4071

Exhibit No. ______
Worldwide Court
Reporters, Inc.

From: Shaughnessy, John M.
Sent: Mon Mar 01 20:21:18 2010
To: Daigle, Keith G
Subject: RE: Questions from the UK group- Dual Activity
Importance: Normal
Attachments: Well Control Supplement NAX.doc; Hanging Csg Backed Offl.ppt

Tried to answer some of the questions below.

Questions sent in advance to GOM Deepwater Teams:

1. How do you optimize your BHA configurations to minimize online time with a dual activity rig?
2. Do you use conductor cement top up systems (if you cement your conductor in place)? If so which one?
3. What weight slurry do you cement your conductor with?

At Atlantis - 6,800' of water. 28" @ 8,100' with 13.5 ppg foamed cement.

22" @ 9,200' with foamed cement 12.5 ppg. Pumped through an inner string.

4. Do you have any lessons/experiences for racking casing and testing the shoe tracks offline?
5. What hydrate modeling do you perform prior to the job and who performs it (fluids company)? Do you have hydrate prevention practices? Hyrdrates are supressed by the synthetic mud.
6. In the UK we have very prescriptive connection and drilling practices (see attachment). Do you have anything equivalent which is applicable for deepwater (eg deal with mud cooling and gelling up)?
7. Are there any special deepwater considerations when planning and performing the data acquisition programme (E-line and Coring)? On Atlantis we have gone away from wireline logging. All data recovered by LWD or the pressure tools while drilling.
8. The plan is to use the West Phoenix 6th Gen Semi to drill the well and it will only be the 2nd well that the DP system has been used in anger. Do you have any advice/lessons that may be useful?
9. Well control considerations and issues in deepwater drilling? See attached DW Well Control Guidelines that were approved in GomX a few years ago.
10. Do you employ strakes on your conductor and 20" to minimize vortex induced vibrations? No. However, want to limit the amount of time those connections are hanging in the water column. See attached problem where some minimum turn make up connections backed out.
11. What crew size do you employ to allow you to utilize the dual activity rig? DD2 has 176 beds. Often they are all full.
12. What are you top 10 technical limit improvements?
13. Efficiency opportunities offered by dual derrick? Rack back casing. Make up BHAs. Drill riserless top hole while the casing is hanging to minimize off bottom time when concerned about shallow water flow.
14. Lesson learned from working with Seadrill on West Sirius on Kaskida (contact Jim Wellings)?
15. Riser analysis guidelines, particularly around how do you handle VIV modeling and practicalities in the field. For example do they use VIV suppression devices? BP does not. The only operator that I know of that uses fairings on a regular basis is Chevron. They run them regularly when a loop current is a potential problem.

<< File: EPT Technical Note North Uist Drilling Riser Analysis S-EPT-017-10-Rev 1.pdf >>

16. Updated BOD or DW guidelines information. Do you use the BP DW Drilling Guidelines (http://dwdg.bpweb.bp.com/default.htm) or have you developed your own more modern version?

Best Regards,

Keith Daigle

Wells Operations Advisor

BP America GoM SPU

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NAX – DW Gulf of Mexico
Deepwater Well Control Guidelines

Approved by: Drilling Superintendent	 ____________________ Karlin Costa/ George Coltrin Date:
Approved by: Drilling Advisor	 ____________________ Jimmy Reed Date:
Approved by: Sr. Drilling Representatives	 ____________________ Roger Gatte, Martin Breazeale Date:
Prepared by: Drilling Engineer	 ____________________ John Shaughnessy Date:

TABLE OF CONTENTS

1 Introduction – Pre-Well Control Issues

These guidelines have been developed to supplement the BP Well Control Manual and the BP Drilling & Wells Operations policy. The primary reason a supplement is necessary is to mitigate risk due to frequently operating without the Drilling Operations Policy required kick tolerance. They are intended to account for the situation of being unable to conventionally handle a kick when drilling the ultra-deepwater Gulf of Mexico due to the low pore pressure/frac gradient margins and the nature of deepwater well control systems.

This set of guidelines was developed initially by the NAX Operations team. They have been circulated for comment to experts within the greater drilling community.

1.1 Pre-drill Meetings

A meeting to discuss well control issues and required drills should be held on the rig prior to drilling out from any casing string. Document the meeting on the morning reports. In addition to contractor and BP representatives, the meeting should be attended by the mud engineer and the mud logger. The meeting should review the contractor's well control policies.

1.2 Shut-in Procedure

The contractor's shut-in procedure should be reviewed by the wellsite team to ensure conformance with the BP Well Control Manual Guidelines. A "Fast" shut-in should be specified.

1. The remote choke should be closed and isolated by a high pressure valve immediately upstream.
2. Outer failsafe valve on choke line should be closed.
3. The annular BOP will be used to initially shut-in the well.
4. Flow check the riser to ensure that the influx is not already above the BOP's.
5. Evaluate the need to space out and hang off on pipe rams depending on contractor preference, size of kick, intensity of kick, current weather, and forecast of weather. It is intended that the well will be closed on the annular to allow working the pipe unless conditions dictate closing the rams.
6. Open failsafe valve and record SIDPP and SICP's. Determine rate of bubble migration (if any).
7. Ensure that influx is not due to formation ballooning as per the flow chart in section 2.1.

1.3 Drill String Floats

Solid (non-ported) floats will be used at all times.

1.4 Slow Pump Rates and Choke Line Friction Pressures

The BP well control manual recommends that slow pump rates be taken regularly and at least:

- Once per tour
- If mud properties change
- The amount of hole drilled require a more frequent test

- Bit or BHA is changed.

These guidelines will require taking slow pump rates on two pumps when begin drilling each hole section. At a minimum those slow pump rates should be confirmed each tour at one rate on one pump to track the changes. Taking slow pumps rates on each pump at three different rates would take considerable time for minimal benefit.

The BP well control manual recommends the choke line friction pressures be taken initially when the BOP and riser are landed and before drilling out each subsequent casing shoe. It is a recommended good practice to pump through the choke and kill lines daily to ensure no plugging due to barite settling. The mud in the choke and kill lines should be the current drilling mud – not base fluid. No problems have been experienced with settling or excessive gel strengths due to low temperatures when the lines are regularly pumped through. Maintaining drilling mud in the choke and kill lines will minimize potential confusion in the event of a kick.

When a kick cannot be circulated out conventionally through the choke and kill lines due to high friction pressures, it becomes necessary to bullhead the influx back into the formation.

1.5 Requirements for Barite and Cement on location

Company policy requires a minimum quantity of barite on the rig to weight up the mud one pound per gallon. The policy also requires a minimum supply of cement on the rig to set appropriate isolation plugs in the current hole size. Requirements for the MMS are specified in the approved permit to drill.

