MANAGED PRESSURE DRILLING TECHNIQUES AND TOOLS

A Thesis

by

MATTHEW DANIEL MARTIN

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

May 2006

Major Subject: Petroleum Engineering

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Chair of Committee,	Hans C. Juvkam-Wold
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ABSTRACT

Managed Pressure Drilling Techniques and Tools.

(May 2006)

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

The economics of drilling offshore wells is important as we drill more wells in deeper water. Drilling-related problems, including stuck pipe, lost circulation, and excessive mud cost, show the need for better drilling technology. If we can solve these problems, the economics of drilling the wells will improve, thus enabling the industry to drill wells that were previously uneconomical. Managed pressure drilling (MPD) is a new technology that enables a driller to more precisely control annular pressures in the wellbore to prevent these drilling-related problems. This paper traces the history of MPD, showing how different techniques can reduce drilling problems.

MPD improves the economics of drilling wells by reducing drilling problems. Further economic studies are necessary to determine exactly how much cost savings MPD can provide in certain situation. Furter research is also necessary on the various MPD techniques to increase their effectiveness.

DEDICATION

This thesis is dedicated to my parents for all their support and encouragement throughout the years.

ACKNOWLEDGMENTS

I would like to first thank Dr. Hans C. Juvkam-Wold for the chance to do this research and for all of the advice throughout the years.

I would also like to thank Dr. Jerome Schubert and Dr. Ann Jochens for helping me in completing this thesis and for being on my committee.

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INTRODUCTION

As current reserves deplete, it is necessary to drill to reservoirs that are deeper and more complex. Some industry professionals would say that 70% of the current hydrocarbon offshore resources are economically undrillable using conventional drilling methods.[1] Managed Pressure Drilling (MPD) is a new technology that uses tools similar to those of underbalanced drilling to better control pressure variations while drilling a well. The aim of MPD is to improve the drillability of a well by alleviating drilling issues that can arise.

MPD can improve economics for any well being drilled by reducing a rig's nonproductive time (NPT). NPT is the time that a rig is not drilling. Many of the drilling problems in any well can be reduced by using MPD. As with any new technology, MPD introduces new techniques that require understanding; becoming confident enough in the technology to use it on a regular basis takes time. With the resources that are currently uneconomical in the offshore markets and the problems that occur while drilling a well, it is important that industry look to MPD to improve the drilling ability of the drilling rigs.

This literature review summarizes reported successes of MPD over the last 10 years and shows that additional work is still necessary for the complete evaluation of the technique.

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

BASICS OF MANAGED PRESSURE DRILLING

Managed pressure drilling (MPD) is "an adaptive drilling process to precisely control the annular pressure profile throughout the well."[2] The main idea is to create a pressure profile in the well to stay within close tolerances and close to the boundary of the operation envelope defined by the pore pressure, hole stability envelope and fracture pressure.[3] MPD uses many tools to mitigate the risks and costs associated with drilling wells by managing the annular pressure profile. These techniques include controlling backpressure, fluid density, fluid rheology, annular fluid level, circulating friction, and hole geometry in any combination.[4]

The International Association of Drilling Contractors (IADC) has defined MPD further by creating two categories.[4] Reactive MPD includes drilling programs that are tooled up with at least a rotating control device (RCD), choke, and perhaps drill string float to safely and efficiently deal with problems that could occur downhole. Proactive MPD includes designing a casing, fluids and openhole program that precisely manages the wellbore pressure profile. This category of MPD can offer the greatest benefit to the offshore drilling industry as it can deal with unforeseen problems before they occur.

UBD vs. MPD

MPD is similar to underbalanced drilling (UBD). It uses many of the same tools that were designed for UBD operations. The difference between the methods is that UBD is used to prevent damage to the reservoir while the purpose of MPD is to solve drilling problems.[4] UBD allows influx of formation fluids by drilling with the pressure of the fluid in the wellbore lower than the pore pressure. MPD manages the pressure to remain between the pore pressure and the fracture pressure of the reservoir. It is set up to handle the influx of fluids that may occur while drilling but does not encourage influx. UBD is reservoir-issue related while MPD is drilling-issue related.

Pressure-Gradient Windows

As a well is drilled, drilling fluid is circulated in the hole to obtain a specific bottom hole pressure. The density of the fluid is determined by the formation and pore pressure gradients and the wellbore stability.

Fig. 1 shows a pressure gradient profile of a well. This profile shows the change in pressure as the depth increases. The pressure window is the area between the pore pressure and the fracture pressure. The goal when drilling a well is to keep the pressure inside this pressure window. In a static well, the pressure is determined by the hydrostatic pressure of the mud. In conventional drilling, the only way to adjust the pressure during static conditions is to vary mud weight in the well.

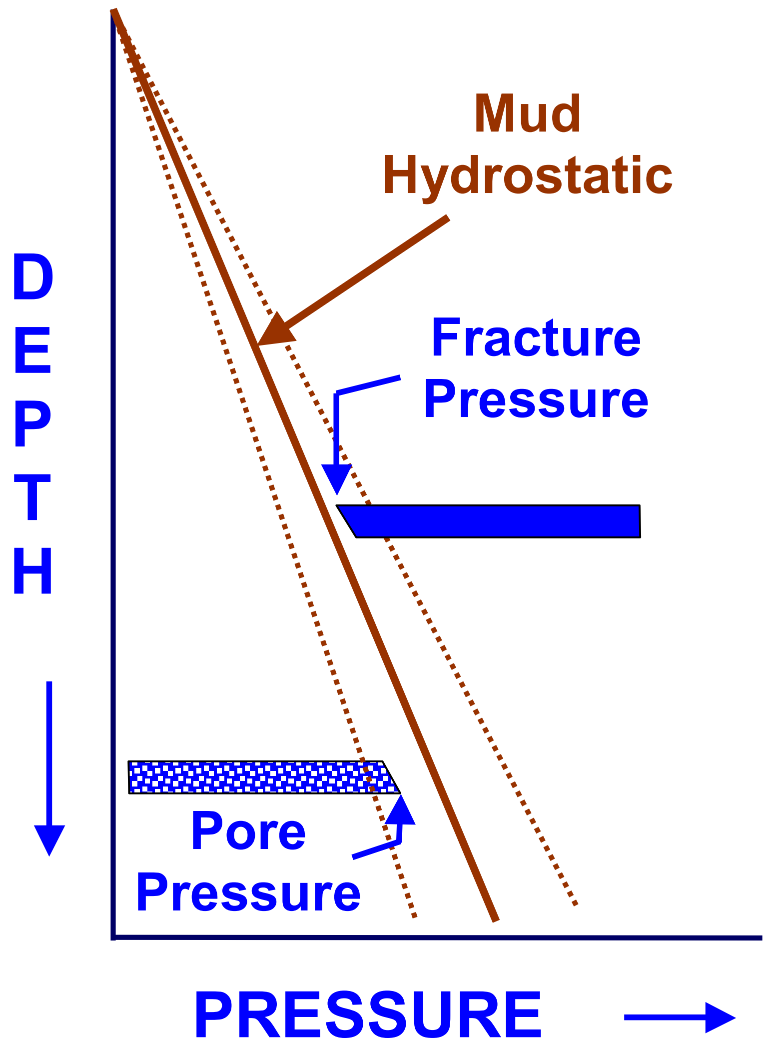

Fig. 1— Pressure-gradient profile (From Juvkam-Wold[5]).

Fig. 2 shows the problem that can occur when dealing with tight pressure-gradient windows. When the well is static, the pressure in the well is less than the pore pressure and the well takes a kick; that is, hydrocarbons flow into the well.[6] Before drilling can begin again, the kick has to be circulated out. After a connection, the pumps restart, the BHP (Bottom Hole Pressure) increases, and the pressure goes above the fracture-pressure, resulting in lost circulation, or fluid flowing into the formation. The goal of managed pressure drilling is to "walk the line" of the pressure gradients. Managing the pressure and remaining inside this pressure gradient window can avoid many drilling problems.

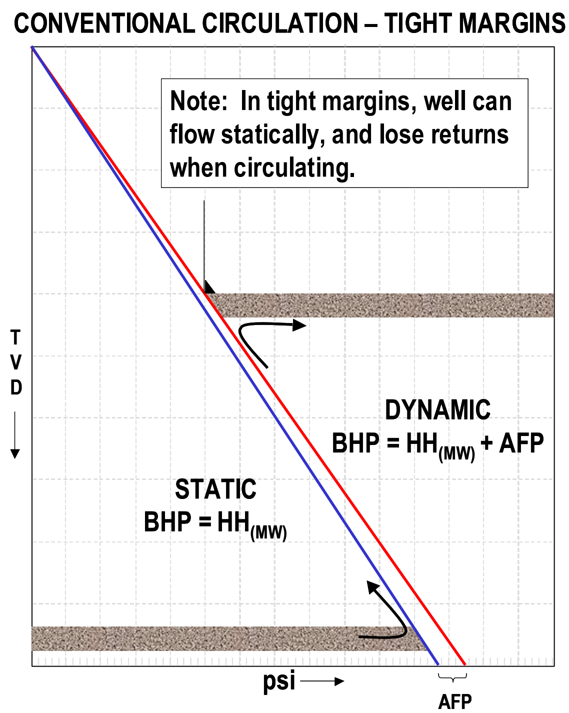

Fig. 2— Pressure gradient window for tight margins (From Hannegan[6]).

