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Analysis of alternative well control methods for dual density deepwater drilling

Mikolaj Stanislawek

Louisiana State University and Agricultural and Mechanical College

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ANALYSIS OF ALTERNATIVE WELL CONTROL METHODS FOR DUAL DENSITY DEEPWATER DRILLING

A Thesis

Submitted to the Graduate Faculty of the
Louisiana State University and
Agricultural and Mechanical College
in partial fulfillment of the
Requirements for the degree of
Master of Science in Petroleum Engineering

in

The Department of Petroleum Engineering

by

Mikolaj Stanislawek

B.S., M.S., University of Mining and Metallurgy in Krakow, 2002

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I dedicate this work to the Forgotten Heroes of World War II, Polish Pilots from Squadrons 303, 302 and any others from The Royal Air Force during the Battle of Britain in 1940.

TABLE OF CONTENTS

ACKNOWLEDGMENTS	ii
LIST OF TABLES	vi
LIST OF FIGURES	vii
ABSTRACT	ix
1. INTRODUCTION	1
1.1. Deepwater Drilling Challenges.....	1
1.2. Dual Density Drilling Concept	1
1.3. General Project Description.....	2
1.4. Overview of Report.....	3
2. LITERATURE REVIEW	5
2.1. Dual Density Drilling Systems	5
2.1.1. Subsea Mudlift Drilling.....	5
2.1.2. Deep Vision Project	6
2.1.3. Riser Gas Lift.....	7
2.1.4. Riser Dilution	7
2.1.5. Hollow Sphere Dual Gradient System	8
2.1.6. Riserless Systems with Returns to the Seafloor.....	8
2.2. Underbalanced Drilling.....	8
2.3. Well Control.....	9
2.3.1. Conventional Deepwater Methods.....	9
2.3.2. Dual Gradient Methods	10
2.3.2.1. Mudlift Pumps.....	10
2.3.2.2. Riser Gas-Lift.....	11
2.3.3. Other Well Control References.....	12
3. RESEARCH METHOD.....	14
3.1. Introduction.....	14
3.2. Specific Well Control Concerns.....	14
3.3. Addressing Concerns with Simulation.....	15
3.3.1. Transient Multiphase Simulator.....	16
3.3.1.1. General Description	16
3.3.1.2. Industry Applications.....	17
3.3.1.3. Additional Simulator Evaluation.....	18
3.3.2. Simulation Method.....	20
4. POSSIBLE ALTERNATIVE WELL CONTROL METHODS	23
4.1. Introduction.....	23
4.2. Comparison of Alternative Well Control Concepts.....	23
4.2.1. Well Control Concerns in Dual Density Drilling.....	23
4.2.2. Selection of the Alternative Well Control Methods.....	26
4.3. Discussion and Observations	28
5. RISER GAS-LIFT FEASIBILITY	30
5.1. Feasibility of Seawater Pressure at the Mudline for the Gas-Lift.....	30
5.1.1. Gas-Lifted Riser.....	30

5.1.2. Gas-Lifted Choke Line.....	31
5.2. Riser Multiphase Analysis	32
5.2.1. Mud and Nitrogen Injection Stopped.....	33
5.2.2. Mud Circulation Stopped with Continued Nitrogen Injection.....	34
5.3. Discussion and Observations	36
6. KICK DETECTION	38
6.1. Simulation Results	38
6.1.1. Gas Kicks	38
6.1.2. Water Kicks.....	41
6.2. Discussion and Observations	42
7. STOPPING FORMATION INFLOW	43
7.1. Dual Density Drilling Simulation Results	43
7.1.1. Decreasing Injection Gas Rate	43
7.1.1.1. Gas Kicks	43
7.1.1.2. Water Kicks.....	45
7.1.2. Shutting in with Subsea BOP	46
7.1.2.1. Gas Kicks	46
7.1.2.2. Water Kicks.....	48
7.2. Single Density Drilling Simulation Results.....	49
7.2.1. Shutting in with Subsea BOP	49
7.3. Discussion and Observations	51
8. KICK CIRCULATION.....	53
8.1. Dual Density Kick Circulation.....	53
8.1.1. Circulation through a Gas-lifted Choke Line and a Surface Choke.....	53
8.1.1.1. Gas Kick	53
8.1.2. Circulation through a Gas-lifted Choke Line with the Choke at the Seafloor...	56
8.1.2.1. Gas Kick.....	56
8.1.2.2. Water Kick	58
8.1.3. Circulation through a Gas-lifted Riser with the Choke at the Seafloor.....	59
8.1.3.1. Gas Kick.....	59
8.2. Single Density Kick Circulation	61
8.2.1. Gas Kick.....	61
8.3. Discussion and Observations	63
9. KILL WEIGHT MUD CIRCULATION	65
9.1. Dual Density System.....	65
9.1.1. Circulation through the Gas-lifted Choke Line and a Subsea Choke	65
9.2. Kill Weight Mud Circulation in Single Density System	69
9.3. Discussion and Observations	72
10. SUMMARY, CONCLUSIONS, AND RECOMMENDATIONS.....	73
10.1. Summary	73
10.2. Conclusions.....	73
10.3. Recommendations.....	75
REFERENCES	77

APPENDIX	
SIMULATOR EXAMPLE INPUT FILE	83
VITA.....	87

LIST OF TABLES

3.1. Full-scale field experiment data.....	19
3.2. Input data for all well control simulations	22
6.1. Different gas kicks detection parameters magnitude	40

LIST OF FIGURES

3.1 OLGA testing with full-scale experimental data	20
5.1 Riser bottom pressure with various rates of mud and nitrogen	31
5.2 Choke line bottom pressure with various rates of mud and nitrogen	32
5.3. Liquid holdup distribution for 10,000 ft riser in dual density drilling.....	33
5.4. Riser bottom pressure and riser holdups at various depths.....	34
5.5. Riser bottom pressure and riser holdups at various depths.....	35
5.6. Riser return liquid flowrate and riser bottom pressure	36
6.1. Drillpipe pressure and flowrate out as gas kick indicators	39
6.2. Pit gain as a gas kick indicator.....	39
6.3. Gas kick with no action undertaken.....	40
6.4. Water kick indications	41
6.5. Early water kick indications.....	41
7.1. Pressures and bottomhole holdup with N2 injection stopped after 1 minute	44
7.2. Pressures and bottom hole holdup with N2 injection stopped after 4 minutes.....	45
7.3. BHP with formation flowrate with N2 stopped 4 minutes after a water kick.....	46
7.4. BHP and liquid holdup with BOP closed 5 minutes after a gas kick	47
7.5. BHP and formation flow with BOP closed on a water kick after 5 minutes	48
7.6. Pit gain and surface flowrate as kick indicators.....	50
7.7. Well pressures and liquid holdup with BOP closed 5 minutes after a gas kick.....	50
8.1. Bottomhole pressure with gas kick circulation	55
8.2. Casing shoe pressure versus liquid holdup when circulating the gas kick	55
8.3. Standpipe and wellhead pressure when circulating the gas kick	56
8.4. Gas kick circulation through the gas-lifted choke line with the subsea choke	57
8.5. Casing shoe pressure when gas kick circulated with the subsea choke.....	57
8.6. Gas kick circulation through the gas-lifted choke line with the subsea choke	59
8.7. Gas kick circulation through the gas-lifted riser with the subsea choke.....	60
8.8. Riser behavior when gas kick circulated through the gas-lifted riser	60
8.9. Gas kick circulation in the single density system	62
8.10. Casing shoe pressure and liquid holdup during gas kick circulation.....	62
8.11. Choke line pressure and liquid holdup during gas kick circulation.....	63

9.1. BHP with KMW circulation in the dual density gas-lift system	67
9.2. SPP with KMW circulation in the dual density gas-lift system.....	68
9.3. Casing shoe pressure with KMW circulation in the dual density gas-lift system	68
9.4. Choke pressure with KMW circulation in the dual density gas-lift system	69
9.5. BHP with KMW circulation in the single density system.....	70
9.6. SPP with KMW circulation in the single density system	71
9.7. Casing shoe pressure with KMW circulation in the single density system	71

ABSTRACT

The recent push into deepwater is currently limited by high drilling costs resulting from conventional well designs. As a result, dual gradient drilling methods have been proposed. This research investigates riser gas-lift as a potential means to implement a dual gradient system. A primary concern is well control in a system containing so many different density fluids and different flow paths.

