WELL CONTROL PROCEDURES FOR

EXTENDED REACH WELLS

A Thesis

by

BJORN GJORV

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

August 2003

Major Subject: Petroleum Engineering

WELL CONTROL PROCEDURES FOR

EXTENDED REACH WELLS

A Thesis

by

BJORN GJORV

Submitted to Texas A&M University
in partial fulfillment of the requirements
for the degree of

MASTER OF SCIENCE

Approved as to style and content by:

Hans C. Juvkam-Wold (Chair of Committee)	Jerome J. Schubert (Member)
Jean-Louis Briaud (Member)	Hans C. Juvkam-Wold (Head of Department)

August 2003

Major Subject: Petroleum Engineering

ABSTRACT

Well Control Procedures for Extended Reach Wells.

(August 2003)

Bjorn Gjorv, B.S., Stavanger University College, Norway

Chair of Advisory Committee: Dr. Hans C. Juvkam-Wold

The limits of directional drilling continue to be pushed back as horizontal or near-horizontal reservoir sections are being drilled, cased, cemented and completed to tap reserves at extreme distances. Continuous development of new technology and adopting a technical-limit approach to performance delivery are key elements for the success and further development of extended-reach drilling projects.

For this study a two-phase well control simulator was used to evaluate different kick scenarios that are likely to occur in extended-reach wells. An extensive simulation study covering a vide range of variables has been performed. Based on this investigation together with a literature review, well-control procedures have been developed for extended-reach wells. The most important procedures are as follows:

- Perform a "hard" shut-in when a kick is detected and confirmed.
- Record the pressures and pit gain, and start to circulate immediately using the Driller's Method.
- Start circulating with a high kill rate to remove the gas from the horizontal section.
- Slow down the kill circulation rate to ½ to ⅓ of normal drilling rate when the choke pressure starts to increase rapidly.

The simulator has been used to validate the procedures.

DEDICATION

This work is dedicated to my grandfather, Bjarne L. Rabbe, for his support and love throughout the years.

ACKNOWLEDGMENTS

Sincere thanks go to my advisor, Dr. Hans C. Juvkam-Wold, for his continuous support and encouragement, and mostly, for his intellectual advice.

Dr. Jerome Schubert, thank you for giving this project to me and for the support you have provided.

Dr. Jean-Louis Briaud, thanks for all your help and for being part of my committee.

To my family back home, thank you for the support while I have been here.

I would like to thank Martin Alvarado and his family for the complete support and hospitality; your friendship has been of invaluable importance for me the two years I stayed here.

Ray Tommy Oskarsen, thank you for being such a cooperative office mate and giving me the moral and intellectual influence I needed to finish.

I would also like to thank Minerals Management Service and OTRC for funding this project.

TABLE OF CONTENTS

Page

LIST OF TABLES

Page

LIST OF FIGURES

Page

INTRODUCTION

Introduction to Extended Reach Drilling (ERD)

Extended reach (ERD) wells are defined as wells that have a horizontal departure (HD) at least twice the true vertical depth (TVD) of the well.[1] ERD wells are kicked off from vertical near the surface and built to an inclination angle that allows sufficient horizontal displacement from the surface to the desired target. This inclination is held constant until the wellbore reaches the zone of interest and is then kicked off to near horizontal and extended into reservoir. This technology enables optimization of field development through the reduction of drilling sites and structures, and allows the operator to reach portions of the reservoir at a much greater distance than possible with a conventionally drilled directional well. These efficiencies increase profit margins on viable projects and can make the difference whether or not the project is financially viable.[2]

It is well known that ERD introduces factors that can compromise well delivery, and the first challenge prior to drilling an ERD well is to identify and minimize risk.[3] Technologies that have been found to be critical to the success of ERD are torque and drag, drillstring design, wellbore stability, hole cleaning, casing design, directional drilling optimization, drilling dynamics and rig sizing.[4] Other technologies of vital importance are the use of rotary steerable systems (RSS) together with measurement while drilling (MWD) and logging while drilling (LWD) to geosteer the well into the geological target.[5] Many of the wells drilled at Wytch Farm would not have been possible to drill without RSS,[6] because steering beyond 8,500 m was not possible as axial drags were too high to allow the orientated steerable motor and bit to slide.[7]

Drilling ERD wells in deep waters is the next step, even though there are some experiences offshore, they are related to wells drilled on shallow waters from fixed platforms. In Brazil, where the major oil fields are located in deep waters, ERD wells might be, in some cases, the only economically viable solution.[8]

This thesis follows the style and format of *SPE Drilling & Completion.*

BP's Wytch Farm oilfield

The Wytch Farm field was discovered in 1974 and is located southwest of London on the UK coastline near Poole, England. It is an area of outstanding natural beauty with many sites of special scientific interest. About a third of the Sherwood reserves are under Poole Bay, where an artificial island was first planned to be developed **(Fig. 1)**. Drilling ERD wells from an onshore location may have reduced the development costs by as much as $150 million.[4]

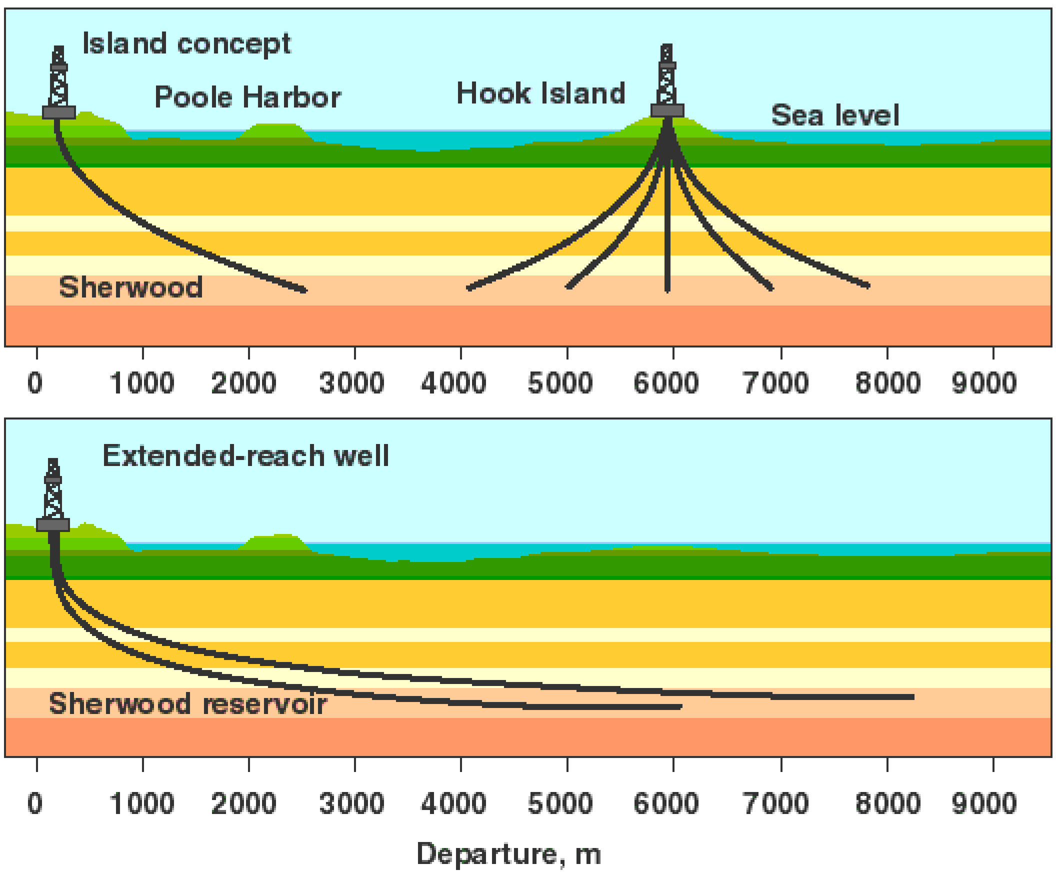

Fig. 1 – The artificial island development concept versus the ERD wells (from Allen *et al.*[9]).

The step-out of wells has increased dramatically during the years. The first well in 1993 had a departure of 3.8 km, M5 in 1995 reached 8 km, M11 in 1997 broke the 10-km milestone, and M16 in 1999 became a record breaking well drilled to 11,278 m.[7] **Fig. 2** shows the industry comparison of ERD wells, where the Wytch Farm wells have the most extreme ratio of departure to TVD.

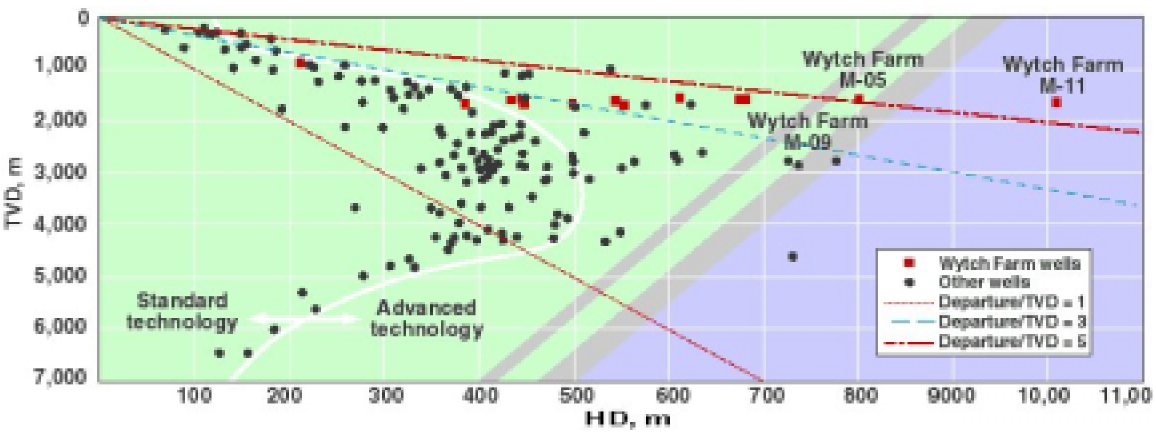

Fig. 2 – Industry comparison of ERD wells (from Allen *et al.*[9]).

Well-control challenges in ERD wells

A gas kick represents probably the most dangerous situation that can occur when drilling a well since it can easily develop to a blowout if it is not controlled promptly. ERD wells are more prone to kicks and lost-circulation problems than more conventional and vertical wells, but have some advantages when the well takes a kick because gas migration rates are lower.[10] The maximum migration velocity occurs at 45^o inclination and the velocity rapidly drops to zero as the wellbore approaches horizontal,[11] and a kick will rise faster in a viscous mud than in water.[12] Significant migration rates are found at inclinations up to 80^o; the inclination which efficiently stops migration is close to 90^{o} in smooth wellbores and may be as low as 70^{o} if the wellbore is extremely rugged.[13] The gas will then be trapped and accumulate in the top side of the hole until its original volume is depleted **(Fig. 3)**. The trapped gas may be brought out of the traps and circulated up in the well when the normal drilling operation resumes. This may lead to an underbalanced situation that could result in another kick.

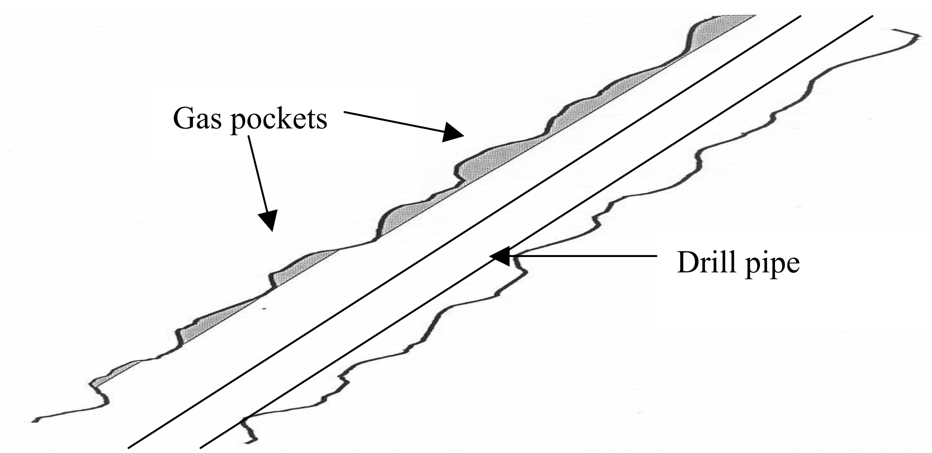

Fig. 3 – Gas migration in a highly inclined and rugose wellbore.

In ERD and horizontal wells the maximum casing-shoe pressure during a well control procedure is usually smaller and the choke pressures remain lower for a longer period of time than in a vertical well. The reason for this is that the TVD at casing shoe is often very close to the TVD of the influx zone. As long as the kick is in the horizontal section, the shut-in casing pressure (SICP) and shut-in drill pipe pressure (SIDPP) are about the same because hydrostatic pressure on both sides of the U-tube are the same. **Fig. 4** shows a horizontal well that has taken a kick and is shut-in.

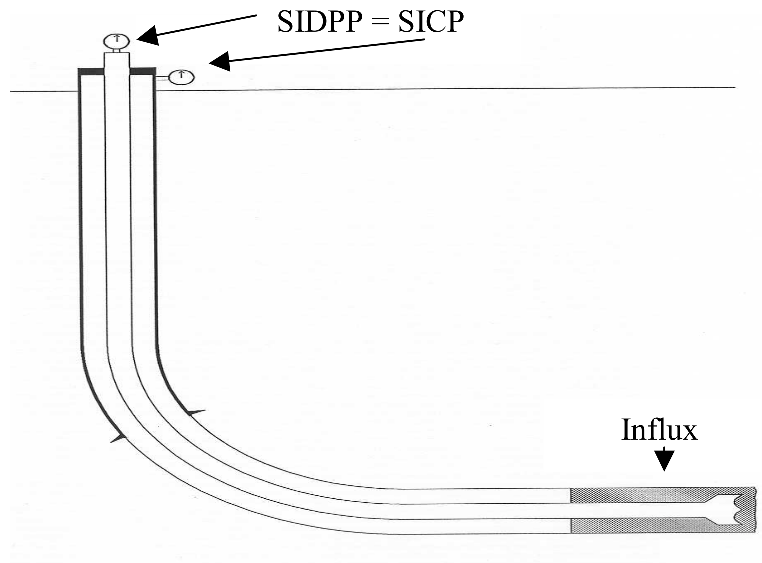

Fig. 4 – Well shut in after taken a kick in a horizontal well.