How Managed Pressure Drilling Works

The basic technique in MPD is to be able to manipulate the BHP and the pressure profile as needed. In conventional drilling, the BHP can be calculated by summing the mud weight hydrostatic head and the annular friction pressure (AFP). The AFP is the friction pressure that results from the circulation of the mud while drilling. ECD is defined as the equivalent circulating density of the BHP. It is basically the BHP while circulating converted into the units of mud weight. During a connection, the pumps turn off and the fluid stops circulating, thus eliminating the annular friction pressure. The starting and stopping of pumps can greatly affect the pressure profile, causing the pressure to fluctuate out of the pressure-gradient window and thus leading to drilling problems.

A conventional drilling system is open to the atmosphere so that the returns gravity flow away from the rig floor.[3] The only way to adjust BHP while drilling is by the pumping rate. MPD uses a closed and pressurizable mud system. With a closed system the equation for the BHP can be varied to include backpressure. BHP now can be found by summing the mud hydrostatic and the AFP with the amount of backpressure being applied. Adjusting backpressure while drilling can quickly change the BHP.

The basic configuration for MPD is to have a rotating control device (RCD) and a choke.[4] The RCD diverts the pressurized mud returns from the annulus to the choke manifold. A seal assembly with the RCD enables the mud returns system to remain closed and pressurized and enables the rig to drill ahead. The choke with the pressurized mud return system allows the driller to apply backpressure to the wellbore. If the pressure starts to climb above the fracture pressure of the formation, the driller can open the choke to reduce backpressure and bring the pressure down. If the driller needs to increase the pressure throughout the well, closing the choke will increase backpressure. This technique is mainly used during connections when the pumps are turned off then on. When the pumps are turned off, the choke is closed to apply backpressure to replace the lost AFP. As the pumps are turned on and the AFP increases, the choke can be opened to decrease backpressure. This helps keep pressure profile to remain inside the pressure window throughout the well.

In **Fig. 2**, the pressure profile shows that, in static conditions, the pressure will fall below the pore pressure and that, while circulating, the pressure will exceed the fracture pressure. By adjusting the mud weight and using backpressure, a driller would be able to keep the pressure inside the pressure window. The driller can decrease mud weight so that the pressure stays below the fracture pressure while circulating. Applying back pressure while not circulating could keep the pressure above the pore pressure of the formation. By adjusting the drilling plan, a driller would be able to successfully drill a well that has tight pressure margins.

The Need for Managed Pressure Drilling

The need for MPD is clearly illustrated by current drilling statistics and problems that currently exist. **Fig. 3** shows the results of a database search of NPT while drilling offshore gas wells.

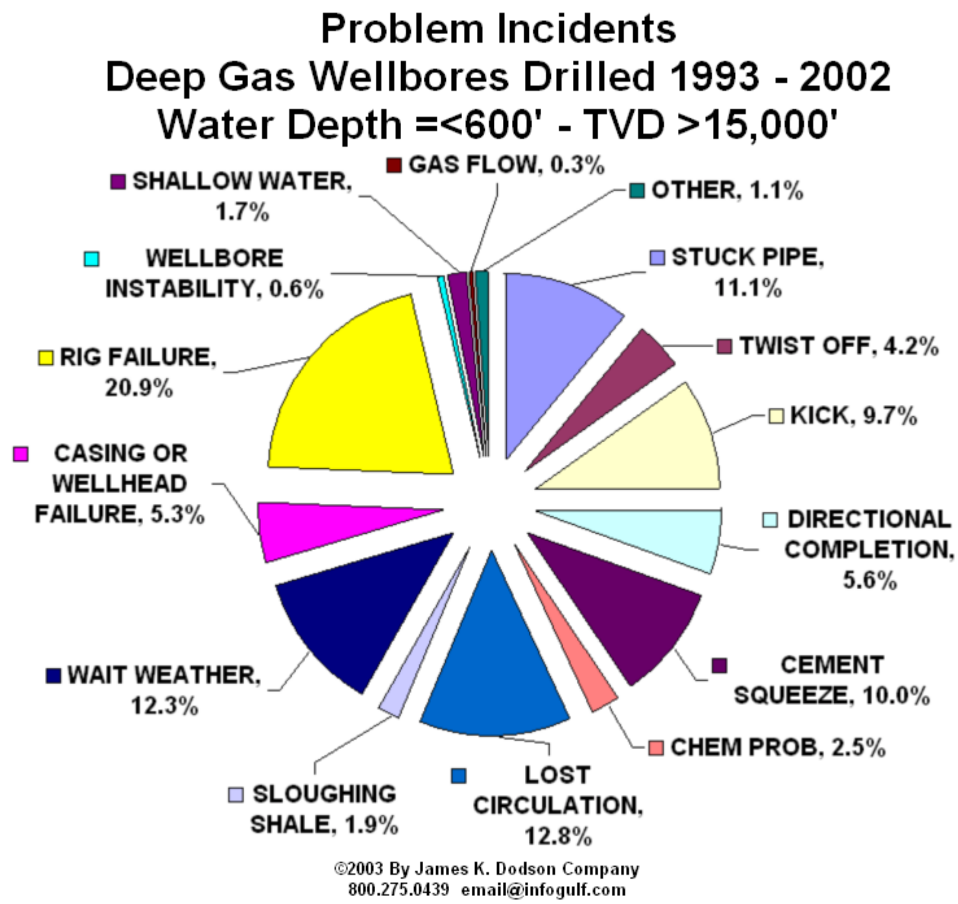

Fig. 3— Report of drilling downtime—TVD> 15,000 ft. (From Dodson[7]).

MPD can solve a large percentage of the problems the database lists, especially those that are caused by wellbore pressure deviating out of the pressure gradient window during drilling operations.[4] **Table 1** shows the NPT from **Fig. 3** that could be reduced by using MPD.

Table 1— NPT downtime—TVD> 15,000 ft. (From Dodson[7]).

Lost Circulation	12.8%
Stuck Pipe	11.1%
Kick	9.7%
Twist Off	4.2%
Shallow Water/Gas Flow	2.0%
Wellbore Instability	0.6%
Total Downtime	**40.4%**

Numerous problems can occur if the wellbore pressure goes below the pore-pressure gradient. At shallow depths, water or gas can flow into the wellbore. As noted above, a kick can occur. With a lower pressure in the wellbore, the hole can also become unstable and start to fall in on the drillpipe. This can lead to the pipe becoming stuck and could cause a twist off, which is breaking the pipe. The main problem when the pressure exceeds the fracture pressure-gradient is lost circulation, losing mud into the formation. Reservoir damage can also occur and the wellbore can become unstable. These problems account for more than 40% of drilling problems in the 10 years this study covers.

Table 2[7] shows the economic impact that these hole problems have on drilling cost. These hole problems basically cost a company $98 per foot drilled. If we can eliminate the problems with MPD, we could reduce hole costs by about $39 per foot drilled. On wells drilled to 15,000 ft, that can equate to an average savings of $585,000 per well. These figures assume that MPD will reduce the downtime by 40%. MPD will reduce these problems, although other events could still occur to prevent solving some of these problems. Even if we assume MPD could reduce that 40% to 20%, it could result in a savings of $19.50 per foot, or an average savings of $293,000 per well that is drilled to a depth of 15,000 ft.

Table 2— NPT cost of 102 wells drilled with TVD > 15,000 ft (From Dodson[7]).

Total Drill Days	NPT Time, days	NPT %	Dry Hole Cost/Foot	Cost/ft Due to NPT
7680	1703	22	$444	$98

Fig. 4 shows similar results for offshore wells that were drilled to less than 15,000 ft. **Table 3** shows the NPT for these wells that could be reduced by using MPD.

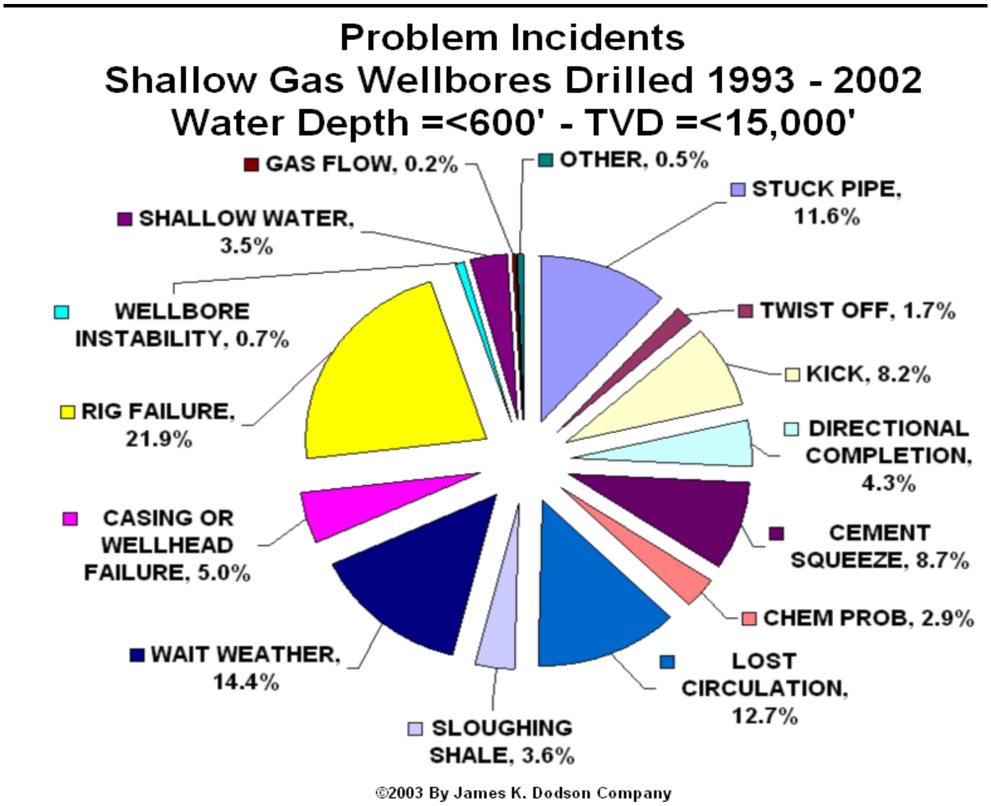

Fig. 4—Report of drilling downtime —TVD < 15,000 ft (From Dodson[7]).