The specific concerns addressed in this study were kick detection, cessation of formation feed-in, removal of kick fluids, and re-establishing hydrostatic control with a constant bottom hole pressure method. These concerns were studied using a transient, multiphase simulator whose validity was confirmed with comparison to transient, multiphase flow tests in a test well.

Conventional kick detection methods relying on the pit gain and return flow rate were concluded to be effective. Two alternatives for stopping formation flow were considered, a “load-up” method of reducing the nitrogen rate versus closing a subsea BOP. BOP closure was shown to be more reliable for stopping flow and minimizing kick volume. Further, a relatively conventional approach of circulating up a gas-lifted choke line against a surface choke was compared to a dynamic approach based on reducing the nitrogen rate and to the use of a seafloor choke. It was concluded that methods using a choke were much simpler and more effective for controlling pressure than controlling the nitrogen rate. The subsea choke has an advantage over the surface choke due to faster pressure responsiveness, smaller pressure variation, and needing fewer and smaller choke adjustments.

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 deepwater 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 deepwater wells while retaining a useable borehole size is often difficult. Ultra deepwater 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 deepwater 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^{1,2,3,4,6,7,9,10,11,12} 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^{9,10,11} is being investigated in this study 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, gas-lift system^{9,10,11} and is intended to utilize more standard equipment than the separate industry projects called dual gradient systems^{1,2,3,4,6,7,9,12} 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”¹¹. 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 addresses the three major well control concerns: kick detection, stopping inflow, and kick removal. These are presented and analyzed in a sequential order. The results presented for each question are based on simulations with the OLGA 2000^{23,24,25,26,27} transient multiphase simulator. Smith²¹, Lopes¹⁰, Maus²⁹, and Herrmann⁹ discussed some aspects of well control with a riser gas-lift system. In addition, a

number of well control studies have been done for a dual gradient system based on use of a mudlift pump, including those by Choe^{16,17,18} and Schubert^{17,18}. However, no tests, simulations, or comprehensive study have been conducted for well control using a riser gas-lift system. Therefore, the simulations described herein are the first serious study of well control for a riser gas-lift system.

1.4 Overview of Report

As mentioned before, this project was intended 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.

Chapter 1 describes deepwater drilling challenges and gives the general overview of this research.

Chapter 2 reviews the existing technical literature information concerning dual gradient drilling systems and the related technologies necessary to implement the dual density systems being studied. Published information on well control in dual density and conventional deepwater systems is highlighted.

Chapter 3 describes the research method that was used in this study. Evaluation criteria for the specific well control concerns are explained. Furthermore, a specific approach of addressing these well control concerns with simulation is presented.

Chapter 4 considers several well control methods that may be attempted for controlling a kick while drilling with the gas-lift system. These selected methods are qualitatively evaluated for each phase of well control considering possible hazards and limitations. The specific complications that are likely to occur in dual density drilling are described. Also, methods that were initially proposed and rejected from further investigation in this study are presented with explanations.

Chapter 5 describes work to assess the overall feasibility of a riser gas-lift system. Specifically, the major question addressed is whether the pressure at the base of the riser may be lowered to the seawater hydrostatic pressure by gas injection for different mud flowrates and mud densities. Furthermore, the riser collapse issue is considered. Also, the applicability of the multiphase simulator used in this study is assessed by comparison to field tests.

Chapter 6 addresses kick detection. Description of the simulation cases and data is included. Results of these simulations were used to define reliable kick indicators for the gas and water kicks.

Chapter 7 proposes the solution for stopping the formation influx and controlling the well. Two primary alternatives for stopping formation flow with a dual density gas-lift system are considered. The first is cessation of 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.

Chapter 8 describes and analyzes several alternative procedures to circulate a kick out of the well with a dual density gas-lift system. These are namely circulation through 1) a gas-lifted choke line with a surface choke, 2) a gas-lifted choke line with a subsea choke, and 3) a gas-lifted riser with a subsea choke. Each is simulated and analyzed separately in order to define which procedure is the most feasible and safe to accomplish. Furthermore, conventional kick circulation in a single density system is compared versus the dual density system.

Chapter 9 analyzes the procedure of killing the well. Kill weight mud is pumped to fill the well after circulating the kick as described in Chapter 8. Kill procedures are presented for both the dual density and a single density system. Complications and differences between these two methods are highlighted. Circulating the kill weight mud through the gas-lifted choke line with the subsea choke was chosen to represent the best method for a dual density system as concluded in Chapter 8. Possible complications of maintaining the seawater hydrostatic pressure with gas injection when kill weight mud fills the choke line are addressed. Complications and differences between these two methods are explained.

Chapter 10 summarizes this study with the overall conclusions and recommendations for future research.

2. LITERATURE REVIEW

A literature search was undertaken to identify and review published information regarding dual gradient drilling systems and the related technologies necessary to implement the dual density systems being studied. Accordingly, the goal was to find and review information on the Subsea Mudlift Drilling^{1,2,3,6,8,9} concept researched by the joint industry project led by Conoco and Hydril, the Deepvision^{7,8} concept that would also use seafloor pumps researched by Baker-Hughes and Transocean, the concept of using hollow glass beads¹² to reduce the density of riser fluids researched by Maurer Technology, the riser gas lift^{10,11} concept proposed by LSU and Petrobras, reduction of the riser fluid density by liquid dilution, and of riserless drilling^{4,13,16} with returns to the seafloor. A well control literature search was conducted separately, along with an underbalanced drilling, drilling fluids, and other topics that could potentially be helpful in determining the practicality of the dual density drilling systems. An overall summary of the findings is included in the following section, and a summary of each reference is given in the separate annotated bibliography report²² for the research sponsor.

2.1 Dual Density Drilling Systems

2.1.1 Subsea Mudlift Drilling

Gault⁴ introduced the the subsea mudlift drilling (SMD) method for the first time and it was originally referred to as “riserless” 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 mudlift 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^{1,2,3,6,8,9} to investigate and develop a subsea mudlift drilling system has been reported in multiple conference papers and journal articles. The specific subject relating to the mudlift technology that is of most interest for this specific study is a well control consideration.

The special requirements for successful well control operations with the mudlift 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. A concept of the SMD Joint Industry Project (JIP) is presented by Smith³¹ in a very comprehensive and overall description including its history, organization and management. Equipment overview and engineering of this system is presented along with the discussion on drilling and well control procedures for this dual gradient drilling. Finally, the system design, fabrication, and planned field testing by the JIP are described.

