OPTIMIZATION OF WELL CONTROL USING SMART KICK DETECTION TECHNOLOGY FOR DUAL DENSITY DEEPWATER DRILLING

A Project Report

submitted by

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in partial fulfilment of the requirements
for the award of the degree of

BACHELOR OF TECHNOLOGY
in
APPLIED PETROLEUM ENGINEERING
with specialization in
UPSTREAM ENGINEERING

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April - 2016

DECLARATION BY THE SCHOLAR

We hereby declare that this submission is our own and that, to the best of our knowledge and belief, it contains no material previously published or written by another person nor material which has been accepted for the award of any other Degree or Diploma of the University or other Institute of Higher learning, except where due acknowledgement has been made in the text.

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CERTIFICATE

This is to certify that the thesis titled **Optimization of well control using Smart Kick Detection technology for Dual Density deep water drilling** submitted by Abhinav Sharma (R870212002) & Vishesh Amarpuri (R870212044) to the University of Petroleum & Energy Studies, for the award of the degree of BACHELOR OF TECHNOLOGY in Applied Petroleum Engineering is a bonafide record of project work carried out by them under our supervision and guidance. The content of the thesis, in full or parts have not been submitted to any other Institute or University for the award of any other degree or diploma.

Mr. Mohammed Ismail Iqbal	**Dr. Pushpa Sharma**
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ACKNOWLEDGEMENTS

First and fore-most we would like to thank the Dean Dr. Kamal Bansal (College of Engineering Studies-University of Petroleum & Energy Studies) for allowing us to undertake project report on the Topic - "Optimization of Well Control Using SMART Kick Detection Technology for Dual Density Deepwater Drilling" and express our sincere thanks for providing us this great opportunity to learn.

Very sincere and honest thanks to Mr. Mohammad Ismail Iqbal (Faculty, Dept. Of Petroleum and Earth Sciences, College of Engineering Studies – University of Petroleum & Energy Studies) for providing us an opportunity to work with him and undertake a Project of such importance.

We would also like to thank Dr. Pushpa Sharma Mam, our Course Co-coordinator who helped us in the project and without her guidance it would have been extremely difficult to grasp and visualize the project theoretically and practically.

NOMENCLATURE

A. BHP – Bottom Hole Pressure
B. BOP – Blowout Preventer
C. DDD – Dual Density Drilling
D. DGD – Dual Gradient Drilling
E. DSV – Drill String Valve
F. FCP – Final Circulating Pressure
G. ICP – Initial Circulating Pressure
H. KMW – Kill Mud Weight
I. MD – Measured Depth
J. OMW – Original Mud Weight
K. PI – Productivity Index
L. RKB – Rotary Kelly Bushing
M. SCR – Slow Circulating Rate
N. SICP – Shut In Casing Pressure
O. SIDPP – Shut In Drill Pipe Pressure
P. SMS – Subsea Mud lift System
Q. TD – Total Depth

ABSTRACT

On land or offshore, kick detection is primarily achieved by means of measurement and observation at surface of the drilling fluid and drilling equipment. A kick, if not controlled, will progressively grow in the wellbore until it becomes a blowout. Control of a kick is dependent upon time-to-detection. Kick detection in a subsea well is more problematic because the subsea well contains a large volume of drilling fluid between the wellbore and the surface kick detection – the volume of mud in the riser – which can mask a kick or delay detection. This additional volume in the riser may be up to twice as much as the volume in the wellbore. In any case, control of a kick in a subsea well can be improved if detection of the kick can be made sooner.

Automating the initial well control response to an influx is the initial focus area with the goal of assisting rig personnel to identify and stop any influx without delay. This will lead to a well control automation collaboration project being initiated between an operator, a rig contractor and a rig equipment supplier. The first phase of the project is to develop a system that could detect an influx across a broad spectrum of well construction related rig operations.

To understand where to focus the kick detection system upgrade efforts, a fault tree style sensitivity analysis of kick detection and well shut-in procedures will be undertaken. The results will point to the high value of improved sensor data (both accuracy and reliability) and of improved detection software for alarming (both in terms of coverage and how the driller is alerted to respond to a confirmed kick condition). Based on this sensitivity analysis, a kick detection system upgrade functional specification will be created and used to develop a trial upgrade plan for a deep water rig.

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CHAPTER 1

INTRODUCTION

1.1 Deepwater Drilling Challenges

Deepwater sedimentary basins provide immense opportunities and challenges for the oil and gas industry. While these frontier areas are expected to yield a large number of new resources, large uncertainties and the large capital investments that are required make realization of these opportunities uncertain. Without a proper enabling technology and a corresponding decrease in finding and development costs, substantial deep water resources may remain out of reach, regardless of the current urgency surrounding the need for additional oil supply.

A narrow margin between formation pore and fracture pressure exists in many over pressured basins around the globe including the Gulf of Mexico, Brazil, and West Africa. This limited margin between pore and fracture pressure often becomes narrower with increasing water depth due to the reduced overburden pressure and shallow onset of abnormal pressure. As a result, reaching the target depth for deep water wells while retaining a useable borehole size is often difficult. Ultra-deep water drilling poses problems such as shallow water flows and increased risk of lost circulation or loss of well control. Any of these may prevent a well objective from being reached. To tackle these concerns, multiple casing strings must be run. This means that the production casing may not be large enough for the high rates needed for deep water wells to be economic.

1.2 Dual Density Drilling Concept

Presently, high costs involved in exploration of deepwater gas resources limits their development. Therefore, dual gradient drilling methods have been proposed as a means to provide simpler, safer, more economic well designs and subsequently increase the ultimate development and utilization of deepwater gas resources. A dual density drilling concept using riser gas-lift is being investigated in this report as potential means to implement a dual gradient system.

Substantial costs of deepwater exploration constrain deepwater gas production in spite of their economic importance. Although a great deal of effort was undertaken on new technologies, development to tackle these deepwater exploration and production concerns, and on building new deepwater drilling rigs, no major new technologies have been commercialized to reduce drilling costs by improving the drilling and well design concepts so far. In spite of fact that wells have been drilled in 10,000 ft water depth, these constraints increase even further with water depth. There is a serious concern that due to the current drilling and well design technology being too expensive to be used, some deepwater resources will be left unexplored or undeveloped.

A new system that would provide a more simple and economic design consisting of a light density fluid equivalent to a seawater density in the riser annulus and of a higher density mud in the wellbore. It is expected to provide a favorable pressure profile in these deepwater wells with narrow pore and fracture pressure margins. This system is called a dual density, gaslift system and is intended to utilize more standard equipment than the separate industry projects called dual gradient systems focused on the use of seafloor pumps to achieve the advantages of a dual gradient method. Two different fluid gradients would be present in this system. Specifically, one from the surface to the mudline being equivalent to a seawater gradient, and the second one in a wellbore below a mudline to provide enough overbalance for a trip margin. The apparent advantages of such a system would be fewer casing strings, larger mud weight margins and larger production casing size for increased production revenue.

This work focuses on nitrogen injection at riser bottom to create a dual density by gas lifting the mud in the riser. “This gas lift system would be fully automated and would maintain the pressure in the sub sea wellhead equal to the seawater hydrostatic pressure at the sea floor while injecting the non-aerated mud through the drillstring”. This will result in the effective mud weight at the casing shoe being less than the effective mud weight at the drilling depth. The result is fewer casing points when compared with a conventional deepwater well design. This result would be achieved by reducing the average density in the riser mud section to the seawater hydrostatic pressure gradient or even less by nitrogen injection.

1.3 General Project Description

The focus of this report is to address the question whether an effective well control method can be defined for a system containing the many different density fluids and different flow paths inherent with a riser gas-lift system. The project will address the three major well control concerns: kick detection, stopping inflow, and kick removal. These are presented and analyzed in a sequential order.

In addition, a number of well control studies have been done for a dual gradient system based on use of a mudlift pump.

CHAPTER 2

LITERATURE REVIEW

2.1 Dual Density Drilling Systems

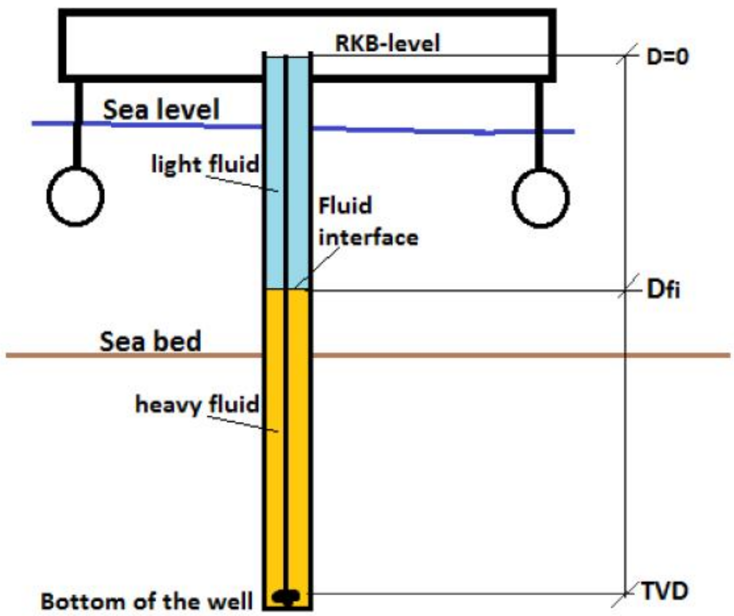


Figure 1: DGD schematic overview

2.1.1 Subsea Mud Lift Drilling

The subsea mud lift drilling (SMD) method was originally referred to as “riser less” drilling due to the idea of replacing the riser with a separate “mud return line” that is not concentric with the well. A concept of a dual gradient in the wellbore would be achieved using positive displacement mud lift pumps placed on the seafloor. Returns would be lifted from the wellhead into the riser using the seafloor pumps, and these pumps would provide a suction pressure so that the wellhead annulus pressure would be equivalent to the sea water pressure at the seafloor. Therefore, the annulus pressures below the wellhead would effectively be the result of a dual gradient, due to the mud weight from any point in the well back to the seafloor and then equivalent to seawater from the seafloor to the surface.

The progress of a joint industry project led by Conoco and Hydril to investigate and develop a subsea mud lift drilling system has been reported in multiple conference papers and journal articles. The specific subject relating to the mud lift technology that is of most interest for this specific study is a well control consideration.

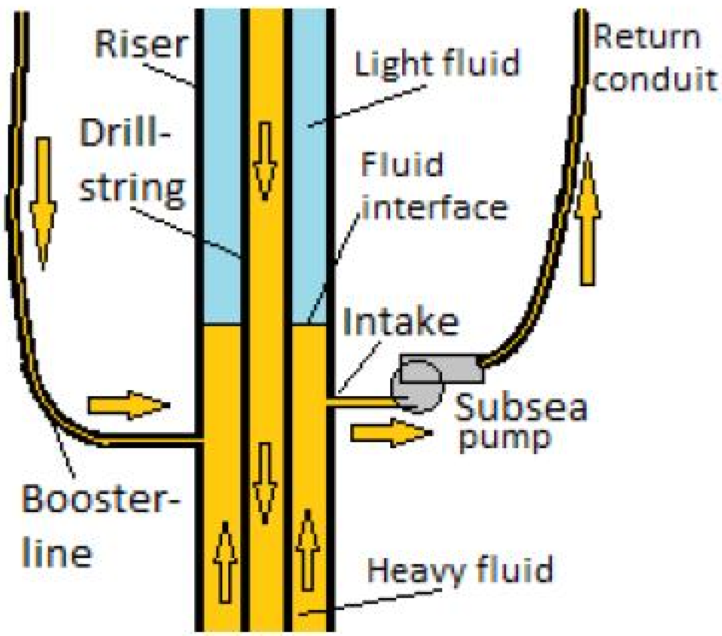


Figure 3: DGD fluid circulation

The special requirements for successful well control operations with the mud lift technology are of particular importance due to its similarity to the well control concept being studied in this project. The references specific to dual gradient well control are described in a subsequent section on that specific topic. Equipment overview and engineering of this system is presented
along with the discussion on drilling and well control procedures for this dual gradient drilling.

The subsea mud lift drilling system is apparently the only dual gradient drilling system that has been evaluated in a full-scale, offshore field trial. This was performed on a well drilled in about 1,000 feet of water in GC Block 136 in 2001.

2.1.2 Deep Vision Project

This project was led by Baker Hughes and Transocean in order to implement a dual density system applying a reeled pipe drilling system. In the Deep Vision system, centrifugal pumps placed at the seafloor return mud up the separate line and there is the absence of a conventional riser. No more current information regarding the conclusions reached or future plans for this technology have been found.

2.1.3 Riser Gas Lift

This is an automated gas-lift system for a marine riser that would maintain the hydrostatic pressure in the subsea wellhead equal to that of the seawater at the seafloor. Hydrostatic control of abnormal formation pressure would be maintained by a weighted mud system that is not gas-cut below the seafloor.

Once verified, a model is used to define the gas requirements and practical limits of a riser gas-lift system based on estimated additional costs of gas compression and nitrogen membrane filters. These limits were presented in terms of maximum mud density, water depth, and riser diameter combinations.

2.1.4 Riser Dilution

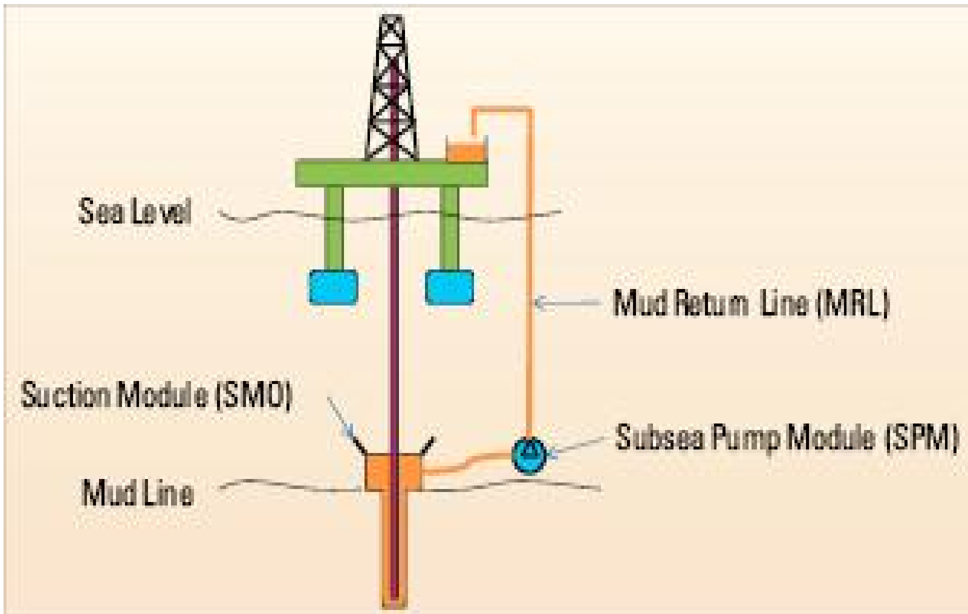
Riser dilution method concept is to inject a drilling base fluid into the bottom of the riser to achieve a riser fluid density equivalent to seawater density. It would then separate the mixture of weighted drilling fluid and base fluid using centrifuges.

2.1.5 Hollow Sphere Dual Gradient System

This considers alternatives for using low density, hollow spheres to reduce fluid density in a riser and achieve a dual gradient system. Some aspects of the primary alternative of using slurry of hollow spheres and drilling fluid injected into the base of the riser are similar to the riser dilution concept.

2.1.6 Riser less Systems with Returns to the Seafloor

In the upper hole intervals of deep water wells, drilling with returns to the seafloor is a common practice. Seawater is being used as the drilling fluid and when formation pressure requiring higher density mud was encountered, seawater as a drilling fluid was stopped. The desirability of maximizing the well depth before installing the blowout preventer stack and riser have resulted in using a weighted mud with returns to the seafloor that is referred to as “pump and dump.” It is a truly dual density drilling method, but it does not provide for reuse of the drilling fluid or a positive method of well control.



2.1.7 Underbalanced Drilling

Due to fact that that the dual density, riser gas lift method will have multi-phase flow in the riser, the equipment and operating methods similar to underbalanced drilling of a gas reservoir will be required. Furthermore, the multi-phase flow behavior and pressures in a riser will be similar to that in the annulus when drilling an underbalanced gas well. Therefore, references on underbalanced drilling were selected to focus on two topics: operations and flow modeling.

Underbalanced drilling equipment and operating methods specific to offshore rigs are particularly relevant to application of riser gas lift for dual density deep water drilling.

In order to better plan and effectively control underbalanced drilling operations, modeling of multi-phase flow has been heavily researched and developed.

2.2 Conventional vs Dual Density Drilling Systems

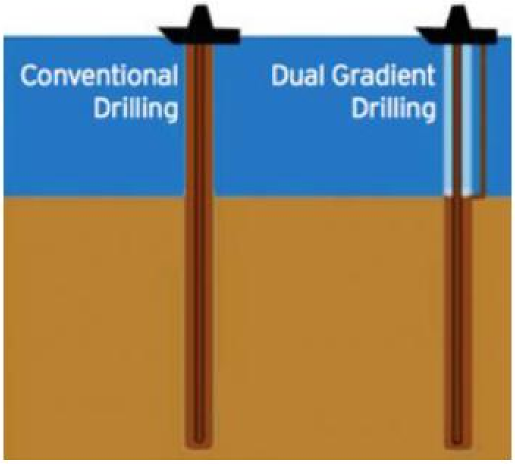
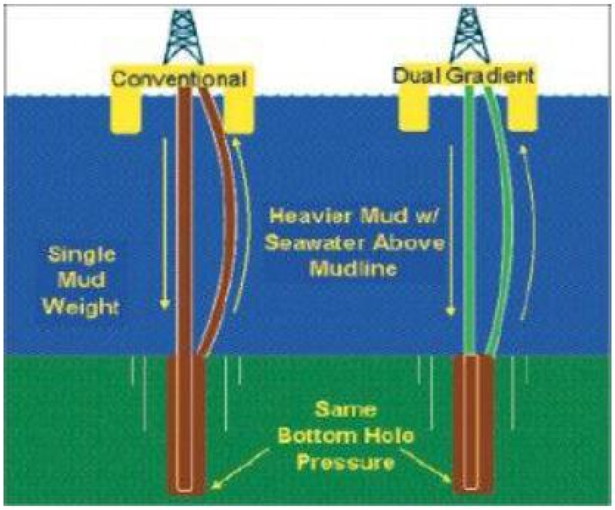


Figure 2: Principle difference: Conventional and DGD



Advantages

There is a broad range of advantages offered by dual gradient drilling that include:

• Casing strings can be run deeper without the risk of exposing the formation to the high pressures of the mud column. This not only means fewer casing strings, but a larger wellbore at TD.

• Smaller deck loads for rigs and lower hook loads will result. This means smaller rigs might be called into service to drill deep water wells.

• Reduced mud losses

• Adaptability: easy change from single gradient to dual gradient drilling

• Risk reduction & safety improvement due to less manual handling & improved kick detection

• Reduced non-productive time.

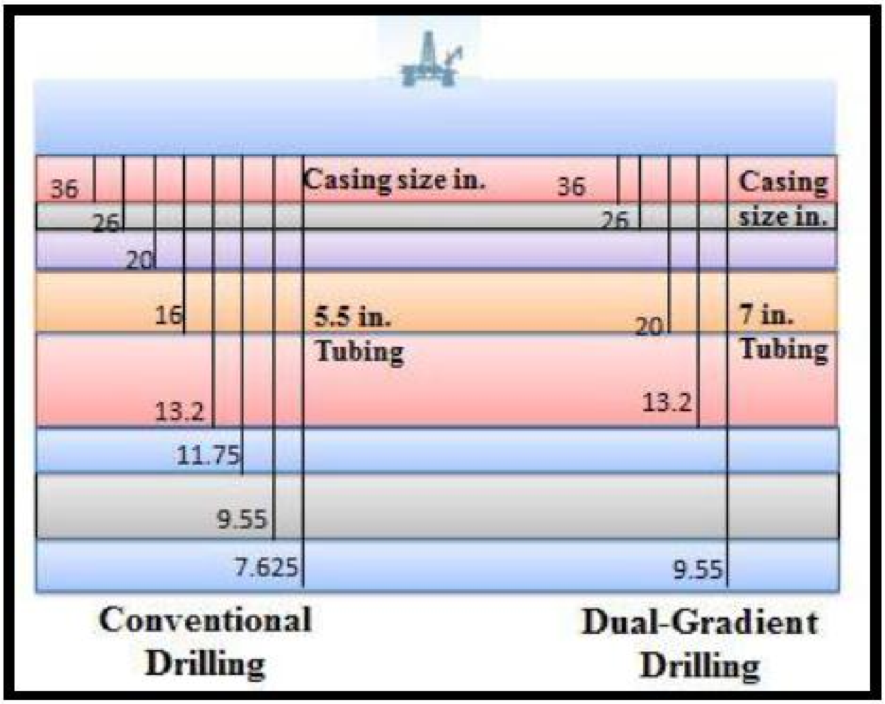
• Increased efficiency due to reduction of non-productive time.

• Improved access to challenging drilling targets.

• Financial savings for the operators.

• Improved wellbore management

Dual-gradient drilling promises to overcome the limitations imposed by sending drilling mud through thousands of feet of drill pipe and riser. This tremendous volume of fluid creates a huge hydrostatic head that can induce fracturing, particularly in shallow zones. Dual-gradient techniques dramatically change the physics of the drilling process, such that the rig effectively sits on the seafloor, rather than at its actual physical location thousands of feet above on the sea surface. In dual gradient, the mud column extends only from the bottom of the hole to the mudline. Subsea pumps are used to reduce the hydrostatic head from the mudline to the surface. Other benefits include reducing the number of casing strings, enabling the use of larger completion strings for increased flow capacity, improved drilling efficiency and decreased mechanical risk.



Limitations

Some of the limitations of Dual gradient drilling faced by Operating companies that employed DGD process in the past includes:

• Difficulty in primary subsea cuttings separation that necessities the use electrical submersible pumps (ESP).

• Subsea well control vents gas subsea, protecting rig personnel and eliminating the need for high-pressure containing equipment downstream of the subsea choke.

• Major drawbacks in gas dilution dual gradient drilling includes:

Corrosion and in flammability associated with air injection.

Deeper water depths require huge amount of gas for it to be effective.

Large gas expansion takes place when the gas traverses from shallow to deep.

Control of hydrostatic pressure for riser margin difficult.

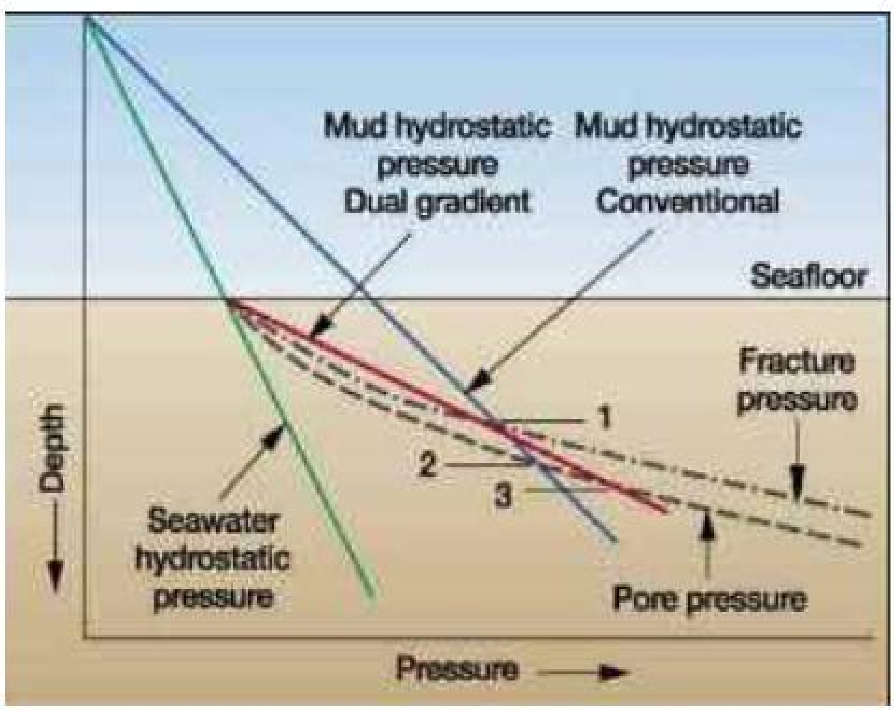


Fig 2: Pressure effects with conventional and dual gradient drilling.

2.3 Kick Detection

Kick detection in dual gradient drilling is more complex than conventional drilling method because of the effects of its dual gradient systems. The U-tubing effect makes kick detection by flow checking not completely reliable as returns will continue from the annulus until the U-tube becomes balanced due to the fall of the fluid level in the drill string. The subsea pump has its complication in the detection of kick in Riser less drilling. However, the kick detection methods in dual gradient drilling are explained below.

- **Increase in pit level:** An increase in flow rate due to the influx of formation fluid can be a sign of kick. This could be a rapid or gradual process depending on the pressure regime of the system. The amount of pressure required to control such condition depends on how quickly the well was closed in as quick closure retains more mud in the well than slow closure. However, the dual gradient nature of Riser less drilling requires the combination of this method with other kick detection methods to confirm a kick.

- **Well flow when the pump is shutdown:** In Riser less drilling the effective hydrostatic pressure due to the column of mud in the drillstring is always higher than the annulus pressure. As a result it is difficult to determine if the well is taking a kick when the pump is turned off as the well will always keep flowing even without a kick until the hydrostatic pressure in the drill string and annulus pressures balances up.

- **Increase in mud flow from the well:** The method of using flow check to confirm the increase in mud flow from the well is not completely reliable as mud flow will continue from the annulus until the level of mud in the drillstring balances with the level in the mud return line due to U-tubing effect.

- **Fluids fill up on trips:** Tripping of the drillstring after the balance in pressure has been achieved by the U-tubing effect. Although there are difficulties in measuring the mud level in the drillstring but improper filling up of hole can be used as a kick indicator. This can be achieved by attaching measuring devices in the drillstring.

