Petroleum Technology Development Journal

Managed Pressure Drilling with Automatic Choke Control in Low Pressure Reservoir

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Published in:
Petroleum Technology Development Journal (ISSN 1595-9104)
An International Journal

July 2011 - Vol. 1

Abstract

The primary objective of carrying out Managed Pressure Drilling is the ability to decrease mud costs by reducing lost circulation, and rig costs by reducing in-trouble and non-productive time.
The results have helped to identify several important considerations. One important consideration was expected: the ability to minimize casing pressure and therefore the risk of lost returns by continuing to circulate rather than shutting in. In cases with narrow margins between pore and fracture pressure, small differences in the drillpipe pressure being held constant during circulation with lost returns can potentially cause results ranging from total lost returns to uncontrolled flow at the surface. A tentative result of this on-going study is that there may be no single best initial response to a kick taken during MPD. The best response may depend on well geometry, kick zone productivity, and likelihood of lost returns. Managed pressure drilling operations provide alternative initial reaction to a kick that can have advantages over shutting the well in. specifically, increasing either the choke pressure or the pump rate may stop formation feed-in faster than shutting in and impose less choke pressure, resulting in less choke pressure, resulting in less kick volume and lower risk of lost returns.

Introduction

Managed pressure drilling (MPD) is an adaptive drilling process to precisely control the annular pressure profile throughout the well. 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. This defined by the pore pressure, hole stability envelope and fracture pressure. 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.

The term “Managed Pressure Drilling” (MPD) is a frequently misused. Some people equate MPD to Underbalanced drilling, and others equate it to “Power Drilling.” These associations are understandable, as all three practices share some key components: a rotating control head and a choke. Frequently, mud-gas separation equipment and a drill string float are used. However, the goals of these operations differ significantly.

Underbalanced operations are generally directed at reducing producing formation damage by encouraging inflow from the producing zone while drilling, thus keeping the drilling fluids out of the formation.
Power drilling is generally associated with hard formations, and significant Underbalance is sought to maximize penetration rate. In these wells, influx may or may not occur, but the goal remains to maximize penetration rate. These wells are frequently drilled with air or foam.

Underbalanced drilling was initially adopted for resolving drilling problems, but it soon became evident that this technique could also minimize reservoir damage. As originally conceived, Underbalanced drilling technology included techniques that were fully Underbalanced with influx to the surface as well as methods called “low-head” and “at-balance” drilling, in which the bottomhole pressure was kept marginally above or approximately equal to the pore pressure. These techniques later became designated as part of a separate category called managed pressure drilling, which has been adopted by the IADC. Many would agree that all drilling from conventional to air drilling might be considered as a form of “Managed Pressure Drilling,” since for a drilling project to be conducted in the safest manner, the pressure must be controlled or managed.

MPD is quickly being accepted as a technology that can reduce well costs and drill prospects that were previously considered challenging, expensive, or in some cases, even undrillable. While MPD should always be considered as a solution to challenging drilling scenarios, the application of MPD techniques can also have a significant impact on the cost of drilling wells in fields where even small improvements in drilling efficiency can result in a significant improvement in field economics.

Managed Pressure Drilling, as an emerging technology; continually demonstrates the ability to decrease mud costs by reducing lost circulation, and rig costs by reducing in-trouble and non-productive time. With the application of appropriate equipment and techniques, Managed Pressure Drilling reduces the impact of surprises brought on by the advent of uncertainties. MPD operations are directed at manipulating "windows" that exist between either formation pore pressures or wellbore stability pressures, and fracture pressures. In these wells, influx is absolutely avoided, just as in conventional drilling operations. 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.

Literature Review

Several researches have attempted to present the theory and practice managed pressure drilling and its application in drilling process. A review of the literature reveals a variety of solutions and addressing various problems area.

Managed Pressure Drilling (MPD) technology has evolved on land drilling programs since the mid-sixties. However, it has been only fairly recently that the technology has found an important niche in the minds of offshore drilling decision makers. With most of the world's remaining prospects for oil and gas being economically un-drillable with conventional wisdom casing set points and fluids programs, MPD is now being viewed as a technology which can render a significant increase in economic drill-ability by reducing excessive drilling-related costs typically associated with conventional offshore drilling.

With an ever-improving safety record and excellent value propositions, MPD is shaping up to be the spearhead of the company's drilling and development strategies in the coming years. Management of pressure is at the core of all drilling activities, with the balance of pressure in a wellbore being the critical factor in determining success or failure.

Conventional overbalanced drilling maintains a downhole pressure greater than the pore pressure of the formation into which the wellbore penetrates. Underbalanced drilling, on the other hand, intentionally keeps the wellbore pressure lower than that of the surrounding formation.

Managed Pressure Drilling and its Application

Several researches have attempted to present the theory and practice of simulation of tubular buckling and its effect on hole tortuosity. A review of the literature reveals a variety of solutions and addressing various problems area.

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In 1998, Weatherford acquired and developed key technologies, from proprietary RCDs to nitrogen-generation units to patented fluid and foam technology. In 2000 the quality, health, safety and environmental (QHSE) management system was recognized worldwide. In 2003, the Weatherford SURE process offered clients both quick screening tools and detailed evaluation. And today Weatherford continue to strengthen MPD engineering and well planning services through the application of two MPD techniques:

Reactive MPD. Weatherford has equipment that can be set up on "standby" for enhanced passive well control. This equipment can be brought into play quickly to manage unexpected downhole pressure during conventional drilling.