Table 3— NPT downtime—TVD< 15,000 ft. (From Dodson[7]).

Lost Circulation	12.7%
Stuck Pipe	11.6%
Kick	8.2%
Twist Off	1.7%
Shallow Water/Gas Flow	3.7%
Wellbore Instability	0.7%
Total Downtime	**38.6%**

Table 4 shows the economic impact of these problems. If MPD eliminated the 38% of drilling problems, the benefit could be $27 per foot.

Table 4— NPT cost of 549 wells drilled—TVD < 15,000 ft (From Dodson[7]).

Total Drill Days	NPT Time (days)	NPT %	Dry Hole Cost/Foot	Cost/ft Due to NPT
17641	4264	24	$291	$71

On a 10,000 ft well, a savings of $270,000 can be made. If MPD only reduces these problems by half, the benefit of $13.50 per foot would yield an average savings of $135,000 per well that is drilled to a depth of 10,000 ft.

These statistics show that MPD can help reduce NPT for current drilling operations with associated excellent economic benefits. These economic benefits illustrate the need for MPD with current operations to help companies reduce their drilling costs.

MANAGED PRESSURE DRILLING TECHNIQUES

Projects that have used five of the many different variations of MPD have demonstrated techniques that are proactive in managing the pressure profile.

Continuous Circulation System

The continuous circulation system[8] (CCS) is a new technology that enables a driller to make connections without stopping fluid circulation. A CCS enables a driller to maintain a constant ECD when making connections. In normal drilling operations, a driller must turn the pumps off when making a connection. Numerous problems can occur as pumps start and stop in a drilling operation.

In a narrow drilling window, where the pore pressure and fracture pressure gradients are close, continuous circulation can prevent many problems from occurring.

Fig. 5 shows the pressure spikes that occur when making a connection. When the pumps stop, the pressure in the well decreases. This decrease in pressure can cause a kick, formation fluids enter the wellbore. The formation could also relax and the formation could collapse on the hole, resulting in stuck pipe. The differential pressure between the reservoir and the wellbore can also stick the pipe. The drilling fluid starts to form a gel when the pumps are turned off as the fluids stop circulating. When the pumps are restarted, pressure increases to break the gel, causing a pressure spike which could cause lost circulation, where fluids enter the formation, and ballooning of the wellbore. Before a connection is made, the rig has downtime associated with circulating the cuttings out of the bottomhole assembly.[8] This is required so that the cuttings do not settle at the bottomhole assembly.

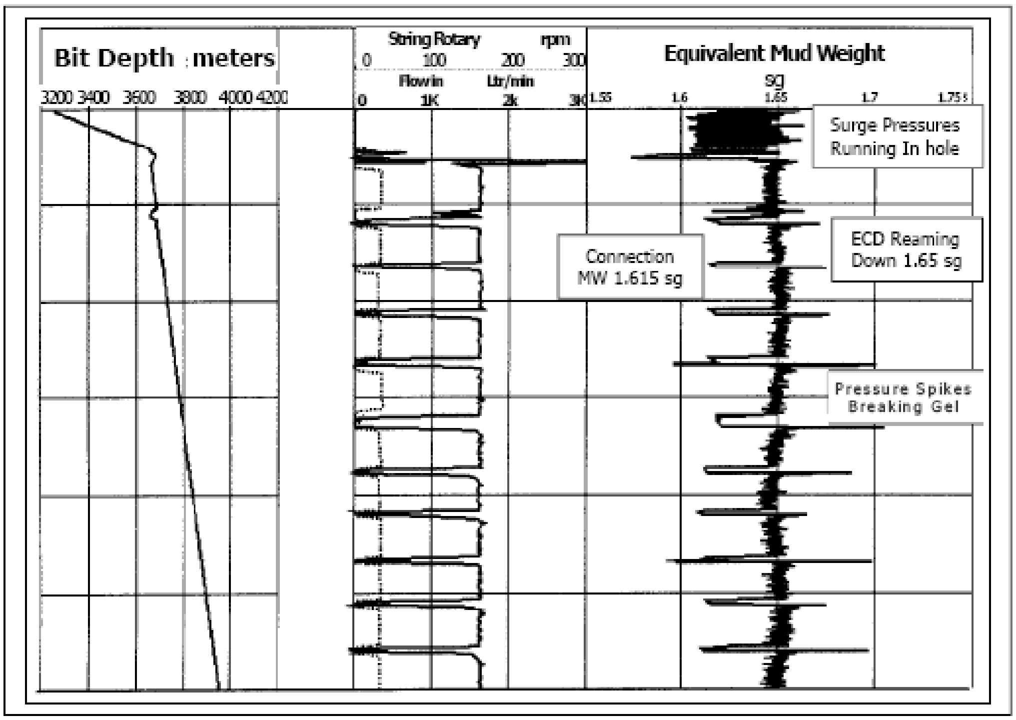

Fig. 5—Change in equivalent mud weight during connections (From Jenner[6]).

A CCS could solve these problems when drilling.[8] It would enable a driller to have improved control of the ECD and reduce these problems that can result from shutting down the pumps during a connection.

Fig. 6 shows a coupler[8], the device that enables the continuous circulation of the fluid. The drillstring passes through this device, and during the connection process it provides a seal around the drillstring. The coupler can be divided into an upper and lower section. A sealing device can separate the two sections.

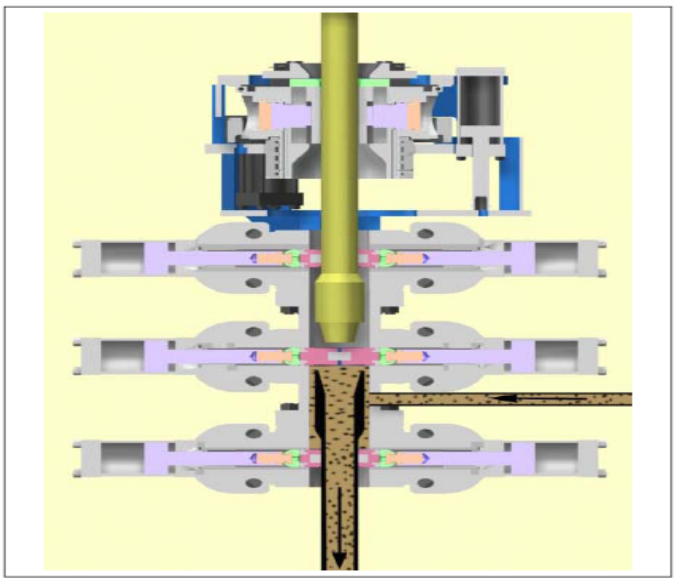

Fig. 6— Coupler device used in the continuous circulation system (From Jenner[8]).

Fig. 6 also shows the mud flow that occurs during connections.[8] When it is time to make a connection, the fluid flows into the coupler, thus equalizing the pressure around the drillstring. With the pressure equalized, the connection is broken and the tool joint pin is backed out and raised out of the lower section. The sealing device then closes and the pressure in the upper chamber is bled off, allowing the tool joint pin to be removed. The fluid that is in the upper chamber drains back into the mud pit. The lower section continues to circulate fluid down the hole during the entire operation. The new joint of drillpipe is then lowered into the upper chamber. The chamber is sealed and repressured by fluid from the circulating system. Once the pressure is equalized between the two chambers, the dividing seal opens. The drillpipe joint is lowered and a connection is made. Once the connection is made, the pressure is bled off and the seals are opened so that normal drilling operations can continue.

In a field trial in 2003,[8] the CCS was tested for 14 hours drilling a 12 ¼-in. hole. The system made 72 connections. The first 6 were done manually to calibrate the system. The rest of the connections were controlled automatically by the driller using a touch screen. Circulation rate for the test was 800 gpm and pressure was kept between 2,800 and 3,000 psi. The test showed that the continuous circulation system can be used to drill sections of the well without turning the pumps off during a connection. After the test was run, the drillpipe used was tested and no damage was found on the drillpipe that was handled by the coupler. The connection times ranged from 13 to 20 minutes. The actual connection time can be reduced to about 8 minutes with improvement in the guidance system when performing the connection.[8]

The continuous circulation system is useful in preventing pressure spikes when making connections, thus reducing wellbore problems. Benefits of using the CCS include[9]

- Reducing nonrotation time by eliminating the need to circulate the cuttings out of the bottom hole assembly.
- Reducing the possibility of a stuck drillstring by keeping the cuttings from dropping to the bottom.
- Constant ECD can be maintained.

ECD Reduction Tool

A better understanding of equivalent circulating density (ECD) is necessary to understand how this tool can help manage the pressure profile window. A high ECD can cause problems in complex wells, including reducing the operating margin between the pore pressure and fracture pressure. If a well has wellbore stability issues then a higher downhole pressure may be required.[10] A high ECD in this case could result in exceeding the fracture pressure of a formation. With a high ECD, a common problem is lost circulation.