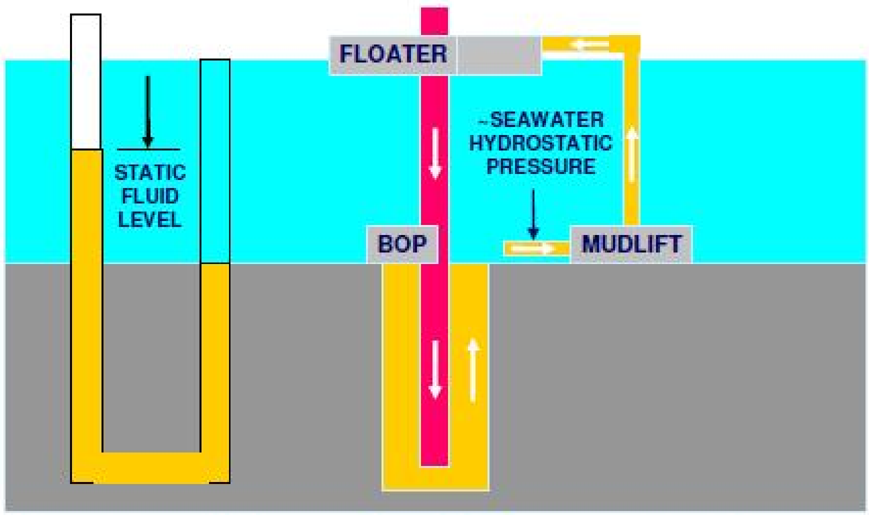
- **Sudden increase in ROP:** This method of kick indication in Riser less drilling has the same principle with conventional drilling method. Sudden increase in ROP is a direct means of detecting over pressured sand and shale formation as the bit drills faster due to reduction in pressure overbalance. Under this condition, the hydrostatic pressure of the mud column is less or equal to the formation pressure. However, a reverse drilling break can occur under the same condition if an oil based mud and diamond drilling bit are used.

- **Change in pump pressure:** The reduction in subsea pump pressure is caused by the reduction of hydrostatic pressure in the annulus. This occurs when there is imbalance in hydrostatic pressure between the inside and outside of the drill pipe. Gas expansion leading to displacing of fluid in the annulus causes this change and is good kick detection method when combined with other methods. Generally, the dual gradient concept and the U-tubing effect of Riser less drilling made it more complex for kick detection. For effective kick detection, there is need for combining various kick detection methods.

2.4 U- Tubing Effect –

Riserless drilling involves the use of a subsea pump and a surface pump. The surface pump is responsible for pumping mud into the drill string while the subsea pump is responsible for pumping used mud and cuttings to the mud return path and for balancing the pressure differential on the sea floor such that the hydrostatic pressure on the sea floor is equal to the hydrostatic pressure due to the water column on the sea floor. When the surface pump is shut down, the fluid level in the drill pipe will drop rapidly at the onset and then drops gradually to its final level. At the final level, the hydrostatic pressure in the drill pipe above the sea floor is equal to the hydrostatic pressure of the seawater column. Thus, the driving force of the U-tubing effect is the hydrostatic imbalance inside the drill string as shown in the figure below.

During U-tubing effect, there is the tendency for the hydrostatic pressure inside the drill string to fracture the formation when the annulus pressure is allowed to be increasing. This can be avoided by operating the subsea pump at constant inlet pressure as determined by the mud level in the drill pipe.



2.5 WELL SHUT-IN PROCEDURES FOR DUAL GRADIENT DRILLING

The key to successful well shut-in is early kick detection and as a result adequate planning, procedures and monitoring of kick measuring equipment and facilities should be provided. Upon detection of a kick, the kick influx must be stopped in a systematic and timely way. Otherwise it could result to loss circulation or a blowout in an uncontrolled scenario. The major determinant factor of Shut-in procedures in Riser less drilling is the excessive hydrostatic pressure of the mud in the long length of drillstring as it is capable of fracturing the formation.

When the well is shut-in, the U-tubing effect will cause the mud in the drillstring to move into the annulus before moving up the recovery line before complete shut-in is achieved. This movement of mud is capable of fracturing the formation. However, the use of drillstring valve (DSV) prevents the U-tubing effect when the well is shut-in as it permits flow only in one direction. The DSV is specially designed to support the hydrostatic pressure due to the mud column in the drill string when the pumps are shut down thereby preventing U-tubing effect. The DSV has an opening pressure that is a little more than the difference in pressure between the hydrostatic pressure due to the mud column in the drillstring and the hydrostatic pressure due to seawater at a depth equal to the water depth. It is located near a bottom hole assembly and part of its component is a spring activated mechanism. This mechanism is very sensitive to the pressure inside the drill string and only permits flow if sufficient surface pump pressure is applied to the column of mud in the drill string. Anytime the surface pump pressure is not sufficient, the spring will activate a flow cone that will move to block the flow ports thereby preventing flow of mud and formation fluid in the drill string.

When a kick is detected, the well can be shut-in immediately and the well can be killed in a similar way to the conventional riser drilling if the DSV is in place. However, the well shut-in procedures vary if the DSV is not in place and it follows a systematic way as illustrated below.

- ✓ Upon kick detection, slow down the subsea pump rate to the same level as the influx rate.
- ✓ Maintain the surface pump at constant rate.
- ✓ There will be pressure buildup at just below the sub-sea pump.
- ✓ This pressure build-up will allow the drill pipe pressure to stabilize.
- ✓ The stabilized drill pipe pressure and corresponding circulating rate is recorded.
- ✓ Continue the kick circulation at the stabilized drill pipe pressure rate until all the kick fluids are circulated from the wellbore through the mud return line.
- ✓ Always maintain the circulation rate at the stabilized drill pipe pressure by adjusting the subsea pump inlet pressure.
- ✓ Kill fluid of higher density is circulated into the wellbore to properly kill the kick after the kick fluid is circulated out from the well bore.

CHAPTER 3

MATERIALS AND METHODLOGY

3.1 RESEARCH METHOD

3.1.1 Introduction

The overall objective of the project is to offer alternative methods of achieving a dual gradient deep water drilling system that utilizes more standard equipment than the separate industry projects focused on the use of seafloor or mud lift pumps to achieve the advantages of a dual gradient method.

This research investigates riser gas-lift as a potential means to implement a dual gradient system. A primary concern in evaluating the feasibility of riser gas-lift is well control in a system containing so many different density fluids and different flow paths.

3.1.2 Specific Well Control Concerns

The major question addressed in this study is whether effective well control can be applied to this system with so many different fluid densities, continuous multiphase flow, and relatively complex flow paths.

First of all, the feasibility of reaching appropriate dual density operating conditions with a gas-lift system must be determined. This simply means that bottom pressure in the riser must be equal to the seawater hydrostatic pressure for various mud flowrates. Since during kick circulation returns will be taken through the choke line, its bottom pressure must be also equal to the seawater hydrostatic pressure during kick circulation. Furthermore, it is important to consider the case of an emergency when the mud pumps and nitrogen injection fail, and riser bottom pressure will decrease potentially causing a riser collapse.

A number of issues specific to well control are also important. A kick influx needs to be detected as early as possible to safely control the well. In a gas-lift system, kick detection is expected to be more complex than in a conventional system due to multiphase fluid behavior in riser. The major question is if it is possible to detect a kick early enough that the kick volume is low and the well may still be controlled in a safe manner in spite of the continuous multiphase flow and offshore rig movement.

After a kick is detected, the next step that must be addressed in this study is how to stop the influx and prevent the well from becoming a blowout. Alternative methods for stopping formation flow must be identified and compared based on whether flow was stopped, the time to stop the kick, and the kick volume taken. The methods should be evaluated and results and complications compared to a conventional approach in the single density system. The next pertinent issue after stopping the formation influx is removing formation fluids from the well. Several alternative methods were proposed, and they will be compared and evaluated. The proposed methods are

1) gas kick circulation through the gas-lifted choke line using surface choke adjustments,

2) gas kick circulation through a gas-lifted choke line with adjustment of a subsea choke placed at the seafloor between the riser and the choke line

3) gas kick circulation through a gas-lifted riser with adjustment of a subsea choke placed at the seafloor.

The evaluation criteria are maintaining the bottom hole pressure above the formation pressure, the magnitude of bottom hole pressure variations, the risk of fracturing the formation, responsiveness to choke adjustments, difficulty of choke operation, and any complications and difficulties in the overall process. Regaining the overbalance in the well after kick circulation must also be considered. Kill weight mud circulation can be evaluated applying the same evaluation criteria as for the kick circulation. An additional complication that must also be accommodated in this study is how to maintain bottom hole pressure constant when kill weight mud reaches the choke line. In each case, well control operations with the dual density, gas lift system should be compared versus the conventional, single density well control operations to evaluate its feasibility, complications and practicality, and to decide which system is more favorable.

3.1.3 Addressing Concerns with Simulation

The specific concerns regarding the feasibility of effectively controlling kicks with a riser gas lift drilling system are most readily addressed with realistic simulations. The ability of different equipment arrangements and operating strategies to maintain pressures in a safe range throughout a wide range of circumstances can be assessed and compared to conventional operations without the expense of conducting full-scale experiments. The quality of the conclusions based on these simulations is dependent on the ability of the simulator to accurately predict system response for a relatively complex flow path with multiphase flow, Non-Newtonian liquids, and changing operating conditions.

Specifically, for the well control simulations in this study, OLGA was used in the pressure prediction and overall system stability evaluation due to its complex, dynamic, multiphase fluid analysis capability. First, OLGA was used for the validation example to verify its accuracy. Furthermore, more complex well control analysis in the system with many different density fluids and flow paths were conducted. Various scenarios were considered due to characteristic and unique OLGA capabilities including achieving the multiphase system stability, formation fluid inflow, circulation shut down, restarting circulation, and introducing several different density fluids to the system.

3.1.4 Transient Multiphase Simulator

A transient, multiphase simulator – OLGA 2000^{TM}, is being used as the primary means of predicting well pressures during dual density operations in this project. Results presented for pressure predictions at the base of the riser and choke line versus various mud and nitrogen rates are based on simulations with the OLGA 2000 as well. Representative deep water well data were used in simulations to obtain and analyze the results for each case.

3.1.5 General Description

OLGA 2000^{TM} is a transient, two-phase, flow model that was originally created for complex, transient, pipeline flow problem analysis. The full OLGA program is not interactive and requires that all inputs be entered into the program in batch mode. This requires prior knowledge of specific conditions that will be changed and the duration of each change.

Two-phase flow is modeled in OLGA 2000 as a dynamic feature, increasing its applications versus steady state models. OLGA is capable of dynamic simulation with pipeline networks and process equipment as well.
The dynamic feature of the program imposes additional requirements on the user, compared with steady state models, but the results of the transient program are significantly more useful in design of the pipeline and its attendant facilities than steady state methods. A steady state processor is included in the OLGA, and it is mainly intended as a generator of initial values for dynamic simulations but it may be used independently as well.

OLGA is generally designed to characterize the operational strategies of a multiphase flow system. Consequences of changes in operating conditions are able to be predicted with OLGA in spite of their complexity.

The input file in OLGA consists of six files. The first file contains the data particular to a given case such as geometry, operational conditions, output variables etc. The second contains the fluid property tables, the third file is a restart file that is used to continue a previous calculation, and the fourth file is a compressor data file, the fifth file is the pump data file for the pump characteristics, the sixth file contains process equipment data to be simulated in OLGA.

Industry Applications

OLGA 2000^{TM} is to be used as the primary means of predicting well pressures during dual density operations in this project.

3.1.6 Simulation Method

The cases simulated in this study for all alternative well control methods and stages represent a very deep water well in 6,000 feet of water. They were based on real Gulf of Mexico deep water well designs. A relatively high formation well productivity was assumed based on two considerations.
First, the objective reservoirs being drilled must be high productivity in order to be economic.
Second, a high productivity formation is more difficult to control and therefore provides a more rigorous test of a given alternative well control method.

A special item of equipment required for most dual gradient drilling methods is a drill string valve or DSV. This valve is placed in the drillstring to arrest the U-tube effect that occurs due to the density of the fluid in the drill string being greater than the average density of the fluid in the riser.

The DSV is placed in the drillstring near the bit to support the excess hydrostatic pressure of the full mud column in the drillstring when the rig pumps are shut off. It allows mud to flow through it only when the surface mud pumps are operating at a predetermined "set point" pressure required to force the valve open. When circulation stops, the DSV closes, arresting the U-tube and maintaining a full column of mud inside the drillstring. Use of a DSV was assumed in all of the simulations conducted for the project.

As a means of comparing dual density gas-lift methods to currently accepted methods with single density systems, two separate simulations were conducted with the same water depth, well design, well depth and formation data with only the difference of mud densities and casing shoe depths required for the two different drilling methods. The simulation input data describing the comparable example wells and the two cases in general, are presented in Table. As described previously, the only difference between dual density and conventional cases are the different mud used and casing set depths. Therefore, there are different kick margins in these cases as well. This results from the dual density system's wellbore fluid gradient falling between pore and fracture pressures for a longer section of hole. As expected with a dual density system, it achieves the well's objectives with less casing strings and provides a higher safety factor for avoiding lost returns at the casing shoe.

Table 1 -Input data for all well control simulations

Data	Dual Density Drilling	Single Density Drilling
TVD	23,400 ft	23,400 ft
WD	6,000 ft	6,000 ft
Riser ID	19.25 in	19.25
Choke line ID	4.5 in	4.5 in
DP OD, ID	5 in, 4.276 in	5 in, 4.276 in
DC OD, ID	300 ft – 6.75 in, 2.88 in	300 ft - 6.75 in, 2.88 in
Casing OD	11.75 in,	11.75
Casing ID	10.772 in	10.772
Last casing set depths	13,780 ft	15,610 ft
Casing shoe kick margin	800 psi	200 psi
Casing shoe trip margin	200 psi	200 psi
10 5/8 ‘’ bit at 20,500 ft	3 x 16/32 nozzles,	3 x 16/32 nozzles
Mud weight used	16.0 ppg	14.0 ppg
Mud flowrate when drilling	550 gpm	550 gpm
Wellhead pressure when drilling	2,674 psi	2,674 psi
Bottom hole pressure when drilling	17,120 psi	17,120 psi
Formation pressure	17,320 psi @ 23,400 ft	17,320 psi @ 23,400 ft
Productivity Index	25 STB/d/psi	25 STB/d/psi
Riser surface pressure	200 psi	-
Nitrogen injection rate, drilling	11.51 mmscfpd	-
Time when kick begins	774 min	774 min

3.2 WELL CONTROL

3.2.1 Introduction

The objective of this work is to determine if an effective well control procedure can be defined for a dual density, riser gas-lift system during a kick. Due to the complexity of this system with many different density fluids and different flow paths, well control with riser gas-lift is more challenging than for conventional operations. Specific problems directly related to a dual density, gas-lift system are considered and the probable field feasibility evaluated.

The purpose of this work is to consider known complications, identify potential well control methods, and identify methods that warrant further study. Conventional well control methods are considered for their possible adaptation to the riser gas-lift system, and for possible complications and limitations. The specific operational objectives that are addressed in this study for each of the methods, are kick detection, cessation of formation feed-in, and removal of kick fluids while maintaining a constant bottom hole pressure.

3.2.2 Comparison of Alternative Well Control Concepts

Well Control Concerns in Dual Density Drilling

Well control is of great importance for any drilling operation. For decades, the first step in effective well control is to detect a kick as fast as possible. The next step is to stop the formation influx without exceeding the casing shoe fracture pressure. This is accomplished in conventional drilling by closing the well with the subsea BOP, opening the choke line valve with choke closed at the surface. Shut in drillpipe pressure (SIDPP) and shut-in casing pressure (SICP) are then recorded to use in calculating the formation pressure.

In a dual density, gas-lift system, several complications exist relative to a conventional shut-in procedure. First of all, the excessive hydrostatic pressure of the mud in the drillstring creates a U-tube effect immediately after mud pumps are stopped. This is caused by the pressure difference between the hydrostatic pressure at the bottom of the riser equivalent to seawater and the higher mud density pressure in the drillstring at the same depth.

This means that mud will fall and U-tube into the annulus. The distance that the fluid level will fall if riser gas lift continues to keep wellhead pressure constant may be predicted knowing the mud weight and water depth using the equation below -

$$H_{max} = D_w * (\rho_m - \rho_{sw})/\rho_m$$

where, H_{max} – maximum expected mud level drop inside drill string, ft

D_w – water depth, ft

ρ_m – mud density, ppg

ρ_{sw} – seawater density, ppg

This also means that during drilling operations, the drillstring pressure losses must exceed the difference between the mudline seawater pressure and drillstring hydrostatic mud pressure to prevent mud free fall down the drillstring to the annulus while circulating. The circulating pressure minimum value of losses to prevent mud free fall may be calculated from the equation

$$P_{circ} > (\rho_m * 0.052 * D_w) – (\rho_{sw} * 0.052 * D_w)$$

where, P_{circ} - circulation pressure equal to pressure losses in the drillstring, the bit nozzles and any possible restriction placed inside of the drillstring, psi

The U-tube effect greatly increases the risk of formation fracturing when the well is shut in as the shut in casing pressure prevents mud from the drillstring from U-tubing into the annulus. Therefore, the excess drillstring hydrostatic must be supported by open hole formations. However, if shut in is deployed until the two pressures in the drillstring and annulus reach equilibrium, there are also complications. This increases the risk that the well will remain underbalanced while waiting for these two pressures to equalize and additional kick be taken. Furthermore, the conventional approach of using the SIDPP for bottom hole pressure determination is not possible as the liquid level inside the drillstring is below the surface. A solution proposed by Lopes to use a well sounder to determine the fluid level inside the drillstring will still not accommodate problems with well-being underbalanced while waiting for two pressures to equalize. A possible solution to overcome these problems was an application of a drillstring valve (DSV), originally designed for the subsea mud lift project. The U-tube effect is prevented by placing the DSV, which closes when mud pumps are shut down, above the bit. DSV application will allow closing the well immediately after kick detection without any danger of the mud U-tubing into the annulus. The opening pressure of the DSV must be greater than the difference between the seawater pressure at the mudline and the hydrostatic pressure of the mud in the drillstring at the same depth. The next concern is a formation pressure determination with the DSV to be able to start a kick circulation procedure. “After closing the well when pressure equalizes, DSV may be opened by pressuring up on top of the valve and the opening pressure will be recorded”. “SIDPP will be equal to the after kick opening pressure minus the originally recorded pressure”. This makes the formation pressure determination feasible to accomplish with the dual density system.

A concept from underbalanced drilling has been proposed for use due to its similarity to the dual density. It would reduce the gas-lift rate or increase the backpressure on the annulus to maintain a constant pit level. In conventional underbalanced drilling, constant pit level maintains the gas volume in the annulus constant. The complication that exists when compared with the gas-lift system is that in conventional underbalanced drilling, gas is spread through the entire annular column of fluid. Therefore, maintaining a constant pit level keeps the average volume of liquid in the annulus constant. In a dual density, gas-lift system, gas is not spread through the entire column of annulus as gas is only distributed throughout the riser and in kick contaminated fluids. Therefore, this option requires further analysis.

A widely recognized problem in conventional deep water drilling is excessive frictional pressure losses in small diameter choke lines. Furthermore, complications are expected when a gas kick enters a small diameter choke line and mud is displaced rapidly with gas. This tends to decrease the hydrostatic pressure of the mud column and bottom pressure drops rapidly. In order to adjust for a sudden bottom hole pressure drop, surface choke pressure adjustments must be made, increasing the choke manipulation complexity and pressure instability accordingly. To overcome these concerns, application of a subsea choke and routing the returns through a gas-lifted choke line or a gas-lifted riser were proposed.

Complications presented in this section make well control procedures for a dual density, gas-lift system more rigorous but not impossible. Application of a DSV seems feasible, and it was already used in the industry. This should prevent the well from flowing and allow for the safe well control procedure without inducing the formation fracturing. Adaptation of well control concepts from underbalanced drilling to riser gas-lift well control is another possible solution for addressing complications inherent in riser gas-lift. A gas lifted choke line or riser with a subsea choke were proposed as a possible solution. The major question that needs to be addressed is how well these different concepts address the concerns identified and which concepts are most likely to be effectively applied in the field.

3.2.3 Selection of the Alternative Well Control Methods

Selection of the alternative well control methods in dual density, gas-lift system was undertaken to determine whether effective methods can be defined and proposed for further evaluation in this study. Conventional well control methods were considered and their potential adaptation to the gas-lift system evaluated. The potentially effective well control alternatives proposed for further evaluation were prioritized, and analyzed during each phase of the well control operation in the following chapters of this study.

Possible alternatives that were considered in the selection process include:

1. Possible adaptation of the conventional well control method by closing the subsea BOP and taking returns through the deep water choke line to the surface with a surface choke. However, this is expected to cause an excessive pressure on the well annulus during a kick circulation as mud densities used are higher than in conventional drilling causing an excessive hydrostatic pressure in the choke line. Therefore, it is not recommended for further investigation in this work.

2. Develop a more complex adaptation of a conventional well control method with closing the subsea BOP and kick circulation through a gas-lifted choke line. This looks promising, as problems with the unacceptably high frictional pressure losses imposed on the annulus may be overcome. There is a question however, if a gas injection is effective enough to lower the circulating pressure at the bottom of the choke line to achieve a dual density system during well control. Consequently, this approach is proposed for further evaluation.

3. Applying a lubrication method to the dual density concept. Kill weight mud is pumped down the well according to the predetermined volume and surface pressure. Afterwards, well is closed and mud is allowed to fall through a gas kick. Gas is then bled from the well. The major benefit of this concept is that a lubrication method is expected not to create an excessive annular frictional pressure losses due to small diameter choke line like in conventional methods mentioned earlier. However, due to fact that lubrication applies only when gas reaches the seafloor at the BOP stack. Consequently, it would both be slow and require volumetric control as gas was migrating in the well. Therefore, it is rejected as a primary method for further investigation in this study.

4. Possible adaptation of the method used for control during underbalanced operations to the dual density system. Instead of closing a subsea BOP, the gas lift rate would be reduced to increase bottom hole pressure, stop formation influx, and control the well. A relevant concern is not to exceed the fracture pressure while stopping and/or decreasing gas injection rate to the riser. Consequently, this approach is proposed for further evaluation.

5. A bull heading alternative had originally been proposed by Lopes for a dual density system. The idea of bull heading is to force kick fluids down the well into formation. The advantage would be that kick circulation

to the surface and the associated complications with the choke line would be avoided. Lopes proposed to apply this method when the open hole interval is short, decreasing the possibility of fracturing into formations above the kick zone. However, due to fact that the objective of the dual density concept is to minimize the number of casing strings and maximize open hole length, that scenario is unlikely to exist. Consequently, due to the high risk of lost returns near the top of an open hole interval, the risk of an underground blowout exists. Therefore, this alternative is rejected from further evaluation in this work.

6. Application of a subsea choke placed at the seafloor with returns either through the gas lifted choke line or the riser. This is expected to “decouple” the well pressure from the pressure above the seafloor. It was proposed by Lopes. This choke needs to be controlled from the surface. Application of such a choke is expected to avoid the problems associated with the unacceptably high annular pressure during a kick circulation and the potential need for rapid, complex choke manipulation as well. Also, faster pressure responsiveness to the choke adjustments is expected. Therefore, this method is proposed for further evaluation.

The proposed alternatives for further investigation offer two different ways to stop a kick. The first one is the conventional method of closing the subsea BOP. This method will require that the U-tube effect be prevented with the drillstring valve (DSV) that closes just after shutting down the mud pumps. The second one, relies on shutting down or decreasing the gas injection rate to the riser to increase the bottom hole pressure and stop the formation influx. Both seem reasonable for application in the dual density, gas-lift system. Complications involved in the underbalanced procedure include a risk of exceeding a fracture pressure while increasing the bottom hole pressure due to gas shut-down. The next concern is to circulate the formation influx volume out of the well safely.

Several circulation procedures are proposed in this study including taking the returns through: 1) the gas-lifted choke line with the surface choke, 2) the gas-lifted choke line and a subsea choke, and 3) the gas-lifted riser with a subsea choke. Each of these methods is expected to avoid problems associated with the long, deepwater choke lines causing the unacceptably high frictional pressure losses on the well annulus. The relevant concern that should be addressed in a more detail is whether the dual density conditions may be reached for different mud flow rates in the small diameter choke line. Furthermore, application of a surface-controlled, seafloor choke is expected to reduce the complications caused by a multi-phase flow in the subsea choke line and make effective choke adjustments easier to make. Choke adjustments would also act more directly to affect the bottom hole pressure, simplifying the choke manipulation. Circulation of a gas kick through the gas-lifted riser with the seafloor choke creates a riser collapse concern that is dependent on the gas kick volume taken. Therefore, more detailed analysis of the proposed system is necessary.

3.2.4 Discussion and Observations

The alternative well control methods for dual density, gas-lift system are identified and proposed for their further study. Well control complications inherent with the gas-lift system are presented and described. Specific concerns that were addressed are the U-tube-effect, determining the formation pressure, and conventional deep water problems with the unacceptably high frictional backpressure held on the annulus during kick circulation and surface choke manipulation. These problems make the dual density well control more rigorous and challenging but still feasible. Several ideas to address these complications are mentioned, and at least one of them was previously successfully applied in field operations. Adaptations of conventional well control methods to the dual density system are identified. They rely on keeping the bottom hole pressure constant and avoiding the formation fracture as in conventional drilling. Alternatives to avoid excessive frictional pressure in the choke line are suggested to be gas injection into the bottom of the choke line and rerouting the returns through the gas-lifted riser. Application of the subsea choke is expected to avoid concerns associated with rapid choke manipulation and bottom hole variations during a circulation procedure. Adaptation of control methods used in underbalanced drilling is also identified as a potentially feasible alternative.

The alternatives proposed for further evaluation need to be verified thoroughly and prioritized for each stage of the well control procedure including kick detection, formation fluid cessation, and kick circulation. The most feasible and successful alternative should be then applied to evaluate a kill weight mud circulation in the dual density system. This will be presented in the further work of the project.

3.3 RISER GAS-LIFT FEASIBILITY

The first step to address the well control concerns for dual density drilling with the gas-lift system is the overall concept feasibility. It must be shown that the dual density method is possible for the routine drilling conditions before analyzing well control cases. For the dual density gas-lift system to be effective, riser bottom pressure must equal the seawater hydrostatic pressure at the mudline. This is achieved by nitrogen injection at the riser bottom. Therefore, this pressure must be achieved for the various mud densities and flowrates using nitrogen injection. Specifically, considering well control scenarios, the same pressure must be also achieved at the base of the choke line during well control phases for dual density drilling with the gas-lift.

3.3.1 Feasibility of Seawater Pressure at the Mudline for the Gas-Lift

3.3.1.1 Gas Lifted Riser

A dual density system could reduce drilling costs by reducing the number of casing strings required to drill the well and the drilling time as well. This will be feasible only if the dual density conditions will be constantly maintained in the riser during the drilling operation. These results present a study of decreasing the pressure at the base of the riser to the seawater hydrostatic pressure by nitrogen injection to obtain dual density conditions for routine drilling. This will prove the whole dual density system feasibility.

