and note other pertinent rig activities).
- Post person at choke panel to monitor shut-in pressures for possible gas migration.
- Have clear decision on whether to work pipe. YES or NO
- Set annular closing pressure to minimum with no leakage.
- Toolpusher walk-around to assure well and equipment status. Check annular preventer, standpipe manifold, pump relief valves, casing valves, choke and overboard lines for possible leaks. Also , Check or broaching to surface on offshore rigs. .
- Complete well control kill sheet.
- Check that there is a sufficient supply of barite (if necessary). Suction pit should be separate from return pit, if possible.
- Check that there are clear communication between Driller and Choke Operator.
- Begin kill operations.

4.2.2 Well-Kill Procedure

a) Bring the pump up to kill speed for the first circulation.
Line up the pump to the drillpipe and route returns through the choke manifofl to the mud gas separator.
Set the stroke counters to zero.

b) Circulate the influx from the well, maintaining constant bottomhole pressure.
Influx behavior will be similar to that discussed for the Wait and Weight method. Once the influx has been displaced from the hole, the shut-in drillpipe and shut-in casing' pressures should be equal (same MW all around the system). If the casing pressure is slightly higher, it may indicate that some kick fluid may still be in the annulus, and additional circulation through the choke may be necessary.

c) Bring the pump up to speed for the second circulation, for underbalanced kicks).
Line up the pump) to the drillpipe and route returns through the choke manifold to the mud gas separator.
Set the stroke counters to zero.

d) Circulate the hole-to-Kill Weight Mud Maintaining Constant Bottomhole Pressure.
As the drillpipe is displaced to Kill Weight Mud the drillpipe pressure should be stepped down according to the drillpipe pressure versus pump strokes schedule. Once the KWM has been circulated to the bit, the Final Circulating Pressure should be maintained constant on the drillpipe by manipulating the choke.
e) As the KWM is circulated up the annulus, the drillpipe pressure may tend to increase. The choke should be adjusted (opened), if necessary. When the returned mud is at the Kill Weight Mud value, stop the pump and shut-in the well. Shut-in pressures should be equal and zero. Flows check the well prior to opening the BOPs. If the flow check is negative, open the rams (or annular) and flow check further.

f) Once the well has been killed, a further complete-hole circulation should be carried out to increase the mud weight to an appropriate overbalance.

4.3 Controlling Gas Migration

Gas migration represents a potential problem any time the well is shut-in. Uncontrolled gas migration causes a pressure increase everywhere in the wellbore. There are two primary methods of controlling gas migration during periods of well shut-in. The Drillpipe Pressure method is by far the simplest and should be implemented any time the well is shut-in. The Volumetric procedure is used only when the drillpipe pressure gauge does not indicate bottom-hole pressure. The Key indicator of gas migration is: Both the shut-in drillpipe and casing pressures will increase at the same rate.

4.3.1 Volumetric Procedure

The volumetric procedure may be required if the drillstring is stuck off bottom, out of the hole or too far off bottom to be stripped back or if the bit is plugged. The drillpipe pressure gauge cannot be used in these cases to monitor bottomhole pressure. The choke or casing pressure and the volume bled from the well is used to infer bottomhole pressure. Gas migration causes the shut-in casing pressure to increase. The increase is directly related to the rise of gas in the annul us/well bore. Mud must be bled from the well to allow the gas to expand, such that bottomhole pressure is controlled at a value slightly higher than formation pressure. Mud is bled in increments from the well as the casing pressure raises. The amount of mud bled for each "cycle" of pressure increase is determined by the increase in casing pressure.

Equipment Considerations:

- A trip tank or similar tank capable of measuring to 1/2 bbl accuracy must be rigged up to measure accurately the mud bled from the well.
- A manual-type choke will provide better control and response than a remotely operated hydraulic choke.

Procedure:

- Select a Safety Margin and Range to control bottomhole pressure.
- Recommended: SM =100 psi & Range = 100 psi
- Calculate the hydrostatic pressure per bbl of mud in the upper annulus.
- HP per bbl (psi/bbl) - Mud gradient (psi/ft) / Annular capacity (bbl/ft)
- Calculate the volume to bleed each cycle.
- Volume bleed per cycle (bbls) = Range (psi)/ HP per bbl (psi/bbl)
- Construct a schedule of casing pressure versus volume to bleed per cycle.
- Allow shut-in casing pressure to increase by the safety margin without bleeding.
- Allow shut-in casing pressure to increase by the range without bleeding.
- Maintain the increased casing pressure constant by bleeding small increments of mud from the choke until the volume per cycle i~ bled (measured in trip tank).
- Repeat steps 6 & 7 until another well control procedure is implemented or gas is at the surface.(Annexure graph#6)

4.4 Bullheading

4.4.1 Bullheading -Drilling Wellbore

Bullheading may be used in certain circumstances during drilling operations to pump an influx back into the formation. The success of the bullheading operations will depend, to a great extent on two factors:

1. The amount of open hole present
2. Where the influx is relative to a permeable zone.

However, bullheading is commonly used to kill a well prior to a well workover operation. In these cases, the reservoir permeability is such that the influx can be easily pumped back into the formation and the well killed. Usually this is done with a clear completion brine to minimize formation damage.

When to Bullhead:

- During drilling operations, bullheading operations may be considered in the following situations:
- When the influx is very large in volume.
- When displacement of the influx by conventional methods may cause excessive surface pressures.
- When displacement of the influx by conventional methods would result in excessive volumes of gas at surface conditions.
- If the influx is believed to contain an unacceptable level of H_2S.
- When a kick is taken with the pipe off-bottom and it is not considered feasible to strip-back to bottom.
- When an influx is taken with no pipe in the hole.
- To reduce surface pressures prior to implementing further well control operations.

Important Considerations:

Bullheading during drilling operations should only be implemented when standard well control procedures are considered inappropriate. In most cases, the success of bullheading will not be known until the operation is attempted and the results evaluated. The following factors may help determine the feasibility of bullheading:

- The characteristics and condition of the openhole.
- The rated pressure of the well control equipment and the casing (making allowance for wear and deterioration).
- The type of influx and the relative permeability of the formation.
- Use riser boost to displace riser with kill weight mud (or open upper preventer and circulate via kill/choke lines).
- The quality of the filter cake at the permeable formation.
- The consequence of fracturing a section of the open hole.
- The position of the influx in the hole.

Bullhead Volume

On wells highly susceptible to formation damage even by properly treated workover fluids, only the exact tubing volume should be pumped. The tubing may not be completely dead, but pressures are greatly reduced and subsequent circulation is simplified.

On other wells, the tubing will be substantially over-displaced to achieve a more certain kill, especially if the zone is being abandoned or reworked inevitable high fluid losses will occur later or the formation would suffer little from the workover fluid.

Pump Pressures

In high permeability wells surface pressures required to start the pumping are frequently only slightly higher than shut-in tubing pressures. However, pump rates are often restricted to keep sand-face pressures below the fracture point. Except in the earliest wells, fracture pressures for development reservoirs are reasonably well-known.

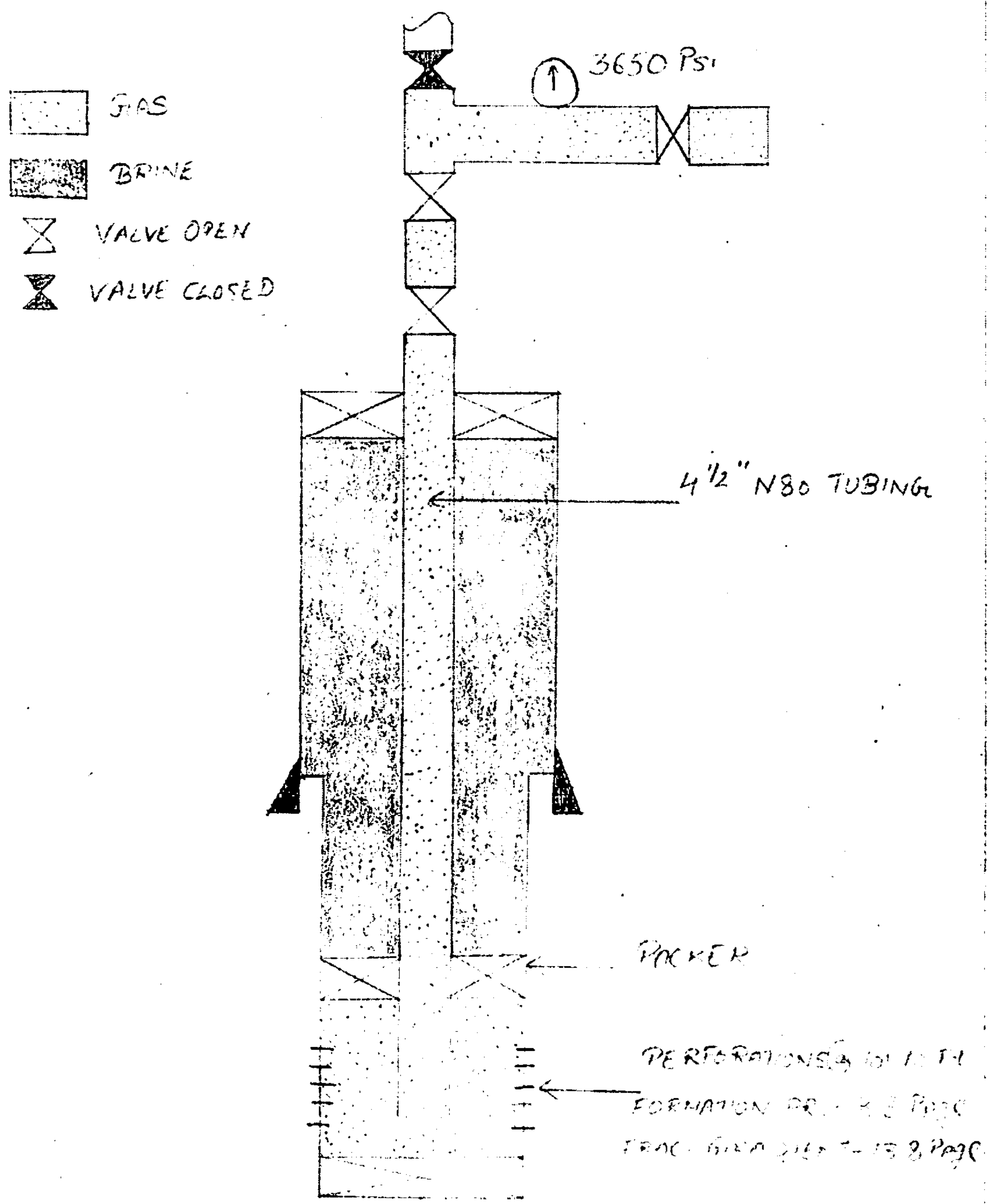
Procedure

A plan for bullheading the tubing with brine on a straight gas well might be drawn up as follows:

1. Calculate surface pressures that will cause formation fracture during bullheading. Also calculate the tubing burst pressure as well as casing burst (to cover the possibility of tubing failure during the operation).
2. Calculate the static tubing head pressure during bullheading.
3. Slowly pump kill fluid down the tubing. Monitor pump and casing pressure during the operation.

WELL SHUT IN AFTER PRODUCTION - TUBING FULL OF GAS PRIOR TO BULLHEADING

#8



5. KICK ANALYSIS

5.1 Displacing a Kick from the Well

5.1.1 Driller's Method

The Driller's Method requires two complete circulations to kill the well. The original mud is used to first circulate bottoms up to displace the kick from the well; the hole is then circulated to kill weight mud during the second circulation.

The drillpipe pressure is maintained constant the correct Initial Circulating Pressure (sum of the shut-in drillpipe pressure and the slow circulating rate pressure). During the second circulation, the drillpipe pressure is controlled with the choke to decrease according to the increased hydrostatic of the string being filled with kill weight mud. Once the drillpipe is filled with the kill weight mud, the drillpipe pressure is maintained constant at the Final Circulating Pressure until kill weight mud returns to the surface.

Pressure at points in the annulus will change as the influx moves up the annulus and is displaced from the well. Once the well is shut-in, the major factors that determine the pressure at any point in the annulus. During displacement of the kick are the height of the influx in the annulus and the relative position of the influx in the annulus.

Graph 10(Annexure):

- Point A represents the shut-in casing pressure. From A to B, the casing pressure drops as the influx shortens in length as it is displaced past the BHA.
- From point B to point D, the influx is expanding as it is circulated up the hole and, hence, the choke pressure required to balance the kick zone pressure is increasing. The choke operator will need to continually make closing adjustments to the choke to maintain the correct standpipe pressure. At point C, the gas has expanded to occupy its original length in the annulus when opposite the BHA.
- At point D, the gas arrives at the choke; the choke operator will have to close in en the choke to ensure that the choke pressure does net drop significantly as the low density gas passes across the choke,
- From point D to E, gas is vented from the well and the hydrostatic pressure of the mud column is increasing to replace the exiting gas. The choke operator will need to open the choke to reduce the "back-pressure" to maintain the correct standpipe pressure.
- At point E, the gas has been displaced from the well and the choke pressure will stabilize to a value determined by the original underbalance.

Graph 11(Annexure):

- The well is circulated to kill weight mud during the second circulation of the Driller's Method.
- After establishing the correct Initial Circulating pressure (ICP), the standpipe pressure must be reduced as the drillpipe is displaced to kill weight mud. In

practice, very little choke manipulation will be required at this stage, because the standpipe pressure will drop automatically as the kill weight mud is pumped down the drillpipe. Once kill weight mud starts up the annulus, the choke size will have to be increased so that the correct Final Circulating Pressure (FCP) is maintained.

- Once the hole has been displaced to kill weight mud, the choke pressure required to maintain the Final Circulating Pressure will be zero. In practice, the choke will be wide open at this point, and it may not be possible to keep the standpipe pressure down at the FCP value.

5.1.2 Wait and Weight Method

During the Wait and Weight Method (sometimes called the "Engineer's Method"), the kick is displaced from the hole with kill weight mud. In some instances the Wait and Weight Method may be preferred over the Driller's Method. The well is killed in one circulation which means the wellbore (and equipment) is subjected to well control related pressures for a shorter time. Also, if the kill mud enters the annulus prior to the influx being circulated to the casing shoe; the maximum shoe pressure is less than if the Driller's Method was used.

Graph 12(Annexure):

- The choke pressure during the Driller's Method is included for comparison. As can be seen, the choke pressure during both techniques is the same until the kill weight mud starts up the annulus at point B. From this point on, the pressure at every point in the annulus will be lower than if the Driller's Method had been used.
- Between points D and E, the volume of original mud behind the influx is displaced from the well until at point E, the kill weight mud arrives at the choke.

Graph 13(Annexure):

- The pressure at the casing shoe for both the Wait & Weight and the Driller's Methods is shown above.
- Between point P and point Q, the shoe pressure decreases as the influx is displaced above the BHA. The influx expands as it is circulated to the shoe at point R, after which, the pressure at the shoe decreases.
- At point S, the kill weight mud starts up the annulus and, hence, reduces the choke pressure below that for the Driller's Method. Between points T and U, the original weight mud is displaced past the shoe until point U, when the kill weight mud arrives at the shoe.
- The pressure at point U is equal to the kick zone equivalent mud weight and, thus, represents the minimum pressure that the shoe will see once the well has been killed.
- In this well example, the maximum shoe pressure is unaffected by the technique used to kill the well; however, the shoe will be under pressure significantly longer if the Driller's Method is used.

5.2 Factors Affecting Wellbore Pressure

5.2.1 Size of the Influx

The allowed volume of the kick is the most singular important factor affecting the success of the well kill operation. It is also the factor most easily controlled by ensuring that the drill crews are properly trained and that detection equipment is in good working order.

The larger volume of influx, the longer the time equipment is required to process the surfacing kick and the higher the surface pressures.

5.2.2 Kick Intensity

Kick intensity is the amount of underbalance of the kick relative to the mud weight being used. The greater the underbalance the higher the mud weight will need to be raised to kill the well. The higher the kick intensity the greater the impact of ,the kick on the stability of the wellbore and integrity of the casing shoe.

In most instances, the Wait and Weight Method is preferred over the Driller's, when handling high intensity kicks.

5.2.3 Annular Geometry

In nearly every case, the maximum surface pressure during kick displacement will be lower when using the Wait and Weight Method. The maximum shoe pressure is not necessarily affected by the choice of the kill procedure. This is because in many cases the maximum shoe pressure occurs when the well is first shut-in (the influx is occupying more annular footage than when circulated to the shoe because of the reduced annular capacity around the BHA).

If the maximum shoe pressure does not occur at initial shut-in, it will be lower with the Wait and Weight method, providing that kill weight mud enters the annulus prior to the influx reaching the shoe.

5.2.4 Influx Type

Gas kicks have the most pronounced affect on wellbore pressures during kick displacement. Gas expands as the pressure is reduced and the expanding gas pushes mud (and hydrostatic) from the well. This loss of hydrostatic must be compensated for in terms of surface choke pressures during well control operations. .

Water is non-compressible and cannot expand when circulated from the well. As soon as kill weight mud begins to fill the annulus, the surface pressures will start down. Water is also heavier than gas, which also results in less loss of hydrostatic due to the volume of influx, which results in less pressure at the surface. Oil kicks behave more like gas kicks, since most oil will contain gas at reservoir conditions, which will come out of solution and expand as it is displaced up the hole.

Graph 14(Annexure) compares choke pressure in driller's method and wait and weight method for various influx volumes.

5.3 Subsea Considerations

The small equivalent annulus of the choke line during kick displacement can have a dramatic affect on the surface pressures during well control operations. This is because the height of the influx will be much greater when displaced into the choke line compared to the equivalent height of the influx in an annulus from a surface stack type rig.

When the gas enters the choke line, the required rate of choke pressure increase can be very high at normal displacement rates. This makes it very difficult for the choke operator to react and pinch down on the adjustable choke sufficient to the required choke pressure increase. The result is a drop in bottomhole pressure and then a corresponding drop in drillpipe pressure. Graph 15 in annexure compares choke pressures during displacement of a gas kick on a fixed and floating rig.

Also, the drop in drillpipe pressure will be noted after the lag time, which can be substantial in deep wells. On surface-stack type rigs the lag time effect will not be as dramatic, because the required rate of choke manipulation will not be as great.

A similar problem occurs as the gas exits the choke line and drilling mud is displaced behind the gas into the choke line. Here the required rate of choke manipulation can be high, as well, with the potential for over-pressuring the well and causing loss of returns.

Graph 16(Annexure):

Non-compensated choke line friction pressure will show up on the drillpipe side during the pump start-up and should be considered undesirable, since it's an extra pressure on the shoe. For significant gas kicks, this friction pressure can be compensated for as gas expands and the choke operator adjusts the choke from full opening to some "choking" value.

5.4 Safety Factors

Prudent well control procedure calls for maintaining bottom-hole pressure constant at a value slightly above that of the kicking zone. This will provide a margin of error for the choke operation and help prevent additional influx. Excessive additional pressure, especially in the form of safely factors, should be avoided.

Additional pressures may needlessly over-pressure the wellbore causing loss of circulation and complicate well control operations.

Possible causes of additional pressures during the displacement of a kick are discussed below:

5.4.1 Annulus Friction Pressure

Normal well control procedure relies on the annulus friction pressure to act as a safety margin over an above the kick zone pressure. Normally, the annular pressures are not significant at slow pump speeds used during well control operations. However, excess choke line friction pressures common in deepwater cannot routinely be avoided and must be dealt with correctly.

5.4.2 Kill Weight Mud with a Safety Margin

The mud weight required to balance the kick zone pressure is the recommended mud weight to use in almost all situations. Additional safety margins built into the kill Weight mud only serve to apply extra pressure at the shoe during the well kill and should be avoided.

An overbalance factor should be added to the mud weight on subsequent circulations after the well kick has been displaced and the well dead.

5.4.2 Additional Choke Pressure

An increase in choke pressure will exert an additional pressure throughout the circulating system. If the choke pressure is increased 100 psi by closing the choke slightly, the pressure at the casing shoe, at the bottom of the hole and at the standpipe will also increase 100 psi.

Additional choke pressure should only be used when the annular friction pressure is known to be less than adequate for that ensuring bottom-hole pressure is maintained above the kick zone pressure. Generally, downhole pressures are greatest early on the well kill and additional choke pressure should not be applied at this critical time. An advantage to using choke pressure to create a safety margin is that it can be controlled during kick displacement. For example, it may be applied only at a late stage of the well kill when the influx is in casing and kill mud has started up the annulus and, consequently, pressures on the openhole are at a minimum(Annexure graph# 17)

6. SECONDARY WELL CONTROL

6.1 Blow-out preventers

6.1.1. Basic Types and Operation

a) Ram BOP'S

Sealing elements, or rams, are located in the BOP body on opposite sides of the wellbore. Opening and closing is performed with hydraulic cylinders attached to both sides of the BOP body. When open, the rams will leave an unobstructed passage through the wellbore. When closed-depending on the type of ram selected-they will seal around the drillpipe, seal off the open hole, or in emergencies shear the drillpipe and seal off the hole.

The basic concept of the ram BOP has not changed in 50 years. Such improvements as automatic locks, shear rams, and load-carrying pipe rams have increased the efficiency but has left the technical concept the same. Many improvements were developed as subsea drilling activity increased. The major one was the development of multibore or variable-bore rams, which solved the inherent problem of the ram BOP sealing on only one specific size of tubular goods, Multirams can adapt to different sizes within a limited range—e.g. For all tubulars with diameters between 3.5 and 5 in. [8.9 and 12.7 cm]. Ram BOP's are still considered the main pressure control tools in oil well drilling, primarily because of their high degree of reliability.

b) Annular BOP'S

The main feature of the annular preventer sometimes called "universal" or "bag"-type BOP, is the capability to close and seal on almost any size tools in the borehole-drillpipe, tool joints, drill collars, kellys, casing, etc.-within most of its range.

It also has the capability to seal off the open hole, The heart of the annular preventer is the sealing element. When the closing mechanism is actuated, hydraulic pressure is applied to the piston, causing it to move upward and force the sealing element to extend into the wellbore around the drillstring. Steel segments molded into the element partially close over the rubber to prevent excessive extrusion when sealing under high pressure, The BOP is opened by application of hydraulic pressure on the opposite side of the piston, causing it to move downward and allowing the sealing elements to return to the original open position.

c) Rotating BOP

The sealing element of the rotating BOP, the stripper rubber, is attached to a rotating assembly mounted on a BOP body by a quick-release bonnet. The stripper rubber adapts to the drillstring portion it seals on and rotates with it. The rotating BOP is a low-pressure device used in special situations when drilling is performed in a slightly underbalanced condition; i.e., the hydrostatic head of the drilling fluid is slightly less than the formation pressure (this will increase the penetration rate), Also, the rotating BOP is very suitable for drilling operations with air or gas as the drilling fluid because of relatively low pressures. The rotating BOP is always used on top of a regular BOP stack consisting of ram and annular BOP's.

6.2 Operation of BOP's

Given here are the details of working of the annular and ram BOP's with the salient features of its various parts.

6.2.1 Annular Blowout Preventers

Annular preventers have a doughnut shaped elastic element with bonded steel internal reinforcing. Extrusion of the element into the wellbore is effected by upwards movement of a hydraulically actuated piston. The element is designed to seal around any shape or size of pipe and to close on open-hole.

An important function of annular preventers is to facilitate. the stripping of the drillpipe in or out of the well, with pressure on the wellhead. Undue wear of the element is avoided by the use of a pilot operated hydraulic regulator, which controls closing pressure.

The majority of annular preventers currently in use are manufactured by Hydril (Types MSP, GK, GL, GX), Shaffer (Spherical) and Cameron (Type D). These are illustrated below together with a summary of major operating features.

The following are the most important aspects of the operation of annular preventers:

- To obtain maximum sealing element life, hydraulic closing pressures should conform to the manufacturer's recommendations for pressure testing and operational use of the preventers. Excessive closing pressure, when coupled with wellbore pressure sealing effect, causes high internal stresses in the element and reduces element life.

- Cavities should be flushed out and the element inspected following each well. Preventers should be stripped and inspected annually. Seals should be replaced and all sealing surfaces inspected.

- Cap seals should be replaced when changing elements.

- Drilling tools, especially rock bits, should be cautiously run through BOP's to minimize element damage. On occasion, elements of annular preventers do not retract fully.

- The type of elastomers (natural rubber, synthetic rubber, neoprene) used in the packing element should be the most suitable for a particular wellhead environment.

- Although most models and sizes of annular preventers will seal an openhole in an emergency operation, it is not recommended as such gross deformation of the elastomer causes cracking and accelerated wear.

- Closing pressures should be regulated to the pressures specified by the manufacturers; this information should be available at the rig site.

- When stripping, the closing pressure should be regulated to the minimum required for a slight weeping of mud past the element. Closing pressures higher than this will increase element wear. The pipe should be moved slowly, particularly as tool joints pass through the element. The manufacturers also provide information regarding recommended closing pressures during stripping operations. Surge vessels on the closing ports will help to smooth-out surge pressure as tool joints pass through the element.
- Most annular preventers are designed to use wellbore pressure to assist in maintaining closure. In some circumstances and depending on the preventer size, the well pressure can maintain closure without any closing hydraulic pressure being applied. An annular preventer should never be operated without some closing hydraulic pressure applied. The reason is that with only well pressure maintaining closure, the packing unit may suddenly open with only a small surge or reduction in well pressure. Also, the pressure seal may be lost around the body of the drillpipe after a tool joint passes through the element during stripping operations.