The subsea mudlift 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. The engineering planning and preparations for these trials were described in detail by Eggemeyer², Furlow³³, Kennedy³⁴, Schumacher⁶, and Witt³². These references provide significant detail in describing the prototype system, its component equipment, its installation on the rig, and the planned testing protocol. Hariharan³⁶ described three aspects of this test. The first was testing of the continuous dual-gradient drilling operations in the field. Then detailed descriptions of the mud lift pumps ability to control system pressure, the testing of the solids processing unit, tripping operations, application of the increased pressure margin by subsea pumps, and casing running and cementing operations were given. Finally, the operational and running procedures for the subsea mud pumps were provided. After testing, it was concluded that SMD pumps could be integrated with a rig and that a real well could be drilled with a dual gradient system.

2.1.2 Deep Vision Project

Little has been published about the Deep Vision project. The primary references for this concept are Fontana⁷ and Forrest⁸. 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

The most comprehensive description and analysis of riser gas lift as a means of achieving a dual gradient drilling system was provided in a Ph.D. dissertation by Lopes¹¹. He presents the results of a feasibility study on the use of 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.

A mathematical model of the gas and mud flow in the riser is described. It was verified through tests conducted in a 6,000 foot research well. These tests also provide a useful basis for verifying the applicability of multi-phase flow models, such as OLGA 2000TM, to be used in this research. Once verified, a Lopes' model was 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. The dissertation also discusses the operational changes that would be required for various drilling procedures such as making a connection, running casing, kick detection, and well control operations. Finally, the economic feasibility of these systems was assessed, and it was concluded that overall well cost reductions of ten percent or more could be achieved versus conventional drilling methods.

Herrmann⁹ also describes a riser gas lift approach to dual density drilling. His proposal is that a smaller, high pressure, concentric riser be used to reduce the gas volumes required.

2.1.4 Riser Dilution

There is little information published on riser dilution with liquids to achieve a dual density system. Riser dilution method was described and patented by De Boer³⁹. A 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. An additional patent application, de Boer⁴¹, and a presentation to a Drilling Engineering Association meeting, de Boer⁴⁰, continue to describe this concept being developed by Dual Gradient Services.

2.1.5 Hollow Sphere Dual Gradient System

Maurer Technology¹² describes 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. These alternatives were investigated in Phase I of a joint industry project. The results of the project are confidential to the project participants. The status of a proposed Phase II is unknown.

2.1.6 Riserless Systems with Returns to the Seafloor

In the upper hole intervals of deepwater 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. This kind of operation and the use of a dynamic kill method to regain well control if a kick is taken are described by Johnson¹³.

2.2 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 deepwater drilling. They were described by Hannegan⁴², Nakagawa^{43,44}, and Santos⁴⁵.

In order to better plan and effectively control underbalanced drilling operations, modeling of multi-phase flow has been heavily researched and developed. While much of this knowledge is potentially relevant to predicting pressures in the riser during drilling with riser gas lift or in the choke line during well control, Perez-Tellez⁴⁶, Lage⁴⁷, and Fjelde⁴⁸ were selected as particularly relevant because they include case history or experimental data that can be used to

validate the prediction methods used for riser gas lift. In addition, Perez-Tellez⁴⁶ describes a mechanistic model for steady-state flows that is available for use in this project and was shown to be more accurate than other published methods.

2.3 Well Control

2.3.1 Conventional Deepwater Methods

Conventional methods of deepwater well control are relatively well understood and are only partially relevant to dual gradient systems. Nevertheless, many of the challenges are similar, and some of the research is directly relevant. Bourgoyne⁴⁹ documents experiments performed at LSU that are the best published information on multi-phase flow with actual drilling fluids in a choke line that are available. Isambourg¹⁴ describes use of a low density liquid such as base oil or water, to reduce hydrostatic pressure in a choke line that is very similar in concept to the likely well control method for a riser dilution system. He concludes that friction losses in the choke line can be significantly reduced and risk of fracturing the formation may be subsequently minimized. The next important lesson learned is that the kill line surface pressure may be used to monitor the subsea BOP pressure instead of the BOP pressure sensor.

Hargreaves¹⁹ documents a field test of a sensitive new kick detection system for deepwater drilling that is based on the Bayesian probability. The statistical approach tackles the problem of noise in the return flowrate, and models both kick and non-kick events in order to avoid false alarms due to ambiguous data. Deepwater kick indication data were presented from the semisubmersible compared with the onshore rig data. The high heave noise does have the effect of generating a kick probability which first increases over the alarm level and then decreases. In such a noisy environment, the presence of the probability log to visually match with the flow logs increases the usability of the system, providing easy visual confirmation that there has not been a false alarm. Results from an engineering prototype of this system show that the system performs within specification in the field. Other benefits are automatic sensitivity adjustment for signal noise and thus giving sensitivity improvements over existing systems. The probability output aids the operator in decision making. The model-based approach allows events that cause false alarms to be modeled explicitly. Models can extend over any number of channels. The model set captures prior engineering and physical knowledge of the problem.

2.3.2 Dual Gradient Methods

2.3.2.1 Mudlift Pumps

Well control methods for the subsea mudlift dual gradient drilling method have been fairly well developed. Schubert¹⁷ provides a concise, but reasonably complete, description of how essentially conventional well control methods would be applied with a subsea mudlift system. Schubert describes kick detection for subsea mudlift drilling by comparing conventional and dual gradient methods. An important assumption and kick indicator for the subsea mudlift system is that subsea pumps operate on a constant inlet pressure and the increase in flow may be seen by an increase in the subsea pump rate, this value is closely monitored by system computers. An U-tube phenomenon is described along with a Drill String Valve (DSV) to arrest it. Furthermore, a “shut-in” procedure is presented where influx is stopped and circulated from the wellbore without complete shut-in. He proposed to slow the subsea pumps to the rate before the kick and allow the drillpipe pressure to stabilize. Afterwards, the drillpipe pressure and pump rate should be recorded and kept constant while circulating the kick from the wellbore. Adjusting the subsea pump inlet pressure would maintain the constant drillpipe pressure in a way similar to the conventional kill procedure with the choke. Determination of SIDPP with DSV is equal to the post-kick opening pressure with pumps at slow circulating rate minus the pre-recorded opening pressure. In the case when no DSV is used, a more complicated approach must be undertaken to determine SIDPP. Kick circulation concerns are addressed including measurement of kick circulating pressures and determining a drillpipe pressure schedule.

The previously mentioned U-tube effect, is a complication that results from the pressure in the well annulus at the wellhead being significantly less than the pressure inside the drill string at the same depth. It is caused by the dual gradient only existing in the annulus whereas the drillstring is filled with the weighted mud from surface to total depth. Therefore, the U-tube created by the drillstring and the annulus is inherently unbalanced. This unbalanced U-tube creates several complications for well control. The traditional method of using a flow check to verify whether a kick is being taken is impractical because returns will continue from the annulus until the U-tube becomes balanced due to the fall of the fluid level in the drillstring. This process is expected to be too slow to be practical or safe. The hydrostatic imbalance affects surface and downhole pressures if the well is shut-in conventionally. Therefore, a special drill string valve (DSV) has been developed to help overcome this complication. It is essentially a

back pressure valve placed in the drillstring to oppose, or support, the excess hydrostatic pressure in the drillstring. It allows the well to be shut in at the subsea BOP or the seafloor pump without the excess hydrostatic pressure in the drillstring being imposed on the annulus, which would typically cause lost returns. Once the well is shut in, an annulus pressure greater than the normal seafloor pressure is indicative of a kick being taken. Trapped pressure can be relieved by operating the mudlift pump, and if continued pumping is required to maintain a pressure equivalent to seafloor pressure then the well is confirmed to be flowing. The drill string valve prevents measurement of a shut-in drill pipe pressure, and a method roughly equivalent to “bumping the float” and then using a driller’s method pump start up is used as a basis for determining kill weight mud and proper drillpipe pressure during a kill.

