

Managed Pressure Drilling—Automation Techniques for Horizontal Applications

C.J. Bernard, Randy Lovorn, Derrick Lewis, Emad Bakri and Saad Saeed, Halliburton

Copyright 2013, AADE

This paper was prepared for presentation at the 2013 AADE National Technical Conference and Exhibition held at the Cox Convention Center, Oklahoma City, OK, February 26-27, 2013. This conference was sponsored by the American Association of Drilling Engineers. The information presented in this paper does not reflect any position, claim or endorsement made or implied by the American Association of Drilling Engineers, their officers or members. Questions concerning the content of this paper should be directed to the individual(s) listed as author(s) of this work.

Abstract

When operators face complex pressure regimes that make conventional drilling in horizontal applications next to impossible, the implementation of managed pressure drilling (MPD) techniques has proven successful in achieving planned well objectives while minimizing non-productive time (NPT) from pressure and stability related events.

When properly planned and executed, MPD techniques will ultimately reduce overall time and cost of even the most complex wells by managing the challenges from narrow pressure profiles. MPD, where a constant bottomhole pressure (BHP) dynamic target is at, or just above, reservoir/pore pressure for drilling, during connections and tripping and also while running casing and during cementing operations, offers solutions for many of today's challenges in horizontal applications.

This dynamic target BHP for horizontal applications, whether controlling at the curve, the heel, or the toe (an exclusive technology), can be dialed into on demand according to current conditions and situations encountered using these automated techniques. The challenges discussed in this paper that these automated techniques solve include:

1. Accessing mature reservoirs
 - More solutions for managing depleted zone challenges
 - Better equivalent circulating density (ECD) control for extended-reach drilling (ERD)
2. Navigating through narrow pressure margins
 - Provides instantaneous, accurate, and precise bottomhole pressure adjustments, as well as - equivalent mud weight (EMW)
3. Operating in fragile formations
 - Minimize pressure cycling
 - EMW on demand to improve borehole stability and control collapse issues
4. Improving Zonal Isolation
 - Dynamic BHP control during cementing operations
5. Minimizing fluid infiltration into reservoir
 - BHP maintained at, or just above, reservoir/pore pressure
6. ROP enhancement
 - Ability to lighten mud weight but maintain "BACK UP EMW ON DEMAND"

This paper will discuss how operators have used automated MPD techniques in horizontal applications, including unconventional shale plays, to increase efficiency, reduce costs, and improve recovery.

To drive the results demanded by today's cost-driven operations, NPT must be kept to a minimum. MPD is proving itself day in and day out to be a value-added service.

This paper will cover an introduction to MPD automation techniques and how they bring solutions to the challenges seen in horizontal applications. Several case-history examples, where MPD automation techniques were employed by different operators, will be discussed, with an overview provided of the techniques used and the results observed. We will compare and contrast MPD to conventional operations, focusing on ROP, NPT, and economic values of the technology in these types of applications and operations.

Introduction

MPD has been deemed an enabling technology because of the ability to provide accurate and precise downhole pressure control "on demand." Not only can today's MPD systems provide the capability to operate in tight operational envelopes, but they, more importantly, provide dynamic real-time well-event detection and control capabilities, while continuing with drilling operations. These capabilities have given operators access to assets that were previously considered virtually "undrillable" by either physical or economic limitations.

One of the main reasons for the observed successes is in the automation features developed by a limited number of MPD service providers. Automation can provide levels of dynamic functional control and precision that are difficult, if not impossible, for human operators to achieve and maintain. MPD's inherent closed-loop setup, coupled with conventional methodology, naturally lends to automated applications [2].

In applying these automation techniques to horizontal applications, it can be demonstrated that many of the challenges encountered in the construction of these wells, from building the curve, drilling the lateral, and in casing and cementing operations, have been solved and/or minimized with full implementation of MPD automation techniques.

Overview of Horizontal Application Challenges

The use of horizontal drilling technology in oil and gas exploration, development, and production operations has grown rapidly over the past few years. This technology has enabled regions, led by the US, to unlock unconventional and more energy-efficient resources to help meet the world's growing demand for energy.

Predictions speculate that energy demand across the world will soar 35% by 2040, compared to 2010, with petroleum supplying about 60% of that demand.

This forecast comes as new technologies continue to fuel production of more energy-efficient resources. The future holds opportunities for North America, particularly in Oklahoma, for example, where operators have shifted to oil- and liquids-rich shale plays, tight sandstones, and the Mississippian limestone in jump-starting Oklahoma's oil production once again. It is expected that unconventional gas production will grow substantially in North America. The growth in unconventional supplies is a result of recent improvements in technologies to tap these resources.

The technology includes use of hydraulic fracturing, a technique that has been around for decades in the oil and gas industry, and horizontal drilling. These technologies unlock resources from shale plays that had been considered uneconomical for many years.