If the annular packing element wears out during stripping or well killing operations, the element can be changed without pulling the pipe. After the pipe rams are closed and locked below the annular preventer and the hydraulic and well pressure bled off, the cover of the preventer can be unbolted and the packing element lifted out without a hoist line. With the element above the preventer, the damaged unit can be split and removed from the pipe. New packing elements for Hydril and Shaffer annular preventers can be split in the field and installed in reverse order. Cameron has recently developed a packing element for their Type D annular preventer which can be split in the field.

Modelling and Management of Annular Surface Blowouts-A Shell Petroleum Development Company Case Study

a. Introduction

After a blowout, everyone wants to find the cause, prevent recurrence and understand how it was controlled. In-house papers/documentations may be written, measures are introduced to prevent another occurrence and be better prepared next time. In time, experience is lost as individuals leave and conditions become ripe for another blowout. Therefore, it is important to record, publicize, discuss and review case histories and past actions to learn about and prevent future disasters. Failure to use available information, not a lack of knowledge, usually causes and can certainly worsen disasters. This article is meant to disseminate information on an SPDC well blowout, analysis of causes, control methodology, etc., which will prove useful in educating and helping to avoid the disasters of blowout control in another well or region.

Surface control operations are normally more difficult to develop due to the many possible blowout scenarios; potential escalation and unknown well response associated with intermediate control steps. For example: (1) removing debris from Wellhead area; (2) extinguishing fire; (3) capping and diverting wellhead; (4) shut-in and bullhead well dead or (5) dynamically kill well.

At these points additional information is gained that guides the team to the course of action required to meet the next milestone. This well was put on production in 1966, with current wellbore configuration (figure: A 1). installed in 1970. The well has been closed-in since 1983.The well was initially completed as a Two String Dual completion (TSD) on the F5000 and F6000 sands in November 1966 without a top packer. A repair was performed in August 1970 to eliminate water production from the F6000 sand. However the F6000 failed to produce, thereafter the well was re-completed on the F4200 and F5000 reservoirs. Only the Long string has NRV installed. The F4200 interval came on stream in August 1970 with an off take rate of 500 bopd and a GOR of 2800 scf/d. By November 1974 the GOR had increased to 4700 scf/d with a production rate of 360 bopd. The interval was beaned down to control the rising GOR. In March 1983 the interval was closed-in due to high GOR. The high GOR was suspected to be due to gas coning and the proximity of the PGOC. High casing head pressure was observed in 1988 and the interval was killed to eliminate the excessive casing head pressure. A wellhead check in February 1992 revealed that the F4200 sand had come back live with a CITHP / CHP of 1250 / 1764 psig respectively. The well was subject to sabotage on the 16th May 2004 when people attempted to open the well and steal hydrocarbons.

During this operation, the well started flowing uncontrolled and caught fire. Following the uncontrolled hydrocarbon discharge with subsequent fire at the well, an Emergency response team (ERT) headed by an ERT Commander was activated as part of the overall company emergency response plan. The ERT team recognized that the first priority and single most important factor in assuring a successful blowout intervention was the formation of a focused team charged with the management of the right mix of operational and technical professionals. The ERT team on activation therefore developed strategies that required evaluating alternatives, analyzing risks and tradeoffs before reaching agreement on the mode of controlling the blowout. To avoid overlooking critical steps in development of a final strategy for the blowout control operations, clear and structured guidelines were discussed and issued to all parties concerned on a daily basis. A number of options were thus developed, evaluated and do-able and workable ones implemented by the ERT team. Options considered were:

Option A: fight the fire with the fire hydrant to contain the fire (close valve, extinguish fire and kill well).

Option B: Use CO_2 remover to deny the fire oxygen thereby extinguishing the fire.

Option C: Cut wellhead, cap and kill well or divert the fire with casing thereafter rig-up and kill the well.

Option D: drill a relief well.

The flowchart (figure: A 2) shows the various options analyzed before the well kill.

b. Discussion

Option "A" was started but later discarded when the fire thought to be an oil fire turned out to be mostly gas fire and the smoldering of the fire with foam was not effective. Unsuccessful attempts were also made to remotely close annulus valve using fabricated tool.

Option B: was discarded because of the potential hazard of the gas vapors after eliminating the fire, which could re-ignite and cause havoc. Option D was progressed together with option C, however option C was successful and thereafter the well was killed.

c. Implementation

With the intervention options analyzed and course of action chosen, the ERT went ahead to implement the plan using available resources. This meant organizing several small, sub-task forces (surface and relief well) for detailed planning, equipment procurement, modification and manufacturing, operations, kill procedures, safety, documentation and administration. Pre-planning avoided competitive pressures and personal attachments, allowing operators time to review competing proposals. While reviews are underway, an organized team was already moving toward a possible solution. Thus a site commander was appointed to work at the site with the BOOTS and COOTS personnel.

d. Equipment and material.

The key to the successful blowout control, was the proper and timely initial decisions, fast and efficient mobilization of required support. For example the BOOTS and COOTs were called in immediately, after a thorough evaluation of the blowout revealed the needfor external assistance. Civil equipment (dozers, cranes and front end loaders) and trucking were obtained locally.

In many ways surface blowout control onshore in remote areas like this case proved to be more challenging than envisaged. For example the fire was impinging on the cellar slab and deflects back thus making approach to the wellhead very difficult. Water that is needed to control fires, and protect men and equipment were in short supply and this necessitated the drilling of several boreholes and water containment pits dug around the well. Transportation and support issues were complex but successfully managed.

e. Modelling Considerations

While efforts were being made to divert flow/gain access to the wellhead, Well Flow dynamics (WFD) carried out series of simulations to get a better understanding of the rates and pressure regimes expected for the kill operation.

The objective of Well Flow Dynamics were among others to

- o Collect pertinent data
- o Set up a simulation model that matches with the actual situation on well
- o Simulate various kill methods:
- o Bullheading
- o Dynamic kill of S/S from L/S.

2 scenarios were investigated:

• Scenario 1: Blowout from the F4200 reservoir through the annulus (Figure A 3)
• Scenario 2: Blowout from the F4200 reservoir through both annulus and short string 1.9" production tubing (Figure A 4)

The most likely case is Scenario-1 blowout through the annulus, but scenario 2, blowout through both annulus and the short string tubing was also modelled. Initial result from these two scenarios showed however, small differences and can more or less be treated as the same scenario with respect to blowout rates and kill technique. Initially a match was obtained from available production data.

This was done using a permeability of 300 mD, a net pay interval of 18 ft and a mechanical skin of 78. Using these parameters in a blowout situation with open flow to the environment, (assuming scenario 1) a liquid rate of 4000 Stb/d was observed. Water rate was 550 Stb/d. A GOR of 2678 scf/stb yields a gas rate of 11 mmscf/d. The difference in rates observed in scenario 2 was negligible. Several sensitivity simulations with respect to skin factor were run. Zero skin yields a blowout rate of 10 100 Stb/d of oil. Next step in the work process was to simulate killing the blowout, initially through a bullheading job after the well was assumed capped.

Resulting production rate from the OLGA simulation was 450 stb/d (1.20 mmscf/d associated gas) with a flowing bottomhole pressure (@ the perforations) of 3120 psia.

After this steady production rate was established, the production was shut in to get an idea of the shut in pressure and to compare with the observed CHP of 1764 psig. Resulting shut-in wellhead pressure from the simulations was 1782 psia (1767 psig) and this is a good match with the measured pressure.

f. Modelling Issues

The main questions addressed by this well kill modelling were: Can the well be killed? What size of equipment and capacities, and volumes of bulk material are needed? These were then evaluated by the ERT team in terms of: Logistics and mobilization times, Cost efficiency of alternative methods, Safety and risk analysis. Often a well kill is described in terms of its main contributing element (dynamic kill, bullheading, volumetric kill, plugging, etc.). Calculations then can be made using a model or equations designed for the particular purpose. Results can be used to obtain densities, rates, pressures,

As a method is chosen and developed, detailed engineering are then provided: Pumping schedules (rate, time, power), Kill fluid types and volumes, Pressure and temperature predictions, Monitoring program. To describe the modelling procedure, dynamic kill modelling as applied to top kill through tubing was performed.

It described dynamic kill as a technique using flowing frictional pressure drop to supplement static pressure of the kill fluid being pumped up the annulus of the blowing well.

Production profiles and model set up
Initial model Assumptions
Reservoir data

Two potential reservoirs (API>450) may be feeding hydrocarbons into this uncontrolled discharge – the F4200 and the F5000 reservoirs. It is however, more likely that it is only the upper F4200 reservoir that is flowing. The reservoir temperature is estimated to be 210 deg F.

g. Blowout Simulations

Using the specified base case skin of 78 resulted in a blowout rate of 4000 stb/d with 11 mmscf/d associated gas for the annulus scenario. Figure A 5 shows the blowout rate for scenario 1 (through annulus) versus mechanical skin and Figure A 6 (scenario 2) almost identical rates.

h. Sensitivity on GOR

From the production profile it was observed that there has been a variation in the produced GOR from the well since it came on stream in August 1970. Actually, the well was closed-in in 1983 due to high GOR. To investigate the blowout rate dependency on the GOR, several simulations were performed with lighter fluids. The initial composition (GOR of 2673 scf/Stb) was recombined to specified GOR's in a range up to 9700 scf/Stb (highest specified in the data set).

Figure A 7 shows the blowout rate of gas as a function of GOR. The gas rate increases with increasing GOR. The oil/condensate rate increases to approximately 4200 Stb/d at a GOR of 5000 scf/Stb, and from that point the liquid rate decreases.

i. Bullheading

The blowout situation as described in the prior sections was assumed controlled by installing a new wellhead, after a successful capping operation. Simulations were set up to model the bullheading of the gas and condensate back into the reservoir and hence stabilize the well with water. An efficient bullheading usually require a certain pump rate in order to push gas/condensate back into the formation. As a rule of thumb the minimum mud velocity should be 1 m/s to avoid a long mixing zone. Generally, several parameters decide the efficiency of a bullheading operation:

- Pump rate
- Weight and viscosity of the kill fluid
- Hydrocarbon composition
- Well bore diameter (flow area)
- Well inclination (inclined pipes worse than vertical)
- Pore and fracture pressures
- Zone injectivities, both hydrocarbons and kill fluid.

Bullheading Simulations

Simulations were set up with different pump rates to investigate the efficiency of a bullheading operation. Water was used as the kill fluid and is more than sufficient to get a static dead well (reservoir gradient is 0.77 sg).Usually a proper bullheading operation should be planned with a certain minimum pumping velocity to ensure a short mixing zone between the hydrocarbonsand the kill fluid. In the annulus between the 7" casing and the two tubings, this 1 m/s criteria results in a pump rate of 5.5 bpm as a minimum.

When pumping at a rate of 5 bpm, the operation of displacing the entire well volume of 286 bbls would ideally take 57 minutes. A mixing zone between the phases will however cause the operation to last longer. The simulated operation lasted approximately 75 minutes before the entire volume was displaced to water. The actual pump pressure is however depending on the zone injectivity at the formations, and a low injectivity index will result in higher pump pressure for the same pump rate. In the simulations, the injectivity has been the same as the productivity for the F4200 sand. Another issue is that after the water reaches the perforations the subsequent pressure increase can be reduced by reducing the pump rate gradually at this point. E.g. the high resulting pump pressure for 7 bpm can be reduced, since all the hydrocarbons have been pushed back into the formation (a controlled operation can be simulated where the pump rate is controlled by a gauge set on the bottomhole pressure at a certain value).

j. Killing Operation

The wellhead flow/fire has to be diverted by the use of 9-5/8" casing worn over the Dual Completion Block (DCB) side outlet valve after several attempts to operate the valves failed. With spray of cooling water as shield the wellhead was assessed and the X-mas tree master and wing valves changed on the long string (L/S) which has a non return valve installed. However, the Short string (S/S) tree valves could not be changed as there was no Non return valve (NRV) installed at the time the well was closed in.

With the blowing fire diverted safely, and simulation models concluded, the ERT team proceeded to kill the well. First the L/S master /swab valves were changed on the X-mas tree with access gained to approach the wellhead. The L/S was drifted with 2" drift and thereafter killed by bullheading (squeeze killing) back the string hydrocarbon content with 80bbls of water at 1200-psi surface pressure. A 2.3 gauge ring was run to 10344 ftah followed by a 2-7/8" tubing bridge plug set at 10225 ftah. The plug was tested to 500 psi in dynamic mode.

Considering the inherent margin of error in Totco surveys obtained in this field, the opportunity was used in this well to run a North seeking gyro survey to compare with the multi shot survey earlier taken when the well was first drilled. The L/S was then perforated below the F4200 reservoir of interest with good indication while circulating at 0.25 bpm and zero pressure to avoid pressure surge from the annular flow affecting the wireline tool string. The S/S and "A" annulus was then circulation killed through the perforated holes in the L/S with 390 bbls of water by pumping L/S in and Annulus out at the rate between 4- 9 bpm and pressures between 500-1600 psi. The blowout fire was observed to be out. Thereafter kill line was lined up to the choke manifold and both the "A/B annulus" circulation killed with fluid returns through the choke.

Pressures in both SS and LS were checked and observed to be zero. A balanced cement plug was then set with about 62 bbls. Top of cement (TOC) was tagged with wireline on both S/S and L/S at 7840 ft and 8310 ft respectively. With the cement set, and TOC confirmed in both strings, the x-mas tree was changed, a 1.9 tubing bridge plug set in the S/S at 22 ft below CHH and all wellhead valves closed. The Gas divert line were then removed, and all dug pits backfilled, to mark the end of kill operation.

k. Conclusions

The well flow dynamics simulation model proved very useful as it gave insight into the kill requirements under different scenarios. This along with accurate and practical approach by the ERT site and office personnel proved instrumental to our success especially when it comes to the kill rates and expected pressures. The SPDC modelling/simulations of the kill rates and pressures in WePS agreed with the Well flow dynamics simulations. The project achievements are attributable to the following key steps:.

- The quick formation of a dedicated Task force to plan, execute, analyze and perform risk analysis for both the surface intervention operation and relief well planning was crucial

- In an operation of this magnitude, with hundreds of people at site, written and oral communication must be top priority. The key to good communication is to weigh the effects of one group's plan on another constantly. Tradeoffs can then be made so that the most efficient overall strategy is maintained.

- The repetitive steps like pep talks, re-planning and re-engineering gave successful well control operation. The predicted total volume and pressures were particularly useful in designing/ planning for the kill operation. The data from the operation confirmed that the kill performance compared well with the base case model prediction.

- Multi disciplinary planning effort, Structured site and office organisation, Utilisation of first class technical specialist in both surfacecontrol operation and preliminary relief well planning,

- Continuity of field and office personnel during planning and execution, Effective management of uncertainty and strong Management commitment and support were instrumental to the well control success.

6.2.2 Ram-type Preventers

Ram-type BOP's have two hydraulically actuated horizontal opposed rams, which are either designed to seal off an openhole or an annulus against a pipe of specific diameter. Variable bore pipe rams are also available for most ram preventers.

At least one preventer should be fitted with rams to suit each size of drillpipe in the hole. However, it is not considered necessary to install casing ram under normal circumstances; annular preventers suffice for closing on casing, unless conditions are exceptional.

On subsea stacks, pipe rams should be designed to support the string weight, (e.g. to hang-off on) and at least one set of blind/shear rams installed.

The working pressure of ram preventers should be at least equal to the maximum anticipated surface pressures, plus a margin for pumping to the well. There are several different types of ram preventers, as outlined below:

a) Pipe Rams

Standard pipe rams are designed to centralize and pack-off around one specific size of drillpipe or casing.

b) Variable Bore Rams (VBRS)

Variable pipe rams are available for some models. One set of variable rams will provide back-up for two different pipe rams, e.g., 3 ½ in., 5 in. and 7 in. Some variable rams have a limited hang-off capacity, which is dependent on relative tool joint size and ram range.

c) Blind/Shear Rams

These are designed to cut drillpipe and then seal as blind rams. The pipe stub is accommodated in a recess. Shearing of drillpipe should be carried out with the pipe stationary, which involves hanging-off on floating rigs, in tension, if practical. Care should be taken to ensure that the pipe body, not a tool joint, is opposite the rams. On some preventers, it may be necessary to increase operating pressure above 1500 psi to shear. Blind/shear rams should be specified when ordering a preventer, as some preventers require oversized cylinders or other special features. Some models of blind/shear ram are unsuitable for sour service

d) Casing Shear Rams

Normal shear rams used on drillpipe crush the pipe and then shear the flattened mass of steel. This is not effective when shearing large diameter pipe such as casing. Special shearing rams for casing should be used in deepwater drilling. Booster pistons may also be required to assure cutting larger size casing and 6 5/8" drillpipe.

Self Feeding Action of Elastomer

The front elements of ram seals have steel plates bonded to the rubber. As the rams are brought together, these steel plates meet before the preventer is fully closed; further movement of the ram bodies causes extrusion of the rubber element, thereby effecting a seal.

If the rams are used for stripping pipe, the front' face of the ram sealing element will wear. The self-feeding action brought about by the steel plates will ensure that rubber from the packing element moves forwards to replace that which is worn away.

Ram Locking Devices

Hydraulically operated ram preventers are provided with locking-screw stem extensions and large diameter hand wheels similar to the operating screws of manually closed preventers.

The main purpose of the locking screws is to manually lock the rams in the closed position after they are shut hydraulically. In an emergency, the screws can be used to close the rams if the hydraulic system fails. If the locking screws are used to close the rams, the hydraulic closing unit valve handle should be turned to the closed position. This will eliminate the possibility of hydraulic oil being trapped on the opening side of the actuating pistons.

An optional hydraulic lock mechanism (Cameron's Wedge Lock, Shaffer's Paslock and Hydril's MPL) can be used in place of locking screws to lock the rams in the closed position. The hydraulic lock holds the rams closed until unlocking pressure is applied even though the primary control pressure is released. The hydraulic ram lock was developed for subsea BOP stacks and can be used on land rigs in place of the manually operated locking screws.

Secondary Shaft Seals

All ram preventers with rated working pressure of 5000 psi or higher, should be equipped with secondary piston rod seals in case the primary rod seal fails. Due to routine wear, the primary rod seal is plastic. It is stored in a cavity until it is activated by forcing it around the ram rod. This plastic seal is used only during emergency situations. The secondary seal is designed for static conditions; movement of the rod causes rapid wear of both the seal and rod. The primary rod seal must always be repaired when the emergency is over. During the initial pressure testing of a BOP stack, the secondary seals on each ram preventer should be removed to assure that the main rod seals are tested; the secondary seal can be removed by unscrewing the energizing plug, removing the check valve and digging out the plastic packing.

Closing Ratios

Ram-type preventers have specially designed opening and closing ratios. These are the ratios between the well pressures and the operating pressures needed to open or close the rams. Closing ratios are generally in the range of six-to-one to nine-to-one. This means that a preventer having a closing ration of six-to-one would require 500 psi closing pressure to close the preventer when the wellbore pressure is 3000 psi. Opening ratios are much lower, because the wellbore pressure acts behind the ram to oppose opening. An opening ratio of two-to-one is common.

It should also be noted that, for high wellbore pressure, pressures greater that 3000 psi may be required to open some ram preventers.

Bonnet Seals

Bonnet (or door) seals are exposed to wellbore pressures and fluids. Since they can be subjected to high pressures and temperatures without being backed-up by another seal, bonnet seals are critical to the integrity of the BOP system. The seals are generally of fibrous/rubber construction and require careful handling and installation.

The following manufacturers' recommendations should be observed meticulously:

- Replace each time bonnets are opened.
- Handle carefully, particularly on installation, and store at controlled temperatures in darkness.
- Discard after one year storage.
- Manufacturers recommended torque-levels, which can be extremely high with some compression type seals.
- The type of lubricant used should be checked (make-up torque is reduced by approximately 50% if a molybdenum di-sulphide lubricant, rather that an AP15A lubricant is used).
- Bonnet faces, preventer faces and seal grooves should be clean and dry before seal installation and make-up.
- Bonnet seals should be tested after installation.

The following are important for the care and maintenance of ram preventers:

- Pipe rams should not be closed on openhole or on mis-matched pipe. This would induce excessive extrusion of the elastomer and can cause cracking or bonding failures. Ram recesses should be washed out and the ram element inspected following each well.

- Preventers should be stripped, inspected (particularly all sealing surfaces) and seals replaced annually. When in good operating condition, ram preventers should close with 300 psi or less hydraulic pressure without wellbore pressure. If high closing pressure is required during test operations, the preventer should first be checked for debris in the ram cavity and then inspected for piston rod misalignment or other mechanical problems.

- Wellbore pressure helps close ram preventers. They are designed to hold pressure from the lower side and will not seal properly if installed upside-down. Also, ram preventers are not designed to be pressure tested from the top side, as this can damage the preventer. Field experience has proven that ram preventers are more likely to leak with a low wellbore pressure than high pressure. For this reason, they should be tested at 200/300 psi prior to the rated working pressure.

- Ram preventers close faster than annular preventers, especially in the larger sizes. Usually, ram preventers require only one-third or less of the hydraulic fluid volume to close, compared to an annular. In instances where mechanical problems prevent rapid closure of the annular preventer, a ram preventer should be closed immediately to minimize additional well flow.

- The main closing unit control handle for operating blind or blind/shear rams should always be protected against accidental closure with pipe in the hole, Numerous costly incidents have resulted from accidentally closing the blind rams and flattening or cutting the drillpipe during well control or drilling operations. A flip-up cover without locking device should be used. If the handle is locked in the open position, it prevents closing the preventer from a remote station. Shear rams are NOT recommended for land rig operations.

- When aluminum drillpipe is used, special consideration rliustbe given to ram size selection. For example, 5 in. aluminum drillpipe has an outside body diameter of 5.150 in., versus a 5,000 in. body diameter for 5 in. steel pipe. Thus, regular 5 in. ram blocks must be slightly modified to seal and not damage the main tube section of aluminum pipe. In addition, 5 in. aluminum pipe has a tapered transition zone for a length of 41 in: to 46 in. on both the box and pin ends from 5.150 in. OD up to 5.688 in. OD. Standard rams will not seal on the tapered end sections. Variable bore rams can be used to seal on the body and end sections pf aluminum drillpipe.

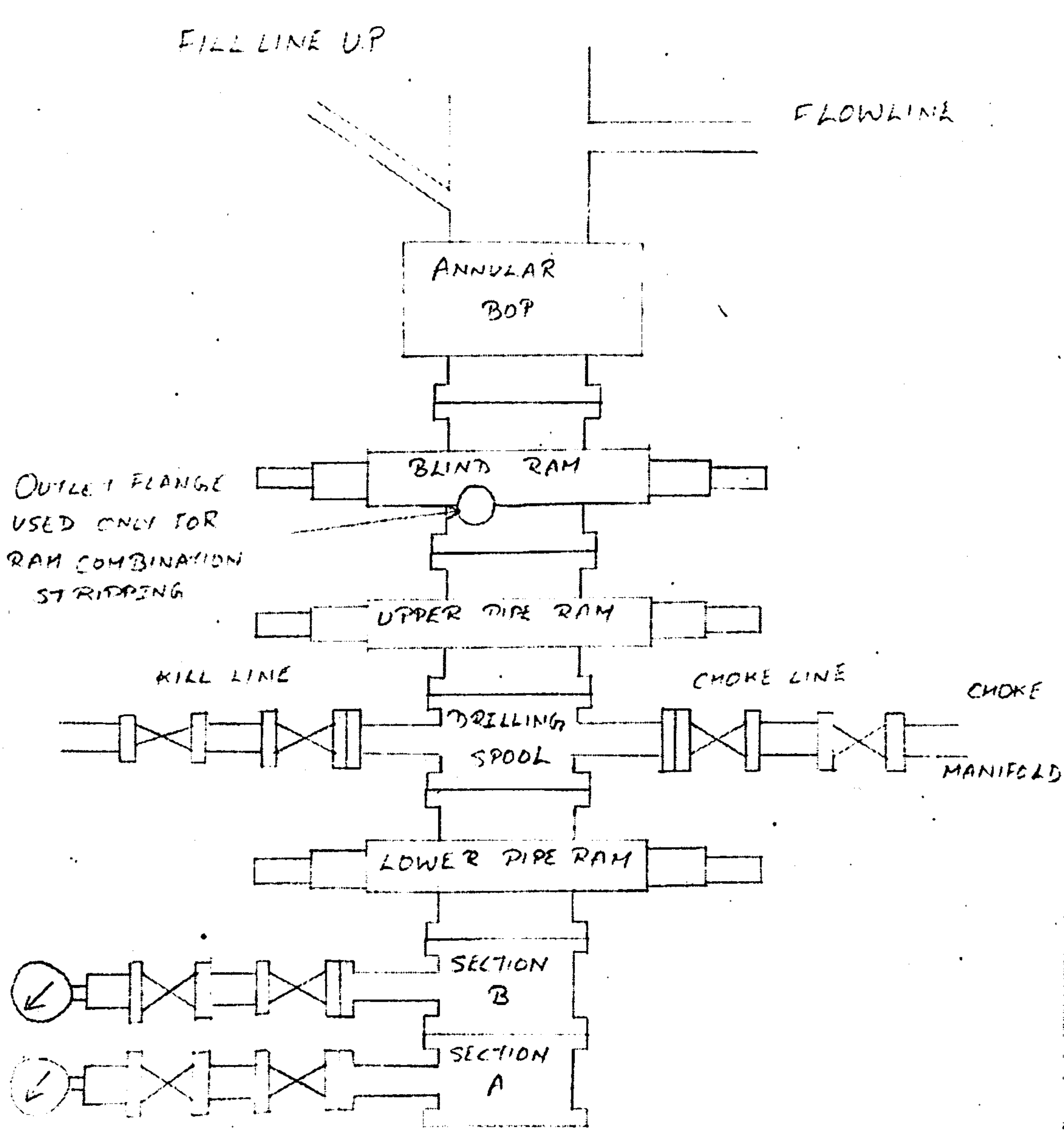
- Ram preventers can be used to strip drillpipe in or out of the hole under pressure, but it is necessary to use two preventers which have sufficient distance between rams to isolate a tool joint box. The drilling spool provides this space in a five-preventer stack. The upper and lower rams of a double ram preventer are too close together for this purpose. Excessive hydraulic pressure should not be applied on the rams when stripping pipe under pressure, because it tends to wear the resident material of the ram. The lowest ram in the BOP stack should never be used for stripping, since it is always considered the master valve.