1.6 Contingency Pressure

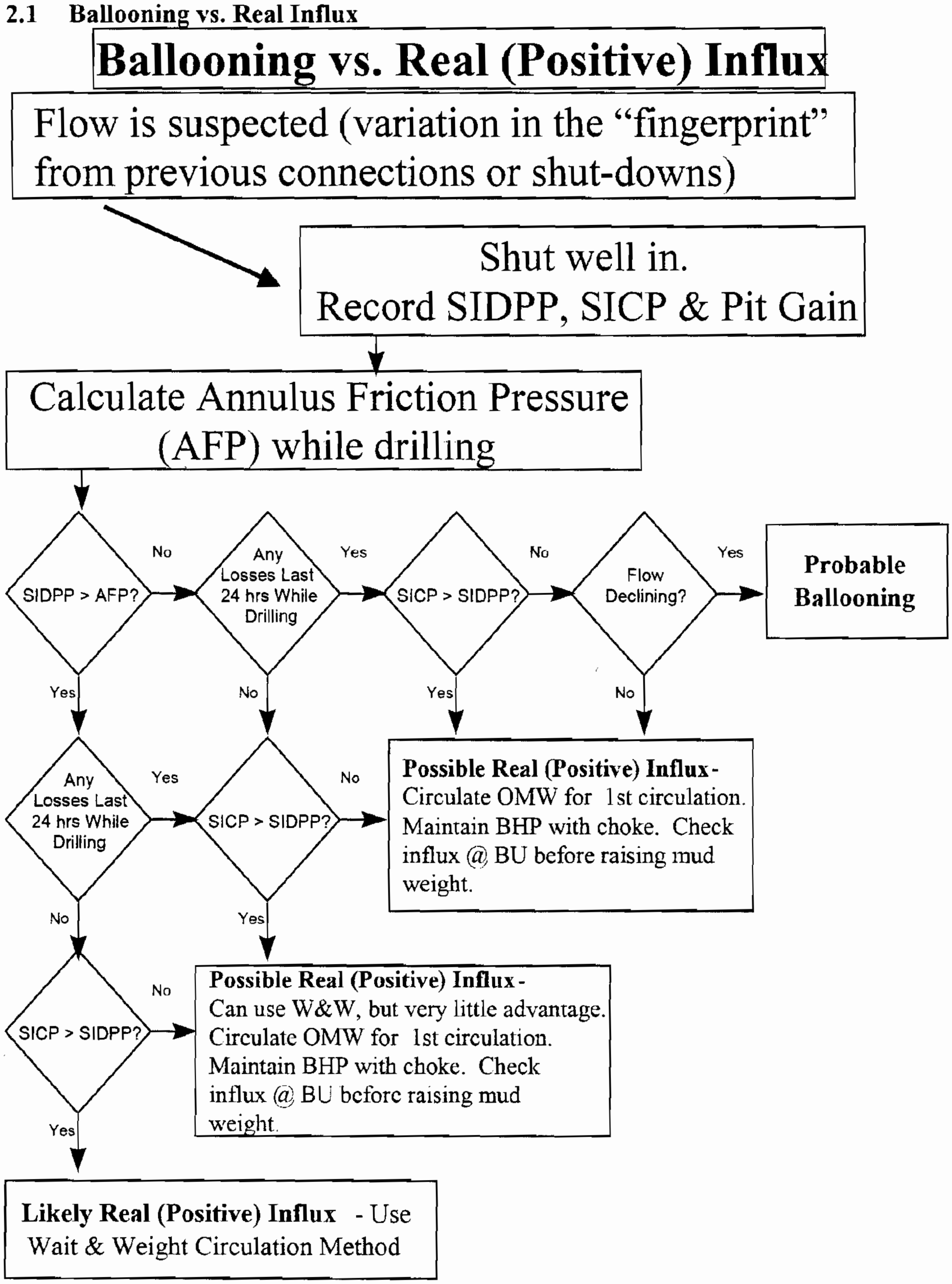
The implementation of a conventional well kill can be subject to problems with choke operator error, choke line plugging, etc, in addition to choke line friction. Ideally, an additional contingency margin of pressure (±150 psi) would be included in determining whether or not to follow conventional kill procedure. However, this is frequently not possible due to the close tolerance between the mud weight and the fracture gradient at the previous shoe. It will be left to the operations team to decide if any additional margins of safety should apply through evaluation of the actual conditions at the time of the kick.

2 Kill Technique

When there has been a well flow the team will have to make decisions as to how to handle that flow. Several factors will be considered; size of influx, shut-in pressures, fracture pressure of the open hole, weather. The first decision is evaluating if the flow is real or from a ballooning formation. The following decision trees are provided to guide the team to the optimum technique.

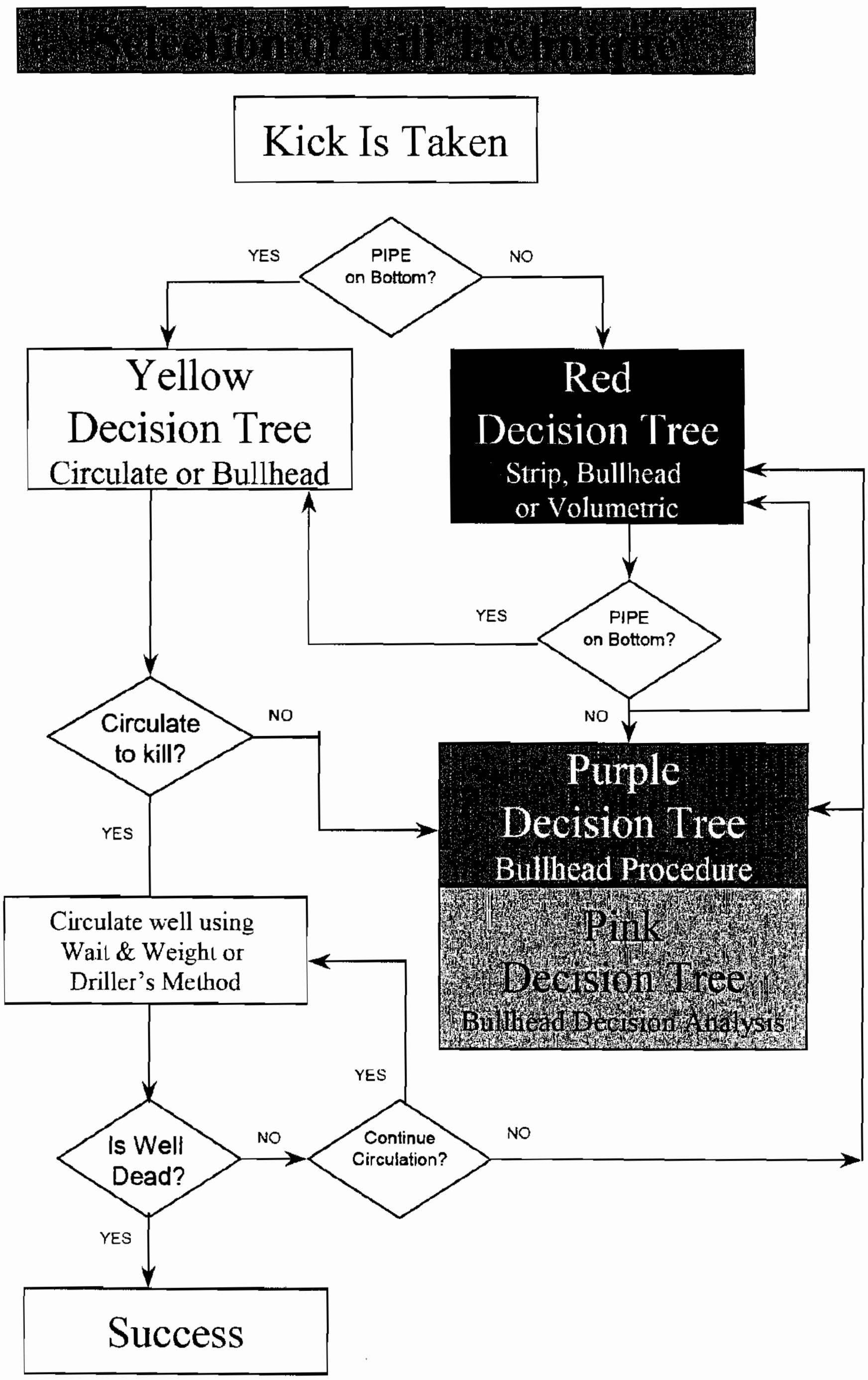
The On Bottom Kill Diagram (Yellow Sheet) leads the team through the choice of Wait and Weight method or the Drillers Method. On recent deep kicks in NAX the team has used the drillers method to get circulation started while preparing to weight up the system and to get a better handle on the pressures. The Drillers Method has also been used to assist keeping the drill string free when circulating out a kick from a rubble or gouge zone.