The intent of a horizontal well is to maximize the reservoir exposure, allowing for an optimized exploitation/production from a field. The use of horizontal drilling has become popular in reservoirs classified as "unconventional," where the permeability of rock is marginal and hydraulic stimulation is often required. An unconventional reservoir is typically organic-rich shale, a tight-gas sandstone, or coal-bed methane. Because unconventional formations have low permeability and porosity, the main production mechanism is through the natural fracture system.

Intersecting fractures requires geomechanical knowledge of the stress orientation. Usually, this direction is that of the least principle stress, which can be a more problematic drilling direction for borehole stability and can require mud weights greater than those from a vertical well. To maximize the production potential of a well, a lateral that can intersect a high quantity of fractures is planned.

Quite often, a mud program is designed around predicted or observed events, such as losses, break out, and kicks from previous wells, and the accuracy of predictions and observations builds some level of uncertainty in the pore, fracture, and collapse pressure profile in the well being drilled. This approach could lead to mud weights that are higher than those actually required, resulting in higher equivalent circulating density, slow penetration rates, and damage to any micro-fractures that could contribute to the production.

Depending on the hole size, flow rates, fluid properties, and temperature, ECDs can become substantially high as the lateral is drilled. In narrow drilling windows, the ECDs could exceed the fracture pressures of rock, minimally causing ballooning. Ballooning, in essence, is hydraulic fracturing of rock while drilling. Once ballooning begins, losses are seen

immediately, but may be gradual and could go unnoticed on the rig site. What is not immediately observed is the gas that can be produced from the dilated fractures once the pumps are shut off for connections, and the ECD effect is relieved. On long laterals, one theory is that the gas bubble will travel along the lateral and will only begin expansion once it has reached the vertical section. At this point, an influx will be detected at surface, and standard shut-in procedures and pressures may lead to a misinterpretation of the actual pore pressures along the lateral owing to gas expansion affects.

A worst-case scenario for the ECD effect in laterals is once the fracture gradient is exceeded, total losses could be experienced, which could lead to loss/kick scenarios, wellbore collapse, stuck pipe, or sidetracks. These types of issues have historically caused cessation of drilling, not achieving the required exposure to the reservoir, reservoir damage, and extreme cost on an already strained economic asset.

In narrow pressure windows, the challenge does not end when the drilling has concluded. Once TD has been reached, dealing with surge/swab effects on trips and while running casing has, in some cases, exacerbated or created the entire scenario again that was depicted in the ECD effect discussions above, adding additional cost and risk to the well at a critical point in the well-construction stage. While running casing, the surge pressures often exceed the fracture pressure as soon as the shoe enters the open hole; thus, losses are experienced running the casing, sticking is possible, and once cementation begins, zonal isolation may not be achieved owing to weakened rocks and elevated ECDs.

MPD is another recent technology improvement that is creating a whole new economic outlook for unlocking these resources. As will be highlighted in this paper, MPD and its associated automation techniques are allowing operators to change their game plans and the economic risk of their unconventional assets by reducing the overall costs to drill and exploit these resources.

This concludes the discussions on the challenges observed in horizontal applications. The remainder of this paper will be a focused discussion on how MPD mitigates the risk in wellbore construction by minimizing the associated non-productive time.

MPD Automation Solutions Overview

Precise BHP control, though important in conventional vertical wells, is absolutely critical in horizontal applications—in many cases, being the difference between success and failure of planned well objectives. As a result of the MPD's closed system setup and the ability to dial in BHP "on demand," advanced automation techniques were needed to increase precision.

The main advantage of an automated MPD setup is that it provides near instantaneous "on demand" control of BHP (and the associated annular pressure profile), thereby enabling fine navigation of these in-situ pressure profiles. This optimized pressure drilling technique [7] has, for the first time, enabled the drilling of challenging horizontal wells, which were deemed undrillable in the past.

In a typical MPD operation, the BHP pressure is maintained slightly above the pore pressure and collapse pressure of the formation, without exceeding the associated fracture pressure. In a conventional drilling setup, this could only be attempted purely by manipulation of the fluid system and mud weights, which can equate to increased costs owing to time and materials. In MPD, because of a closed-loop setup, BHP can now indirectly (yet dynamically) be controlled in real time by the application of surface backpressure. This surface backpressure is usually delivered by an automated choke setup, which regulates and restricts return flow from the annulus.

There are several levels of control that are common in the industry today—all providing different functionalities and levels of precision. These include manual and automated mechanisms [2]:

- *Stand-by*: This is the fully-manual mode in which the system continues to actively acquire data but does not perform any automatic control actions.
- *Position*: In this manual mode, the system simply adjusts the position of the choke to a desired position. This position movement and set point is directed by operator input. No consideration is provided to resultant well conditions. All other actions are manual and must be taken by an operator.
- *Surface Pressure*: In this automated mode, the system adjusts the position of the choke to achieve a desired choke or surface pressure. Convergence to the desired surface pressure is an automatic process, which usually relies on a feedback control scheme. No consideration is provided to resultant well conditions. All other actions are manual and must be taken by an operator.
- *BHP*: This is the most complex mode of all. In this mode, a surface-pressure set point is calculated by a hydraulic model, which is receiving real-time well-based information and data. The hydraulic model has a range of desired BHP pre-configured, and using this information, generates a value that should be held at surface to (theoretically) produce the desired value at a particular depth. The system takes this pressure set point and then holds it at the choke(s). Convergence to the desired surface pressure is an automatic process, which usually relies on a feedback control scheme. In this case, resultant well conditions are taken into consideration, as the hydraulic model is continuously monitoring the effects of change and recalculating the set point.