6.3 Stack Configurations

There are various types of stack configuration that are in use- both surface and subsea, for e.g. (a) 5M Surface BOP Stack, (b) Five Inlet/Outlet 10M/15M Subsea BOP Stack for Deepwater Operations (fig. 19), (c) 10M/15M Surface BOP Stack (figure 18). Of the three type given below 10M/15M Surface BOP Stack is explained with the help of a diagram.

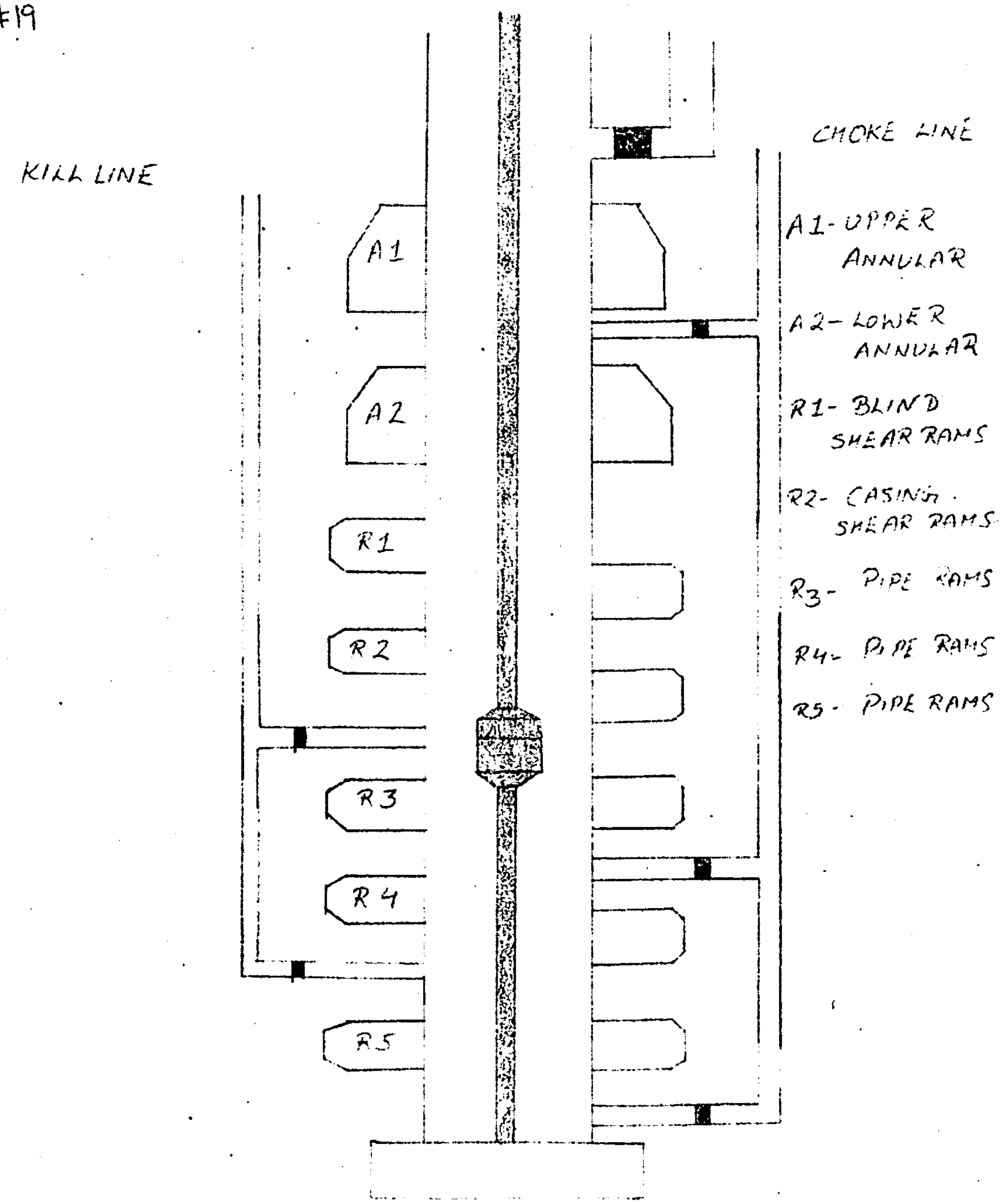
c) 10M/15M Surface BOP Stack (figure 18)

- Three ram preventers and one annular preventer in line with company policy.
- Pipe can be stripped through annular preventer and between annular and upper pipe ram. .
- Ram preventer combination stripping is possible when blind rams are replaced with pipe rams, if suitable space is available between top two ram type preventers.



10M / 15M SURFACE BOP STACK

#19



5" INLET/OUTLET 10M/15M BOP STACK FOR DEEPWATER OPERATIONS

- A line must be rigged up to the flange between the top two ram preventers to facilitate ram combination stripping.
- Annular access below the lowermost ram is possible through well outlet.
- Well can be circulated either under the annular preventer or under the upper pipe rams.
- Lowermost rams not for use for stripping operations and only used when no other ram available for this purpose.
- If casing rams are required, they should be positioned in the upper pipe ram preventer cavity. The rams should be changed out on the trip out of the hole prior to running casing, before pulling the BHA through the stack. The bonnet seals are tested against the test plug and the annular, prior to running casing.

6.4 Downhole Blowout Preventer

a. The Concept

The concept includes an inflatable packer to seal off annulus and a double acting poppet valve to seal of the drill string and to open a circulation port. The DHBOP is located below the MWD and actuated by mud pulse telemetry. When actuated, both the drillstring and the annulus are sealed off. The circulation port allows displacement and replacement of annular fluid with mud of sufficient density. Temporary control is achieved immediately. The well is fully stabilized after the well is circulated with mud of adequate density. The main advantage by using the DHBOP during influx and lost circulation is to have the well sealed off close to the bit when the well is circulated. This section describes the tool and the field test. Modifications based on experiences are also discussed. The downhole blowout preventer is based on a concept developed at NTNU Department of Petroleum Engineering and Applied Geophysics.

b. System description

The DHBOP will have no influence on the drilling process in drilling mode (Fig B1b). When the DHBOP is in the actuated mode (Fig. B1c), both drillstring and annulus is sealed off. The drilling fluid is now circulated through a circulation port just above the annular seal. The functional structure from drilling mode to actuated mode follows. Influx or lost circulation is detected. The mud pump is still running. A pressure code is generated in standpipe. The code is transmitted inside the drillstring to the DHBOP. The actuator inside the DHBOP moves the poppet after the electronic unit in the actuator hasaccepted the code. The drillstring is closed and the circulation port is opened. The pressure drop through the nozzles in the circulation port inflates the packer. The well is sealed off closed to the bit and the well above the packer can be circulated with mud of sufficient density. Temporary control is achieved immediately. The well is stabilized after the well is circulated with mud of adequate density. The tool is reset back to normal drilling mode by sending a new pressure code.

c. Description of DHBOP

This prototype is designed for actuation in the 12 ¼" open hole section. Outside diameter in the packer area is 9 ½". Above the packer and the circulation port the diameter is 8 ½". Standard stabilizers are used on both sides of the DHBOP. Total length with stabilizers is about 9 m (Fig. B1d). Total length without stabilizers is about 6 m (Fig. B1c).

Actuator. The actuator consists of a pressure sensor, electronic unit, power supply, logger, power electronics, electric motor, gear and a roller screw (Fig. B1a). The design is module based and each module is easy to manufacture, assemble and exchange. Relevant information of each module follows.

Pressure sensor. The sensor is located at the back end of the DHBOP. The element is designed to avoid mud erosion and plugged inlet. The pressure range is 0 to 600 bar and the sensor has no build-in electronics. The amplification of the signal is done in electronic unit. The input resistance of the sensor is 3 kohm. High resistance of the sensor reduces the power consumption of the electronics.

Electronic unit (CPU). Basic philosophy when designing electronics for downhole applications is to minimize the number of components. Anyway, two almost identical electronic units were used. One main electronics and one supplementary electronics. They are working independent of each other and have to agree to accept the pressure code. The electric motor is started by the electronics when the code is accepted. Motor current is continuously controlled by the electronics during actuation. The motor current increases at the end position of the poppet stroke, and is switched off by the electronics at a predetermined value. If any unforeseen motor loads should occur during actuation, the electronics will control the current to prevent parts to be damaged. The electronics are in a sleeping mode when the tool is out of hole. In this mode the current consume is less than 2 mA. The electronics wakes up when the DHBOP is exposed to pressure when run in hole. This feature will save power and protects the tool from premature actuation during transport and storage. Additional protection for premature actuation is achieved by protecting all electronics with a faraday cage made of copper. The electronic also have a watchdog timer restarting the electronics before any uncontrolled signal is sent to the motor. All electric wires for communication to other modules are located in the center of the module for simple connection and disconnection. Finally the entire module is protected from shocks and vibrations by being cased into silicon rubber. Allwires inside the module are also cased in rubber to prevent movement and thus connection fractures.

Power supply. There are three batteries. Two lithium batteries designed for downhole applications and one rechargeable nickel cadmium (Ni-Cd) battery. The Lithium batteries (7.2 volts) are used for the electronics and the logger (black box). The Ni-Cd battery (24 volts) is used for the motor. Extensive testing of the actuator was the reason for using rechargeable motor batteries. Disadvantages are limited temperature limit and self-dischargement. Lithium batteries will be used as motor batteries in later versions. Capacity of the electronics battery is 33 Ah, the logger 22 Ah and the rechargeable Ni-Cd battery 1.8 Ah. This power admits the DHBOP to be actuated/reactivated 30 times and to be in standby for about two years without changing batteries. Electronics and logger battery is build into one module. The motor battery is another module. All electric wires for communication to other modules are located in the center of each module for simple connection and disconnection. Finally the entire module is protected from shocks and vibrations by being cased into silicon rubber.

Logger (black box). The logger is recording internal temperature, external pressure and motor current. The logging device is included to improve observability of performance and is helpful in terms of optimising activation time and for any downhole failure diagnosing.

Power electronics. The power electronics consist of a traditional four-transistor motor bridge and a transistor switch. The motor bridge is controlled by the main electronics, and connects the battery to the motor in such a way that the direction of rotation is correct. The switch is controlled by the supplementary electronics, and has to be switched on to allow power to the motor.

Electric motor and gear. The electric motor has nominal voltage of 24 volt and an output power of 120 watt at the nominal speed of 3350 rpm. Using a three-stage planetary gear with reduction ratio 92.8:1 increases output torque. Both the motor and the gear are operating in an air filled chamber.

Roller screw. Inlet to the roller screw is the rotating movement from the gear. Outlet of the roller screw is an axial moving and non-rotating stem. The poppet valve is connected to the end of this stem. Several actions have been taken to reduce the total needed of power and to reduce the breakout force. That includes (1) pressure equalising the roller screw in oil filled chamber, (2) trust roller bearings, (3) releasing stored energy from disc springs during breakout and (4) low friction rotation seals. The disc springs are reloaded when the poppet enters the other position. Maximum outlet force on the stem is 100kN. This is more than double of what needed to break out the poppet during actuation at a differential pressure of 100 bar. When the poppet is moving from one position to the other, only a fraction of the power is needed.

Poppet valve. The poppet valve is used to open/close the drillstring and to open/close the circulation port (Fig. B1b and B1c). Stroke is 50 mm and the time for moving the poppet is about 17seconds. The seal is provided by metal to metal contact. Leakage due to setting in the seal surface is prevented by the spring preloaded transmission.

Circulation port. In the actuated mode, the poppet valve seals the drillstring and opens the circulation port just above the packer element (Fig. B1c). The circulation port consists of three radial ports and a metal cap for guiding the flow in parallel to the tool. This will prevent formation washout. Each radial port includes a standard bit nozzle for pressure buildup inside the tool. This pressure is used to inflate the packer element. The pressure is determined by the nozzle size. Typical rate of circulation will be about 2000 l/min and typical pressure buildup for inflating the packer will be 100 bar. The nozzles are easy to change before running in hole if another circulation rate or another packer pressure is wanted.

Packer element. Annulus is sealed by an inflatable packer element with weave type reinforcement, specially designed for multiple set (Fig. B1b, B1c and B1d). The functions of the packer are to seal annulus and to anchor the drillstring. There are three bores for mud communication to the packer element. These are opened when the circulation port is opened and closed when the circulation port is closed. The length of the bores are minimized in length and maximized in diameter to provide easy mud evacuation when deflating the packer. The packer is automatically deflated by internal stresses in the packer element when the circulation port is closed and the tool is in the drilling mode.
The sealing length of the annulus packer is about 1 m. Maximum inflation pressure is 193 bar in a 12 ½" hole and 172 bar in a 14" hole.

d. Pressure code

A drain line is connected to standpipe (Fig. B2). Pressure inside standpipe and the entire drillstring will fall when the drainline is opened. Opening and closing the drainline makes the pressure code. The current pressure code consists of two pressure drops. Each drop is 15 seconds long and the downhole pressure amplitude inside the drillstring is set to minimum 20 bar. The total time for making the code is 1 minute. Seven check points are controlled by the DHBOP to accept the code. Noise from the MWD is filtrated and will not disturb the pressure code. Emphasis has been put on making a simple and reliable pressure code, which can be used on both traditional drilling rigs and coiled tubing rigs. Emphasis has not been put on optimizing the transmission speed and pressure amplitude.

The functional structure for sending a pressure code follows. The switch for actuation on the control panel is turned on. The micro-controller inside the control panel operates a directional control valve, which is used to control a standard hydraulic operated plug valve on the drainline. When the plug valve is opened, drilling fluid is drained from standpipe to the mud pit; thus pressure will fall in standpipe. A standard choke valve controls the pressure amplitude. Hydraulic power tooperate the plug valve is provided by an air operated hydraulic power unit. The plug valve may also be hand operated as a backup.

e. Field test

In November 2000, the DHBOP was actuated and re-actuated in well "Cascina S. Francesco 1" in Italy. The field is located between Ravenna and the river Po. The DHBOP was going through a functional test in 13 3/8" casing before starting the 12-¼" drilling from 300m to 1400m. The pressure code for setting the DHBOP was made in standpipe and accepted by the DHBOP. The poppet valve inside the DHBOP moved down and closed the drillpipe. The packer element inflated and closed the annulus. The mud was circulated through circulation ports just above the packer element. Some minutes later the pressure code for re-setting the DHBOP was sent. The code was accepted by the DHBOP. The poppet valve inside the DHBOP moved up. Drillpipe was opened and the circulation port was closed. The packer element was pressure equalized but wrapped (Fig. B3) at the end of the deflation process. The reason for this failure is a combination of buildup pressure below the packer while deflating and bad anchor effect when the packer is set in casing. The problem has never occurred in open hole in previous tests. Anyway, having a temporary increase of pressure in annulus below the packer is unwanted. The reason for the packer problem is related to the concept of having only one valve for operating the packer, circulation port and the drillstring. The packer is not fully deflated before the circulation port is closed and the drillstring is opened. Thus, there will be some pressure build up below the packer element before the packer is deflated. This has not damaged the packer during previous tests in open hole, but did so during the functional test in the casing. The problem can easily be avoided by introducing an independent valve for operating the packer element.

f. Modifications

A single valve for operating the packer element should be introduced. The actuator will be equal to the current actuator, but smaller in size. The current actuator is still used for operating the circulation port and the drillstring. In this case, the mud pumps may run all the time both during setting and re-setting without building up any pressure below the packer element. High pressure below the packer during deflation can now only occur in a normal killing situation when mud of insufficient density has been circulated above the DHBOP. One solution is to circulate highest allowable mud weight before the packer is deflated. Another solution is to introduce an annular pressure sensor below the packer. The pressure is communicated acoustically through the DHBOP to the measurement while drilling (MWD) pulse generator above. All this is standard technology.

Another possibility is to introduce three actuators (Fig. B4). The first actuator operates the drillstring valve. The second operates the annular packer. The third operates the circulation port. All valves can be activated independently. In addition of being a DHBOP, the circulation port may be used for improved clean up and the drillstring valve may be used as a downhole choke. A third possibility is to introduce a retrievable compression plug with an anchor mechanism instead of the inflatable packer (Fig. B5). A compression plug can not be used in open hole, thus the packer have to be set in casing.

Advantages by introducing a compression plug are improved annular sealing and anchoring capacity. Disadvantages are longer distance to the bit. Direct drive torque motors should be used to actuate both the compression plug and the circulation port. These motors have an annular shape and will not prevent wireline operations inside the drill pipe and cementing if needed. No crossover between the motor and the compression plug will be needed and the circulation port will be very simple. Redundancy may be achieved by having several independent motors to rotate the same shaft. The drillstring valve should still be located close to the bit.

Another possible application for this tool is a test plug for the traditional BOP. Instead of running the entire drillstring out of hole and a plug into hole each time the BOP should be tested, the DHBOP based on the compression plug could be used. Product development based on systematic use of previous experiences is a key factor for success (but not a guarantee) when developing new technology. The core team in this project has through a number of years developed an adviser system for project management. The system follows the product development process from market need to final tested prototype.

Multidiscipline "help" support is linked to each activity. Example of "help" support within system reliability is reliability analysis, physical failure mechanisms, human failure mechanisms, drilling problems and checklists. The "help" system is not necessary the ultimate support. It could also be an overview of a subject making the project team able to think and communicate with specialists. A network of recommended specialists is included. All documents are linked together electronically, thus becoming an effective base for knowledge and previous experiences. Good as well as bad experiences from the DHBOP project are now integrated in the system. This approach is strongly recommended. The quality is improved and the cost and time to develop the technology are reduced.

g. Conclusion

Downhole blowout preventer is not meant to replace the traditional BOP, but to be an additional barrier when the mud is out of control. The main advantage by using the DHBOP during influx and lost circulation is to have the well sealed off close to the bit when the well is circulated. Based on experiences from the latest field tests, modifications are needed to prevent packer problems. This can be achieved by operating the packer independently from other functions.

6.5 Choke and Kill Lines

6.5.1 Surface BOP Stacks

The location of kill and choke outlets on a BOP stack will be influenced primarily by the number of rams used and their sizes.

Choke and Kill Outlets

The choke line must have a minimum ID of 3 in. The kill line may be as small as 2 in. (This might restrict operational flexibility should it be required to substitute for a washed out choke line). During normal operations, the inner (manual) choke and kill line valves should be open and the outer (HCR) valve closed.

Remote Kill Line

On a land rig, a remote kill line can belied in to the kill line so that it may be used regardless of which preventer is closed. The remote kill line should be rated at the pressure rating of the BOP stack and should terminate at a similarly rated flanged valve at least 100 ft. from the well. The purpose of this line is to enable a pump truck to be tied into the well in an emergency situation.

Wellhead Outlets

It is recommended that wellhead spool outlets are not used for a choke and kill line tie-ins. Each wellhead spool should be have dual valve isolation on one side and valve removal plugs(VRP)should be installed on the non-active side.

Check Valves

Traditionally, a check valve has been installed outboard of the sack valves on the kill line. Many rigs, particularly jack-ups have the facility to use the kill line to augment or replace the choke line. In such a hook-up, check valves are omitted. Company policy is that check valves are not mandatory on the kill line.

Choke and kill lines are generally fabricated in line with the following specifications:

- All connections should be flanged, clamped or welded. Screwed fitting, unions and chicksans should not be used on the choke lines, although minimal use is acceptable on kill lines.
- All welding should be performed under shop conditions with machine cut weld preparations. All welding should be conducted by certified welders to approved weld procedures, and all welds should be suitable, non-destructively tested and pressure tested prior to use.
- Lines, particularly the primary shock line, should be installed with the minimum number of bends. Where bends are required, target tees or block tees should be used. Swept bends are undesirable.
- Choke lines should be well-braced, to withstand severe vibration. Supports should be fitted, as required; but these should not be welded to the choke line.

6.5.2 Subsea BOP Stacks

Subsea choke and kill lines differ from surface systems:

- Subsea choke and kill lines require flexible connections at the ball/flex joint and the telescope joint.
- All subsea choke and kill line valves are fail-safe and hydraulically actuated.
- Subsea choke and kill lines are much longer. Depending on water depth, line size and mud properties, pressure losses in the lines might be significant.
- Choke and kill lines are tied into BOP outlets, not to drilling spools or the wellhead. Generally BOP stacks for exploration wells should have 4 rams and 2

annular preventers. This provides some flexibility in case a ram or an element fails during a well killing operation.

The following points should be noted regarding the major choke and kill line components:

- All valves should be fail safe. Two valves are required per outlet. Valves should be installed as close to the BOP outlets as possible and preferably in line with the outlets. Side-arms and valves should be well protected by the framework around the stack.
- Targeted tees should be used for all 90 degree bends.
- Choke and kill connections at the lower riser disconnect should be rigidly supported by the framework so that they will not part when full working pressure is applied simultaneously to both lines.
- The choke and kill line across the ball/flex joint should be flexible and not restrict movement of the joint up to its maximum designed deflection.
- Riser couplings and the LMRP stab plates should be designed to withstand induced loadings when full working pressure is applied simultaneously to both lines.
- The choke and kill lines across the telescopic joint should be able to accommodate the maximum designed travel of the joint.
- All surface connections should be flanged, clamped or welded. Screwed fittings, chicksans and unions should not be used.
- Lines should be installed with the minimum number of bends. Where bends are required, target tees or block tees should be used. Swept bends are not desirable.
- Choke lines should be anchored to withstand vibration. Supports should be fitted, as required, but these should not be welded to the choke line.
- Both the choke and kill line should be tied into the choke manifold to allow one to replace or augment the other.

Hydraulically Operated Valves

- A remotely operated valve is installed on the choke line adjacent to the BOP stack to rapidly shut off hazardous flow in the event of downstream equipment failure.
- Another advantage for remote operation is that this valve is usually located at an elevated working level in the substructure, which makes hand operation difficult and unsafe.
- Specifically designed hydraulically controlled gate valves (HCV) are extensively utilized for this service.
- The valve must be rated WOGM, which means that it is serviceable for water, oil, and gas or mud flow. The hydraulic actuator must be designed for 3000 psi maximum working pressure; however, the actuator should fully open the valve with 1500 psi control pressure for maximum design conditions. The 3000 and 1500 psi design pressures are required for compatible operations with standard BOP closing units. As an optional feature, hydraulic operated valves are available

with stem and handle for manual operating (to close but not open) in case of hydraulic system failure.

- Cameron introduced the HCR (High Closing Ratio) as the first remotely controlled valve for choke line service. This valve has the same basic design and operational features as a Cameron QRC preventer. The HCR valve has been used so extensively throughout the industry that most oil field personnel refer to any make of remotely controlled valve as the HCR. Because the HCR is limited to 5000 psi working pressure, the advent of 10,000 psi and higher working pressure BOP required additional valve development. Currently, Cameron's Type-F hydraulically operated gate valve is probably the most widely. used and is available with rated working pressures from 3000 psi to 15,000 psi. NL Shaffer's choke line valve is Type-DB, which is rated for 5000, 10,000 and 15,000 psi working pressures. Other reputable valve manufacturers' equipment may be acceptable for choke line service; however, prior well control reliability and experience should be verified.

Subsea Fail-safe Valves

These valves are made by a number of companies including Cameron, NL Shaffer, WKM, Rockwell and Vetco. Generally, these are gate valves closed with a spring operated, sometimes pressure assisted closing mechanism.

Two of the more important parameters used in evaluating these valves for floating drilling operations are their susceptibility for forming hydraulic blocks when used in tandem with water depth sensitivity of their operators. The latter is important because, when used subsea, hydrostatic head alone may be sufficient to hold the valves open (in the absence of closing pressure) if a means is not available to balance the hydrostatic forces acting on the operator and stem.

BOP Stack Connections

There are three types of connections available for blowout preventer units: flanged, studded and clamped. Bolted flanges or studs are the most common type of connection used. The tensile rating of the bolts used in these connections must be sufficient to withstand the maximum load which may be imposed.
The torque applied to the nuts and bolts must meet API recommended values to maintain the pressure seal.