2.1 Ballooning vs. Real Influx

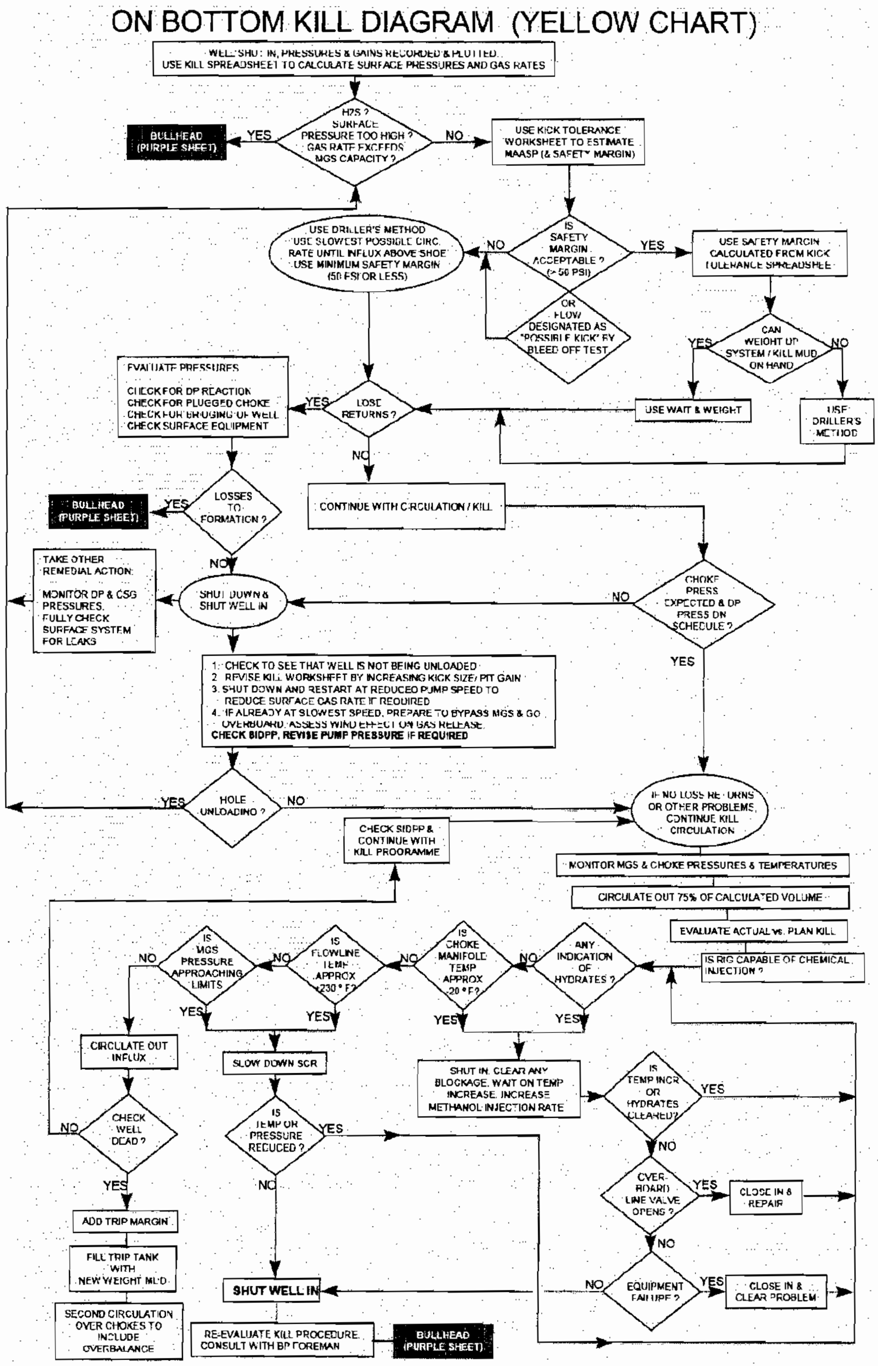


2.2 Kill Technique Decision Tree

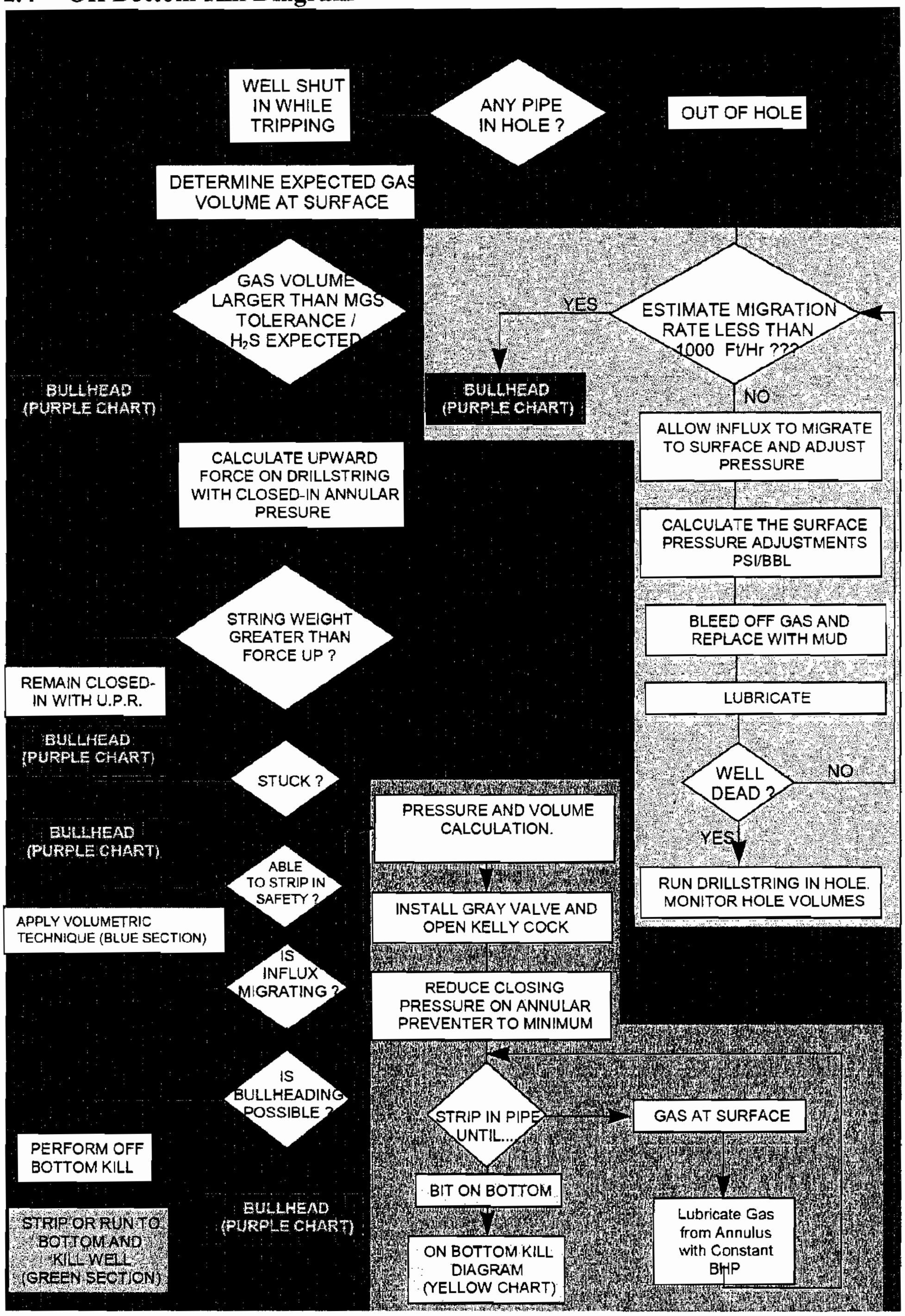
The attached decision tree is intended to lead the team through the best option for handling the well control event. If possible, all attempts should be made to circulate out the influx using the weight and wait method at a reduced pump rate up both choke and kill lines.