Such functionality provides a rich tool set which is required for challenging horizontal applications.

Now that we have conceptually discussed what automation is, let us turn our attention to how it is practically achieved. In a nutshell, automation is achieved by a symbiotic setup between specialized equipment and software systems. Only

with a close coupling of hardware modules with associated supervisory software subsystems can a successful system be achieved [2]. So, let us examine each in more detail; the physical components required for automation include:

- Rotating Control Device (RCD) – To form a closed-loop system.
- Sensors (surface and downhole) – To monitor equipment and the well and feed hydraulic models
- Controller – Provides automated control of the choke system
- Choke – Restricts return flow and applies required surface backpressure used to obtain desired BHP

The above components are the minimum requirements for automation and assume the availability of a pressure source (such as rig pumps) to achieve control. The choke(s) cannot be used to control backpressure applied to the annulus (for control of BHP) unless fluid is flowing through the choke(s). Most often, this lack of circulation occurs whenever a connection is made in drilling operations, while tripping, running casing, and during cementing operations.

In conventional drilling operations, the sole method for managing BHP is by making time-consuming adjustments to the density of the drilling fluid. As previously stated, MPD gives an “on demand” density adjustment, which requires continuous flow across the choke(s), so a technique is required in which the flow of fluid through the choke is maintained, even though the fluid does not circulate through the drill string and back up the annulus. Thus, in this case, pressure can still be applied to the annulus by restricting flow of the fluid through the MPD choke. This is achieved using one of the following secondary components:

- Backpressure Pump (BPP)
- Rig Pump Diverter (RPD)

The BPP has been in use from the beginnings of MPD operations, but has its limitations based on the operator(s) coordination (non-automated), footprint restrictions, and reliability. The RPD, which has now been in use for more than two years, functions as part of the automated MPD system, minimizes the potential for human error, has a minimal footprint and rig-up time, and allows for a much more precise BHP control during connections and in other applications (i.e., tripping, running casing, etc.) [3].

We will now cover a detailed description of the systems most commonly found in MPD applications, the solutions to the challenges mentioned, and will also introduce other related technologies.

MPD Automation System Description

Rotating Control Device (RCD) – forms a positive seal around the rotating Kelly or drillstring and safely diverts flow from the annulus down the MPD flowline to the choke. The RCD is the key component in enabling a closed loop system.



Automated MPD Choke – is the pressure regulator in the closed-loop control system throughout all operations, including drilling, tripping, casing running, and cementing operations. The system also incorporates a mass flow (Coriolis) meter for continuous measurement of rate and density of the return fluid, which aids in precise BHP control and event detection.



Backpressure Pump (BPP) – first-generation MPD required the use of BPP to supply continuous flow across flow across the chokes for BHP control.

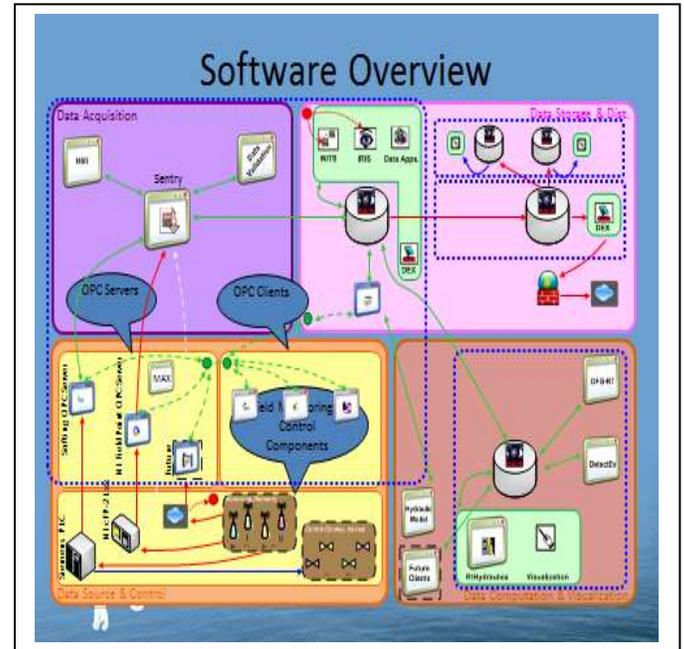


Rig Pump Diverter (RPD) – evolved from BPP lessons learned and diverts flow from existing rig pumps away from stand pipe and down the drillstring to across the annulus into the MPD flowline and across the automated choke(s), providing continuous non-interrupted flow during multiple operations. This automated approach is key to precise BHP during these operations.



