MPD automation addresses drilling challenges in conventional, unconventional resources

By Paul D Fredericks and Don Reitsma, At Balance Americas

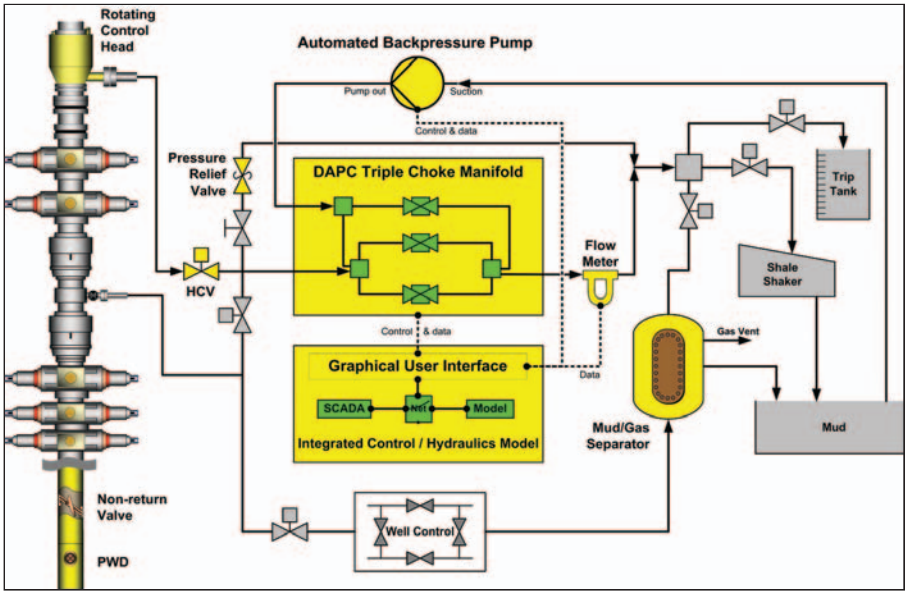

Figure 1: An illustration of a backpressure MPD system for constant BHP showing the basic components (non-return valve, rotating control head, pressure relief valve, choke manifold, and mud/gas separator) and additional features that enhance automation — pressure while drilling (PWD), integrated data acquisition/hydraulics model/control, automated backpressure pump, choke redundancy, and flow meter.

Figure 2: DAPC system during yard trial prior to deployment on North Sea rig. The system is functionally tested under different drilling scenarios and contingency events. The on-demand triplex backpressure pump is on the left, framed in white, and the automated choke manifold on the right, framed in red. The blue hose is the flow line from the pump to the auxiliary choke inlet. The black hose connected to the main choke inlet is the flow line from the well head.

WHEN NEW TECHNOLOGY and processes are applied in increasingly challenging fields to evaluate, identify, drill and produce more oil and gas, the entire industry benefits through greater knowledge of complex resources, more production from less footage drilled, increased recovery from low permeability reservoirs, and decreased finding and development costs.

Now, new managed pressure drilling (MPD) technology is contributing to the value chain. Constant bottomhole pressure (BHP) is enabling operators to drill conventional and unconventional resources with less risk and cost by eliminating the damaging pressure fluctuations that are unavoidable with heavy overbalanced drilling.

MPD BACKPRESSURE TECHNOLOGY

Managed pressure drilling refers to a collection of drilling processes designed to control the annular pressure of a well while drilling. The key word is control — probably the single most empowering feature of any new technology. Gaining control over annular pressure empowers operators to set the limits of BHP and to actively manage it while drilling, while stuck in the hole, during connections, trips and even during well control events.

The primary objectives of MPD are to reduce drilling risks and costs in narrow pressure margins, manage the pressure profile, avoid fluid influx and contain incidental flow. A direct benefit of those objectives is preventive well control.

Not all MPD systems work the same way to achieve those objectives — some control backpressure, some continuous circulation, and others mud gradient — and not all work with the same level of control. Rig type, field geology, reservoir type, drilling objectives, types of hazards, pressure profile, type and degree of control, and cost are some of the factors that influence decisions about which type and what level of control is appropriate for a particular application.

This article will discuss MPD systems that control backpressure to achieve constant BHP.

BACKPRESSURE MPD

A basic MPD system designed to manage backpressure and drill with constant BHP requires at a minimum a drillstring non-return valve, rotating control head and choke. These are not requirements for all MPD systems.

Figure 1 illustrates a schematic of a backpressure MPD system for constant

BHP control. It also illustrates other components that enhance automation and extend control of BHP.