Choe⁵⁰ investigates kick detection in subsea mudlift drilling with the inherent U-tube effect. He determines the transient flow rate and the corresponding mud level inside the drillpipe. A comparison of kick detection methods while circulating for subsea mudlift and conventional drilling is presented. He considers two cases as a means to detect a kick during the U-tube effect, one with the circulation rate that is higher than the maximum free fall rate, and the second one with the circulation rate below the maximum free fall rate. When circulating with the drillstring full of mud, an increase in return flow is indicative of a kick as long as surface rate is higher than the free fall rate. If the drillstring is not full of mud due to pump rate lower than the maximum free fall rate, kick indications are missing as fluid level in the drillstring is unknown and surface pressure equals zero. Summarizing, if circulation rate is higher than the maximum free fall rate, kick detection will be much more feasible compared with the circulation rate below the free fall rate.

2.3.2.2 Riser Gas-Lift

Lopes¹¹ proposed a shut-in procedure for dual density drilling. He indicates that after a kick is detected, the pumps should be stopped. The nitrogen injection should be stopped also and the BOP should be closed with the choke line open. The choke line should be kept filled with seawater, as it is the common practice. The density difference between the mud inside the drillstring and the composite column in the wellbore and choke line should lead to a “U-tube” effect. This lowers the mud level until the hydrostatic pressure in the drillstring equals the bottom hole pressure. The difficulty here is how to determine the bottom hole pressure since the liquid level inside the drill pipe is below surface, there should be no pressure reading in the

drillstring. One solution was proposed by Lopes¹¹, to read the pressure using a well sounder to determine the fluid level inside the drill pipe. This approach however, would include complications while waiting for pressures to equalize. That might inevitably lead to the underbalanced conditions in a well as indicated by Lopes. He also proposed using the bullheading procedure for kick circulation if the open hole interval is small. He briefly stated that reduction of the gas injection rate to increase bottomhole pressure and underbalanced techniques should be considered for the future well control research.

Smith²¹ proposed various well control alternatives for dual density, gas lift system. Several alternatives were described in detail including reactions to each well control stage and relevant complications were considered. Furthermore, two alternatives were proposed for their further evaluation and analysis.

Well control procedures for riser gas-lift system were also briefly outlined by Herrmann⁹. Kick detection problems were recognized as the main difficulty in this system. Hermann proposed that in order to avoid the inherent well control concerns with dual density system, only the upper part of the well should be completed using the gas-lift system and the prospective pay zone should be drilled using the conventional drilling system. This will probably decrease the chance of kicks and simplify well control as well. According to Herrmann, a drilling break and reduced pump pressure with nitrogen injection rate constant will indicate a kick in progress. The U-tube effect will take place and mud level in the riser should be measured. Again, pressure sensors should be applied to give the direct measurement of the wellhead pressure and riser mud level as well. Finally, Herrmann proposed shutting down and/or decrease the gas injection rate as an promising alternative to control a kick.

2.3.3 Other Well Control References

Bourgoyne⁵¹ describes the special considerations and practices applied in underbalanced drilling of gas wells. Many of these concepts will also apply to overbalanced operations with riser gas lift. Lloyd⁵² describes modeling and experiments on gas migration in a riser that is also relevant to riser gas lift systems. Rygg⁵³ describes the application of OLGA, a dynamic multi-phase flow simulation program, to use of a dynamic kill to control an underground blowout. This reference is potentially important because OLGA is being used as the primary means of predicting well pressures during dual density operations in this project.

Use of a subsea choke would potentially simplify well control operations with either of the dual density systems being investigated. Consequently, it was explicitly defined as a well control equipment option that would be evaluated. Matthews⁵⁴ modeled use of a subsea choke with returns up the riser as a method of eliminating the problems associated with long choke lines for conventional deepwater well control. He concluded that use of a subsea choke was feasible and that pressure in the riser could be controlled best if there was also a surface choke on the riser. However, he also concluded that operation of this system was probably too complicated to be practical. Subsequently, Cyvas⁵⁵ described the successful application of remotely controlled subsea chokes for production operations, which implies that subsea drilling chokes are at least mechanically feasible.

3. RESEARCH METHOD

3.1 Introduction

This study was conducted as a part of a research project entitled “Comparative Analysis of Dual Density Drilling Systems to Reduce Deepwater Drilling Costs” originally proposed by Smith²¹. The overall objective of the project was to establish whether more comprehensive research concerning dual density drilling systems based on the use of low density fluids, either liquid or gas, is justified. The project was intended to continue the research initiated by LSU and Petrobras, and described by Lopes¹¹ and Lopes and Bourgoyne¹⁰, on the riser gas-lift method and to begin assessing injection of unweighted liquid into the riser as another alternative. These methods are intended to offer alternative methods of achieving a dual gradient deepwater drilling system that utilizes more standard equipment than the separate industry projects focused on the use of seafloor or mudlift pumps^{1,2,6,8,9} 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.

3.2 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. These concerns were accommodated in this research.

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, and 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 bottomhole 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.

3.3 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. A detailed description of each well control stage simulation is included in chapters 6,7,8 and 9.

3.3.1 Transient Multiphase Simulator

A transient, multiphase simulator – OLGA 2000TM, 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 deepwater well data were used in simulations to obtain and analyze the results for each case.

3.3.1.1 General Description

OLGA 2000TM 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”²³. “This requires prior knowledge of specific conditions that will be changed and the duration of each change”²³.

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”²⁷. “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”²⁷. “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”²⁷.

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”²⁷. “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”²⁷. An actual input file used for this dual density study is included as Appendix I.

3.3.1.2 Industry Applications

OLGA 2000TM is to be used as the primary means of predicting well pressures during dual density operations in this project. Therefore, literature references regarding this program and its industry applications are pertinent to this project.

Burke²⁴ presents comparisons between field data from a North Sea oil flowline and predictions made by the OLGA model. The significance of the oil’s phase behavior, fluid properties, and heat transfer on the simulation performance is highlighted. Field data compared with the OLGA model results included mass flow rate, platform temperature and pressure, and wellhead temperature and pressure data. Burke concludes the good match between the results predicted by OLGA and the transient field data that again proves that OLGA is a very exact tool for transient, multiphase simulations.

A study of gas slugging phenomena in production wells offshore Africa was conducted with OLGA by Noonan²⁵. The conditions are similar to riser gas-lift as liquid and gas phases are present in both systems and similar problems are involved. Specifically, OLGA was used to determine the approximate size and frequency of the gas bubbles and liquid slugs. Field results from nine wells matched very well with the OLGA

simulator, and means to minimize the slugging for the next field developments were indicated by the program.