Software Components and Data Acquisition System (DAS)

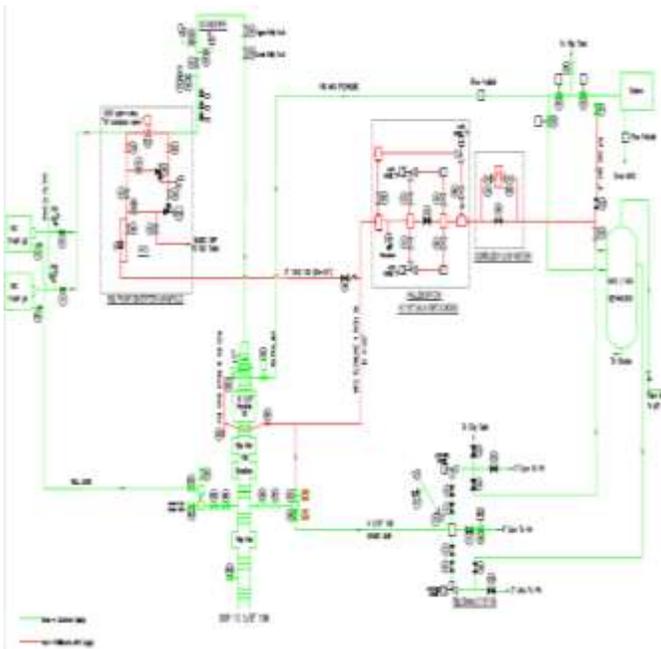
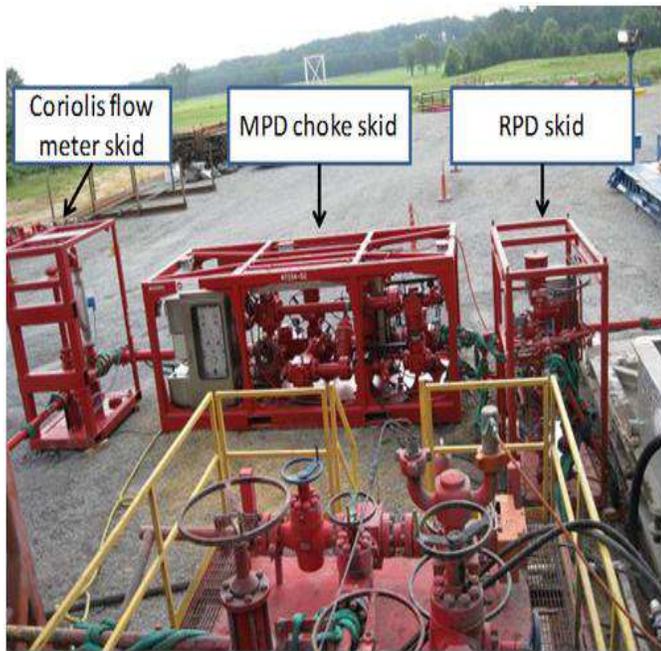
– Gathers and stores all relevant parameters and other drilling data from downhole and surface sensors. Furthermore, it provides supervisory/logic control and automation functionality.



Pressure While Drilling (PWD) – Though an optional component, it provides real-time BHP monitoring and the ability to validate hydraulics models. PWD data is essential for early event detection.



The image and the simplified valve numbering diagram (VND) shown below give an overview of the configuration of the equipment and the flow paths for a typical MPD application.



MPD Solutions Summary and Value Proposition

ROP

A typical MPD mud weight is designed to exclude ECD effects by focusing on a MPD BHP target equal to the static mud weight used on conventional wells. This target BHP minimizes the confining effects caused by use of an

overbalanced fluid plus the ECD effects.

Stability

With the ability to minimize pressure cycling (fissure damage effects) and to increase BHP as conditions dictate, related stability issues can be managed with MPD techniques.

Cementing Improvements

By taking returns through MPD equipment and managing BHPs for cementing operations, the system provides ability for lighter fluids to be used in the lateral annulus while running casing and also provides the ability to place cement correctly in narrow pressure margin wells. With the ability to achieve a precise BHP level, should any loss of cement slurry to the formation or any flow of fluid from the formation occur, it would be detected nearly instantaneously, and BHP would be adjusted to minimize these events.

Dynamic Fracture and Pore/Stability Pressure Testing

Real-time pore, collapse, and fracture pressure measurement during drilling allows verification of, and adjustments to, the assumptions made in the initial planning of the well. This allows for adjustments in the ECD window and reestablishment of the on-demand pressure range (“NPT cushion”) provided by MPD. For example, if formation pore pressure is difficult to establish while drilling, owing to the well-developed fracture systems encountered, MPD can be used to perform pore-pressure tests when the fractures are cut. Determining this conventionally has caused major difficulties with controlling the well. A mud weight that is slightly higher than the formation pore pressure can result in lost circulation with subsequent reservoir contamination. On the other hand, slightly low mud weights can cause kicks or blowouts. For horizontal wells, these conditions are even more challenging and difficult to control. Having an adjustable ECD range at your disposal “on demand” lets you “thread that pressure needle.”