- Pressure while drilling (PWD) for real-time hydraulics model calibration.
- Integrated data acquisition, hydraulics model and control.
- Automated backpressure pump for independent, on-demand flow.
- Choke redundancy for backup and enhanced functionality.
- Flow meter for early kick detection.
- Mud gas separator.

Backpressure MPD systems that utilize choke manifolds differ from each other by, among other things, the extent of their ability to control and create backpressure. As long as a sufficient volume of mud flows through an open choke, there will be backpressure. When flow decreases, the choke has to close to hold the same level of backpressure. If flow stops, then the choke has to close completely to trap the remaining backpressure. The amount of backpressure that gets trapped will depend on how quickly an operator or system can respond. However, no matter how fast a choke can be closed, it is unlikely that it will ever be fast enough to respond to an immediate loss of pressure due to sudden pump failure or human error. Lost backpressure stays lost until flow from the well resumes or is provided by another source. Unfortunately, loss of backpressure means loss of BHP control.

The solution is to equip the backpressure MPD system with its own on-demand pump and the critical automation to control it and backpressure whenever it needs to. This extends the dynamic range of a system's backpressure control and ability to actively create backpressure as and when needed.

Another differentiating aspect of backpressure MPD systems that extends control even further is remote operations capability — not on the rig but from another geographic location. This capability allows operators to reduce the number of people on-board a rig or platform with limited space.

DAPC SYSTEM DESCRIPTION

The Dynamic Annular Pressure Control (DAPC) system shown in Figure 2 is a backpressure MPD system provided by **At Balance** that uses critical automation

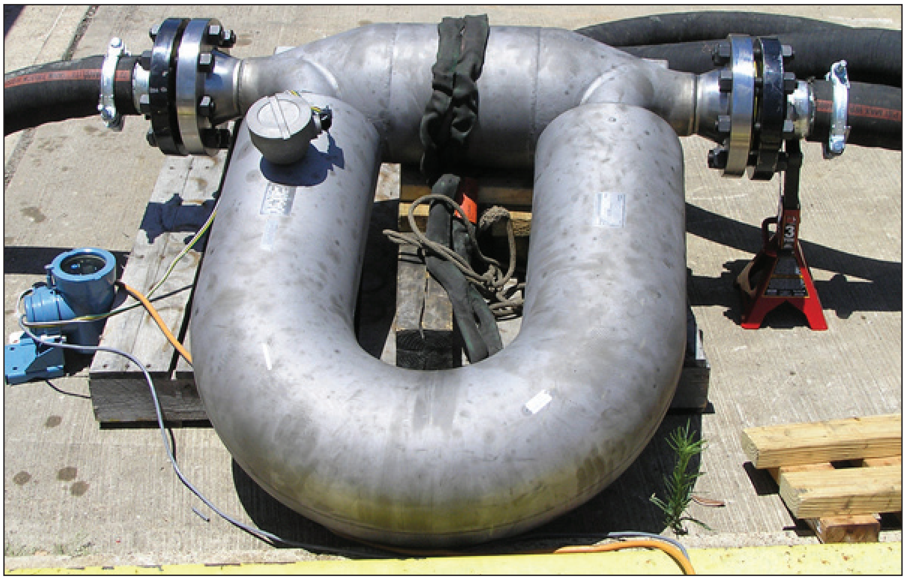

Figure 3 (above): Flow meter being functionally tested with the DAPC system during yard trial prior to deployment on deepwater GOM rig. Figure 4 (below): Mars TLP in deepwater GOM. Shell drilled a 50° re-entry well to 19,000-ft MD through depleted and abnormally pressured sands and unstable shales. They stabilized BHP and the wellbore by managing backpressure between 50-600 psi, reduced mud weight, continuously maintained ECD within 0.2 ppg tolerance, reduced overbalance from previous sidetracks, and eliminated losses using the Dynamic Annular Pressure Control system.

of an on-demand backpressure pump, choke manifold, hydraulics model, and integrated data acquisition and control. In addition, it can be operated from anywhere in the world from a remote data communications center.

The manifold contains 3 chokes — 2 redundant main chokes and 1 auxiliary choke. Normally, only 1 main choke is active while the other is in standby mode. However, the redundant main choke can also be used as a pressure relief valve. In live yard trials it was used to control pressure relief faster and more accurately than the primary pressure relief valve. In addition, the system can use both legs of the manifold whenever it needs extra flow capacity.