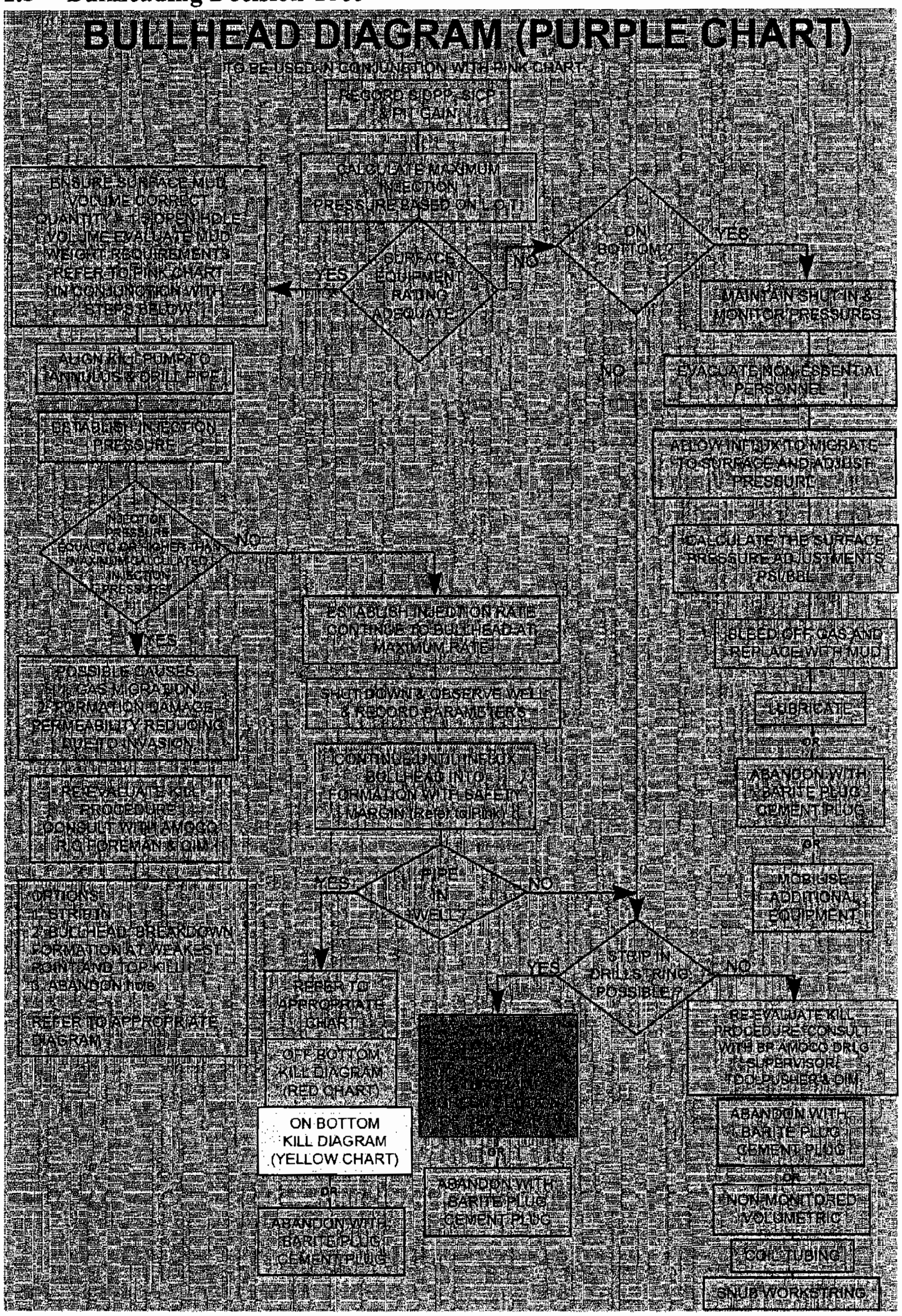
2.3 On Bottom Kill Diagram



2.4 Off Bottom Kill Diagram



2.5 Bullheading Decision Tree



3 Bullheading Procedure

Bullheading procedures will be drawn up bearing in mind the particular circumstances at the rig site. The following section contains some key guidelines and considerations when preparing for the contingency of bullheading and developing bullheading procedures.