Simulating wellbore pressures during a kill procedure

As a result of studies conducted for several years, well-control procedures have been developed to prevent such incidents from occurring, or if a kick is taken, how to control it.[14] These studies of the kick development and the factors influencing the mechanisms that control the kick usually include full-scale kick experiments,[15] kick simulators,[16-21] or physics like gas-rise velocity.[11-13] Another phenomenon that also has been investigated through experiments is counter-current and co-current gas kick migration in high angle wells.[22-23] Further there has been conducted an experimental and theoretical study of two-phase flow in horizontal or slightly deviated fully eccentric annuli.[24]

The two-phase well-control simulator used for this research was developed by Choe and Juvkam-Wold.[25, 26] The simulator can handle vertical wells, directional wells, extended-reach wells, and horizontal wells with different buildup rates for onshore or offshore wells. The simulator also provides the theoretical kill sheet for any selected well geometry. It demonstrates the basic concepts of well control and shows the pressure and volume responses of the kick with time.

WELL CONTROL METHODS

Introduction

Well control has always been a very important issue in the oil and gas industry because it involves enormous amount of money, people's safety, and environmental issues. Well-control fundamentals have been understood and taught for almost half a century, but still well control problems and blowouts occur in the industry. Substantially, all blowouts are related to human failure and error relative to well operations.[27] **Table 1** shows the incidents of loss of well control reported to Mineral Management Service (MMS) from 1992 to June 2003. Loss of well control means either of the following[28]:

- Uncontrolled flow of formation or other well fluids. Flow may be between two or more exposed formations or it may be at or above the mudline. Includes uncontrolled flow resulting from failures of either surface or subsurface equipment or procedures.
- Flow of formation or other well fluids through a diverter.

Table 1 – Losses of well control in the Gulf of Mexico and Pacific Region (from MMS[28]).

Losses of Well Control												
	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
GOM	3	3	0	1	4	5	6	5	8	9	6	3
PAC	0	0	0	0	0	0	1	0	1	1	0	0
Total	3	3	0	1	4	5	7	5	9	10	6	3

Kick causes

A kick is defined as an unscheduled entry of formation fluids into the wellbore which must be contained initially by shutting in the surface equipment and removed from the wellbore in controlled manner.[10, 14] A blowout might occur if the kick is not controlled properly. Blowouts cause valuable resources to be wasted, harm the environment, damage equipment, and even endanger the lives of rig personnel. Blowouts can be surface blowouts or underground blowouts.

A surface blowout is an uncontrolled flow of formation fluids to the surface, and the consequences are sometimes catastrophical. If formation fluids flow into another formation, and not to the surface, the result is called an underground blowout. This crossflow from one zone to another can occur when a high-pressure zone is penetrated, the well flows, and the drilling crew reacts promptly and closes the blowout preventers (BOPs). The pressure in the annulus builds up until a weak zone fractures, and depending on the pressure, the flowing formation can continue to flow to the fractured formation. Underground blowouts are historically the most expensive problem in the drilling arena, surpassing even the cost of surface blowouts. In many cases the only technique to kill an underground blowout is to drill a secondary relief well.

Kicks may occur if two requirements are fulfilled. The wellbore pressure has to be lower than the pore pressure, and the formation has to be sufficiently permeable for the formation fluids to flow at a significant rate. **Fig. 5** shows the influx rate for various kick sizes, illustrating that the influx rate increases rapidly with increased kick size.

While circulating, the pressure at any point in the wellbore is obtained by adding the hydrostatic pressure to the annular friction losses of above the depth of interest. This additive pressure can be converted to a convenient mud weight equivalent termed the equivalent circulating density (ECD).

The main reason kicks occur while drilling is an insufficient ECD. Drilling into abnormally pressured permeable zones can cause a sudden pressure differentiation where the formation pressure is higher than the bottomhole pressure (BHP), or in in the term of density, the ECD is too low. Increasing the ECD is usually not difficult, and can easily be done by increasing the mud weight and/or increase pump rate. Heavier mud weight increases the hydrostatic pressure, and higher pump rate increases the system pressure loss.

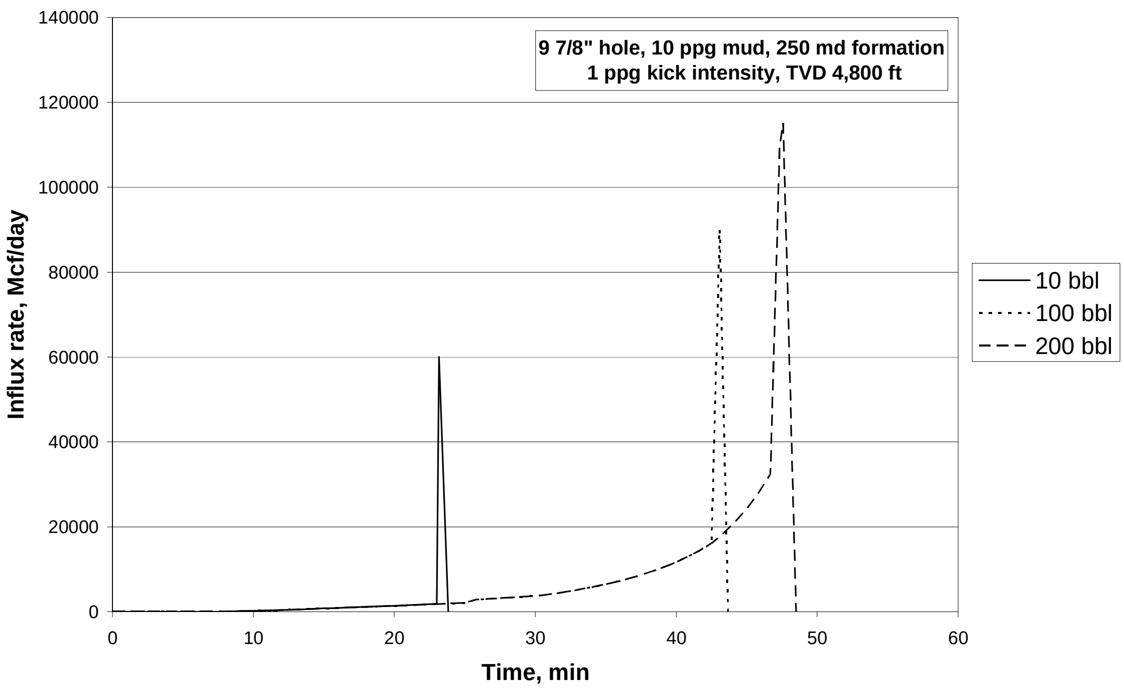

Fig. 5 – Influx rate for various kick sizes in an onshore ERD well.

Swabbing is another common reason for taking a kick. The drillpipe acts like a piston when it is moved in a wellbore filled with mud. When pulling out of the hole, the mud has to be displaced past the bit. If the drillstring is pulled too fast, the pressure is immediately reduced below or behind the bit. This swabbing effect can cause the formation to flow. The best way to avoid swabbing is to keep the hole full at all time and pull slowly until the casing shoe is reached.

Severe lost circulation is a more difficult problem to deal with. Lost circulation occurs when drilling into natural fissures, fractures, caverns, or a depleted formation, and mud flows into the newly available space. If the hole does not remain full of fluid, the vertical height of the fluid column is reduced and the pressure exerted on the open formations is reduced. This reduction in hydrostatic pressure can cause formation fluids to flow from another zone into the wellbore while the loss zone is taking mud, which can result in a catastrophic loss of well control. If an overbalance is not obtained by continuously pumping drilling fluid or water into the annulus, an underground blowout is most likely to be the result.

Kick detection and verification

Detecting a kick early is the most critical factor in determining whether or not the situation is manageable, because early shut-in limits the volume of influx taken.

One of the first indications of a kick to occur is a sudden increase in rate of penetration (ROP), termed drilling break. The influx of formation fluids tends to clean the bottom hole very efficiently, and in combination with the underbalanced condition, the bit cuts the rock more easily and faster. An increase in ROP does not necessarily mean that a kick is occurring, but could just indicate that another formation is encountered.

If the return flow rate from the wellbore increases to a greater level than what is pumped into the wellbore, there is an influx of formation fluids into the wellbore. The difference in pump rate and return rate is the rate at which the influx is entering the wellbore at bottomhole conditions. This excessive volume of mud that the influx displaced over a period of time is called the pit gain. Constantly monitoring the balance between well inflow and outflow is very important in early kick detection.

While tripping out of the hole, the drillstring is removed from the wellbore. The drillstring represents a specific volume of steel displacing an equal volume of mud. To prevent the BHP from dropping below pore pressure, this volume of steel has to be replaced with mud to make sure that the hydrostatic column in the wellbore is not dropping. If the wellbore takes less mud than the displacement of the pipe pulled out from the well, it may be an indication of swabbing. Action has to be taken immediately to prevent the well from flowing with the pipe off bottom or out of the hole.

Another indication that a kick is taking place is an increase in hook load. This reduced buoyancy in the wellbore is caused by the influx of fluid with a lower density than the mud. This weight indicator may not be a good kick detector, because the change in hook load will probably not be seen until the well has taken a large kick.

MWD is a relatively new technology that can be helpful in early detection of kicks. The mud-pulse telemetry tool takes downhole measurements, converts the data to coded binary signals, and transmits the information via mud pulses to the surface where a receiver decodes the signals so the information can be viewed and analyzed on a computer. The great advantage of MWD is that it delivers the desired information in real time while drilling.

Shut-in procedures

As soon as an influx is detected and confirmed, the well shut-in procedure must be performed. Situations when shutting in the well is not an option include shallow gas kicks and when the surface casing has not been set. In those cases the well has to be killed "on the fly" by increasing the ECD, which involves increasing mud weight and circulation rate. A diverter is used to guide the returning wellbore fluids away from the rig, following the direction of the wind. If the well is shut in, the outcome is most likely to be a combination of underground and surface blowout, where the conductor casing shoe is fractured and the blowout breaks through the formation up to the surface.

The two principal methods for shutting in the well are the "hard" shut-in and the "soft" shut-in. The "hard" shut-in is done by closing the blow-out preventer (BOP) with the choke valve shut. This procedure generates a pressure wave, called a "water hammer," through the mud. It was believed that in some circumstances this increase in wellbore pressure could provoke formation damage and lead to an underground blowout.[29] Many operators prefer the "soft" shut-in, which is accomplished by closing the BOP with the choke valve open, and then closing the valve slowly. The drawback of the delay in closing the choke to obtain complete shut-in of the well is the additional influx from the formation.

An experimental and theoretical study concluded that the "hard" shut-in was a better alternative than the "soft" shut-in.[30] The reason for this was that the water hammer caused a pressure increase that was negligible, at least in deep water and long wellbores. With the risk of taking a larger kick as a result of longer closing time and human error associated with closing and opening the valves, the "hard" shut-in is the preferred method.

Circulation kill techniques and procedures

After the well is shut-in, the pit gain is recorded while the surface pressures start to build up. When the pressures have stabilized, SICP and the SIDPP are recorded. These values are then used to identify the kick fluid, estimate the height of the kick column, and calculate the new kill-mud weight needed to stabilize the formation pressure.

Several different kill methods have been developed during the years, but the two most common kill procedures are the Driller's Method and the Engineer's Method (Wait-and-Weight Method). There are some differences, but they are both based on the same principles: keeping the bottomhole pressure constant while circulating out the kick and replacing the old mud with kill-weight mud. Kill sheets are very helpful when planning and executing a well kill. The prerecorded data are used to calculate the kill-weight mud density and generate the desired circulating drillpipe pressure schedule as a function of pump strokes. A standard kill sheet will show a straight line between the initial circulating pressure (ICP) and the final circulating pressure (FCP). This approach is valid only for vertical wells and could cause an excessive overbalance if used on a horizontal or ERD well.[31] This overbalance could fracture the formation and complicate the well kill operation with loss of circulation. An example of a kill sheet and pressure decline schedules for vertical, horizontal, and ERD wells are presented in Appendix A.

The Driller's Method uses the old mud to circulate out the influx and requires two circulations to kill the well. The first circulation displaces the influx with old mud from the pits, and the second circulation replaces the old mud with new kill mud.

The Engineer's Method uses only one circulation to kill the well. We have to wait while the kill-weight mud is weighted up before starting to circulate out the influx and replacing the old mud with new kill mud, all in just one circulation.

Which circulating kill technique to use varies from situation to situation; no well control problems are the same, and it all depends on the circumstances. The maximum surface pressure with a gas kick will be greater when using Driller's Method, so if the concern is the pressure rating of the BOP, the Engineer's Method may be preferrable. On the other hand, if mixing kill weight mud is expected to take a long time, and there have been problems with hole cleaning, the Driller's Method may be the best option because of the early start of circulation.

Special well control situations might occur if the bit is plugged, the pipe is off-bottom, or the annulus cannot handle the backpressures during a conventional kill. In these cases the BHP cannot be recorded from the drillpipe gauge, nor can the kick be circulated out conventionally. The well-control methods to apply when the traditional concepts cannot be followed are presented in Appendix B.

OBJECTIVES AND PROCEDURES

Research objectives

The objective of this research is to perform an extensive simulation study of vertical, directional, horizontal, and ERD wells. Based on the simulation study recommendations will be made to improve well control for situations that warrant improvement, especially for ERD wells. The simulator will again be used to validate the procedures.

Procedures

The two-phase well control simulator developed by Choe and Juvkam-Wold was used to complete this simulation study. These simulation runs include land, shallow water, intermediate water, deep water and ultradeep water. Other factors that were considered follow:

- Kick size.
- Circulation rate.
- Kick intensity.
- Wellbore trajectory.
- Water depth.
- Hole size, casing and drillstring dimension.

