MPD with DAPC system proves successful on Auger TLP redevelopment program in GOM

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ACCESS TO PREVIOUSLY unattainable offshore drilling targets continues to expand through advancements in managed pressure drilling (MPD) and dynamic annular pressure control (DAPC) technologies since their first application on the Mars TLP in 2005. **Shell E&P** successfully executed a MPD operation eliminating lost circulation and hole instability risks by using a DAPC system on the Auger TLP.

Redevelopment drilling in maturing deepwater fields is challenged by high circulating density (ECD) and depletion-induced fracture gradient (FG) reduction for intervals that require original mud weights (MW) for borehole stability. The DAPC system provides automated control of surface-applied annular backpressure to the wellbore to a specified bottomhole pressure (BHP) set point. This allowed drilling on the Auger TLP with a surface MW lower than required by conventional drilling, effectively reducing the ECD magnitude on the open hole.

BACKGROUND

Shell's Auger TLP is located in the Gulf of Mexico in 2,860 ft of water. It began production in 1994 as the first deepwater platform in the GOM and has continuously produced from five main reservoirs. Cumulative production has surpassed 400 million bbls equivalent, which has yielded reservoir pressure depletion in excess of 5,000 psi. The depletion has caused rock stress modification in both the sands and shale overburden, resulting in reduction of original FGs and therefore tighter drilling margins.

Redevelopment drilling programs have been conducted on the Auger TLP since 1999 with limited success, with unmanageable lost-circulation events identified as the root cause. The reduced FG challenge is further compounded in redevelopment sidetracks as the casing and drill pipe geometry yield larger annulus friction pressures than original well drilling. MPD has been identified as a critical technology to mitigate these challenges.

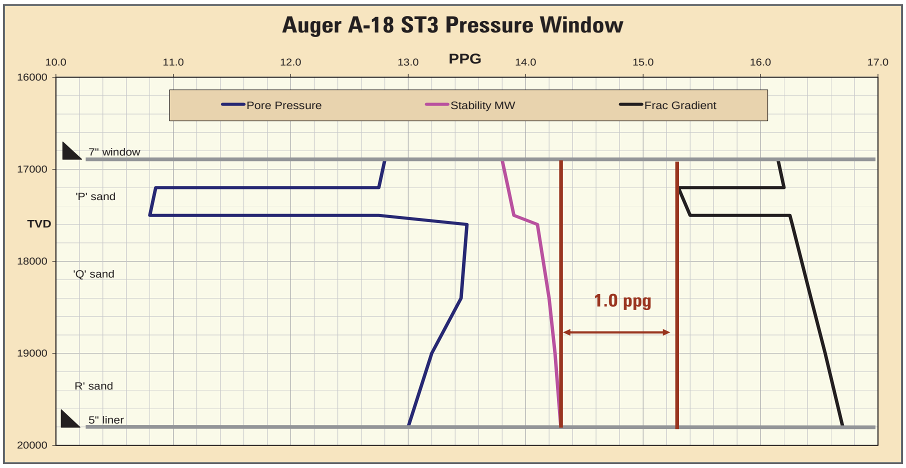

Figure 1: In planning the A-18 ST3 well in the 2006 redevelopment campaign on the Auger TLP, the pore pressure, fracture gradient plot was used to define the drilling pressure window of 1.0 ppg for the drilling interval.

The A-18 ST3 well was the first well in the 2006 redevelopment campaign. The objective was an up-dip target location in an undepleted reservoir fault block. The required sidetrack depth, however, was above known depleted reservoirs, thus presenting the risk of lost circulation if drilled with conventional mud weights.

The original well was batch set in 1992 prior to the TLP installation and later drilled to TD from the TLP in 2000 as an exploration step-out well. The drilling of ST1 and ST2 was performed as part of the original TD due to wellbore positioning and a well control event in the objection section, resulting in stuck pipe. Eventually successful, the ST2 was drilled and cased across the objective targets with a 5 ½ in. x 7 in. tapered production liner, then cased to surface with a 7 in. x 7 ⁵/₈ in. tapered production tieback.

Due to the existing casing configuration, the casing exit for ST3 was made via a whipstock through the dual casing geometry of 7-in. 38-lb production liner x 9 ⁵/₈ in. 43.5-lb drilling liner at 17,600 ft MD. The directional plan consisted of a 3,900 ft interval and a two-dimensional "S"-shaped profile starting at 20° inclination, then building to a maximum of 55° and dropping to a target inclination of 25° through the objective reservoir. A 5 ¾ in. x 6 ½ in. under-reamed hole was drilled with rotary steerable and measurement and logging while drilling (MWD/LWD) drilling bottomhole assembly (BHA).