The simulated study consists of 5,000 feet long riser with 19.25 in inside diameter and 5 in outside diameter drill pipe inside the riser. Various rates of 16 ppg mud and nitrogen are used. Results of these simulations may be seen in the Figure 3.3.1. As may be seen from Figure 3.3.1, the bottom pressure in the riser annulus at the mudline can be successfully lowered to the desired seawater hydrostatic pressure and even further. The seawater hydrostatic pressure for this case equals 2,236 psi, and the resultant pressure due to gas injection can be controlled at or far below this value. This is a crucial achievement for dual density system with riser gas-lift. The riser circulation system with gas injection operates in a hydrostatic dominated mode. Specifically, the riser's large inside diameter limits the friction effects and the hydrostatic effects tend to dominate. This makes controlling the wellhead pressure straightforward as pressure is constantly decreased for increased gas rate over a very broad range and riser bottom pressure may be successfully lowered even for the high mud rates of 1,500 gpm.

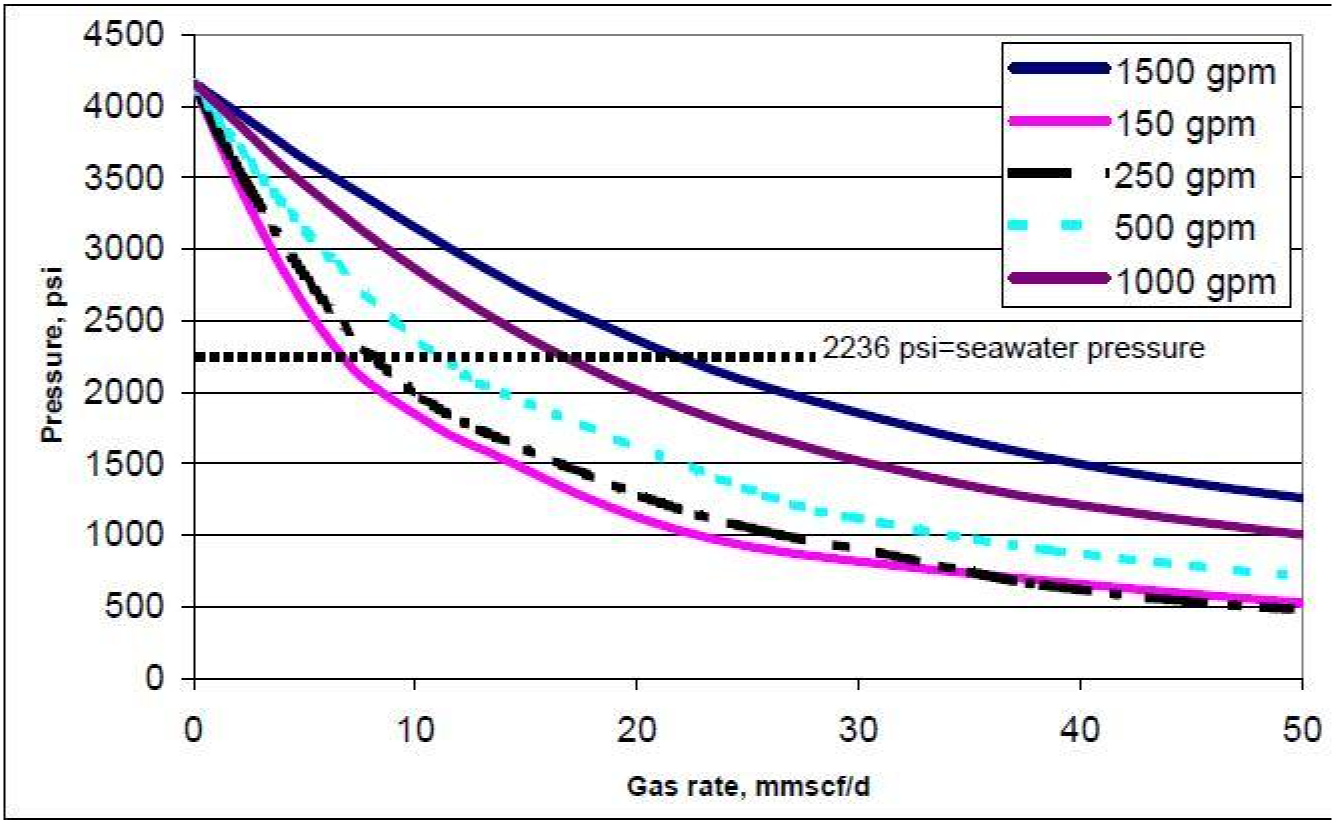


Fig 3.3.1 Riser bottom pressure with various rates of mud and nitrogen

3.3.1.2 Gas-Lifted Choke Line

Dual density conditions must be maintained during well control operations as well as during drilling operations. Given that returns must normally be taken through a choke line during well control operations, nitrogen injection into the base of the choke line would be required if a kick were being circulated out through the choke line. Therefore, several scenarios of nitrogen injection into a choke line with simultaneous mud circulation were simulated to assess the feasibility of such operations.

The simulated study consists of 5000 feet long choke line with 5 in inside diameter. Various rates of 16 ppg mud and nitrogen are used. Results of these simulations are shown in Figure 3.3.2. Again, this system with the gas injection may operate on either hydrostatic or friction-dominated mode. These two effects are both important for the choke line due to its small diameter causing the friction effects. When the choke line operates in the hydrostatic-dominated mode, bottom choke line pressure rapidly decreases due to reduction in the hydrostatic pressure by increases in gas injection. Conversely, when the choke line operates in the friction-dominated mode, an increase in gas rate increases the bottom choke pressure due to significantly increased pressure losses. For high mud flow rates, it is impossible to decrease

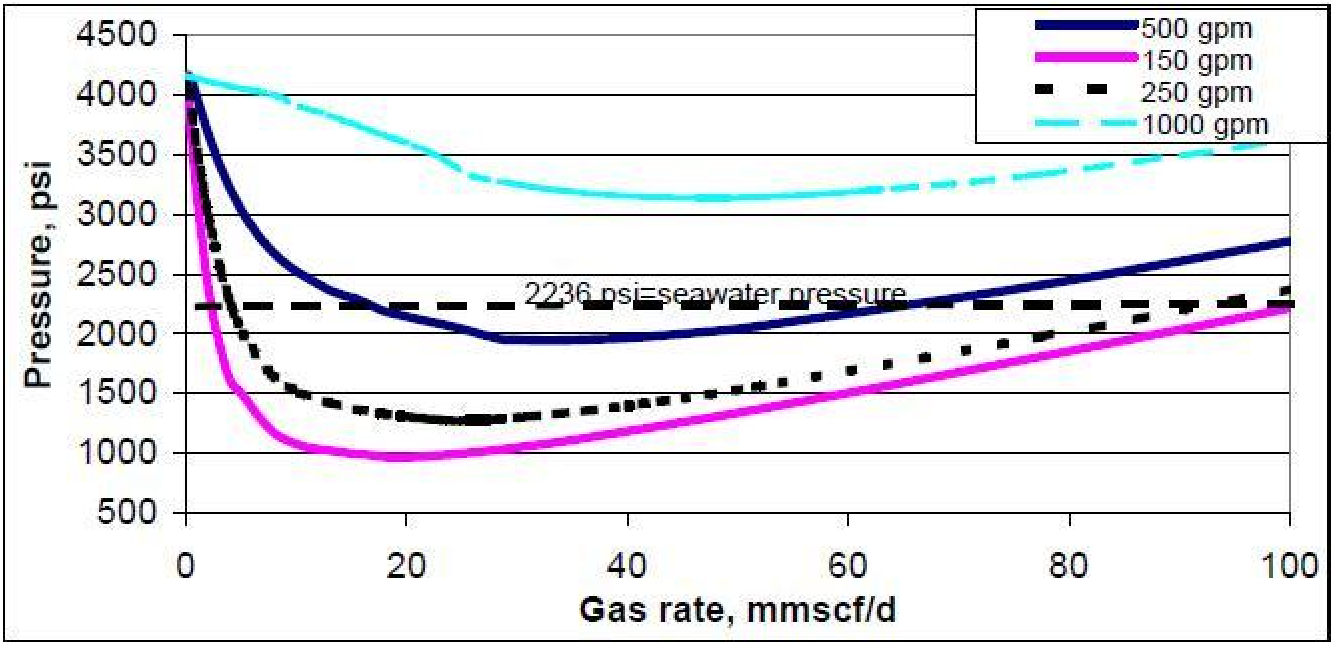


Fig 3.3.2 Choke line bottom pressure with various rates of mud and nitrogen

pressure to the desired value as friction pressure losses start to dominate earlier due to small choke line diameter. This study shows the required gas rate to achieve the "breaking point" between the hydrostatic and friction-dominated modes. Also, choke line simulations show that when reaching the "break point", the pressure does not increase rapidly and is stable for a certain gas injection rate and then increases steadily. This may be helpful while circulating kicks out of the well, so that small gas injection rate changes or gas circulated from the well will not have a big impact on the bottom pressure.

3.3.2 Riser Multiphase Analysis

A possibility of the emergency situations (i.e. power outage) where pumps fail and gas injection is stopped, are always present and should be considered in a dual density, gas-lift system. Therefore, scenarios when mud and nitrogen injection are suddenly stopped for any reason need to be analyzed and evaluated in order to avoid great pressure differences that might collapse the riser. Work done specifically for this study focuses on stopping the mud and gas circulation to analyze a riser collapse concern and is presented below.

Simulations were applied in this study to analyze multiphase (gas and drilling mud) liquid behavior in the riser during emergency situations. Dual density drilling conditions with a seafloor pressure equal to the seawater hydrostatic pressure were reached, and two cases were separately simulated. The first case consisted of gas and mud circulation stopped simultaneously at 106 minutes, and in the second case, mud circulation was stopped at 106 minutes, and gas was still injected to the riser. These simulations were conducted for 10,000 ft riser with 19.25 in inside diameter and the 5 in outside diameter of drill pipe inside the riser, 200 psi surface riser pressure, 14.55 ppg mud, 618 gpm mud flow and a nitrogen rate of 8.5 mmscfpd. These conditions give a riser bottom pressure of 4,711 psi, which is slightly higher than seawater pressure.

3.3.2.1 Mud and Nitrogen Injection Stopped

As previously mentioned, there is a possibility that mud pumps and nitrogen injection will fail and a risk of riser collapse will arise. The question is if the final differential pressure at the seafloor between seawater hydrostatic pressure outside riser and pressure inside will collapse the riser. In the case where both mud and nitrogen circulation are stopped, a liquid segregation in the riser annulus will occur. Gas separates from mud and escapes from riser causing mud fall back. The mud level after shutting down gas and mud circulation depends on the liquid holdup before mud and gas stoppage. The overall average steady-state holdup in the riser before stopping circulation was 0.83, and the holdup distribution in the riser is shown in Figure 3.3.3

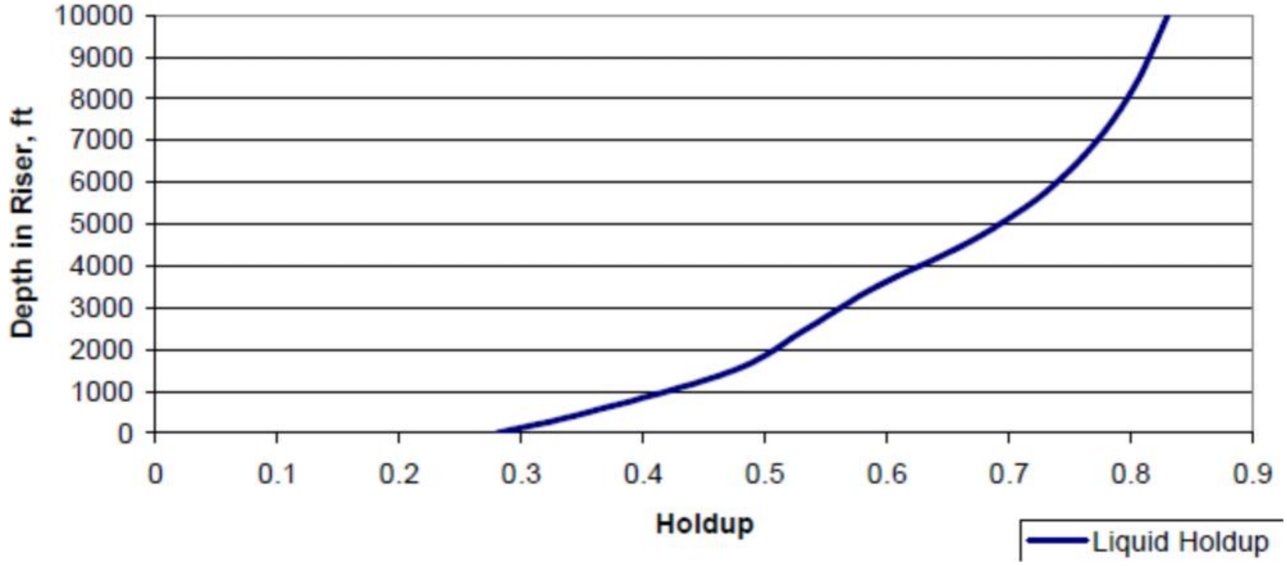


Fig 3.3.3 Liquid holdup distribution for 10,000 ft riser in dual density drilling

The steady-state holdup is very important as the gas "escapes" from riser annulus, and riser bottom pressure is dependent on mud that stays in riser. Figure 3.3.4 presents riser bottom pressure and riser liquid holdups at various depths before and after mud and gas circulation were stopped, constantly holding 200 psi pressure at the surface. The rate that a gas bubble rises through a drilling fluid depends on fluid rheology, gas bubble geometry, and gas and liquid density. The seafloor pressure stabilizes after all gas migrates from the riser at 4,340 psi. This is due to gas that emptied the riser leaving it filled partially with a mud volume that is strongly dependent on liquid holdup in the riser before mud and gas shutdown. Pressure stabilization requires about 7 hours and is mainly affected by the gas migration process and the resulting liquid slug flow from riser top. Figure 3.3.4 shows that liquid holdup at 2500 ft is zero at 234 minutes after gas and mud shutdown suggesting that mud level decreased significantly.

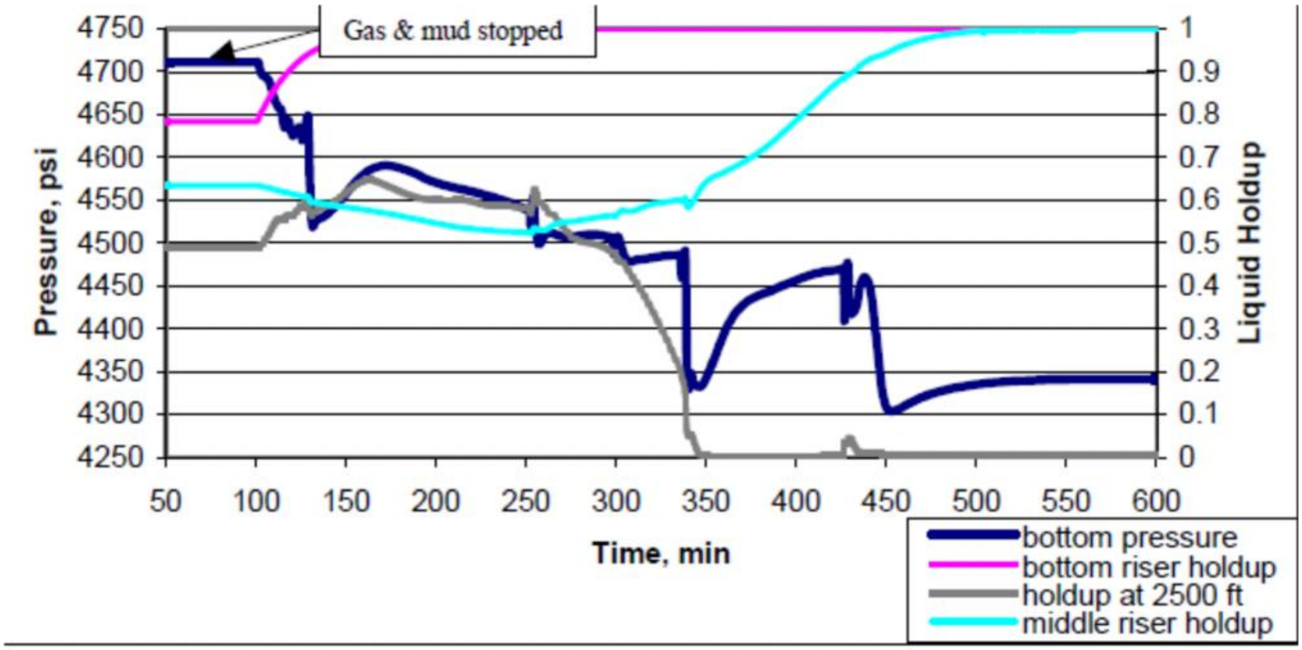


Fig 3.3.4 Riser bottom pressure and riser holdups at various depths

The final differential pressure at the seafloor between seawater hydrostatic pressure outside riser and pressure inside riser is 160 psi. This should not pose any riser collapse problems.

3.3.2.2 Mud Circulation Stopped with Continued Nitrogen Injection

Riser gas lift operations result in reduced pressure within the riser and consequently an increased risk of riser collapse. The worst case conditions from a riser collapse perspective is complete evacuation of the riser. The most likely conditions that might cause riser evacuation are continued nitrogen injection while liquid circulation has stopped. There is a high probability of the riser collapse as gas will be displacing mud from the riser causing further pressure decrease and pressure differential between outside and inside of the riser will be excessively high.

Figure 3.3.5 presents riser bottom pressure and riser liquid holdups at various depths when mud circulation is stopped and gas injection continued at a constant rate. It can be seen that pressure at the base of the riser decreases to 1,100 psi in 164 minutes after stopping mud circulation. When mud circulation is stopped at 106 minute, the riser bottom pressure doesn't decrease immediately. However, decreasing liquid holdup in the riser starts to dominate pressure in the riser about 100 minutes after shutting down mud injection. Figure 3.3.6 presents riser surface return flowrate and riser bottom pressure. It may be observed that as bottom riser pressure starts to decrease significantly, return flowrate "spikes" are observed indicating slug flow at the surface.

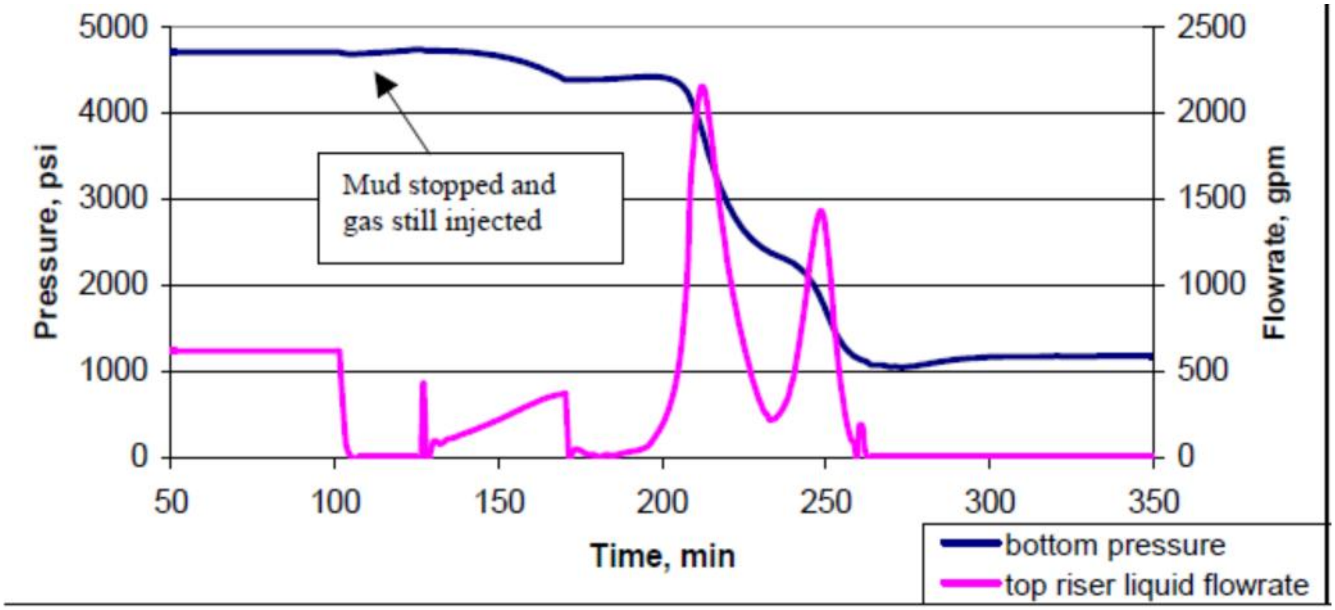


Fig 3.3.5 Riser bottom pressure and riser holdups at various depths

Ultimately, the riser annulus bottom pressure will decrease to 1,100 psi in this case with 10,000 ft water depth. At this point, the pressure stabilizes because an additional liquid is unloaded from the riser. The differential pressure between seawater and riser bottom pressure will be 3400 psi, which would cause collapse of typical deep water risers currently in use. One solution might be to decrease or stop the nitrogen injection rate or either pump mud into the base of the riser through the kill line. Furthermore, in case if neither of these concepts works, a riser fill-up valve will be used. Riser fill-up valve would open the riser annulus to take in seawater to avoid a pressure differential that could cause riser collapse. This valve is installed in the riser below the water line and will open when a preset collapse differential pressure value is reached. This causes the valve to open and seawater enters the riser, equalizing the pressure and preventing its collapse. The valve remains closed during normal drilling operations.

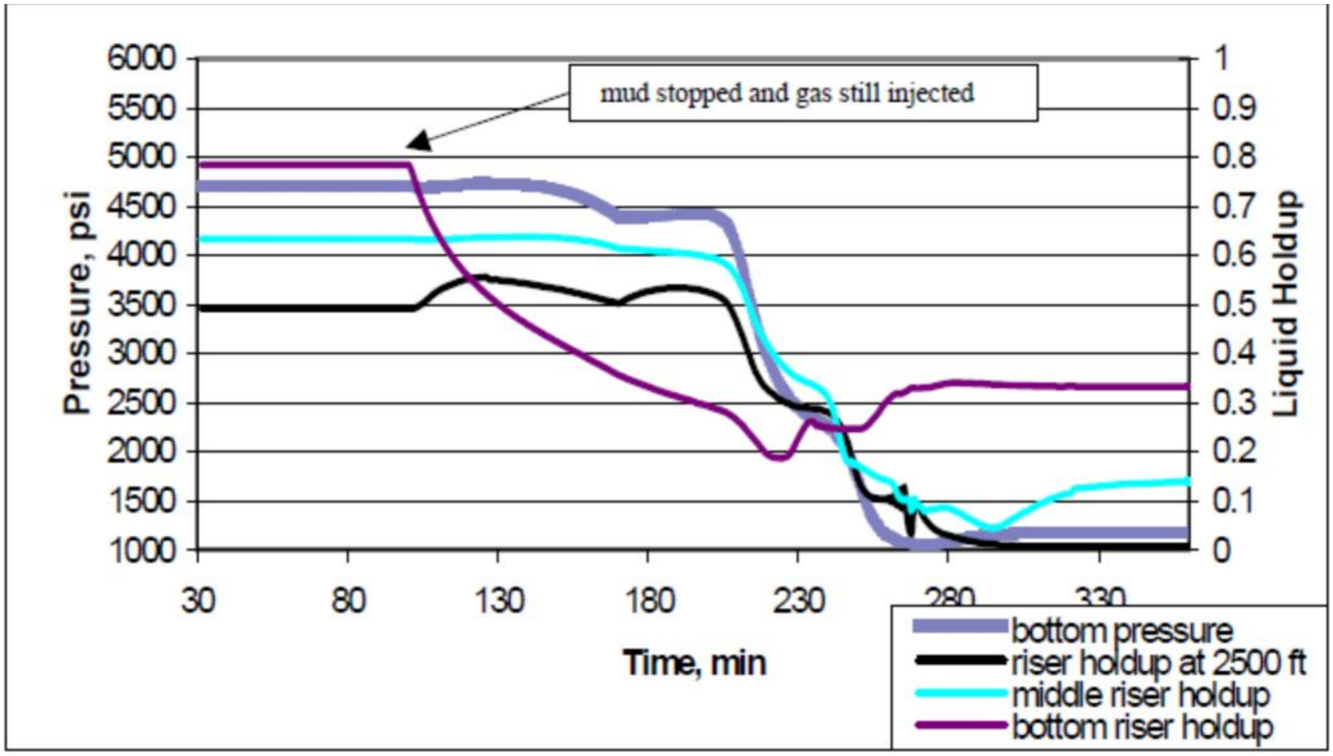


Fig 3.3.6 Riser return liquid flowrate and riser bottom pressure

3.3.3 Discussion and Observations

Feasibility of seawater pressure at the mudline was proven for the riser during drilling operations and for the choke line during well control procedures. Dual density drilling conditions may be established for the gas-lifted riser for various mud flowrates. Thus, controlling the wellhead pressure is fairly straightforward as riser bottom pressure may be constantly decreased for increased gas rate over a very broad range. Feasibility of dual density conditions that must be maintained during well control operations in the choke line is successfully assessed. This may be established only for certain mud flowrates. However, dual density conditions may be reached for the mud flowrates that will be still high enough to circulate the kicks. Furthermore, during kick circulation through the gas-lifted choke line, it was shown that small gas injection rate changes will not have a big impact on the bottom pressure. This makes the overall procedure more feasible and stable.

Riser multiphase behavior during emergency scenarios and risk of riser collapse were evaluated. Two possible emergency situations were presented with

1) mud and nitrogen injection stopped simultaneously and
2) mud circulation stopped with continued nitrogen injection.

Specifically, the differential pressure between seawater and riser bottom pressure was assessed according to the risk of deep water riser collapse.

It was found that in the first case of simultaneous mud and gas injection shut down, differential pressure is too low to pose any serious risk of riser collapse. This is dependent on the mud level in the riser defined by the riser liquid holdup before pumps were shutdown, as gas “escapes” from the riser annulus leaving it partially filled with mud.

In the second scenario of mud circulation stopped with continued nitrogen injection, differential pressure would cause collapse of typical deep water risers currently in use. Several possible solutions were proposed including decrease or stop the nitrogen injection rate or either pump mud into the base of the riser through the kill line.

3.4 KICK DETECTION

Kick detection is a necessary first step in controlling a kick. Early kick detection minimizes kick size and therefore decreases the difficulty of safely controlling the kick. Kick detection for deep water operations and dual density drilling is more complicated with rig motion and multiphase flow in the riser during drilling. In order to detect a kick in its earliest stages, awareness of the indicators that can warn us that the well is flowing under these circumstances is to be made.

3.4.1 Simulation Results

The following case was analyzed in order to identify the most reliable kick indicators for dual density drilling with a riser gas-lift system. Input data are described earlier. Dual density drilling conditions with a seafloor pressure equal to the seawater hydrostatic pressure were reached, and indicators of the gas and water kicks entering the well were recorded separately with the emphasis on indicators that could be monitored in actual field operations. These indicators were liquid flow rate out, pit level, standpipe pressure, wellhead pressure, and bottom hole pressure.