Proactive MPD. This application involves working in advance to plan for MPD, engineering the system most appropriate for the particular needs of your well and drilling program. Proactive MPD radically reduces drilling NPT—along with costs—by enabling fundamental changes to fluid, casing and open-hole programs. As wells become deeper, hotter, higher-pressured or more depleted, many will require some form of proactive MPD. It can be the difference between making a profit or not. Because MPD is an advanced form of well control using a combination of Underbalanced and conventional techniques, we assess all potential MPD programs for appropriateness and risk. Our documentation helps ensure that all parties clearly understand not only the potential risks and rewards but also roles and responsibilities. The Weatherford QHSE management system includes an industry benchmark training and competency assurance program, formal documentation and revision control.

Typical applications of Managed pressure drilling

I will be discussing two cases where managed pressure drilling needed to be applied. They are discussed below:

Case 1:

A two-well project was commissioned in Puguang, the largest gas field in China, to determine if percussion air drilling technology could provide ROP benefits. Because the feasibility report determined that wellbore stability could be an issue, a certain amount of project risk was involved. In addition, the main reservoir is sour, with sweet gas secondary zones above. Conventional 5,500 m wells were being drilled and completed in about 200 days. The first well was spud in March 2006, and immediate benefits were realized. In the main section, over 60 days were saved. Future wells are expected to eliminate an additional 40 days .As the project progresses, MPD techniques will be employed in the secondary gas reservoir with the goal to improve ROP performance.[1]

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[1] R.K. Bansal, D. Brunnert and R. Todd, C. Shen and X. Niu, Sinopec; S. Nas and C. Holt, Weatherford (2006). Directional Drilling- Case Study, paper SPE 18340, presented at SPE European Petroleum Conference, United Kingdom.

Case 2:

The ECDRT was designed to counter increased fluid pressure in the annulus due to friction loss and cuttings loading. A prototype was recently tested in a BP onshore operation in southeast Oklahoma. The ECDRT was field-tested by drilling 8 ¾-in. hole with the tool at a depth of 4,500 ft. Wellbore pressure management was clearly demonstrated in the field trial. The ECDRT consistently reduced ECD by about 0.7 ppg at 4,500 ft. Drilling performance was not limited by the ECDRT. Fluid return and wellbore cleaning were normal throughout the drilling operation. The ECDRT processed all of the cuttings generated by the drilling at 100 ft/hr. Over 500 ft was successfully drilled before the team decided to pull the tool due to an issue that caused difficulties with the directional drilling system. Post well analysis of the tool revealed that there are still a number of issues that must be addressed to secure the longevity and sustained performance of the tool, but overall results are encouraging[2]

Case 3:

Three RNS148, is located in Potiguar basin in Brazil, Weatherford drilled three wells to a depth of 16,174ft (4,930m) with a pore pressure of 11,670psi (805bar). The bottomhole temperature (BHT) was 287°F (142°C).

The main objective was to drill a High Temperature High Pressure (HTHP) offshore exploratory well without Safety, Environmental or Stuck pipe problems, using Weatherford's Managed Pressure Drilling techniques and equipments. The well was successfully circulated through the Rotating Control device (RCD), without having to close Blowout Preventer Rams (except when closing pressure reached 500 to 1000psiPSI/34 to 69bar). Also, stuck pipe situations was avoided which was often seen when the string is on bottom during well control procedures.

Reservoir depth was achieved using RCD, which allowed the operator to drill the well to planned depth. The RCD provided a barrier for improved safety while drilling with synthetic fluid at a high temperature. The RCD enhanced environmental protection by preventing spills when gas was present in the oil-base mud. Fishing operations were prevented for additional cost and timesaving.[3]

Case 4:

In case study, a jackup rig in offshore Angola was having serious problems drilling through a fractured carbonate reservoir with a low bottomhole pressure (4.7ppg to 5.5 ppg equivalent mud weight), a situation complicated by up to 2 percent hydrogen sulfide in the returning gas. The rig was forced to abandon one well when mud losses reached 1,400 bbl per hour. Drilling just 1,400 ft (427 m) in another well would require 35 days. Switching to pressurized mudcap drilling (PMCD), a variation of MPD, cut drilling time to just 3.5 days for 770 ft (235 m), a rate of penetration (ROP) of 220 ft (67 m) rather than 40 ft (12 m) per day. PMCD also allowed the well to reach total depth and prevented any H_2S from being brought to the surface. Likewise, on an MPD application in the Wild River area of Western Canada, Weatherford helped an operator realize an ROP increase of 250 percent and an overall cost saving of 18 percent for the relevant section of drilling as compared to previously drilled offset wells. In addition, the well was cased and cemented in a near-balanced state, thereby avoiding formation damage while achieving the operator's best cement job to date in the area. (March 2006)

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[2] R.K. Bansal, D. Brunnert and R. Todd, Weatherford (2004).

[3] R.K. Bansal, D. Brunnert and R. Todd, C. Shen and X. Niu, Sinopec; S. Nas and C. Holt, Op. Cit

Methodology

The two wells to be discussed are both required to maintain relatively constant bottomhole pressure at roughly the same true vertical depth; however they were significantly different in other respects. The most distinct differences were the hole size and drilling method.