The drill pipe required to achieve adequate drilling flowrate and margin of overpull was a 4 ½ in. x 3 ½ in. tapered string. Planned TD was 21,500 ft MD, to be cased with a 5-in. production liner to facilitate the frac pack completion.

Drilling challenges were reduced fracture gradient strength at the depleted interval and shale overburden; original MWs required for shale stability and virgin pressured formations; high ECD from annulus friction pressures (AFP) resulting from the casing and drill pipe geometry.

The solution of MPD allows reduction of surface MW based on resulting ECD from annulus friction pressure while at drilling flowrate. The MPD method of constant bottomhole pressure consists of additional surface equipment that makes the wellbore a closed system while drilling, enabling the automatic application of surface backpressure to the annulus. The backpressure applied to the wellbore is designed to compensate for the reduction of BHP while making a drilling connection, reduction in pump rate, change in MW or other disturbances such as pipe movement.

WELL PLANNING

The drilling pressure window definition was made from the pore pressure fracture gradient (PP/FG) plot as shown in Figure 1. Minimum BHP of a 14.3 ppg equivalent mud weight (EMW) is required for borehole stability at TD.

The depleted reservoir at 17,200 ft TVD defines the maximum BHP of a 15.3 ppg EMW as the interval fracture gradient. These minimum and maximum boundary conditions define the drilling pressure window of 1.0 ppg for the drilling interval.

Drilling hydraulics is critical for MPD applications. The casing and drill pipe geometry were modeled with planned mud rheological properties at optimum drilling parameters. The model resulted in a 1.3 ppg EMW of AFP while circulating at drilling rates. Using conventional mud weight alone, the static mud weight would have to be 14.3 ppg. But, according to the PP/FG plot, the additional AFP would push the ECD over the maximum limit by 0.3 ppg. The PP/FG plot in Figure 2 illustrates the conventional drilling mud weight scenario. This would pose a significant risk of lost circulation in the first sand package, which was known to suffer from depletion-induced fracture gradient reduction. If the MW were slightly lowered to reduce the lost circulation potential, then additional risk of borehole instability would be introduced for both drilling and casing operations.

With the functionality of a constant BHP MPD method, alternate MW scenarios are possible to safely drill the interval. The DAPC system allowed reduction of surface MW by 0.4 ppg (from 14.3 ppg to 13.9 ppg). This reduction equally reduces the magnitude of ECD, resulting in an ECD of 15.2 ppg EMW while drilling at modeled flow rates, rotary speed and penetration rate.

The pressure reference or set point that was to be held during connections when the rig pumps were off was fixed at 14.7 ppg EMW. A tolerance of +/-0.3 ppg EMW was applied to the set point to ensure the BHP was maintained above the borehole stability and below the drilling ECD. This tolerance is equivalent to 300 psi minimum and 800 psi maximum applied surface backpressure on the wellbore annulus during a drilling connection.

EQUIPMENT

The most common automated MPD method of constant BHP is the DAPC system. As illustrated in Figure 3, the system relies on a rotating control device (RCD) to seal and allow pressurization of the wellbore annulus. The drilling returns are diverted by the RCD and routed into a choke manifold, which is completely independent of the rig BOPE.

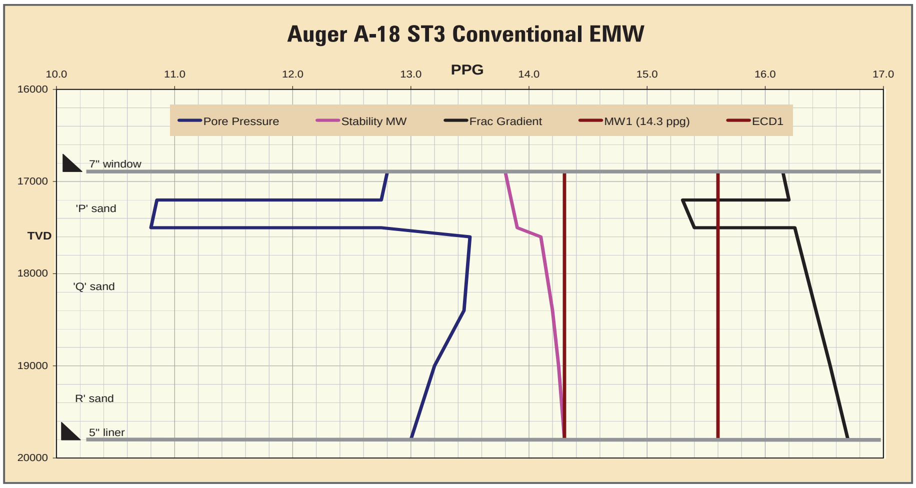

Figure 2: In this pore pressure/fracture gradient plot illustrating the conventional mud weight scenario, there is a significant risk of lost circulation in the first sand package. With a slightly lower mud weight, there's additional risk of borehole instability for both drilling and casing operations.