3.4.1.1 Gas Kicks

Dual density drilling is in progress in this simulation, and after 774 minutes of drilling, a gas kick enters the well from a formation with a pressure of 17,320 psi and a PI (Productivity Index) of 25 STB/d/psi. The first noticeable indication of a gas kick entering the well bore is an increase in the return flow rate that should be readily noticeable at the surface under normal field conditions, see Figure 3.4.1. Also, pit gain as a kick indicator may be seen in the Figure 3.4.2. Its usefulness increases with time as the gain increases and the indication becomes more conclusive. Another indication is a standpipe pressure increase of about 50 psi over a period of 1 minute and then eventually a readily noticeable standpipe pressure decrease that is caused by the loss of hydrostatic pressure in the annulus as the volume of gas increases. The initial pressure "peak" is due to the flow of gas entering the well annulus and "pushing" the mud ahead of it, causing additional annular friction. Over time, hydrostatic effects tend to dominate the whole system, and bottom hole pressure and standpipe pressure decrease significantly as shown in Figure 3.4.3. These pressure changes only become conclusive when the pressure decrease is large and therefore are likely to be a slower indicator than flow rate out or pit gain. For the specific conditions presented, the kick should be detected after a few minutes relying on the surface return flow rate and surface pit gain.

Particularly, after 6 minutes of gas influx (780 minutes), the flow rate out has increased about 47 %, and a pit gain of about 25 bbl can be observed indicating the presence of formation influx. The earliest that the kick is potentially detected is after about 3 minutes when the flow rate out has increased about 36%, which should be noticeable. The pit gain and therefore kick volume is still relatively small at this time, about 9 bbls.

Figure 3.4.3 presents additional, long-term data from simulation of an uncontrolled kick. The ultimate pressure draw down after 60 minutes of gas kick influx accounts for almost 6,000 psi that represents an uncontrolled formation influx. Bottom hole pressure and bottom hole holdup were also recorded.

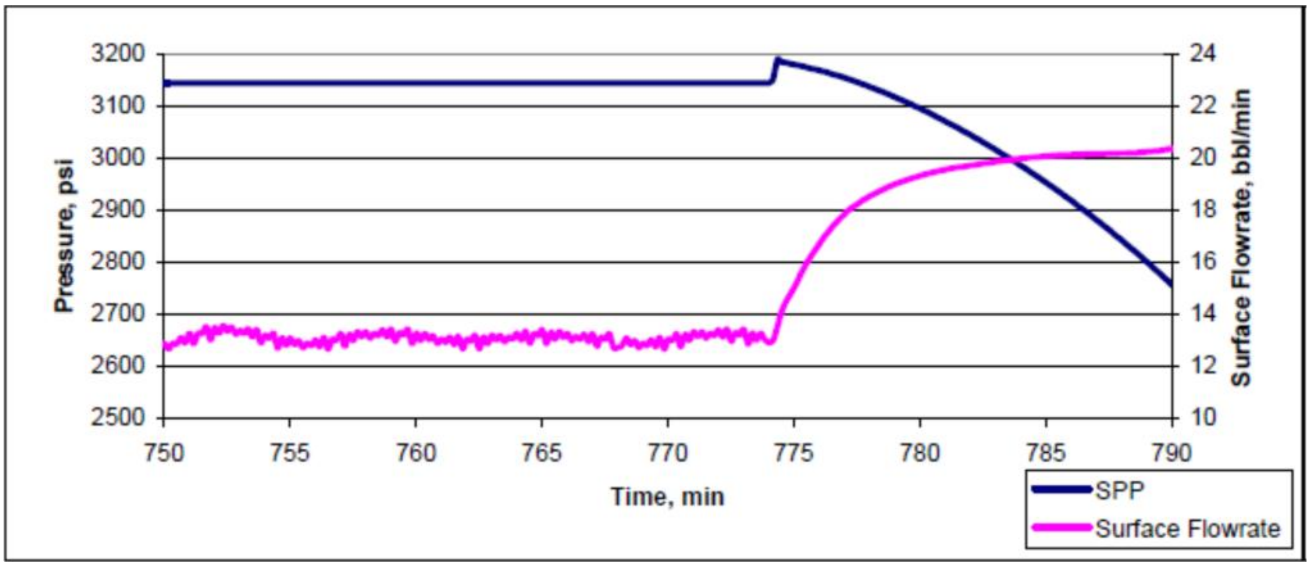


Fig 3.4.1 Drillpipe pressure and flowrate out as gas kick indicators

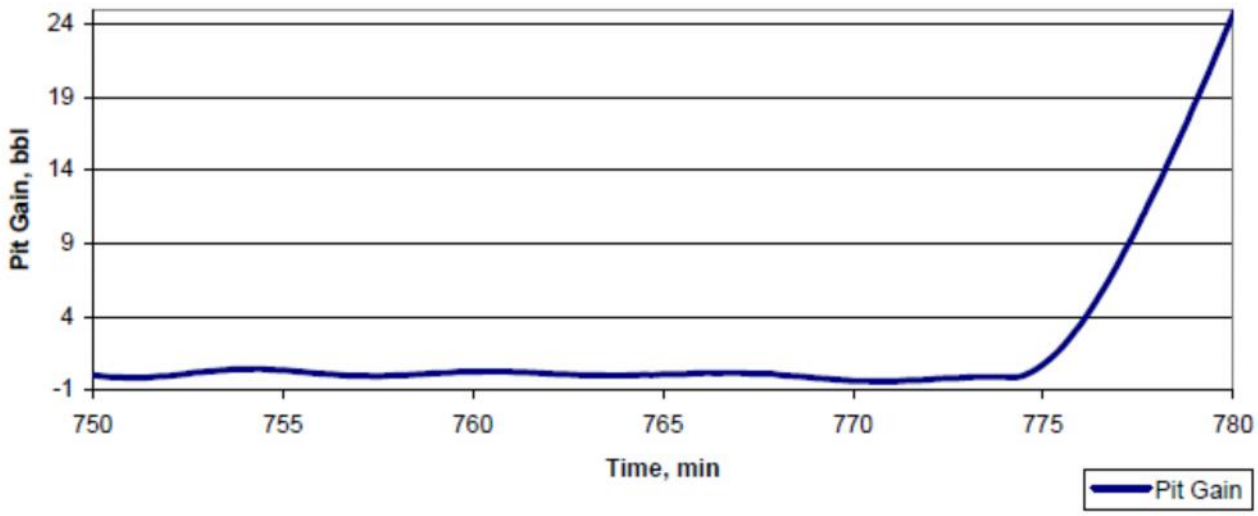


Fig 3.4.2 Pit gain as a gas kick indicator

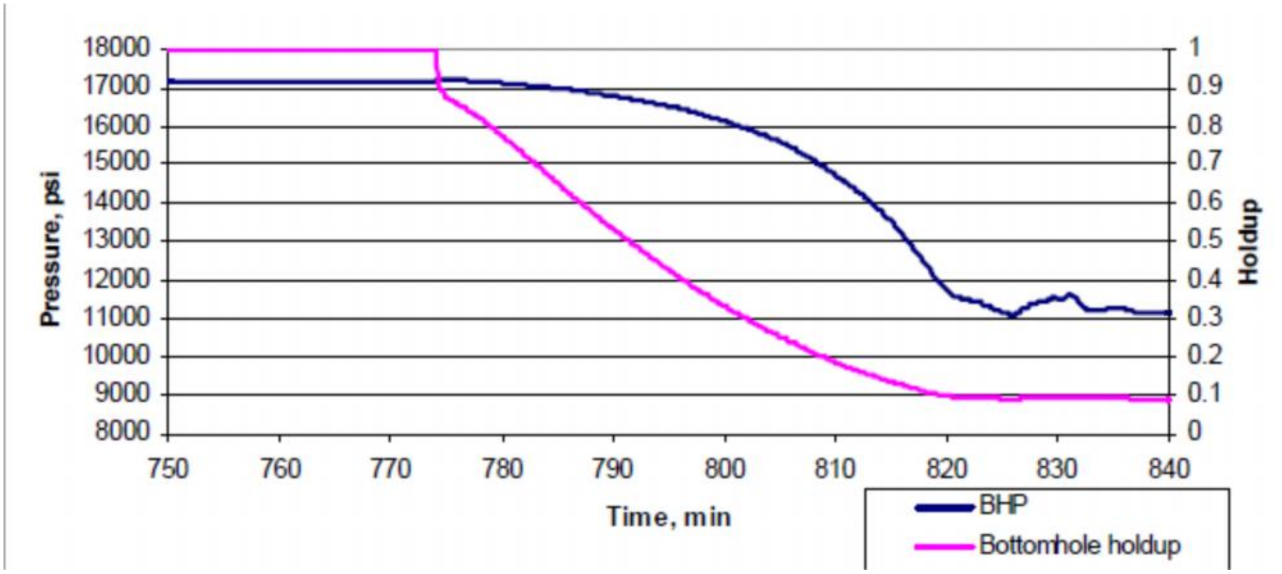


Fig 3.4.3 Gas kick with no action undertaken

Table 3.4.1 presents simulation results for several gas kicks taken with different formation pressures and productivity indexes as a means to compare kick indicators for various formation pressures and productivity values. As it may be seen, the gas kick number 1 may be detected at least after 6 minutes when flowrate increased 50% and pit gain accounts for about 25 bbl. In the field conditions, approximately 10 bbl kick should be possible to be detected. The gas kicks number 2, 3, 4 and 5 due to their lower formation pressures and productivity indexes are very difficult to be detected after 6 minutes of kick influx. Furthermore, these kicks may even be more serious as the formation fluid “feeding” into a well is slow but continuous and very difficult to detect. This kick will increase its volume constantly and when noticed its volume may be too excessive to control a well. Summarizing, the change in the magnitude of the kick indicators will be less noticeable in the field than for kicks from higher productivity or higher pressure formations.

Table 3.4.1 – Different gas kicks detection parameters magnitude

Case number	Pressure underbalance, psi	PI, STB/d/psi	Flowrate Increase after 6 min, %	Pit gain after 10 min, bbl
1	200	25	50	25
2	100	5	3	1.5
3	100	3	2.1	1
4	200	5	5	4
5	200	2	2.4	3

3.4.1.2 Water Kicks

Simulation of a water influx to show the kick warning signs are also performed. Dual density drilling was in progress, and after 774 minutes of drilling, a water kick was taken from a formation with a pressure of 17,320 psi and a PI (Productivity Index) of 25 STB/d/psi. The increase in the return flowrate and pit gain are shown in Figure 3.4.4. The pit gain and surface flow rate increase are the main kick indicators for the water kick as well. Standpipe pressure along with the return surface flowrate, are presented in Figure 3.4.5. The water kick should be detected within 4 minutes when flow rate out has increased 30% and the pit gain is about 10 bbls. The gas and water kicks used in this simulation were from a high productivity formation. Therefore, the change in the magnitude of the kick indicators will be more noticeable in the field than for kicks from lower productivity or lower pressure formations.

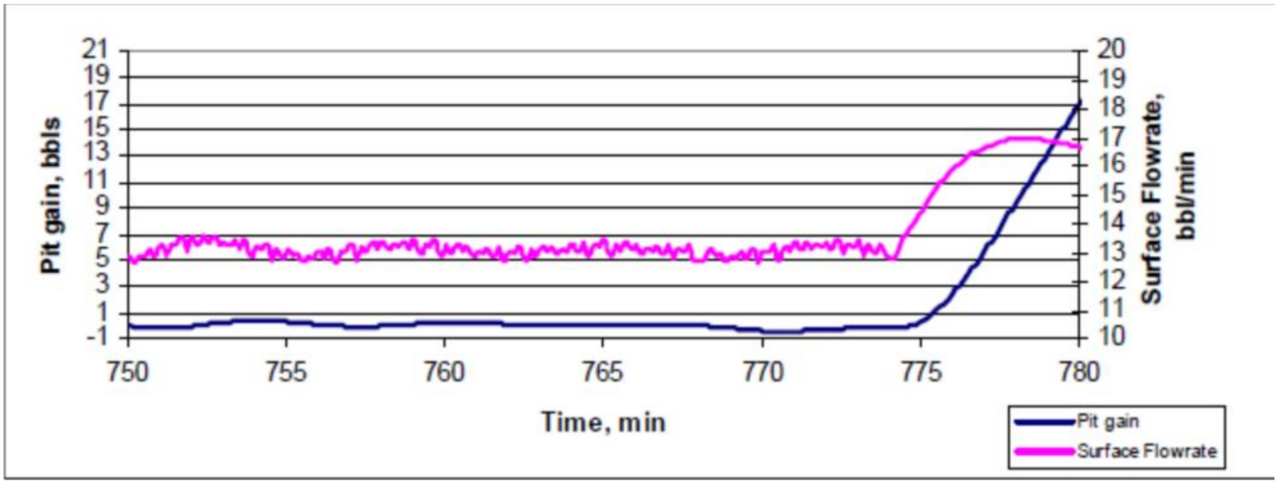


Fig 3.3.4 Water kick indications

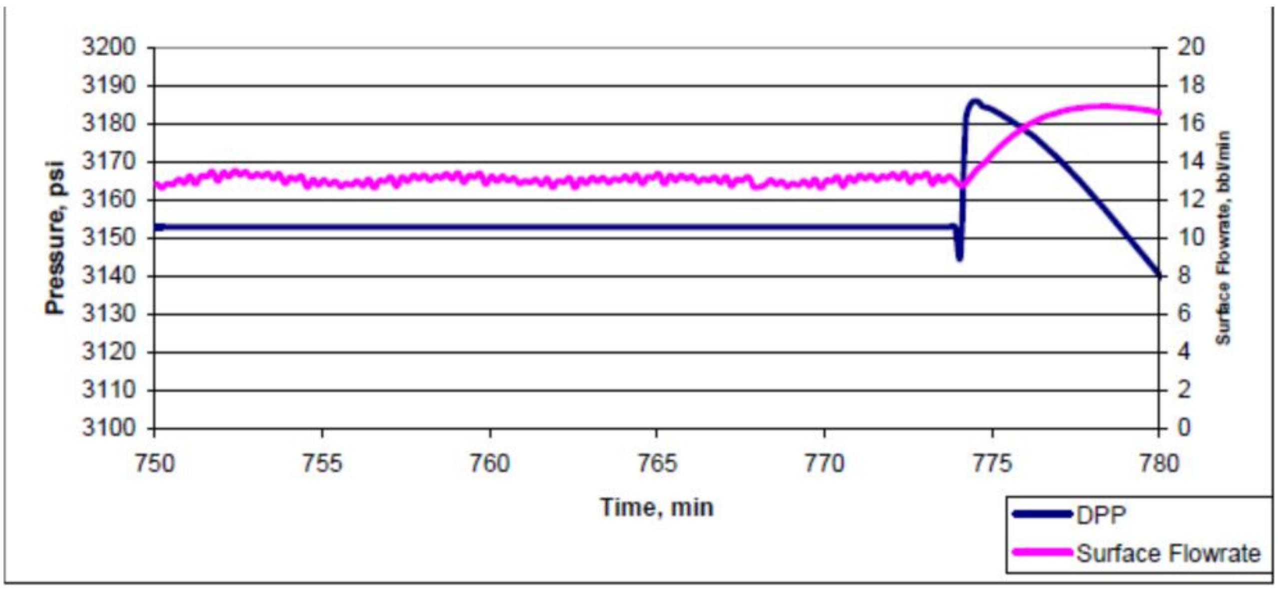


Fig 3.4.5 Early water kick indications

3.4.2 Discussion and Observations

From the simulation results obtained, the surface return flow rate increase, and the resulting significant pit gain, may be detected after a few minutes. Consequently, these are the main indications of a gas kick entering the well bore for dual density drilling. The decrease in standpipe pressure, and in bottom hole pressure if a “pressure while drilling” tool is being used, can be used as a secondary kick indicator.

As mentioned previously, kick detection for deep water operations and dual density drilling is more complicated with rig motion and multiphase flow in the riser during drilling. Rig motion concept is known in the industry and a kick on a semi-submersible drilling rig may be detected at less than 3 barrels with the presence of 25 barrel/minute peak to peak rig heave variation. The next concern of multiphase flow (gas and liquid) in the dual density drilling system is slugging, that makes kick detection more difficult. Furthermore, when steady state conditions are not reached and slugging flow pattern exists, it poses a serious problem of kick detection. However, based on the simulation results presented in this study, problem of slugging is discarded if the steady state conditions are reached and surface return flowrate changes are relatively small and kick may be detected after 3-4 minutes of its formation fluid influx.

Conventional operations often use a “flow check” procedure to confirm that a kick is in progress before trying to stop the flow. While this is possible with a conventional deep water drilling system, the nitrogen migrating in the riser for a riser gas-lift system precludes a simple flow check. Therefore, the reaction to positive kick indications should be to stop the inflow.

3.5 STOPPING FORMATION INFLOW

The next important step after detecting a kick is to prevent further influx from the formation, specifically to stop formation flow from becoming a blowout. Two primary alternatives for stopping formation flow in dual density gas-lift drilling were considered. The first is reducing the nitrogen rate used for riser gas-lift to increase the annular pressure resisting flow. The second is closing a BOP to stop flow from the well. Furthermore, stopping formation flow in single density drilling as a means of comparing and evaluating dual density and conventional drilling methods for the same well conditions were analyzed. This is very important as it is expected to reveal dual density advantage versus the conventional drilling for deep water wells with narrow fracture and pressure margins.

3.5.1 Dual Density Drilling Simulation Results

3.5.1.1 Decreasing Injection Gas Rate

A major question posed was whether shutting down nitrogen injection into the riser would stop a kick and allow formation influx volume to be circulated out of the well safely. This was expected to depend on the kick severity: productivity index, formation pressure, formation fluid density, and the reaction time to stop nitrogen injection. Simulations with OLGA^{TM} are again used to address this question. The formation and well characteristics in Table 3.1.1 were used, and simulations were performed for several reaction times to stop a gas and water kick separately in order to analyze the effect on the time required to stop formation inflow. In this case, dual density drilling conditions were reached, and after 774 minutes of drilling, a kick entered a well with formation pressure of 17,320 psi and PI of 25 STB/d/psi.

3.5.1.1.1 Gas Kicks

Dual density drilling conditions were established, and a gas kick was taken. For the first simulation, nitrogen injection at the seafloor was stopped 1 minute after taking a kick. This simulation was therefore intended to represent a very fast response to a high severity gas kick. The results are presented in Figure 3.5.1 showing bottom hole, casing shoe and wellhead pressures, and bottom hole liquid holdup. The kick indications after only 1 minute of influx would be very small and probably impossible to detect. The purpose of simulating only 1 minute to shut down the nitrogen injection is to present the most optimistic possible case when considering the effect of reaction time on kick control. The main conclusion is that in this specific case, the gas kick can be stopped when nitrogen injection is shut down 60 seconds after a kick first entered a well. However, gas formation influx continues for an additional 47 minutes. Pressure buildup due to the earlier nitrogen shut down starts to dominate and is high enough to stop the influx and control the well. The casing shoe pressure reaches 10,882 psi, which creates a highly overbalanced situation. Therefore, the nitrogen rate must be reestablished and controlled to avoid formation fracture. This issue is out of the scope of this project as nitrogen shut down will not be a recommended alternative to stop formation flow and control a kick. The kick volume that was taken during the 47 minutes of continued influx is highly significant and equals 79 bbl. A kick volume this large poses a substantial risk of an underground blowout. The 1minute time to detect and react to a kick is probably impossibly short to achieve in the field, therefore a longer and more realistic time period was also considered.

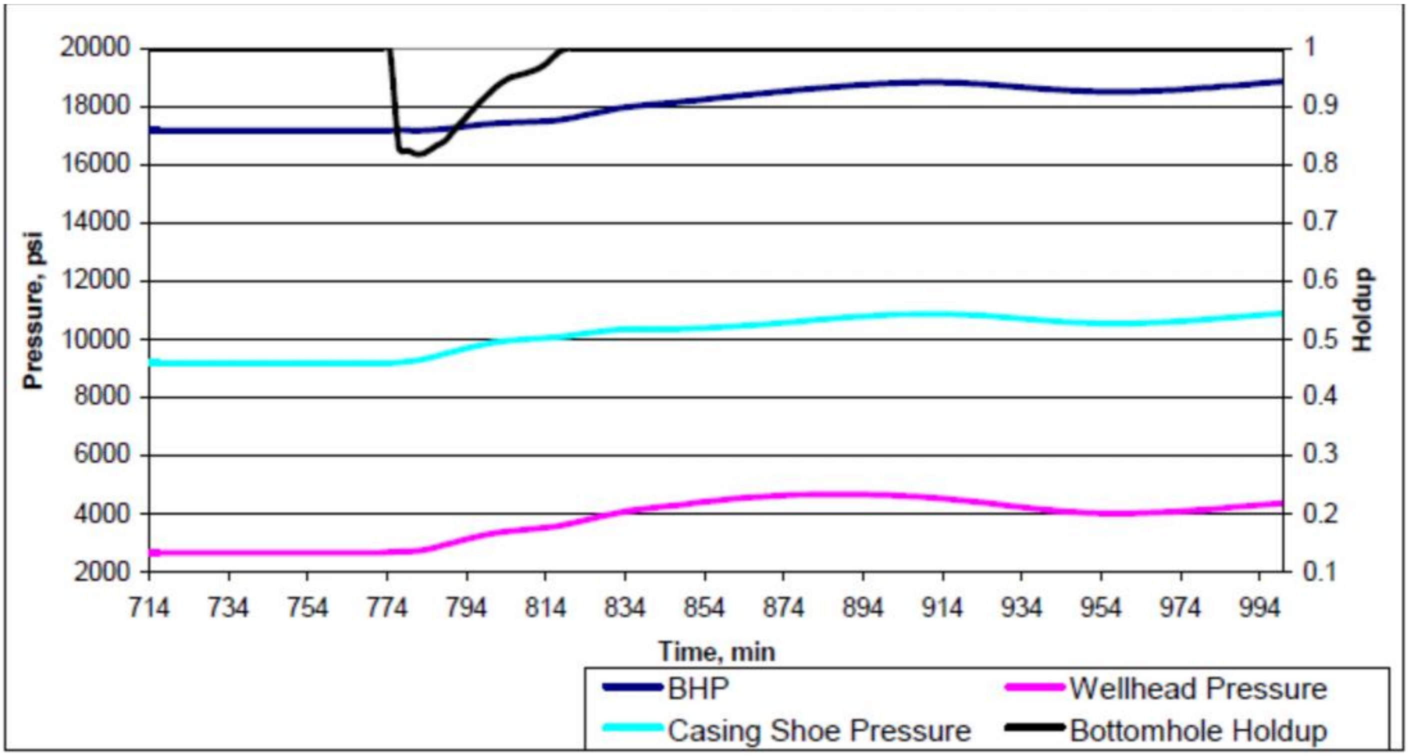


Figure 3.5.1 - Pressures and bottom hole holdup with N2 injection stopped after 1 minute

Figure 3.5.2 shows the results of a simulation when nitrogen injection was shut down 4 minutes after gas kick entered the well. In this case, ceasing nitrogen injection is not enough to control and stop the kick as bottom hole pressure continues to decrease and kick volume continues increasing. For these conditions representing a kick from a high productivity formation, it is apparently easy to have an inflow rate greater than the original nitrogen injection rate. The gas kick is never controlled in this case. Consequently, the shutdown of nitrogen injection to the riser is unacceptable as a well control method.

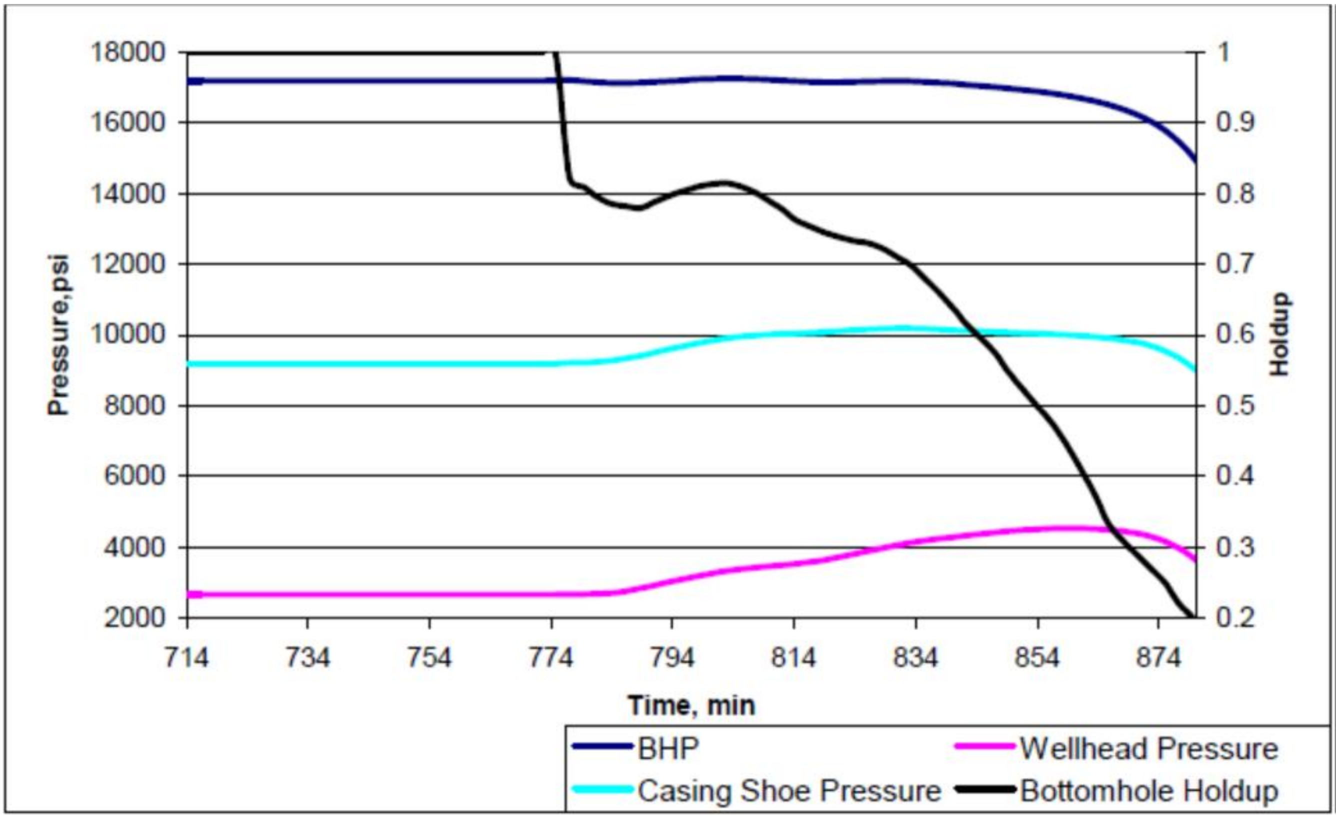


Figure 3.5.2 – Pressures and bottom hole holdup with N2 injection stopped after 4 minutes

In summary, shutting down the nitrogen injection rate 60 seconds after taking a kick still causes a significant kick volume of 79 bbl that would be difficult to control in spite of eventually stopping the influx. Given the best case reaction time of 3 to 4 minutes estimated for this case in the previous kick detection chapter and the undesired large kick volume for a reaction time of only 1 minute, the nitrogen injection shut down alternative to regain control in a well is not an effective means to control even a moderately severe gas kick.