TWO-PHASE WELL CONTROL SIMULATOR

Description of the simulator

The well-control simulator used for this research was developed by Choe and Juvkam-Wold at Texas A&M University.[24, 25] The main objectives of the two-phase well control model are to simulate the behavior of kicks on the basis of realistic assumptions of unsteady two-phase flow and to integrate this into a user-friendly, Windows-based, well-control simulator for use in well control training and education. This model is based on the following assumptions:

- Unsteady-state two-phase flow.
- One-dimensional flow along the flow path.
- Water-based mud, where gas solubility is negligible.
- Known mud temperature gradient with depth.
- Kick occurring at the bottom of the well while drilling.
- Gas influx rates calculated from the formation assuming an infinite-acting reservoir.

Simulator input

The simulator takes a set of user input data and incorporates it through a well-control situation from the drilling mode and the well takes an influx until the kick is completely circulated out of the hole. Once the simulation is completed, the results are available as graphical presentations and the output data can be saved as a file for future investigation.

The default data used in this investigation are listed in **Table 2**. Even though offshore location is listed as default, the study also included onshore simulations runs. The gas deviation factor was also not considered in some runs, and the wellbore profiles were actively changed for different situations. Strokes per minute at kill rate were also changed for different cases. In very deep water the offshore temperature gradient was changed to a value that represented a realistic water temperature at the mudline.

Table 2 – Default input data.

```
      --- Input Data ---
      ------------------

 Rig Location     (1:On Shore)  =      2
 Selected Method (1:Driller)    =      2
 Pump Type        (2:Duplex)    =      2
 Friction Loss    (1:Condsider) =      1
 Fluid Model      (1:Power law) =      1
 Gas Deviation    (1:Consider)  =      1
 Direc. Well Type(0:Vertical)   =      4

 Shear Stress @ 600 rpm         =      35.
 Shear Stress @ 300 rpm         =      25.
 Old Mud Density                =      10.           ppg
 Mud compressibility            =      6.0E-06       1/psi
 Critical Reynolds number       =      2100.
 Bit Nozzle Size 1,2,3,4        =      12.           /32nd in
 Roughness of Pipe              =      0.            in

 Liner Size of Pump             =      6.            in
 Rod Size of Pump               =      2.5           in
 Stroke Length of Pump          =      18.           in
 Pump Efficiency                =      0.85          fraction

 Strokes # @ Drilling Rate      =      60.           st/min
 Strokes # @ Kill Rate          =      30.           st/min
 Flow Rate @ Drilling           =      410.44        gal/min
 Flow Rate @ Kill               =      205.22        gal/min

 Pit Warning Level              =      10.           bbls
 Kick Intensity                 =      1.            ppg
 Specific Gravity of Gas        =      0.65          (air=1)
 Mole Fraction of CO2           =      0.            fraction
 Mole Fraction of H2S           =      0.            fraction
 Surface Temperature            =      70.           'F
 Mud Temperature Gradient       =      1.1           'F/100 ft
 Off Shore Temperature Gradient =      -0.3          'F/100 ft

 Formation Permeability         =      250.          md
 Formation Skin Factor          =      2.
 Formation Porosity             =      0.25          fraction
 Rate of Penetration            =      60.           ft/hr

 Choke Valve Status (1:open)    =      1
 Kill Valve Status  (1:open)    =      0
 ID of Choke Line               =      4.            in
 ID of Kill Line                =      3.            in
 ID of Marine Riser             =      19.           in
```

Simulator output

The results from the simulation are presented graphically under the main menu right after the circulation is successfully completed. The results can also be saved as an output file for future investigation. **Table 3** shows the data that are available after a completed run:

- Time.
- Xtop = distance to top of kick.
- Xbotm = distance to bottom of kick.
- Px@top = pressure at top of kick.
- Pit Vol = pit gain.
- Kick density.
- Pump P = pump pressure.
- Stand PP = stand pipe pressure.
- Choke P = choke pressure.
- CsgSeat = casing seat pressure.
- P BHP = bottomhole pressure.
- P@Mudline = pressure at the mudline.
- Number of pump strokes.
- Volume circulated.
- Surface choke valve opening in percent.
- Influx rate.
- Mud-return rate at surface.
- Gas-return rate at surface.

Table 3 – Output data after a completed run.

	Output from the Well Control Simulator					
Time	Xtop	Xbotm	Px@Top	Pit Vol	Kick Densi	ity
(mins)	(ft)	(ft)	(psig)	(bbls)	(ppg)	
------	----	-----	------	-------	-------	-----
0	0	0	0	0	0	
8	3987.9	4000	2123.8	7.49	1.16	
16.25	3979.5	3989.7	2264.5	13.54	1.24	
30.92	3963.6	3973.1	2248.9	13.62	1.23	
45.58	3706.8	3953.3	2129.4	13.82	1.17	
60.25	2093.7	2822.9	1386.4	19.17	0.78	
71.58	436.1	1618	602.2	33.33	0.31	
84.97	0	858.1	508.3	11.34	0.25	
101.62	0	0	0	0	0	

Time	Pump P	Stand PP	Choke P	CsgSeat	P BHP	P@Mudlin
(mins)	(psig)	(psig)	(psig)	(psig)	(psig)	(psig)
------	------	--------	-------	-------	-- ------	---------
0	0	0	0	1025.3	2065.3	520
8	2489.1	2489.1	0	1046.6	2142.2	520.9
16.25	819.5	819.5	144.4	1210	2288	685.7
30.92	706.2	706.2	148.4	1210.4	2288	686.7
45.58	758.2	758.2	169.6	1231.6	2288	708
60.25	758.2	758.2	271.9	1337	2288	813.2
71.58	758.2	758.2	363.5	1203.3	2288	848.2
84.97	758.2	758.2	508.3	1184.4	2288	660.8
101.62	758.2	758.2	64.9	1126.8	2288	603.2
116.29	758.2	758.2	18.8	1101.6	2288	557
130.87	823.6	823.6	0	1167.1	2353.4	591.4

Time	Strokes	Vol Circ	ChK Open	InFlux	Mud Rate	Gas Rate
(mins)	(#)	(bbls)	Dia Rat	io (Mcf/D	) (gpm)	(Mcf/Day)
------	-------	--------	---(%)-	-- -------	- -------	- ---------
0	0	0	0	0	0	0
8	0	0	0	6661.6	514.7	0
16.25	182.5	29.72	35	0	228	0
30.92	622.5	101.39	33.1	0	205.5	0
45.58	1062.5	173.05	32.1	0	206.2	0
60.25	1502.5	244.71	30.3	0	228.3	0
71.58	1842.5	300.09	30.6	0	268.7	0
84.97	2244	365.48	18.9	0	30.8	1306.2
101.62	2743.6	446.86	39.5	0	205.2	0
116.29	3183.6	518.53	49.1	0	205.2	0
130.87	3621	589.76	100	0	205.2	0

Simulation procedures

Drilling. After turning on the pump we start drilling, and a kick is taken when the bit reaches the planned target. The drilling rate can be increased up 10 times the regular speed. The alarm goes off when the pit gain reaches 10 bbl.

Pump off. The mud-return rate increases when taking a kick, and this can be confirmed by shutting down the pump to see if the well is flowing.

Shut-In. The next important step after the kick is detected is to shut in the well. This prevents more influx into the wellbore, but still there is some flow from the formation until the bottomhole pressure (BHP) builds up to formation pressure. When the BHP equals formation pressure, the system reaches equilibrium and the shut-in drillpipe pressure (SIDPP) and shut-in casing pressure (SICP) are recorded. The shut-in data can be saved as a file when the BHP is within 5 psi of formation pressure. This makes it possible to circulate with other rates and compare the results for the exact same shut-in conditions.

Circulation. The choke can be manipulated either manually or automatically by the computer (perfect control). In this investigation perfect control was chosen for all the cases, and the clock speed was set to 40 times more than normal. After the circulation is completed the results can be viewed and saved as a file. Each output file was then opened and saved as an Excel file, which made it possible to plot the results of interest.

SIMULATION RESULTS FOR THE EXTENDED REACH WELLS

Effect of varying kick sizes and true vertical depth

Introduction

For this investigation I used the M-16 well drilled at Wytch Farm in 1999 as the base case for the typical extended reach well profile. I rebuilt the wellbore profile with data from the actual well. Assuming that varying kick sizes would have the most effect on maximum choke pressure and gas rate at surface when circulating out the kick, I performed several simulation runs for different kick sizes with the original TVD and with the TVD doubled. I lowered only the kick-off point; the wellbore profile remained the same. The results are presented in **Figs. 6 and 7.**

Discussion of the results

From **Figs. 6 and 7** we can see that the increase in kick size causes an increase in the maximum choke pressure. It can also be seen that the maximum choke pressure increases with TVD of the well. A 10 bbl gas kick taken in a deep well is more compressed by the higher hydrostatic pressure and will expand more as it approaches the surface than a kick taken in a shallower well. This expansion is reflected in the choke pressure at the surface. The figures also show that there is not much difference in maximum choke pressure for kick sizes of 100 and 200 barrels; the most significant increase is from 10 bbl to 50 bbl. From 10 to 50 barrels mud and gas will be mixed together through the choke, and for larger kick sizes only dry gas will be circulated through the choke when the highest pressure is observed.

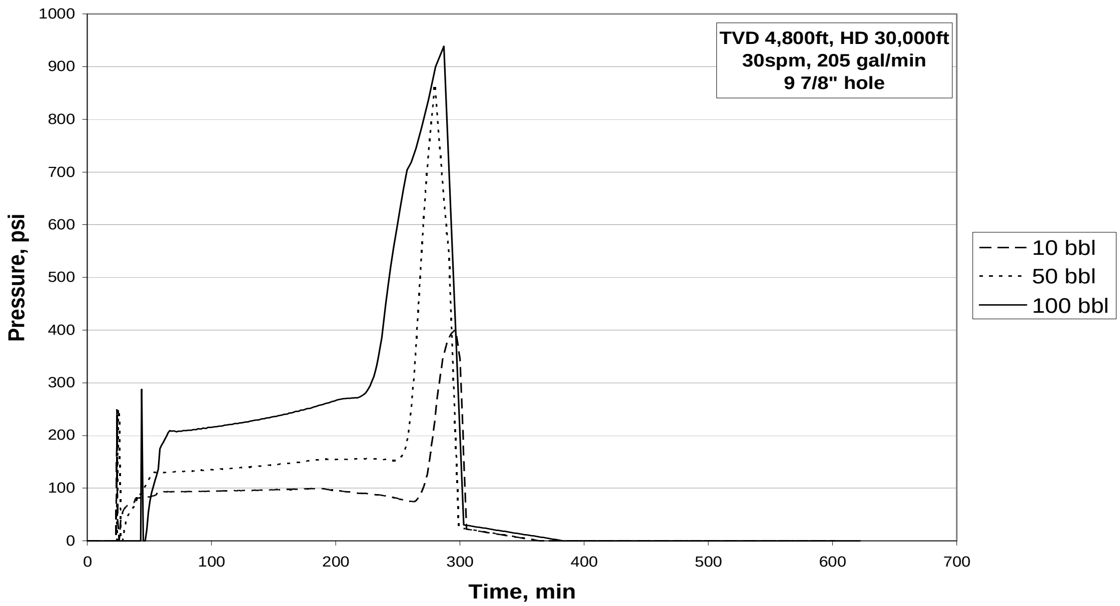

Fig. 6 – Choke pressure for various kick sizes (original TVD).

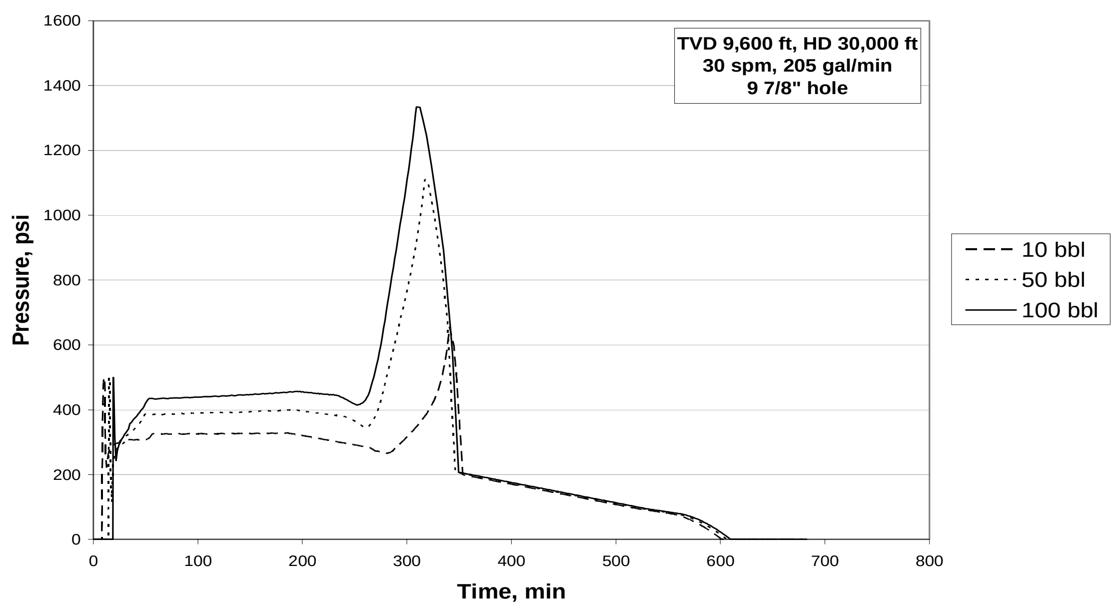

Fig. 7 – Choke pressure for various kick sizes (2X original TVD).

Effect of varying water depth and kick size

Introduction

Even though there are some experiences of drilling extended-reach wells from offshore locations, they are mostly related to shallow waters from fixed platforms. It is believed that in the near future there will be drilled several ERD wells in deep – and ultradeep water.[8] Therefore, I performed many simulation runs in water depths of 5,000, 10,000 and 15,000 ft to try to understand the scenarios that could occur when drilling under these conditions. The same M-16 Wytch Farm wellbore profile was used for this study by just adding water depth.