A very complicated study of the East Java Gas Pipe Line consisting of about 420 km were conducted with OLGA and described by Putra²⁶. Simulations were used as a means to evaluate the pipeline hydrodynamic performance including liquid condensation in pipe, change of gas properties during the process of flow, pigging and other dynamic scenarios. Pipeline data were collected to validate the OLGA simulation results. What is most interesting is that the simulation again matches the operational data increasing the confidence on the simulation results with OLGA.

Simulation of underbalanced conditions to predict the multiphase wellbore pressure was performed using OLGA, and its interactive interface engine, UbitTS. This is the published application that is most similar to riser gas-lift and was described by Mykytiw²³. The main concern was to minimize the variations in bottomhole pressure. The same concern of pressure instability and slugging that is valid for the dual density system is described in detail. Generally, establishing and maintaining the proper gas to liquid ratio is fundamental to minimize slugging and subsequent pressure variations. The required gas injection rate to reach steady state conditions and to be within the desired operational range must be determined. Mykytiw determines the required gas injection rate with OLGA to reach these conditions for the underbalanced drilling. He also proposes to use the surface choke to decrease the well pressure variations that is mainly dependent on the operator's ability to manipulate the choke appropriately. "However, it is not possible to use this choking approach to minimize slugging due to its complexity and uncertainty of slugging predictions and it should be applied as a last resort to manage well slugging"²³.

3.3.1.3 Additional Simulator Evaluation

Results of an additional full-scale well experiment were used to evaluate the validity of the OLGA program before conducting well control simulations for the dual density, gas-lift system. This evaluation was conducted using the full-scale experimental data obtained by Lopes¹¹ from an experiment performed at LSU as summarized in Table 3.1. A 6,000-foot well filled with drilling fluid of 9.37 ppg density was used. The experiment consisted of injecting nitrogen through a gas injection line and mud through a

separate drilling fluid injection line into the well. The well therefore had the liquid filled annulus unloaded until reaching a nearly steady-state, two-phase flow condition. This experiment was conducted specifically to simulate unloading a riser to initiate riser gas lift. Annular pressure during the unsteady state system behavior was measured at a depth of 5,800 ft from the beginning of the experiment, using pressure sensors lowered through a perforated tubing in the annulus. Figure 3.1 presents the comparison between the measured pressures and the simulator results. It may be seen that the OLGA simulation is very satisfactory, with a maximum error of about 2.5 % that is equal to 70 psi pressure during very rapidly changing conditions. Therefore, the unsteady-state field experiment results were predicted with very reasonable accuracy by the OLGA simulator. The quality of this match for a transient condition provides confidence that OLGA will provide relevant predictions for the transient well control scenarios of interest in this project. It is especially relevant that the full-scale experiment was conducted in a relatively large 9.625 inch by 3.5 inch annulus rather than in a tubing or a pipeline because the conditions of most interest in this study are generally in the well annulus or the riser annulus.

Table 3.1 - Full-scale field experiment data

Casing ID	8.287 in	Gas Rate	1,120 scf/min
Total Depth	5,800 ft	Choke Pressure	141 psi
Gas injection Line ID	1.25 in	Bottom Temperature	112 F
Drilling Fluid Line OD	3.5 in	Mud Density	9.37 ppg
Mud Rate	152 gpm	Plastic Viscosity	6 cp

Figure 3.1 OLGA testing with full-scale experimental data

3.3.2 Simulation Method

The cases simulated in this study for all alternative well control methods and stages represent a very deepwater well in 6,000 feet of water. They were based on real Gulf of Mexico deepwater 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. The well description and conditions were revised to be more complete and more realistic.

A special item of equipment required for most dual gradient drilling methods is a drill string valve or DSV (also described in chapter 4). 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 and was described by Schubert¹⁷. 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 “setpoint” pressure required to force the valve open”². “When circulation stops, the DSV closes, arresting the U-tube and maintaining a full column of mud inside the drillstring”². Use of a DSV was assumed in all of the simulations conducted for this study.

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 3.2. Dual density gas-lift case data are maintained the same beginning with the chapter on kick detection in order to use constant input data through all of the well control scenarios and therefore obtain the best results in terms of their comparison and representative evaluation. 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.

An original simulator example input file for the conditions described in Table 3.2 during a kill weight mud circulation in a dual density, gas-lift system is included in Appendix.

Table 3.2 - 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

4. POSSIBLE ALTERNATIVE WELL CONTROL METHODS

4.1 Introduction

The objective of this research 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 chapter 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. The methods proposed for further investigation from this section are evaluated and analyzed in more detail using a multiphase, transient simulator in the following chapters of this study.

4.2 Comparison of Alternative Well Control Concepts

4.2.1 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 4.1.

$$H_{\max} = D_w * (\rho_m - \rho_{sw}) / \rho_m \quad (4.1)$$

$H_{\max}$ – 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 4.2.

$$P_{\text{circ}} > (\rho_m * 0.052 * D_w) - (\rho_{sw} * 0.052 * D_w) \quad (4.2)$$

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 Lopes¹¹ 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 valve¹⁷ (DSV), originally designed for the subsea mudlift project^{2,17}. 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”¹⁷. “SIDPP will be equal to the after kick opening pressure minus the originally recorded pressure”¹⁷. 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 deepwater 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 and are described in the next section of this chapter.

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 and described in the literature overview section in this study. 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 and are described more fully in the next section of this chapter. 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.

4.2.2 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 deepwater 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 study.
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 and analyzed in the following chapters of this study.
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 and is analyzed in the following chapters of this study.
5. A bullheading alternative had originally been proposed by Lopes¹¹ for a dual density system. The idea of bullheading 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. Lopes¹¹ 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 study.
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 Lopes¹¹. 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 and analyzed in the following chapters of this study.

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 were 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.

4.3 Discussion and Observations

The alternative well control methods for dual density, gas-lift system were identified and proposed for their further investigation. Well control complications inherent with the gas-lift system were presented and described. Specific concerns that were addressed are the U-tube-effect, determining the formation pressure, and conventional deepwater 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 were 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 were 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 were 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 was 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 is presented in the following chapters of this study.

5. 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.

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

5.1.1 Gas-Lifted Riser

As mentioned earlier, 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 and the further research on well control aspects of such a system will be justified.

The simulated case geometry consisted of 5,000 ft long riser with 19.25 in inside diameter and 5 in outside diameter drillpipe inside the riser. Various rates of 16 ppg mud and nitrogen were used. Results of these simulations may be seen in the Figure 5.1. As may be seen from Figure 5.1, 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.

Figure 5.1 Riser bottom pressure with various rates of mud and nitrogen

5.1.2 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 case geometry consisted of 5000 ft long choke line with 5 in inside diameter. Various rates of 16 ppg mud and nitrogen were used. Results of these simulations are shown in Figure 5.2. 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

Figure 5.2 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 example 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.

5.2 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 that was done specifically for this study focuses on stopping the mud and gas circulation to analyze a riser collapse concern and is presented below. A detailed study of pump shut down procedures was out of the scope of this project and has been studied in more detail by Anamika Gupta⁵⁸.

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 drillpipe inside the riser, 200 psi surface riser pressure, 14.55 ppg mud, 618 gpm mud flow and a nitrogen rate of 8.5 mmscfd. These conditions give a riser bottom pressure of 4,711 psi, which is slightly higher than seawater pressure.