3.5.1.1.2 Water Kicks

A water kick was also simulated for the same well description and reservoir characteristics as the gas kick simulations. The nitrogen injection to the riser was stopped 4 minutes after the kick began.

Shutting down nitrogen injection into the base of the riser was much more effective for stopping the water kick than it was for a gas kick. The water kick is controlled as shown in Figure 3.5.3. However, in spite of the nitrogen injection shutdown eventually stopping the formation flow, the time required is undesirably long. Consequently, the kick volume taken is still significant, 36 bbl, which could also lead to an uncontrolled formation influx.

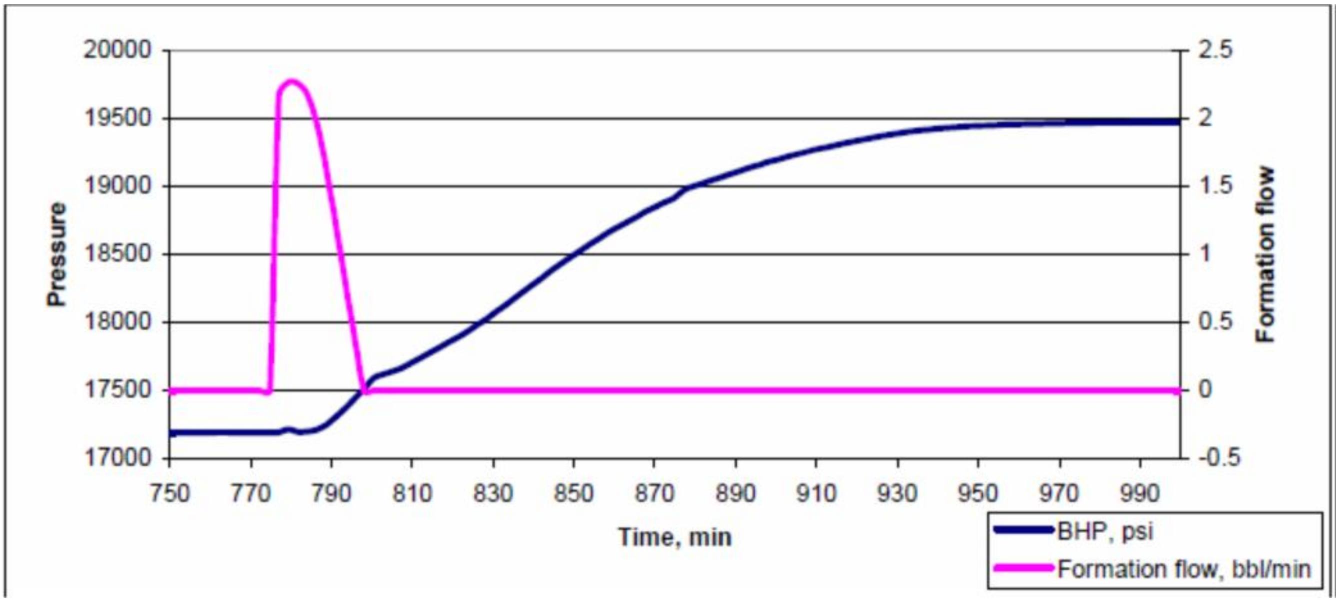


Figure 3.5.3 - BHP with formation flowrate with N2 stopped 4 minutes after a water kick

3.5.1.2 Shutting in with Subsea BOP

The second alternative for stopping formation inflow was to close the subsea BOP, as in conventional well control operations. This alternative was also simulated for gas and salt water kicks.

3.5.1.2.1 Gas Kicks

Dual density drilling conditions were simulated, and a gas kick was taken. The rig pumps and nitrogen injection at the seafloor were stopped at 4 minutes (778 minutes), and the BOP closed at 5 minutes (779 minutes), respectively after the gas kick began. The detection time of 3 minutes was based on the magnitude of the surface kick warnings at 777 minutes described in the previous chapter on kick detection. Figure 3.5.4 shows the effects when the kick enters the well at 774 minutes, nitrogen and mud circulation are stopped at 778 minutes, and the BOP is closed at 779 minutes. It may be observed that in spite of nitrogen injection being shut down, the influx continues as BHP drops rapidly. When the BOP is closed, bottom hole pressure starts to increase, and bottom hole liquid holdup increases rapidly what means that formation flow decreases. Flow essentially stopped at 790 minutes, after 16 minutes of gas influx. The total kick volume taken is

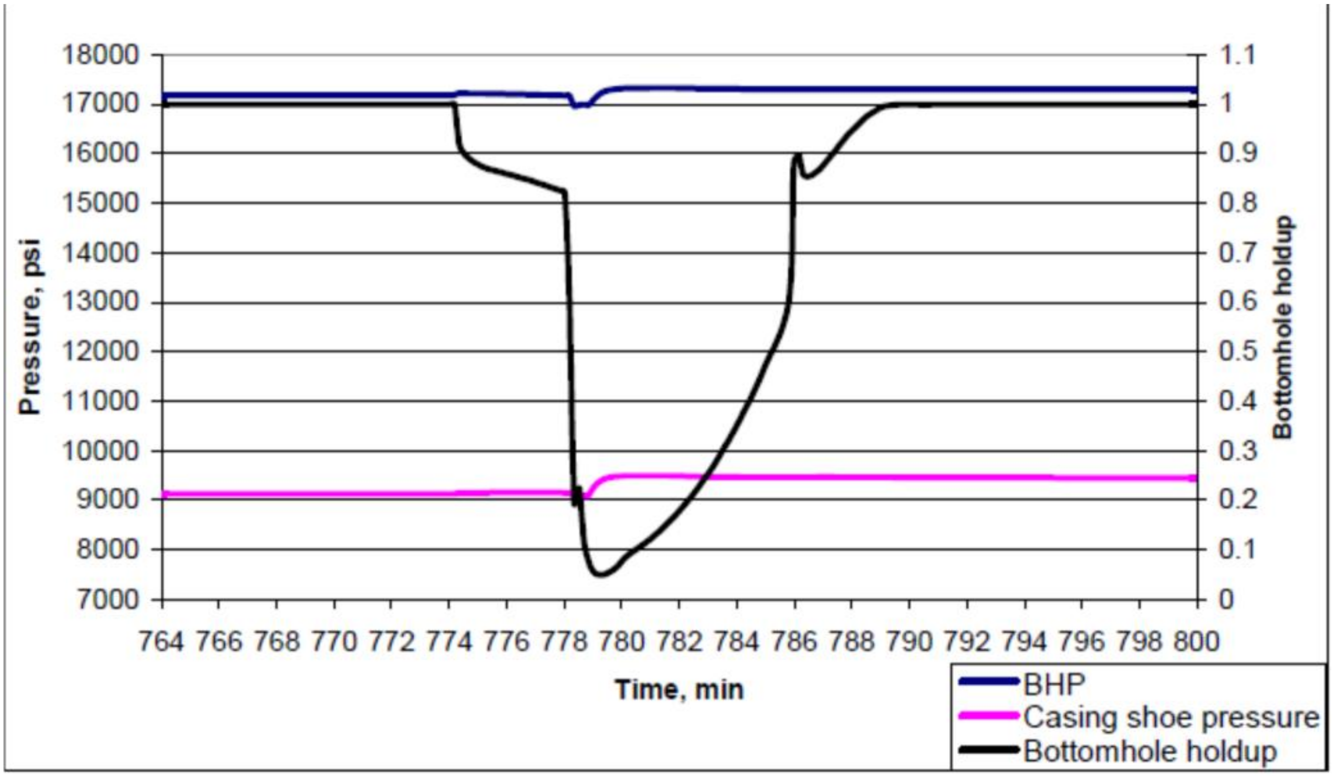


Figure 3.5.4 - BHP and liquid holdup with BOP closed 5 minutes after a gas kick

18.5 barrels, which is much less than the 79 bbl taken assuming a 1minute reaction time when only nitrogen is shut down as described in the previous section. The selection of 5 minutes to close the BOP after stopping circulation for this case is arbitrary. It should easily be possible to close the pipe rams in less than 2 minutes on most-deep water rigs. When formation flow stops, the holdup at total depth becomes 1. After closing the BOP, bottom hole pressure increases to finally reach the formation pressure. The bottom hole pressure build-up time is dependent on the volume of kick taken and its migration in the well annulus as well.

The next relevant issue for the deep water drilling, and therefore very narrow margins between pore and fracture pressure, is the formation fracturing at the casing shoe and therefore kick tolerance as well. In conventional drilling, even small kicks may lead to the lost returns and consecutively to losing the whole well. As already mentioned, dual density gas-lift system advantage over the conventional system is that larger kick volumes may be safely controlled without the risk of fracture at the casing shoe. The representative deep water example presented in this study, contains the trip margin at the casing shoe of 800 psi for dual density as opposite to only 200 psi in the conventional drilling. Casing shoe pressure after taking a gas kick and closing the subsea BOP in dual density drilling, is presented in Figure 3.5.4. It may be seen that this pressure increases by a value of 335 psi which is below the trip margin of 800 psi. It means that kick volume of 18.5 bbls for this deepwater dual density case may be safely controlled with closing the subsea BOP without the risk of formation fracture. There is still an additional safety pressure margin of 465 psi for the bigger kick volumes and/or slower reaction times to detect and stop the kick.

Summarizing, the BOP should be closed as early as possible to stop a kick, decrease its volume and avoid lost returns as well. The presented dual density gas-lift well control scenario shows that risk of formation fracture and consequently lost returns may be significantly decreased and successfully avoided applying this method. It is expected that the same case using the conventional deep water system will fail and lost returns will take place.

3.5.1.2.2 Water Kicks

A water kick is also simulated for the same well description and reservoir characteristics as the gas kick simulations. Circulation of drilling fluid was stopped, and then injection of nitrogen was stopped 4 minutes after the kick began. The BOP was closed to stop the water kick 5 minutes after the kick began as shown in Figure 3.5.5. There is almost an immediate bottom hole pressure buildup after closing the BOP. This is due to primarily to the compressibility of the water kick being much less than that of the gas kick. This is very important as the time period while underbalanced is significantly reduced for shut in on a water kick and accounts for 7 minutes comparing with 16 minutes of gas kick.

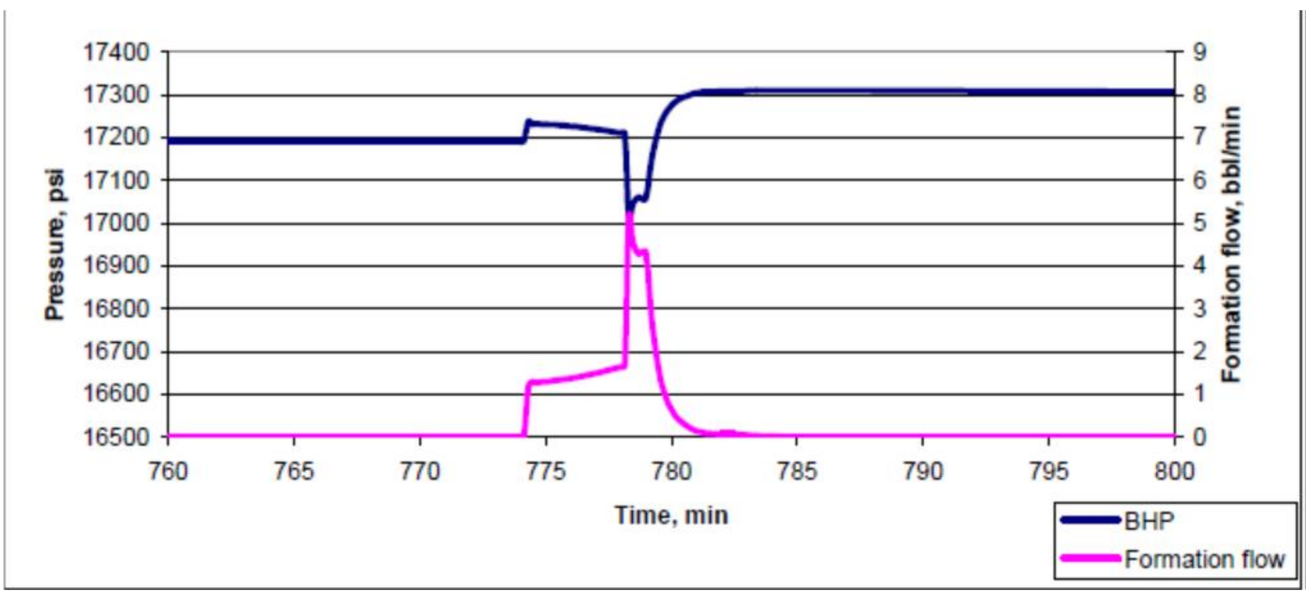


Figure 3.5.5 - BHP and formation flow with BOP closed on a water kick after 5 minutes

Furthermore, the total kick volume taken was only 11 barrels when BOP was closed in comparison to 36 barrels when relying on only stopping the nitrogen injection. In summary, use of BOP closure to stop a kick should always be preferable to relying only on cessation of nitrogen injection for riser gas-lift.

3.5.2 Single Density Drilling Simulation Results

As previously mentioned, dual density gas-lift and single density system were separately simulated as a means of comparing these two methods. The simulation input data describing the single density well and the two cases in general are presented in Table 3.1. As it was concluded in the kick detection unit, kick detection for the dual density drilling is generally similar to the conventional drilling as slugging is not a concern for the steady state conditions. Therefore, kick detection should not generally differ for the conventional drilling and previously analyzed indicators are valid for this case as well.

3.5.2.1 Shutting in with Subsea BOP

Conventional drilling conditions are simulated, and a gas kick was taken. The rig pumps were stopped at 4 minutes (778 minutes), and the BOP closed at 5 minutes (779 minutes), respectively after the gas kick began. The detection time of 3 minutes was based on the magnitude of the surface kick warnings at 777 minutes described in the previous chapter on kick detection. It may be seen from Figure 3.5.6 that after 3 minutes of gas kick influx pit gain accounts for about 12 bbl and surface flowrate increases about 35 % that should be readily noticeable at the surface. Figure 3.5.7 shows the effects when the kick enters the well at 774 minutes, mud circulation is stopped at 778 minutes, and the BOP is closed at 779 minutes. Bottom hole pressure starts to increase along with the liquid bottom hole holdup when BOP is closed. The total kick volume taken is 16.2 barrels. When formation flow stops, the holdup at total depth becomes 1.0. After closing the BOP, bottom hole pressure increases to finally reach the formation pressure. The bottom hole pressure build-up time is dependent on the volume of kick taken and its migration in the well annulus as well. Due to very narrow margins between pore and fracture pressure, there is a serious risk of formation fracturing even for small kicks taken. Casing shoe pressure starts to increase after taking a gas kick and closing the BOP by a value of 259 psi, which is above the allowed kick margin value of only 200 psi. It means that kick volume of 16.2 bbls for this deep water single density conventional case will cause formation fracture and lost returns will occur after closing the subsea BOP.

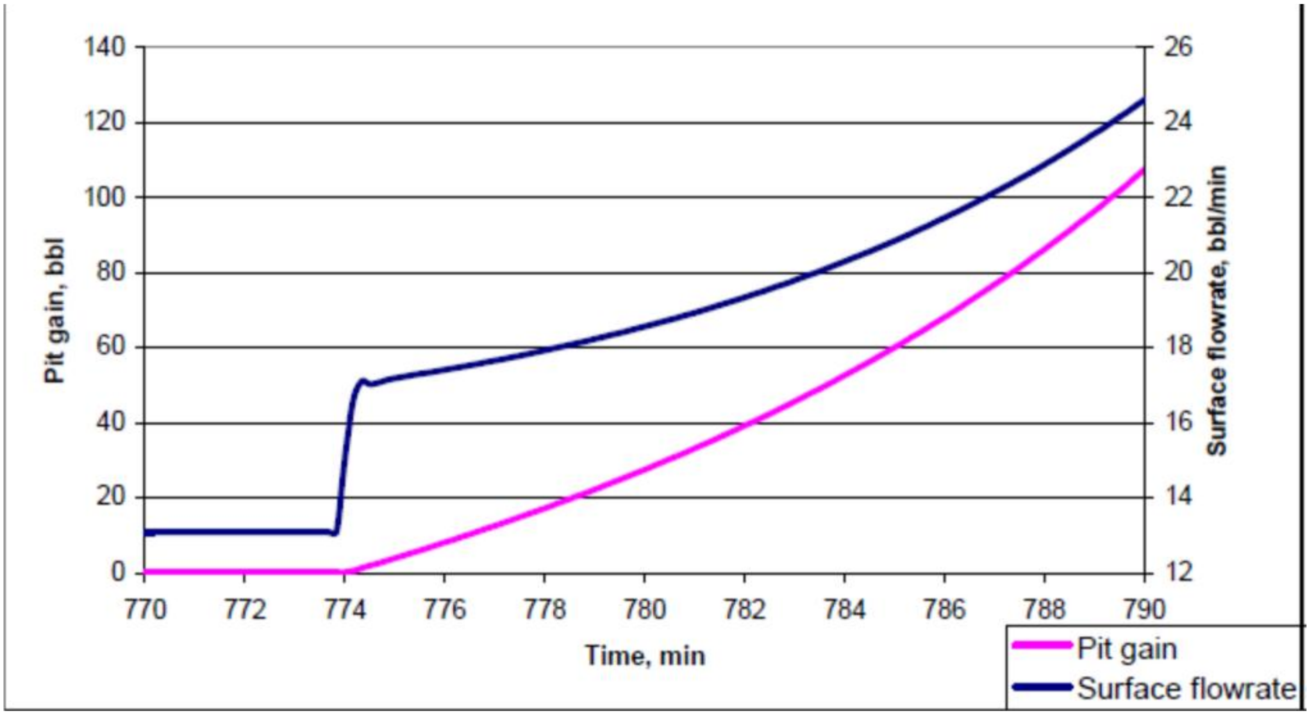


Figure 3.5.6 – Pit gain and surface flowrate as kick indicators

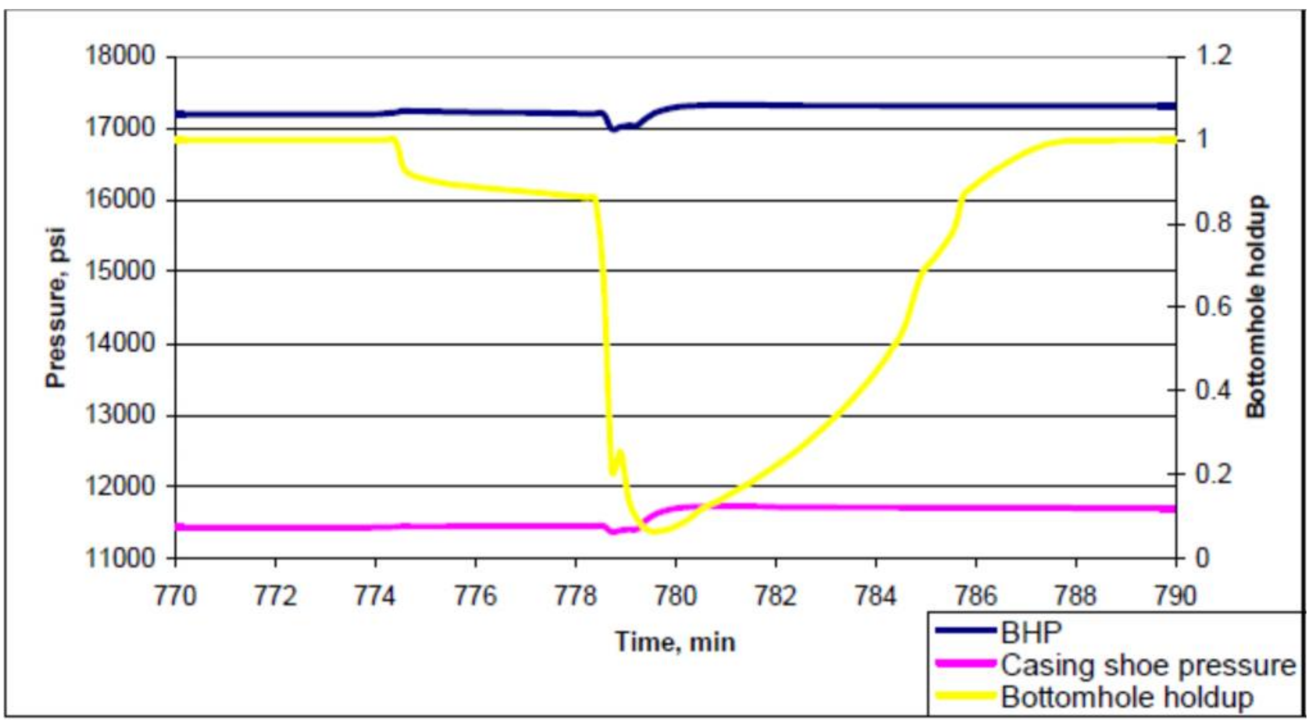


Figure 3.5.7 – Well pressures and liquid holdup with BOP closed 5 minutes after a gas kick

3.5.3 Discussion and Observations

When comparing the two cases, single density drilling will start to lose returns at the casing shoe as its fracture pressure was exceeded by 59 psi. As opposite, dual density case will not experience lost returns as its kick margin is still above the pressure increase at the casing shoe after taking a kick and closing the BOP. Results of these two cases are presented in Figures 3.5.4 and 3.5.7. It may be seen from Figure 3.5.7 that even very fast reaction time to shut-in the well for the conventional drilling may lead to lost returns for these very narrow pressure and fracture margins for deep water well. After 5minute reaction time to close the subsea BOP, the kick volume taken was 16.2 barrels causing fracture at the casing shoe. As comparison, the same reaction time in dual density method causes kick volume to be 18.5 barrels and there is no risk of formation fracture at the casing shoe.

Analysis of results presented for controlling the kicks in the dual density gas-lift and single density system shows that gas-lift method is of advantage versus the conventional drilling. The main factor is the favorable pressure system distribution for the deep water wells with the riser bottom pressure equal to the seawater hydrostatic pressure. Therefore, kick margins are much higher than in conventional drilling and bigger kick volumes may be taken without the risk of lost returns.

When nitrogen injection is stopped almost immediately after taking a kick, kick volume taken is still significant and underground blowout may occur in spite of bottom hole pressure increase. Furthermore, if nitrogen injection shutdown is conducted later, according to the proper kick indicators, it is not enough to stop a kick, bottom hole pressure can't be controlled and underground blowout will follow. Therefore, shutting down the nitrogen injection is not recommended for further investigation as a well control method based on the evidence.

Application of BOP closure to stop and control a kick should always be preferable for riser gas-lift to control a kick. Therefore, BOP should be closed as early as possible to stop a kick and consequently decrease its volume and avoid lost returns.

Single density system will lose returns with the smaller kick volumes as its kick margins are lower and therefore not allowing very small kick volumes to be safely controlled. Dual density system will allow for taking the bigger kick volumes due to its higher kick margins as opposite to the single density conventional system. Therefore, dual density gas-lift system is preferable to single density system for deep water wells with the very narrow pore and fracture margins.

3.6 KICK CIRCULATION

After a well is shut in, the bottom hole pressure increases to equal the formation pressure, and the formation fluid flow stops. This bottom hole pressure must be held above the formation pressure to prevent more formation fluid flow while circulating out the kick. At the same time, excessive bottom hole pressure must be avoided to prevent loss of circulation. If an influx is to be circulated and removed from the well, it requires circulating the kick fluids out of the well while maintaining the bottom hole pressure essentially constant. The results presented in this study concentrate on circulating the influx out of the well with three alternative methods. These are 1) gas kick circulation through the gas-lifted choke line using surface choke adjustments, 2) gas kick circulation through a gas-lifted choke line with adjustment of a subsea choke placed at the seafloor between the riser and the choke line, and 3) gas kick circulation through a gas-lifted riser with adjustment of a subsea choke placed at the seafloor. Furthermore, kick circulation in dual density system is compared with the single density system.

3.6.1 Dual Density Kick Circulation

3.6.1.1 Circulation through a Gas-lifted Choke Line and a Surface Choke

The first alternative considered for circulation to remove a gas kick is similar to the procedure routinely used on floating rigs. The only difference is nitrogen injection into the bottom of choke line to reduce the hydrostatic pressure in the choke line and avoid lost returns.

3.6.1.1.1 Gas Kick

The simulation to study this alternative begins with a gas kick taken after 774 minutes of dual density drilling. Gas injection to the riser and mud circulation are stopped 4 minutes later (at 778 minutes), and the BOP is closed 5 minutes (at 779 minutes) after taking the kick. The kick volume taken is 18.5 bbl. Bottom hole pressure then increases to reach the formation pressure and formation flow stops. This was presented in the previous chapter. Circulation to begin removing the kick could, and practically should, begin at this point.

Kick circulation in the simulation was begun at 850 minutes. Due to the drillstring valve (DSV) application above the bit that is closed immediately after mud pumps are shut down, it is impossible to record a SIDPP and define formation pore pressure. Therefore, a different method was proposed and adapted to the dual density, gas lift system to obtain a SIDPP during a pump start up. This gas-lift pump start-up differs from the procedure used in the conventional drilling and is described below. The choke at the surface is opened, mud circulation is resumed, and nitrogen injection begins. As pump is being constantly brought to a slow circulating rate (SCR), wellhead pressure is being kept constant using choke adjustments. Specifically, for the gas-lift system, this SCR must be high enough that the pump pressure will be higher than the pressure difference between the seawater pressure at the mudline and the mud pressure in the drillstring at the same depth. When the pump is brought to a slow circulating rate, pump pressure is recorded and choke operator switches from keeping the wellhead pressure constant to keeping the pump pressure constant until the kick is removed from the well. The pressure recorded after reaching the slow circulating rate is defined as Initial Circulating Pressure (ICP) and is equivalent to the pump pressure for a slow circulating rate plus a formation pressure overbalance. Difference between recorded ICP after bringing the mud pump on speed and a slow circulating rate pressure recorded before kick circulation is equivalent to a SIDPP that is a direct indication of the formation pore pressure.