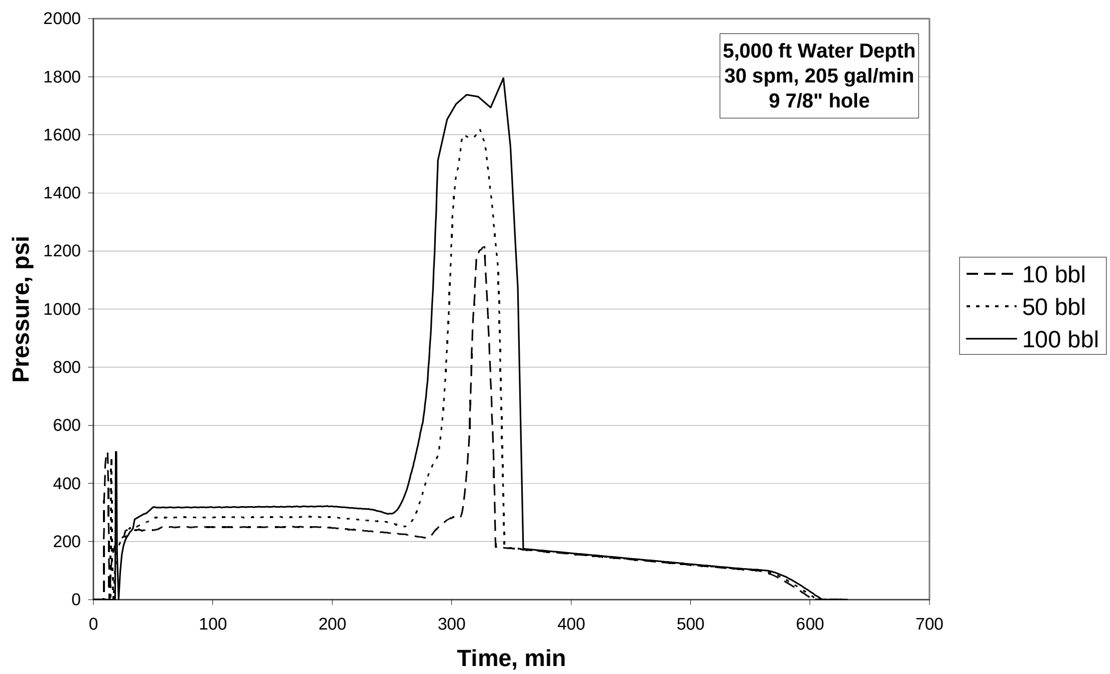

Fig. 8 – Choke pressure for various kick sizes in 5,000 ft of water.

Discussion of the results

Figs. 8, 9, and 10 show the maximum choke pressure obtained for 10-, 50-, and 100-bbl kicks taken in water depths of 5,000, 10,000 and 15,000 ft. We can see from the figures a considerable increase in choke pressure as the water depth increases. This is because of the change in depth of the hydrostatic column, similar to when increasing TVD of a well.

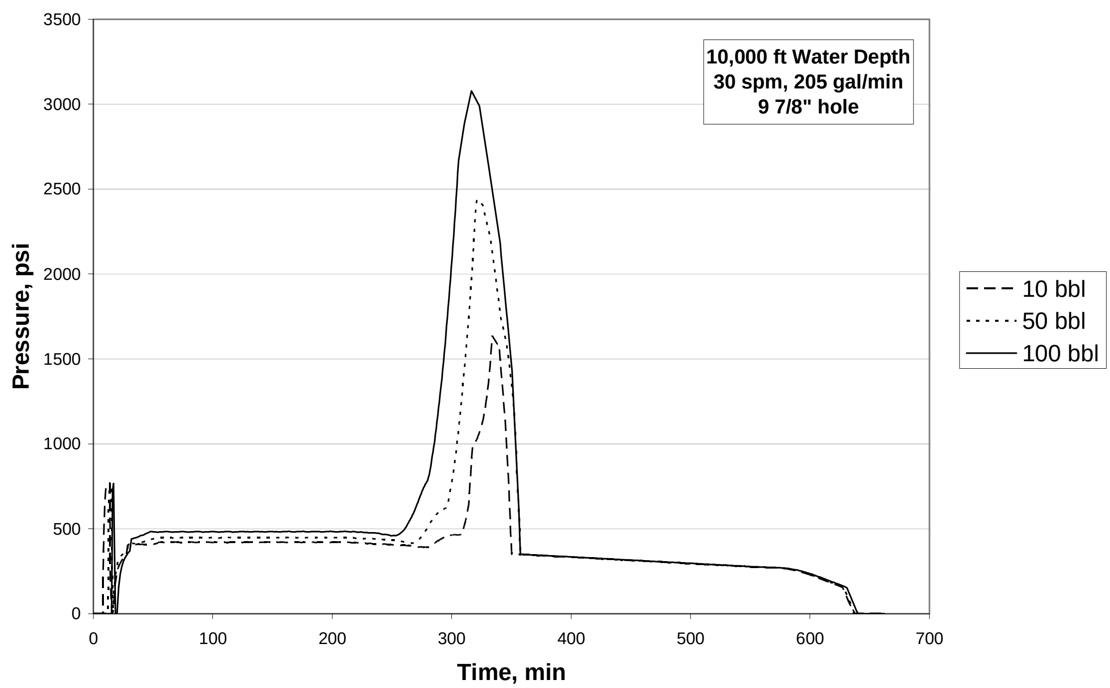

Fig. 9 – Choke pressure for various kick sizes in 10,000 ft of water.

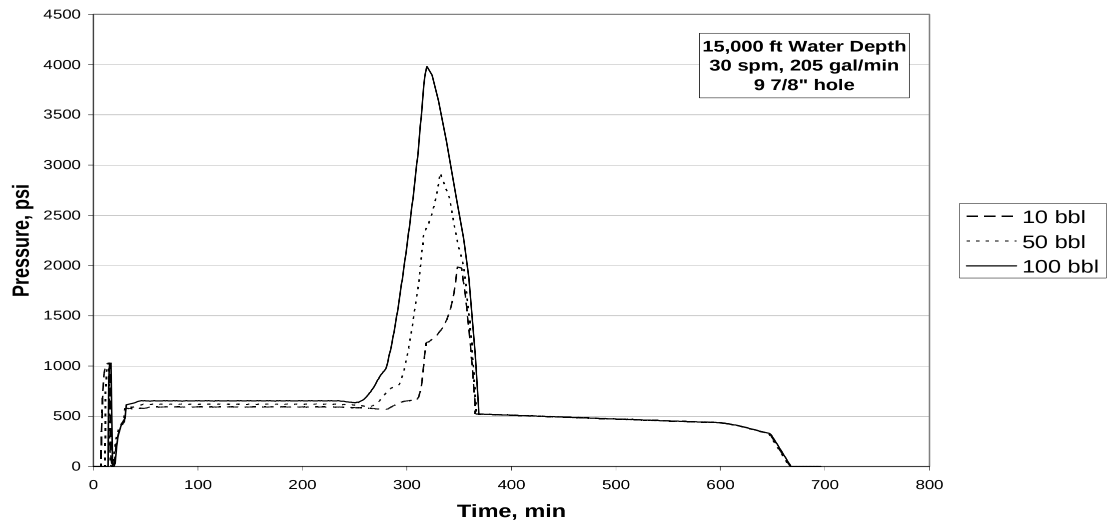

Fig. 10 – Choke pressure for various kick sizes in 15,000 ft of water.

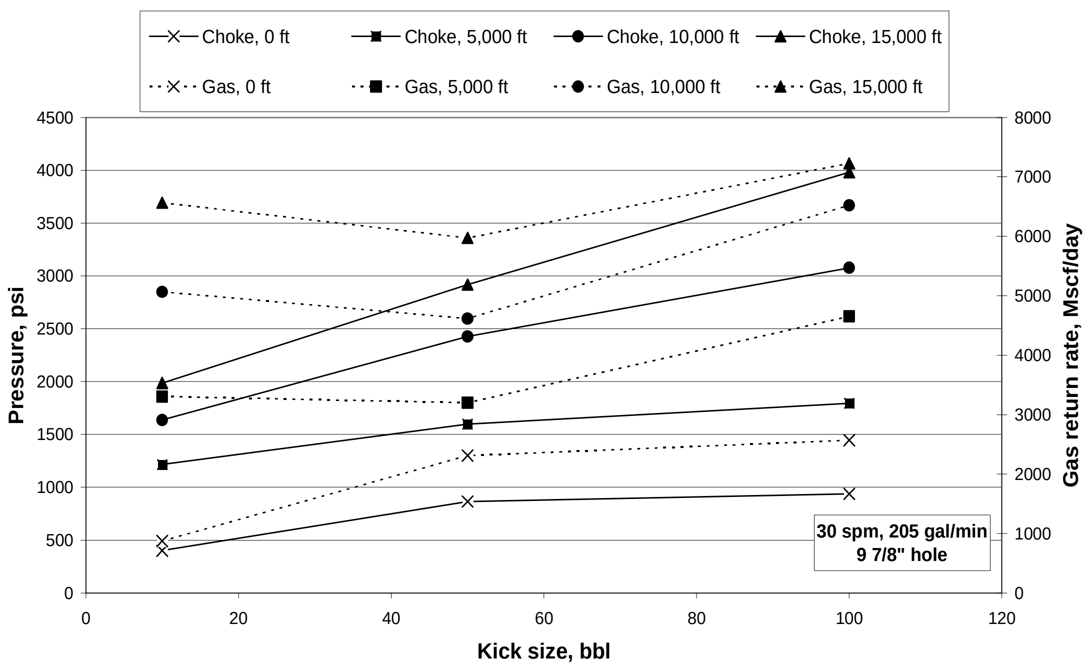

Fig. 11 – Maximum choke pressure and gas return rate for various kick sizes and water depths.

Fig. 11 shows the maximum choke pressure and gas-return rate at surface observed for 10-, 50-, and 100-bbl kicks in water depths of 0, 5,000, 10,000, and 15,000 ft. Here the choke pressure increases more rapidly in deep water than in more shallow water as the kick size increases. We can see that for all offshore cases the gas-return rate at the surface is greater when circulating out a 10-bbl kick than it is for the 50-bbl kick, but then rises and reaches its highest value at the 100-bbl kick size. I expected the maximum gas rate to increase with larger kick sizes, but in these cases the peak gas rate seems to have occurred between two time steps in the simulator, resulting in recorded values less than the real values. On the other hand, the onshore cases follow the predicted pattern where the maximum gas rate increases with greater kick size.

Effect of varying kick sizes and circulation rates for different hole sizes

Introduction

It believed that the hole size would be of great importance in a well-control situation. A given kick size will displace a greater length interval of mud in a slim hole than it will for a larger hole. This can cause a rapid loss of hydrostatic pressure even for relatively small kick sizes, which again can cause the well to flow even more. Another important parameter is the kill-circulation rate. Obviously a large hole would require a higher circulation rate than a slim hole to maintain the desired annular fluid flow velocity. During a well-kill operation, the circulation rate should be high enough to remove the gas out from the hole, which can be a problem in highly inclined wellbores. On the other hand, too high circulation rate could lead to an excessive ECD, fracturing the formation with the subsequent fluid loss. Also circulating too fast could cause large amounts of gas to approach the surface too fast, which could lead to hazardous pressure on surface equipment and a gas peak rate that exceeds the maximum rate the gas/mud separator can handle.

Discussion of the results

From **Fig. 12** we can see that the trend is a bit different for the 6½-in. hole than the larger hole sizes. The maximum choke pressure increases with larger kick size for all cases, as expected. As the kick size increases from 50 bbl to 100 bbl, note the significant increase in gas return rate for the 6½-in. hole. The reason for this, as mentioned in the introduction, is the higher annular velocity in the slim hole that causes a rapid approach of gas to the surface.

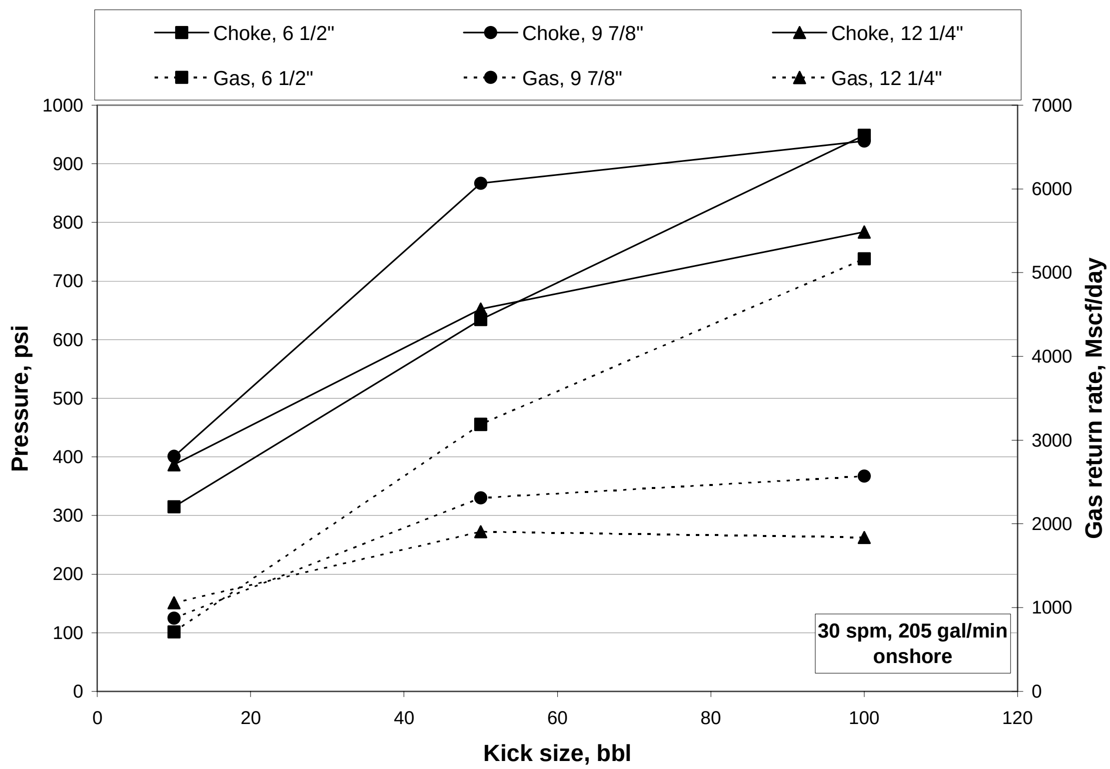

Fig. 12 – Maximum choke pressure and gas return rate for various kick and hole sizes.