5.2.1 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 that should be addressed 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 5.3.

Figure 5.3. 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 5.4 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 5.4 shows that liquid holdup at 2500 ft is zero at 234 minutes after gas and mud shutdown suggesting that mud level decreased significantly.

Figure 5.4. 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.

5.2.2 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 5.5 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 5.6 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.

Figure 5.5. 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 deepwater 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

Figure 5.6. Riser return liquid flowrate and riser bottom pressure

used. Riser fill-up valve would open the riser annulus to take in seawater to avoid a pressure differential that could cause riser collapse²⁸. 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 collapse²⁸. The valve remains closed during normal drilling operations.

5.3 Discussion and Observations

OLGA 2000TM simulator that was used in the well control simulations in this project was characterized and described. The simulator was validated against a full-scale, unsteady-state, field well experimental data obtained by Lopes¹¹. Highly acceptable level of confidence was achieved with very reasonable accuracy of about 2.5 % of maximum error. Due to its unique, multiphase and dynamic analysis capabilities, complex, dual density, gas-lift well control scenarios may be simulated and analyzed with the satisfied accuracy.

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 was 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 deepwater 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 deepwater 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. Furthermore, an application of a fill-up valve²⁸ was proposed as a last resort.

6. 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 deepwater 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, we must be aware of the indicators that can warn us that the well is flowing under these circumstances.

6.1 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 in Table 3.2. 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.

6.1.1 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 6.1. Also, pit gain as a kick indicator may be seen in the Figure 6.2. 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 6.3. 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 6.3 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 bottomhole holdup were also recorded.

Figure 6.1 - Drillpipe pressure and flowrate out as gas kick indicators

Figure 6.2 - Pit gain as a gas kick indicator

Figure 6.3 - Gas kick with no action undertaken

Table 6.1 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 6.1 – 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

6.1.2 Water Kicks

Simulation of a water influx to show the kick warning signs was 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 6.4. 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 6.5. 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.

Figure 6.4 - Water kick indications

Figure 6.5 – Early water kick indications

6.2 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 deepwater 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 variation¹⁹. 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 deepwater 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.

7. 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 deepwater wells with narrow fracture and pressure margins.

7.1 Dual Density Drilling Simulation Results

7.1.1 Decreasing Injection Gas Rate

A major question posed in the original project proposal 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 OLGATM are again used to address this question. The formation and well characteristics in Table 3.2 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.

7.1.1.1 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 7.1 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 1 minute 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 7.1 - Pressures and bottomhole holdup with N2 injection stopped after 1 minute

Figure 7.2 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 shut down of nitrogen injection to the riser is unacceptable as a well control method.

Figure 7.2 – 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.

7.1.1.2 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 7.3. 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 7.3 - BHP with formation flowrate with N2 stopped 4 minutes after a water kick

7.1.2 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.

7.1.2.1 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 7.4 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 bottomhole 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 7.4 - 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 1 minutes 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 deepwater 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 deepwater 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 deepwater 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 7.4. 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 deepwater system will fail and lost returns will take place. This will be presented and compared to the dual density case respectively in the following section.

7.1.2.2 Water Kicks

A water kick was 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 7.5. 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 7.5 - 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.

7.2 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 3.2. As it was concluded in the kick detection chapter, 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.

7.2.1 Shutting in with Subsea BOP

Conventional drilling conditions were 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 7.6 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 7.7 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 bottomhole 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 simply means that kick

volume of 16.2 bbls for this deepwater single density conventional case will cause formation fracture and lost returns will occur after closing the subsea BOP.

Figure 7.6 – Pit gain and surface flowrate as kick indicators

Figure 7.7 – Well pressures and liquid holdup with BOP closed 5 minutes after a gas kick

7.3 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 7.4 and 7.7. It may be seen from Figure 7.7 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 deepwater well. After 5 minutes 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 deepwater 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 bottomhole pressure increase. Furthermore, if nitrogen injection shutdown is conducted later, according to the proper kick indicators, it is not enough to stop a kick, bottomhole 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 in this study.

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 deepwater wells with the very narrow pore and fracture margins.

8. 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 bottomhole 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. Simulation input data were described in the previous chapter and presented in the Table 3.2.

8.1 Dual Density Kick Circulation

8.1.1 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.

8.1.1.1 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 8.1, bottomhole 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 8.2, 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 8.3 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 bottomhole 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, bottomhole 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 8.1 – Bottomhole pressure with gas kick circulation

Figure 8.2 - 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 bottomhole 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 8.3 - Standpipe and wellhead pressure when circulating the gas kick

8.1.2 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.

8.1.2.1 Gas Kick

The results of simulating kick removal using a system with a subsea choke are presented in Figures 8.4 and 8.5. 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 8.4, 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 bottomhole pressure responsiveness during gas kick circulation compared to using the surface choke.

Figure 8.4 - Gas kick circulation through the gas-lifted choke line with the subsea choke

Figure 8.5 – 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 8.5. 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, bottomhole 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.

8.1.2.2 Water Kick

A water kick circulation was simulated for the same well description as the gas kick simulations presented in Table 3.2. Results for water kick circulation through the gas-lifted choke line and subsea choke are presented in Figure 8.6. 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 8.6 - Gas kick circulation through the gas-lifted choke line with the subsea choke

8.1.3 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.

8.1.3.1 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 8.7.

Figure 8.7 - 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 8.8.

Figure 8.8 – 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 bottomhole 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.

8.2 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 3.2. 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.

8.2.1 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 8.9. Bottomhole 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 8.10. 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 8.9 - Gas kick circulation in the single density system

Figure 8.10 – Casing shoe pressure and liquid holdup during gas kick circulation

Figure 8.11 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 bottomhole pressure in the desired pressure margin. As a result of keeping the bottomhole 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 8.11 – 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.

8.3 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, bottomhole 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 bottomhole 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. Furthermore, more dedicated work is needed with the higher kick volumes.

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.

9. 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 deepwater 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. Therefore, it is important to consider these issues and establish the best solution based on the simulation results and their analysis. The original simulator input file that was used for this case is included in the Appendix.

9.1 Dual Density System

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

As concluded in the previous chapter, 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 in this chapter.

The data describing the well conditions used in this simulation are presented in Table 3.2. 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 way as described in the chapter 7 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.

$$\text{KWM} = \text{OMW} + ((\Delta\text{SPP}_{\text{start up}})/(0.052*(D-D_w)))$$

$$\Delta\text{SPP}_{\text{start up}} = \text{ICP} - \text{KCP}$$

$$\Delta\text{SPP}_{\text{start up}} = 520 - 320 = 200 \text{ psi}$$

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

$$\Delta P_{KWM\text{losses}} = ((KWM/OMW)*(KCP+(0.052(OMW-SW)*(D_w+RKB))))$$

$$FCP = \Delta P_{KWM\text{losses}} - 0.052*(KWM-SW)*(D_w+RKB)$$

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

$$FCP = 280 \text{ psi}$$

Where:

KWM - kill weight mud density, ppg

OMW - original mud weight density, ppg

$\Delta SPP_{\text{start up}}$ - 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

$\Delta P_{KWM\text{losses}}$ - 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 9.1, 9.2, 9.3 and 9.4. 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 mmcfpd 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 9.1. 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 2000TM 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 9.1 – BHP with KMW circulation in the dual density gas-lift system