Minimization of Fluid Damage to Formations

MPD is designed to minimize formation damage, though residual damage in the near-wellbore area after MPD may still be present. The reservoir-related or production-related benefits of both MPD and underbalanced drilling (UBD) are quite significant when compared with conventional overbalanced drilling. Primarily, these benefits are seen through higher productivity of UBD wells, and to a lesser extent, with MPD wells as a result of reduction, or in the case of UBD wells, elimination of drilling-induced damage. In fact, reservoir benefits of some MPD wells vs. conventional wells are only recently being compared and recognized in the industry.

Temperature Reductions

Reducing the bottomhole circulating temperature is achieved by drilling the well with a fluid system that contains fewer solids. MPD accomplishes this by allowing higher BHP

to be controlled with lower density fluids. The solids that make up the drilling fluid are thought to be more thermal conductive than the base fluid (oil or water).

Higher Pump Rates

With lower mud weights used in MPD applications, the standpipe pressure will be lower with a lighter mud column and lower ECD effect. This lower standpipe pressure and ECD effect provides room to increase the flow rate, which contributes, along with the correct rheology, to hole cleaning and also the temperature reductions mentioned above.

New Technologies Developed

Kick Detection and Automated Well Control

The GeoBalance® software suite includes a real-time hydraulics model- GB Setpoint and also includes DetectEv- the event detection software and ActEv- the automated response software.

The DetectEv portion of the software evaluates trends in well parameters and signals events when desired trends are matched. Any parameter, whether time-, depth-, or activity-based variables logged into the INSITE© database, can be used in detecting an event. Each parameter is evaluated over a specified period of time and compared against a signature profile. This signature profile can be comprised of multiple variables, and an example of a signature could be where one can look for an increase in one parameter, a decrease in another parameter, and holding steady in yet another parameter. The event will signal when the set of trends being looked for is matched.

DetectEv software is designed with base signatures for kicks and losses but allows the user to tailor signature profiles for events that may be unique for their well or region. ActEv provides for the configuration of automatic actions to be taken when an event has been detected by DetectEv.

For instance, in the case of a detected kick, ActEv can automatically take the system out of bottomhole pressure control, switch to position control, and provide choke closing by a preconfigured percent. This action serves to minimize the influx by detecting and acting on the wellbore at the very earliest stage of the influx. DetectEv and ActEv will facilitate the next generation of well control in the GeoBalance® MPD systems to identify and manage any pressure or flow anomalies. ActEv will take appropriate steps to contain and circulate out the influx under “supervised automation.” This new ActEv system will have fail safe features, which will allow the user to abort and “take control” of the process at any time.

RPD for Connections, Tripping, Casing Running

Managing pressure cycling on connections during drilling operations remains the greatest challenge for MPD operators today. During conventional MPD operations, older systems typically employed backpressure pumps to compensate for well backpressure across the wellhead. These conventional systems require a delicate control on connections between the

driller managing rig pumps and the MPD operator managing backpressure pumps. This issue is solved with the implementation of a fully automated MPD system, which incorporates a rig pump diverter (RPD) that allows a smooth transition from circulating to non-circulating downhole during connections while maintaining continuous rig-pump circulation. The RPD system allows flow to be diverted from the standpipe and drillstring to a surface route that maintains flow across the choke manifold, enabling accurate control of the bottomhole pressure (BHP) for controlled transition from the drilling mode to connection mode [5].

Flow can also be maintained across the chokes during tripping in and out of the hole and while running casing, which enables precise BHP control by managing surge and swab.

Barrier Pill

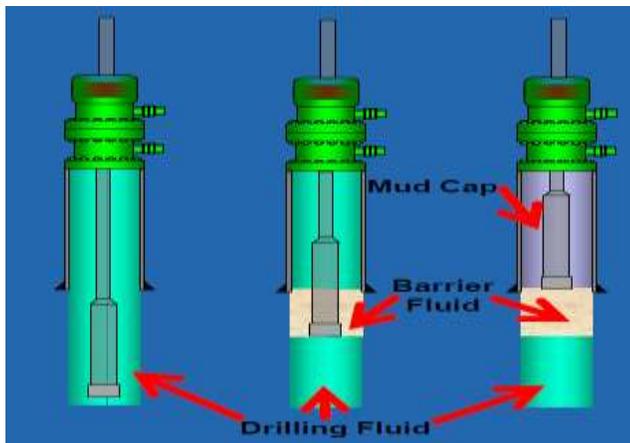
Since the typical drilling mud used for MPD operations is of a lower density than that employed for normal overbalanced drilling, a hydrostatic overbalance is required when tripping to avoid a kick or stability issues.