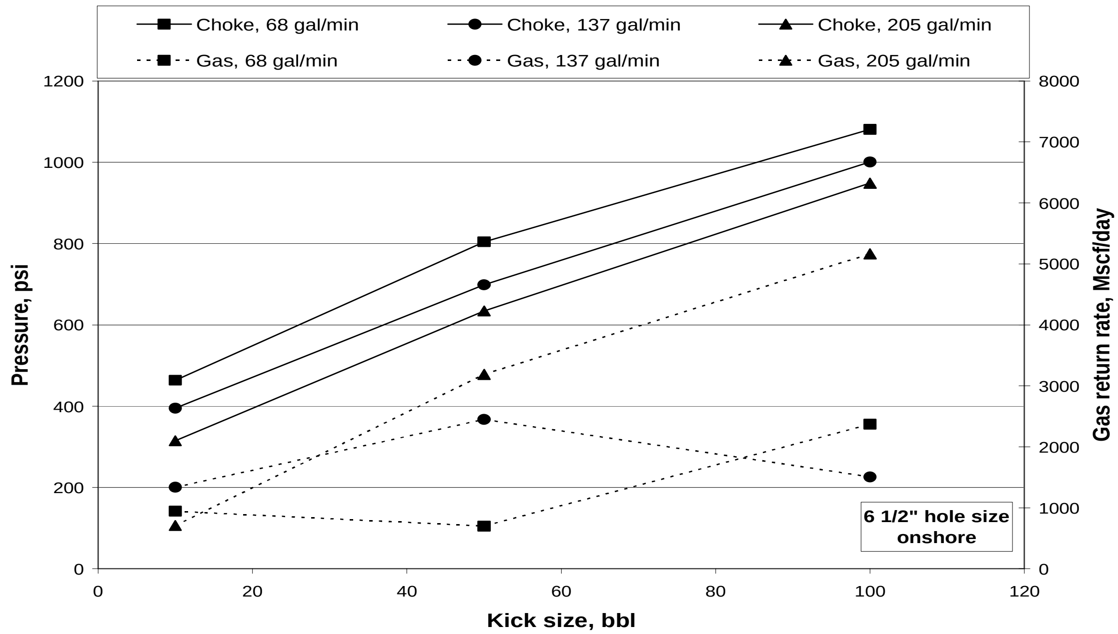

Fig. 13 – Maximum choke pressure and gas return rate for various circulation rates and kick sizes in a 6½-in. hole.

Figs. 13, 14, and 15 show maximum choke pressure and peak gas return rate at surface recorded for different kick sizes. Each kick was circulated out with three different kill rates. For the 6½-in. hole, the chosen kill rates were 68, 137, and 205 gal/min. Any higher kill rate would be unrealistically high, and was not tested. For the $9^{7}/_{8}$-in. and 12¼-in. hole the selected circulation rates were 137, 205, and 274 gal/min. The maximum choke pressure increases as the circulation rate increases, also as expected. But another quite consistent pattern cannot fully be explained are the maximum gas return rates in **Fig. 14 and 15.** We can see that the gas return rates increase to the largest value for the 50-bbl kicks, and then decrease to a lower value for the 100-bbl kicks. I expected the gas return rates to increase with larger kick sizes all the way, not only the step from 10 to 50 bbl. Results of a further investigation are presented later in this section.

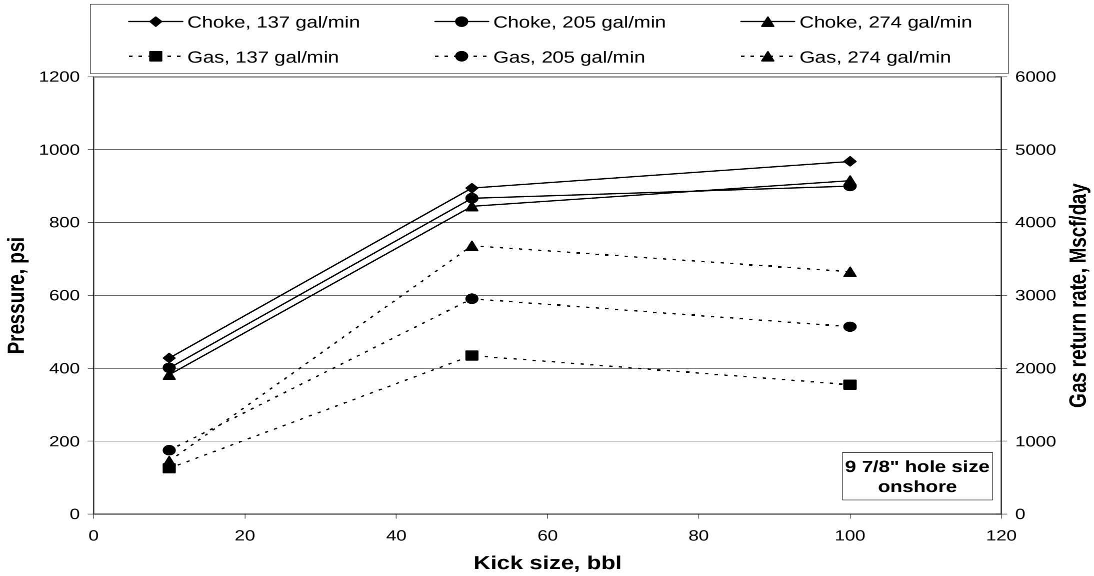

Fig. 14 – Maximum choke pressure and gas return rate for various circulation rates and kick sizes in a 9⁷/₈-in. hole.

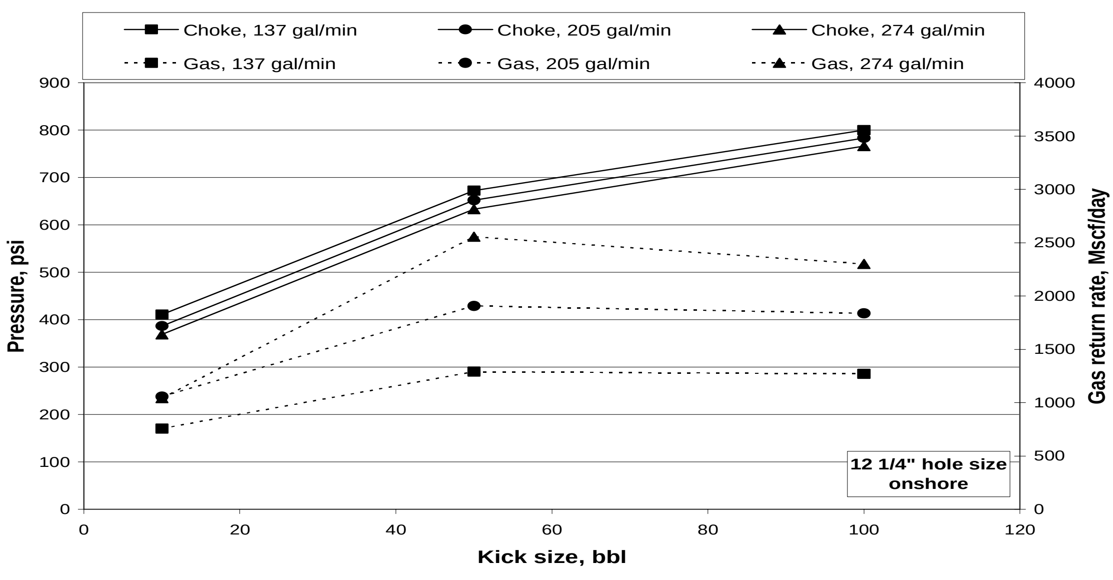

Fig. 15 – Maximum choke pressure and gas return rate for various circulation rates and kick sizes in a 12¼-in. hole.

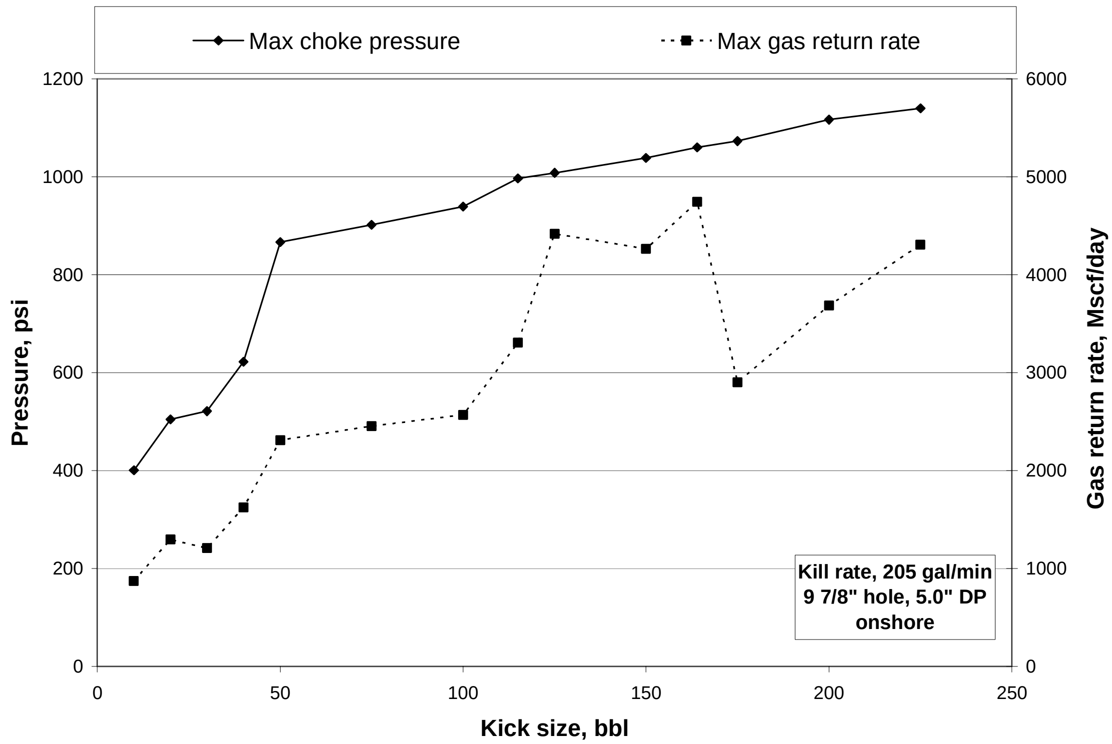

Fig. 16 - Maximum choke pressure and gas return rate for various kick sizes in a 9 $^7/_8$-in. hole.

To get a more detailed overview of the development of the maximum choke pressure and gas rate, I performed many more simulation runs for the 9$^7/_8$-in. and 12¼-in. holes. The kill circulation rate was set to 205 gal/min for all the runs, and the kick sizes ranged from 10 to 225 bbl. From **Fig. 16** we can clearly see the jump in choke pressure as the kick size get close to 50 bbl. The reason for this is that kick sizes of 50 bbl or more will have dry gas through the whole choke when the maximum choke pressure is recorded. **Fig. 17** does not show the same tendancy as clearly, the choke pressures increase almost linearly with increased kick size. Also the maximum gas return rates show a more even trend than **Fig. 16**, which is much more crooked. The time steps used in the simulator make the recorded values for maximum gas-return rates less accurate than the choke-pressure values. The peak gas rates occur only for a very short period of time, and are most likely to fall between two time steps.

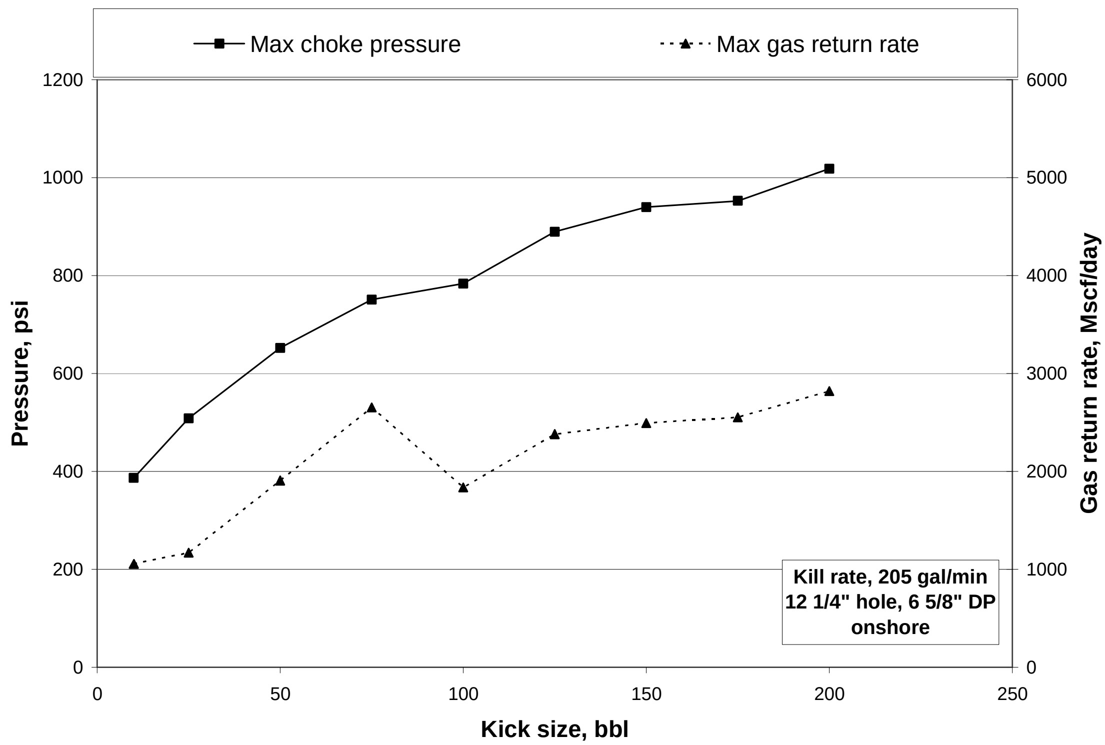

Fig. 17 - Maximum choke pressure and gas return rate for various kick sizes in a 12¼-in. hole.