The Mars A14-ST3 well in the Gulf of Mexico was drilled using jointed pipe and a final hole size of 10.25" while the GA-03 well on the Gannet platform in the North Sea was drilled with coiled tubing and a hole size of 3.375". Though, the configuration of the two wells were different but the system was designed to automatically respond to hydraulic changes in the well in order to maintain a relatively constant bottomhole pressure by holding the necessary backpressure on the annulus.

Managed pressure drilling utilizing backpressure to control bottom hole pressure is based on the simple formula:

$$P_{downhole}=P_{surface}+P_{annular}$$

Where, $P_{annular}=P_{dynamic}+P_{hydrostatic}$

$$P_{hydrostatic}\,(\text{bar}) = \frac{\text{Fluid Density (kg/l) x TVD (m)}}{10.2}$$

To maintain $P_{downhole}$ constant, $P_{surface}$ is varied to compensate for changes in $P_{annular}$ caused by variations of the drilling pump rate, mud density and other causes of pressure transients such as motor stalls, cuttings loading and pipe rotation. To ensure bottomhole pressure was constant at all times the system was designed to operate automatically without operator intervention.

Elements of the Backpressure Control System

The primary components of the backpressure system are:

1. Control System / Hydraulics Model.
2. Choke Manifold / Backpressure Pump.

Control System & Hydraulics Model.

The control system consists of five primary components:

1. Single-phase hydraulics model.
2. Data communication interface and historical database.
3. GUI (Graphical user interface).
4. PID (Proportional, Integral, Derivative) controller or other algorithm to control the annulus discharge or downhole pressure.
5. PLC (programmable logic controller), sensors and controls.

Hydraulics Model

The purpose of the hydraulics program is to calculate the required $P_{surface}$ set point to obtain the desired $P_{downhole}$. It is necessary to use a hydraulics model to calculate the pressure set point since feedback from the downhole pressure sensor is usually too slow or intermittent due to low telemetry speed or interruptions to be used directly with the control loop. This is particularly the case when mud pulse telemetry is used, but can be the case with any of the current telemetry systems. The bottomhole pressure tool would also have to be nearly 100% reliable.

The hydraulics model performed pressure calculations, using a set of input values that described the state of the well while operations were in progress. Three categories of input data can be distinguished for the hydraulics model to function in this manner:

1. Frequently changing, direct measurements from rig sensors such as pump rate and string velocity. These values were entered into the model via a real time data link with the rig data system and from system-own sensors.

2. Static values such as well and string geometry. Values were input prior to the start of the operation. When conditions changed, the file was updated and reloaded into the model. In future versions it will be possible to update hole geometry based on real time caliper logs and the proprietary model runs in near real time at a rate of more than once per second. Although the calculation routine was not considered to be particularly onerous in terms of CPU time, the hydraulics program was run on a standalone PC to ensure priority was not given to less critical requirements memory intensive elements such as the graphical user interface. Other hydraulic models purpose built for specific mud systems or generic models for simple mud systems may also be used but would need to be thoroughly tested to ensure reliability in near real time use. For the purpose of maintaining the required bottomhole pressure constant, the calculated annulus pressure at the bit or some other point in the borehole versus the desired value was used to determine the additional backpressure required;

$$P_{BH} = P_{HYD} + AFP + Backpressure$$

Standpipe pressure could also have been used as a pressure reference but is complicated by the transient effects of pipe movement and motor operation. The hydraulics program calculates standpipe pressure as a normal part of the routine but a comparison of the model versus actual values has not been performed to confirm the reliability given the transient effects mentioned.

Data Communications and Database

Data communications used the WITS Level II protocol with an expected data transfer rate of 1 record every 10 seconds, in the case of GA-03 and 1 record every 5 seconds on MARS A14-ST3. These data rates were too slow to ensure the hydraulics model was updated as a result of planned or unplanned transient effects, so the maximum possible data exchange rate was requested.

There were concerns from the third party data distributor that increasing the data transfer rate would overload their system but this proved not to be the case. Data was received at a rate of at least once per second but delays of up to 10 seconds from the source to the central data provider were experienced. In the case of pump rate data; this resulted in the hydraulic model calculations lagging behind actual conditions, resulting in delayed choke response and subsequent lag in backpressure behind the desired values. Even with these delays, the system maintained bottomhole pressure within acceptable limits, although not as accurately had the data been available in a more timely manner. Continued efforts to increase the data rate and obtain data in real time proved to be one of the critical success factors to providing accurate control of bottomhole pressure. Data received and internally measured was logged in a historical database. Custom reports were generated to trend pressure data as well as providing the ability to playback the data using a simulator.

Data Quality

While data quality and reliability of data communication was considered essential to ensure the correct estimation of bottomhole pressure, it was expected that at some point data communication would be lost or data errors would be transmitted. It was therefore necessary to manage these occurrences with system control or procedures. Data communication was monitored by the system and warnings were generated when data communication was compromised. This allowed sufficient time to alert the necessary personnel to maintain the steady state condition.