3.1 Objective

Bullheading is the term used to describe killing the well by forcing formation fluids back into the formation by pumping kill weight fluid down the drill pipe and/or down the casing.

During drilling operations, bullheading may need to be considered in the following situations.

- When a very large influx has been taken.
- 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.
- When displacement of the influx by conventional methods would result in an excessive volume of gas at surface.
- If the influx is suspected to contain unacceptable levels of H2S.
- Returns are lost when starting to circulate out the kick.
- **When displacement of the influx by conventional methods may cause excessive surface pressures which could result in break-down of the casing shoe.**

Ideally, bullheading would be pumping back into the permeable zone which was the source of the influx, analogous to bullheading in completion operation well-kills. However, in drilling operations with low fluid loss mud systems and long open hole sections it cannot be assumed with certainty that the permeable "kick" zone will be taking the fluid. Conventional wisdom is that initially this may happen but with the filter cake being left behind from the mud, the permeable zone, will probably heal/plug off and the well bore will fracture in another weaker zone. This scenario could repeat itself several times during the well kill operation depending on how long the job continues.

Actual experience in the Gulf of Mexico deep water operations has shown that the formations just below the casing shoe have broken down when bullheading has been used. Procedures for a "sandwich kill" had to be developed that required simultaneously displacing fluid from the bit to the shoe and from the surface to the bit to ensure complete displacement of the influx because it cannot be established with certainty where the fluids were going,

Regardless of which model or theory is most representative of what may be encountered, the reality is that a bullheading procedure will be unable to assume, with any degree of certainty, where the fluids will go in the open hole interval. Therefore, it is important in the development of a bullheading procedure that the whereabouts of the influx in the annulus can be assured to have been displaced into an open hole formation and could not have migrated above the casing shoe. It is also critical to ensure that kill weight mud has actually been fully displaced in the well bore.

This suggests that the base-case bullheading procedure for a kick taken while drilling should account for the possibility that the bullhead fluids could be breaking down formations anywhere in the open hole interval. This means that the openhole annulus has to be completely displaced from down the annulus from the casing shoe to the bit and down the drillpipe from the bit to the casing shoe. (i.e. two-times the open hole annular volume).

After recognizing the importance of displacing the annulus from both directions, it is important to recognize, particularly in the case of a gas kick, that the pumping schedule and mud volume required should be designed to account for migration of lighter hydrocarbons. This means that pumping down the choke and kill lines should be at a rate exceeding the rate of migration of the influx. It also means that that pumping down the drillpipe displacing fluid from the wellbore from below, should be coincident with bullheading down the C&K lines to account for possible migration of gas above the zone taking fluid. Ideally, this type of "sandwich" displacement from top and bottom would be designed to finish at the same time. If this is not possible, displacement from the bit should always finish before displacement from the surface.

At the end of bullheading operations in the past the well has experienced ballooning of the injected fluids. A riser kill has been used to minimize the adverse effects of this ballooning. The mud weight in the riser is increased to offset the ballooning force which allows the pipe to be tripped. For example, if the ballooning pressure is 200 psi a rig in 5,000' of water would need to increase the mud weight in the riser by 0.8 ppg.

3.2 Contingency Requirements

Contingency plans for bullheading must be considered in well planning with respect to equipment and materials (specifically mud volumes) which should be available on the rig.

3.2.1 Mud

Achieving the displacement objectives outlined above can require a lot of mud. Two examples are shown below to illustrate situations where 2,000 to 3,500 bbls would be needed. An actual assessment should be made for each hole section determining the amount of mud which has to be available to bullhead kill mud weight into place.

In the following example, water depth is 5,000', 22" is run to 7,500', 18" is run to 11,500', TD is 14000'.

Item	OD	ID	Depth	Length	Vol. Factor	Total
Drillpipe Volume	6.63 in	5.70 in	14000	14000	0.032 bbl/ft	442 bbl
OH Annulus (from bit to shoe)	6.63 in	17.5 in	14000	2500	0.260 bbl/ft	648 bbl
Total Volume down drillpipe						1090 bbl
Liner x DP	6.63 in	16.50 in	11500	4000	0.222 bbl/ft	887 bbl
Casing to seafloor	6.63 in	20.00 in	7500	2500	0.346 bbl/ft	865 bbl
OH Annulus (from shoe to bit)	6.63 in	17.50 in	14000	2500	0.260 bbl/ft	648 bbl
Total Volume down kill line						2,400 bbl
Total Volume to pump kill weight mud						3,490 bbl

In the following example, water depth is 5,000', 13-5/8" is run to 15,000', TD is 17,000'.

Item	OD	ID	Depth	Length	Vol Factor	Total
Drillpipe Volume	6.63 in	5.70 in	17000	17000	0.032 bbl/ft	537 bbl
OH Annulus (from bit to shoe)	6.63 in	12.25 in	17000	2000	0.108 bbl/ft	216 bbl
Total Volume down drillpipe						752 bbl
Csg x DP	6.63 in	12.25 in	15000	10000	0.108 bbl/ft	1080 bbl
OH Annulus (from shoe to bit)	6.63 in	12.25 in	17000	2000	0.108 bbl/ft	216 bbl
Total Volume down kill line						1,296 bbl
Total Volume to pump kill weight mud						2,048 bbl

Note: 4-½" ID Choke and kill lines in 5,000' of water will hold 100 bbls, each.

3.2.2 Wireline

A temperature gradient logging tool and a wireline lubricator for running a log inside drillpipe should be available for immediate call out in the event of a well control problem. Schlumberger has 1-11/16" OD tools readily available in Houma.

The small margin between pore pressure and frac gradient could result in an underground transfer to an undeterminable (from surface indications) level in the open hole interval. Likewise, post bullheading bleed off/flow-back procedures may benefit from information regarding where most of the fluid exited the wellbore.

3.2.3 Dart Sub

A dart sub in the BHA's is not recommended. Similar documents as this have included a dart sub to provide for a mechanical means of plugging the drillpipe before backing-off. However, the sub would be another piece in an already complex BHA. Getting the dart to seat and test could be a problem. A wireline drillpipe bridge plug can be considered as an option for plugging the string. HPI (High Pressure Integrity, Inc – New Orleans 504-733-5555 or Lafayette 337-837-6070) can supply the Magna-Range bridge plugs that can be set by most wireline companies. Note, in drill pipe the plug must be spaced out in the tool joint upset and the experience of the wireline operator is critical for a successful application.

3.3 Data Requirements

The pre-recorded data sheets for well control should be prepared before drilling out and updated on a consistent basis. The mud volumes needed for a bullhead well kill operation can be obtained from these sheets.

Volume information required:

- Cased–hole annular volume from wellhead to casing shoe
- Open hole annular volume
- Drill string from surface to bit
- Volume of choke and kill lines.

Kick Information

- SIDPP
- SICP

- Volume/height of influx
- Top of influx if migration has occurred

Pressure Limitations

- Maximum casing pressure – 80% of internal yield adjusted to account for internal vs. external fluid gradients
- Drillpipe maximum allowed internal pressure.