The MPD choke manifold is used to impose backpressure on the annulus during connections and trips to replace the friction pressure component of ECD. The backpressure pump is used to energize the annular fluid and more precisely control and adjust the applied backpressure. A computerized modeling and control system is used to establish the required backpressure set point, which is then applied by the choke to maintain the desired bottomhole pressure.

Suitable piping, hoses, valves and connectors must be included to integrate the drilling mud and cuttings back into the existing rig circulation system. In addition to the DAPC manifold and pump, a flow meter manifold was incorporated downstream of the choke manifold for enhanced kick detection as a replacement to the flowline flow sensor.

RCD, SLIP JOINT ASSEMBLY

Most TLPs with a surface BOP stack contain a slip joint with an overshot packer between the stack and rig floor. For Auger, a HOLD 2500 RCD was modified to provide a rotating seal above the clamping mechanism and a top flange. This allowed the RCD to be installed between the annular preventor and slip joint. Among the benefits are:

• Stripper rubbers can be installed and retrieved through the upper portion of the riser with minimal interruptions to operations.

• With the stripper rubber removed, the riser can be flooded, allowing for conventional use of the rigs standard mud return system (trip tanks, flowline, etc).

• Side loads and bending moments are carried through the RCD as in normal riser installations.

• MPD backpressure is not applied to the slip joint.

Additionally, a new slip joint design was required to accommodate the installation and retrieval of the RCD element due to the outer diameter (OD) size. The new slip joint design consisted of a 21-in. inner diameter (ID) marine riser type ball joint and an equivalent ID slip joint utilizing a standard overshot packoff.

DAPC SYSTEM DESCRIPTION

The DAPC system is a fully automated backpressure control system that uses a hydraulics model running in real time to maintain the desired BHP set point or ECD. The set point is entered into the DAPC system along with drilling assembly, well geometry, mud properties, planned directional data and temperature. In real time, the model calculates BHP as changes occur, and updates are received for bit depth, drill string revolution (rpm) and pump flow rate (gpm). A proprietary process calibrates the hydraulics model if downhole pressures while drilling data are available for MWD tools.

Prior to deployment of the choke manifold, pump and controller were set up in a test well facility to allow the DAPC system to be rigged up and connected to other MPD components and evaluate its responsiveness to simulated pressure events under controlled conditions. The service provider used this testing stage as an opportunity to make minor adjustments to the system and check software changes made for Auger. The system operated well within the expected operating limits.

FLOW METER

In a closed loop, it is not possible for the driller to monitor flow-out of the well during connections. Also, the hydraulics model requires the actual flow-out to accurately calculate the BHP. While pump rate is typically used in the hydraulics model, it is also possible to calibrate the model based on actual flow out values. A Coriolis flow meter was installed downstream of the choke manifold to monitor flow-out of the well. Alarms were set to alert the driller of a developing kick or losses event.

PRESSURE RELIEF VALVE

A re-settable pressure relief valve was located near the RCD in the event of an uncontrolled overpressure due to line plugging or failure of the DAPC system. The relief pressure was variable based on the backpressure set point value. Since the MW provided a static overbalance, the only risk associated with the pressure relief was a reduction in borehole stability for a short period of time.

PERSONNEL TRAINING

Hazard Identification (HAZID) and Hazard Operability (HAZOP) workshops were conducted to review the MPD system and identify potential risks and response actions. HAZID results were categorized into a matrix of operations and relative risk. Contingency plans were created to define the identifying parametric changes and both operational reactions to secure the wellbore. These plans became the basis for personnel training.

The first stage of training was classroom-oriented and carried out with rig and service personnel. Objectives were to introduce the MPD concept and required equipment, define the case for action, detail the specific system to be used and interactively review the contingency plans. The second stage was performed on-site and included pre-tour presentations and equipment walk-through. Additionally, a dedicated trip for cased hole testing was made prior to milling the casing exit to ensure system functionality, practicing contingency plan actions and establishing confidence in the DAPC system's ability to meet the required operating window.