Figure 9.2 shows the drillpipe pressure during KWM circulation. Drillpipe 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 drillpipe 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 mmcfpd to 15.52 mmcfpd as shown in Figure 9.4. 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 9.3. 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 9.2 – 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 9.3 – Casing shoe pressure with KMW circulation in the dual density gas-lift system

Figure 9.4 – Choke pressure with KMW circulation in the dual density gas-lift system

9.2 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 chapter, 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.

$$\text{KWM} = \text{OMW} + (\text{SIDPP}/(0.052 \cdot D))$$

$$\text{KWM} = 14.07 + (200/(0.052 \cdot (23400))) = 14.3 \text{ ppg}$$

$$\text{ICP} = \text{KCP} + \text{SIDPP} = 280 \text{ psi} + 200 \text{ psi} = 480 \text{ psi}$$

$$\text{FCP} = \text{KCP} \cdot (\text{KWM}/\text{OMW}) = 280 \cdot (14.3/14.07) = 284 \text{ psi}$$

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 9.5, 9.6, and 9.7. Circulation begins at 1,400 minutes when KWM is circulated down the drillstring at the kill rate of 50 gpm. Drillpipe pressure follows the drillpipe 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 drillpipe 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 drillpipe and bottomhole 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 9.5 – 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 9.7. This was the main constraint to use very low kill rate of 50 gpm. As it may be seen from Figure 9.5, 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 9.7.

Figure 9.6 – 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 chokeline 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 9.7 – Casing shoe pressure with KMW circulation in the single density system

9.3 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 bottomhole 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 deepwater wells with very narrow pore and fracture pressure “windows” as concluded in the previous chapter.

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.

10. SUMMARY, CONCLUSIONS AND RECOMMENDATIONS

10.1 Summary

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 deepwater 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 deepwater 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.

10.2 Conclusions

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 bottomhole 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. Bottomhole 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.
7. 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.

10.3 Recommendations

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, deepwater 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. The costs considered must include nitrogen generation and compression, casing and rig costs, operational costs and nitrogen volume requirements.

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APPENDIX

SIMULATOR EXAMPLE INPUT FILE

```
!*****
!  CASE Definition by OLGA-2000
!-----
CASE  AUTHOR="nick", \
      TITLE="KWM Circulation"

!*****
!  OPTIONS Definition
!*****
OPTIONS  COMPOSITIONAL=OFF,  DEBUG=OFF,  PHASE=THREE,  POSTPROCESSOR=ON,
SLUGVOID=SINTEF, \
        STEADYSTATE=ON, TEMPERATURE=WALL, WAXDEPOSITION=OFF, DRILLING=OFF

!*****
!  FILES Definition
!*****
FILES  PVTFILE="KWM1.tab"

! REMOVED KEYWORD FILES due to no keys
! REMOVED KEYWORD FILES due to no keys
! REMOVED KEYWORD FILES due to no keys
!*****
!  INTEGRATION Definition
!*****
INTEGRATION  CPULIMIT=7 h, DTSTART=3 s, ENDTIME=10 h, MAXDT=5 s, MINDT=0.1 s, MINTIME=0 s,
\
          NSIMINFO=20, STARTTIME=0 s

!*****
!  MATERIAL Definition
!*****
MATERIAL  LABEL=MATERIAL-1, CAPACITY=500 J/kg-C, CONDUCTIVITY=50 W/m-K, DENSITY=7850
kg/m3

!*****
!  WALL Definition
!*****
WALL  LABEL=WALL-1, MATERIAL=MATERIAL-1, THICKNESS=0.724 in
WALL  LABEL=WALL-2, MATERIAL=MATERIAL-1, THICKNESS=3.87 in

!*****
!  GEOMETRY Definition
!*****
GEOMETRY  LABEL=Drillstring

PIPE  LABEL=PIPE-1, DIAMETER=4.276 in, ELEVATION=-6000 ft, LENGTH=6000 ft, NSEGMENTS=10, \
      ROUGHNESS=5e-005 m, WALL=WALL-1
PIPE  LABEL=PIPE-2, DIAMETER=4.276 in, ELEVATION=-7780 ft, LENGTH=7780 ft, NSEGMENTS=50, \
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    ROUGHNESS=5e-005 m, WALL=WALL-1
PIPE LABEL=PIPE-3, DIAMETER=4.276 in, ELEVATION=-9320 ft, LENGTH=9320 ft, NSEGMENTS=50, \
    ROUGHNESS=5e-005 m, WALL=WALL-1
PIPE LABEL=PIPE-4, DIAMETER=2.88 in, ELEVATION=-300 ft, LENGTH=300 ft, NSEGMENTS=20, \
    ROUGHNESS=5e-005 m, WALL=WALL-2
GEOMETRY LABEL=Annulus, YSTART=-23400 ft
PIPE LABEL=PIPE-5, DIAMETER=12.5 in, ELEVATION=300 ft, LENGTH=300 ft, NSEGMENTS=20, \
    ROUGHNESS=5e-005 m, WALL=WALL-1
PIPE LABEL=PIPE-6, DIAMETER=11.625 in, ELEVATION=9320 ft, LENGTH=9320 ft, NSEGMENTS=50, \
    ROUGHNESS=5e-005 m, WALL=WALL-1
PIPE LABEL=PIPE-7, DIAMETER=11.772 in, ELEVATION=7780 ft, LENGTH=7780 ft, NSEGMENTS=50, \
    ROUGHNESS=5e-005 m, WALL=WALL-1
GEOMETRY LABEL="Choke Line", XSTART=0 ft, YSTART=-6000 ft
PIPE LABEL=PIPE-8, DIAMETER=5.2 in, ELEVATION=6000 ft, LENGTH=6000 ft, NSEGMENTS=70, \
    ROUGHNESS=5e-005 m, WALL=WALL-1

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!*****

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! NODE Definition

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!*****

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NODE LABEL=inlet, TYPE=TERMINAL
NODE LABEL=bottomhole, TYPE=MERGE, Y=-23400 ft
NODE LABEL=wellhead, TYPE=TERMINAL
NODE LABEL=seafloor, TYPE=MERGE, Y=-6000 ft

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!*****

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! BRANCH Definition

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!*****

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BRANCH LABEL=drillstring, FLUID="1", FROM=inlet, GEOMETRY=Drillstring, TO=bottomhole
BRANCH LABEL=annulus, FLUID="1", FROM=bottomhole, GEOMETRY=Annulus, TO=seafloor
BRANCH LABEL=chokeline, FLUID="1", FROM=seafloor, GEOMETRY="Choke Line", TO=wellhead

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!*****

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! ANNULUS Definition

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!*****

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ANNULUS LABEL=ANNULUS-1, STARTSECTIONS=( 20, 1 ), ENDSECTIONS=( 1, 50 ), STARTPIPES=(
PIPE-4, \
    PIPE-5 ), ENDPIPES=( PIPE-2, PIPE-7 ), BRANCHES=( drillstring, annulus ), \
    XCENTER=( 0, 0 ) ft, YCENTER=( 0, 0 ) ft

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! REMOVED KEYWORD SLUGTRACKING due to no keys

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!*****

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! BOUNDARY Definition

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!*****

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BOUNDARY NODE=inlet, TYPE=CLOSED
BOUNDARY GASFRACTION=( -1, -1, -1 ) -, NODE=wellhead, PRESSURE=( 60, 60, 60 ) psia, \
    TEMPERATURE=( 10, 10, 10 ) C, TIME=( 0, 3.78, 3.79 ) h, TYPE=PRESSURE, WATERFRACTION=( 0, \
    0, 0 ) -