During gas kick circulation, 16 ppg mud is circulated with the constant rate of 300 gpm, and nitrogen injection rate is kept constant at 7.76 mmscf/d. Only choke adjustments were applied to keep the bottom hole pressure in the desired pressure range. Nitrogen injection to the choke line was kept constant to maximize the simplicity of this procedure. As can be seen in Figure 3.6.1, bottom hole pressure was maintained above formation pressure and was kept in a relatively safe margin minimizing the risk of formation fracturing as well. When gas is circulated above the casing shoe (casing shoe liquid holdup decreases) as it may be seen in Figure 3.6.2, casing shoe pressure decreases much below the fracturing pressure of 9955 psi and risk of lost returns is automatically discarded. Furthermore, relatively high kick margin of 800 psi in this case, allows the safely gas kick circulation without any risk of formation fracturing. Figure 3.6.3 presents the standpipe pressure and wellhead pressure while circulating the gas kick from the well. During pump start up, wellhead pressure is maintained constant, and as slow circulating kill rate is reached, initial circulating pressure is recorded. Once ICP is known, this pressure is maintained constant to maintain bottom hole pressure relatively constant. Pump start up in gas lift system is different from the conventional well control start up as described earlier. However, when the pump is brought on speed, bottom hole pressure is controlled by monitoring and maintaining the standpipe pressure variations in the safe pressure margin. This is the same as in the conventional method.

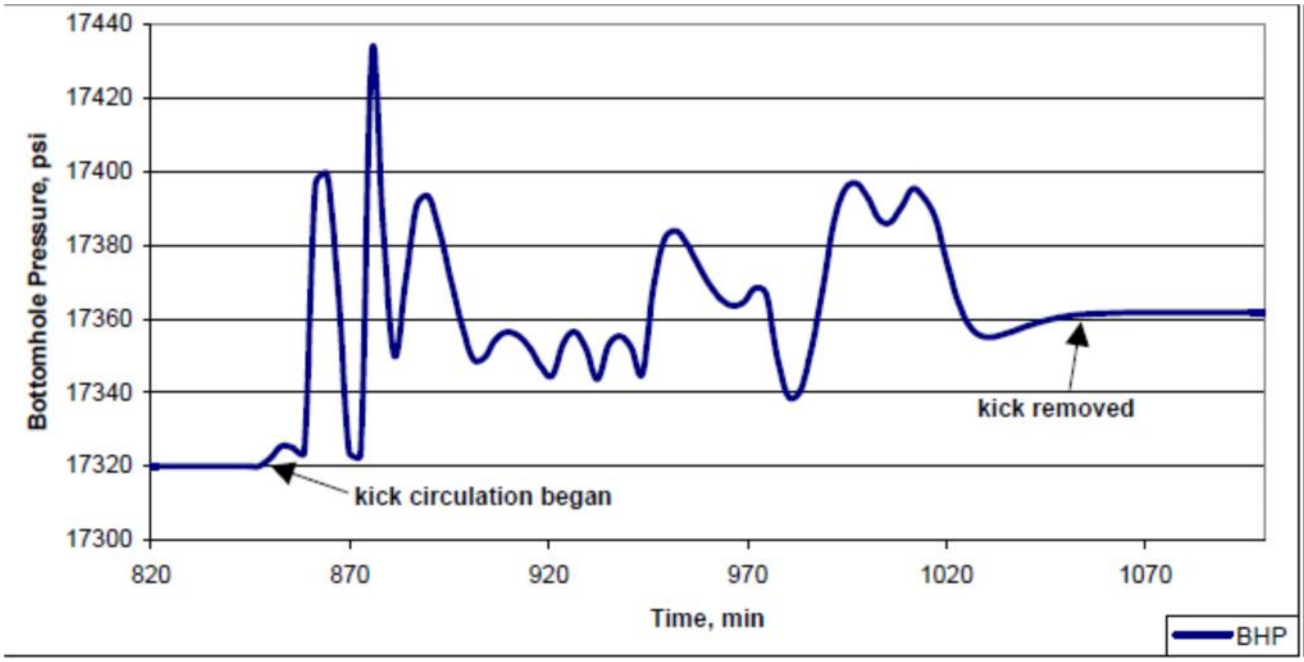


Figure 3.6.1 – Bottom hole pressure with gas kick circulation

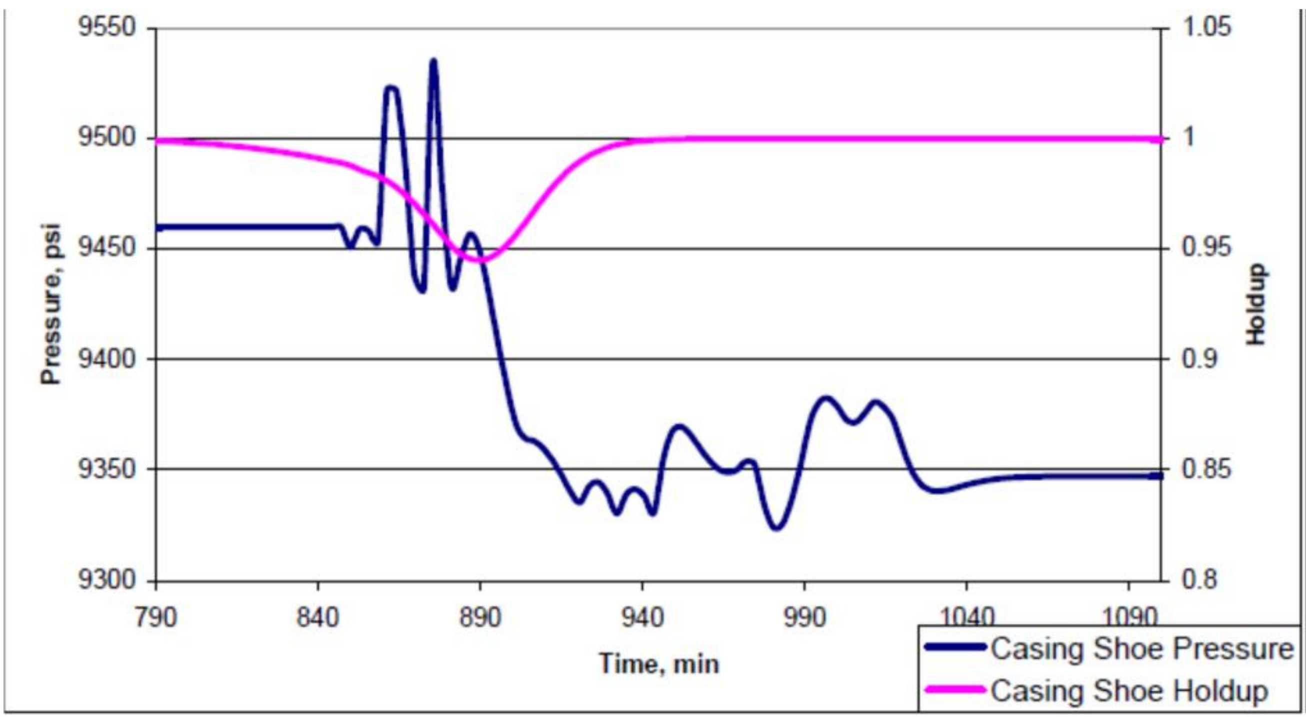


Figure 3.6.2 - Casing shoe pressure versus liquid holdup when circulating the gas kick

The magnitude of pressure variations was 115 psi. As a result of keeping the bottom hole pressure above the formation pressure during the gas circulation, there was no additional kick influx and the gas kick was successfully circulated out of the well.

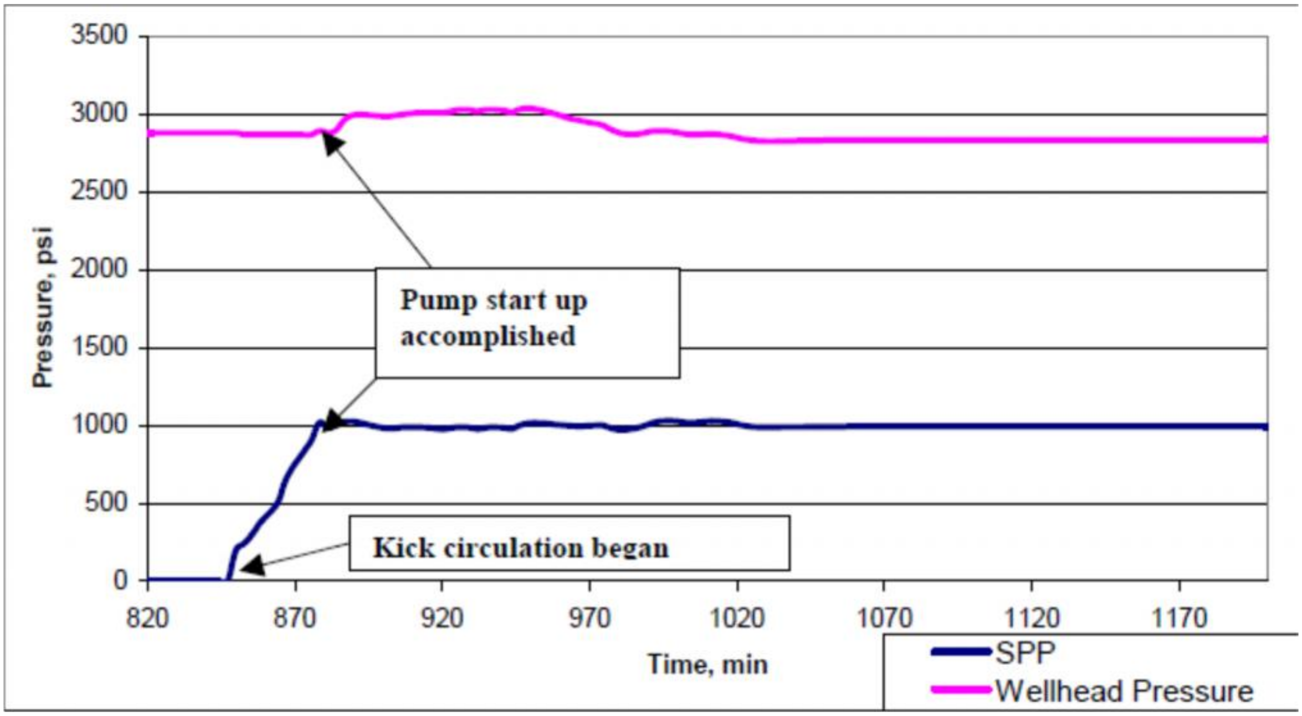


Figure 3.6.3 - Standpipe and wellhead pressure when circulating the gas kick

3.6.1.2 Circulation through a Gas-lifted Choke Line with the Choke at the Seafloor

The second alternative uses a surface-controlled, subsea choke system to help reduce the complications caused by multi-phase flow in the subsea choke line. The great length of the subsea choke line can result in unacceptably high hydrostatic and/or frictional backpressure being held on the annulus during kick circulation. The injection of nitrogen into the base of the choke line helps overcome these effects but also means that surface choke adjustments always affect the multiphase flow conditions in the choke line. The potential advantage of using the subsea choke is to place the choke ahead of the multiphase flow in the choke line such that choke pressure adjustments act more directly to affect bottom hole pressure. This should simplify choke manipulation.

3.6.1.2.1 Gas Kick

The results of simulating kick removal using a system with a subsea choke are presented in Figures 3.6.4 and 3.6.5. A gas kick is again taken after 774 minutes of dual density drilling. Gas injection to the riser and mud circulation are stopped 4 minutes later (at 778 minutes), and the BOP is closed 5 minutes (at 779 minutes) after taking a kick. The kick volume taken is again 18.5 bbl. At 850 minutes, mud circulation and nitrogen injection into the choke line are resumed with returns through the subsea choke and into the choke line. During gas kick circulation, 16 ppg mud is circulated down the drillstring at a constant rate of 300 gpm, and nitrogen injection rate is kept constant at 7.76 mmscf/d. The bottom hole pressure was kept in the desired pressure range with the subsea choke adjustments.

As shown in Figure 3.6.4, bottom hole pressure was kept in a very small margin of 45 psi, resulting in the successful circulation of the kick out of the well. The apparent advantage of using the subsea choke instead of the surface choke is the faster pressure responsiveness to the choke adjustments. This is because the subsea choke is placed at the bottom of the choke line and there is less compressibility effect in the annulus below the seafloor where there is no nitrogen. Using the subsea choke exclusively in this simulation, it was found that fewer and smaller choke adjustments are needed, and there is a more direct bottom hole pressure responsiveness during gas kick circulation compared to using the surface choke.

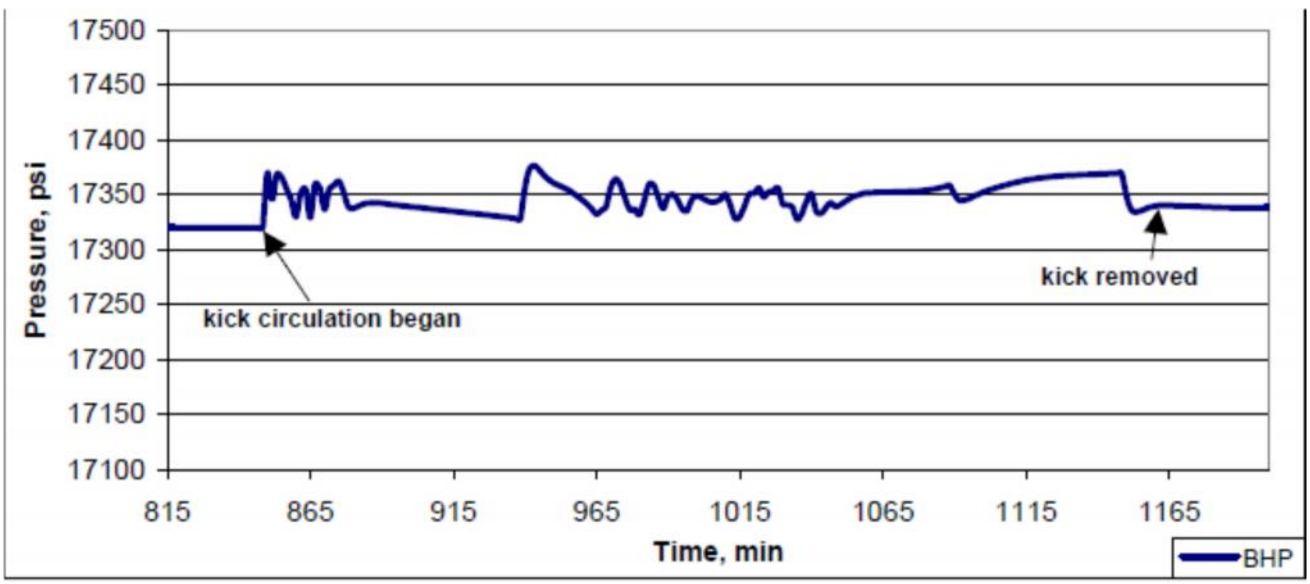


Figure 3.6.4 - Gas kick circulation through the gas-lifted choke line with the subsea choke

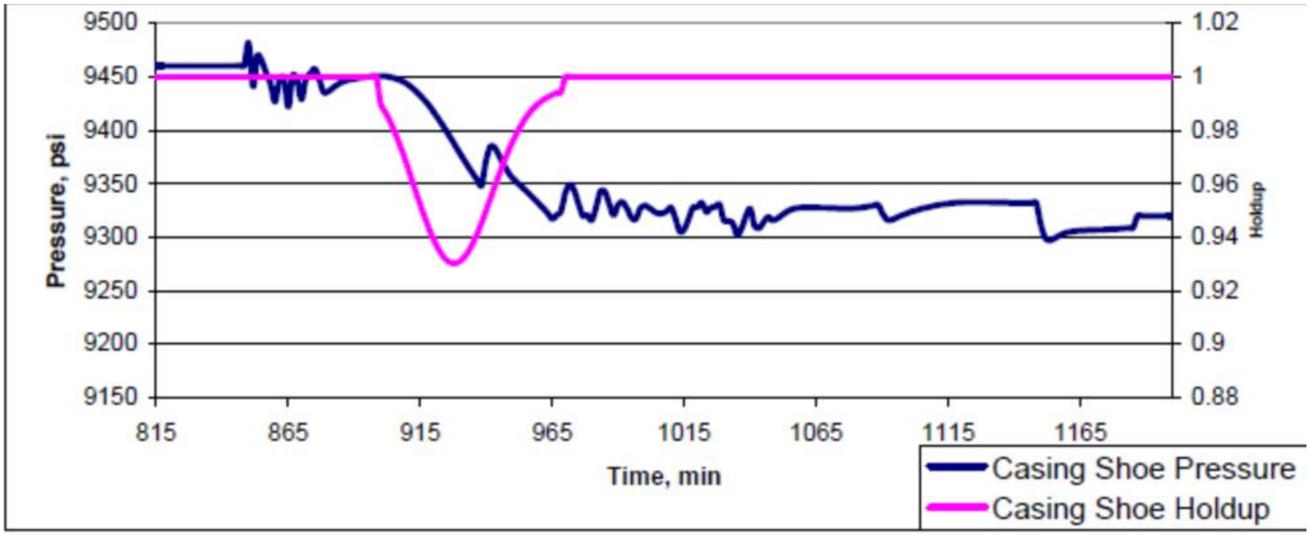


Figure 3.6.5 – Casing shoe pressure when gas kick circulated with the subsea choke

Casing shoe pressure was controlled in the small pressure margin, much below fracturing pressure of 9955 psi, discarding the risk of lost returns, as may be seen on Figure 3.6.5. Furthermore, rapid choke adjustments are avoided when the gas kick enters the small diameter choke line using the subsea choke and gas injected choke line. It may be observed that wellbore annulus is decoupled from the pressure in the choke line by applying the subsea choke. Therefore, by applying the subsea choke, bottom hole pressure at the same time is not dependent on the wellhead pressure but rather on the subsea choke adjustments.

In the gas kick simulation with the subsea choke, recorded bottom hole pressure variations were about 45 psi compared to the surface choke case, which experienced 115 psi bottom hole pressure variations. This is very important as the whole gas kick circulation procedure is controlled more easily and accurately with the application of the subsea choke.

3.6.1.2.2 Water Kick

A water kick circulation was simulated for the same well description as the gas kick simulations presented in Table 3.1.1. Results for water kick circulation through the gas-lifted choke line and subsea choke are presented in Figure 3.6.6. A gas kick is again taken after 774 minutes of dual density drilling. Gas injection to the riser and mud circulation are stopped 4 minutes later (at 778 minutes), and the BOP is closed 5 minutes (at 779 minutes) after taking a kick. The kick volume taken is 11 bbl. At 850 minutes, mud circulation and nitrogen injection into the choke line are resumed with returns through the subsea choke and into the choke line. During water kick circulation, 16 ppg mud is circulated down the drillstring at a constant rate of 300 gpm, and nitrogen injection rate is kept constant at 7.76 mmscf/d. The bottom hole pressure was kept in the relatively safe pressure range with the subsea choke adjustments resulting in removing the water kick. As described previously, application of the subsea choke is of advantage versus the surface choke.

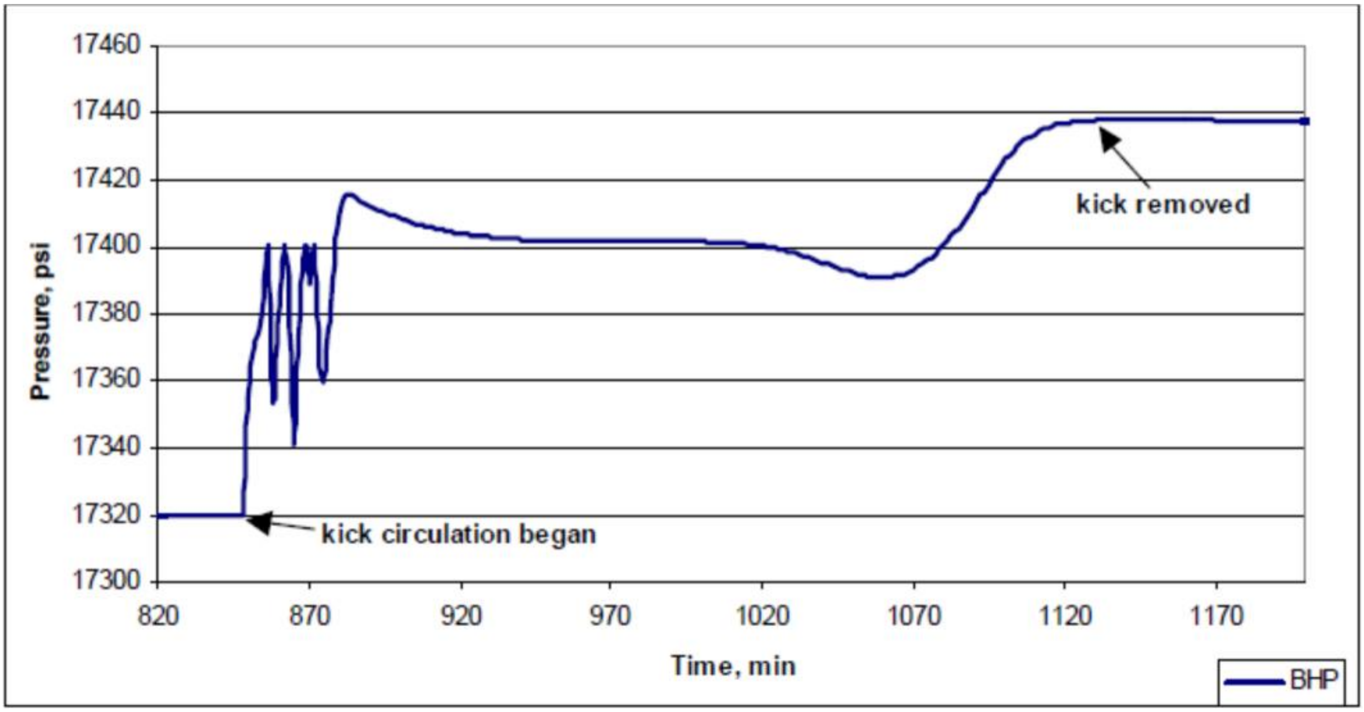


Figure 3.6.6 - Gas kick circulation through the gas-lifted choke line with the subsea choke

3.6.1.3 Circulation through a Gas-lifted Riser with the Choke at the Seafloor

The third alternative considered for circulation to remove a gas kick, is to take returns through the gas lifted riser with the subsea choke at the bottom. This is expected to eliminate the choke line concerns with the excessive pressure exposed on the formation and lost returns due to friction pressure losses will be avoided. The potential advantage of using the subsea choke would be again placing it ahead of the multiphase flow in the riser such that choke pressure adjustments act more directly to affect bottom hole pressure. This should also simplify choke manipulation. However, there is a concern of riser collapse when considerable volume of kick is circulated through the gas lifted riser.

3.6.1.3.1 Gas Kick

Again, a gas kick is taken after 774 minutes of dual density drilling. Gas injection to the riser and mud circulation are stopped 4 minutes later (at 778 minutes), and the BOP is closed 5 minutes (at 779 minutes) after taking a kick. The kick volume taken is again 18.5 bbl. At 850 minutes, mud circulation and nitrogen injection into the riser are resumed with returns through the subsea choke and into the gas-lifted riser. During gas kick circulation, 16 ppg mud is circulated down the drillstring at a constant rate of 500 gpm, and nitrogen injection rate is kept constant at 15.52 mmscf/d. The bottom hole pressure was kept in the desired pressure range with the subsea choke adjustments as may be seen in Figure 3.6.7.

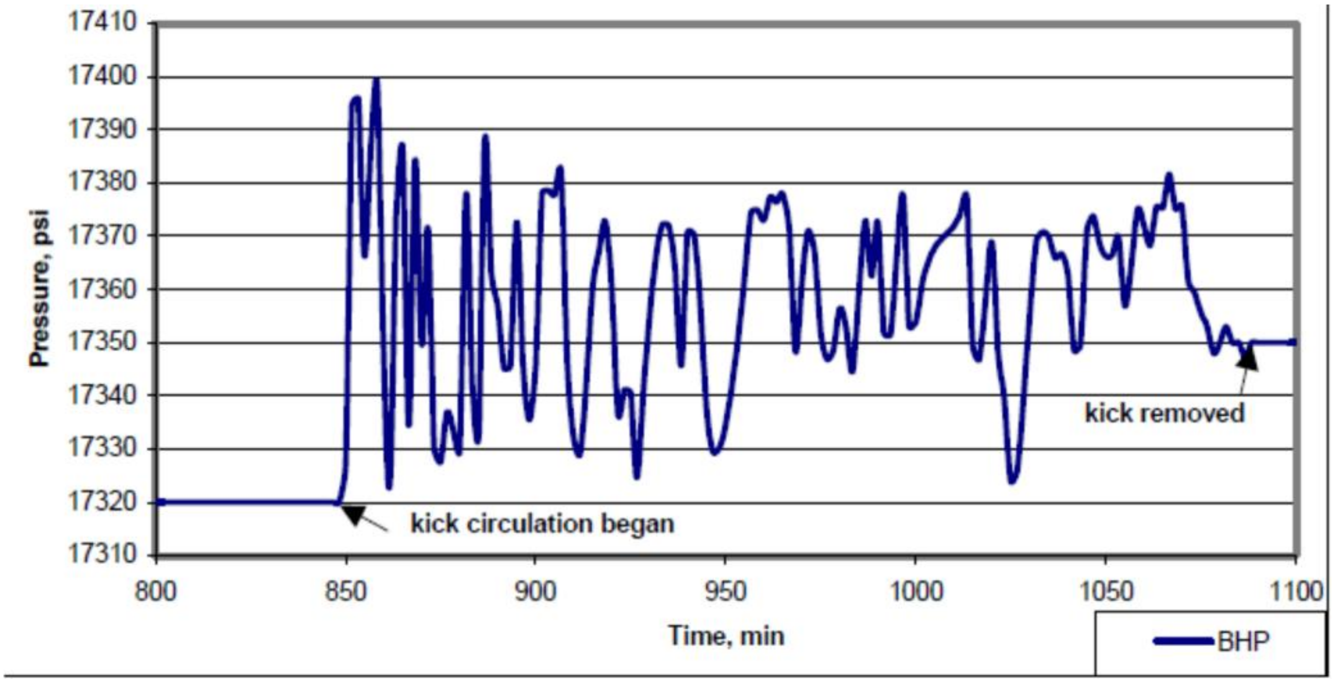


Figure 3.6.7 - Gas kick circulation through the gas-lifted riser with the subsea choke

As already mentioned, one of the major concerns in this method is the risk of riser collapse. This is true when gas kick enters the gas lifted riser decreasing its liquid holdup and increasing riser collapse risk simultaneously. The larger kick volume the higher the probability of riser collapse exists. Riser analysis during gas kick circulation with the subsea choke valve is presented in Figure 3.6.8.