There were several occurrences where steady state had to be maintained and was achieved by maintaining the backpressure set point in the last value calculated and all drilling operations constant until data communication could be restored. With data communication restored it was then possible for the system to continue maintaining the bottomhole pressure constant. One procedural action was for the Driller to control the pumps should a control system error occur. The pump rate could be increased or decreased to effect bottomhole pressure as required if the choke was in a fixed position and not responding to the controller in most cases. Several other procedures were developed in the event of non-standard processes. Data was also filtered to ensure that quality was within specified limits. For example, it was critical that only valid PWD readings be used for updating the hydraulics model since inaccurate readings would have resulted in significant variations to the BHP. Using PWD readings directly for bottomhole pressure control would have required continuous operation of the PWD.

PLC and PID Controllers

The Gannet and Mars systems differed in that they used different control algorithms and logic.
The Gannet system was fully developed in-house. The system included two computers running the GUI and the hydraulics model, and two PLC's. One PLC was dedicated to choke positioning and used as sensor interface. The other PLC ran the PID controllers for pressure control and the switching logic required to control all the gate valves on the manifold and backpressure pump, including the ability to automatically switch to the redundant choke leg, control pressure with both legs simultaneously and also provide extensive system diagnostics.

Pressure Control PID Tuning

A PID controller is used in the system to determine the optimum choke position set point to control the well pressure. As generally known, PID controllers need to be tuned to the process for optimum responsiveness. Poor tuning may lead to oscillations, slow response or pressure overshoot. In the case of the system described in this work, the optimum setting of the PID controller depends primarily on determining the compressibility of the hydraulics system, comprising the mud type, well geometry, flow rate and pressure.

The PID pressure controller was tuned through step response tests. It took approximately 2 hours to perform these tests prior to the start of drilling operations. It was also necessary to occasional fine-tune the system during operations, for example when well characteristics changed, particularly when tripping.

Initial Responses to Kicks

The procedure for initial kick response in conventional drilling is well established. It involves shutting-in the well after a positive flow check is recorded. This is followed by recording the shut-in drill pipe pressure, shut-in casing pressure and pit gain versus time. However, in the CBHP method with a pressurized circulation system, there are several other options that exist for initial response to kicks. The specific initial responses to kicks investigated in this study are:

- Shut-in the well, similar to conventional drilling
- Apply back pressure through the choke while continuing to circulate at same rate
- Increase the pump rate to increase the annulus frictional pressure drop.

Simulation Method

One 6 inch slim hole section of a representative well 'X' and one large 17-1/2 inch hole section of another representative well 'Z' were used in this study for simulating a range of well control scenarios. The well data such as geometry, pore pressure, fracture pressure, trajectory, productivity index, geothermal temperature, mud weight and zones of interest were provided by the project sponsors. These wells are planned as MPD wells due to constraints unsuitable for conventional drilling. The operating parameters such as kick size, kick fluid type (oil or gas), and kick intensity (difference between the pore pressure and the bottomhole pressure) were varied between simulation cases as a sensitivity study. An increase in return flow rate to a value higher than the pump rate during drilling was used as the primary kick detection method during the simulations. The following parameters are listed in the Tables below for Well X and Well Z respectively;

Table 1. Well X Simulation Cases for Intact Wellbore

S/N	Initial Kick Response	Mud Weight (ppg)	Reservoir Fluid	Kick Intensity		Produc Productivity Index (mmscfd/psi)/stb/day-psi	Kick Size(bbl)			Type of Mud
				Static	**Dynamic**		**High**	**Medium**	**Low**	
1	Shut-in Well	13.2	Gas	0.4 ppg	68 psi	0.4286			0.64	WBM
2	Apply Back Pressure	13.2	Gas	0.4 ppg	68 psi	0.4286			0.72	WBM
3	Increase Pump Rate	13.2	Gas	0.4 ppg	68 psi	0.4286			0.76	WBM
4	Shut-in Well	13.2	Gas	0.4 ppg	68 psi	0.4286	16.4			WBM
5	Apply Back Pressure	13.2	Gas	0.4 ppg	68 psi	0.4286	16.35			WBM
6	Increase Pump Rate	13.2	Gas	0.4 ppg	68 psi	0.4286	16.35			WBM
7	Shut-in Well	13.2	Gas	0.4 ppg	68 psi	0.4286		4.83		WBM
8	Apply Back Pressure	13.2	Gas	0.4 ppg	68 psi	0.4286		4.89		WBM
9	Increase Pump Rate	13.2	Gas	0.4 ppg	68 psi	0.4286		4.89		WBM
10	Shut-in Well	13.2	Oil	0.4 ppg	68 psi	87	15.49			WBM
11	Apply Back Pressure	13.2	Oil	0.4 ppg	68 psi	87	15.35			WBM
12	Increase Pump Rate	13.2	Oil	0.4 ppg	68 psi	87	15.35			WBM
13	Shut-in Well	13.2	Oil	0.4 ppg	68 psi	87		5.71		WBM
14	Apply Back Pressure	13.2	Oil	0.4 ppg	68 psi	87		5.84		WBM
15	Increase Pump Rate	13.2	Oil	0.4 ppg	68 psi	87		5.84		WBM
16	Shut-in Well	13.2	Oil	0.4 ppg	68 psi	87			0.96	WBM
17	Apply Back Pressure	13.2	Oil	0.4 ppg	68 psi	87			1.03	WBM
18	Increase Pump Rate	13.2	Oil	0.4 ppg	68 psi	87			1.03	WBM