API Ring Gaskets

API high-pressure connections are pressure sealed by means of ring-joint gaskets made of soft iron, low carbon steel or stainless steel. API Type-RX and Type-BX ring-joint gaskets are pressure-energized seals but are not interchangeable. Rings that have been coated with Teflon, rubber or other resilient material are NOT acceptable. All flanges in the stack and side-outlets should be fitted with new ring-joint gaskets each time they are assembled. It 'is important that the ring groove in the flange be clean and dry prior to flanging up.

- API Standard 6A, "Wellhead Equipment", provides specifications for flanged wellhead fittings.
- API Type-6B flanges are available in the following pressure rating: 2000 psi to 5000 psi range, API Type-
- 6BX flanges are available for the 5000 psi to 30,009 psi range. Bolts must always be the right size –not larger and not smaller than required for the specific bolt holes.
- Hub and clamp connectors are principally used on subsea BOP stacks to reduce the weight and height.
- The bolts are designed for easier make-up, especially in cramped quarters, because the wrench movement is downward instead of horizontal.
- When clamp connectors were first used; there were numerous problems with the clamp loosening during the drilling operation, creating a hazard in well control situations. This problem has been greatly reduced by the manufacturer furnishing recommended bolt torque make-up values and the availability of power torque wrenches on the rigs.
- Camsron Iron Works clamp connections are installed on most major manufacturer's hub and clamp preventers. When a clamp-connected BOP stack is used, recommended torque requirements should be obtained from the manufacturers, and all bolts should be made up to the required torque with power wrenches.

Drilling spools

Drilling spools are recommended for choke and kill line outlets on all BOP stack arrangements (subsea BOP stacks and low pressure surface stacks are excluded). The spool provides space between ram preventers to facilitate stripping operations and localize possible erosions during well control operations in the less expensive spool rather that the preventer body. Drilling spools should be designed and fabricated in accordance with API 6A, "Specifications for Wellhead Equipment". Most wellhead manufacturers can fabricate drilling spools to any dimension required, although lead time is usually several weeks.

6.6 Choke and Standpipe Manifolds

6.6.1 Choke Manifold

A typical choke manifold features inlets for the primary choke line, the kill or secondary choke line, and from the kill pump, two remotely adjustable chokes, two manually adjustable chokes, a straight choke bypass, a buffer chamber and outlets to the pits, direct or via the poorboy degasser. Valves upstream of the chokes should be rated to the working pressure of the BOP's; lower rated valves are acceptable downstream. Each choke can he isolated by two valves on the high pressure side. The system offers complete redundancy (except of the buffer tank), since flow can be directed via an alternative route while a section is repaired.

A bypass line to the poorboy degasser,is provided in order to be able to deal with return in the event of failure of the buffer tank. It is recognized that the majority of choke manifolds installed on drilling rigs comprise a buffer tank into which all the lines downstream of the chokes are tied. Field personnel should be aware that this design compromise seriously reduces the flexibility/redundancy of the manifold. If the buffer tank cuts out, the manifold is, in effect, rendered useless. Consideration should, therefore, be given to installing split buffer tanks and separate flare lines or, as previously mentioned, a bypass line upstream of the buffer tank. All connections should be flanged, welded or clamped. Field welding is not acceptable.

Company policy specifies that choke manifolds should incorporate at least two variable chokes on offshore rigs, one of which must be remotely adjustable. On some manifolds, mandatory in some areas, an additional outlet from the buffer chamber is provided so that hydrocarbons can be directed via production separator to a flare. An inlet to facilitate the tying-in of a specialized choke manifold curing formation testing is also provided..

On wells where there is a possibility of encountering hydrogen sulphide, all equipment and material should be suitable for sour service. The control panel for the chokes should be near the Driller's station and should have read-outs for standpipe manifold pressure, choke manifold pressure and pump stroke counters. A pressure gauge reading standpipe pressure should be located at the choke manifold if manual chokes are used during a well kill operation. The MAASP function, where fitted, should not be used.

A recording chart for standby pressurelnd choke manifold pressure may also be considered. This chart can be used when testing BOP's or when handling kicks. Under normal drilling conditions, valves on the choke line and manifold should be left open up to the valve immediately upstream of the remotely operated choke that will be used in the event of a kick. The valves downstream should be open to the poorboy degasser and mud tanks. The remote adjustable choke(s) should be left closed. The outer choke (HCR or fail-safe), valve on the BOP stack should be closed during drilling. It must be possible to record choke pressure when the well is shut-in with choke manifold lined up in this manner.

6.6.2 Standpipe Manifold

This manifold, for example, permits one mud pump to be lined up on the annulus (through killline, perhaps via the choke manifold) and the second, to kelly, or circulating head, to facilitate control of severe lost circulation. For 10,000 and 15,000 psi BOP systems, it is acceptable to use 5000 psi standpipe manifold, but the isolation valve should be the same pressure rating as the BOP stack, as should connecting pipework.

Control Chokes

Chokes are used to restrict flow exiting the well beneath a closed BOP and apply back-pressure on the wellbore. Both hydraulically operated remotely controlled chokes and manually operated chokes are used and are part of the choke manifold. Many rigs also have manual type chokes installed in the standpipe manifold as well.

Cameron Remote Controlled Choke

This choke has a bored cylinder as a choke 'seat and a cylindrical gate on a rod. As the gate is moved closer to the seat the area for flow is reduced. The seat and gate are not designed for use as a shut-off valve but under some conditions the closed choke may stop flow completely.

The gate and seat are reversible and can be serviced without removing the choke from the manifold. All parts of the choke unit are rated for H2S service. The maximum operating temperature is 4000 F. Units are available for working pressures of 5,000psi , 10,000 psi, 15,000 psi and 20,000 psi.

An air operated hydraulic pump located in the control console furnishes the power to operate the choke under normal conditions. The unit can be operated by hydraulic fluid from an attached accumulator.

Swaco Super Choke

The Super Choke employs two tungsten carbide plates with off-setting "half-moon" orifices. One plate rotates across the mud flow and as the matched orifice opening decreases the flow is reduced. The unit is designed to achieve compete shut-off.

The choke can be operated hydraulically by means of a pump working off of rig air, by manually operated hand pump permanently installed on the remote control skid, or manually by using a lever which is furnished with the choke unit. The Swaco Super Choke has pressure ratings available 10,000 psi and 15,000 psi working pressure duty.

6.7 Diverters

- If a kick is taken when the conductor is set in incompetent formation, the well will not be shut-in, but instead, will be diverted.
- A surface diverter system, consisting of an annular preventer and vent lines, allows the flow to be directed to a safe area, away from the rig and personnel.
- Vent lines should be as large (12 in. minimum of offshore rigs) and as straight as practical so as to minimize back pressure, erosion and the risk of plugging by well debris. The lines should be sufficiently braced to absorb severe shock loadings; sections likely to suffer erosion, e. g. bends, should be reinforced. There should be no restriction to the bore; any valves/in the lines should be full opening ball valves. Periodically, the lines should be flushed through to ensure that they remain unobstructed.
- To prevent the well from being inadvertently shut in, any valves on the vent line should be designed to automatically open when the diverter is closed. Any

acceptable alternative is to elevate the vent line above the flowline so that no valves are necessary.

- If the BOP stack is installed, the control panels should be clearly marked that the well is not to be closed in but that the diverter is to be actuated.
- The working pressures of the diverter and vent lines is not of prime importance (particularly on floating rigs where the slip joint packing may be the limiting factor). 500 psi is a typical rating.
- Company policy states that subsea wells should be drilled riserless until a pressure containment string is set. This is to avoid allowing shallow gas flow to the rig. If , however, it becomes necessary to drill for subsurface casing with a riser, company policy states that the well will be diverted subsea in the event of a shallow gas flow.

The most likely stack-up that will be used to divert subsea will comprise the following:

1) Pin connector with subsea dump valves (minimum10 in ID)
2) LMRP with annular preventer.

This will be a relatively inexpensive stack that will, 'inmost cases, be made up mainly from existing rig equipment. In the event of a shallow gas flow, the dump valves will be opened and the annular closed to divert subsea. In order to move the rig, the LMRP can be disconnected and the well allowed to flow at the seabed.

6.8 Control Systems

The control system provides the means to individually close and open each BOP and valve conveniently, rapidly, repeatedly and at the correct operating pressure. The equipment should be designed to operate in emergencies when primary rig power may not be available.

Following are the essential elements of' a control system:

- Power source (s)
- Control manifolds
- Accumulators
- Pipework/Hose Bundle and Wiring connections

Detailed specification for a particular application will be governed by the number, size and pressure rating of BOP's. Water depth considerations will also influence the design of subsea BOP control systems.

Power Source

Primary Power Source

The primary power source should be the electrical driven pump (or pumps) located at the main control manifold. For 3000 psi accumulator systems, the pump(s) should incorporate a pressure switch set to cut in and out at 2800 psi and 3000 psi, respectively. Diesel-driven pumps may be substituted for land rig applications.
The electric pump output should be twice that of the secondary air pumps. The combined output of electric and air pumps should be sufficient to charge the accumulator system from pre-charge to operating pressure in less than 15 minutes and sufficient to close an annular preventer (without accumulator assistance)in less than 2 minutes.

Secondary Power Source

The secondary power source should be the air power pump system, located at the main control manifold.

For 3000 psi accumulator systems, the pumps should incorporate a pressure switch set to cut in and out at 2750 psi and 3000 psi, respectively. A standby diesel-driven air compressor piped to the pumps should be provided at a location away from the primary rig power source, and where possible, 150 ft. from the well axis.

Battery packs

Where electric panels are used and for electro-hydraulic systems, a battery pack is required. This should be located, where possible,150ft from the well axis.

Control Manifolds

Ideally, the BOP control system should be equipped with three control manifolds or panels.

- Central (Main Control) manifold
- Driller's Control Panel
- Rémote Manifold (or Panel)

a. Central (Main Control) manifold

This manifold should be located away from the rig floor area in an accessible location. It may be all hydraulic, air-hydraulic or electro-hydraulic. The accumulators and charge pumps are usually located with this manifold.

Required features include the following:

- A regulator to reduce accumulator pnissure to manifold (operating) pressure for the ram preventers and valves.

- A regulator to reduce accumulator pressure to the variable operating pressure for annular preventers.
- Control handles, or switches, for all functions. An additional function is required on subsea stacks to transfer command between hose bundles or pods. A hinged cover should be placed overcritical functions (shear/blind rams, wellhead disconnect). A locking device should not be used.
- Pressure gauges for accumulator, manifold and annular pressures.
- A valve to bypass the manifold regulator.
- Tie-in points for accumulators, charge pumps, remote panels and airlines.
- A vent line for bleeding off accumulator fluid to the storage tank.
- A relief valve for the hydraulic and electric pumps.
- A flowmeter to indicate the volume of fluid used in operating a function (essential on subsea stacks, desirable on surface stacks).

b. Driller's Control Panel

The panel should be located on the rig floor within easy access of the Drillers station. It should be air or electric operated. Explosion-proofing is required for electric panels.

Required features include the following:

- Controls for each BOP stack function and to adjust the manifold regulators.
- Read-outs for the accumulator pressure, regulated manifold and annular pressures and flowmeter.
- Air supply pressure read-out.
- A schematic of the BOP arrangement showing kill and choke line outlets and having ram sizes marked
- Covers, or interlocks, for critical functions, e.g., shear rams, wellhead disconnect.
- Visual and/or audible warning devices for low accumulator pressure, air pressure or fluid levels.

c. Remote Manifold (or Panel)

This panel should be located a safe distance from the well axis. For offshore rigs, it is normally located in the Toolpusher's office. It should be air or electric operated and include the following:

- Controls for each BOP function.
- Schematic of BOP arrangements, showing kill and choke line outlets and ram sizes and positions.
- Covers or locks for critical functions.
- Visual and audible alarms for warnings, such as low accumulator pressure, air pressure or fluid volumes.

Accumulators

The hydraulic fluid required to operate the BOP functions is stored in accumulators, pressurized against a nitrogen inflated bladder. The accumulators should be located near the main control manifold location.

The purpose of the accumulators is to provide a store of hydraulic energy and a high rate supply of hydraulic fluid to the BOP functions. The response time of the BOP functions is, therefore, independent of the output of the pumps.
For subsea installation, at least two accumulators should be isolated from the main bank supply to provide pilot line pressure. Also, to ensure acceptable response times, additional accumulators should be mounted on the BOP stack.

Accumulator bottles should be used as surge dampeners on annular preventers for stripping operations on both surface and subsea BOP stacks.

Accumulator Precharge

Operating pressure of accumulators is generally 3000 psi. The optimum bladder inflation or precharge pressure, is governed by the minimum acceptable pressure remaining in the accumulator after operation of the preventers. About 1200 psi is required to hold some annular preventers closed. A precharge of 1000 psi will retain a small liquid reserve in the accumulator when pressure in the system falls to 1200 psi.

Sizing of Accumulators

Company policy for surface stacks specifies that the total accumulator volume should be 1 ½ times that required to close one pipe ram and one annular preventer and open one hydraulically activated choke and still retain accumulator pressure equal to 200 psi above pre-charge pressure without pump assistance.

The following is an example of the technique that can be used to size accumulators for a surface stack
(One Hydril GL 18 ¾ in. 5M annular and 3 Hydril18 ¾ in. 10M ram preventers):
Volume to close:
1Annular =44.0 gal
1 Ram =17.1 gal
1 HCR Valve =0.6 gal
Total Fluid required =61.7 gal x 1.5 = 92.559al

Pre-charge to 1000 psi
Maximum operating pressure = 3000 psi
Minimum operating pressure = 1200 psi
Therefore:
$P_1 = 1000 + 15 = 1015$ psi $Z_1 = 1.0$ T = 80 degrees E F

P_2=1200 + 15 =1215 psi	Z_2 =1.06	V_1= 10 gal (11 gal bottle minus 1 gal bladder replacement)
P_3=3000 + 15 =3015 psi	Z_3= 1.06	

Where:
P_1 = Pre-charge pressure (psi)
P_2 =minimum operating pressure (psi)
P_3 =maximum operating pressure (psi)
V_1 = bladder internal volume at pre-charge pressure (gal)
V_2 = bladder internal volume at P_2 (gal)
V_3= bladder internal volume at P_3 (gal)
Z =compressibility factor for nitrogen

Using the gas law:

$$\frac{P \times V}{T \times Z} = \text{constant}$$

So in this case:

$$\frac{1015 \times 10}{1.00} = \frac{1215 \times V_2}{1.02} = \frac{3015 \times V_3}{1.06}$$

V_2 = 8.52 gal
V_3 = 3.57 gal
Usable volume = V_2 -V_3= 8.52 -3.57 = 4.95
The useable volume is a requirement for
92.55/4.95 = 19 bottles

Subsea Accumulators

Accumulators can be mounted on subsea BOP stacks to perform three separate functions:

Response Improvement

With increasing water depths, the speed with which subsea preventers may be operated decreases. This is caused by expansion of the fluid supply hoses and pressure losses in the lines. (Note that response time is a function of the hose length and not the water depth). Response time can be improved by mounting accumulators directly on the BOP stack. Space and weight constraints will limit the number of accumulators which can be stack-mounted.

Emergency Use

All floating rigs are generally equipped with an acoustic back-up control system. For dynamically positioned rigs and rigs to be used in hazardous (e.g. ice flow) areas this is essential equipment. In such installations, stack-mounted accumulators should be at least capable of closing upon receipt of a command from the acoustic system. The accumulators should be manifolded at the stack so that fluid is not lost, should the supply lines from the rig be severed. The acoustic system and accumulator system should be tailored to the stack configuration.

For subsea stacks, a tie-in should be provided for diver or ROV assistance. Ideally, this will be for shear ram activation and will also include LMRP disconnect and wellhead connector disconnect.

Surge Dampening

Surge vessels should be provided for subsea annular preventer$ to lacilitate stripping, according to manufactures recommendations. Some preventers require surge vessel on the opening as well as closing sides. Normal 10 gal capacity accumulators should be used.

Sizing of Subsea Accumulators

Company policy for the sizing of the accumulators for a subsea stack should be more rigorous than for a surface stack. The accumulator capacity should be 1.5 times the volume required to open and close all the well control functions and still retain accumulator pressure at 200 psi above initial pre-charge pressure.

The majority of the accumulators will be located at surface, However, a small quantity may be located on the stack, in order to speed the response of the system. The total volume of accumulators required will be determined by company policy (or local legislation, if more rigorous). The total volume will be provided by the sum of the fluid available at surface and subsea, at the stack. The surface-located accumulators are sized as previously described; however, a different technique is used for subsea accumulators.

The basic difference between designing for surface operation and subsea operation is that the precharge pressure must be altered to take account of the hydrostatic pressure of the fluid in the supply lines. The useable volume from each subsea accumulator bottle will be lower than the equivalent surface bottle. The deeper the water, the greater will be the reduction in useable volume.

Pipework / Hose Bundles and Wiring

For surface stacks, the simplest hook-up is to assign a dedicated high capacity conduit to each individual function. When a particular function is selected, fluid flows from the accumulators through a regulator, directly to the function. Concurrently, the opposite function is vented. and the displaced fluid is returned to the reservoir. When considering a surface hook-up, the following should be noted:

- Company policy (after API RP53) recommends that the system ensures ram and small annular preventers (less that 20 in.) close within 30 seconds and larger annular preventers within 45 seconds.

- Control lines should be seamless steel tubing of 1 in. in minimum nominal size and of a pressure rating at least equal to the working pressure of the control system (usually 3000 psi).
- Unions and swivels should be used in the BOP stack area to preclude stressing of the lines.
- BOP closing and opening lines should be routed so as to minimize the risk of the damage in the event of a fire or falling debris. Flammable hoses should not be used on surface installations.
- A simple hook-up is impractical for subsea applications; too many individual lines are difficult to handle and the pressure drop through the length of line is too great for acceptable reaction times. Instead, hose bundles are employed, which contain orie high capacity (1 in.) conduit (to transfer the hydraulic fluid required to operate all functions and recharge the subsea accumulators) and up to 64 pilot (3/16 in.) lines (to direct and control the flow of fluid to a particular function). The bulk line is "teed" with the subsea accumulators and terminates at a regulator, which reduces the accumulator pressure to operating pressure.
- The output of the regulator is manifolded to the pilot valves. The pilot lines terminate into function dedicated plot (SPM) valves, which respond to accumulator pressure when a function is selected. Each allows regulated fluid to flow via a shuttle valve to a particular function. The displaced fluid form the opposite function is vented at this pilot valve.
- The pilot valves and regulators are housed in a wireline retrievable pod, which is duplicated to provide complete redundancy. A shuttle valve, located at each function, allows control by either pod.

When considering a subsea system, the following should be noted:

- Company policy (after API RP53) recommends that the system ensure ram preventers close within 45 seconds and annular preventers within 60 seconds of surface actuation. Electro-hydraulic systems will be required where water depths preclude satisfactory closing times with all hydraulic systems.
- Systems should be duplicated in all hydraulic and electric lines from the main control panel to the BOP stack functions, i.e., there should be 100% redundancy. The driller's panel and the remote panel should be designed to select and operate either system.
- Dynamically positioned vessels and rigs operating in hazardous areas should have an acoustic back-up system to secure the well and release the riser.
- Any unused functions (such as when the Io.wpressure stack in a two-stack system is run) should be blanked off to ensure that fluid is not vented,inadvertent operation of that function.

Operating Fluids

For subsea systems, where the fluid from the main supply line is dumped when it is vented, the fluid should be potable water with the recommended percentage of soluble oil added to prevent corrosion.

Control line fluid is in a closed system and, hence, is not replaced. It is, therefore, important to flush out the control lines with the recommended fluid mix when the pods are pulled, prior to rerun.

In all cases, the fluid mix should be maintained year round, such that the fluid will not freeze at the minimum anticipated temperature for the year. Pure ethylene glycol should be added to prevent freezing when necessary. Under no circumstances should sea water be used. The reservoir should be self-filling, with an automatic mixing system for additives. Operating fluids must be non-pollutant and bacteria resistant.

Most surface installations employ a simple closed system with the operating fluid returned to the reservoir when it is vented. Either a light hydraulic oil or a subsea-type fluid is suitable.

The accumulator fluid reservoir should have a capacity of twice the working liquid volume of the accumulators.

7. WELL CONTROL IN CAMPOS BASIN – BRAZIL- A CASE STUDY

7.1 Introduction

By far, Campos Basin is the most prolific Brazilian basin and for this reason most of the exploration and production efforts have been concentrated in that area. It is located nearly 250 Km north from Rio de Janeiro. In 1959 the basin had its first well drilled in a location called São Tomé Cape. Nowadays, with more that 1300 drilled wells, this region accounts for nearly 75% of the total daily oil production in Brazil. The reserves in Campos Basin located in water depths from 400 m to 1000 m (deep waters) and over 1000 m (ultra deep waters) accounts for 73% of Brazilian hydrocarbon total reserves. High oil production rates and the difficulty and complexity of well control operations in those ever-increasing water depths have demanded from the managerial and technical bodies of Petrobras, especially those from the Campos Basin Exploration and Production Operational Unit (E&P-BC), a huge and continuous effort in order to minimize the occurrence of well control problems that could bring heavy losses to Petrobras. In Campos Basin, the Well Safety and Drilling Contracts Group (GSC) of the Well Engineering Division (GENPO) is responsible for promoting actions in order to make drilling, completion and workover operations safer, especially in deepwaters. These actions aim at precluding the occurrence of blowouts and reducing the rig downtime due to well control equipment failure to less than 3% of the total operation time. The most important actions are listed below:

1. Personnel Qualification in Well Control

- Require well control certification for the supervisory and fundamental certification levels (to be defined later in this paper) for Petrobras and contractors personnel.
- Suggest the well control certification for the introductory level.
- Control the above action through the creation of a control item called Well Control Certification Index (COPO).
- Require and control the conduction of well control drills.

2. Well Control Equipment

- Carry out the acceptance inspection of the well control equipment of new drilling units. It includes the testing of BOP rams and the shearing of drill pipes by the shear ram at surface conditions and at subsea conditions on dynamic positioning vessels during the testing procedure of the emergency disconnection system (EDS).

- Carry out annual audits at the rig site to verify:
    - the preventive maintenance plan
    - the minimum blowout preventer spare parts available
    - the inspection certificates required by contract

- the implementation of proper well control practices and procedures
- the overall conditions of the well control equipment

- Monitor the control item IBOP (Rig Downtime Due to BOP Repair Index)

- Require from the drilling contractors inspection certificates of the following rig equipment:

  - BOP (each two years)
  - Riser joints (annually)
  - Telescopic joint (annually)
  - Flex and ball joints (annually)
  - Choke manifold (each two years)
  - Accumulator and control unit (each two years)

3. Follow and monitor the well control equipment.

The following sections of this paper will show in details the development, implementation and main aspects of the Safety Program for Dynamic Positioning Vessels (DPPS), the Blowout Contingency Plan for Campos Basin and the qualification in well control of the rig personnel working in Campos Basin.

7.2 Safety Program for Dynamic Positioning Vessels

(DPPS)Aiming at making drilling and production operations from dynamic positioning vessels safer, Petrobras and its contractors stated in 1993 the development of the Safety Program for Dynamic Positioning Vessels (DPPS). This program encompasses several topics related to the safety of dynamic positioning vessels including those related to well control. In this paper, only the aspects associated with well control practices, procedures and equipment in deep waters will be addressed.

As a task of the DPPS, Petrobras invited its drilling contractors to present and discuss their well control procedures and equipment configurations. The information gathered during this process and the experience of the Petrobras professionals in well control were instrumental in the development of the Well Control Manual for Deepwater Operations1 that was finished in November 1993 after its approval in a technical meeting held in Rio. This manual contains the principles and guidelines for the adherence of well control equipment, well design and drilling operations to the prevention, detection and control of kicks in dynamic positioning and moored vessels operating in deepwaters.

In 1996, the manual was revised and approved for use in the Campos Basin by all deepwater drilling contractors attending a second technical meeting held in the city of Macae. All meeting participants have accepted three operational procedures: the well shut-in without checking for flow, the use of the hard close-in method and the utilization of the driller's method for kick circulation. A new well control worksheet and a section covering well control equipment testing were incorporated to the manual:

Finally, in August 1998, a third technical meeting was held in Macae to analyze the use of the manual since the last meeting (1996) and to discuss another relevant aspects concerning well safety in deepwater operations. Currently, the manual is the basic document for well control issues in Campos Basin. It has been used to guide the work of GSC professionals during the well control audits, equipment testing, personnel certification follow-up and drills execution. The dissemination of the topics covered in the manual has also been done through the Well Control Training Manual –Supervision Level2 which is the textbook of the well control training program. The nonexistence of deepwater accidents related to well control in the Campos Basin indicates the importance of the development and implementation of this safety program.

The most important topics presented in the manual are listed below:

- Use and installation of devices or equipment to conform the particularities of the prevention, detection and control of deepwater kicks. The value of well control equipment for the kick prevention, detection and control is emphasized in the manual respectively though the use of mud logging units, the use of accurate detection devices (placed in the mud and trip tanks and in the mud flow line) and the minimum requirements and configurations for the blowout preventors and choke manifold.