Displacing the entire mud column with kill weight for a trip and back afterwards adds undesired rig time and mud costs. Placing a high density mud cap on top of the lighter drilling mud was an early solution to total displacements. Comingling and contamination can result from this design and the separation and management of these fluids also adds to the costs.

A simple solution of placing a barrier fluid between the mud cap and the lighter fluid downhole was developed. This fluid exhibits high thixotropic properties which simplifies spotting the barrier pill and provides an efficient barrier.

The result of the barrier pill development was the substitution of a unique synthetic product as the viscosifier in the final barrier pill formulation. Exhibiting very high thixotropic characteristics, the resulting barrier pill was thin enough to be easily pumped into the wellbore during placement, yet it rapidly developed a gel structure adequate to successfully support separation of the mud cap and the drilling fluid. The fluid could be weighted with barite or calcium carbonate to any practical density without losing its gellation properties [6].

Below is an illustration of the technique for Barrier Pill Placement.



Real-Time Density and Viscosity, RTDV

In the industry today, the basis of control of an automated MPD system is driven by the hydraulics equation: Wellhead Pressure = Desired Bottomhole - Hydrostatic - Friction (ECD). In most cases, the hydrostatic equation is easily calculated but becomes more difficult to understand in high-pressure/high-temperature (HPHT) wells. The friction component is not easily calculated, as it is a function of many variables: wellbore geometry, temperature, inclinations, flow rates, and fluid rheological properties. To accurately understand the friction component requires a hydraulics program to model the differing parameters. For MPD automation techniques, the model must be capable of one-second computation with real-time data to ensure precise BHP. Even at this high rate of calculations, models are dependent on data input. In most MPD real-time hydraulics models, variables that are germane are often manually entered from either a daily or twice daily mud report. This approach makes assumptions that the fluid properties are remaining constant throughout that time interval. If fluids parameters change and are not corrected in the models, inaccuracy in the overall BHP control will result.

One means of improving BHP control is by implementing automated drilling fluid measurements at the rig site with the RTDV. For use in a real-time hydraulics model, the RTDV system must be capable of generating the six-viscosity reading, plastic viscosity, yield Points, fluid density, along with Herschel-Bulkley (n , k , and τ) values within a timely manner. Once the measurements are made, they are sent to a database and then read by the real-time hydraulics models. The models must be able to track the changing variables through the fluids and circulation system and calculate an effective hydrostatic and friction at a control point within the well. The RTDV system allows the highly valuable parameters to be tracked and inputted into the model, which improves BHP control precision.

Case Histories

NW China

This case history is from a field in Northwest China, as

shown in the following map. The field is a marginally over-pressured, fractured limestone reservoir that produces sour oil and gas from depths ranging between 4,000 and 6,500 m.

Conventionally drilled horizontal wells in this field frequently experience severe lost circulation, which leads to significant reservoir damage owing to the drilling fluid and, often, suspension of drilling operations resulting from the loss of measurement/logging-while-drilling (M/LWD) signals and directional drilling control. Additionally, frequent gas-kick events create high-risk well control situations, often causing early termination of drilling operations. With this, economics are negatively affected by less-than-optimal lateral lengths.

The MPD design for this particular project was challenging, as the wells are horizontal laterals with a narrow drilling window between pore pressure and fracture pressure. Controlling the pore pressure at the “heel” of the well and preventing losses at the “toe” required software and hardware that could provide precise BHP control. For this reason, an automated MPD system, which consisted of a rotating control device (RCD), an automated choke, a continuous-choke flow device, a pressure-while-drilling tool (PWD), a data-acquisition system (DAS), and an accurate integrated hydraulics model, was selected.

A statically underbalanced MPD drilling mud was used to allow the full benefit of the MPD automation techniques (i.e., holding backpressure on the automated choke manifold to provide a designed minimal overbalance to the reservoir with an optimal operating window and an easily adjusted BHP design throughout the drilling of the horizontal lateral). MPD trips were designed to incorporate a balanced mud cap (BMC) placement technique.

The illustration below shows comparative horizontal lateral displacement of previous conventional wells vs. the MPD wells drilled in this field.

Horizontal Lateral Displacement – Conventional vs MPD wells

Conventional Wells			MPD Wells		
Well	Planned Lateral Length (m)	Actual Lateral Length (m)	Well	Planned Lateral Length (m)	Actual Lateral Length (m)
1	780	360	MPD 1	591	982
2	900	187	MPD 2	834	146*
3	830	227	MPD 3	623	600**
4	811	146	MPD 4	719	261*
5	518	159	MPD 5	685	685

*Partially drilled conventionally, experienced well control problems prior to attempting MPD operations.

**TD'd early due to suspected junk in the hole

MPD objectives were successful in the wells in which MPD was implemented throughout the entire reservoir hole section. On those wells, there were virtually no losses, kicks,

or stuck-pipe incidents, which led to significantly lower non-productive time and mud costs. This also enabled the drilling of much longer horizontal laterals. The results demonstrated MPD as a safe and effective solution for the drilling challenges experienced in the field (1).