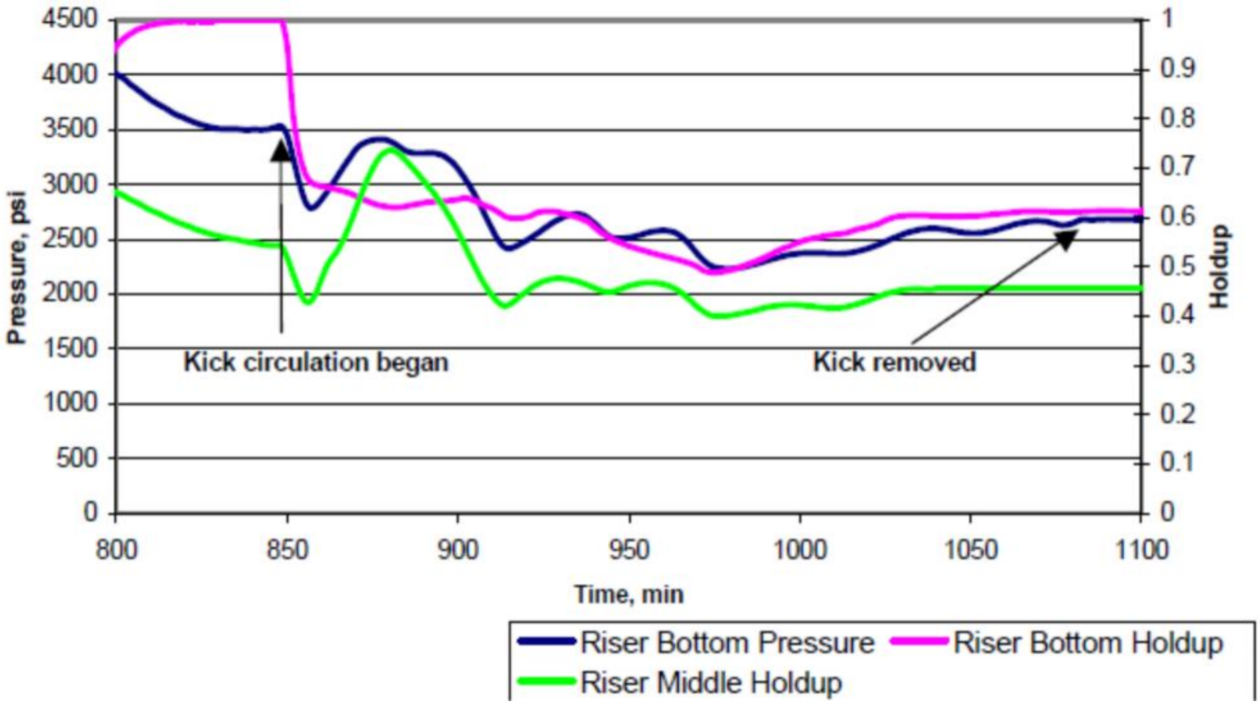


Figure 3.6.8 – Riser behavior when gas kick circulated through the gas-lifted riser

The worst situation occurs when gas kick enters the riser that is additionally gas lifted to keep the bottom hole pressure at the desired value. When subsea choke valve is open and circulation begins, gas kick is circulated toward the surface and finally enters the riser decreasing its liquid holdup. Liquid holdup at the bottom of the riser accounts for 61% due to nitrogen injection for the dual density conditions. Due to additional gas kick entering the riser, liquid holdup decreases from 61% to the value of 48% of liquid holdup. Since then, riser bottom liquid holdup increases to its constant value for normal dual density conditions of 61% as gas kick is circulated out of the riser. The lowest pressure recorded during kick circulation at the bottom of the riser equals 2234 psi. Consequently, pressure difference between the seawater hydrostatic pressure and pressure inside the riser at this moment equals 451 psi and it should not cause danger of riser collapse. This is dependent on the kick volume and therefore, bigger kick volumes should also be considered as expected to increase risk of riser collapse.

3.6.2 Single Density Kick Circulation

Gas kick circulation in the conventional, single density system, was simulated as a means of the representative comparison and evaluation along with the dual density system. The simulation input data describing the single density system are presented in Table 3.1.1. Stopping formation inflow for the single density system was described in the previous chapter and its gas kick circulation was conducted for the same well design.

3.6.2.1 Gas Kick

The simulation to study this alternative begins with a gas kick taken after 774 minutes of drilling. Mud pumps are stopped 4 minutes later (at 778 minutes), and the BOP is closed 5 minutes (at 779 minutes) after taking the kick. The kick volume taken is 16.2 bbl. Bottom hole pressure then increases to reach the formation pressure and formation flow stops. As mentioned in the previous chapter, single density system will experience fracturing at the casing shoe after closing the subsea BOP.

Kick circulation in the simulation was begun at 850 minutes. The choke at the surface is opened, mud circulation is resumed, and circulation begins. During gas kick circulation, 14.07 ppg mud is circulated with the constant rate of 150 gpm. Low circulation rate is caused by the unacceptably high frictional pressure losses in the 4.5 in diameter choke line. Surface choke adjustments were applied to keep the bottom hole pressure in the desired pressure range. This scenario is shown in Figure 3.6.9. Bottom hole pressure was maintained above formation pressure and was kept in 80 psi pressure margin. Risk of lost returns is the serious problem in the single density system as mentioned previously. When circulation starts, casing shoe pressure is still above the fracturing pressure. Casing shoe pressure and liquid holdup is presented in Figure 3.6.10. It may be seen that when the gas kick approaches the casing shoe (liquid holdup decreases), casing shoe pressure decreases minimizing the risk of fracturing. After circulating the kick out of the well, casing shoe pressure decreases slightly below the fracturing pressure of 15,610 psi.

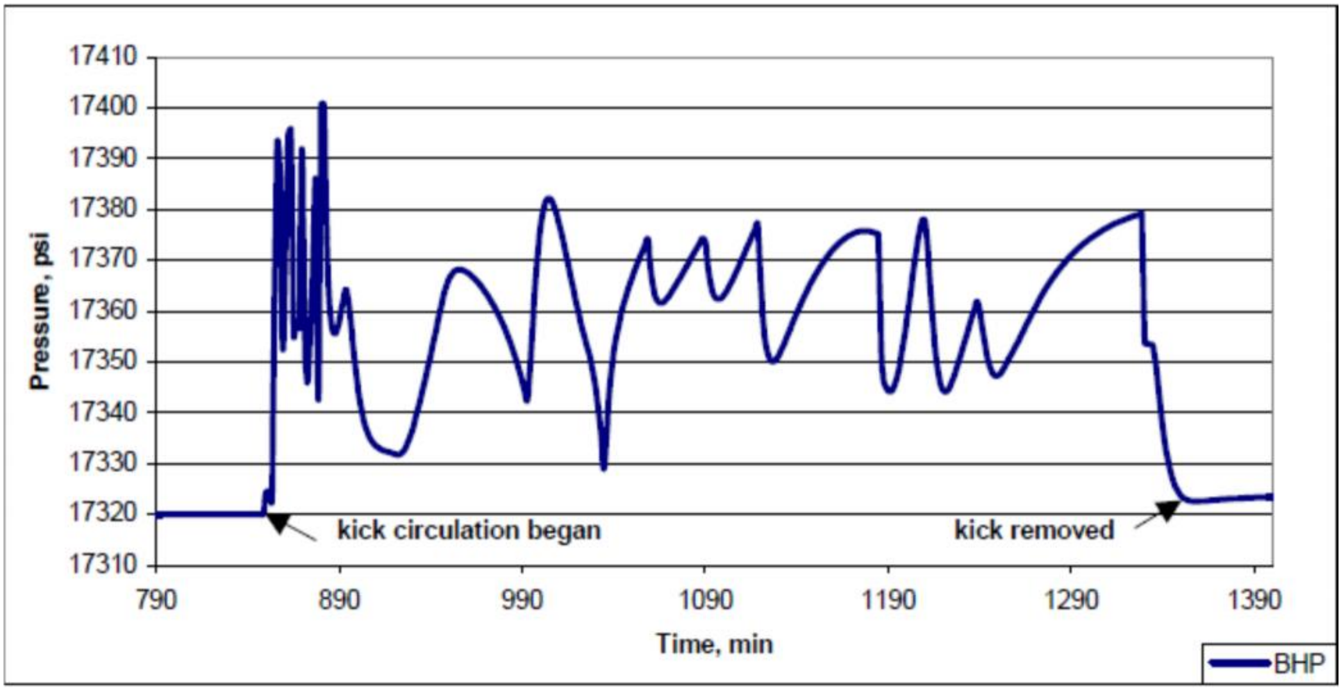


Figure 3.6.9 - Gas kick circulation in the single density system

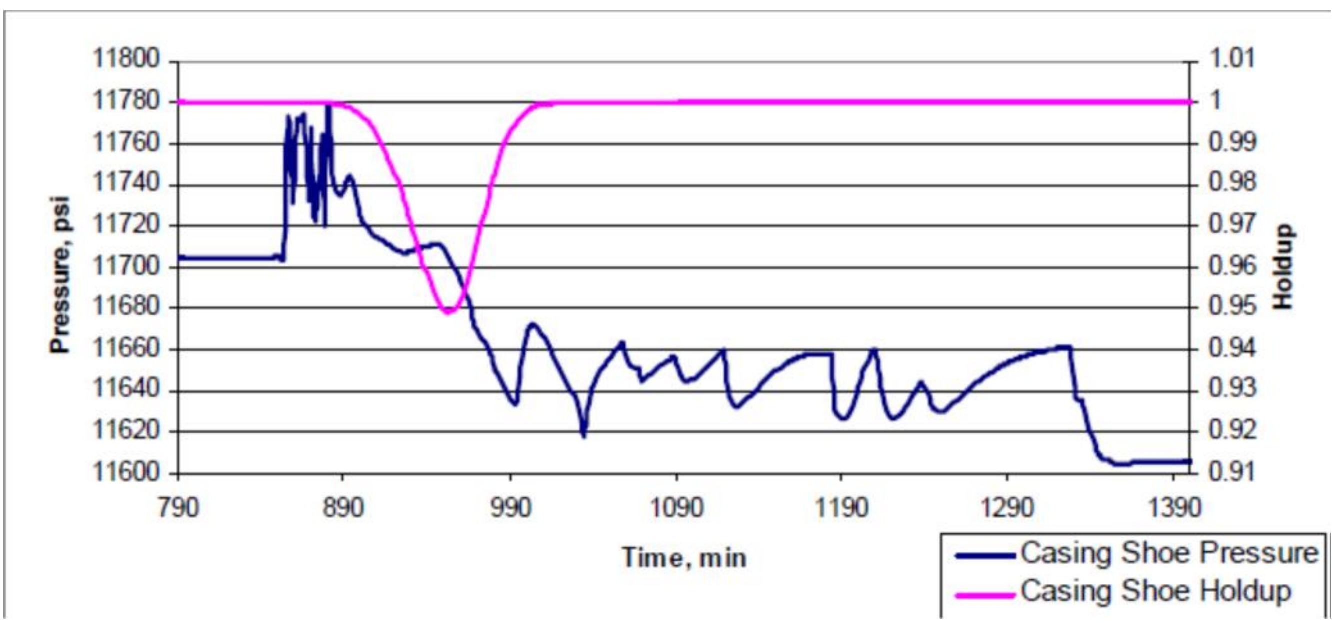


Figure 3.6.10 – Casing shoe pressure and liquid holdup during gas kick circulation

Figure 3.6.11 presents the pressure at the base of the choke line and liquid holdup. It may be seen that when the gas kick reaches the choke line (liquid holdup decreases), choke line bottom pressure decreases due to gas filling the choke line. Also, the rapid choke adjustments were applied due to gas kick entering the small diameter choke line to keep the bottom hole pressure in the desired pressure margin. As a result of keeping the bottom hole pressure above the formation pressure during the gas circulation, there was no additional kick influx. However, the fracturing risk was not discarded during the gas kick circulation procedure. Casing shoe pressure was

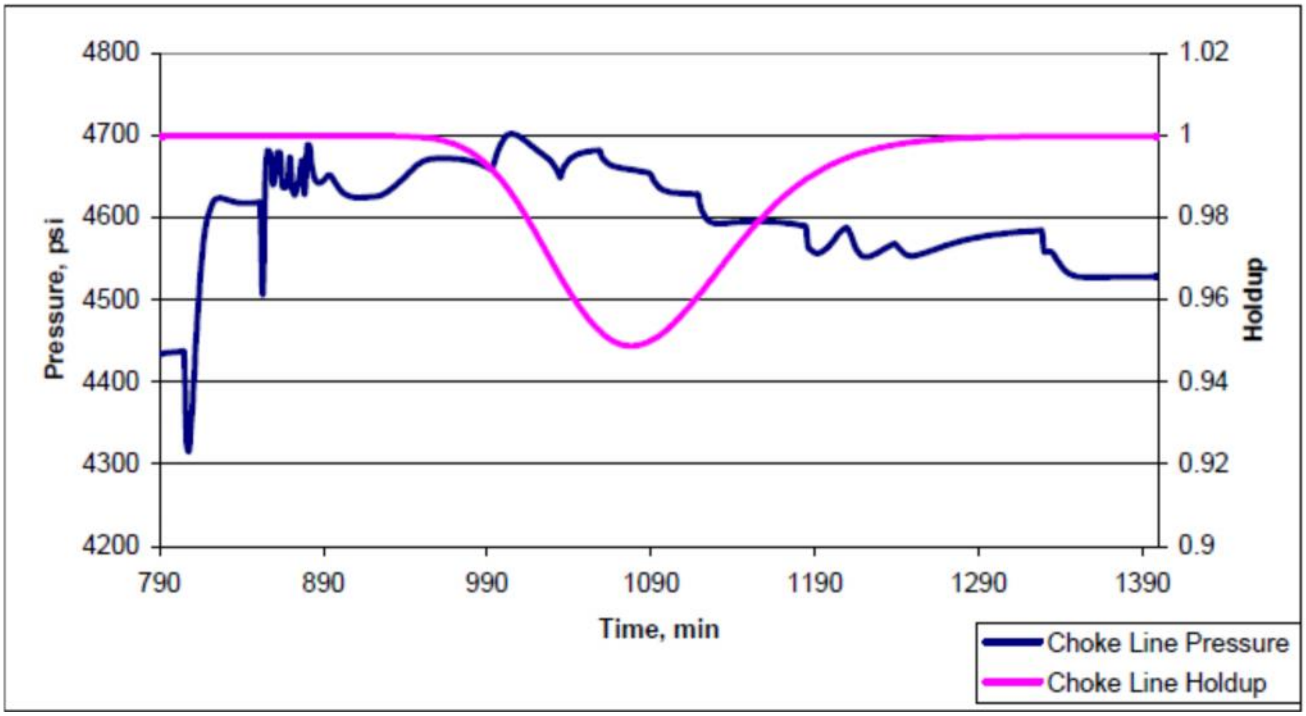


Figure 3.6.11 – Choke line pressure and liquid holdup during gas kick circulation

decreased below the fracturing pressure when gas kick was circulated out of the well. However, the risk of lost returns is a serious and inevitable danger in the single density system as casing shoe pressure was above the fracturing pressure after closing the BOP and during the kick removal.

3.6.3 Discussion and Observations

From the simulation results obtained, it may be concluded that the subsea choke is of advantage comparing to the surface choke. Subsea choke requires less and fewer adjustments, there is faster pressure responsiveness and the pressure in the well annulus may be decoupled from the pressure in the choke line. This is especially important when the gas kick enters the choke line and rapid choke adjustments for the surface choke are required. Also, applying the subsea choke, bottom hole pressure was kept in 40 psi pressure margin, opposite to the surface choke with 115 psi pressure variations.

Dual density gas-lift system was found to be more effective for controlling gas kicks due to its higher kick margin, which avoided the lost returns experienced with the same kick in a single density system. In the dual density gas-lift system with the subsea choke, kicks were safely circulated with the minimal bottom hole pressure variations and without the risk of fracturing. Risk of fracturing in the single density system excludes this system from the safe control of the kick and its circulation as well. High friction pressure losses in the choke line, very slow circulating rates and the high pressure variations in the single density system, makes the gas-lift system even more favorable.

Kick circulation with returns through the gas-lifted riser is feasible. Concerns with the long and small diameter choke line are automatically discarded in the gas-lifted riser method. However, riser collapse concern exists in this case that is strictly dependent on the kick volume circulated. Nevertheless, in the presented case with 18.5 bbl of the gas kick, there is no danger of riser collapse as riser bottom pressure is safely above the riser collapse pressure.

Summarizing, methods using a subsea choke showed faster pressure responsiveness requiring fewer and smaller choke adjustments and resulting in less variation in bottom hole pressure. Dual density well control allowed for safer control of higher kick volumes and reduced concerns associated with the frictional pressure losses when compared to conventional operations. Conclusively, the dual density gas-lift system with the subsea choke was found to be the most effective one in controlling and circulating the kicks.

3.7 KILL WEIGHT MUD CIRCULATION

Once a kick is removed from the well, kill weight mud (KWM) must be circulated through the well while keeping the bottom hole pressure above the formation pressure and within an acceptable safety margin. In conventional deep water kill operations, the high frictional pressure losses in the small diameter choke line are accentuated when the KWM enters the choke line. This can complicate the kill process and constrain the circulating rate used.

Simulations were conducted for both dual and single density systems as a means to compare and evaluate these two systems. As previously concluded, a gas-lift dual density system is expected to overcome the problems associated with the small diameter choke line, and excessive frictional pressure losses, due to gas injection reducing the hydrostatic pressure in the choke line. However, a gas-lift system may also experience pressure variations when the KWM starts to fill the choke line.

3.7.1 Dual Density System

3.7.1.1 Circulation through the Gas-lifted Choke Line and a Subsea Choke

As described before, the dual density gas-lift system with the subsea choke and circulation through the gas-lifted choke line was found to be the most effective in controlling and circulating out kicks. Therefore, this alternative will be analyzed for the KWM circulation here.

The data describing the well conditions used in this simulation are presented in Table 3.1.1. In a style equivalent to the driller's method for single density operations, after removing the kick as described in the previous chapter, the well was ready for circulation of the KWM. The density of the KWM was calculated to be 16.3 ppg. Initial circulating pressure (ICP) was defined in the same was as described in unit 5 and was calculated to be 520 psi, final circulating pressure (FCP) was calculated to be 276 psi. Kill circulating pressure was determined to be 320 psi. The necessary calculations to implement this procedure are presented below.

$KWM = OMW + ((\Delta SPP_{start\ up})/(0.052*(D-D_W)))$

$\Delta SPP_{start\ up} = ICP - KCP$ $\Delta SPP_{start\ up} = 520\text{-}320$

$= 200$ psi

$KWM = 16 + ((200)/(0.052*(23400 - 6000))) = 16.3$ ppg

$\Delta P_{KWMlosses}$ = ((KWM/OMW)*(KCP+(0.052(OMW-SW)*(D_W+RKB)))

FCP = $\Delta P_{KWMlosses}$ – 0.052*(KWM-SW)*(D_W+RKB)

FCP = ((KWM/OMW)*(KCP+(0.052(OMW-SW)*(D_w+RKB)))-(.052(KMW/SW)*(D_w+RKB) FCP = 280 psi

Where:

KWM - kill weight mud density, ppg

OMW - original mud weight density, ppg

$\Delta SPP_{start\ up}$ - pressure difference between the ICP and KCP after a pump start up, psi

D - total vertical depth, ft

D_W - water depth, ft

ICP - initial circulating pressure measured after a proper pump start up, psi

KCP - pump pressure at the kill rate measured before the kick, psi

FCP - final circulating pressure, psi

$\Delta P_{KWMlosses}$ - drillpipe frictional pressure losses with KWM to overcome pressure difference at the mudline between a seawater pressure and a drillpipe mud pressure

RKB – air gap between the kelly bushing and a seawater level, ft

SW - seawater density, ppg

The results of simulating KWM circulation using a system with a subsea choke are presented in Figures 3.7.1, 3.7.2, 3.7.3 and 3.7.4. Circulation begins at 1,200 minutes when KWM is circulated down the drillstring at the kill rate of 460 gpm and proceeds according to the drillpipe pressure schedule. Returns are taken through the gas-lifted choke line with the subsea choke. The nitrogen injection rate to the choke line equals 13.45 mmscfpd to keep the seafloor pressure equal the seawater hydrostatic pressure. The bottom hole pressure was maintained in the safe pressure range with the subsea choke adjustments as may be seen in Figure 3.7.1. The bottom hole pressure peak at 1,400 minutes is caused by the KWM beginning to enter the choke line. The proper reaction is to open the choke to adjust for an additional frictional and hydrostatic pressure increase due to KWM filling the choke line. In conventional well control operations this rapid pressure increase is offset by a proper choke manipulation and constant pressure is maintained. However, OLGA 2000^{TM} used in this study is not an interactive simulator and therefore it was not possible to react in time to prevent pressure from increasing rapidly by an immediate choke adjustment.

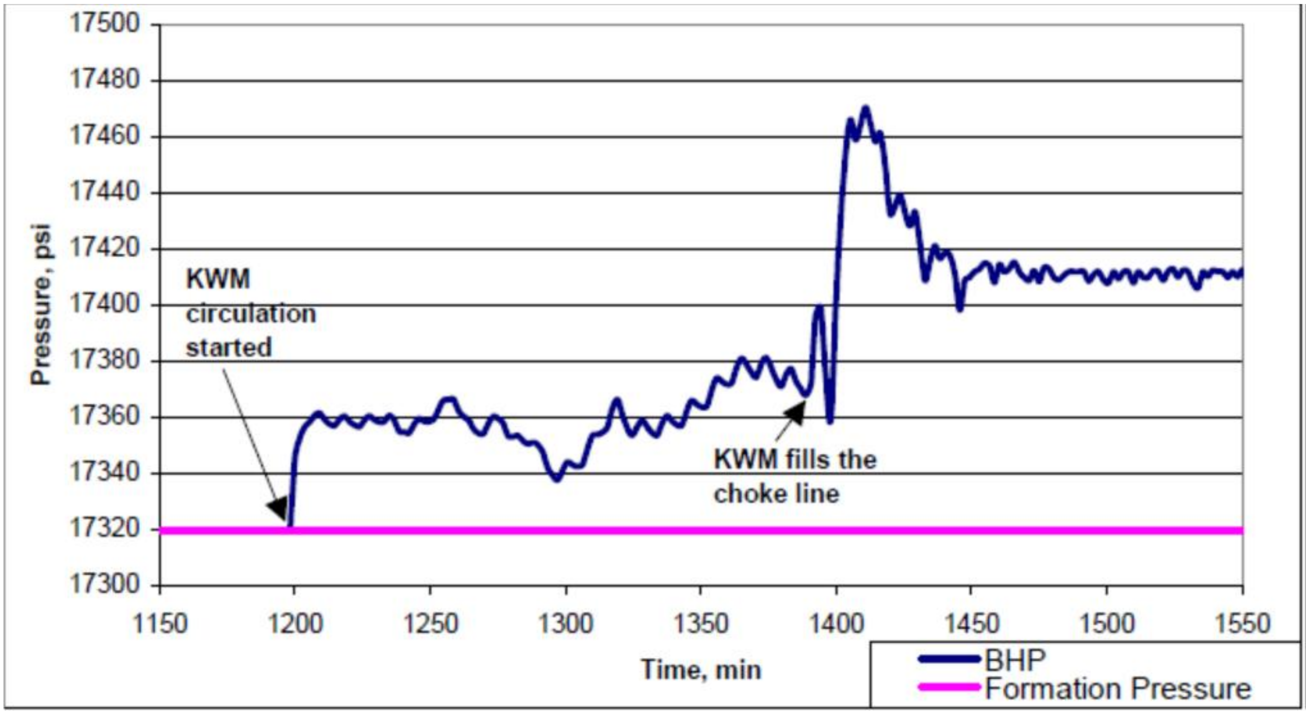


Figure 3.7.1 – BHP with KMW circulation in the dual density gas-lift system

Figure 3.7.2 shows the drill pipe pressure during KWM circulation. Drill pipe pressure decreased from ICP of 520 psi to the FCP of 276 psi. When the KWM was circulated down the bit and FCP was reached, then drill pipe pressure was kept relatively constant until the KWM began to fill the choke line. The main complication in this case occurs when the KWM fills the gas-injected choke line, and pressure at the seafloor will be higher than planned. In order to keep this pressure constant throughout the whole kill procedure, gas injection rate to the choke line was increased from 13.45 mmscfpd to 15.52 mmscfpd as shown in Figure 3.7.4. This new proper gas rate for different mud densities and flowrates must be determined before pumping the KWM, in order to take action in a timely fashion. This allowed maintaining the seafloor pressure relatively constant throughout the whole process. In spite of the initial spikes when gas rate was changed, casing shoe pressure was maintained safely below the fracture pressure and concerns associated with lost returns were avoided as presented in Figure 3.7.3. Casing shoe pressure during KWM circulation was constantly kept below the fracture pressure of 9,955 psi. When the KWM reached the casing shoe, casing shoe pressure stabilized at a relatively constant value of 9,280 psi.

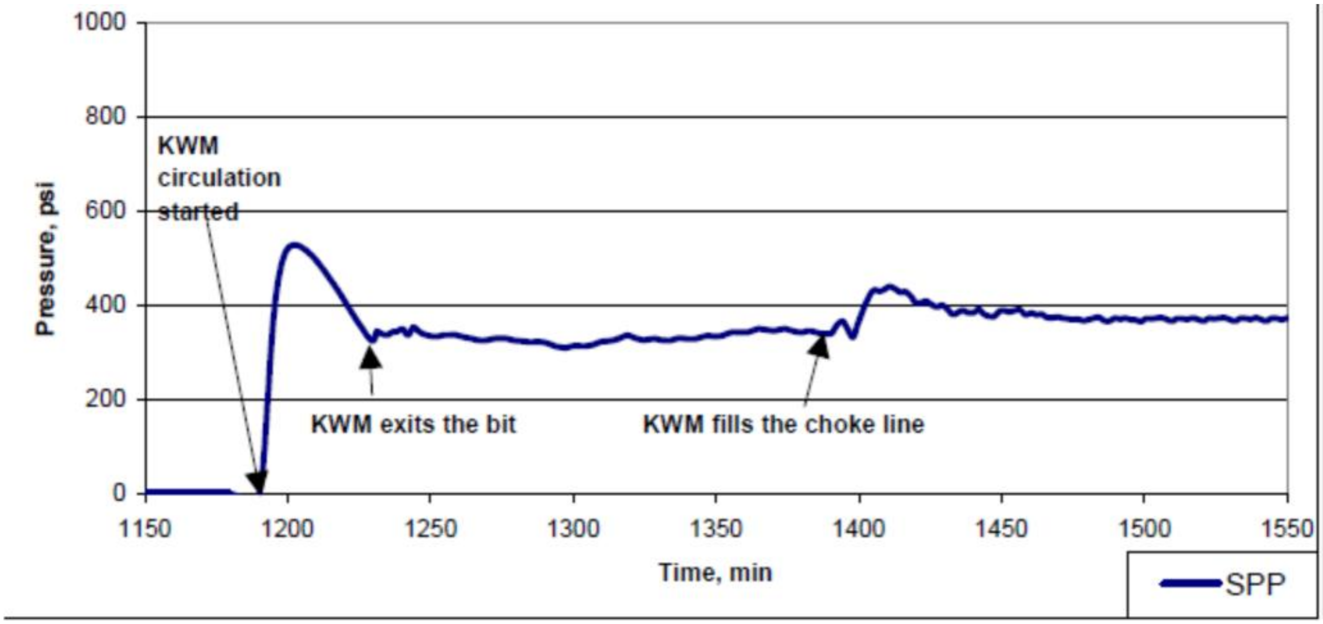


Figure 3.7.2 – SPP with KMW circulation in the dual density gas-lift system

Summarizing, BHP was maintained above the formation pressure and below the fracture pressure in a safe pressure margin to safely accomplish KWM circulation.