- General preventive measures to avoid kicks. They refer to the incorporation of well control aspects into the well design such as kick tolerance concept and the possibility of hydrate formation and to the regular procedures such as the update of the well control worksheet, the execution of inspections and well control equipment testing and the follow-up of personnel qualification.

- Specific measures to prevent kicks in deepwater operations. They include the drilling of pilot wells to avoid shallow gas events, the use of riser safety margin and the avoidance of using oil based mud.

- Kick detection and shut-in procedures. It is stressed the importance of detecting and closing the well in the shortest period of time. Thus, it is recommended that the well should be shut in without checking for flow as soon as a kick warning sign is observed. It is also recommended the use of the hard close-in method.

- Kick circulation procedures. In the section of the manual, general instructions related to kick circulation are presented such as the check of circulation pressures and pumped strokes, the choice of the slow pump rate and the choke and kill lines configuration, the removal of trapped gas in subsea BOP stack and the prevention of hydrate formation. It is recommended the use of the driller's method. The dynamic volumetric method is recommended when circulation is not possible.

- Well control worksheet for the driller's method used in deepwaters.
- Qualification and responsibilities of the rig personnel in the prevention, detection and control of a deepwater kick. This section presents the requirements for training and certification in well control and lists the responsibilities and positions of rig crew members during the kick control operations. It also discusses the implementation of well control drills.

7.3 Blowout Contingency Plan for Campos Basin

The Blowout Contingency Plan for Campos Basin3 was approved in May 1999. The section presents the 10 items that composes the plan and comments its most important aspects. In Item 1, the objective of the plan – that is to establish the procedures and actions to be followed by the Emergency Control Organization (OCE) and by the rig crew in case of blowouts – is stated.

In Item 2, the preventive measures and the responsible sectors or persons for the execution or control of these measures are defined. These measures include (a) the requirement for well control certification of professionals involved in drilling, completion and workover in both supervisory and fundamental levels and the recommendation for certification of professionals in the introductory level; (b) the requirement for the execution of well control drills, and (c) the minimum amount of barite to be maintained at the drill site. The responsible sectors or persons for the execution or control of a certain preventive measure are also stated.

Items 3, 4 and 5 refer respectively to norms and regulations, definitions and terminology, and delimitation of the area to be covered by the plan (the blowing well area and the rig or rigs to be used during the blowout control operations). Item 6 refers to the characterization of Campos Basin region, to the characterization of the facility (rig) involved in the blowout according to its own contingency plan, and to the accident hypothesis which are shown in Figure C1. Item 7 presents the Emergency Control Organization (OCE) that is a part of an overall emergency plan called Contingency Plan for the Campos Basin (Figure C2). It is always convoked when an emergency such as a blowout takes place. Item 8 shows the course of actions to be taken to control a blowout. Figure C3 shows a flowchart of these actions and the four stages of the control: a) immediate actions (series of preplanned measures to be implemented just after the blowout that are independent of the nature of the blowout); b) blowout containment procedures (steps to lessen the damage from the blowout); c) blowout control (operations to control the blowing well that comprise surface intervention and/or drilling of relief wells); and d) assessment of the actions taken during the blowout (to be done by a task force after the blowout control).

Tables C1, C2 and C3 show respectively the actions to be taken in the three first stages. The communication process is also addressed in this item. Upon the blowout occurrence, the rig personnel should notify as soon as possible the operational unit of Campos Basin (E&P-BC) which in turn notifies the coordinator of the Contingency Plan for Campos Basin. Then, he convokes the other members of the Emergency Control Organization to meeting an emergency control room equipped with all resources necessary for the evaluation and control of the blowout.

Item 9 presents the available resources in terms of fire fighting boats and vessels equipped with emergency hot-stab system. Finally, Item 10 states that the manager of the Well Engineering Division (GENPO) is the responsible person for the administration of the blowout contingency plan. The plan also provides a list with the names, telephone numbers and addresses of well control specialists of Petrobras and another with the names of blowout control companies. Well Control Qualification of the Rig Personnel
The well control qualification of the rig personnel working in Campos Basin is done through the Petrobras Well Control Certification and Training System and through the well control drills conducted at the rig site. Petrobras has adopted the IADC Well Control Accreditation Program (Well CAP) as its official certification system since July 1996. This system considers three levels of certification:

- Supervisory level – required for the Petrobras′ representative on the rig (company man), mud engineer, and rig superintendent and tool pusher. The certification is granted when an individual successfully completes a 40-hour course in well control principles, practices and equipment. To successfully complete the course, the professional must score a minimum of 70 % on the written exam, attend at least 90% of the total course time and score a minimum of70 % on the simulator test. The certification is provided in two options (surface or subsea stack) and is valid for two years.

- Fundamental level – required for driller and assistant driller. The certification in this level has the same requirements, validity and options as those of the supervisory level.

- Introductory level – recommended for derrickman and floor hand. To obtain the certification in this level, the candidate must pass a 24-hour course in well control principles, practices and equipment (minimum score of 70% on a written exam) and attend at least 20 hours. The certification is also provided in the two stack options and is valid for two years.

The certification system is conducted by two training institutions: North-Northeast Human Resources Development Center (CEN-NOR) that provides well control training and certification mainly for the supervisory level and Petrobras Training Center in Taquipe, (CETRE) for fundamental and introductory levels.

The well control drills are designed to familiarize the crewmembers with their functions so they can perform them promptly, safely and efficiently during the kick detection and well shut-in procedures. All crews involved in drilling, completion and workover operations in the Campos Basin should be submitted to these drills. Two kinds of drill are conducted in Campos Basin: pit and trip drills. The total time for the crew to close the well should be measured and recorded on the driller's report along with the crew member names and the kind of drill. These drills should be performed at least once in two weeks with each crew. Downtime Due to BOP Repair Index Downtime Due to BOP Repair Index (IBOP) is another control item monitored in Campos Basin. This index is defined as the percent of rig downtime due to BOP repair with respect to total operation time within a month. Figure C6 shows the evolution of this index in the Campos Basis. It can be seen a decreasing trend of this index in the time interval considered (1997 to 1999). It also shows the evolution of this index in the last twelve months. Also in the graph is shown the control item Total Downtime Index (ISR) define as the percent of total downtime due any repair with respect to the total operation time within a month.

7.4 Conclusions

The actions taken in Campos Basin in order to make drilling, completion and workover operations safer, especially in deep waters, have proved to be efficient. Preventive measures such as the development and implementation of a safety program for vessels operating in deep waters, the implementation of well control audits at the rig site, the execution of well control equipment testing and the qualification of the personnel involved in deepwater operations were instrumental for absence of serious accident related to well control in the last ten years in Campos Basin even considering the technical difficulties with the ever increasing water depths. However, in the case of an occurrence of a well control accident, Campos Basis staff has developed a blowout contingency plan to mitigate the consequences of the event.

8. CONCLUSION

Proper condition monitoring is an important part of drilling operation so as to gain control of the well by primary well control methods in the event of a kick. A proper training to the rig personnel will ensure that all preventive measures are being taken at the drill site. However, in the case of an occurrence of a well control accident, a blowout contingency plan should be in place to mitigate the consequences of the event, such as the one developed by Campos Basin staff. It is always to be remembered that well control is the responsibility of everyone on the rig site.

The technical advancements in the designing and making of Blow-out Preventers have been applaudable in the past few years as the deepwater drilling has increased tremendously. The rotating blow-out preventors and the downhole blow-out preventers have added that extra bit of safety factor in drilling operation. These blow-out preventers can be used simultaneously with the conventional ones. The chances of loss of lives and wealth will certainly go down if these developments are put in practical use.

Signature of Candidate.
Date 5/1

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1. Books

Name	Author	Publication
a) Blowout Prevention	W. C. Goins, Jr.	Gulf Publishing Company
b) Blowout Prevention and Well Control	Translation from the French by Paul W. Ellis	Technip, Paris

2. Papers/Articles

Title	Written by	Year
a) Downhole Blowout Preventer	A.Andersen, SINTEF Petroleum Research and A. Sivertsen, NTNU Department of Petroleum Engineering and Applied Geophysics	2001
b) How Blowout Preventers Work	Ado N. Vujaslnovlc, SPE, NL Shaffer	1988
c) Reliability of Deepwater Subsea Blowout Preventers	Per Holand, SINTEF Industrial Management	2000
d) Modelling and Management of Annular Surface Blowouts-An SPDC case Study	Otutu.F, Mojeed Alli, Ogunkoya.A, Ubani.O, Ezewu.C, Emesi John, Onwuzurike.C, Shell Petroleum Development Company Of Nigeria Limited, Morten Haug, Well Flow Dynamics, John Wright, John Wright Company	2005
e) Well Control in Campos Basin - Brazil	F.S.B. Martins, O.L.A. Santos, SPE, and I.L. de Paula, Petrobras	2000

ANNEXURES

1. Graphs:

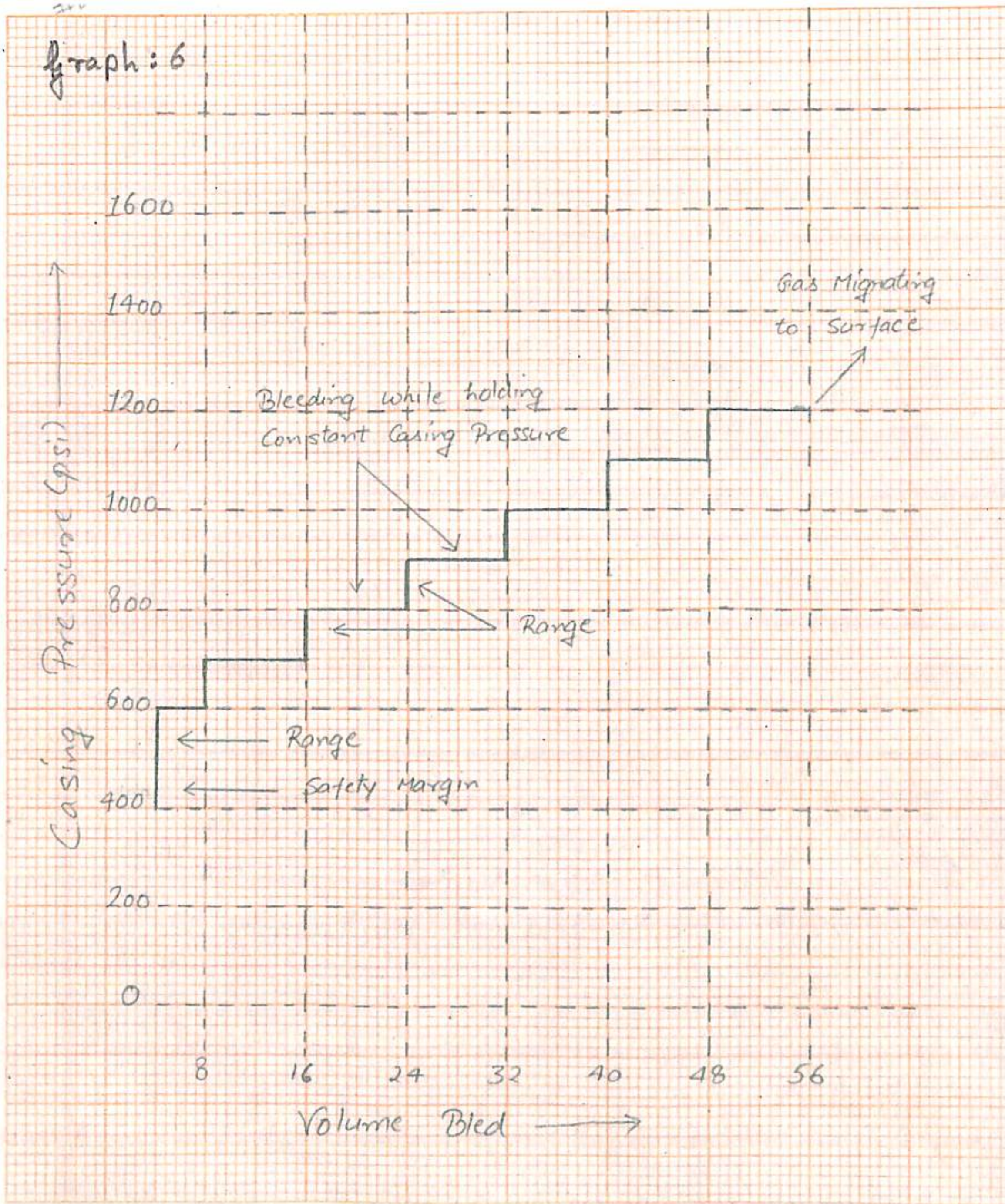
   #6, #7, #10, #11, #12, #13, #14, #15, #16, #17

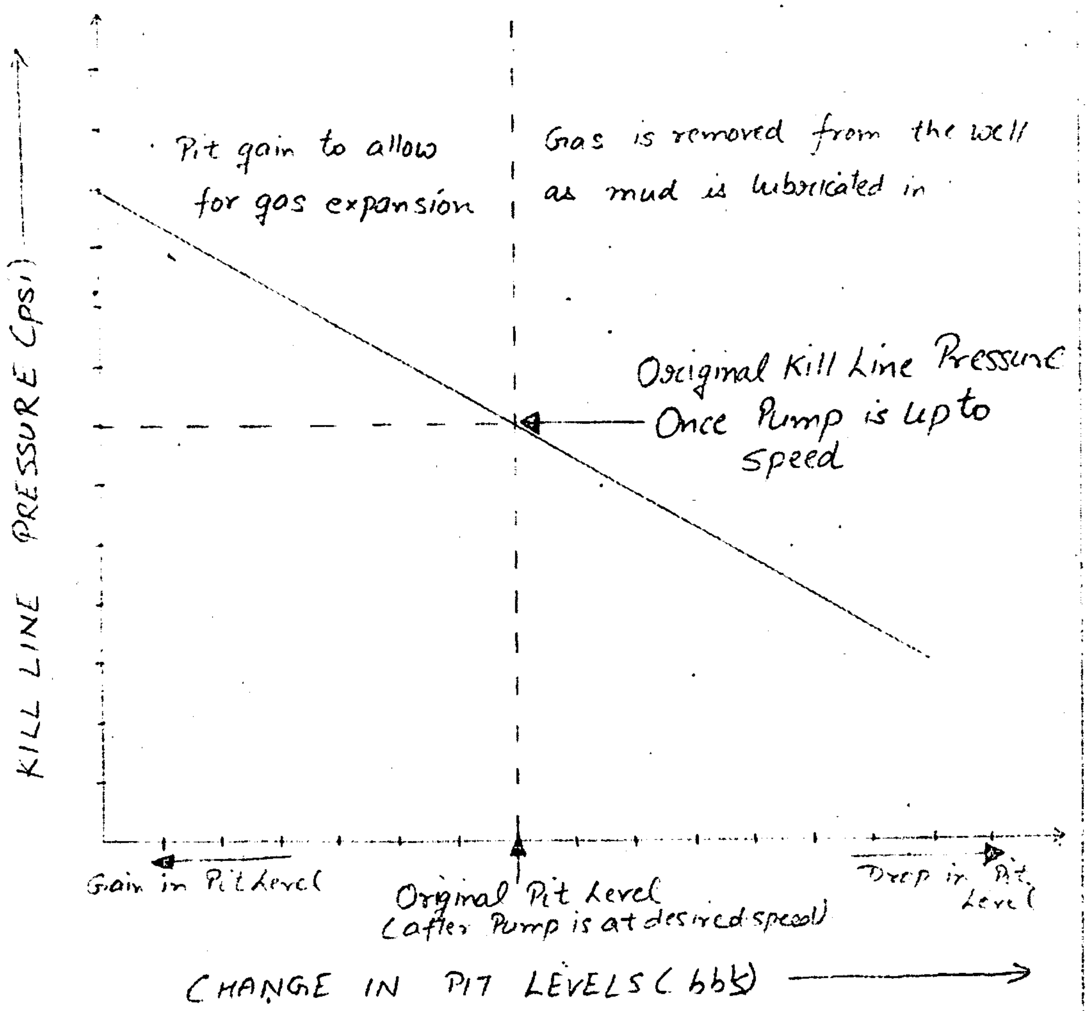
2. Figures:

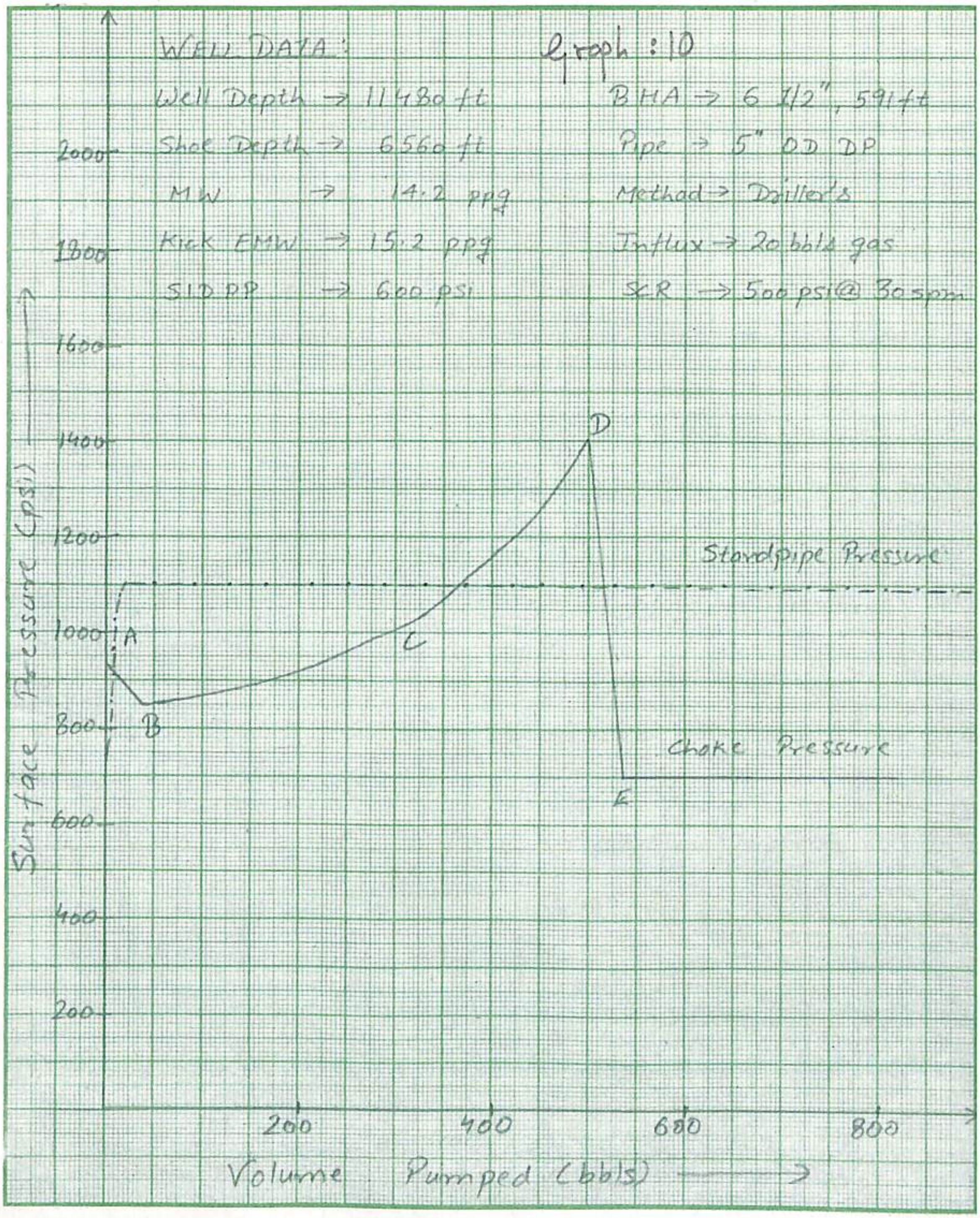
   A1 – A7, B1- B5, C1 – C6.

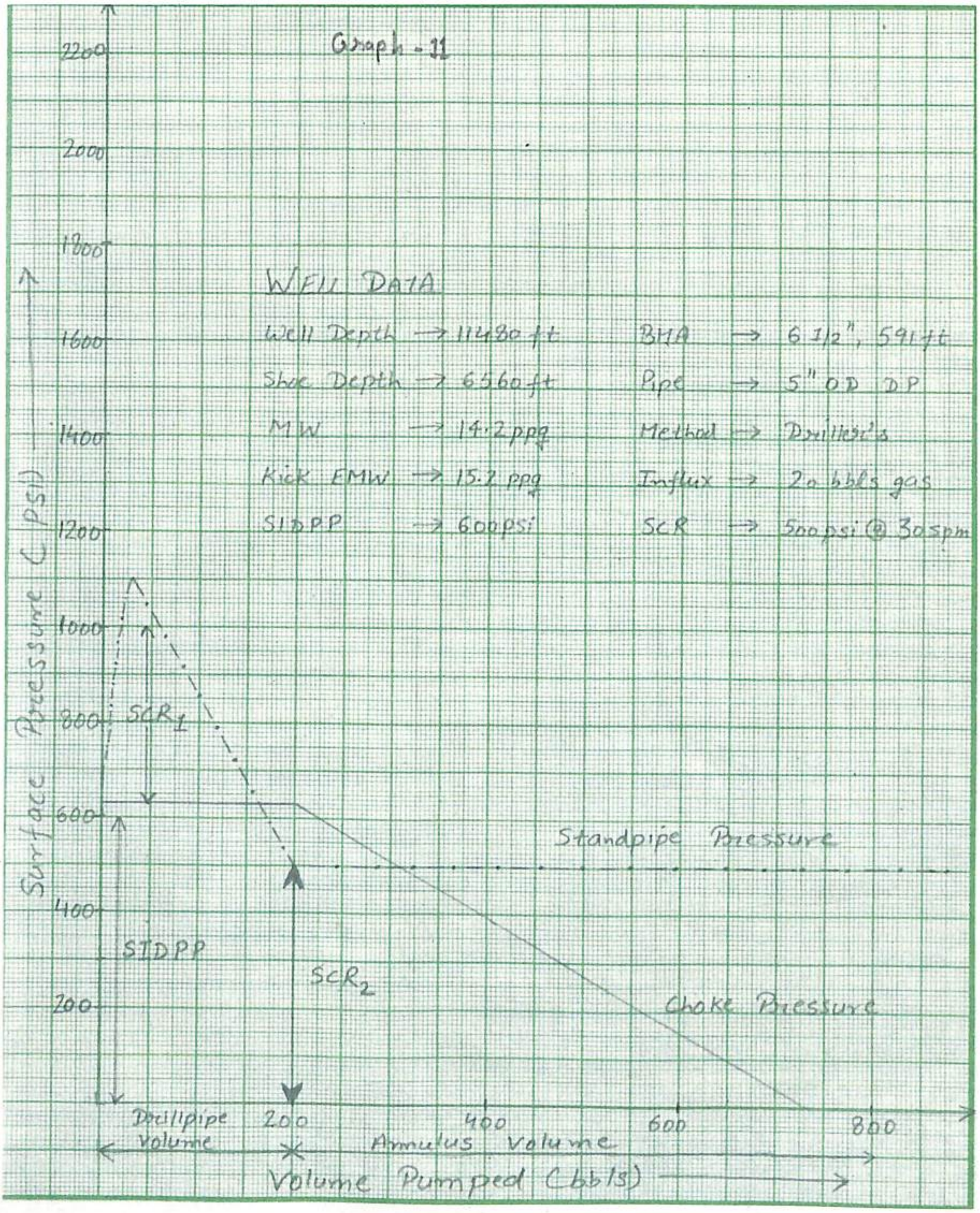
3. Tables:

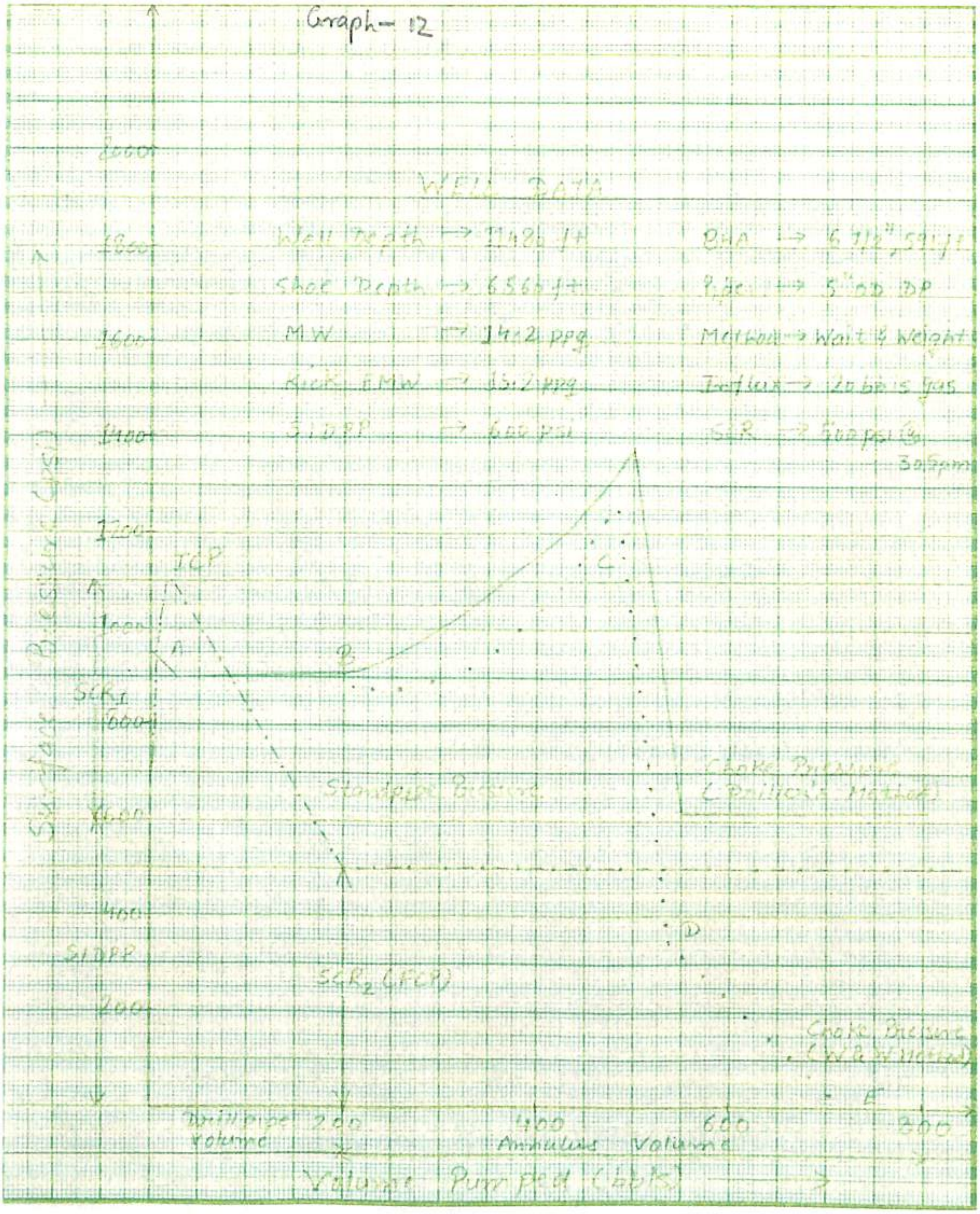
   C1 – C5.