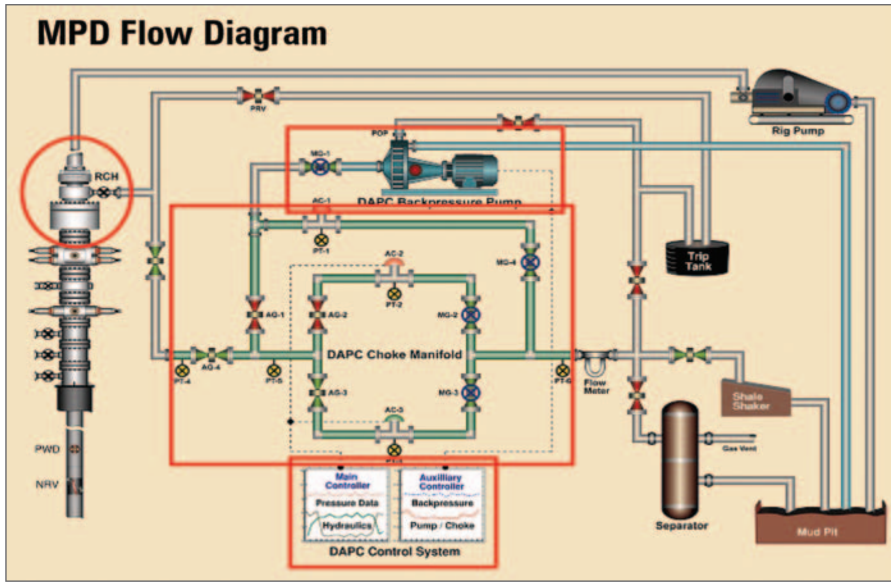

Figure 3: The DAPC system relies on a RCD to seal and allows pressurization of the wellbore annulus. Drilling returns are diverted by the RCD and routed into a choke manifold independent of the rig BOPE. The MPD choke manifold imposes backpressure on the annulus during connections and trips to replace the friction pressure component of ECD. The backpressure pump energizes the annular fluid and more precisely controls the applied backpressure. A computerized system establishes the required backpressure set point, applied by the choke to maintain the desired bottomhole pressure.

RIG-UP, CASED HOLE TESTING

The full MPD system was rigged up and tested prior to drilling out of the casing. Cased hole testing facilitated system calibration, practice of planned MPD operations, which included making connections, RCD element installation and replacement, and execution of pre-defined contingency plans to enable complete understanding of system and personnel reaction. Use of the MPD technique and equipment prior to entry into the open hole allows for inexperienced personnel to gain experience and for identification of overlooked contingent events in a non-critical environment.

Real-time surface data acquisition and distribution was centralized through the mud-logging unit to provide the DAPC system with the required variables. Critical sensors were also run for redundancy to assure proper operation of the automated DAPC controls. The DAPC system control screen was also provided on the rig floor to be monitored by the driller and MPD specialists.

RESULTS

The well was drilled to TD with a 0.4 ppg reduction in surface mud weight (13.9 ppg actual vs. 14.3 ppg conventional) to maintain the ECD below a 15.3 ppg EMW hard line. BHP was maintained by the DAPC system within the required +/- 0.3 ppg tolerance of the 14.7 ppg EMW set point. Figure 4 provides a graphical representation of all pump cycles performed as a function of measured depth throughout drilling of the interval. Both the accuracy of BHP control and connection time improved as drilling progressed in the interval, which was mainly attributed to the consistency in rig pump ramp up and down performance. In the latter half of the drilled interval, the connection performance was improved to within a -0.1 ppg and +0.2 ppg EMW.

The well was drilled without lost circulation due to MPD overpressure events and with no indications of borehole instability from MPD underpressure events. Over 60 MPD pump cycles were executed while interval drilling in which the automated DAPC system maintained BHP. Of these, over 95% were maintained between 14.4 ppg and 15.0 ppg EMW. The few low-side excursions occurred during non-DAPC pump cycles for operations such as changing out the RCD element and top drive swivel packing.

At no time during the drilling and tripping operations was the BHP allowed to fall to the static mud weight hydrostatic. Equally critical, the BHP was never increased over 15.3 ppg hardline due to an MPD overpressure event. Only once in the interval did the recorded BHP go beyond the previous drilling ECD, which was attributed to tuning of the controls system early on in the interval.

The benefit of MPD connection to BHP is proven by comparison of the actual EMW from the applied surface backpressure (14.6 ppg with rig pumps off) to the mud weight of 13.9 ppg used to drill the well.