Alaska

The first MPD well drilled in Alaska was from a man-made island in the Beaufort Sea. Prior to MPD, conventional drilling operations had become very costly as a result of NPT, associated mud costs, and problems with stuck pipe and lost circulation. The entire operation was being considered for abandonment owing to the escalating cost and difficulties reaching the reservoir.

Because these reservoirs were relatively shallow (6000 ft +/-) and were accessed from the island, extended-reach wells with shallow kick-off points were planned. Drilling of the wellbore traverses tectonically stressed and weak formations, which have extremely high collapse pressures at the higher inclinations. In some formations, there is only a .2 ppg drilling window between collapse pressures and fracture gradient.

To cross this boundary, a mud weight was design, which was statically underbalanced to the collapse pressure, and the automated chokes were used to maintain a BHP just above the collapse and below the fracture pressure.

The results of using MPD in this project have seen a five-fold decrease in the cost per reduction, in mud cost, and overall improvement in the rate of penetration. More importantly, MPD has made the field economical. The following is a five-well comparison, two drilled conventionally and three drilled with MPD.

Conventional vs MPD Drilled Wells

NPT

Conventional: 73% and 77%
 MPD: 33%, 23%, and 11%

ROP

Conventional: 8 ft/hr
 MPD: 20.4, 38.0, and 53 ft/hr

Cost per foot

Conventional: \$1,481
 MPD : \$320

Mud cost per foot

Conventional: \$1,240
 MPD: \$47

The following provides more detail on these comparisons.

Evaluation Criteria	Base Case Wells w/o MPD		Wells with MPD		
	Well 1	Well 2	Well 1 MPD	Well 2 MPD	Well 3 MPD
Evaluation of intermediate hole interval drilling performance from start of new hole to ready to ROOH for casing	Non MPD Well. Long open fishhook directional design. Entered HRZ at 9.8 ppg at 80 degrees. Hole stability problems to TD.	Non MPD well. Long reach high angle hook directional design. Entered Torus at 65 degrees with 12.5 cpg MDM. Massive lost circulation and ultimately lost hole.	First MPD well. Simple directional design. Inappropriate bit selection. Trip for MWD failure and used three 17 cpg bit pills.	Second MPD well. Moderately tight fishhook directional design. Some hole trouble on short trip. No trips to surface. 17.0 ppg bit mud was used for casing running weight up.	Third MPD well. Moderate directional design with longer reach and higher angle in shales. No hole problems and minimal MPD downtime. 17ppg bit pill was used for casing running weight up.
Drilling Time (Total Interval Hours / Total NPT Hours / MPD NPT Hours)	912 hr. / 672.5 hr.	821 hr. / 603.5 hr.	208.5 hr. / 199 hr. / 24 hr.	122.5 hr. / 131hr / 9 hr.	131 hr. / 15.5 hr. / 5 hr.
NPT Percentage (Total NPT Hrs / Total Interval Hours)	73.24%	77.16%	33.08%	25.31%	11.83%
Interval Drilling ROP (Intermediate 1' / 1' / 1' / Well to TD / Gross Interval Time / Net NPT Time)	8.1 / 35.3 ft/hr	8.4 / 32.1 ft/hr	20.4 / 27.7 ft/hr	37.8 / 40.8 ft/hr	52.3 / 56.9 ft/hr
Gross Cost Per Foot (Total Interval Cost / Total Interval Hours)	\$1481 / ft	\$1367 / ft	\$626 / ft	\$380 / ft	\$320 / ft
Mud Cost Per Foot (Adjusted for actual drilling time. Cell costs to TD. Includes City. Total including expense & lab)	\$94.11 / \$104.27	\$118.46 / \$124.33	\$72.21 / \$85.66	\$75.60 / \$76.81	\$41.46 / \$47.42

N. America

Automated MPD solutions were used by and operator in the development of onshore gas fields in S. Texas and N. Louisiana. The operator had encountered margins in which the difference between dynamic ECD and static BHP is the difference between lost circulation and influx. These conditions created very narrow mud-weight windows.

The reasons for the narrow mud-weight windows in these vertical and horizontal onshore HPHT tight-gas environments vary. Depletion, complex Geology further complicated by commingled production, and slim-hole well plans (low kick tolerance design and unexpected kicks through fractured intervals) can create unique challenges that can add up to well control events, stability issues, and ultimately create non-productive time and high cost associated with losing mud and/or constantly changing mud weights to prevent losses or influxes.