Graph: 6
1600
1400
1200
1000
800
600
400
200
0
Casing Pressure (psi)
8
16
24
32
40
48
56
Volume Bled
Gas Migrating to Surface
Bleeding while holding Constant Casing Pressure
Range
Range
Safety Margin

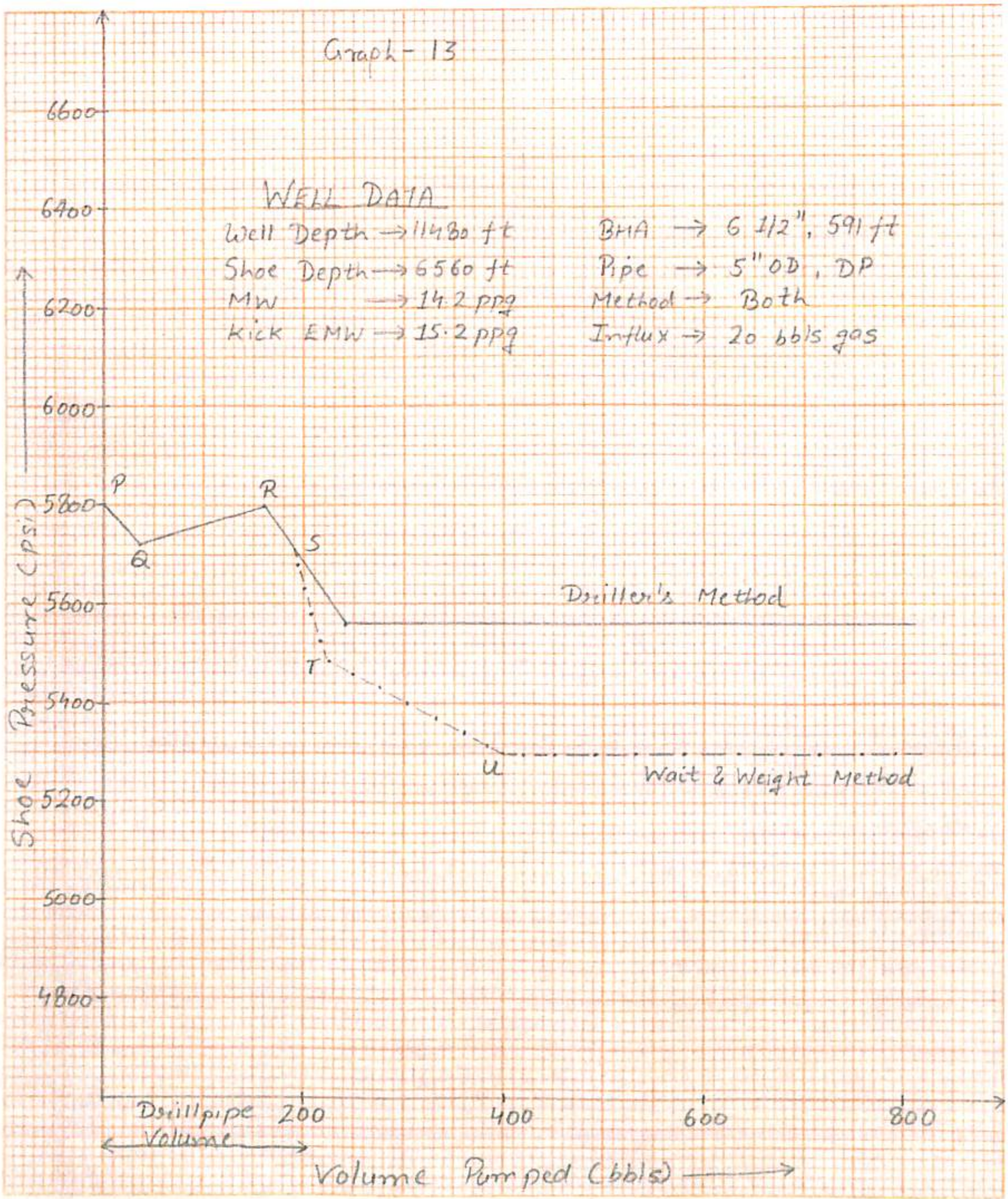

Pit gain to allow for gas expansion
Gas is removed from the well as mud is lubricated in
Original Kill Line Pressure Once Pump is up to speed
KILL LINE PRESSURE (psi)
Gain in Pit Level
Original Pit Level (after Pump is at desired speed)
Drop in Pit Level
CHANGE IN PIT LEVELS (bbls)


WELL DATA:
Graph : 10
Well Depth → 11480 ft
Shoe Depth → 6560 ft
MW → 14.2 ppg
Kick EMW → 15.2 ppg
SIDPP → 600 psi
BHA → 6 1/2", 591 ft
Pipe → 5" OD DP
Method → Driller's
Influx → 20 bbls gas
SCR → 500 psi @ 30 spm
Standpipe Pressure
Choke Pressure
A
B
C
D
E
2000
1800
1600
1400
1200
1000
800
600
400
200
200
400
600
800
Surface Pressure (psi)
Volume Pumped (bbls)

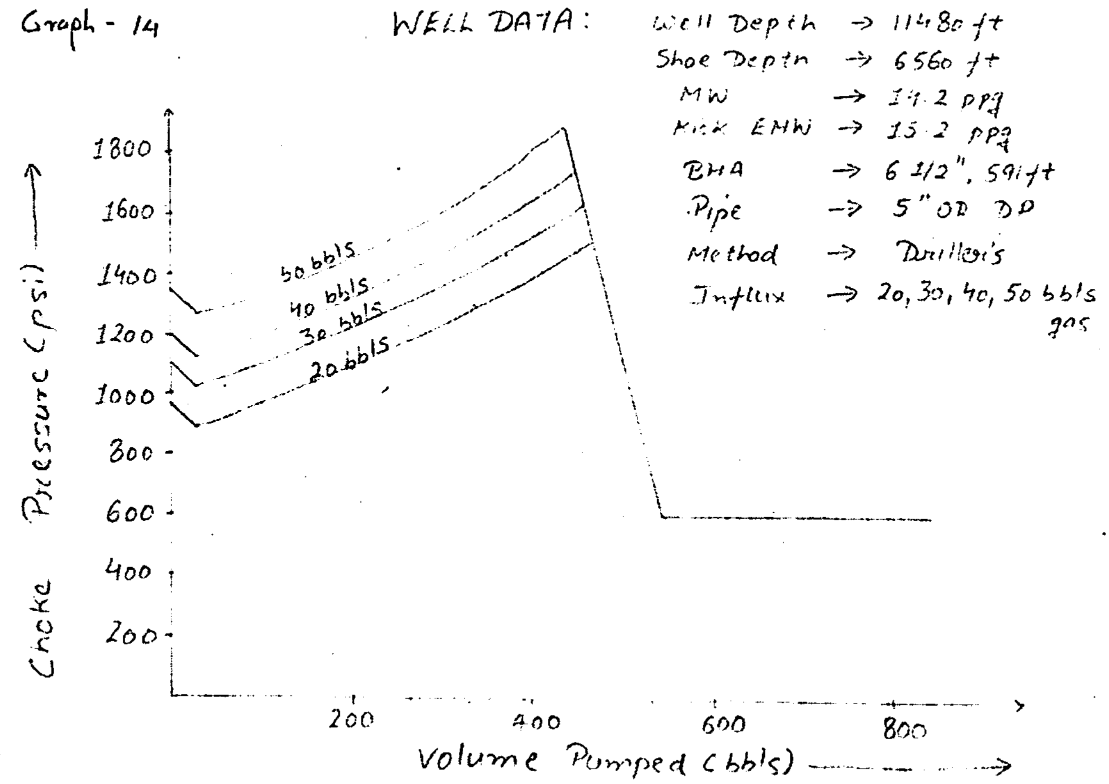

Graph - 11
WELL DATA
Well Depth → 11480 ft
Shoe Depth → 6560 ft
MW → 14.2 ppg
Kick EMW → 15.2 ppg
SIDPP → 600 psi
BHA → 6 1/2", 591 ft
Pipe → 5" OD DP
Method → Driller's
Influx → 20 bbls gas
SCR → 500 psi @ 30 spm
Surface Pressure (psi)
2200
2000
1800
1600
1400
1200
1000
800
600
400
200
SCR1
SIDPP
SCR2
Standpipe Pressure
Choke Pressure
200
400
600
800
Drillpipe Volume
Annulus Volume
Volume Pumped (bbls)



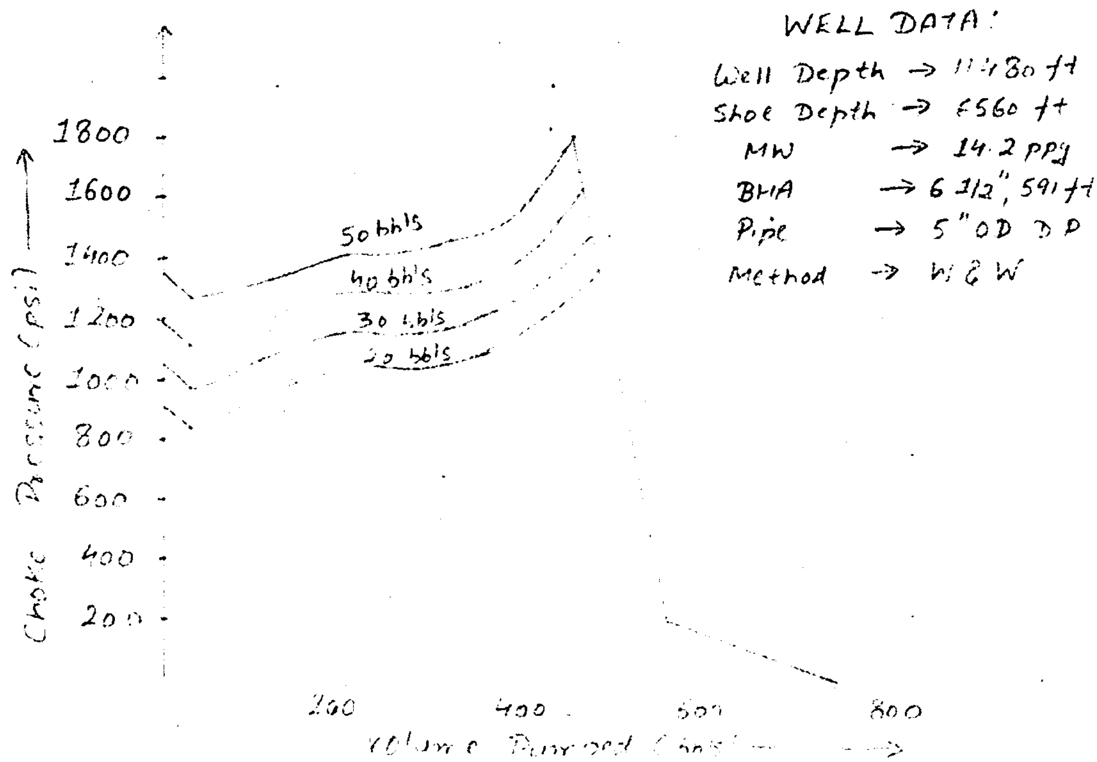
Graph- 12
WELL DATA
Well Depth
Shoe Depth
MW → 14.2 ppg
Kick EMW → 15.2 ppg
SIDPP
BHA
Method → Wait & Weight
Influx
SCR
2000
1800
1600
1400
1200
1000
800
600
400
200
ICP
SCR1
SIDPP
Standpipe Pressure
Choke Pressure (Driller's Method)
SCR2 (FCP)
Choke Pressure (W&W Method)
Drillpipe volume
200
400
600
800
Annulus Volume
Volume Pumped (bbls)
Surface Pressure (psi)


Graph - 13
WELL DATA
Well Depth → 11480 ft
Shoe Depth → 6560 ft
MW → 14.2 ppg
Kick EMW → 15.2 ppg
BHA → 6 1/2", 591 ft
Pipe → 5" OD, DP
Method → Both
Influx → 20 bbls gas
6600
6400
6200
6000
5800
5600
5400
5200
5000
4800
P
Q
R
S
T
U
Driller's Method
Wait & Weight Method
Shoe Pressure (psi)
Drillpipe Volume
200
400
600
800
Volume Pumped (bbls)

Graph - 14



CHOKE PRESSURE - DRILLER'S METHOD FOR VARIOUS INFLUX VOLUMES

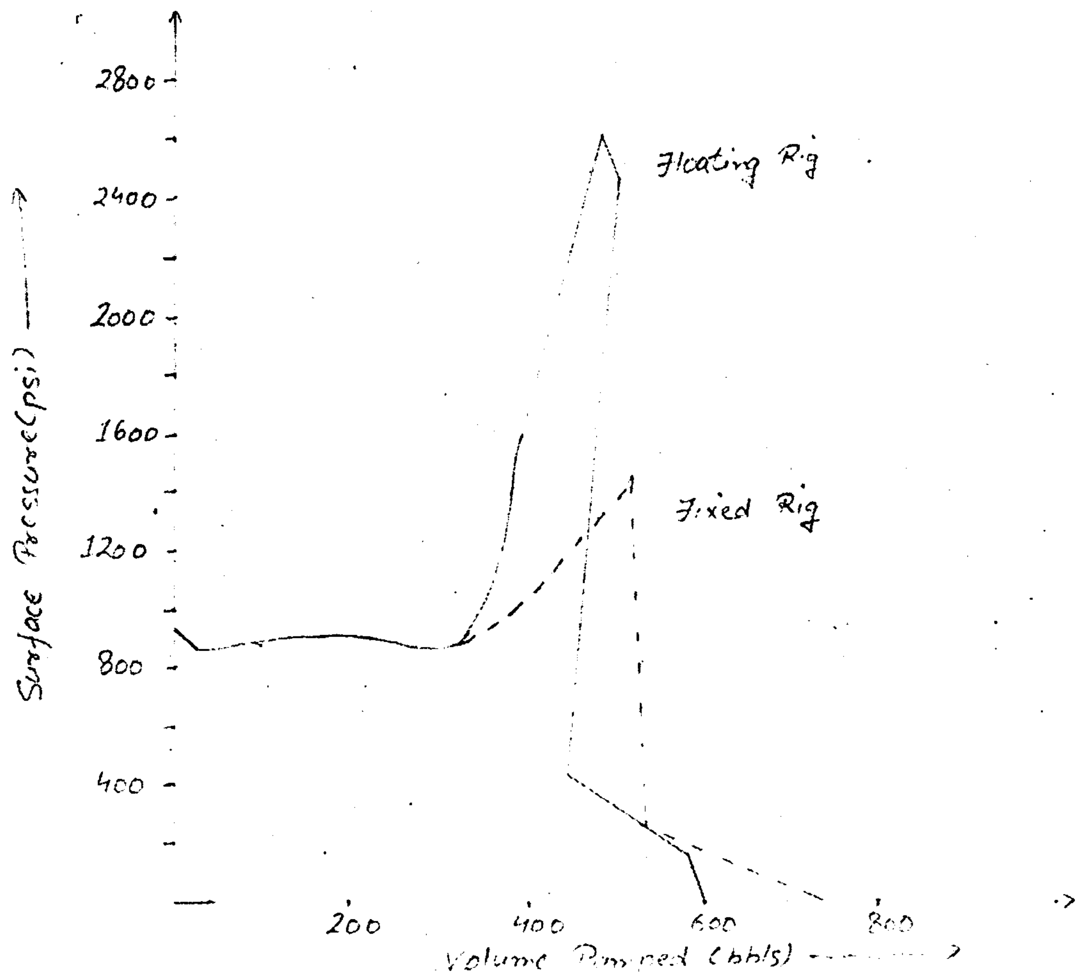


CHOKE PRESSURE - WAIT & WEIGHT METHOD FOR VARIOUS INFLUX VOL

FIXED RIG: Well Depth → 11480 ft
Shoe Depth → 6560 ft
MW → 14.2 ppg
Kick EMW → 15.2 ppg
BHA → 6 1/2", 591 ft
Pipe → 5" OD DP
Method → W & W
Influx → 20 bbls gas

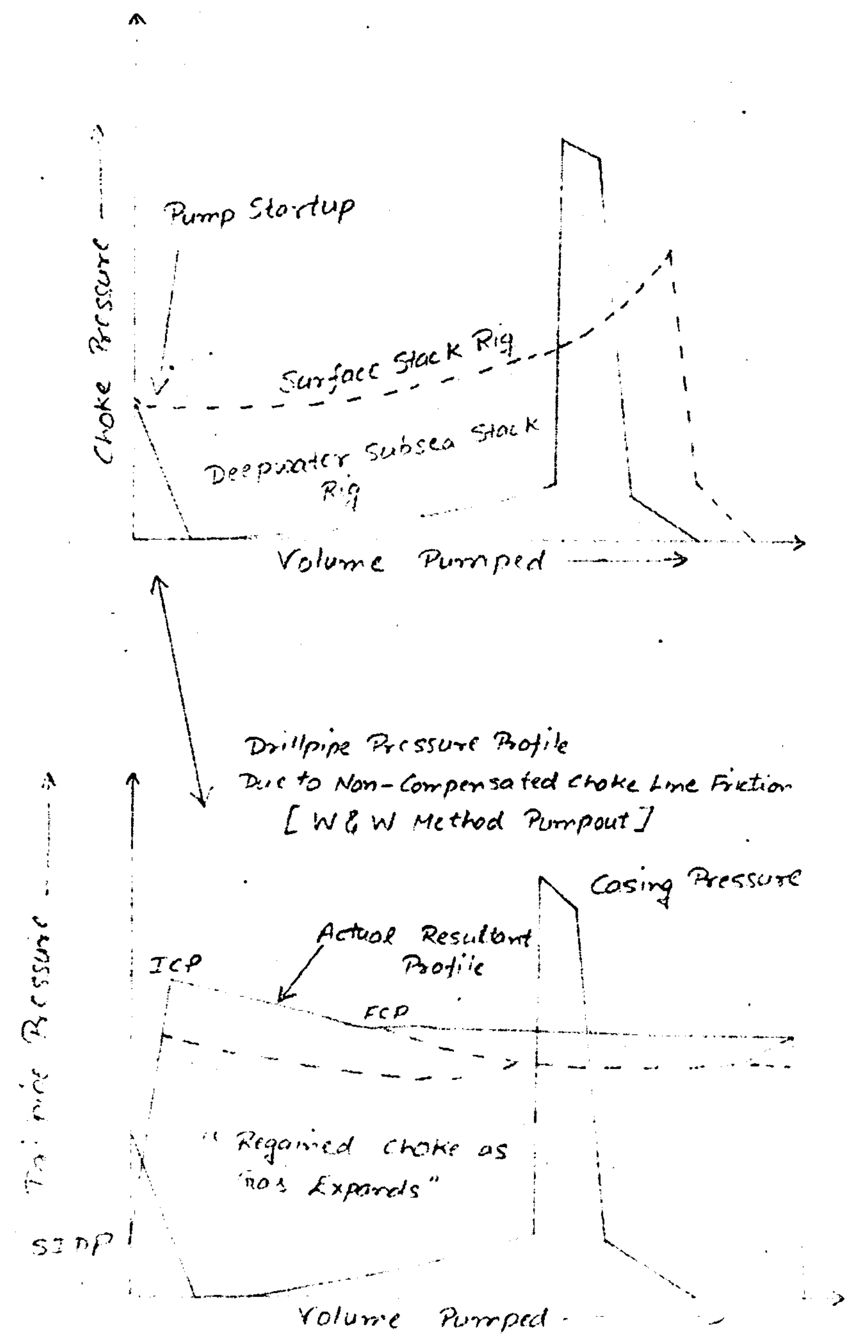
Graph → 15

FLOATING RIG: Well Depth → 11480 ft
Shoe Depth → 6560 ft
MW → 14.2 ppg
Kick EMW → 15.2 ppg
CHOKE LINE → 3280 ft
BHA → 6 1/2", 591 ft
Pipe → 5" OD DP
Method → W & W
Influx → 20 bbls gas



COMPARISON OF CHOKE PRESSURES DURING DISPLACEMENT OF A GAS KICK ON A FIXED AND A FLOATING RIG

Graph 46 TYPICAL CHOKE PRESSURE PROFILE FOR GAS KICK PUMPOUT



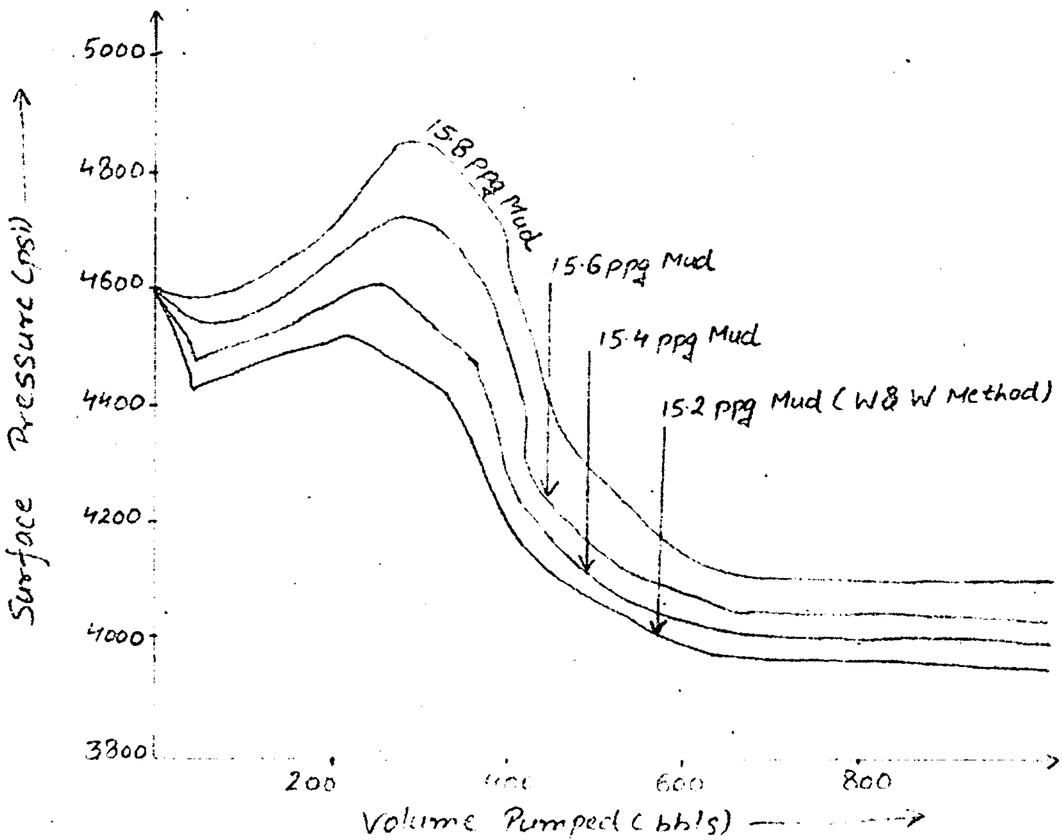
EXCESS CHOKE LINE FRICTION AND GAS EXPANSION DURING SUBSEA PUMPOUT IN DEEPWATER

Graph- 17

WELL DATA

Well Depth → 11480 ft
Shoe Depth → 6560 ft
MW_1 → 14.2 ppg
Kick EMW → 15.2 ppg
MW_2 → 15.2, 15.4, 15.6, 15.8 ppg