ECD is a function of mud density, mud rheology, cuttings loading, annular geometry and flow rate. [10] Drilling-fluid density is required for pressure control and wellbore stability.[11] Viscosity and flow rate are needed for hole cleaning and barite-sag mitigation. Gel strengths are required to suspend drill cuttings. The goal of ECD management is to find balance between these parameters to successfully drill a well.

Reducing ECD in a well can result in many benefits. These benefits can include:

- Reducing the number of casing strings.
- Improving hole cleaning by using higher flow rates.
- Being able to remain in the pressure window for complex wells.
- Reducing lost circulation and differential sticking.
- Reducing formation damage.

These benefits are seen by reducing the ECD to keep the pressure throughout the well inside the pressure profile. By being able to reduce ECD, a driller may be able to drill though a pressure window that can not be drilled conventionally, thus being able to set casing at a deeper depth. An ECD reduction tool may also be used to balance out the use of higher flow rates to improve the cleaning of the hole. Being able to reduce ECD to keep the pressure below the fracture pressure also helps reduce lost circulation and formation damage to the reservoir.

Current techniques that are used to reduce ECD include:

- Using low fluid rheologies to reduce frictional losses.
- Using drillstrings and casing strings that provide greater annular clearance.
- Using expandable tubulars to increase hole size.
- Use of drilling liners in place of casing strings.
- Reducing flow rates to decrease frictional losses.
- Reducing penetration rates to reduce the amount of cuttings in the annulus.

These techniques can solve ECD problems but can result in higher drilling costs. The higher drilling costs could make some wells uneconomical to drill. Dual-gradient drilling and riserless drilling also reduce ECD but can have higher capital expenditures than an ECD reduction tool. The ECD reduction tool is seen as a low-cost alternative to other methods of ECD reduction.

The ECD reduction tool is designed to reduce the bottomhole pressure increase caused by friction in the annulus by providing a pressure boost up annulus. [10]

Fig. 7 shows the effect of a pressure boost up the annulus. The pressure boost decreases the dynamic BHP, thus enabling the pressures to not exceed the fracture gradient.

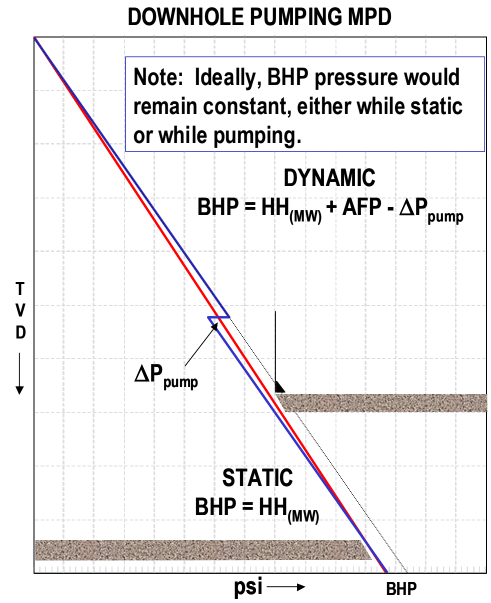

Fig. 7— Pressure-gradient profile showing effect of ECD reduction tool (From Hannegan[6]).

The tool has three basic parts. The top section of the tool has a turbine motor that is powered by the circulating fluid. The middle section consists of a mixed flow pump that is partly axial and partly centrifugal. This section pumps the fluid up the annulus. The bottom section consists of the bearing and seals. Two nonrotating packer-cup seals in the lower section of the tool provide the seal between the tool and the casing. This causes all the return fluid to flow through the pump.

The ECD tool has some features that will enable the tool to be used in both onshore and offshore operations. The initial design of the tool enables it to be run in 9-5/8-in. to 13-5/8-in. tubing. Drill cuttings up to 5/16-in. can flow through the tool. A grinding mechanism in the bottom section breaks up larger drill cuttings, preventing the pump from being plugged. Wireline tools can be run through the tool after retrieving a flow diverter that is located in the turbine motor. The tool has a clearance of 1.812-in. inside the pump once the diverter is removed. The mechanical strength of the tool is comparable to that of new 5”-in., 19.5 lb/foot S-135 drillpipe. It is designed to have a maximum pressure boost of 450 psi in the annulus with a flow rate of 550 gpm. The pressure boost is directly related to the circulation rate. A lower circulation rate will result in a lower pressure boost. [10] The tool can be located in the upper section of the well so that a full trip is not required to install or service the tool during drilling operations.

Tests were performed on the prototype tool to determine the effectiveness of the tool.[10] The tests were conducted with water and with 9.5 ppg and 11.6 ppg mud.

Fig. 8 shows the pressure boost seen in the well as a function of the flow rate. The tool started up at a flow rate of 250 gpm and as the flow rate increased, the pressure boost increased as a quadratic function.

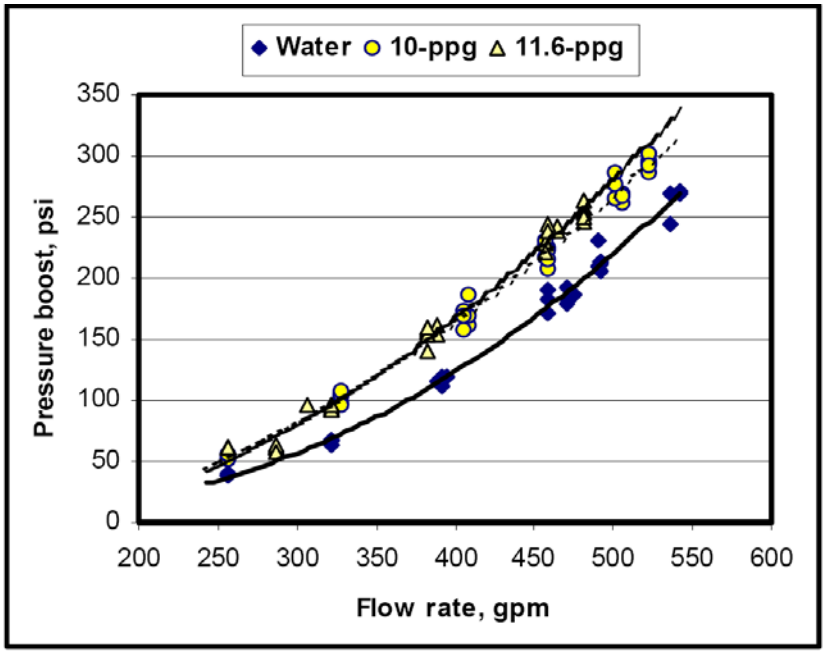

Fig. 8— Pressure boost provided by ECD reduction tool vs. flow rate (From Bern[10]).

Fig. 9 shows the results of the test after making design improvements on the turbine motor. The pressure boost seen at 550 gpm was about 50 psi greater after the design changes were made to the tool.

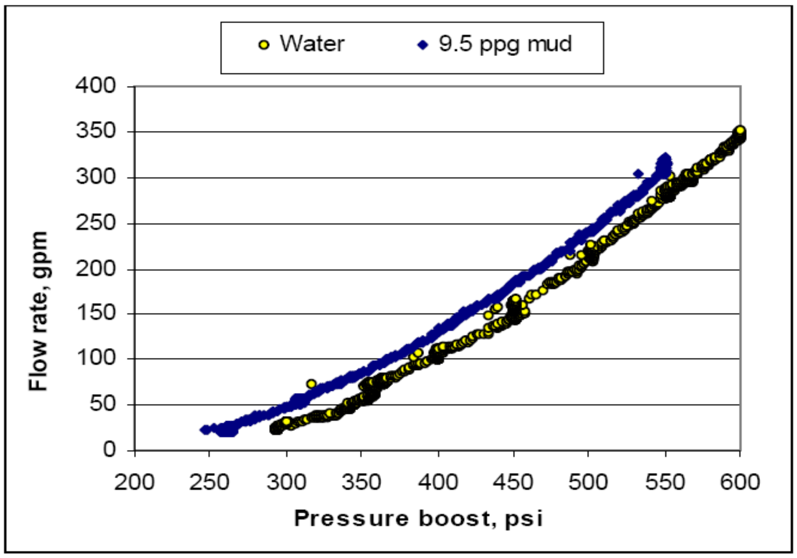

Fig. 9—Flow rate in well vs pressure boost caused by ECD reduction tool (From Bern[10]).

Fig. 10 shows the change in downhole pressure that is seen while the tool is running. At the 550 gpm flow rate, the downhole pressure is reduced by about 250 psi.

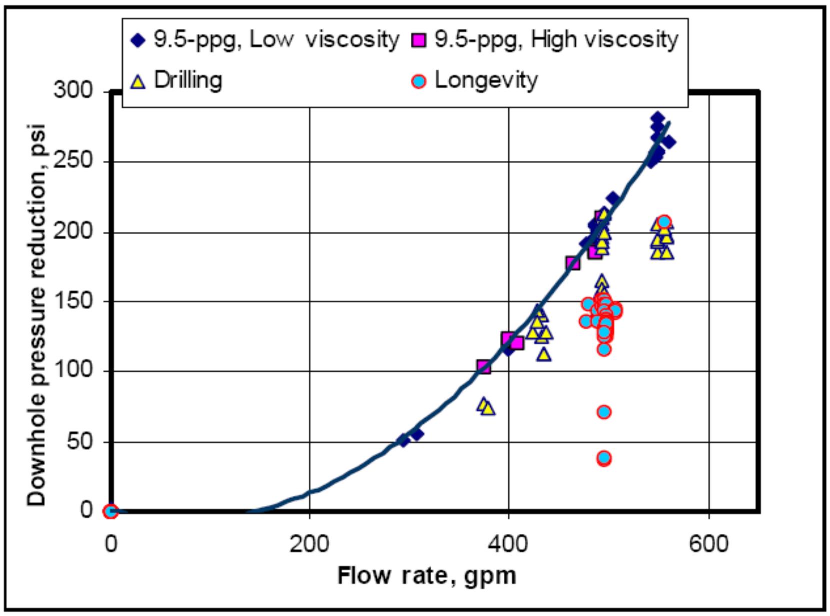

Fig. 10— Downhole pressure reduction seen as a result of ECD reduction tool (From Bern[10]).