3.4 Shut-in Procedure and Bullheading Preparations

1. After fast shut-in on annular preventor (see Section 1.4), space out, shut-in on pipe rams. Hang off DP on rams.
2. Flow check the riser to ensure that the influx is not already above the BOP's. If flowing follow steps in section 4.1.
3. Record SIDPP and SICP's. Determine rate of bubble migration.
4. Ensure that influx is not due to formation ballooning.
5. Calculate kill weight mud density and begin weighting up surface mud system as necessary.
   Note: It will always be preferable to circulate out the influx using the weight and wait method at a reduced pump rate up both choke and kill lines. If this is not possible due to the high choke line frictional pressures and the effect of the temperature on the SOBM, then bullheading may be the only viable option.
6. Prepare specific pumping schedule to bullhead kill mud weight into place. (See guidelines below).
7. When kill mud weight is ready, displace the choke and kill lines to kill mud weight before starting bullheading operations to save mud as follows:
   - Ensure Lower Failsafe valves are closed on both choke and kill lines.
   - With choke closed, open upper choke line fail safe valves.
   - Bleed off pressure below annular.
   - Leaving the annular closed, open upper kill line failsafe valve.
   - Pump kill weight mud down kill line & up choke line. Be aware that any hydrocarbons already trapped below the annular preventer may enter the choke line. Returns should be taken through the mud gas separator.
   - Close choke line and kill line upper failsafe valves. Open Choke and Kill line lower fail safe valves and monitor casing pressure on choke line.
   - Have the ROV in the water inspecting for leaks from the choke and kill lines and the riser.
     Note: Casing pressure increase indicating bubble migration will have to be calculated adjusted by the calculated hydrostatic pressure change in the Choke & Kill Lines.

3.5 Pumping Schedule Guidelines

1. Prepare a pumping schedule of rates and volumes to "sandwich" the influx into an open hole formation by using the following guidelines:
   - Fluid velocity down the annulus exceeds the fluid velocity plus gas migration rate of the fluids coming up from the bit.

- Pump rates should be set so that the time of shut down is approximately equal, but it is important that pumping from the bit to the shoe finish before pumping from the surface to the bit to ensure gas is not allowed to migrate above the shoe.
- Volume pumped down the kill line (after the kill line has been displaced) should be equal to annular volume from the wellhead to the bit.
- Volume pumped down the drillpipe should be equal to the drillpipe volume plus the volume of the open hole annulus from the bit to the casing shoe.

2. With one pump, establish kill rate down kill line. Pressures will build until the formation fractures. There should be a dramatic drop in pressure, then the pressure gauge should stay at a relative constant value. Note pressure at final kill rate.
3. Shut down pump. Open IBOP.
4. Start pumping down drillpipe and kill line at rates determined to have kill weight mud in place at the same time from both directions.
5. The base case pump schedule will require a "sandwich kill" which will bullhead kill weight mud as follows:
   - Pumping down drillpipe a volume of kill weight mud equivalent to the calculated drill string volume from surface to bit and the calculated annular volume from the bit to the casing shoe.
   - Pumping down kill line a volume of kill weight mud equivalent to the calculated annular volume from wellhead to bit. (Assuming the choke and kill lines have already been displaced)
6. If any information can be obtained as to the whereabouts of the loss zone so as to eliminate the need to displace the open hole volume from above and below, it may be possible that the bullheading can be planned without a redundant open hole volume. This compromise should only be made after a thorough risk assessment.
7. Close IBOP.
8. Pump the balance of the kill weight mud volume down the kill line at the maximum rate.
9. The choke line should be monitored throughout the bullheading operations for pressure information.
10. Shut the well in and follow bleed-off pressure guidelines for ballooning of the formation outlined below.

3.6 Kick Off-bottom

Generally speaking an off-bottom kick is usually a swab kick. In this case the guidelines for displacement are still technically the same recognizing that the mud in the hole is the kill weight mud. With a swab kick, an evaluation can first be made of whether or not to strip to bottom. Stripping back to bottom will almost always be the preferred case since this may enable a conventional well-kill operation. The worst case would be that stripping to bottom would lead to a bullheading plan similar to that outlined above. In a situation where it is known that the MASP will be exceeded by the choke line friction pressure, it may be possible to consider bullheading down the drillpipe and kill line at the same time in an attempt to displace the influx into the original zone. This would be done generally as follows:

1. Choose a volume of mud to bullhead, roughly 3-4 times the volume and height accounting for migration of the influx.

2. Bullhead this amount of mud into the formation.
3. Follow bleed off guidelines to assess if well is dead.
4. If the well is dead, the drillstring should be run back to bottom for conditioning of the mud prior to tripping out.
5. If well is not dead, it may be assumed the mud losses were above the influx and it was not displaced out of the annulus.
6. In this case, the bit should be stripped to bottom and the pump schedule guidelines followed to account for the open hole volume.

3.7 Shut-in – Bleed-off

One of the greatest challenges to a bullheading operation will be to distinguish between formation ballooning and flow back or remains of the influx in the annulus.

1. Record the initial shut pressure.
2. Monitor pressures on the choke line until pressure stabilizes. Mud loggers should be recording pressure data on maximum time frequency – e.g 5 sec.
3. If there is still pressure on the choke line this could either be from ballooning of the formation which received the bullhead fluids, or it could be that the well is not dead.
4. To assess:
    - Bleed off a predetermined volume of mud through the choke line.
    - Shut –in and observe pressure behavior.
    - A good indication of ballooning is that although the pressure builds back up it does not exceed the stabilized formation pressure after the initial shut-in.
    - If shut-in pressure after bleed-off builds to above the stabilized shut-in pressure, it is probably an indication that the well is not dead.
        - It is possible that the kill mud weight is not sufficient. However, it is also likely that hydrocarbons are returning to the wellbore as the fracture closed.
        - If this is suspected, pump an additional amount of kill weight mud at least twice the amount bled off before observing the pressure increase.
        - Shut in and observe the pressures. Pump open the float and compare SIDPP vs. SI Casing pressure.
        - Further efforts to assess for ballooning vs. influx and stabilize the well should be coordinated in consultation with the Houston office.
    - Accurate and detailed pressure data should be collected during this time for expert assessment.
5. If the well is not bleeding off pressure, but is not experiencing an increase in pressure, it may be necessary to increase the volume of mud being bled-off in each increment.

Work should be done in parallel to preparing and implementing a bull heading procedure for the worst-case outcome to cement the drill string in place to re-establish control of the well.

4 <u>Well Control Problems Unique to Deepwater</u>

The two well control problems unique to deepwater are the potential to have a kick fluid above the BOP before shut-in (3.1) and having kick fluid "trapped" (3.2) in the subsea BOP after the well is dead.

4.1 Considerations in the event influx is above the BOP

If a kick is detected late, the influx may already be past the BOP's and into the riser. This is more of a potential problem with shallow kicks. When dealing with shallow kicks it is extremely important to know the position of the influx in the hole.