BHA → 6 1/2" 591 ft
Pipe → 5" OD DP
Method → Overbalanced Mud
Influx → 20 bbls gas



SHOE PRESSURE DURING DISPLACEMENT OF A GAS KICK WITH OVERBALANCED MUD WEIGHT

A

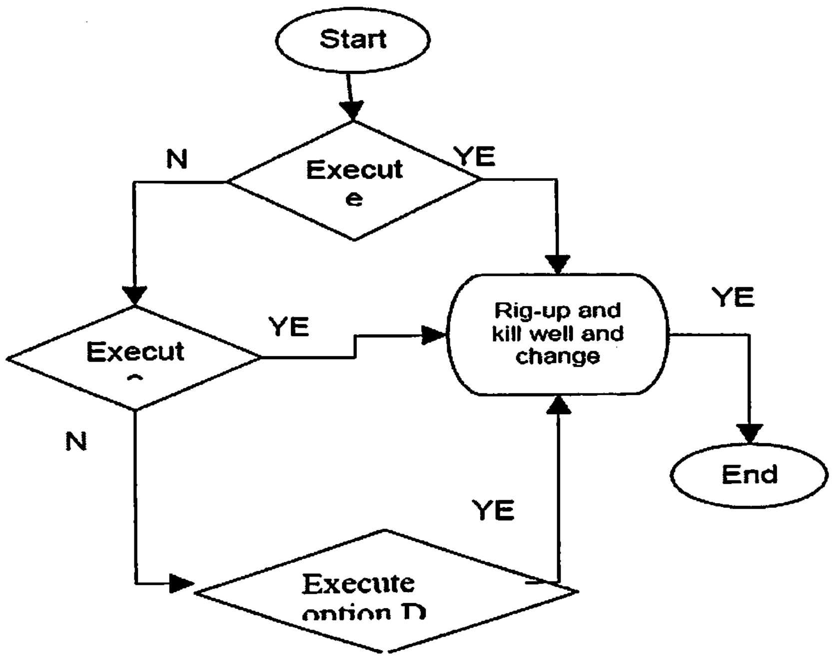
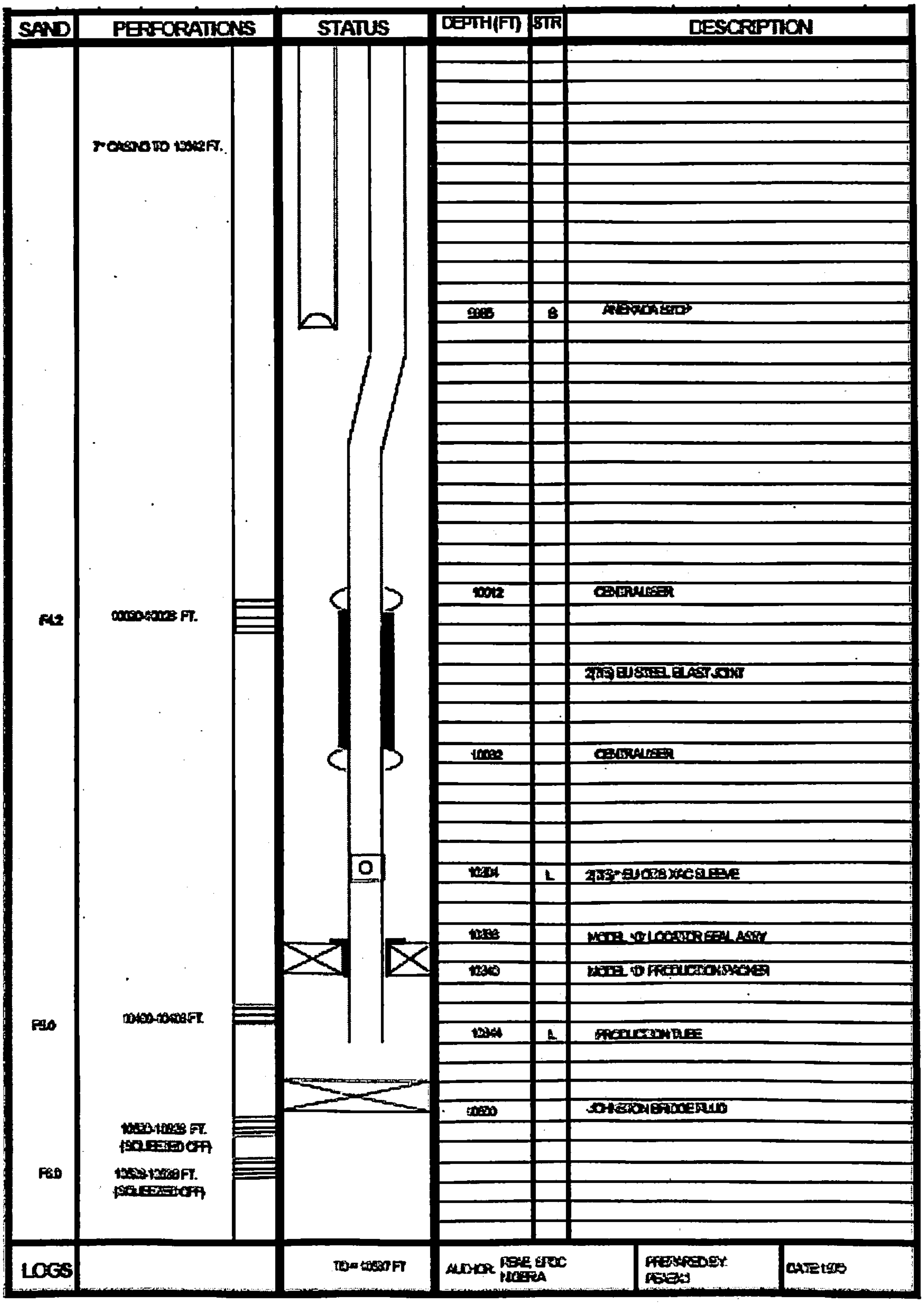


Figure 2: (Flow chart of Well control Options)

A

Figure:1 (well status diagram before the blowout)



A

Figure:4 (Status diagram after partial abandoment)

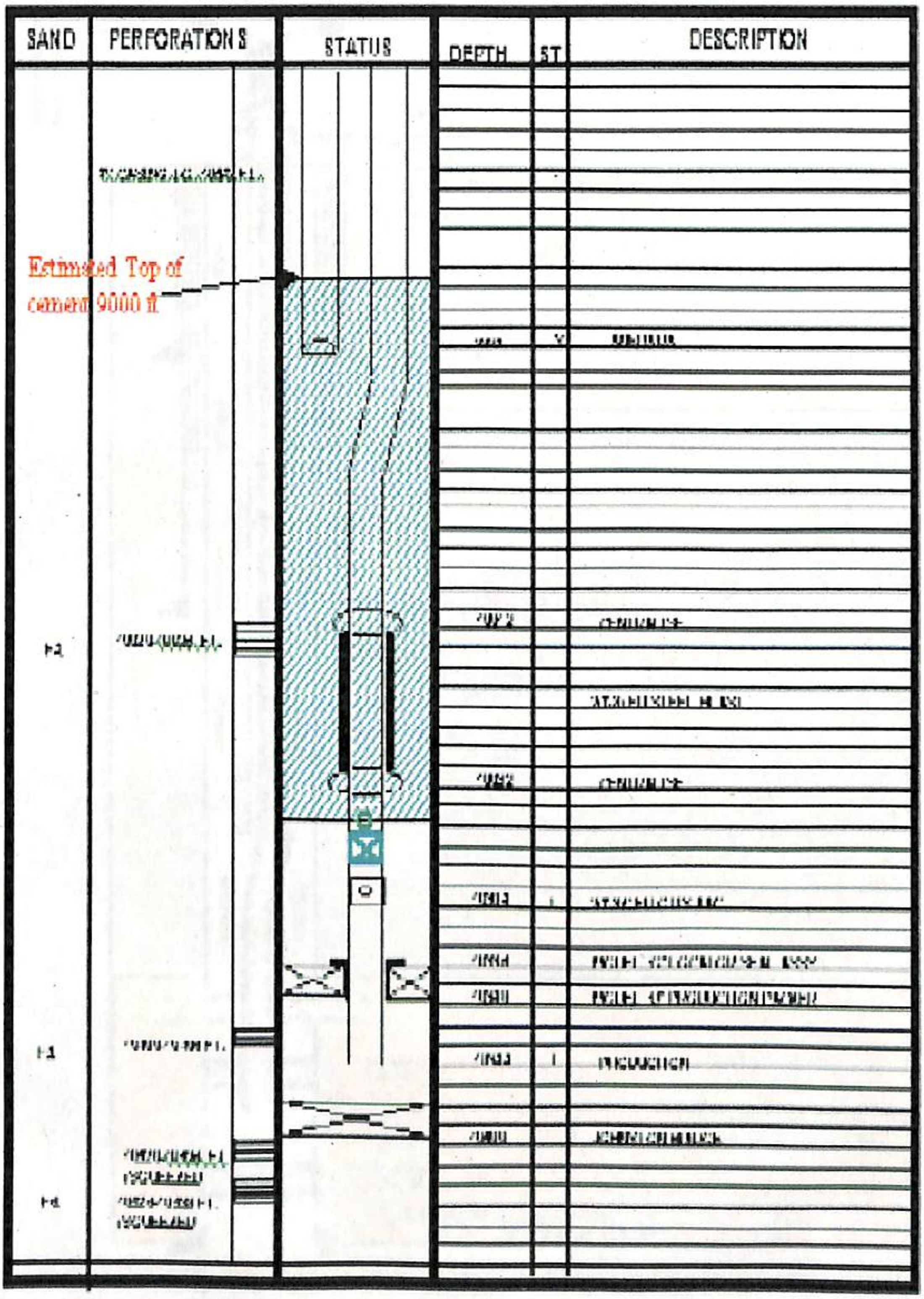


Figure: 3 (Blowout from the reservoir through the annulus)

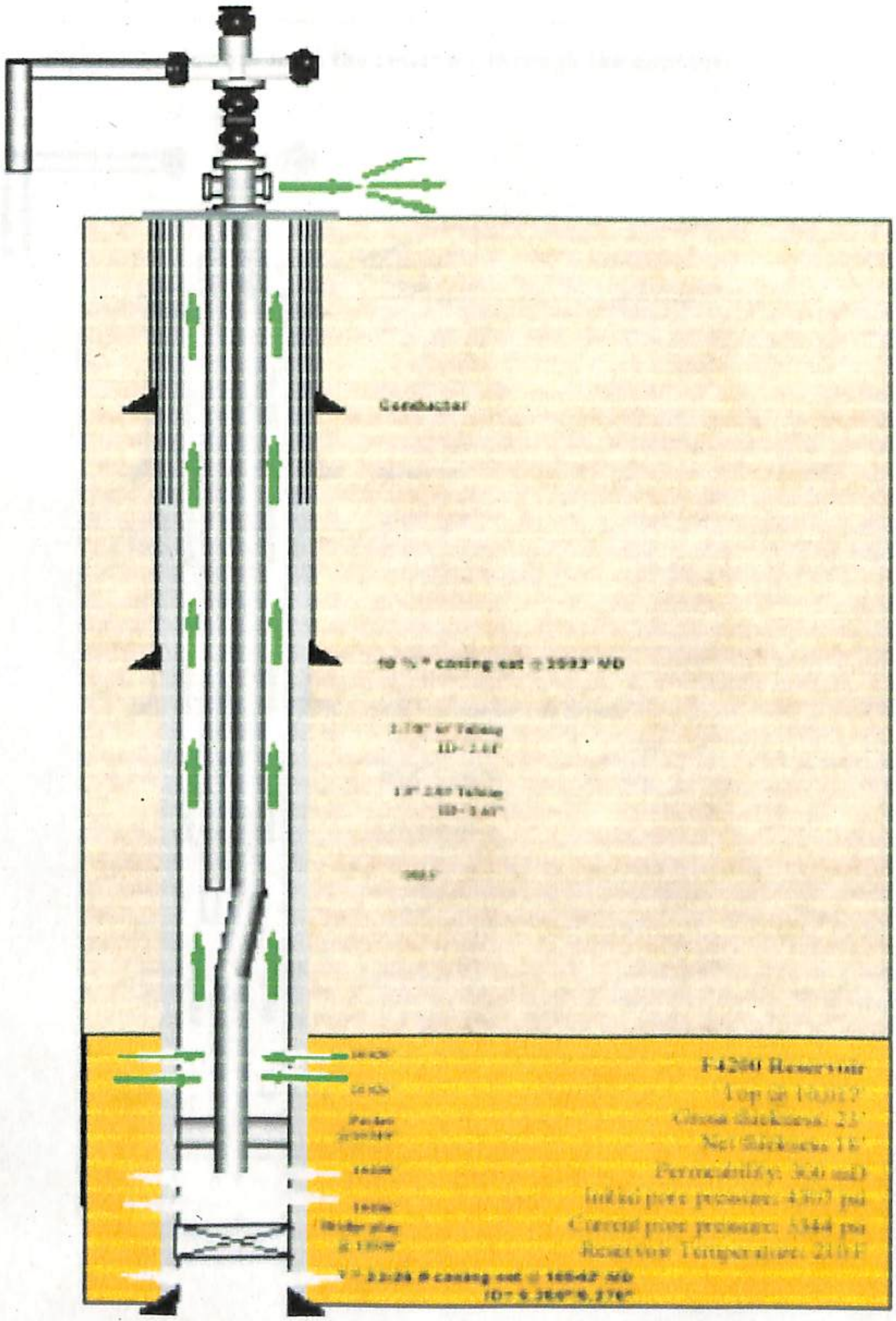
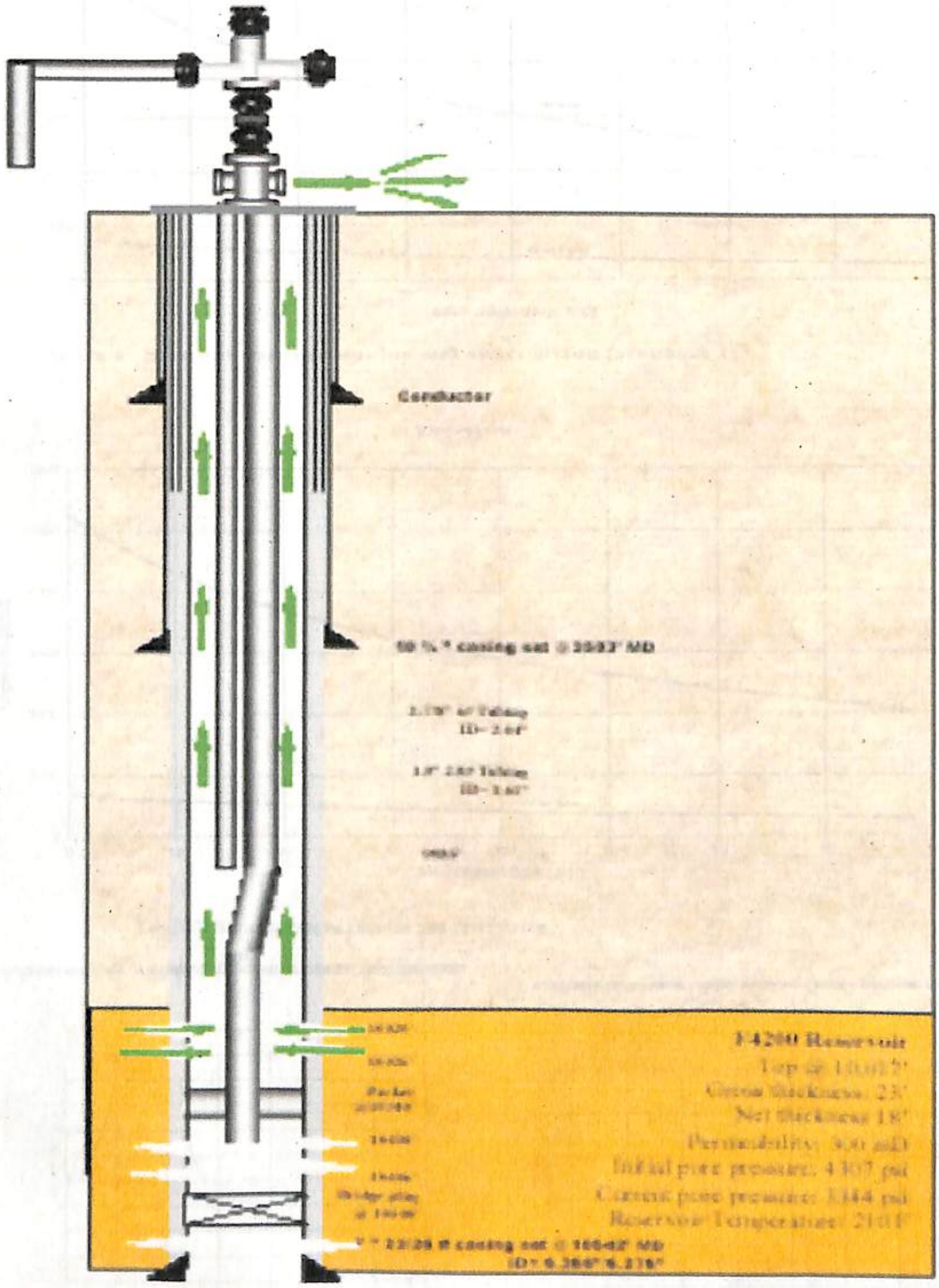


Figure: 3 (Blowout from the reservoir through the annulus)



A

Figure 5: Blowout rate in annulus and short string (scenario 2)

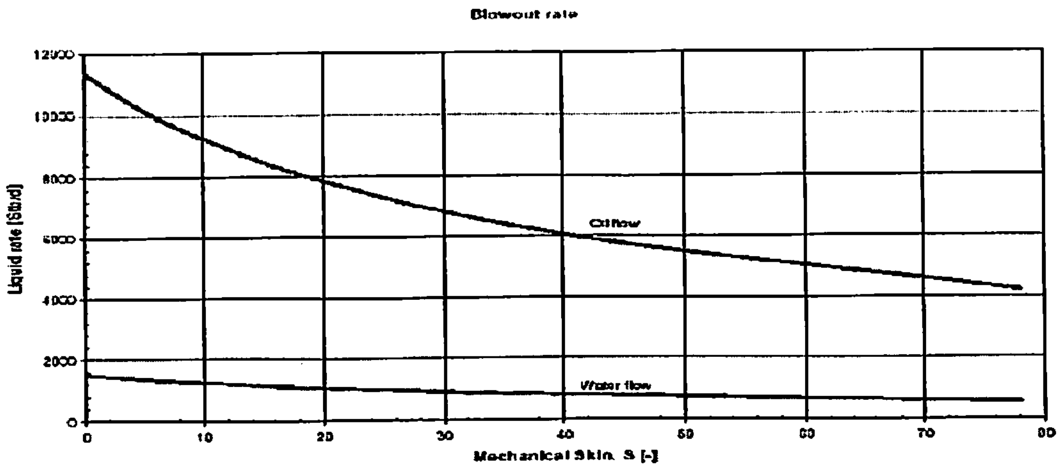


Figure 6: Blowout rate in annulus and short string (scenario 1)

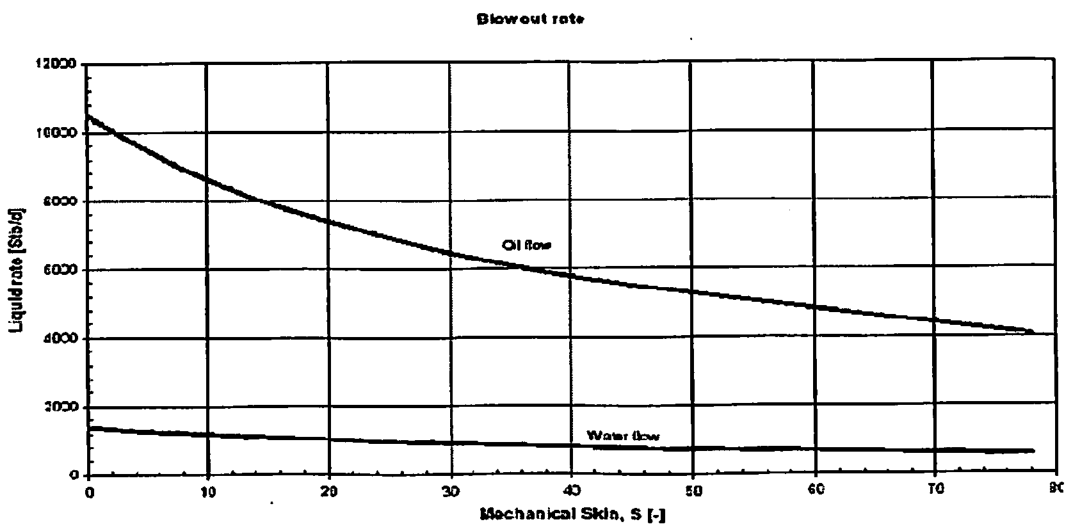
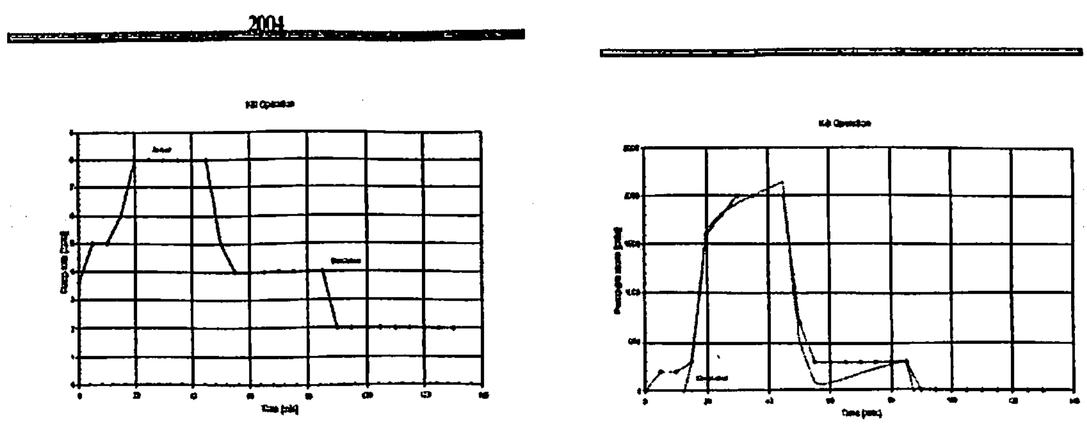


Figure 7: Blowout rate in annulus and short string



B

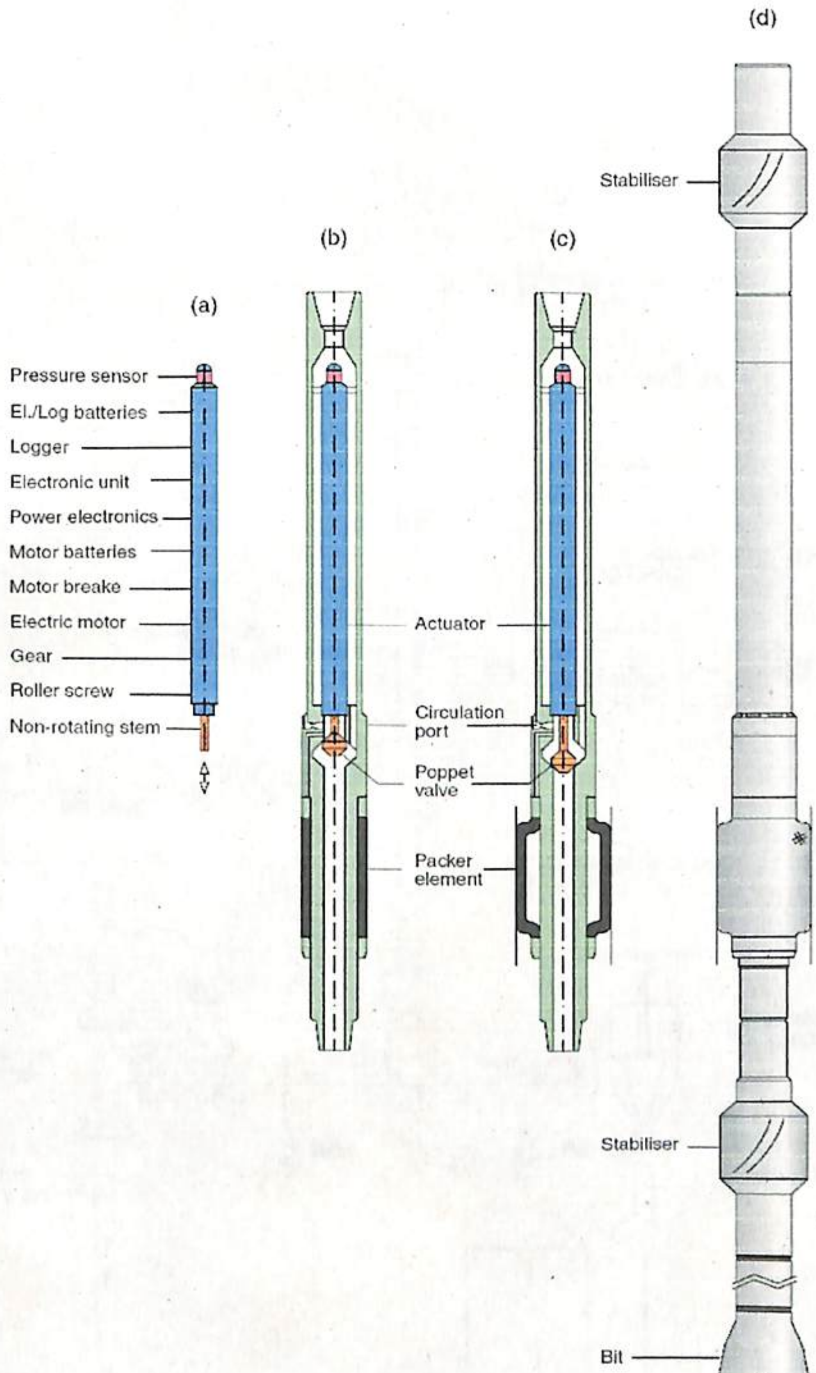


Fig.1-DHBOP actuator (a), DHBOP in drilling mode (b) and actuated mode (c) and the entire DHHOP with stabilizers.