Fig. 11 shows that the ECD reduction tool is not very efficient. A pressure boost of 300 psi, would require an additional 900 psi on the standpipe pressure. This can cause problems with engineering plans if the well is already designed to approach its standpipe-pressure limit.

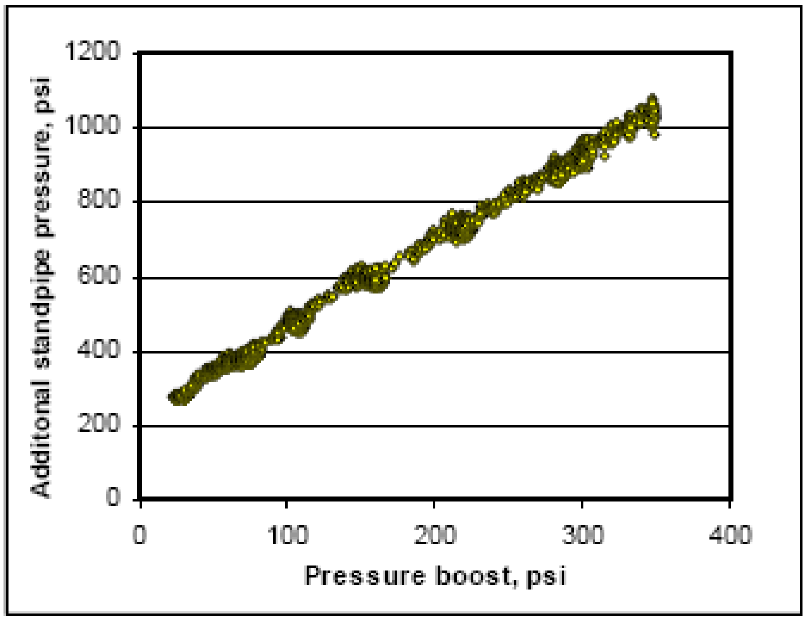

Fig. 11—Additional standpipe pressure needed for pressure boost with ECD reduction tool (From Bern[10]).

Tests performed to see how basic drilling operations affect the tool showed that the ECD tool was able to handle the different sizes of cuttings.[10] A cuttings transport test was conducted with plastic balls of various sizes. The balls were flowed through the tool a number of times. The cuttings that had diameters of less than 0.31-in. passed through the pump with no problem. The cuttings with a diameter of 0.375-in. had split surfaces, meaning that they had to go through the crusher before flowing through the pump. A test run with Measurement While Drilling (MWD) tools showed that the tool would not interfere with communications from the other tools. The tool was found to be able to work with MWD tools and allowed signals to be passed through the tool, allowing correct measurement of the well inclination. This enables the tool to be used in horizontal wells.

A potential disadvantage of the ECD reduction tool is the surge and swab effects that could occur during tripping. Surge refers to the downhole pressure increase due to the downward movement of the drill string in the well. Swab refers to a decrease in downhole pressure when the drill string is being pulled out of the hole.

Fig. 12 shows the surge effects in the test well when using water as the test fluid. The pressure increase varied from 60 – 120 psi. Without the tool, the surge effect was a 5 psi increase.

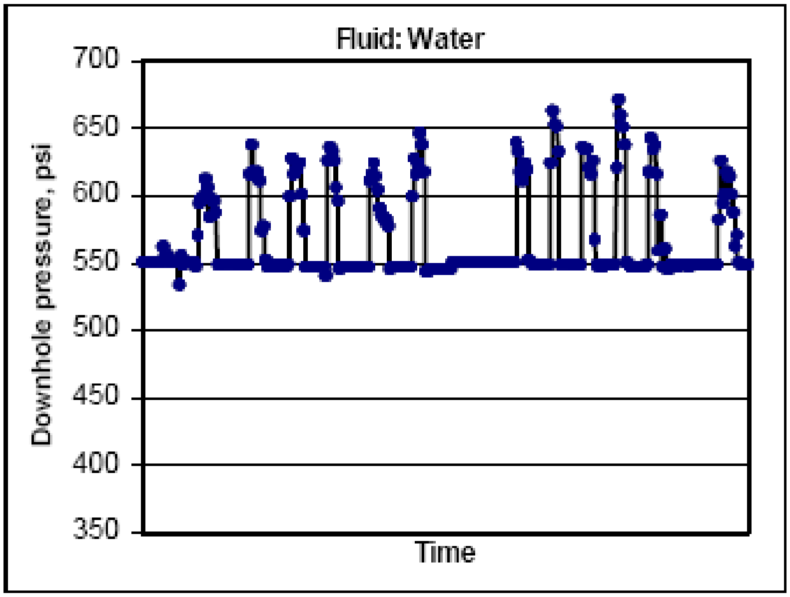

Fig. 12— Surge effect when tripping drillstring with ECD reduction (From Bern[10]).

Fig. 13 shows the swab effects as a result of running the ECD reduction tool. The swab effect ranged from 20 to 150 psi. Without the tool, the swab effect was only 10 to 15 psi. The reason for the high surge and swab is due to the large casing size that was run in the test well. If the tool is run in small casing strings the swab and surge effects will be lower.

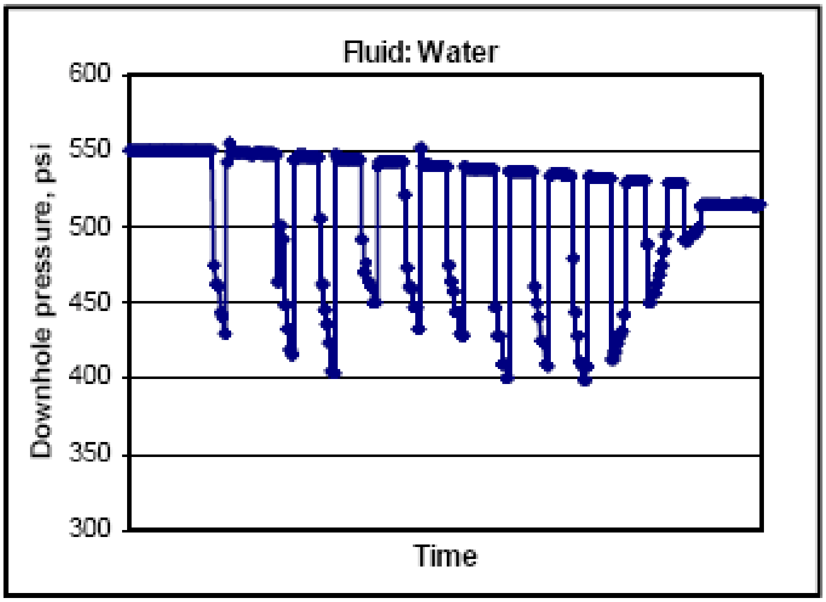

Fig. 13— Swab effect when tripping drillstring with ECD reduction (From Bern[10]).

Fig. 14 shows the surge effects as a function of trip time per stand. The surge pressure increased as trip time decreased. This is due to the increase in pipe velocity while tripping into the hole.

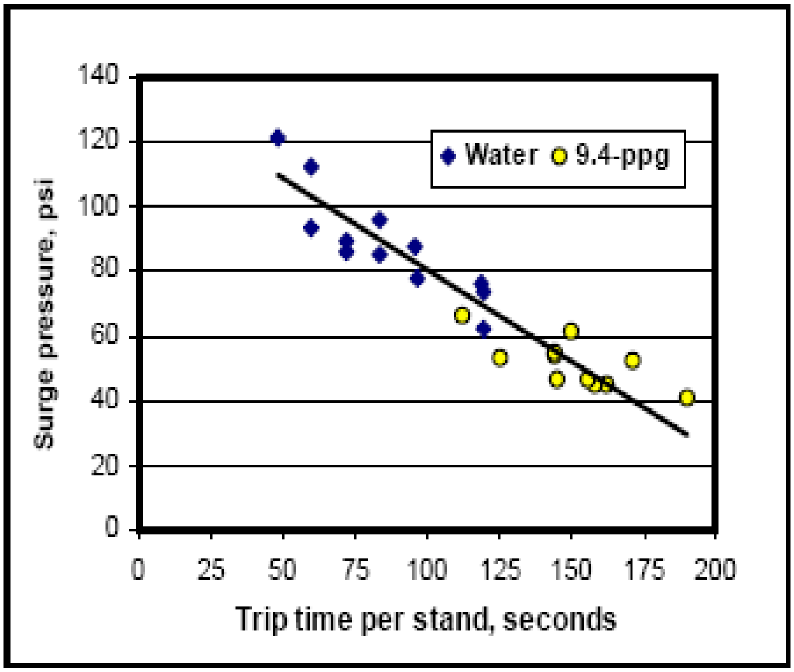

Fig. 14— Surge effects as a function of trip time per stand(From Bern[10]).

When using the ECD reduction tool, it is important to consider the depth of the zone of interest. As you can see in **Fig. 7**, the pressure is only reduced below the location of the tool on the drillstring. This means that if the tool travels below the zone of interest, then the tool will have no effect on the pressure at the zone of interest.