When the system senses that the mud flow is insufficient to maintain backpressure at the level dictated by the hydraulics model, it turns on the auxiliary pump and directs flow through the auxiliary choke, which it uses to manage backpressure while the main chokes are in standby.

An important feature of the DAPC system is its integration of control and hydraulics modeling. It enables BHP control at a depth and within limits specified by the operator, which delivers improved safety, well control and reservoir integrity. The hydraulics model has been in continuous use and development since 1998, in conventional and unconventional fields. It performs more than 60 pressure calculations a minute, uses the real-time pressure while drilling (PWD) data to calibrate itself, and its accuracy is continuously monitored through real-time graphical trend analyses displayed on drilling monitors throughout the rig or in remote data centers.

KICK DETECTION, WELL CONTROL

The DAPC system can be configured to detect kicks by monitoring and comparing flow-out and flow-in. Flow-out is measured using a flow meter, shown in Figure 3, normally installed downstream of the choke manifold (see Figure 1). Flow-in is calculated using data from the pump stroke counters. A graphical user interface is used to plot and compare both flows, analyze their trends, detect kicks and issue alarms.

In a more responsive kick detection method, the system continuously monitors average annulus fluid density by comparing the real-time hydraulics model to actual BHP measurements. Average annulus fluid density changes are determined while drilling by calibrating the hydraulics model to valid BHP measurements. If a kick occurs, the model will detect the reduction in the average density, produce an alarm, and because the system is designed to maintain the BHP constant, it will close the choke in an effort to offset the previously recorded density. This does not automatically increase the BHP, but it does limit influx by maintaining what is in effect a constant drawdown on the reservoir and prevents hole unloading, as would be the case if the kick went undetected. This provides a means to detect kicks with a reduction in BHP of only a few psi.

Once the kick is detected, the standard procedure is to shut the well in and allow the pressure to build up to prevent further influx and determine reservoir pressure. An optional procedure is to let the BHP increase until the DAPC system stabilizes the reduction in the average annulus fluid density, which theoretically should stop the influx though factors such as the production rate from the reservoir and maximum allowable pressures need to be considered. Regardless of the method used, the system will establish a new bottomhole setpoint, and the operator can choose to let the system automatically circulate the kick out of the well.

Simulated tests performed in **Shell**'s SIMWELL demonstrated the system's ability to control a gas kick. A nitrogen gas bubble was injected downhole and circulated out while the DAPC was actively controlling backpressure. When the system detected a reduction in static pressure, it automatically compensated by adjusting the backpressure to maintain the BHP constant. The results showed the system's ability to reduce downhole pressure variations compared with when the kick is not detected or controlled during conventional drilling operations.

CONVENTIONAL RESOURCE CHALLENGES

The generally accepted definition of a conventional resource is an accumulation of oil and gas in a discrete volume of rock bounded by traps, seals, or down-dip water contacts, the existence of which depends on the buoyancy of oil and gas in water. When it comes to drilling, some conventional fields are anything but.

Declining conventional fields are often and somewhat ambiguously referred to as mature or brown fields, names which fail to portray their true nature. Some mature deepwater fields defy conventional drilling practices with layers of depleted, mechanically weak oil sands, abnormally pressured wet sands and wet, unstable shale. But they still have sufficient oil and gas to recover, albeit prudently and unconventionally.

Operators face several conflicting drilling challenges in those fields: maintain equivalent circulating density (ECD) for wellbore stability at all times, control dynamic ECD below the fracture gradient, avoid large BHP fluctuations, reservoir damage, and well ballooning and breathing. Constant BHP addresses those challenges.

Figure 4 shows the Mars TLP, where Shell used the DAPC system to stabilize the BHP over a 6,300 ft (MD) section and drill through abnormally pressured sands, unstable shale and depleted sands to producing targets they could not reach with conventional drilling.