Table 2. Well Z Simulation Cases For Non-Intact Wellbore

Sub Group	S/N	Case No	Initial Kick Response	Mud Weight (ppg)	Reservoir Fluid	Kick Intensity Static	Kick Intensity Dynamic	Productivity (mmscf/ day-psi)	Injectivity (mmscf/ day-psi)	Kick Size (bbl) High	Kick Size (bbl) Low		Type of Mud
	1	Case 1	Increase Mud flow rate	12.51	Gas	1.49 ppg	32 psi	0.5564	0.0004		5.5		WBM
	2	Case 2	Apply Back Pressure	12.51	Gas	1.49 ppg	32 psi	0.5564	0.0004		5.5		WBM
1	3	Case 3	Shut-in Well	12.51	Gas	1.49 ppg	32 psi	0.5564	0.0004		5.5		WBM
	4	Case1 A	Increase Mud flow rate	12.51	Gas	1.49 ppg	266 psi	0.5564	0.0004		5.5		WBM
	5	Case2 A	Apply Back Pressure	12.51	Gas	1.49 ppg	266 psi	0.5564	0.0004		5.5		WBM
2	6	Case3 A	Shut-in Well	12.51	Gas	1.49 ppg	266 psi	0.5564	0.0004		5.5		WBM
	7	Case2 A(longer)	Apply Back Pressure and circulate out kick	12.51	Gas	1.49 ppg	266 psi	0.5564	0.0004		5.5		WBM
3	8	Case3 A(longer)-no float	Shut-in Well for longer duration	12.51	Gas	1.49 ppg	266 psi	0.5564	0.0004		5.5		WBM
	9	Case2 B	Increase Pump Rate	12.51	Gas	1.49 ppg	266 psi	0.5564	0.4	50			WBM
4	10	Case3 B	Shut-in Well	12.51	Gas	1.49 ppg	266 psi	0.5564	0.4	50			WBM
	11	Case2 C	Apply Back Pressure	12.51	Gas	1.49 ppg	266 psi	0.5564	0.4		5.5		WBM
	12	Case3 C	Shut-in Well	12.51	Gas	1.49 ppg	266 psi	0.5564	0.4		5.5		WBM
		Case2 C-Alternate-1	Apply Back Pressure	12.51	Gas	1.49 ppg	266 psi	0.5564	0.4		5.5		WBM
	13	In this simulation, flow was forced to equal the flow rate-in by choke adjustment until the end of simulation.											
		Case 2c-Alternate-2	Apply Back Pressure	12.51	Gas	1.49 ppg	266 psi	0.5564	0.4		5.5		WBM
5	14	In this simulation, flow was forced to equal the flow rate-in for 15minutes, and thereafter, attempted to maintain the drillpipe pressure constant by choke adjustment.											

Results and Discussion

When designing a well, one of the main factors used in determining casing setting depths, is the amount of gas that safely can be circulated out of the well without fracturing the weakest formation in the open hole section, often referred to as kick margin (K_m). In order to show how different drilling methods will have different margins (K_m).

Simulation result for Well X

The drilling plan involves sidetracking from 7 inch existing casing at 14150ft MD and drilling a 6inch hole to 17900ft MD with the objective of producing from a deeper gas condensate reservoir. The main reason for MPD in this well is the desire to minimize overbalance in depleted zones in order to avoid lost returns or differential sticking. A high wellbore frictional pressure lose due to the slimhole geometry complicates achieving the well objective. The highest pore pressure gradient expected in this well is 13.6ppg (pore pressure=9901psi) from a possible gas sand, labeled as HP sand at 15632ft MD, 14000ft TVD. The possible overpressure at this gas sand with underlying depleted zones makes this well a good candidate for MPD operation.

Initial Reactions in Intact Wellbore- Well X

An overall summary of the initial reaction options in an intact wellbore and the controlling well conditions that were simulated in this study is presented in Table 1.

Table 3. Well X Gas Kick Simulation

		Casing Pressure versus kick size for gas kick		
S/N	**Initial Reaction**	**<1bbl**	**5 bbl**	**16 bbl**
1	Shut-in well	404	457	520
2	Apply Back Pressure	179	263	357
3	Increase Pump Rate	56	52	54

The margin between the fracture pressure at the weakest zone (depth of sidetrack) and the pore pressure at the high pressure sand was high enough to allow control without inducing a fracture, implying an intact wellbore during initial reactions.

A total of 18 simulations with alternative initial reactions to kicks taken after penetrating the high pressure sand at 15632 ft were undertaken. Basic input data such as WOB, RPM and pump rate were same for these simulations. 13.2 ppg mud weight and a pump rate of 150 gpm were used for all simulations, which resulted in a kick of 0.4 ppg intensity when the high pressure gas sand was penetrated. The dynamic kick intensity, or underbalance, at this flow rate was equivalent to 68 psi. Kick sizes and fluid types are given in Table 2.

The results of the gas kick simulations are summarized in Table 2. The results show trends that were anticipated:

1. The increased pump rate response gave the lowest casing pressures and therefore the lowest risk of lost returns regardless of kick size.
2. A larger kick size resulted in a higher casing pressure for the shut-in and increased casing pressure responses.
3. The shut-in response resulted in the highest casing pressure for a given kick size and therefore the highest risk of lost returns.