The ECD reduction tool can be used in onshore and offshore environments to help prevent problems associated with drilling wells that have narrow pressure windows. It can help alleviate high ECD that could result in formation damage and mud loss. It may be useful as a low cost alternative to other ECD-reduction techniques. Further testing, though, is necessary to determine if this tool can be used in smaller drillstrings and to further study the effects of the tool on the surge and swab while tripping pipe.

Pressurized Mud Cap Drilling

The pressurized mud cap drilling technique (PMCD) is used when dealing with reservoirs that could result in a severe loss of circulation.[12] Depleted reservoirs, which have lower reservoir pressures because of the production from other wells, often have circulation loss. If the reservoir pressure is significantly lower than the wellbore pressure necessary to drill the well, the lost circulation can be severe. As the mud is lost into the depleted zone, the hydrostatic pressure of the wellbore decreases to balance the reservoir pressure at the depleted zone. At this point, the wellbore pressure is below the reservoir pressure of a zone that is not as deep as the loss zone. This causes gas to begin to flow into the wellbore. One way to keep such a well under control is to fill up the well at a rate that exceeds the gas percolation rate.[12] The PMCD method uses a heavier mud pumped down the annulus to keep the gas influx from reaching the rig floor.

Fig. 15 shows the pressure profile of the pressurized mud cap method. A lighter mud is used to drill the depleted section and the heavier mud forces the fluid into the loss zone. Drilling continues and all the lighter mud and any influx is forced into the depleted zone. This method keeps the well under control even though all returns go to the depleted zone.

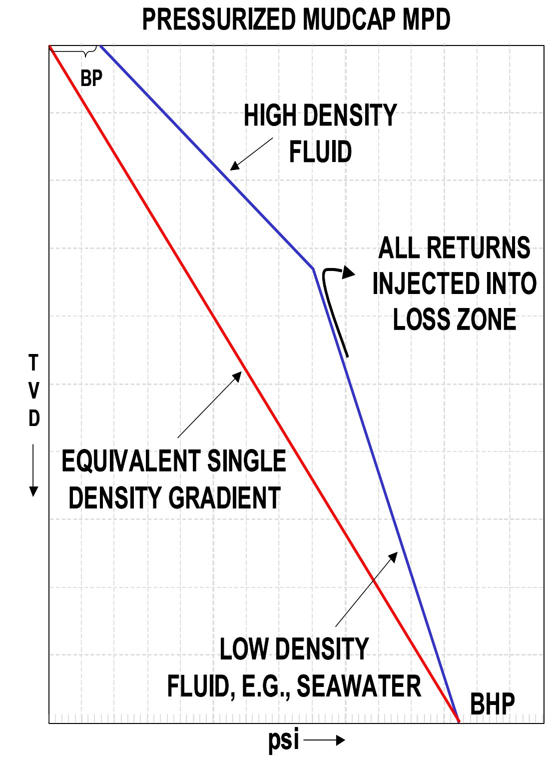

Fig. 15— Pressure-gradient profile for pressurized mud cap drilling method (From Hannegan[6]).

Hannegan[13] found that PMCD also can work well when drilling in high-pressure, fractured zones. In the Austin chalk, conventional mud-cap drilling had been used for many years. In this method, mud that is several ppg heavier than the formation pressure is used in the annulus. The mud balances the reservoir pressure at a minimal volume, but results in an annular fluid level at an uncontrollable depth. A disadvantage of this method is that it does not allow the rig to monitor the downhole pressure directly. If gas breaks through the mud cap, it is difficult to detect and would reach the surface with little warning. This could result in surface pressures that are above the rated working pressures of the rotating control equipment.

Drilling in a high pressure reservoir, the difference between the drilling fluid density and the reservoir fluid equivalent density can cause rapid increases in overbalance at the bit.[13] Fracture-zone pressures in the well can be drastically different if some zones are depleted by other wells through an extensive fracture system. With these different pressures throughout the wellbore, reservoir fluid could flow in and mix with the cap mud, and cross-flow between the fracture zones is possible. The cap mud could become severely overbalanced and cause loss of the cap mud into the fractures.

The PMCD method[12] solves this problem by keeping the pressure of the cap mud at or just under the lowest reservoir pressure. The reservoir is now controlled by the pressure caused by the column of mud with the addition of surface pressure. The mud cap keeps control of the reservoir pressure regardless of what is happening with each of the fracture zones. This prevents loss of the cap mud into the fracture zones due to overbalance. The rig can also directly monitor the pressure.

The important aspects of PMCD are the RCD, cap mud, and drilling fluid. The RCD enables the operator to pump the cap mud into the annulus and to also keep pressure at the surface to compensate for the lower mud weight of the drilling fluid used to control the reservoir pressure during PMCD.[12] The cap mud needs to be the right kind for the specific job. The following are requirements for the selection of the cap mud. [13]

- Nondamaging to the formation.
- Not able to form damaging emulsions with either reservoir fluid or drilling fluid.
- High rheology downhole to minimize mixing with reservoir fluids.
- Mixable in high volume.
- Able to be weighted up quickly during drilling operations.
- Inexpensive.
- The drilling fluid should be an inexpensive fluid that can be lost into the formation at large volumes and also be compatible with the cap mud.

The advantage of the PMCD method is that it can keep the well under control even while suffering severe losses to the formation. The rig is still protected by two barriers, the BOPs and the mud cap. Using a lighter drilling fluid also increases the rate of penetration (ROP) and the lighter mud costs less than the mud that would be lost in conventional drilling. Also another advantage with a lighter fluid is that drilling is underbalanced, resulting in less damage to the reservoir.

Controlled Mud Cap System

A newer drilling concept that is still being tested is the controlled mud cap system (CMC).[3] This system is similar to the pressurized mud-cap system, except that the level of the mud cap is adjusted by a mud pump to better manage the bottom hole pressure.

Fig. 16 shows a basic setup of this system for a well being drilled in deepwater. A 12.5-in. ID riser is run. A subsea mudlift-pump is connected to the riser by a riser-outlet joint. The outlet joint has high-pressure valves that enable it to isolate the pump system from the riser. The pump is connected to the mud pits by a return and a fill line. This allows the pump to increase or decrease the amount of mud in the riser. To determine the level of the mud in the riser, pressure sensors are located throughout the riser. The drilling riser is filled with air above the mud cap.

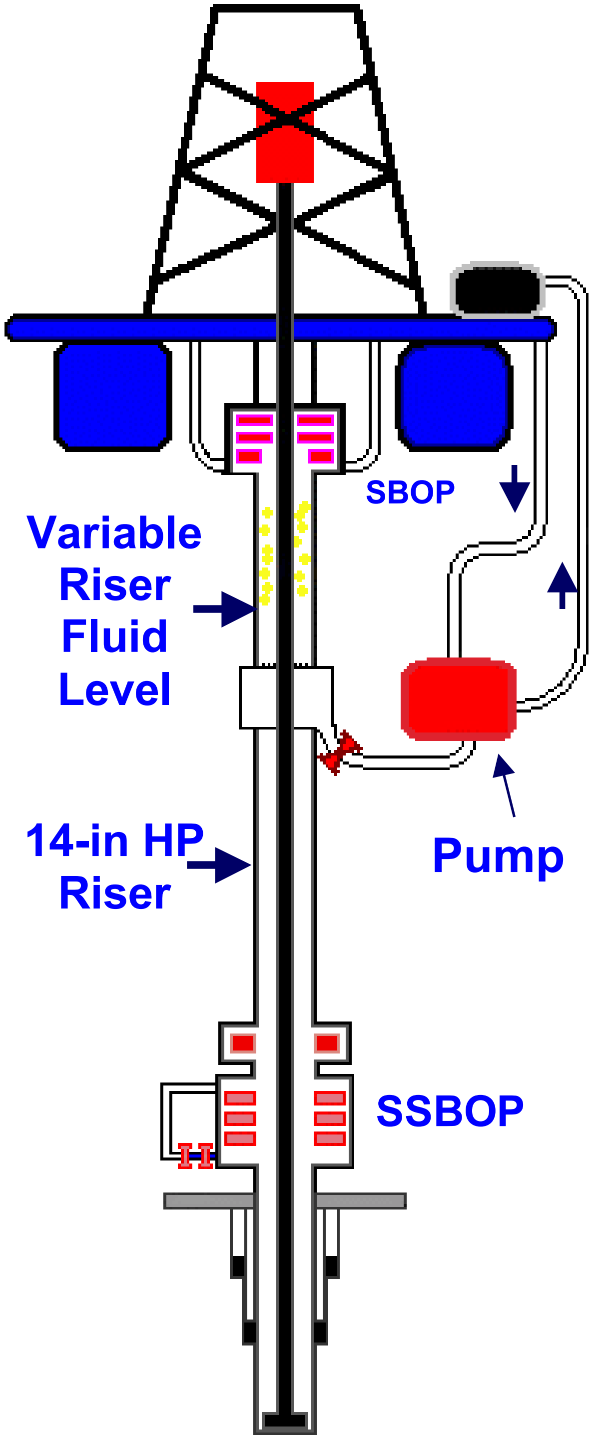

Fig. 16—Controlled mud cap setup (From Juvkam-Wold[5]).