Effect of varying kick intensity for different water depths

Introduction

The kick intensity is a measure of the amount of density increase necessary to balance the formation pressure. That means for a 1 ppg kick intensity, the mud weight has to be raised by 1 ppg to increase the BHP enough to stabilize the formation pressure. For this investigation, cases were run for 0.5 ppg, 1.0 ppg, and 1.5 ppg for onshore and offshore wells. The water depths for the offshore wells were 5,000 ft, 10,000 ft , and 15,000 ft. All the cases are for a 100-bbl kick size. **Fig. 18** shows the effect on choke pressure for various kick intensities and water depths.

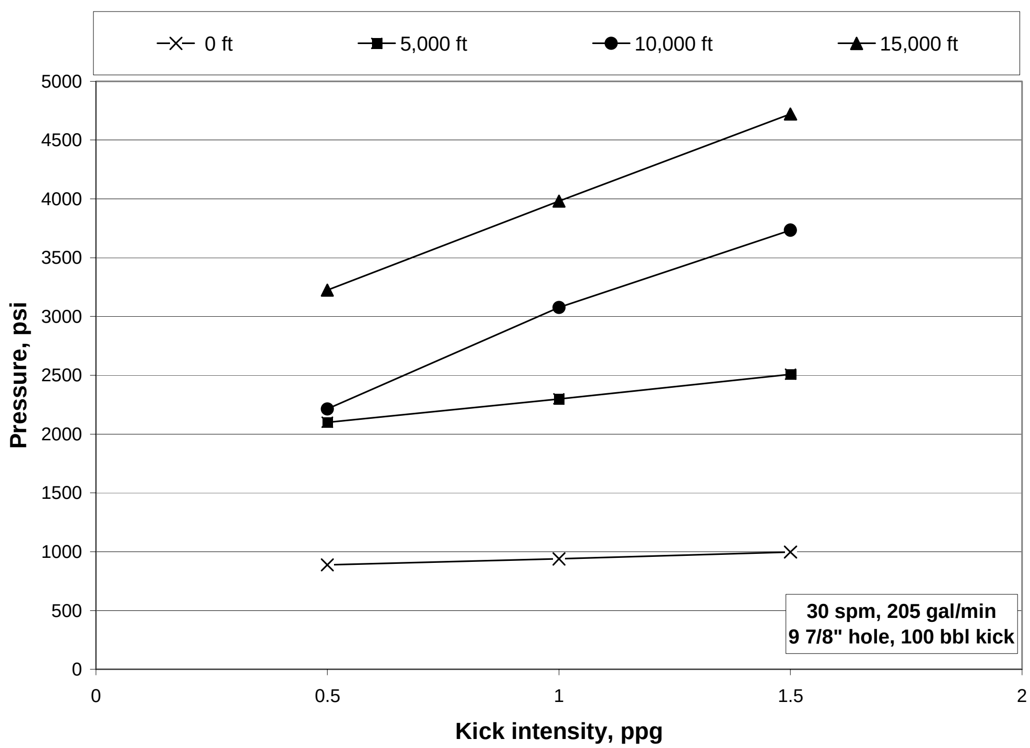

Fig. 18 – The effect on choke pressure when varying kick intensity and water depths.

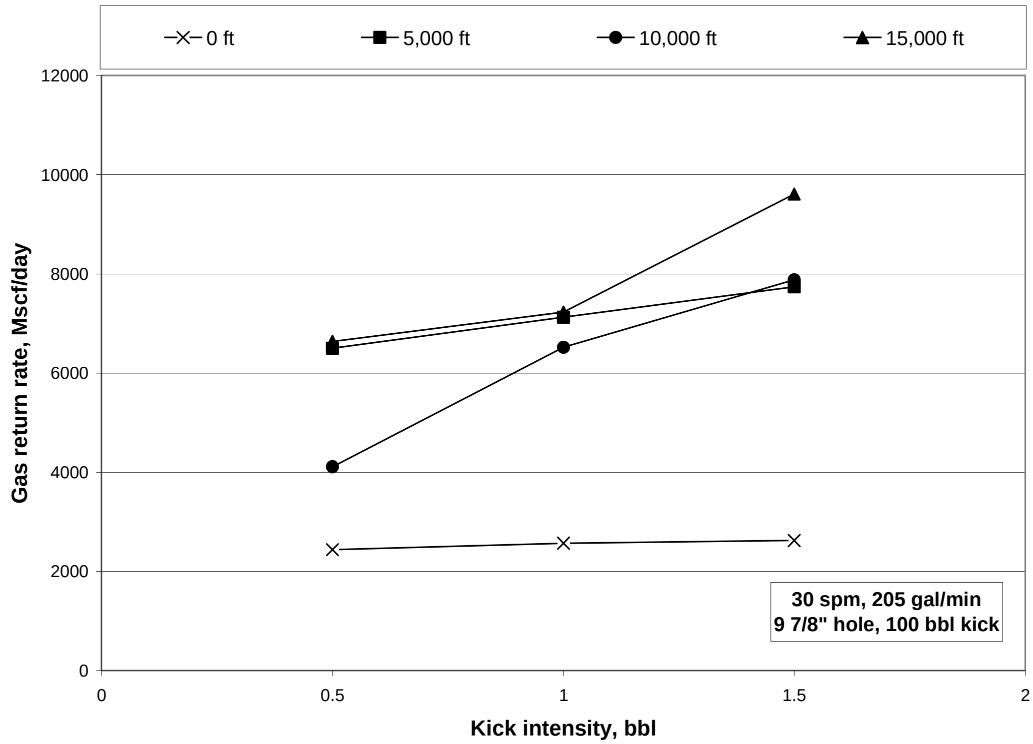

Fig. 19 – The effect on gas return rate at surface when varying kick intensity and water depths.

Discussion of the results

Fig. 18 shows that the higher the kick intensity, the higher the choke pressure will be. The reason for this is that when the kick intensity increases, the bottomhole pressure has to be increased enough to stop the influx, and that means higher choke pressure. For the onshore well there is just a moderate increase in choke pressure with increased kick intensity. As the water depths get deeper, the pressure gradients are steeper. This is because of the formation overpressure which increases with water depth and kick intensity. The same trends are also observed for the gas rates at the surface (**Fig. 19**).

GAS REMOVAL IN HIGHLY INCLINED AND HORIZONTAL WELLBORES

Introduction

Gas kicks in highly inclined and horizontal wellbores introduce some special problems not present in more conventional vertical wells. Buoyancy of the gas may cause the gas to accumulate and get trapped in the end of the well if that section is inclined upwards. The gas can also get trapped in gas pockets in the high-lying parts of the well trajectory or in washouts. These gas pockets may not be possible to circulate out with the lower kill rate, but could become mobile when normal drilling resumes, which itself can cause new well control problems.[32]

Baca *et al.*[33] studied counter current and co-current gas kicks in horizontal wells, but their results do not provide a complete basis for determining superficial velocities that would ensure removal of all gas from either an accumulation or a continuous formation feed-in.

Recommendations for gas removal in ERD wells

All the authors who have studied gas-kick removal in horizontal wells conclude that high superficial liquid velocities are needed to circulate gas out of the horizontal or highly inclined wellbores.[10,15-24,29,32,33] Rommetveit *et al*.[15] concluded that in general, mud velocities up to 0.9 m/s are needed to clean out gas from sections inclined up to 4^{o} upwards. In a 9.875-in. hole and 5.0-in. drillpipe a kill rate of 524 gal/min is required to obtain an annular velocity of 0.9 m/s. That is almost 40% faster than the drilling mode used in the simulation runs, and would not be realistic for an ERD well. A more detailed description of this calculation is presented in Appendix C.

A general recommendation when circulating out a gas kick in an ERD well is to start the circulation with a high rate, maybe close to normal drilling. The reason for this is to get the gas out of the horizontal and into the inclined hold section. An ERD well has a very long wellbore, and should be able to handle a high kill rate for a short period of time without causing excessive surface pressures and gas rates. The casing shoe is usually set close to TVD of the target, and the risk of fracturing the casing shoe should be minimal. When the gas is expected to be circulated out of the horizontal section and into the hold section, the kill rate can be reduced to a normal rate, usually ⅓ to ½ of normal drilling rate. In the hold section, the gas will migrate and flow co-currently, and a normal kill rate should be sufficient to circulate the gas out of the well.

SUMMARY, CONCLUSIONS AND RECOMMENDATIONS

Introduction

The main purpose of this research was to determine which factors have a significant effect on choke pressures and gas-return rates for various kick scenarios. The variables were kick size, true vertical depth of the well, water depth, circulation kill rate, hole sizes, and kick intensity. The tool used for this research is the two-phase well-control simulator developed by Choe and Juvkam-Wold at Texas A&M University.

Effect of kick size

One of the most important parameters in well control is the initial pit volume gain. Kick size was the most frequently changed variable, and the results indicate that it affects the magnitude of the choke pressure and gas return rate throughout the well-control operation.

Effect of water depth

The hydrostatic pressure increases with water depth, so changing both water depths and TVDs has the same trend for the results. The small inner diameter of the choke lines for offshore wells represents a small volume capacity and high flow frictions during well-control operations. From the results we can see that the choke pressures and gas rates increase with water depth. There is a significant difference in choke pressures for onshore and offshore wells, and the reason for this is that the choke pressure increases rapidly to compensate for hydrostatic-pressure reduction when the gas kick starts to fill the choke line, and this becomes more significant the deeper the water is.

Effect of circulation kill rate

The main trend for all the cases is that an increase in kill rate increases the choke pressures and the gas-return rates. Higher circulation means faster arrival of gas to the surface, which leads to greater pressure. The annular friction-pressure loss increases with higher kill rate and reduces the choke pressure; however, this reduction is negligible compared to the effect of gas returning to the surface at a faster rate.

Effect of hole size

Three different hole sizes were used in this investigation, mostly 9 $^{7}/_{8}$-in. but also some cases with 6½-in. and 12¼-in. just to see the effect. Obviously the hole volume capacity increases with hole size, and a 10-bbl kick in a slim hole will displace more feet of mud in the wellbore than in a larger hole size. This results in higher choke pressure and gas return rate for slim holes as long as the circulation rate is constant for all hole sizes.

Effect of kick intensity

With an increase in kick intensity, higher BHP is required to stop the influx of kick fluids into the wellbore. This results in higher choke pressure and gas return rate, which can also be seen from the results.

Recommendations for well control procedures in ERD wells

Based on the literature review and the simulation study, the following recommendations have been made for well-control procedures in ERD wells:

- Once a kick is detected and confirmed, take a “hard” shut-in of the well. Wait until the pressures have stabilized, then record SIDPP, SICP and pit gain.
- Start immediately to circulate using the Driller’s Method. In an ERD well, the casing shoe is close to TVD and should not affect the choice of kill methods. Also the wellbores in ERD wells are very long, and waiting for the kill weight-mud to be prepared will take a long time. If there are problems with hole

cleaning, it is best to resume circulating as soon as possible.

- Start circulating at a high rate for a short time to remove gas from the horizontal section of the wellbore. Once the choke pressure starts to increase rapidly, slow down the pumps and continue the circulation with a kill rate $^1/_3$ to ½ of the rate in drilling mode.

- The drillpipe pressure decline schedules are prepared for one pre-determined kill circulation rate. If various circulation rates are used, pressure decline schedules have to be made for each circulation rate. The reason for this is the friction pressure loss which increases with higher circulation rate.

Recommendations for future work

The next step would be to investigate kick scenarios for multilateral wells, which will also be done shortly.

NOMENCLATURE

ERD	Extended reach drilling
HD	Horizontal departure
TVD	True vertical depth
RSS	Rotary steerable systems
MWD	Measurement while drilling
LWD	Logging while drilling
SICP	Shut-in casing pressure
SIDPP	Shut-in drillpipe pressure
BOP	Blowout preventer
ECD	Equivalent circulation density
BHP	Bottomhole pressure
ROP	Rate of penetration
ICP	Initial circulating pressure
FCP	Final circulating pressure
ppg	pound per gallon
spm	strokes per minute
bbl	barrel
CDPP	circulating drillpipe pressure
P_{ch}	Pressure at the choke
ΔP_{ma}	Hydrostatic column of mud in annulus
ΔP_{md}	Hydrostatic column of mud in drillpipe
ΔP_{kb}	Hydrostatic column of kick fluid in annulus
ΔP_{dp}	Total friction pressure loss in drillpipe
ΔP_{a}	Total friction pressure loss in annulus
ΔP_{bit}	Pressure drop through the bit

REFERENCES

1. Economides, M.J., Watters, L.T., and Dunn-Norman, S.: *Petroleum Well Construction*, John Wiley & Sons Ltd., London (1998).
2. Al-Suwaidi, A.S., El-Nashar, R.A., Allen, F., and Brandao, F.J.: "World Class Extended-Reach Drilling Performance in Abu Dhabi – A Case Study in How to Beat the Learning Curve," paper SPE 72279 presented at the 2001 IADC/SPE Middle East Drilling Technology, Bahrain, 22-24 October.
3. Kamaruddin, S., Lah, M.Z.C., Sering, L., Good, A., and Khun, L.H.: "Pushing the Envelope – Extending the Limits of Current Drilling Technology," paper SPE 64696 presented at the 2000 SPE International Oil and Gas Conference and Exhibition, Beijing, China, 7-10 November.
4. Payne, M., Cocking, D.A., and Hatch, A.J.: "Critical Technologies for Success in Extended Reach Drilling," paper SPE 28293 presented at the 1994 SPE Annual Technical Conference and Exhibition, New Orleans, 25-28 September.
5. Tribe, I.R., Burns, L., Howell, P.D., and Cickson, R.: "Precise Well Placement Using Rotary Steerable Systems and LWD Measurements," paper SPE 71396 presented at the 2001 SPE Annual Technical Conference and Exhibition, New Orleans, 30 September–3 October.
6. Colebrook, M.A., Peach, S.R., Allen, F.M., and Conran, G.: "Application of Steerable Rotary Drilling Technology to Drill Extended Reach Wells," paper SPE 39327 presented at the 1998 IADC/SPE Drilling Conference, Dallas, 3-6 March.
7. Meader, T., Allen, F., and Riley, G.: "To the Limit and Beyond – The Secret of World-Class Extended-Reach Drilling Performance at Wytch Farm," paper SPE 59204 presented at the 2000 IADC/SPE Conference, New Orleans, 23-25 February.