B

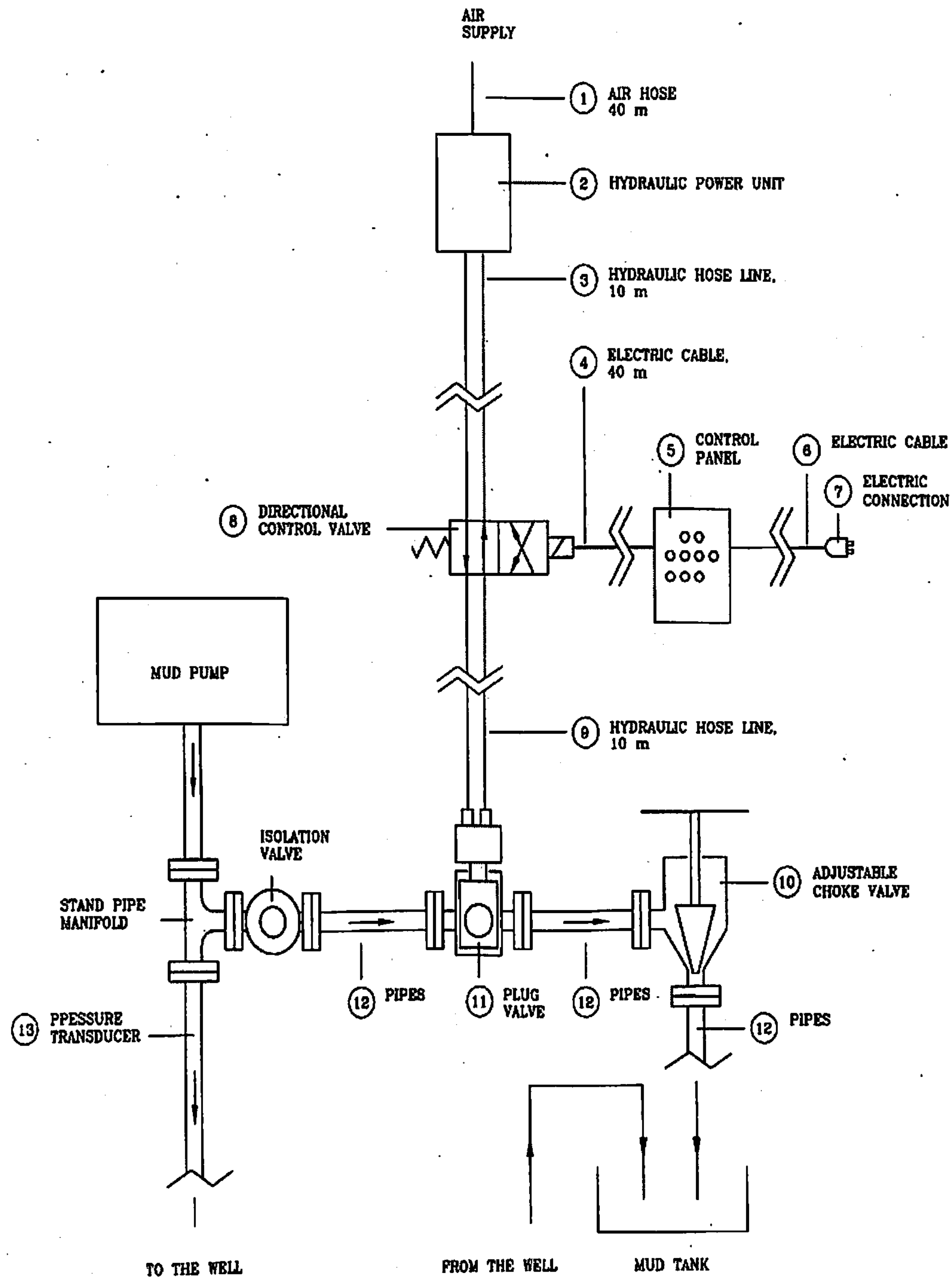


Fig.2-Pressure code equipment on the platform

B

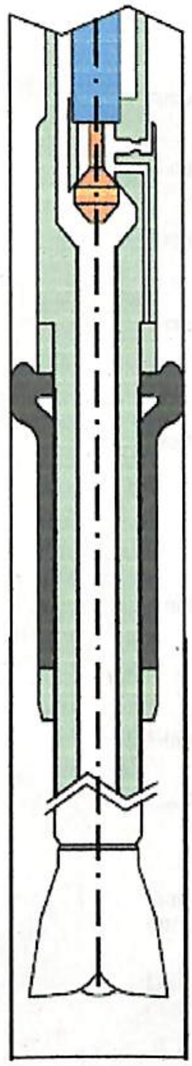


Fig.3-Packer failure during the functional test in casing

B

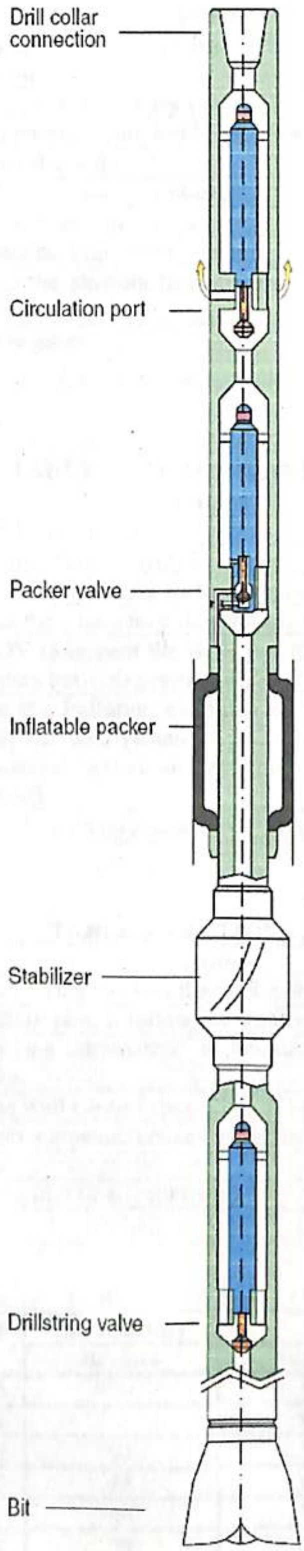


Fig.4-DHBOP with three actuators

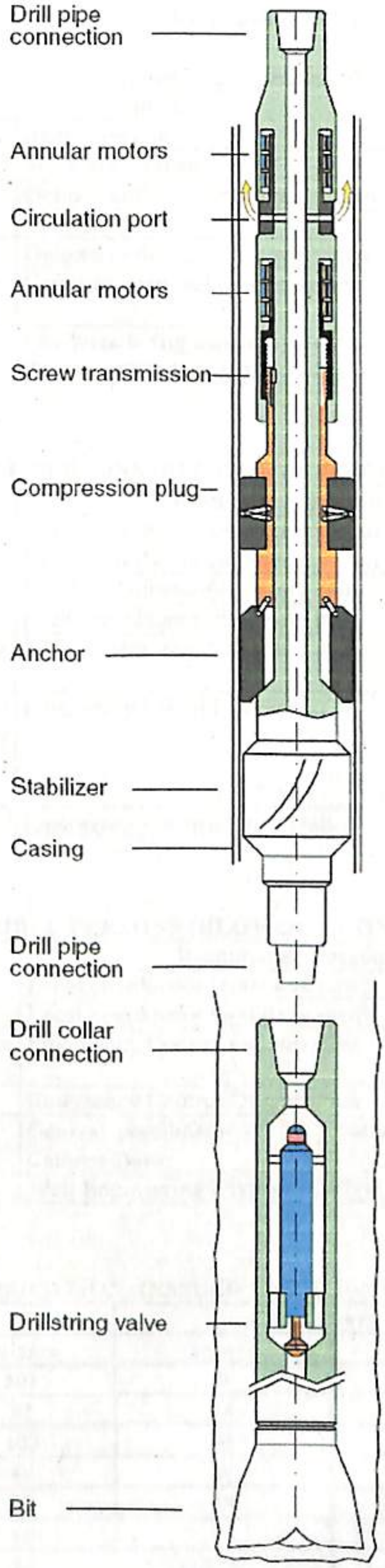


Fig.5-DHBOP with three actuators and compression plug

C

TABLE 1 – ACTIONS AND RESPONSIBLE PERSONS (IMMEDIATE ACTIONS)

Actions	Responsible Persons
Sound the emergency alarm	Driller
Notify the blowout	Local coordinator (company man)
Identify gases on the rig site	Safety technician
Put supporting boats and helicopters on alert	Radio operator
Give the first aids	Medical attendant
Shut down all power sources	Defined in the rig contingency plan
Mobilize firefighter boats	Coordinator local
Evacuate the unnecessary people	Defined in the rig contingency plan
Analyze the blowout flow and the fluid type (oil, gas or water)	Company man and mud engineer
Disperse gases	Fire brigade (rig owned by Petrobras) or defined in the rig contingency plan (contractor's rigs)

TABLE 2 – ACTIONS AND RESPONSIBLE PERSONS (BLOWOUT CONTAINMENT)

Actions	Responsible Persons
Protect the personnel	Defined in the rig contingency plan
Protect the facilities (rig)	Defined in the rig contingency plan
Spray water on the rig with firefighter boats	Local coordinator (company man)
Activate the emergency disconnection system (EDS)	Local coordinator (company man)
Use ROV to inspect the BOP and to close it with the emergency hot-stab system (EHS) if necessary	Local coordinator (company man)
Actuate the Pollution Contingency Plan for Campos Basin if the well remains open after the emergency disconnection system and emergency hot-stab system have failed	Emergency Control Organization
Actuate the Mutual Assistance Plan (PAM)	Emergency Control Organization

TABLE 3 – ACTIONS AND RESPONSIBLE PERSONS (BLOWOUT CONTROL)

Actions	Responsible Persons
Keep on trying to close the well with ROV/EHS	Local coordinator (company man)
If the BOP closes, follow the well reentry procedures	Local coordinator (company man)
Assess the alternative techniques to control the blowout	Emergency Control Organization
Call the well control specialists of Petrobras	Emergency Control Organization
Contract a blowout control company	General coordinator of the Contingency Plan for Campos Basin
Project and drill an relief well	Well Engineering Division (GENPO)

TABLE 4 – WELL CONTROL CERTIFICATION INSSUED UNTIL 10/01/1999

Year	Introductory	Fundamental		Supervisory	
	Surface	Subsea	Surface	Subsea	Surface
1993	-	30	101	0	15
1994	-	53	92	24	29
1995	72	82	103	53	28
1996	35	64	46	39	11
1997	44	55	90	38	8
1998	79	47	46	44	35
1999	146	-	76	129	50

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TABLE 5 – WELL CONTROL CERTIFICATION INDEX FOR THE GENPO AND GESEP UNTIL 10/01/99

Operational Sectors/Division	Certified Professionals	Noncertified Professionals	Total of Profissionals	COPO (%)
GFLUI	71	25	96	74
GPANS	21	2	23	91
GPBAR	13	1	14	93
GPEX	19	0	19	100
GPMRL	24	0	24	100
GPRON	20	0	20	100
GENPO (Total)	168	28	196	82
GEOPS	20	27	47	43
GEP-10	9	6	15	60
GEP-17	13	4	17	77
GEP-23	16	2	18	89
GESEP (Total)	58	39	97	60

Bottomhole Pressure < Pore Pressure → Kick

Uncontrolled Kick → Blowout

Blowout → Oil and Gas on the Rig

Oil and Gas on the Rig → Oil Spill/Fire/Explosion

Oil Spill/Fire/Explosion → Pollution/Material Losses/Human Life Losses

Fig. 1 – Accident Hypothesis

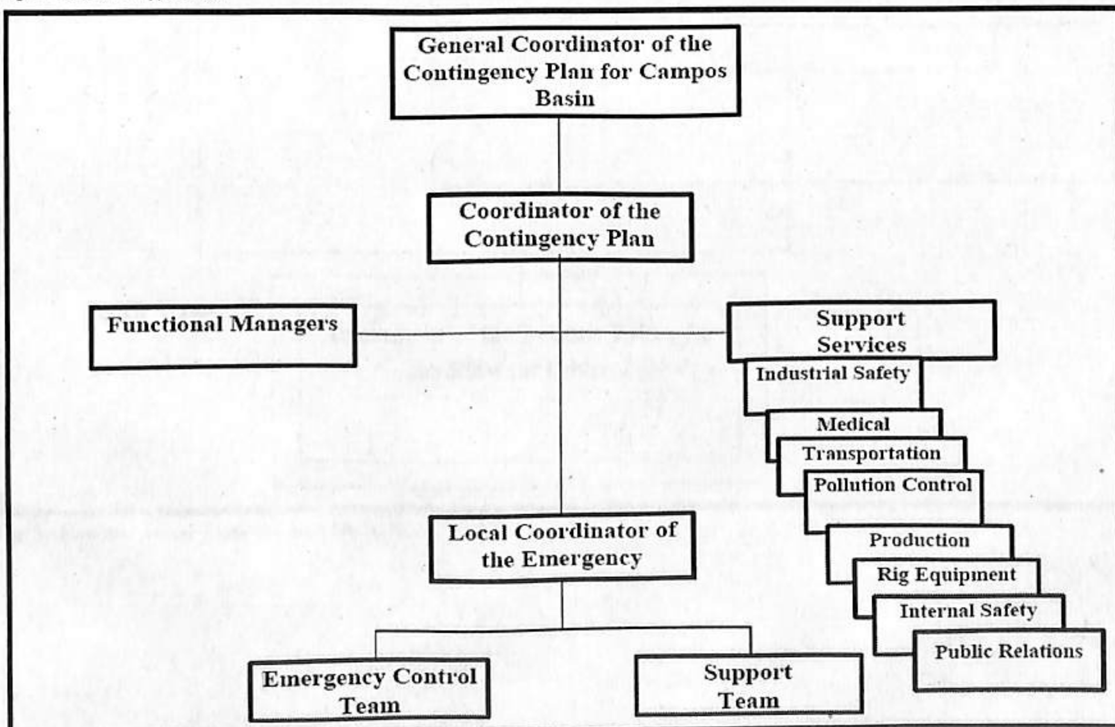

Fig. 2 – Emergency Control Organization for Campos Basin

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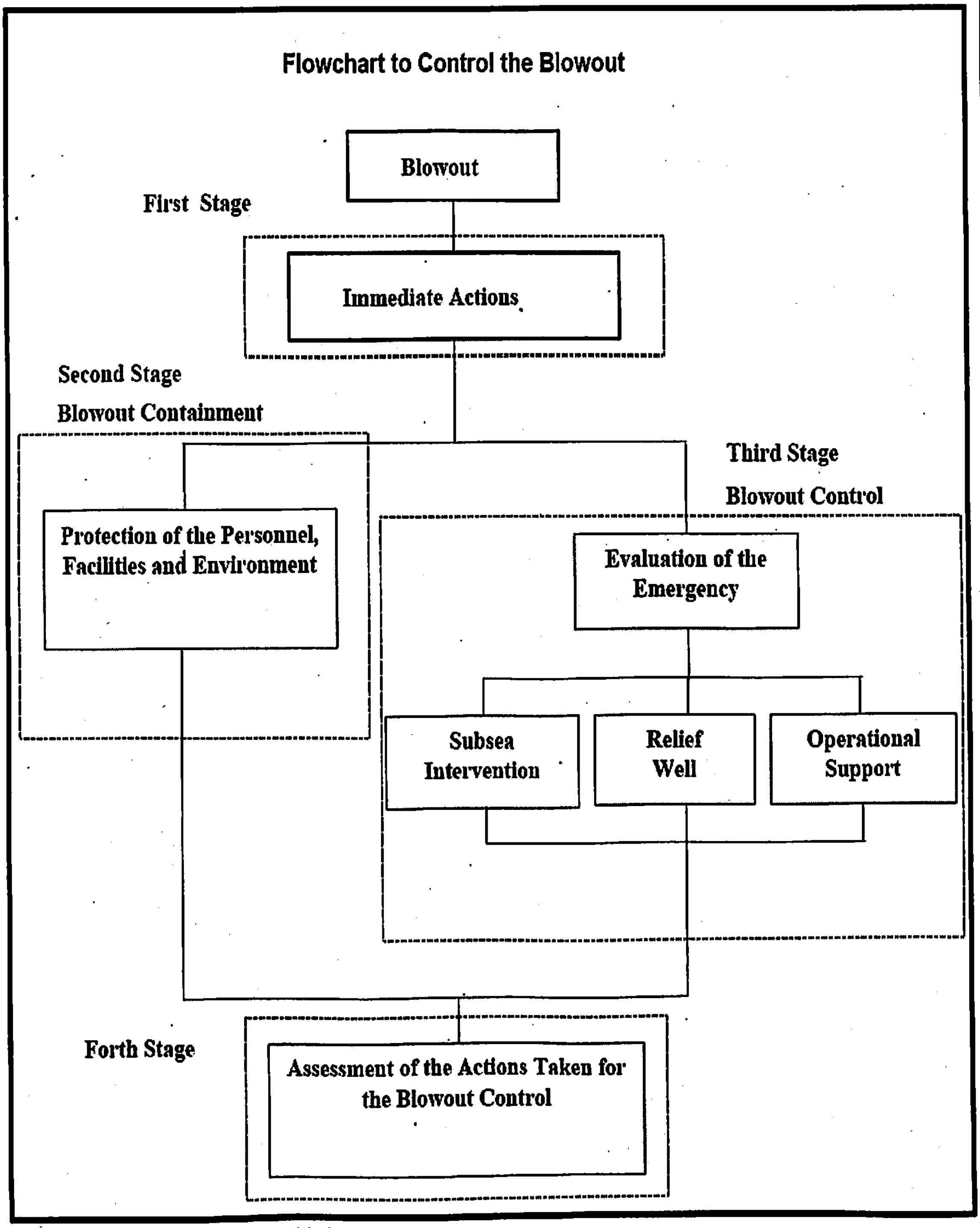

Fig. 3 – Flowchart for the Blowout Control Actions

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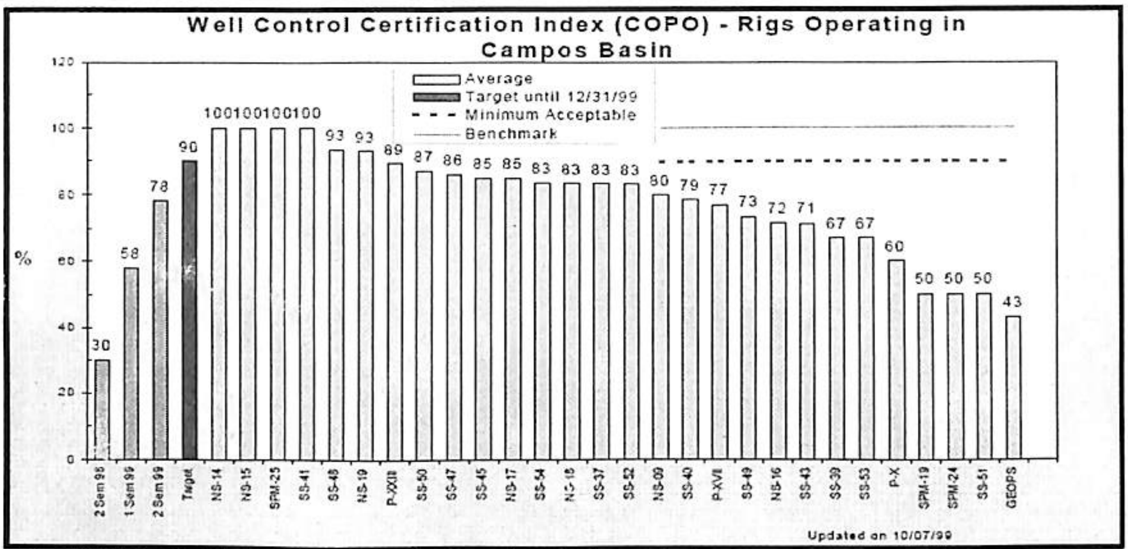

Fig. 4 – Well Control Certification Index (COPO) – Rigs Operating in the Campos Basin

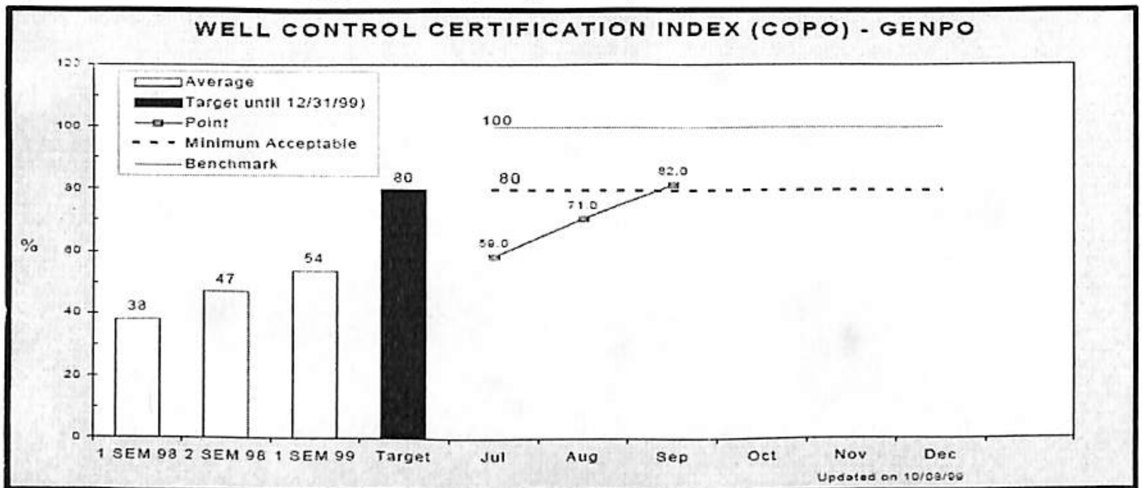

Fig. 5 – Well Control Certification Index (COPO) - GENPO

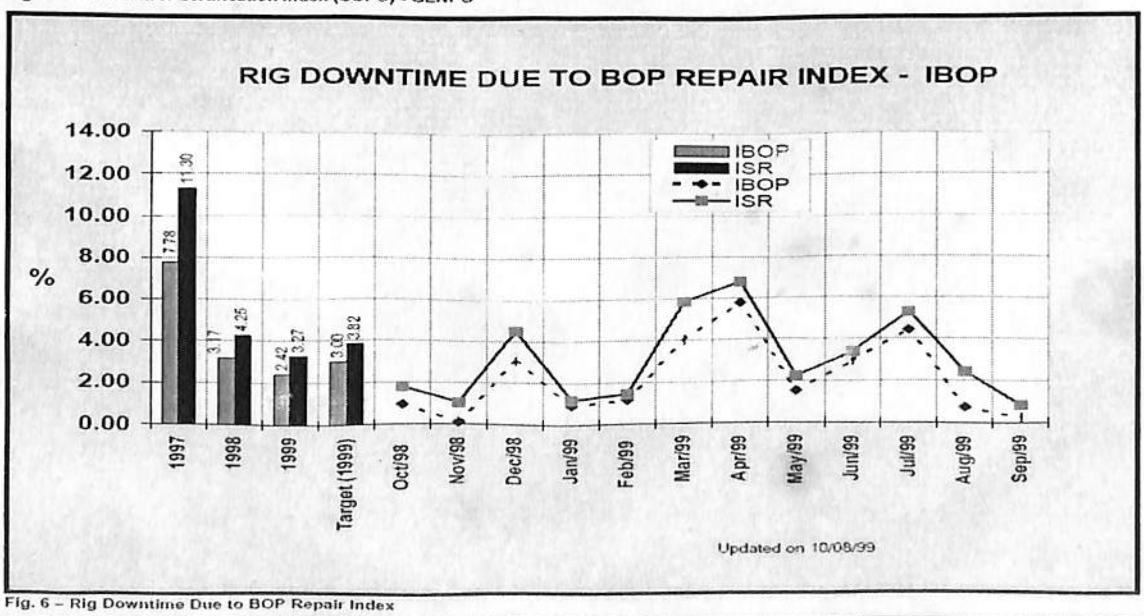

Fig. 6 – Rig Downtime Due to BOP Repair Index