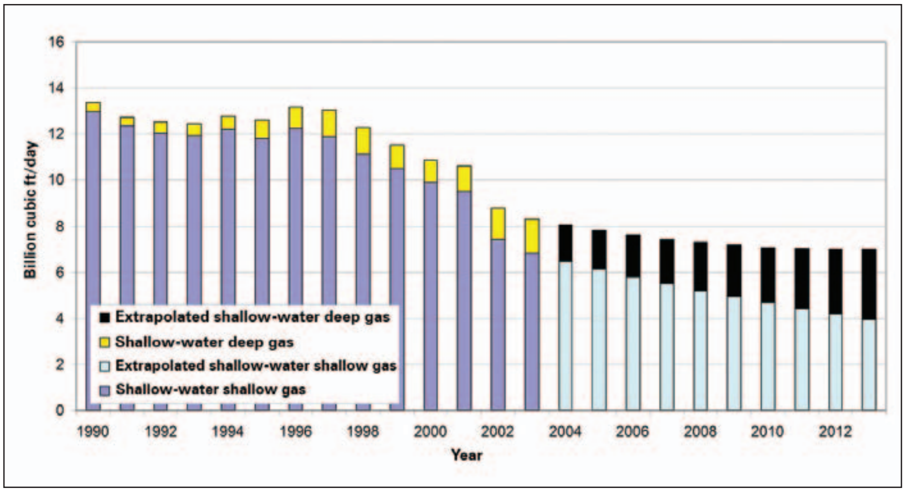

Figure 5: MMS Gulf of Mexico forecast showing decline in shallow-water shallow gas and the growth in shallow-water deep gas (SWDG). The experience and technical capabilities that MPD service companies have acquired in deepwater depleted fields and deep onshore gas wells will serve operators well in SWDG fields, which have similar drilling challenges. (Source: MMS Report MMS 2004-065)

Figure 6: Coiled tubing rig drilling an underbalanced 14,000-ft MD directional well in Wyoming. The operator stabilized pressure to drill unconventional tight gas sand with constant BHP at 7,800 psi while continuously managing backpressure between 400 to 600 psi. Operator was able to identify micro-fracture system by monitoring backpressure fluctuations as small as 4 psi using the DAPC system.

Figure 7: Century Drilling Rig #27 on location in Cooper Basin, Australia, for Geodynamics developing renewable geothermal energy. The operator drilled a vertical geothermal production well underbalanced into hot fractured granite at 14,000 ft, maintained pressure stability, minimized mud losses, preserved fracture permeability, controlled water kick and reduced mud weight 1.0 ppg using the DAPC system.

The deep and ultra deep gas fields being explored in shallow GOM water share many of the same challenges found in deepwater fields: narrow margins, kicks, lost circulation, stuck pipe, wellbore stability and high cost. They also have their own unique set of challenges: high pressure and temperature, unstable mud, high ECD, slow drill rates, deformable shales, shallow weak zones, and old, shallow production zones now depleted.

Operators stand to benefit from MPD technology that can maintain wellbore stability, mitigate the risk of losing well control, and preserve the reservoir integrity. If the growth of deep gas drilling follows the projections shown in Figure 5, then demand will grow for:

- Expandable casing and liner
- Slim monobore wells
- Drilling casing
- Pore pressure modeling from seismic
- Automated pressure management
- Real-time, multiphase hydraulics modeling
- Continuous circulation
- Early kick detection

UNCONVENTIONAL RESOURCE CHALLENGES

Unconventional resources are quite a bit different. They are continuous accumulations of oil and gas that pervasively charge large rock volumes, the existence of which is not dependent on buoyancy.

A generally accepted feature of unconventional oil and gas is that they are economically challenging to develop. It falls to the competent operator to improve the economics through prudent selection and careful application of technology. It is a matter of record that US operators have successfully improved drilling efficiency, well cost, and recovery per well in unconventional resources. In 1995, unconventional gas production from the lower 48 states as a percentage of the total was 24%; in 2005 it stood roughly at 42%, and it is growing.

The increased gas production primarily comes from 3 unconventional deposits: coalbed methane, fractured shale and chalk gas, and tight gas.

Even though these make up a diverse group with diverse challenges, backpressure MPD systems have been used successfully to drill each type of deposit. Drilling continuously at balance, or just under or over balance, enables operators to reduce mud weight, stabilize the well, protect the reservoir rock and fracture permeability, increase penetration rates, and reduce drilling time and cost.

Figure 6 shows a picture of a coiled tubing unit drilling a tight-gas well in Wyoming where the operator stabilized the BHP underbalanced and managed continuous circulation used the DAPC system.

Figure 7 shows a conventional rig drilling a geothermal well in Australia where the operator stabilized the BHP at a mud weight 1.0 ppg less than previously used, managed continuous flow, prevented mud loss, and preserved fracture integrity with the DAPC system.

In both conventional and unconventional applications, operators have benefited from critical automation of a real-time multiphase hydraulics model and integrated backpressure control technology.

This article is based on a presentation to be made at the 2006 IADC International Well Control Conference on 7-8 November in Abu Dhabi, UAE.