8. Cunha, J.C., Martins, A.L., Sa, C.H.M., and Fernandes, P.D.: "Planning Extended Reach Wells for Deep Water," paper SPE 74400 presented at the 2002 SPE International Petroleum Conference and Exhibition, Villahermosa, Mexico, 10-12 February.
9. Allen, F., Tooms, P, Conran, G., Lesso, B., and Van de Slijke, P.: "Extended-Reach Drilling: Braking the 10-km Barrier," http://www.slb.com/ Hub/Docs/connect/reference/oilfield_review/ors97/win97/pdf/ex_drilling.pdf, Winter 1997.
10. Watson, D., Brittenham, T., and Moore, P.: *Advanced Well Control Manual*, SPE Textbook Series, SPE, Richardson, TX (2003).
11. Rader, D.W., Bourgoyne, A.T. Jr., and Ward, R,H.: "Factors Affecting Bubble-Rise Velocity of Gas Kicks," *JPT* (May 1975) 571.
12. Johnson, A.B. and White, D.B.: "Gas-Rise Velocities During Kicks," *SPE Drilling Engineering* (December 1991) 257.
13. Johnson, A.B, and Cooper, S.: "Gas Migration Velocities During Gas Kicks in Deviated Wells," paper SPE 26331 presented at the 1993 SPE Annual Technical Conference and Exhibition, Houston, 3-6 October.
14. Schubert, J.J.: "Well Control Procedures for the Proper Identification and Handling of Kicks for the Prevention of Blowouts," MEng report, Texas A&M University, College Station, Texas (1995).
15. Rommetveit, R., Bjorkevoll, K.S., Bach, G.F., Aas, B., Hy-Billiot, J. *et al.*: "Full Scale Kick Experiments in Horizontal Wells," paper SPE 30525 presented at the 1995 SPE Annual Technical Conference & Exhibition, Dallas, 22-25 October.
16. Nunes, J.O.L., Bannwart, A.C., and Ribeiro, P.R.: "Mathematical Modeling of Gas Kicks in Deep Water Scenario," paper SPE 77253 presented at the 2002 IADC/SPE Asia Pacific Drilling Technology, Jakarta, 9-11 September.
17. Santos, O.L.A.: "Important Aspects of Well Control for Horizontal Drilling Including Deepwater Situations," paper SPE 21993 presented at the 1991 SPE/IADC Drilling Conference, Amsterdam, 11-14 March.

18. Santos, O.L.A.: "Well Control Operations in Horizontal Wells," paper SPE 21105 presented at the 1990 SPE Latin American Petroleum Engineering Conference, Rio de Janeiro, 14-19 October.

19. Vefring, E.H., Wang, Z., Gaard, S., and Bach, G.F.: "An Advanced Kick Simulator for High Angle and Horizontal Wells – Part I," paper SPE 29345 presented at the 1995 SPE/IADC Drilling Conference, Amsterdam, 28 February-2 March.

20. Vefring, E.H., Wang, Z., Gaard, S., and Bach, G.F.: "An Advanced Kick Simulator for High Angle and Horizontal Wells – Part II," paper SPE 29860 presented at the 1995 Middle East Oil Show, Bahrain, 11-14 March.

21. Wang, Z., Peden, J.M., and Lemanczyk, R.Z.: "Gas Kick Simulation Study for Horizontal Wells," paper SPE 27498 presented at the 1994 IADC/SPE Drilling Conference, Dallas, 15-18 February.

22. Baca, H.E.: "Counter Current and Co-Current Gas Kick Migration in High Angle Wells," MS thesis, Louisiana State University, Lafayette, Louisiana (1999).

23. Ustun, F.: "The Effect of High Liquid Flow Rates on Co-Current and Counter-Current Gas Kick Migration in High Angle Wells," MS thesis, Louisiana State University, Lafayette, Louisiana (2000).

24. Lage, A.C.V.M., Rommetveit, R., and Time, R.W.: "An Experimental and Theoretical Study of Two-Phase Flow in Horizontal or Slightly Deviated Fully Eccentric Annuli," paper SPE 62793 presented at the 2000 IADC/SPE Asia Pacific Drilling Technology, Kuala Lumpur, 11-13 September.

25. Choe, J. : "Dynamic Well Control Simulation Models for Water-Based Muds and Their Computer Applications," PhD dissertation, Texas A&M University, College Station, Texas (1995).

26. Choe, J. and Juvkam-Wold, H.C.: "A Modified Two-Phase Well-Control Model and Its Computer Applications as a Training and Educational Tool," *SPECA* (February 1997) 14.

27. Westergaard, R.H.: “All About Blowouts,” *Norwegian Oil Review* (1987) **23**, 103.

28. “Losses of Well Control,” Minerals Management Service, http://www.mms.gov/incidents/blowouts.htm, 4 June 2003.

29. Lage, A.C.V.M., Nakagawa, E.Y, and Cordovil, A.G.D.P.: “Well Control Procedures in Deep Water,” paper SPE 26952 presented at the 1994 Latin American/Caribbean Petroleum Engineering Conference, Buenos Aires, 27-29 April.

30. Jardine, S.I., Johnson, A.B., and White, D.B.: “Hard or Soft Shut-In: Which Is the Best Approach?” paper SPE/IADC 25712 presented at the 1993 SPE/IADC Drilling Conference, Amsterdam, 23-25 February.

31. Al-Shammari, H.A. and Nordquist, D.G.: “Revised BOP and Well Control Policies in the Kingdom of Saudi Arabia,” paper SPE 77227 presented at the 2002 IADC/SPE Asia Pacific Drilling Technology, Jakarta, 9-11 September.

32. Aas, B., Bach, G., Hauge, H.C. and Sterri, N.: "Experimental Modelling of Gas Kicks in Horizontal Wells," paper SPE/IADC 25709 presented at the 1993 SPE/IADC Drilling Conference, Amsterdam, 23-25 February.

33. Baca, H., Nikitopoulos, D.E., Smith, J.R., and Bourgoyne, A.T.: “Counter Current and Co-Current Gas Kicks in Horizontal Wells: Non-Newtonian Rheology Effects,” *JERT*, (March 2003) **125**, 51.

APPENDIX A
PLANNING A KILL

Calculating bottomhole pressure

The bottomhole pressure is the pressure at the surface plus the total hydrostatic pressure between the surface and the bottom.

- Calculating bottomhole pressure before taking a kick:
  BHP = Hydrostatic pressure in DP
- Calculating bottomhole pressure after taking a kick:
  BHP = SIDPP + Hydrostatic pressure in DP

The static bottomhole pressure as determined from the drillstring and annulus legs for the U-tube are:

Annulus Drillstring

$BHP = SICP + \Delta P_{ma} + \Delta P_{kb} = SIDPP + \Delta P_{md}$

The circulating drillpipe pressure (CDPP) is the sum of the pressure losses in the drillstring, bit, and annulus. When killing a well, the hydrostatic pressures are no longer balanced and additional backpressure is created at the choke.

The circulating bottomhole pressures are then defined as:

Annulus Drillstring

$BHP = P_{ch} + \Delta P_{ma} + \Delta P_{a} = CDPP + \Delta P_{md} + \Delta P_{kb} - \Delta P_{dp} - \Delta P_{bit}$

Fig. 20 shows typical drillpipe pressures for a well before and after taking a kick in static condition and CDPP as a function of depth.

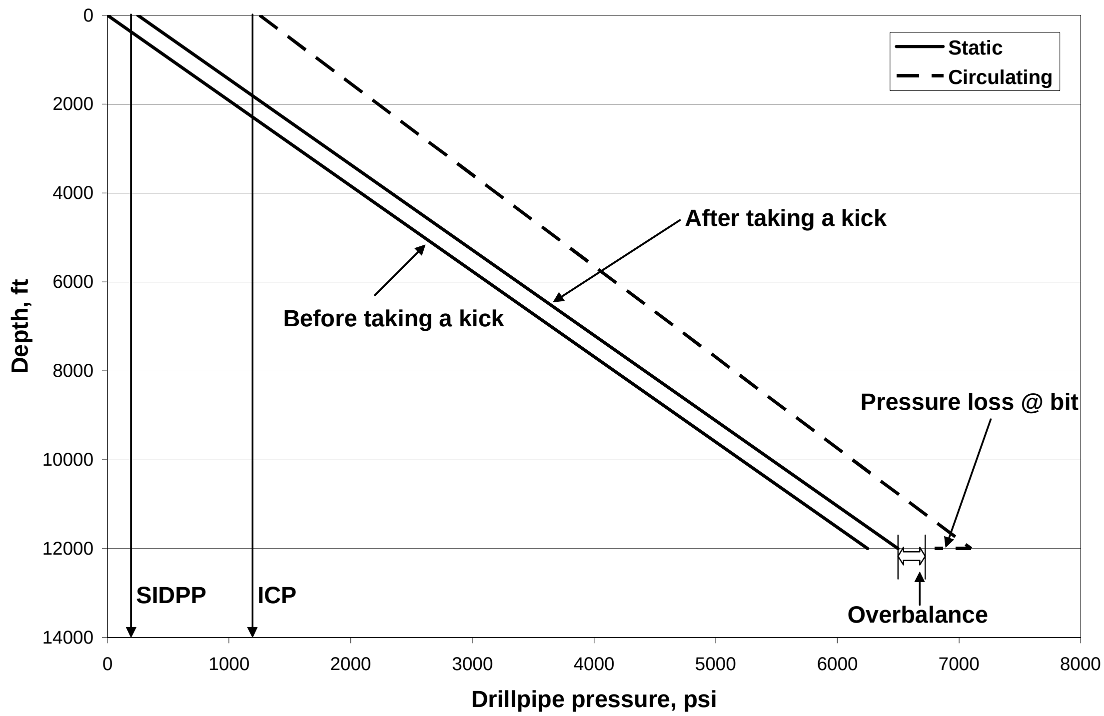

Fig. 20 – Drillpipe pressure vs. depth for circulating and static conditions.

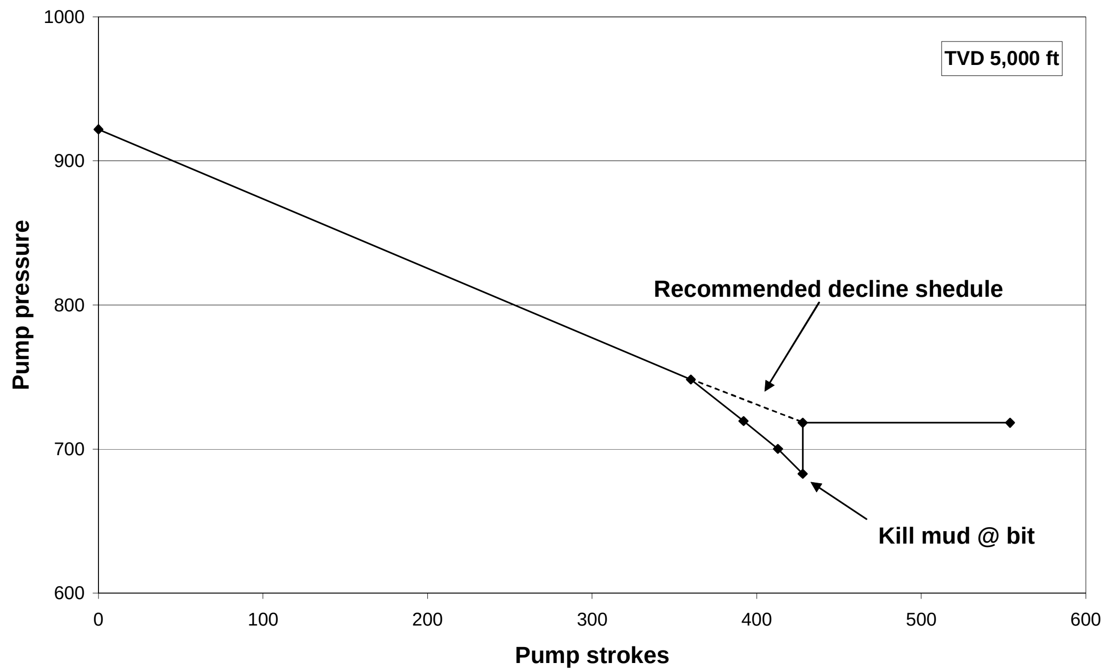

Fig. 21 – Pressure-decline kill sheet for a vertical well.

Figs. 21 – 23 are theoretical drillpipe pressure decline schedules for various wellbore profiles. In **Fig. 21** we have a vertical well, and we can see that the CDPP follows a straight-line decline. This is because it is a vertical well, and since the hydrostatic pressure is a function of TVD and mud weight only, there will be a straight line.

In **Fig. 22** we have a horizontal well, and we have a straight decline line for the horizontal section, and almost a constant pressure in the horizontal section. The slight increase in pressure in the horizontal section is because of the friction pressure loss.

In **Fig. 23** we have an ERD well. The pressure decline is steep for the vertical and the build-up section, but changes to a more constant pressure in the hold section. The TVD increases as we go down the hold section, and so will the hydrostatic pressure. As we reach the horizontal section, the hydrostatic pressure remains constant, but the friction pressure loss causes the pressure to rise slightly. The friction pressure loss is a function of measured depth only, not TVD.