The basic concept of this system is to compensate for ECD and thus manage the BHP. In single-phase flow, to compensate for friction pressure fluctuations related to factors such as pipe connections and circulation rate, the height of mud in the riser will be adjusted. This system enables a driller to compensate for ECD at a specific depth in the open hole section. Fossil[3] built a scale model to test the CMC system with single-phase flow. The mudlift pump in the model was controlled by a downhole pressure recorder. The pump was set to run at a specific BHP. The pump adjusted the level of mud in the riser to keep a constant BHP regardless of the circulation rate, the amount of solids in the annulus, or the RPM rate of the drill string.[3]

For multiphase flow, Jenner[3] is currently working on a simulator to calculate the pressure profile throughout the wellbore annulus. This simulator is also being designed to predict the amount of hydrocarbons in the drilling riser as a function of time to prepare the crew to take the necessary action.

This system also is unique in that it can be operated as either an open or closed system. The first advantage to an open system is that it needs no continuous closure elements to trap pressure in the well.[3] This comes in handy when considerable rig movement can affect the downhole pressure control. This effect can occur when slips are set to make a pipe connection. With the CMC system, the downhole pressure regime will generally be the same as in conventional drilling except the mud weight may be higher and part of the drilling riser may be filled with gas.

The second advantage with an open system is that a “positive” riser margin can be designed to be included in this system.[3] With this system the hydrostatic pressure in the riser at sea level can be designed to equal or be less than seawater pressure. This means a positive riser margin can be added with no overbalance in the well. This positive riser margin means that if the riser was to disconnect, the BHP would increase thus improving well control.

The third advantage is the CMC system’s ability to handle hydrocarbons. The system operates as an open system until one of the rams of the surface BOP is closed. Since this system acts as an open system with gas pressure close to ambient, the drilling riser effectively becomes the hydrocarbon separator.[3] The gas is separated in the riser and the liquids are transported through the pump system up to the rig. Being able to regulate the mud level while this happens enables fast and accurate changes to the BHP.

If a well control problem arises, the system is designed to adjust to compensate for the change. The subsea BOP would be closed. The mud level in the riser would be increased to compensate for the fact that the pumps are shut down and brought even higher to stop the influx or increase till it brings the pressure close to the maximum allowable annulus shut-in pressure. The RCD at the surface would be closed, but the choke line would be open to minimize the pressure in the gas phase in the riser. The gas that remains in the riser can be bled off to the atmosphere via the choke manifold. This procedure could be performed in a very short time frame.

The main challenge with this system is to compensate for the hydrostatic pressure that is caused by the standing column of mud in the drill pipe. Having a full column of mud with the subsea BOP closed would cause the BHP to become higher than the fracture pressure. This is due to the system using a higher mud weight than is used in conventional drilling. A u-tube effect occurs where the mud in the drill pipe flows into the annulus until the pressure equalizes between the annulus and the drill pipe. One way to neutralize this effect is to have a pressure differential valve in the drill string. The valve would be open at a predetermined pressure and compensate for the static imbalance between the drill pipe and the annulus. The valve would be closed if the pressure in the annulus is lower than the pressure in the drill pipe. This blocks the annulus from being affected by the standing column of mud when the subsea BOP is closed.

To show the advantages of CMC, Jenner[3] ran two cases to show how much gas each method can circulate out of the well without fracturing the weakest formation in the open hole. This is referred to as kick margin (KM). Both cases are for wells that are vertical and in 4100 ft of water depth. The tests also assumed that the weakest formation is at the top of the openhole section and the influx is bubble flow. Case 1 involves drilling an 8-1/2-in. hole from the casing shoe at 7550 ft to 12500 ft.[3]

Table 5 shows the results of Case 1. The differential pressure between fracture pressure and borehole pressure at the casing shoe is significantly higher for the CMC method. This means that the operating window for the CMC method is larger. The kick margin is also higher, meaning that this method can handle a larger volume of gas flowing into the wellbore. The other two methods have low kick margins and thus may have to stop drilling and have a casing point at a higher level than the CMC method.

Table 5— Results of Case 1— Drilling 8-1/2-in. hole to 3800 m (From Jenner[3]).

	Conventional Surface BOP	MPD with Surface BOP	CMC with Split BOP
MW SG	1.38	1.33	1.57
ΔP@ 7550 ft Static	229 psi	127 psi	635 psi
ΔP@ 7550 ft SCR	193 psi	215 psi	723 psi
ΔP@ 7550 ft Max circ. rate	154 psi	311 psi	754 psi
(KM) Static	72 ft^3	42 ft^3	172 ft^3
(KM) Slow circ. rate	61 ft^3	71 ft^3	196 ft^3
(KM) Max circ. Rate	49 ft^3	102 ft^3	222 ft^3

Case 2 involves drilling the well to 12500 ft with a 12-1/4-in. bit to see if the original casing point could be extended.

Table 6 shows the results of this case, and the CMC method is the only method that has sufficient margins to drill that deep. In this hypothetical study it can be done, but at that depth a kick margin of only 243 ft^3 may cause the casing point to be reached a little sooner.

Table 6— Results of Case 2— Drilling 12-1/4" hole to 3800 m (From Jenner[3]).

	Conventional Surface BOP	MPD with Surface BOP	CMC with Split BOP
MW SG	1.38	1.33	1.57
ΔP@ 6360 ft Static	- 110 psi	-160 psi	392 psi
ΔP@ 6360 ft SCR	- 124 psi	- 137 psi	415 psi
ΔP@ 6360 ft Max circ. rate	- 148 psi	- 97 psi	460 psi
(KM) Static	0	0	210 ft^3
(KM) Slow circ. rate	0	0	223 ft^3
(KM) Max circ. Rate	0	0	243 ft^3

This method has many advantages. A driller is able to control downhole pressure almost instantaneously by adjusting the height of mud in the riser. Hydrocarbon influxes can be controlled and circulated out with ease. This system also can act as either a closed or open system, depending on what is needed.

Dual-Gradient Drilling Method

Dual-Gradient drilling[6] refers to drilling with two different fluid-density gradients.

Fig. 17 shows the dual-gradient pressure profile. In this case, using a single density fluid for this wellbore will cause the wellbore pressure to exceed the formation pressure and result in lost circulation. With dual-gradient drilling, a lighter fluid is used in the upper portion of a wellbore and a heavier fluid at the lower portion. This enables the pressure to remain in the pressure window between the pore pressure and fracture pressure.

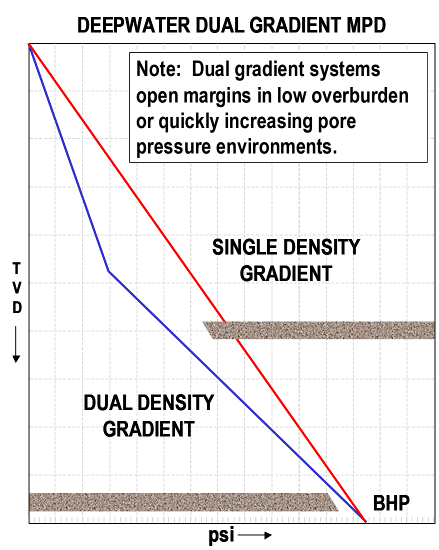

Fig. 17— Dual-gradient drilling pressure gradient profile (From Hannegan[6]).

To achieve a dual gradient, a less-dense fluid such as air, inert gas, or light liquid is injected at a certain point in the wellbore. Introducing this less-dense fluid at this point would decrease the density of the fluid from that point up to the surface. Another technique is used for offshore environments. A small-diameter return line is run from the seafloor to circulate the drilling fluid and cuttings. The marine riser is kept full of seawater. A subsea pump is used to lift the drill cuttings and the drill fluid from the wellbore annulus up to the rig floor. By using seawater in the marine riser, a more dense mud is used in the wellbore to achieve the bottomhole pressure required.

The purpose of dual-gradient drilling is to prevent a large overbalance and prevent exceeding the fracture gradient. Dual-gradient drilling allows the operator to manipulate the pressure profile to prevent exceeding the fracture pressure at a point but still to remain above the pore pressure. It is basically being able to take a tight pressure gradient window and design a drilling plan to manipulate the pressure curve to fit into the window.

Dual-gradient drilling can also be achieved in deep water without a riser when first starting a subsea drilling location. A subsea RCD and remote operating vehicle are used. The ROV is able to adjust backpressure at the mudline by adjusting the choke. If the ROV closes the subsea choke, the BHP increases. This results in drilling with a slight overbalance as if a marine riser filled with drilling fluid were present. The advantage of being able to drill with a slight overbalance is that it helps to prevent shallow gas or water flow. The seawater is used as the drilling fluid so the drilling fluid and cuttings can be left on the sea floor. **Fig. 18** shows the pressure profile for this example and how adding the backpressure at the seafloor causes the pressure profile to equal that which would be achieved by having a single gradient.

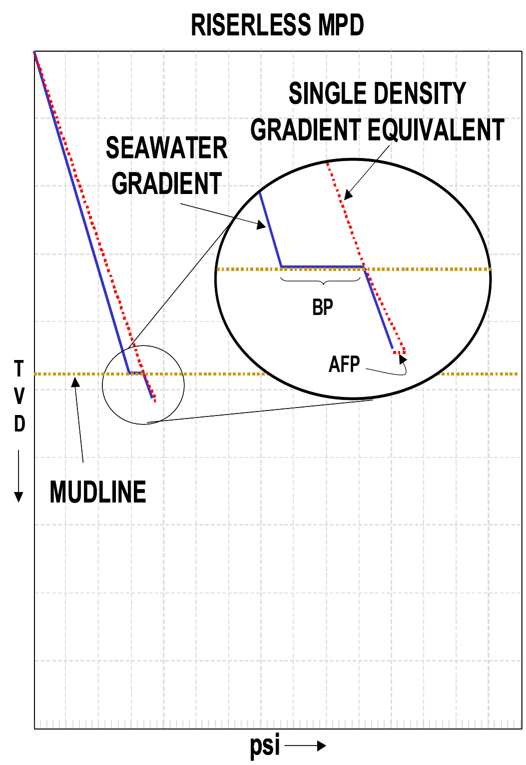

Fig. 18—Pressure profile for drilling dual gradient without a riser (From Hannegan[6]).