By applying automated MPD techniques in these fields, it was found that by lowering the mud weight and manipulating the annular pressure during drilling to adjust the BHP “on demand,” the risk of mud losses and/or well-control events from quick sudden transitions into over-pressured zones is reduced. It was also found that there are additional benefits with lower mud weight, including:

- Higher ROPs
- Lower standpipe pressures
- Lower circulating temperatures
- Lower ECD
- Higher pump rates (improved hole cleaning)

ROP increases from 10 ft/hr conventional to 50 ft/hr MPD were observed with a reduction in drilling days from 9.5 days/well average for the lateral section conventionally drilled down to an average of less than 5 days/well drilled with MPD [4].

Conclusions

MPD Automation Techniques are showing benefits never before realized. These improvements are being seen across the board in Well Construction applications. These include Horizontal Applications in Conventional and in Unconventional fields.

As seen in the Case Histories presented above, operators are realizing the full suite of benefits from MPD in providing safer and more cost efficient operations. A listing of benefits would include;

- Improved Horizontal/ERD performance
- Higher ROPs without compromising safety and well integrity
- Lower standpipe pressures
- Lower circulating temperatures
- Lower ECD
- Higher pump rates (improved hole cleaning)
- Enhanced kick detection
- Automated well-control capabilities
- Improved cementing capabilities
- Dynamic fracture and pore/stability pressure testing
- Minimization of fluid damage to formations

It can be seen from the discussions above that horizontal drilling and hydraulic fracturing have been the featured technologies that have fueled the growth in the USA by serving to unlock resources from shale plays.

Currently, from the results being observed around the patch, MPD is now rising as a featured technology star owing to its abilities to lessen the pressure-related NPT risks in these well-construction endeavors.

Acknowledgments

The authors wish to thank the management of Halliburton for the permission and encouragement to publish this paper.

Nomenclature

MPD = Managed Pressure Drilling

ROP = Rate of Penetration, ft/hr

NPT = Non-Productive Time, hrs

MFC = Micro-Flux Control

HP/HT = High Pressure/High Temperature

PLC = Programmable Logic Controller

ICU = Intelligent Control Unit

HPU = Hydraulic Power Unit

IADC = International Association of Drilling Contractor

UBO = Under-Balanced Operations

DMWM = Dynamic Mud-Weight Management

CBHP = Constant Bottomhole Pressure, psi

MD = Measured Depth, ft

TVD = True Vertical Depth, ft

TD = Total Depth, ft

POOH = Pull Out of Hole

FIT = Formation Integrity Test, ppg

AFP = Annular Friction Pressure, psi

MGS = Mud Gas Separator

MASP = Maximum Allowable Surface Pressure, psi

BOP = Blow-Out Preventers

SBP = Surface Backpressure, psi

SPP = Standpipe Pressure, psi

SICP = Shut-in Casing Pressure, psi

SIDPP = Shut-in Drill Pipe Pressure, psi

ICP = Initial Circulation Pressure, psi

PVT = Pit Volume Totalizer

ppg = pounds per gallon

bbls = barrels

References

1. McMillan, S., An, W.H., Zhang, Y.M., Xu, Z.X., Lovorn, R., Ospina, J., and Saeed, S. 2010. Overcoming Drilling Challenges in Northwest China Using an Innovative MPD Technique. Paper SPE 130317 presented at the SPE/IADC Managed Pressure Drilling and Underbalanced Operations Conference and Exhibition held in Kuala Lumpur, Malaysia, 24–25 February.
2. Saeed, S., Lovorn, R., and Knudsen, K., Halliburton 2012 Automated Drilling Systems for MPD—The Reality SPE 151416 presentation at the 2012 IADC/SPE Drilling Conference and Exhibition held in San Diego, California, USA, 6–8 March 2012.
3. Johnson, R., Montilva, J., Sati, M., Grable, J., Saeed, S., Billa, R., and Derise, W. 2011. Field Demonstration of a New Method for Making Drill-Pipe Connections during Managed-Pressure Drilling Operations. Paper 147278 presented at the SPE Annual Technical Conference and Exhibition held in Denver, Colorado, USA, 30 October–2 November 2011.
4. Montilva, J., Mota, J., Poletzky, I., Sati, M., Lovorn, R., and Grable, J. 2012. Next-Generation Managed Pressure Drilling System Enables HP/HT Horizontal Wells in the Haynesville Shale. Paper SPE/IADC 151168 presented at the 2012 IADC/SPE Drilling Conference and Exhibition held in San Diego, California, USA, 6–8 March 2012.
5. Riker, R., Turner, J., Lovorn, R., Kale, T. 2012. A Thixotropic Barrier Fluid Used to Prevent the Commingling of Fluids While Tripping on Managed Pressure Drilling Wells. Paper SPE/IADC 156904 presented at the SPE/IADC MPD and UB Operations Conference in Milan, Italy, 20–21 March 2012
6. Saeed, S., Lovorn, R., Davis, N. 2012. Event Detection for Managed Pressure Drilling: A New Paradigm. Paper SPE 158491 presented at the SPE Annual Technical Conference and Exhibition in San Antonio, Texas USA, 8–10 October 2012
7. “Optimized Pressure Drilling - White Paper (H06467)”, GeoBalance® Halliburton, 2009