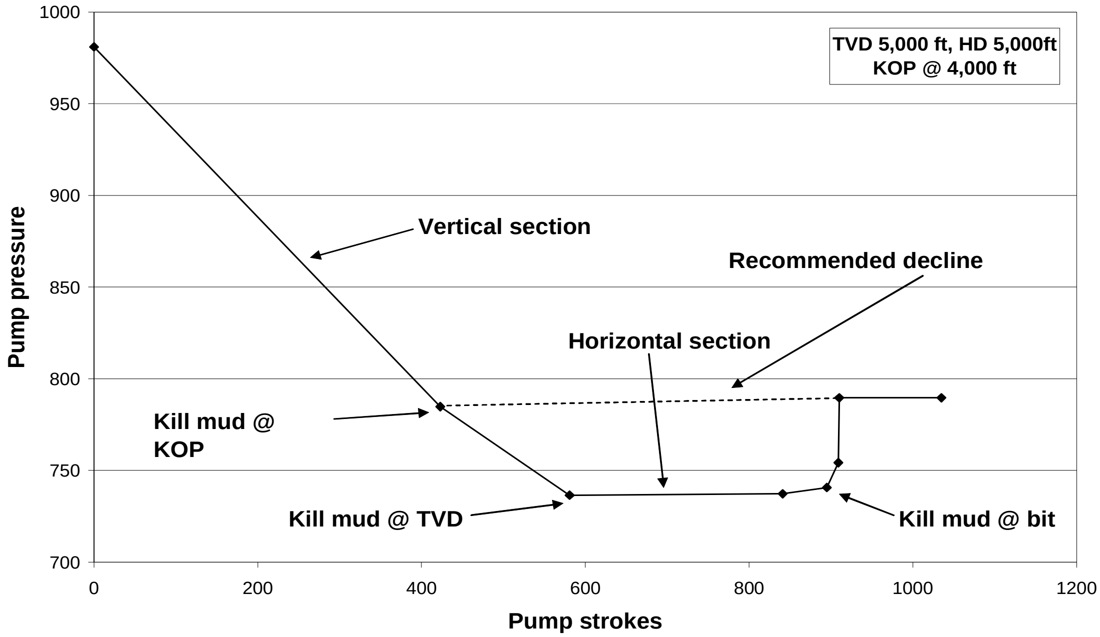

Fig. 22 – Pressure-decline kill sheet for a horizontal well.

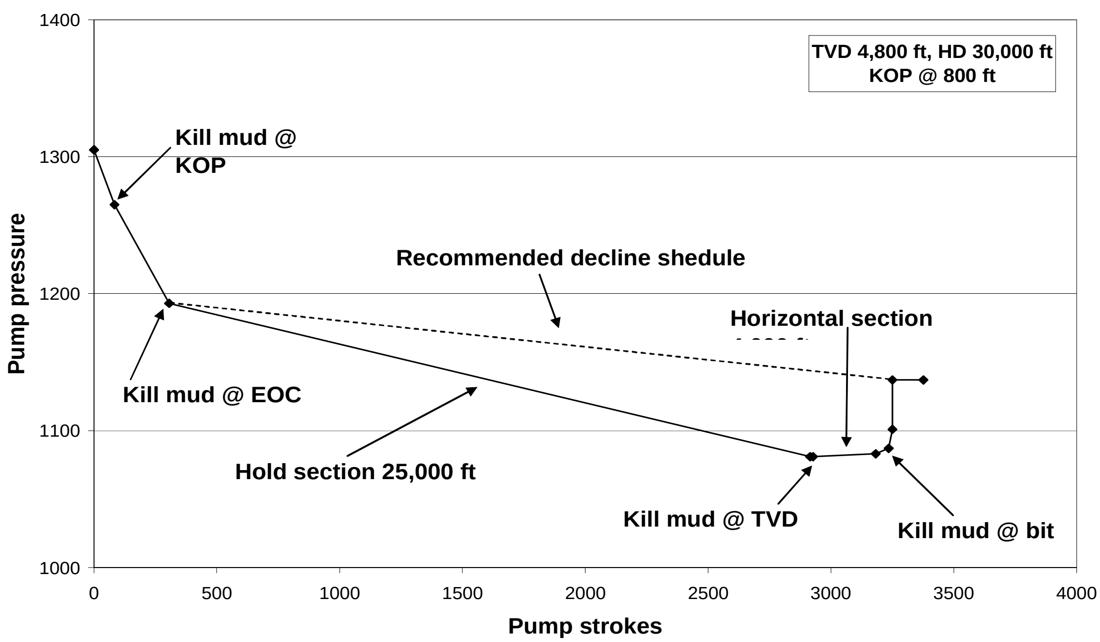

Fig. 23 – Pressure-decline kill sheet for an ERD well.

APPENDIX B
WELL CONTROL COMPLICATIONS

Introduction

The well-control operations presented earlier in this thesis are only for those cases where the drillstring is below the influx, the well can be shut-in without any major complications, the BHP can be read from the drillpipe gauge, and the kick can be circulated out safely. However, there are situations when the conventional circulation kill techniques cannot be applied. These situations could be:

- Drillbit is plugged.
- Migrating influx is beneath the bit or the pipe is out of the hole.
- Drillpipe has parted or has a hole above the influx.
- Annulus cannot withstand the backpressures imposed during kick circulation.
- Well is shut-in with the blind rams.
- Pumps are malfunctioning and the drillstring is not filled with mud.
- Gas has entered the drillstring.

Volumetric method

The volumetric method can be used on a well that is shut in and a migrating influx is indicated, but the bottomhole pressure cannot for some reason be read confidently. Volumetric control is mostly the same as the Driller's Method; the only fundamental difference is that the buoyancy of the kick is the primary drive mechanism rather than the pump.

After the well is shut in, the gas migration will start to drive up the casing pressure from its initial shut-in reading. The casing pressure is allowed to rise to a predetermined safety margin. Reaching the working margin pressure indicates the point when the choke operator starts to bleed mud from the well. He tries to maintain a constant casing pressure while cracking the choke periodically and removing mud from the well. The gas expands, and the idea is to remove enough volume so that the hydrostatic pressure in the removed mud is equivalent to the working margin buildup. After the removal of this amount of mud, the gas influx has expanded by an amount equal to the incremental mud volume removed from the well, and the BHP is reduced back to the original shut-in recording. This operation is continued until the choke pressures stabilize or secondary control can be regained. If the influx reaches the surface and gas is coming through the choke, the bleeding process is stopped. The annulus is then monitored for further pressure buildup. The casing pressures for a typical volumetric procedure are plotted against cumulative pit gain in **Fig. 23**. From the figure we can see that the initial pit gain is 20 bbl and the SICP is 100 psi. The pressure is then allowed to increase by the predetermined safety margin (100 psi) and a further increase of 100 psi which is the working margin. When the maximum working margin is reached, approximately 16 bbl of mud is bled off to reduce the bottomhole pressure back to its initial shut-in value, 4,600 psi (**Fig. 24)**. The casing pressure increases as the procedure continues, because the gas expands as it approaches the surface. These steps are repeated until the casing pressure has stabilized, in this example at 700 psi. The bleeding process is stopped if the gas exits the choke, and the annulus pressure is monitored for further build-up.

Lubrication

Lubrication is a method to replace gas at the surface with mud in a controlled manner without circulation. A calculated mud volume is pumped directly into the gas column, and the mud has to fall through the column before the gas is bled until the casing pressure falls to a calculated level. This procedure is repeated until all the gas has been removed.

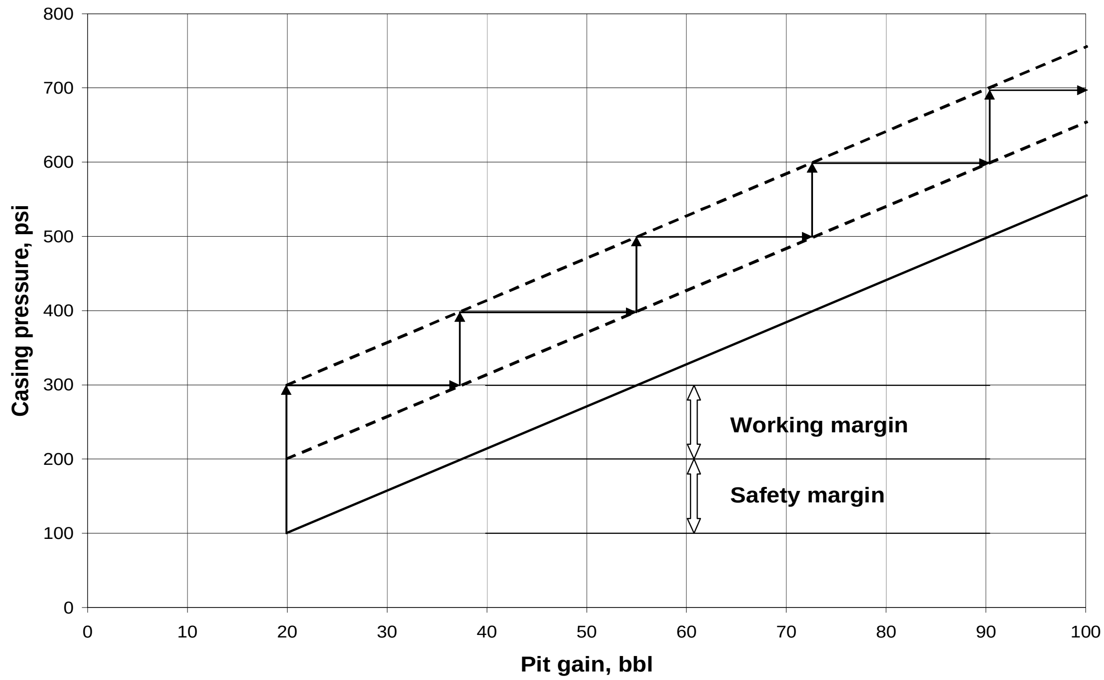

Fig. 24 – Casing pressure during a volumetric procedure.

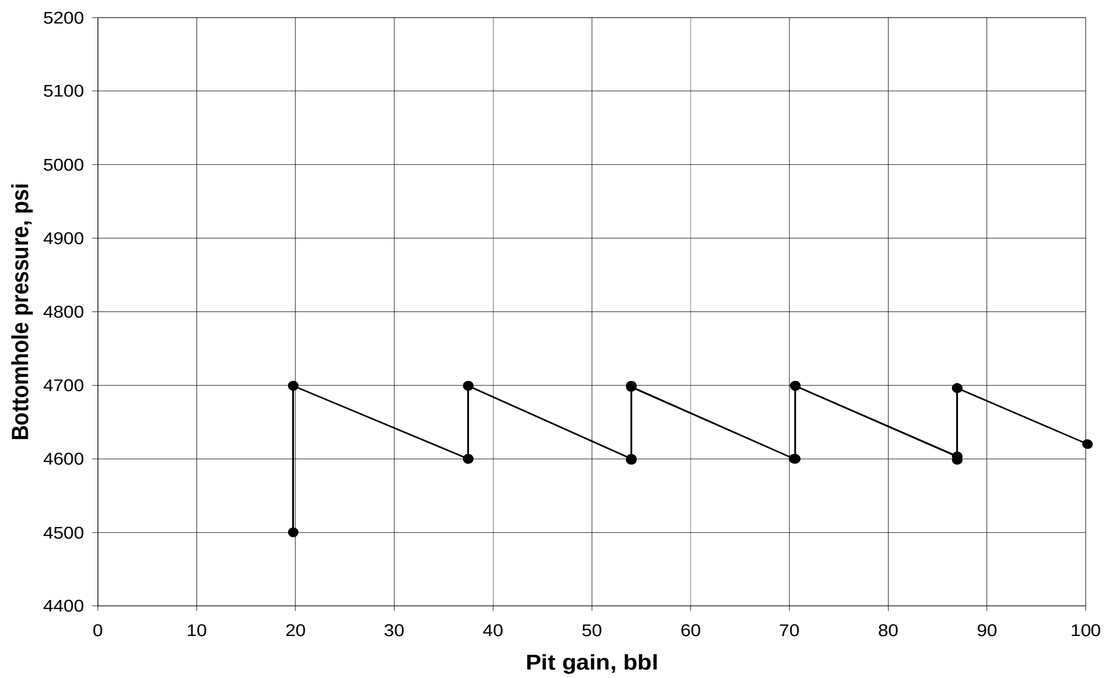

Fig. 25 – Bottomhole pressure during a volumetric procedure.

Staging in the hole

Staging in the hole is used in off-bottom well-control operations. The main idea behind this method is to place heavy enough mud to balance pore pressure from the depth where the bit is located. When the drillpipe is run into the hole, the heavy mud is displaced from the well and lighter mud is replaced from below. This has to be taken into account when calculating the density of the heavy kill-mud.

Reverse circulation

Reverse circulation procedures are most often used during workovers and completion operations, but may be advisable in some situations to circulate out a kick in drilling operations. Fluid is pumped into the annulus and the returns are taken from the drill string. The main advantage of this is that a gas kick is kept within the drill string and protects the formation and casing from excessive pressures. The disadvantages are many; the most important is the friction pressure loss in the drillstring that is much higher than it would be in the annulus. This acts directly on the ECD and the bottomhole conditions, and the ECD can easily get too high resulting in fracture of the formation and loss of circulation.

Bullheading

When applying bullheading, fluid is pumped into the annulus of a shut-in well at a sufficient rate and pressure to fracture the formation and force the kick fluids into the loss zone. This method is fairly common in completed wells, but is not a conventional way of killing a well in standard drilling mode. However, under some circumstances this method may be a good alternative. Reasons for bullheading could include H_2S kicks, inability to circulate on bottom, or a well that is not able to handle a conventional kill.

APPENDIX C

CONVERSION OF ANNULAR VELOCITY TO FLOW RATE

The desired annular velocity = 0.9 m/s.

V = 0.9 m/s × 3.28 ft/m = 2.95 ft/sec.

D_2 = inside diameter of wellbore = 9.875 in.

D_1 = outside diameter of drillpipe = 5.000 in.

Q (gal/min) = V (ft/sec) × 2.448 × [D_2(in)^2 – D_1(in)^2].

Q = 2.95 × 2.448 × [(9.875)^2 – (5.000)^2] = **524 gal/min**.

VITA

Name:	Bjorn Gjorv
Address:	Krokenteig 11
	5760 Roldal
	Norway
Date of birth:	November 7, 1978. Odda, Norway.
Parents:	Mr. Svein Gjorv
	Mrs. Margit Rabbe Gjorv
Education:	Texas A&M University, College Station, TX
	M.S. in Petroleum Engineering, August 2003
	Stavanger University College, Norway
	B.S. in Petroleum Engineering, June 2000