In this case the well must be secured while coping with the effect of gas expansion in the riser. It is important to deal with only one problem at a time. Therefore, the following steps should be taken:

1. Space-out & Shut in.
2. Close pipe rams and hang-off.
3. Close diverter and direct fluid through riser gas buster.
4. Line up hole fill line to continuously fill the riser while gas is venting.
5. Estimate the potential top of the influx. The influx will not likely migrate in oil base mud until the hydrostatic is reduced – it gets near the surface. At that point it will break out of solution rapidly.
6. To get the gas out of the riser circulate one quarter (¼) of the riser volume by pumping down the boost line and the kill and choke lines (through the Upper fail safe valves). Monitor the return flow rate and shut down pumping from below when a flow increase is observed.
7. After pumping the quarter volume, shut down pumping and watch the well.
8. Circulate an additional one quarter of the riser volume.
9. Shut down and monitor for flow.
10. Circulate an additional one quarter of the riser volume.
11. Shut down and monitor for flow.
12. Pump the quarter of the riser's volume.
13. When rapid expansion of the fluids near surface attempt to keep flow going through the gas buster – as opposed to over board lines – to allow minimize synthetic oil mud going into the Gulf, but be prepared to divert.
14. Fill the riser and note the volume necessary.
15. After eliminating the influx from the riser, well kill operations can be undertaken.

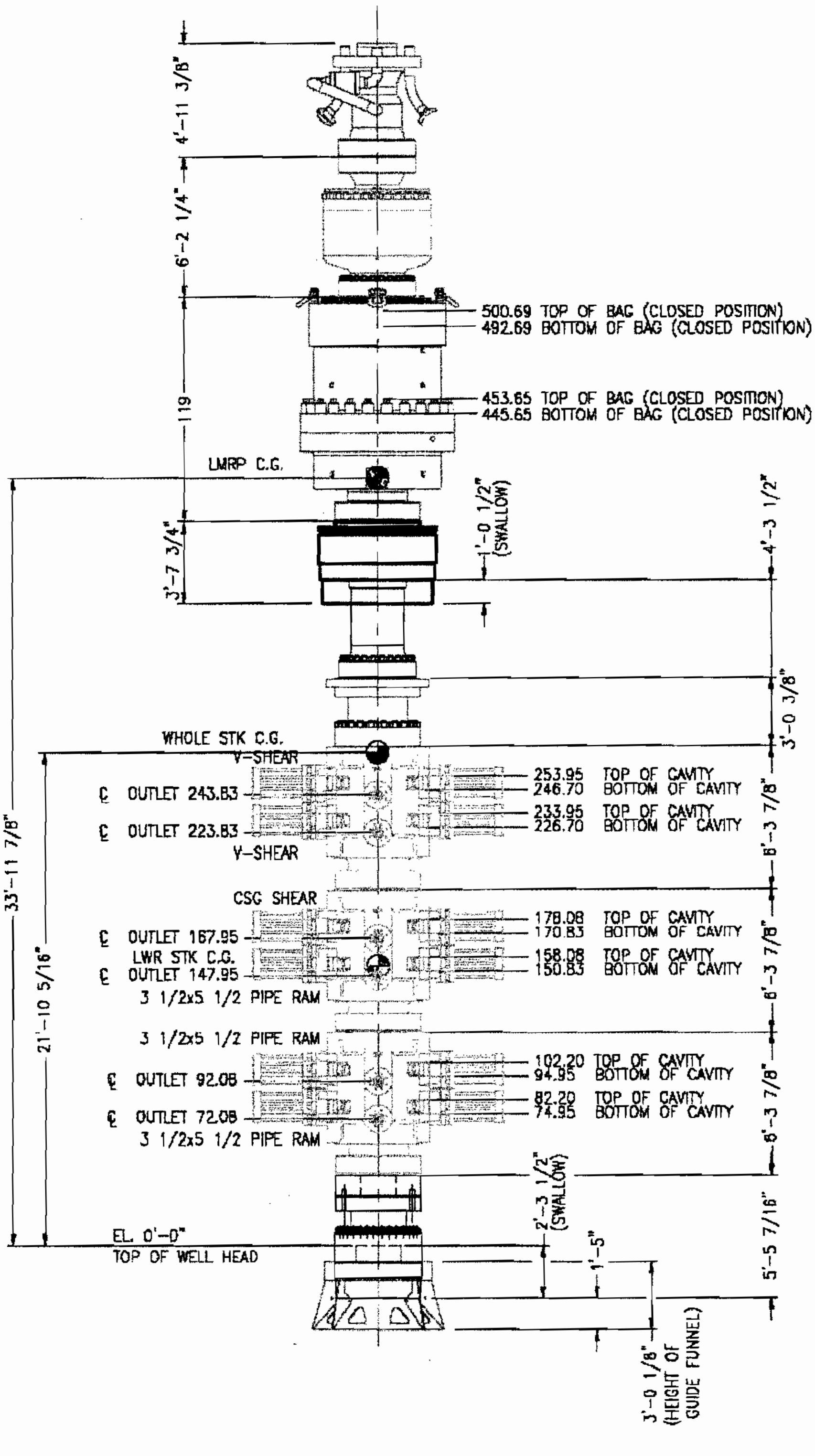
4.2 Stack Sweep of Trapped Gas

The following steps are to sweep gas trapped in the subsea BOP between the close-in point (annular or ram) and the highest circulation outlet (choke or kill line). These steps should be incorporated into the contractor's procedures and the specific procedure for the well which will be developed at the wellsite.