A similar variation of dual-gradient drilling can be seen in **Fig. 19**. Zero-discharge dual-gradient drilling involves using a subsea pump to return the cuttings to the rig floor for disposal. It uses a riserless setup but has a line through which the cuttings can be pumped to the rig floor. The BHP can be adjusted by backpressure on the annulus or by adjusting speeds of the pumps.

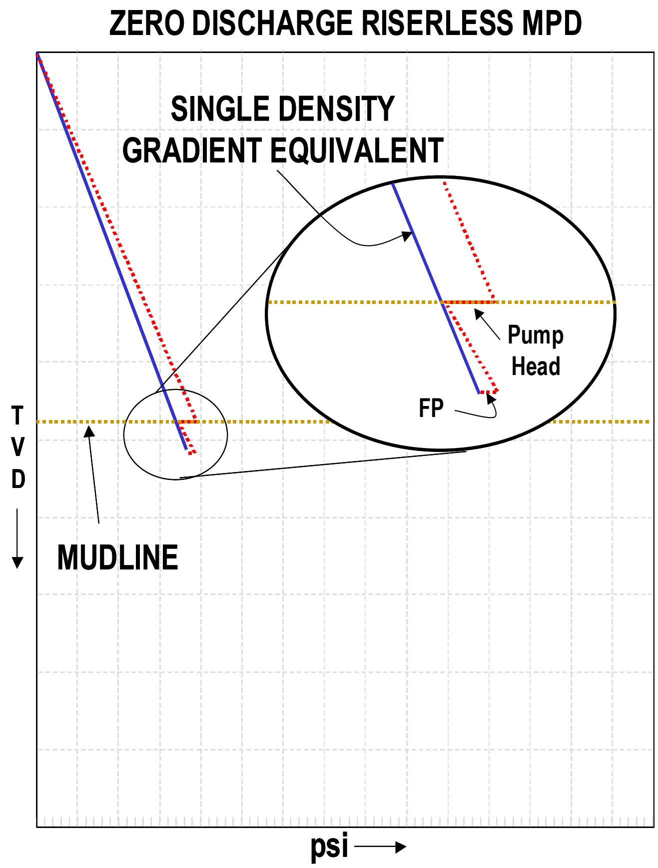

Fig. 19— Pressure profile for riserless dual gradient drilling with zero discharge (From Hannegan[6]).

As far as well control with dual-gradient drilling is concerned, the detection criteria of a kick are very similar to conventional drilling. With dual-gradient drilling, pressure gauges installed on the rig floor are more sensitive to changes than the gauges used in conventional drilling. A decrease in circulating pressure caused by an increase in flow will be more easily seen. If a kick occurs, the annular flow rate of the drilling fluid will increase by an amount equal to the influx rate.[14] If the subsea pump were set to operate at a constant inlet pressure, the subsea pump rate would increase. This increase would be seen on the computers at the rig floor and would give a good indication of a kick. The procedures used to circulate the kick out are very similar to the ones used in conventional drilling.

FUTURE OF MANAGED PRESSURE DRILLING

In applying MPD in the field, many variations[6] are still being developed. Using compressible fluids with MPD is an interesting variation that would allow drilling with a balanced pressure using air, mist, or foam.[6] This could result in increasing ROP when drilling while still keeping the pressure inside the gradient window.

Another variation is having the ability to strengthen the wellbore using solids in the mud to plug and support microfractures that can form in weaker formations when using a higher density mud.[6] This variation would not be adjusting the pressure gradient of the wellbore but would widen the window so that the well could be drilled successfully.

The challenge for the future of MPD is to convince the industry of its benefits. The best way to do this is to have companies run tests out in the offshore environment to prove that these techniques work. A few companies have already used a couple of the techniques when drilling offshore. In 2004, a company used PMCD to help in a formation that was well known for losing drilling fluid.[6] The technique was able to reduce the amount of drilling fluid lost and decrease non-productive time. In 2001, a dual-gradient well was drilled in the Gulf of Mexico.[6] It used an RCD with a subsea pump to pump the cuttings and drilling fluids up to the rig through lines run down to the seafloor. Its purpose was to show that dual-gradient drilling could be used in all phases of the drilling program. This is a good start to showing companies that MPD can work offshore.

The main problem in instituting MPD is that companies think that their way works well enough and do not want to take the risk of trying a newer method. This is similar to situations that occurred when underbalanced drilling and horizontal drilling were first introduced. It is just going to take time for MPD to become an accepted method and be used in regular drilling operation.

The benefits that should be shown to companies at this time to convince them to try MPD include the possibility of improving the drill-ability of depleted formations. Brownfields are fields that are mature and have produced for many years.[15] These fields hold much of the remaining reserves in the U.S. Due to the production throughout the years in these fields, drilling through production zones that no longer have virgin pore pressure is required. Drilling through these depleted zones often result in narrow pressure windows and lost circulation issues. Drilling in these areas require a more constant bottomhole pressure to remain in the narrow pressure window. MPD would help reduce costs and improve current assets held by companies. Companies realizing these benefits and seeing them work would lead to more common use by these companies.

A company can also look at the history of a field to determine if MPD would help the company. Looking at the drilling history and seeing the NPT will show a company what problems they have that occur during drilling. A statistical study of economics showing how reducing these problems using MPD can improve the economics of a well will help companies make the switch to using MPD while drilling.

CONCLUSIONS

- Managed pressure drilling is a new technology that will improve the economic drillability of wells. It can help solve many of the problems that result from pressure variations in the formations. It will increase reserves for companies by enabling drilling of areas that were previously economically undrillable.
- MPD uses tools similar to those that are being used for underbalanced drilling; this could mean a smoother transition for companies to begin using MPD technology. Many variations of MPD are available, but more research is necessary to determine which variation is best to be used in specific drilling situations.
- The ECD reduction tool reduces the dynamic pressure profile of a well from the point where the tool is installed on the drill string to the bottom of the hole. This tool may not be ideal in a deep well where narrow pressure margins are located at shallow depths. If the tool passes the narrow pressure margin while drilling, the tool would cease to have any effect on the pressure at that point. The pressure could exceed the fracture pressure and cause lost circulation.
- The Continuous Circulation System allows the pressure profile to remain consistent when making connections. It prevents pressure spikes that can occur when turning the pumps on and off. It is ideal

for situations where a well can remain in the pressure margins with a specific mud weight in the drilling plan but could deviate out of the pressure margins with pressure spikes while making connections.

- Pressurized Mud Cap Drilling is an ideal MPD method for wells that have severe circulation loss. These usually include wells that are being drilled in depleted formations with reduced pressure. This method improves the economics of drilling with severe lost circulation by using a drill fluid that is less dense and can be lost to the formation. A heavier mud above the point of lost circulation provides the pressure necessary to force mud into the depleted formation. It also allows a driller to keep control of a well even if suffering severe losses.
- Controlled Mud Cap drilling is a newer technology that allows the driller to adjust the pressure by changing the level of mud in the riser. By adjusting the level of mud, the pressure profile throughout the well changes. This is ideal for areas in which a driller is not sure of the exact pressure gradients. A driller can start drilling and see if there are pressure problems and lower or raise the mud level as needed to keep the well within the pressure margins.
- Dual-Gradient Drilling uses two different drilling fluids during drilling to create a pressure profile that has two gradients. This is good for situations in offshore drilling where using one fluid throughout the wellbore would cause the pressure to exceed the fracture gradient.

A less dense fluid can be used to fill the marine riser and then a heavier fluid can be used as the drilling fluid and fill the wellbore from sea level to the bottom of the hole. This creates two gradients for the pressure profile of the well and would allow the driller to design the well to be able to remain in the pressure window. This method would prevent having a large over balance while drilling and prevent exceeding the fracture gradient.

- MPD can solve many of the NPT problems that occur while drilling offshore. By solving these problems, MPD can improve the economics of drilling wells and enable the drilling of wells that previously were thought to be uneconomical.

RECOMMENDATIONS

- Further research into the different variations of managed pressure drilling is needed to see the exact effect that these variations have on the pressure-gradient window. A better understanding of the variations will help the industry in making decisions on which variations they should use when drilling.
- A simulator needs to be designed to show the downhole effects that occur when using MPD. An accurate simulator that can show different situations that can occur while using the system will help in the design of MPD techniques and choosing which techniques are best to use in certain situations.
- A detailed economic study needs to be done on MPD techniques. With economics being a controlling factor in deciding what methods to use when drilling, a good study showing the economic benefits of MPD would help companies make the decision to use MPD. This economic study should look at the cost of the different techniques and the expected savings a company would see by using these techniques.

NOMENCLATURE

AFP	=	Annular Friction Pressure
BHP	=	Bottom Hole Pressure
BOP	=	Blow Out Preventer
CMC	=	Controlled Mud Cap
ECD	=	Equivalent Circulating Density
HH	=	Hydrostatic Head
IADC	=	International Association of Drilling Contractors
KM	=	Kick Margin
MPD	=	Managed Pressure Drilling
MW	=	Mud Weight
NPT	=	Non-Productive Time
PMCD	=	Pressurized Mud Cap Method
RCD	=	Rotating Control Device
ROP	=	Rate of Penetration
TVD	=	True Vertical Depth
UBD	=	Underbalanced Drilling

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