At TD the well was weighted up to a 14.1 ppg mud weight, and the DAPC system was used to compensate for swab effects while the drilling BHA was pulled into cased hole. During pulling out of open hole with the drilling BHA, reaming out tight spots was required and was done successfully with the DAPC system while keeping the ECD below 15.3 ppg.

Once the drilling BHA was pulled back inside casing, the cased hole was weighted up to a 14.5 ppg mud density. This increased mud weight compensated for being off bottom and was chosen to provide the BHP for open-hole stability plus adequate trip margin for swab effect. During the weight up, mud losses were experienced at an ECD of about 15.4 ppg EMW.

Casing was run to depth with minimal returns and cemented without returns. The losses were confirmed to be at the depleted zone with a cement bond log. A frac pack completion was successfully installed, and the well met initial production expectations.

A post-well review defined key issues to be addressed for the next MPD applications. Main issues were procedural enhancements of contingency procedures and further analysis of well control reaction options using the MPD system.

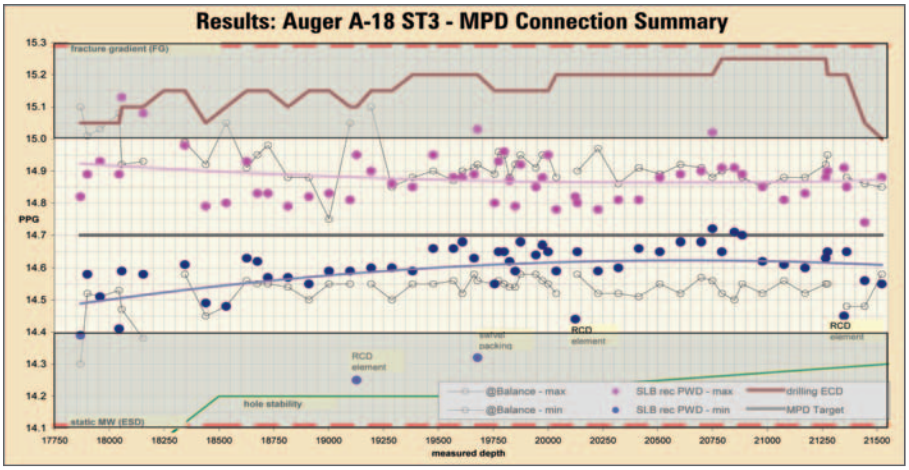

Figure 4: A graphical representation of all pump cycles performed as a function of measured depth throughout drilling of the interval. Both the accuracy of BHP control and connection time improved as drilling progressed in the interval.

OTHER OBSERVATIONS

• Testing and familiarization of the DAPC system prior to deployment reduced critical path time on location.

• Drilling BHA design of floats and rotary steerable communication allowed drilling operations to be conducted without any impact from the MPD system.

• There were no issues of choke or line plugging while drilling at instantaneous penetration rates up to 60 ft/hr with drilling flowrate up to 200 gpm.

• The minimum recorded connection BHP from PWD was consistently observed on the rig pump ramp down.

• The maximum recorded connection BHP from PWD was consistently observed during the rig pump ramp up.

• The flowmeter was successfully used in combination with pit volume totalizer system to fingerprint connections for kick detection.

• The pressure relief valve and associated controls software performed as intended to provide a dynamic pressure relief set point during the connection process.

• The driller's ability to control the rig pump ramp up and down speeds are critical to controlling BHP within a given pressure range.

• Real-time pumps off PWD minimum and maximum readings after each connection were used for continuous improve on connection times.

LESSONS LEARNED

• Preparation time and proactive planning use of MPD were keys to approval, both internally within Shell and externally with the US Minerals Management Services.

• The MPD testing and training in cased hole provided a complete understanding of the MPD system for both planned and unplanned events.

• HAZID/HAZOP workshops and personnel training are vital steps to contingency planning.

• Contingency plans are critical to prevent the undesirable results of over- or underpressure events.

• MPD operations can be performed on critical applications and made safer than conventional drilling practices with the proper personnel for planning and execution.

CONCLUSION

The DAPC system advancements from the first deepwater application on Mars A-14 ST3 in 2005 were implemented on Auger A-18 ST3 in 2006 to successfully eliminate lost circulation and borehole stability events.

The performance of the DAPC system has demonstrated the reliability to automatically control BHP within the required pressure window, and the confidence to further apply the technology on wells which require static mud weight reduction below pore pressure with manageable risk.

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