All three initial reactions successfully stopped the formation fluid influx irrespective of kick size or fluid type without causing lost returns for this well scenario. A comparison of the initial reactions from the perspective of identifying conclusively whether formation fluid flow was stopped and whether lost returns have occurred requires additional cases. So, cases that do not stop formation flow or that cause lost returns were studied for comparison as described below.

Initial Reactions in Non-intact Wellbore - Well X

The possibility of lost returns in the depleted zones below the high pressure sand was a specific concern for this well. In order to investigate the effectiveness of alternative initial reactions in scenarios with simultaneous loss from the lower depleted zone and gain from the overlying high pressure sand, simulation cases were set up with a fracture pressure of 10,000 psi, equivalent to 13.54 ppg at a depth of 16130 ft MD, representing a depleted sand underlying the high pressure sand at 15632 ft MD with a pore pressure of 9901 psi, equivalent to 13.6 ppg. These conditions were selected to effectively eliminate the window between the fracture pressure and pore pressure at this depleted zone and result in kicks caused by the occurrence of lost returns. This enables comparisons of initial reactions when lost returns occur.

A fracture injectivity index of 0.4 mmscfd/psi was used to give the potential for a significant rate of losses in the depleted zone. The high pressure sand was drilled with the same mud weight of 13.2 ppg, but with an ECD higher than the pore pressure gradient by increasing the pump rate from 150 to 225 gpm; therefore, no kick was encountered during drilling of this sand. As the depleted zone was penetrated, mud losses were encountered, and the return flow rate gradually reduced to 150 gpm before it started to gradually increase again. The return flow rate increased above the pump rate and a 10 bbl gain was recorded, at which time an initial response to the kick was taken. In this case, the kick from the high pressure gas sand at 15632 ft was triggered by the loss of ECD due to losses in the weak depleted zone at 16130 ft. An overall summary of the reaction options and the controlling well conditions of these simulations is presented in Table 2. The results of these simulations are described below.

<u>Table 4. Well Simulation Cases For Non-Intact Wellbore</u>

<table>
<tr><th>Case No</th><th>Initial kick response</th><th>Mud weight (ppg)</th><th>Reservoir fluid</th><th>Kick Intensity (static)</th><th>Productivity Index (mmscfd/psi)</th><th>Fracture Injectivity Index (mmscfd/psi)</th><th>Kick Size (bbl)</th><th>Type of Mud</th></tr>
<tr><td>1D</td><td>Apply back pressure</td><td>13.2</td><td>Gas</td><td>0.4 ppg</td><td>0.4286</td><td>0.4</td><td>10</td><td>WBM</td></tr>
<tr><td rowspan="2">1D-Alternate-1</td><td>Apply back pressure</td><td>13.2</td><td>Gas</td><td>0.4 ppg</td><td>0.4286</td><td rowspan="2">0.4</td><td rowspan="2">10</td><td rowspan="2">WBM</td></tr>
<tr><td colspan="5">In this simulation the return flow rate forced to equal the pumping rate until the end of simulation</td></tr>
<tr><td>2D</td><td>Shut-in Well</td><td>13.2</td><td>Gas</td><td>0.4 ppg</td><td>0.4286</td><td>0.4</td><td>10</td><td>WBM</td></tr>
<tr><td>3D</td><td>Increase pump rate</td><td>13.2</td><td>Gas</td><td>0.4 ppg</td><td>0.4286</td><td>0.4</td><td>10</td><td>WBM</td></tr>
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Apply Back Pressure

The application of back pressure to control the well after taking a 10 bbl kick was comprehensively simulated for prolonged periods with different strategies to understand the complex behavior of the well in a simultaneous loss gain scenario.

Table 4 shows the simulation results of case 1D. In this simulation, the choke was adjusted to make flow out equal to the pump rate. Then an attempt was made to maintain drillpipe pressure constant. The choke had to be pinched continuously due to falling drillpipe pressure, and finally the choke was completely closed with total losses of drilling fluid into the formation. Before applying back pressure, simultaneous losses and gains were taking place. After applying back pressure and continuing to pump, the well was experiencing only lost returns in the fractured zone at the end of simulation. Pumping at a constant rate of 225 gpm while holding 2250 to 2300 psi on the drillpipe had successfully stopped the in-flow, but resulted in a total loss, implying the need for further actions to fully regain well control.

A second variation of the back pressure application, case ID-Alternate 1 (see Table 3), was simulated to determine the effect of maintaining flow rate out equal to pump rate for an extended period of time. In this case, the choke was adjusted to keep the liquid flow rate equal to the pump rate for a longer duration. In an intact wellbore, this would typically cause excessive wellbore pressure and risk of lost returns. Although this is not considered to be a correct approach for conventional well control, it is still sometimes considered as a means of preventing additional feed-in. The gas flow continued at a progressively higher rate until the end of simulation, the surface blowout situation with a gas flow rate at the surface of 5.42mmscfd at the end of simulation. After an initial decline, the drillpipe pressure remained nearly constant at 2200psi until the end of the simulation.