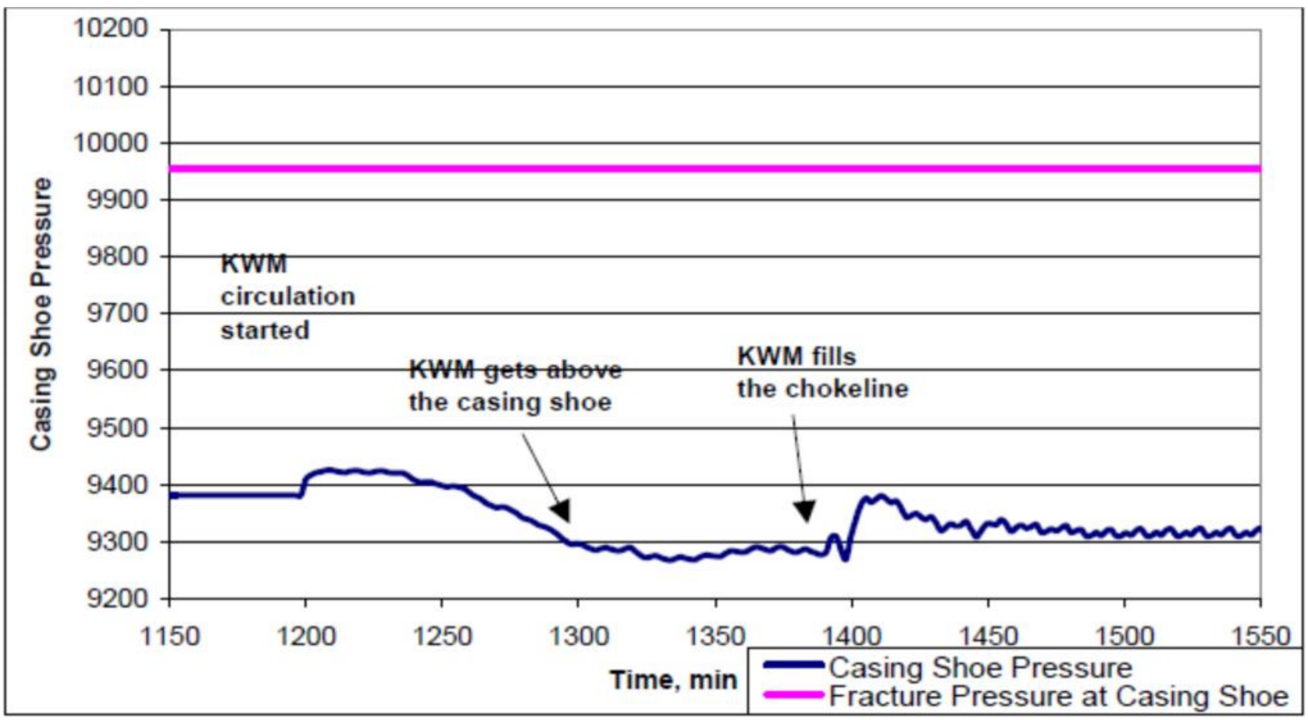


Figure 3.7.3 – Casing shoe pressure with KMW circulation in the dual density gas-lift system

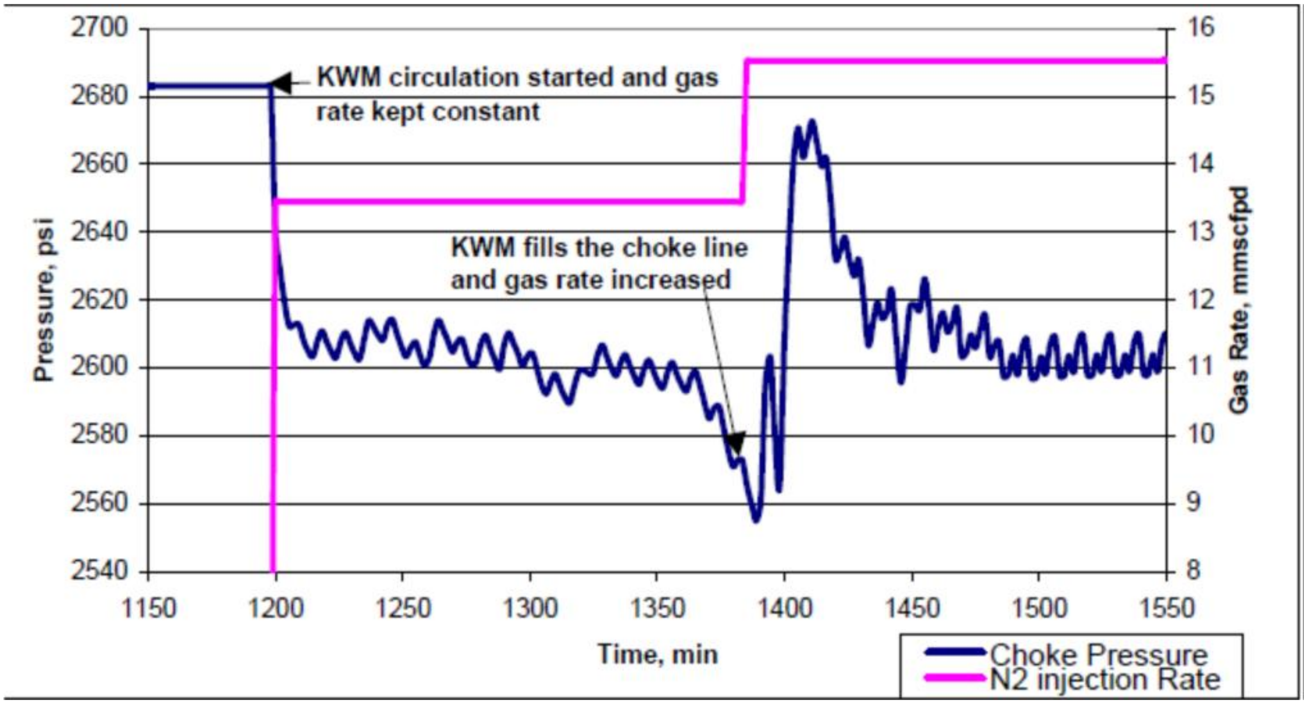


Figure 3.7.4 – Choke pressure with KMW circulation in the dual density gas-lift system

3.7.2 Kill Weight Mud Circulation in Single Density System

KWM circulation in the single density, conventional system, was conducted in order to compare the two systems. Specifically, the feasibility and complications of the gas-lift alternative were compared against the conventional case.

After removing the kick from the well in the conventional system as described in the previous unit, surface choke was closed and well was ready to start KWM circulation as for the second circulation of a driller's method kill. Necessary calculations to implement this procedure are presented below.

KWM = OMW + (SIDPP/(0.052*D))

KWM = 14.07 + (200/(0.052*(23400)) = 14.3 ppg ICP = KCP + SIDPP

= 280 psi + 200 psi = 480 psi

FCP = KCP * (KWM/OMW) = 280* (14.3/14.07) = 284 psi

Where:

D - total vertical depth, ft

ICP - initial circulating pressure, psi

KCP - pump pressure at the kill rate, psi

SIDPP - shut in drillpipe pressure, psi

FCP - final circulating pressure, psi

OMW - original mud weight, ppg

KWM - kill weight mud, ppg

The results of simulating KWM circulation using a conventional, single density system are presented in Figures 3.7.5, 3.7.6, and 3.7.7. Circulation begins at 1,400 minutes when KWM is circulated down the drillstring at the kill rate of 50 gpm. Drill pipe pressure follows the drill pipe pressure schedule from ICP of 480 psi to 284 psi. When KWM reaches the bit, standpipe pressure is maintained at a relatively constant FCP value of 284 psi using the choke adjustments. As kill mud is pumped up the annulus, an increase in the hydrostatic pressure causes the drill pipe pressure to increase. Choke adjustments are necessary to maintain FCP. Gradually, all the backpressure is removed as the kill mud is circulated up the annulus and choke line. When KWM starts to fill the choke line, the drill pipe and bottom hole pressures increase due to higher frictional pressure losses and higher hydrostatic head of the kill mud column in spite of removing the backpressure with the choke at surface.

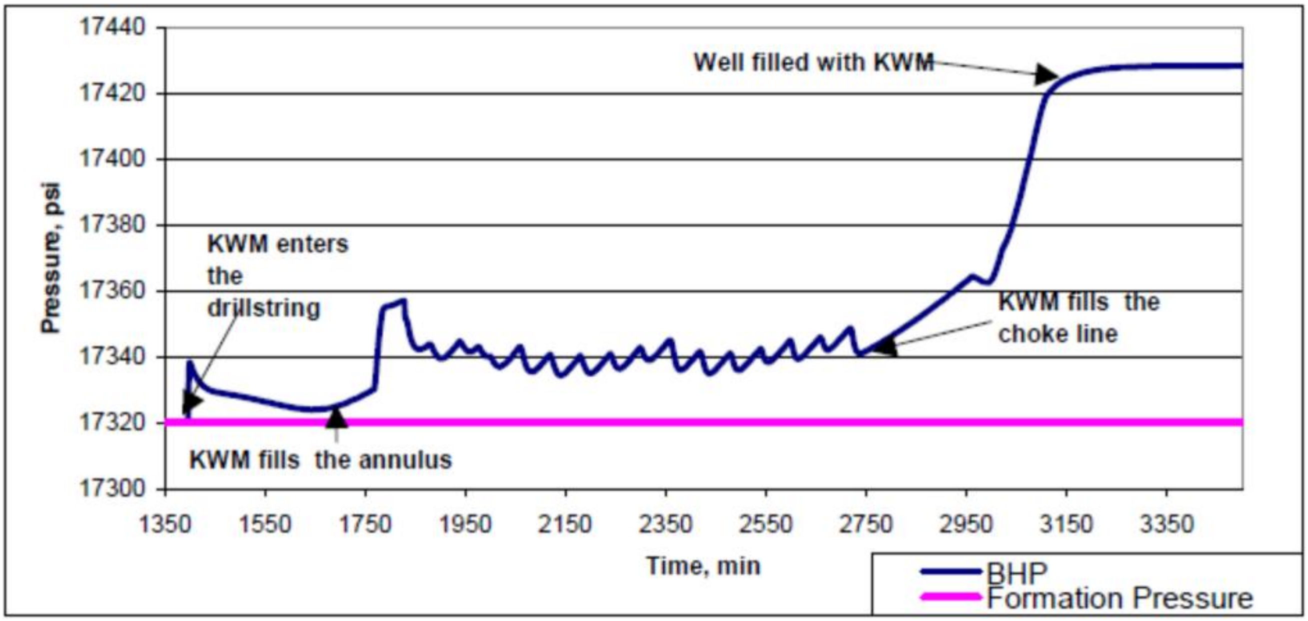


Figure 3.7.5 – BHP with KMW circulation in the single density system

The high choke line pressure losses and very low margins between pore and fracture pressure make it extremely difficult to avoid formation fracturing and lost returns at the casing shoe as may be seen in Figure 3.7.7. This was the main constraint to use very low kill rate of 50 gpm. As it may be seen from Figure 3.7.5, bottom hole pressure was kept above the formation pressure during KWM circulation. However, concerns with fracturing at the casing shoe were not avoided, and casing shoe pressure exceeded the expected fracture pressure at the casing shoe as may be seen in Figure 3.7.7.

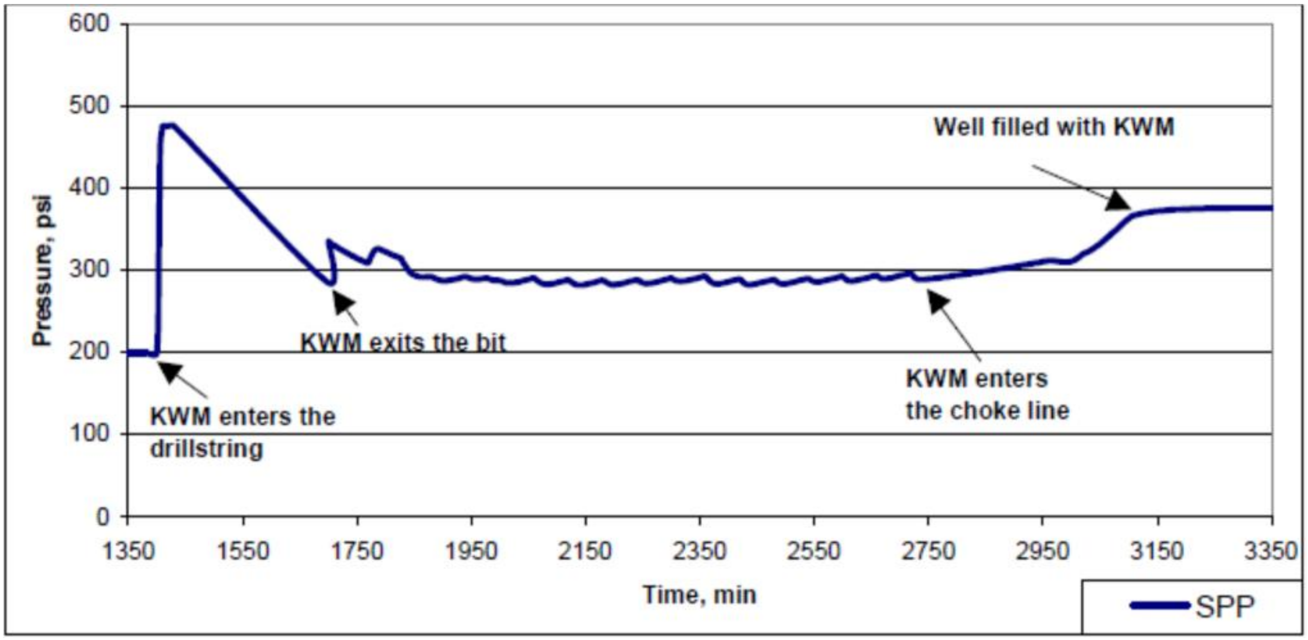


Figure 3.7.6 – SPP with KMW circulation in the single density system

When KWM was at the casing shoe depth, this pressure was lower than fracturing pressure. However, when KWM started to fill the small diameter choke line, casing shoe pressure again was higher than fracture pressure due to high choke line frictional pressure loss. Consequently, this kick, which could be safely controlled with a dual density system would be almost impossible to control without lost returns and reliance on special procedures if a conventional well were being drilled.

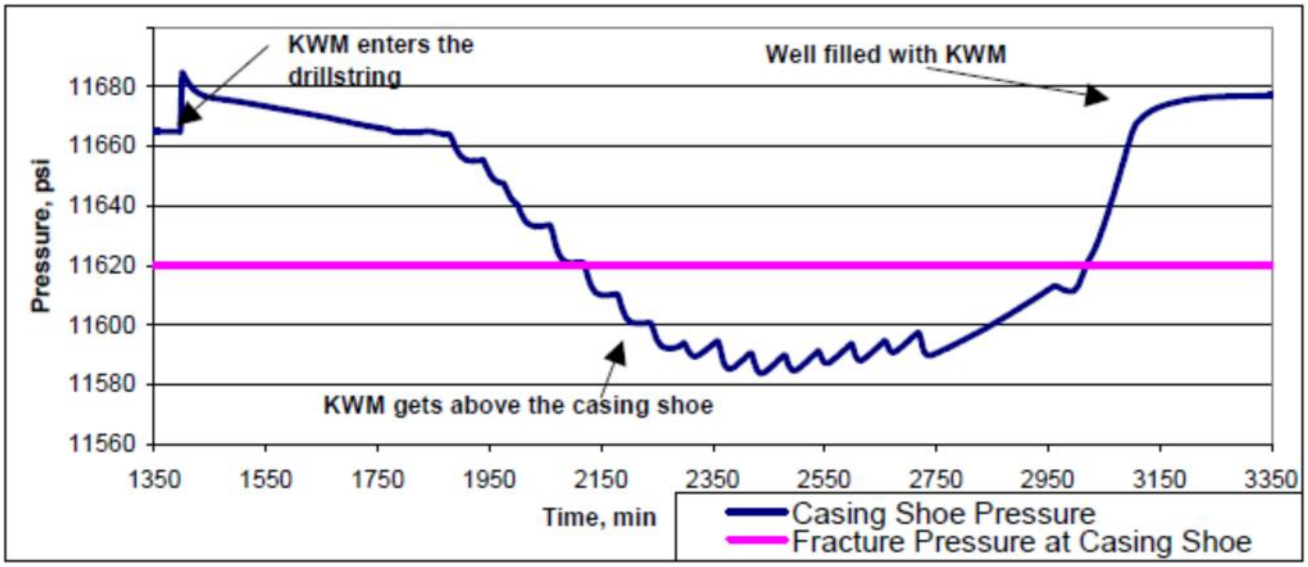


Figure 3.7.7 – Casing shoe pressure with KMW circulation in the single density system

3.7.3 Discussion and Observations

It was concluded that dual density, gas-lift system was more effective for circulating the KWM without a risk of lost returns that were experienced in a similar, single density system. In the dual density, gas-lift system with the subsea choke, KWM was circulated within a safe bottom hole pressure margin and without significant risk of fracturing. Risk of fracturing in the single density system makes it a less-safe well control procedure for these deep water wells with very narrow pore and fracture pressure “windows” as concluded in the previous unit. Nevertheless, KWM circulation in the single density system was conducted as a means to compare the dual density gas-lift system complications and overall system feasibility versus the conventional circulation. In the gas-lift system, the excessive frictional pressure losses in the small diameter choke line and fracturing at the casing shoe were avoided by use of nitrogen injection. The next relevant complication that exists in the gas-lift case is maintaining the constant seafloor pressure during KWM circulation. This concern is especially relevant when the KWM mud enters the choke line and hydrostatic pressure increases. As a solution, the nitrogen injection rate to the choke line was increased to adjust for the higher mud density. In spite of the initial pressure variations, seafloor pressure was maintained relatively constant when KWM was circulated up the choke line.

In a dual density gas-lift system, the frictional pressure losses and nozzle pressure losses at the kill rate must exceed the difference in pressure between the mud and seawater filling the drillstring from the seafloor to the rig as necessary to avoid mud free fall and having no standpipe pressure. This requires kill rates that are typically higher than used in conventional drilling. However, it doesn’t cause the additional excessive choke line friction pressure losses as nitrogen injection into the choke line maintains the seafloor pressure essentially constant and equal to the seawater hydrostatic pressure.

Furthermore, subsea choke advantages over the surface choke are again relevant in this method and were described more fully in the previous chapter.

Summarizing, dual density KWM circulation allowed for safe control of the well and reduced concerns associated with the frictional pressure losses and lost returns when compared to conventional case.

CHAPTER 4

RESULTS AND DISCUSSION

4.1Summary

Deepwater well control is extremely important, and additional complications exist when compared to the shallow water and onshore well control procedures. Dual density gas-lift well control is even more complicated due to its complex system containing different density fluids and different flow paths.

Alternative well control methods for dual density deep water drilling were identified and described. These methods were evaluated, interpreted, and compared to conventional well control for a single density system as a means to analyze the gas-lift system feasibility and reliability. These evaluations were based on simulations of well control operations using a multiphase, numerical simulator. A representative deep water Gulf of Mexico well description was used to define simulation parameters.

The simulations of alternative well control approaches were studied as a means to determine the most effective well control alternative for a riser gas-lift system containing so many different density fluids and different flow paths. Four critical phases of a well control operation were addressed: kick detection, stoppage of formation inflow, circulation to remove kick fluids, and kill weight mud circulation. Each phase of the well control process was analyzed separately. Gas and water kicks in a riser gas-lift system were considered with returns

1) up a gas-lifted choke line through a surface choke,

2) through a subsea choke and up a gas-lifted choke line, and

3) through a subsea choke and up a gas-lifted riser. These were then compared with conventional, single density, well control operations.

CHAPTER 5

CONCLUSIONS

5.1Conclusions

1. Kick detection for a riser gas-lift, dual density system is essentially conventional. Kicks should be possible to detect in a timely fashion relying on changes in the return flowrate and pit gain. However, a flow-check to verify that a kick is in progress is not possible.

2. There is a possibility that small kicks may be controlled only by changing the nitrogen injection rate. However, this procedure would be more complicated and would lead to significantly increased risk of a blowout in the case of a kick from a high productivity formation. Thus, the kick influx should be shut-in with the subsea blow out preventers, BOP, as shutting down the riser nitrogen injection without shutting in the BOP is too slow and has uncertain results.

3. Kick circulation may be accomplished with returns through the gas-lifted choke line. Risk of high friction and hydrostatic pressures in the choke line is avoided by nitrogen injection that lowers the pressure to the desired value even for relatively high mud flowrates. Subsea choke application has an advantage over a surface choke with faster pressure responsiveness, smaller pressure variations, and fewer and smaller choke adjustments needed. Choke adjustments were applied to keep the bottom hole pressure relatively constant without requiring any variation in the nitrogen injection rate, which should simplify implementation in the field.

4. Kick circulation with returns through the gas-lifted riser is feasible. Concerns with the long, small diameter choke line are eliminated with this method. Nevertheless, the risk of riser collapse is a significant concern and is dependent on the kick volume taken. In the case of an 18.5 bbl gas kick, no danger of riser collapse exists, as pressure is still safely above the riser collapse pressure.

5. Circulation of kill weight mud with returns through the gas-lifted choke line with the subsea choke can be safely implemented. Bottom hole pressure was maintained within safe pressure margins and lost returns were avoided in simulated operations. Problems associated with pressure variations due to new kill mud entering the choke line were addressed by a single, simple increase in the gas injection flow rate that maintained seafloor pressure relatively constant near the seawater hydrostatic pressure.

6. Well control with a gas-lift, dual density method is advantageous versus a conventional single density method for controlling kicks due to the more favorable pressure distribution in the open hole. Therefore, higher kick volumes may be taken with less risk of fracturing and lost returns. Furthermore, the high frictional pressure losses in the choke line requiring very slow circulating rates and the higher pressure variations due to choke line hydrostatics experienced in the single density system make the gas-lift, dual density system more favorable.

   Finally, the data and results presented show that well control procedures for dual density drilling are feasible and give a positive answer to the question of whether an effective well control method can be defined for a system containing so many different density fluids and different flow paths. Nevertheless, more work is necessary.

5.2Recommendations

1. The conclusions regarding well control operations with a riser gas-lift, dual density system presented in this report are favorable, and more comprehensive future research is justified. As well control is considered to be the biggest hurdle for dual density system implementation, the overall project application seems feasible and likewise warrants further research

2. Additional kick circulation simulations through the gas-lifted choke line with 1) subsea and 2) surface chokes would improve simulator operator skill and allow a more rigorous comparison to show which of these two methods is more effective.

3. More dedicated work is needed with the higher kick volumes in the kick circulation alternative with the returns through the gas-lifted riser with the subsea choke in order to analyze more fully the problem of

riser collapse.

4. Kick simulations should be performed for a much higher PI, representative of a commercial, high productivity, deep water gas reservoir. Representative reservoir parameters are 1000 md permeability and 100 feet of thickness.

5. Kick detection and control methods during connections and trips must also be considered. Possibilities include monitoring wellhead pressure with a partial column of mud in the riser as a proxy for filling the hole when measuring volumes required to replace drill string displacement while tripping out and using riser or choke line gas-lift to maintain proper wellhead pressure. These should be compared to the method described by Maus using auxiliary subsea pumps.

6. Consideration of the field feasibility and practicality of dual density well control should continue. Specifically, detailed well control procedures for dual density drilling should be prepared to support practical implementation in the field. The best confirmation for well control methods described in this report would be full-scale well tests or field tests to evaluate and confirm their feasibility and applicability.
7. After successfully defining and testing well control procedures for a dual density system, the complete drilling process and system must be defined. Drilling operations include mud change-overs, leak-off tests, connections, trips, logging, casing runs, cementing operations, and wellhead operations. Consideration must be given to each of these, and field-applicable procedures developed. Complications, especially the U-tube effect that currently requires use of a drill string valve (DSV), should be identified and receive special emphasis. The potential application of a zero net liquid holdup method for controlling the pressure in the riser and minimizing the risk of riser collapse during periods when mud circulation is stopped should be considered.
8. Ultimately, the costs to implement a dual density system must be estimated and compared to the savings in time and equipment versus use of conventional drilling methods to determine the economic feasibility of dual density alternatives.

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1 OPTIMIZATION OF WELL CONTROL USING SMART KICK DETECTION TECHNOLOGY FOR DUAL DENSITY DEEPWATER DRILLING A Project Report submitted by Abhinav Sharma R870212002 Vishesh Amarpuri R870212044 in partial fulfilment of the requirements for the award of the degree of BACHELOR OF TECHNOLOGY in APPLIED PETROLEUM ENGINEERING with specialization in UPSTREAM ENGINEERING Under the guidance of Mr. Mohammed Ismail Iqbal Dr.

Pushpa Sharma Assistant Professor Professor Department of Petroleum & Earth Sciences Department of Petroleum & Earth Sciences DEPARTMENT OF PETROLEUM & EARTH SCIENCES COLLEGE OF ENGINEERING STUDIES UNIVERSITY OF PETROLEUM & ENERGY STUDIES Bidholi Campus, Energy Acres, Dehradun-248007. April - 2016 ii DECLARATION BY THE SCHOLAR I hereby declare that this submission is my own and that, to the best of my knowledge and belief, it contains no material previously published or written by another person nor material which has been accepted for the award of any other Degree or Diploma of the University or other Institute of Higher learning, except where due acknowledgement has been made in the text.

Vishesh Amarpuri (R870212044) Abhinav Sharma (R870212002) iii CE R TIFIC A TE This is to certify that the thesis titled Optimization of well control using Smart Kick Detection technology for Dual Density deep water drilling submitted by Abhinav Sharma (R870212002) & Vishesh Amarpuri (R870212004) to the University of Petroleum & Energy Studies, for the award of the degree of BACHELOR OF TECHNOLOGY in Applied Petroleum Engineering is a bonafide record of project work carried out by them under our supervision and guidance.

The content of the thesis, in full or parts have not been submitted to any other Institute