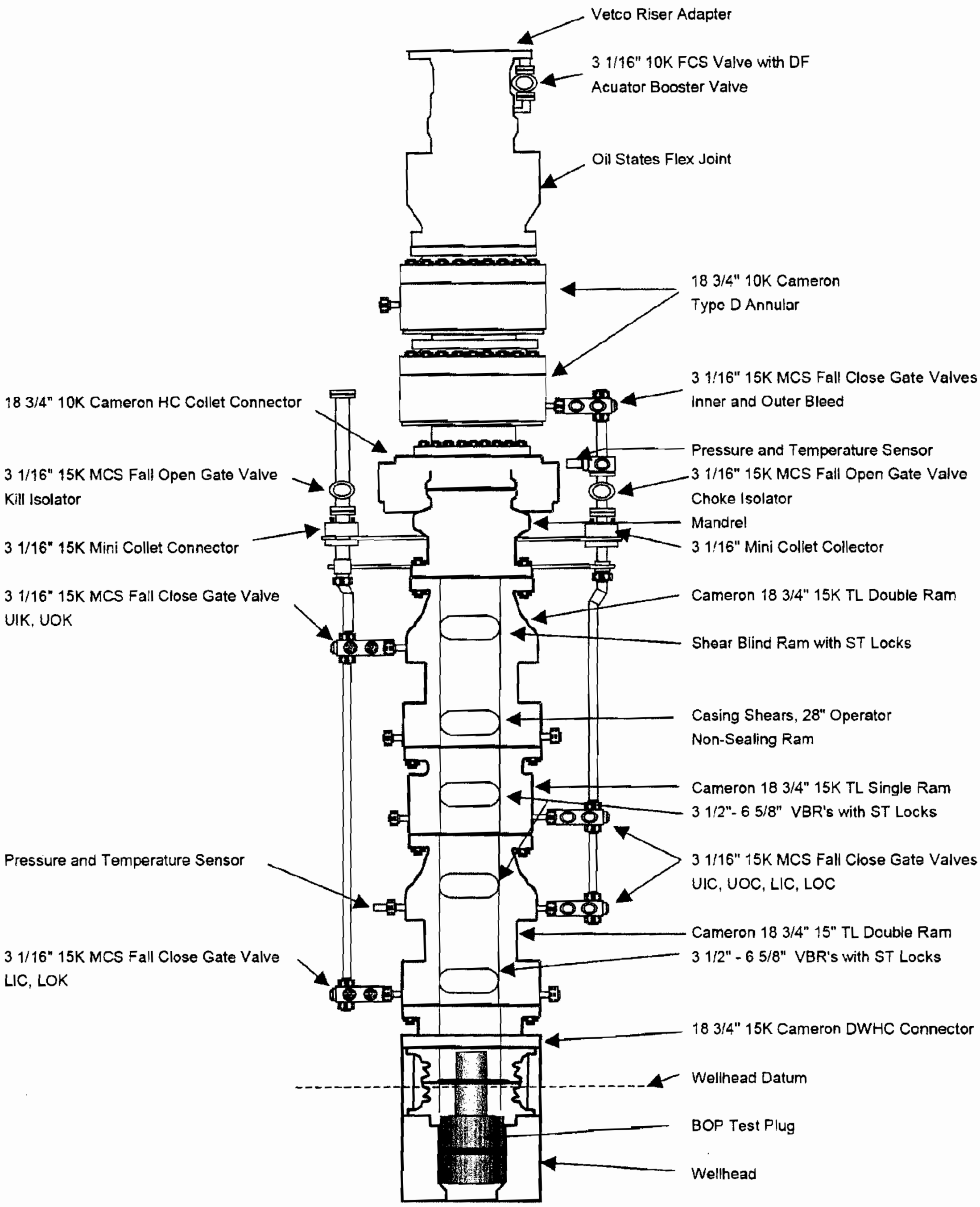
1. Displace the riser to kill weight mud through the boost line.
2. Close the lowest pipe ram to isolate the open hole.
3. Circulate base oil (when using synthetic oil mud) or seawater (when using water mud) down the choke line taking returns on the kill line. U-tube pressure will cause the displacing pressure to ramp up.
4. When base oil has been circulated to the stack, close the valves on the kill line. Hold the pressure on the choke line.

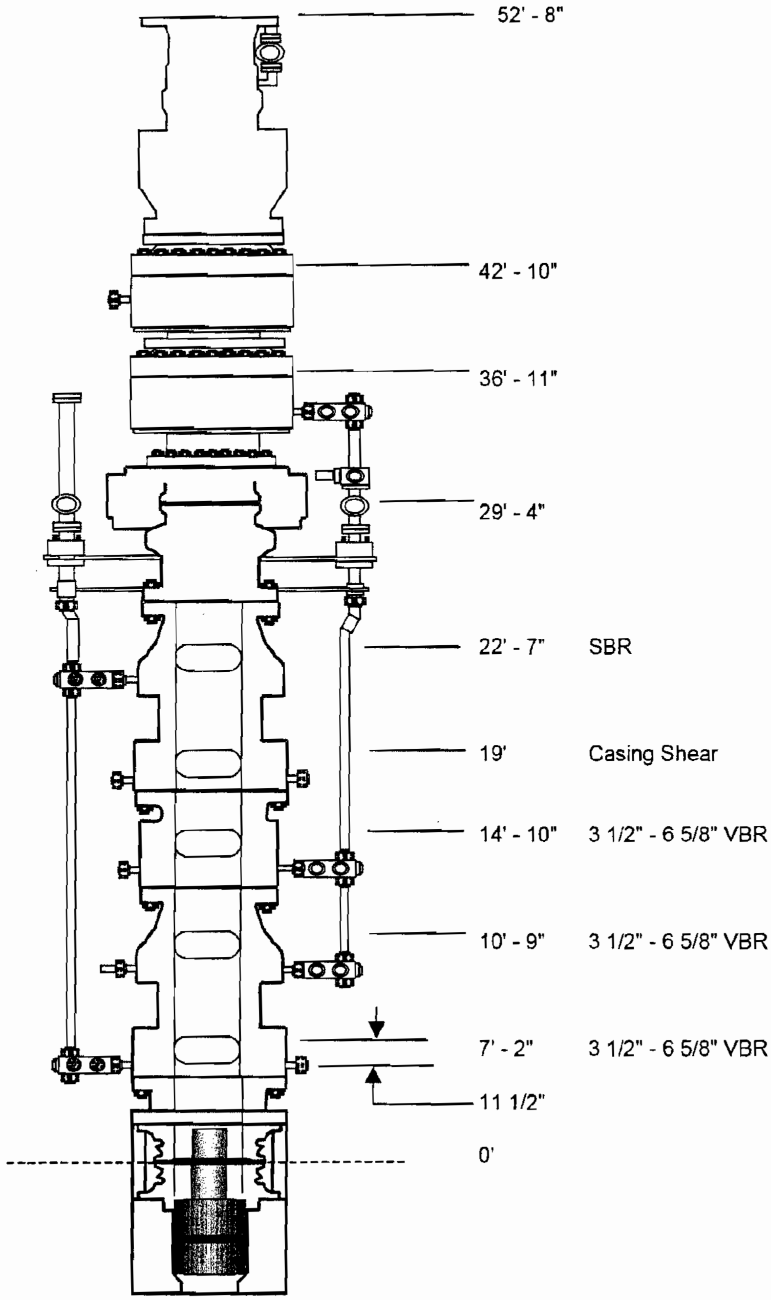
5. Line up the choke line to the gas buster.
6. Bleed off the pressure from the choke line allowing any gas trapped in the stack to be recovered up the line.
7. Open the annular preventer (or the top shut-in point on the stack) to flush the final trapped "fluid" into the choke line. Fill riser from the fill up line.
8. Close the annular and circulate kill weight fluid from the kill line out the choke line.
9. When kill fluid is circulated to the surface, circulate bottoms up from the riser.
10. Open the lower pipe rams and work the pipe while circulating the well. The kill is complete.

5 Sketch of Ocean Confidence BOP



6 Sketch of Transocean DW Horizon BOP




52' - 8"
42' - 10"
36' - 11"
29' - 4"
22' - 7" SBR
19' Casing Shear
14' - 10" 3 1/2" - 6 5/8" VBR
10' - 9" 3 1/2" - 6 5/8" VBR
7' - 2" 3 1/2" - 6 5/8" VBR
11 1/2"
0'

Ballooning vs. Real (Positive) Influx