These simulations of kicks caused by lost returns in a deeper zone with a fracture pressure only 100psi more than the pore pressure of the overlying high pressure zone demonstrates the difficulties in controlling the well. Completely successful well control, i.e. stopping formation fluid influx and maintaining full return was not possible. Because the margins between PP and FP was only 100psi, a variation of less than 100psi in wellbore pressure caused results ranging from essentially uncontrolled gas flow to the surface to complete lost returns.

Shut-in Well

The well was shut-in in this simulation, case 2D (Table 3) after a 10bbl kick was detected at the surface. The casing pressure was monitored during the shut-in period. Table 4 shows the simulation results. The choke pressure and the bottomhole pressure fluctuated, suggesting a cyclic pattern of gains from the upper kick zone in a closed well experiencing gas migration. However, the short period of this rapid fluctuation is probably more related to the simulation code than to actual well behaviour. Although there is no gas flow at the surface, the liquid hold up profile that occurred at the end of simulation, suggests that the influx from the gas zone at 15632ft is continuing as gas is migrating toward the surface. Also, the choke pressure has increased to 2200psi about two hours after shutting in the well. This contrasts with the result of back pressure reaction of case 1D where the inflow had stopped with a choke pressure of 1500psi although total loss of the 225gpm pump rate was experienced. It also contrasts with case 1D-alternate 1 where significant and increasing gas flow to the surface was experienced.

Increase Pump Rate

The pump was increased gradually in simulation case 3D (Table 2) in an attempt to increase the ECD and stop the influx after a 10 bbl kick was taken in the well. The flow rate out was monitored and compared with pump rate interactively. The pump rate was increased to about 390gpm, which required a pump pressure of about 6200psi. This rate and pressure were considered to be realistic limits for the system. Because of the losses on the bottom, the increased annulus flow rate needed to increase the ECD and to counterbalance the pore pressure could not be achieved. In this case, in spite of a narrow annular clearance, the increase flow rate option to stop the influx was not effective because of losses below the kick zone. Both losses and influx were occurring at the end of simulation. The return flow rate was greater than the pump rate and increasing rapidly confirming that the increased pump rate was not adequate to stop the influx.

Simulation Result for Well Z

Well Z is a planned offshore vertical wildcat well. The 17-1/2 inch hole section of this well is an interesting pore pressure (from 8.8 ppg at3280 ft to 13.94 ppg at 4756 ft), and a progressively decreasing margin between the pore pressure and the fracture pressure at the casing shoe of 14.16 ppg. The simulation well was drilled with a 12.51 ppg mud to induce a gas kick at 4500 ft with a kick intensity of 0.49 ppg in the first batch of simulation. In the subsequent batches of simulations, more several well control scenarios were simulated by increasing the kick to 1.49 ppg. Also, the fracture injectivity index at the previous casing shoe was increased from 0.0004 to 0.4 mmscfd/psi in some simulations to show the impact of significant lost returns on the simulation results. The pump rate used for drilling was 984 gpm for all simulation cases.

An overall summary of the initial reaction options and the controlling well conditions that were simulated in this study is presented in Table 4. The results of the most informative simulations are discussed in the following sections.

Increase Pump Rate

At an increased pump rate of 1155 gpm, the standpipe pressure reaches the assumed pump pressure limit of 6285 psi. at that time, the influx had not stopped as evidenced by the return flow rate of 1169 gpm, which was 14 gpm higher than the pump rate. The friction factor for annular clearance; therefore, the increase of mud pump rate has a smaller impact on the bottomhole pressure. The increase of mud flow rate has a much higher impact on pump pressure due to rapid increase of frictional pressure losses in the drillstring with smaller flow areas and higher pressure drop through the small restrictions in the bit nozzles. This reaction did not stop formation fluid flow and could not prevent a blow out.

Apply Back Pressure

Table 4 shows the simulation results for the back pressure reaction of case 2. A low kick intensity of 0.49 ppg and low fracture injectivity index of 0.0004 mmscfd/psi were used in this simulation. A 5.5 bbl gas kick was taken, and thereafter, back pressure was applied to stop formation fluid influx. The influx stopped with about 53 psi back-pressure and a reduced choke opening of 87%. The choke pressure was then increased slowly to maintain constant drillpipe pressure while beginning to circulate the kick out of the well. The wellbore was intact with no indications of lost returns.

Table 4 shows the simulation results of the back pressure response of case 2A with the same 5.5 bbl kick, but intensity was selected specifically to represent the possibility of taking a kick near the bottom of the hole interval where the pore pressure gradient is almost equal to the fracture pressure gradient at the shoe. This scenario also creates the potential for lost returns and therefore the opportunity to see the effect of lost returns on the different responses. In this case, the choke was again adjusted to maintain drillpipe pressure constant after the return flow rate became equal to the pump rate to maintain a constant bottomhole pressure during kick circulation. The kick was successfully circulated out because the mud losses due to exceeding the fracture pressure, and evidently, there was no secondary kick during the kick circulation. The liquid hold up was nearly 100% at the end of simulation, implying all gas had essentially been circulated out throughout the well.