```

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!*****

```

! HEATTRANSFER Definition

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!*****

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```

HEATTRANSFER BRANCH=drillstring, HAMBIENT=500 W/m2-C, TAMBIENT=5 C
HEATTRANSFER BRANCH=annulus, HAMBIENT=500 W/m2-C, TAMBIENT=3 C
HEATTRANSFER BRANCH=chokeline, HAMBIENT=500 W/m2-C, TAMBIENT=3 C

```

```

!*****
! SOURCE Definition
!*****
SOURCE LABEL=Mud, BRANCH=drillstring, GASFRACTION=( 0, 0, 0 ) -, MASSFLOW=( 55.5, \
55.5, 55.5 ) kg/s, PIPE=PIPE-1, SECTION=1, TEMPERATURE=( 10, 10, 10 ) C, \
TIME=( 0, 3, 3.01 ) h, WATERFRACTION=( 0, 0, 1 ) -
SOURCE LABEL=GasLift, BRANCH=chokeline, GASFRACTION=( 1, 1, 1, 1 ) -, MASSFLOW=( 5.2, \
5.2, 6, 6 ) kg/s, PIPE=PIPE-8, SECTION=1, TEMPERATURE=( 10, 10, 10, 10 ) C, \
TIME=( 0, 6.2, 6.201, 7 ) h, WATERFRACTION=( 0, 0, 0, 0 ) -

!*****
! VALVE Definition
!*****
VALVE LABEL=VALVE-1, BRANCH=annulus, DIAMETER=3 in, OPENING=( 1, 1, 0.215, 0.215, \
0.18, 0.18, 0.19, 0.19, 0.21, 0.21, 0.23, 0.23, 0.26, 0.26, 0.3, 0.45, 0.45, \
1 ) , PIPE=PIPE-7, SECTIONBOUNDARY=50, TIME=( 0, 0.1, 1.01, 3, 3.01, 3.6, \
3.601, 4, 4.01, 4.3, 4.301, 4.5, 4.501, 5, 5.01, 6, 6.2, 6.201 ) h
VALVE LABEL=VALVE-2, BRANCH=drillstring, DIAMETER=4.276 in, OPENING=( 1, 1, 1, \
1, 1 ) , PIPE=PIPE-4, SECTIONBOUNDARY=20, TIME=( 0, 0.5, 0.501, 4.306, \
4.307 ) h

!*****
! BITNOZZLE Definition
!*****
BITNOZZLE LABEL=BITNOZZLE-1, BRANCH=drillstring, DIAMETER=( 0.5, 0.5, 0.56 ) in, \
NNOZZLES=3, PIPE=PIPE-4, SECTIONBOUNDARY=19

!*****
! OUTPUT Definition
!*****
OUTPUT BRANCH=drillstring, DTOUT=10000 s, TIME=0 s, VARIABLE=( pt, ug, ul, hol, \
id, gt, psi )
OUTPUT BRANCH=annulus, DTOUT=10000 s, TIME=0 s, VARIABLE=( pt, ug, ul, hol, id, \
gt, psi )

!*****
! TREND Definition
!*****
TREND BRANCH=drillstring, DTPLOT=0.0011574074074074 d, PIPE=PIPE-1, SECTION=1, \
TIME=0 d, VARIABLE=( pt, qg, ql, hol )
TREND BRANCH=annulus, DTPLOT=100 s, PIPE=PIPE-5, SECTION=1, VARIABLE=( pt, qg, \
ql, hol, accgaq )
TREND BRANCH=chokeline, DTPLOT=100 s, PIPE=PIPE-8, SECTION=1, VARIABLE=( pt, qg, \
ql, hol, accwaq )
TREND BRANCH=annulus, DTPLOT=100 s, PIPE=PIPE-5, SECTION=1, VARIABLE=( pt, qg, \
ql, hol )
TREND BRANCH=drillstring, DTPLOT=0.0011574074074074 d, PIPE=PIPE-4, SECTION=18, \
TIME=0 d, VARIABLE=( pt, qg, ql, hol )
TREND BRANCH=drillstring, DTPLOT=0.0011574074074074 d, PIPE=PIPE-4, SECTION=19, \
TIME=0 d, VARIABLE=( pt, qg, ql, hol )
TREND BRANCH=chokeline, DTPLOT=100 s, PIPE=PIPE-8, SECTION=1, VARIABLE=( pt, qg, \
ql, hol, accwaq )
TREND BRANCH=chokeline, DTPLOT=100 s, PIPE=PIPE-8, SECTION=35, VARIABLE=( pt, qg, \
ql, hol, accwaq )
TREND BRANCH=chokeline, DTPLOT=100 s, PIPE=PIPE-8, SECTION=70, VARIABLE=( pt, qg, \
ql, hol, accwaq )

```

```

TREND BRANCH=drillstring, DTPLOT=0.0011574074074074 d, PIPE=PIPE-1, SECTION=10, \
  TIME=0 d, VARIABLE=( pt, qg, ql, hol )
TREND BRANCH=annulus, DTPLOT=100 s, PIPE=PIPE-5, SECTION=1, VARIABLE=gtwell
TREND BRANCH=annulus, DTPLOT=100 s, PIPE=PIPE-6, SECTION=5, VARIABLE=( pt, qg, \
  ql, hol )
TREND BRANCH=annulus, DTPLOT=100 s, PIPE=PIPE-7, SECTION=5, VARIABLE=( pt, qg, \
  ql, hol )
TREND BRANCH=annulus, DTPLOT=100 s, PIPE=PIPE-6, SECTION=50, VARIABLE=( pt, qg, \
  ql, hol )
TREND BRANCH=annulus, DTPLOT=100 s, PIPE=PIPE-5, SECTION=2, VARIABLE=( pt, qg, \
  ql, hol, accgaq )
TREND BRANCH=annulus, DTPLOT=100 s, PIPE=PIPE-7, SECTION=1, VARIABLE=( pt, qg, \
  ql, hol )
TREND BRANCH=drillstring, DTPLOT=0.0011574074074074 d, PIPE=PIPE-4, SECTION=20, \
  TIME=0 d, VARIABLE=( pt, qg, ql, hol )
! REMOVED KEYWORD TREND due to no keys
! REMOVED KEYWORD TREND due to no keys
! REMOVED KEYWORD TREND due to no keys
!*****
! PROFILE Definition
!*****
PROFILE DTPLOT=6 s
PROFILE BRANCH=drillstring, VARIABLE=( pt bara, tm, hol, ug )
PROFILE BRANCH=annulus, VARIABLE=( pt bara, tm, hol, ug )
PROFILE BRANCH=annulus, VARIABLE=( pt bara, tm, hol, pt, ug, id, vol, qg )
!
ENDCASE

```


VITA

Mikolaj Stanislawek is from Poland. Mikolaj is a graduate from the University of Mining and Metallurgy in Krakow, Poland, with specialization in drilling and geo-engineering. After graduation, Mikolaj worked for six months with Nafta Pila, Drilling Contractor Company as a Field Drilling Engineer. He later was accepted by Louisiana State University and began his graduate studies in petroleum engineering in January of 2003. His interests include deepwater drilling, well control, underbalanced drilling, and field drilling operations.