Table 4 the simulation results of a second variation of a back-pressure reaction, case 2C. The severity was increased again in this case with a kick intensity of 1.49ppg and fracture injectivity index of 0.4 mmscfd/psi. Back pressure was applied after taking a 5.5 bbl gas kick into the wellbore, and the return flow rate was monitored. Back-pressure was increased by choke adjustment until the flow out became equal to the pump rate, and thereafter, an attempt was made to maintain drillpipe pressure decreased continuously in spite of continuous pinching on the choke adjustments. However, the drillpipe pressure decreased continuously in spite of continuous pinching on the choke to arrest the declining trend. Eventually, the choke was completely closed with a total loss of drilling fluid into the induced fracture in the openhole section of the wellbore. The liquid holdup was 70% at the kick zone suggesting that an underground blow out was underway with continuous inflow and corresponding total losses. The occurrence of lost returns becomes evident relatively quickly in this simulation as indicated by the inability to maintain drillpipe pressure constant and the rapid decrease in return flow rate. The gradual decrease in drillpipe pressure and increase in choke pressure with the choke fully closed are also indicative of an underground blowout developing.

Table 4 shows the simulation results of case 2C-Alt-1, which is another variation of back pressure application for a well control scenario similar to case 2C. In this case, the choke pressure was adjusted to maintain flow returns or formation feed-in until the end of simulation. The result of this simulation was not favorable from well control perspective as gas broke out early at the surface, and the well flowed at 20.43 mmscfd at the end of simulation indicating a surface blowout.

Both versions of case 2C reinforce the observation in case 1D-Alt-1 for Well X that achieving flow in equal to flow out does not ensure that formation feed-in has been stopped.

Shut-in well

Table 4 shows the simulation results of shut-in reaction of case 3. A low kick intensity of 0.49 ppg and low fraction injectivity index of 0.0004 mmscfd/psi was used in the simulation. A 5.5 bbl gas kick was taken, and thereafter, the well was shut-in to stop formation fluid influx. A casing pressure of 74 psi was recorded when the influx stopped after shut-in, which was slightly more than the casing pressure recorded in the increasing back pressure option, as expected. After the well was shut-in, a negligible amount of influx entered the wellbore before it finally stopped. A conventional flow check was not carried out, but a peck in the influx rate was recorded. This was attributed to loss of pressure during shut-down of the mud pump without increasing casing pressure to condensate for the decrease in frictional pressure losses. The wellbore was intact in this case as there were no indications of lost returns.

Table 4 shows the simulation results of another shut-in reaction for case 3C. The well control scenario used in this case was equivalent to that in case 2C with a kick intensity of 1.49 ppg and a fracture injectivity index of 0.4 mmscfd/psi. The well was shut-in after a 5.5 bbl gas kick was taken. The choke pressure continuously increased after the well was shut-in indicating gas migration. The bottomhole pressure initially decreased, probably due to loss of hydrostatic pressure in the annulus due to heavy downhole losses, and then it stabilized at about 2600 psi after about 110 minutes into the simulation. The bottomhole pressure was significantly lower than the pore pressure (3276 psi) during the shut-in period, implying a continuous influx into the wellbore. Interestingly, after shut-in, the drillpipe pressure decreased to zero psi from about 99 to 125 minutes of simulation time, although the choke pressure was rising during this period. This corresponded to the time when bottomhole pressure followed was also decreasing. Therefore, the drillpipe pressure followed an increasing trend until the end of simulation. After the well was shut-in, the fluid level in the drillpipe fell due to bottomhole pressure being less than the hydrostatic pressure in the drillpipe. Once the drillpipe hydrostatic pressure equalized with the bottomhole pressure, gas could swap with falling out of the drillpipe. The increase in drillpipe pressure after 125 minutes was evidently due to gas migration in the openhole at the end of simulation was only about 5% implying that gas flow from the kick zone had displaced almost all of the mud from the openhole into the loss zone. The simulation also indicated that simultaneous losses at the casing shoe and formation fluid influx from the kick zone were occurring signifying that an underground blowout was in progress. In this case, the ability to observe drillpipe pressure falling as casing pressure was increasing is a strong indication that losses are occurring in addition to gas migration. The use of a drillstring float or non-return valve complicates this diagnosis.

Summary

MPD is an advanced form of primary well control typically employing a closed, pressurizable fluid system that allows greater and more precise control of the wellbore pressure profile than mud weight and mud pump rate adjustments alone.

Two offshore wells were successfully drilled within the desired bottomhole pressure limits using an automated backpressure control system consisting of a choke and pump connected to the annulus discharge. The bottomhole pressure was maintained within required limits on both wells. Managed pressure drilling has been proven that quick recovery from a differentially stuck pipe situation can be obtained by momentarily reducing the back pressure, which potentially results in substantial cost savings.

Managed pressure drilling operations provides alternative initial reactions to kick that can have advantages over shut-in well. Specifically, increasing either the choke pressure or the pump rate may stop formation feed-in faster than shutting in and imposing less choke pressure, resulting in less kick volume and lower risk of lost returns.

Conclusion

Managed pressure drilling is a new technology that will improve the economic drill ability 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 was previously economically undrillable. By using this method during well control events, when hydrocarbon influxes are being circulated out of the well, the inherent problem with added annular pressures due to friction is neutralized. In fact it can be shown that being able to circulate out influxes at higher circulating rates improves the margins against weaker formations at a higher interval of the well, such as at the casing shoe.

This advantage also counts for MPD; however the margins will be substantially higher for the Controlled Mud Cap method. The amount of improvement CMC method introduce will depend on several factors such as the length and depth of well.

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.

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