

OVERVIEW



Drilling Performance Improvements— Push Into New Horizons

Increased global demand for oil and gas has created situations in which operators are forced to drill deeper and into much harder formations. These drilling environments present enormous operational and technical challenges. In addition to the low rate of penetration (ROP), downhole tool failures occur at much higher frequencies. As a result, operators must make multiple trips to replace drill bits and other downhole tools, thereby incurring additional operational costs.

The known challenges of hard-formation drilling are compounded by the effects of depth, primarily the result of elevated downhole pressure and temperature. To reduce operational costs in such applications, ROP and downhole-tool reliability must be improved substantially. Researchers, focusing on these challenges, have identified the need for system-based solutions. Such an approach evaluates all the elements that influence the drilling process.

Researchers have gained valuable insights into the effects of depth and pressure on the properties and behaviors of different rocks. Consequently, the drilling efficiencies of different bit types, in terms of their energy requirements, also have been studied. To complement these efforts, specialized data-acquisition tools that can be placed inside the bit have been developed. These tools detect dynamic events at the bit/rock interface, which makes the data more relevant compared to data from previous tools. The effects of different drilling fluids or additives on the rock-failure process also have been studied extensively.

As part of the system-based solution, the drilling process must be executed effectively. Drilling-system definitions must facilitate efficient energy transfer to the drill bit. Energy received at the bit must be used to cause rock failure, not be lost through vibration events. In addition, system or operational flounders must be identified and resolved in real time to minimize their negative effects.

Considering the understanding gained and the tools that have been developed, performance gains now can be made in hard-rock applications. Bottomhole founder contributes to poor ROP in hard formations. In addition, vibration founder has been classified as contributing immensely to poor ROP and downhole-tool failures. Tools are being developed that can withstand higher operating temperatures. We know the contributing factors as well as the science behind the problem—now, let us go after this problem aggressively. **JPT**

Graham Mensa-Wilmot, SPE, is Drilling Engineering Advisor in Chevron's Global Drilling and Completions Upstream organization. He has more than 20 years' experience in drilling-applications research, downhole-tool development, and drilling-performance improvement. Mensa-Wilmot serves on the SPE Drilling Technical Committee, the SPE/IADC Drilling Conference Program Committee, the Technical Review Committee of SPE Drilling and Completions, and the JPT Editorial Committee. He earned an MS degree in drilling engineering from Romania's University of Petroleum and Gas.

Bit Technology and Bottomhole Assemblies additional reading available at the SPE eLibrary: www.spe.org

SPE 104502

"Maximizing Drilling Performance With State-of-the-Art BHA Program" by David C.-K. Chen, Halliburton Sperry Drilling Services, et al.

SPE 107530

"How To Select PDC Bit for Optimal Drilling Performance" by R. Nygaard, University of Calgary, et al.

SPE 105565

"Aggressive Drilling Parameters Capitalize on Cutter Technology and PDC Frame Advancement in Mature Field" by Peter Langille, Marathon Oil Company, et al.

Optimization of Deep-Drilling Performance

Industry partners and the US Department of Energy (DOE) successfully completed benchmark testing of advanced diamond bits and high-pressure/high-temperature drilling fluids at high pressures. The full-length paper describes the results of this testing and identifies factors limiting rate-of-penetration (ROP) performance in deep wells and describes the development of drilling-fluid systems and bit-design philosophy to improve drilling performance significantly. Benchmark results match data from target field applications very well. This project is part of the DOE Deep Trek program. Sixteen full-scale tests of 6-in. bits were conducted at wellbore pressures greater than 10,000 psi.

Introduction

An important factor in future gas-reserves recovery is the cost to drill a well. This cost is dominated by the ROP, which becomes increasingly important with increasing depth. The object of this study was to improve the economics of deep exploration and development.

The original proposal was to test drill bits and advanced fluids under high-pressure conditions. Phase 1 of the proposal set out to establish a performance baseline and provide data upon which

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Fig. 1—Drill bits after testing.

to make design improvements. Phase 2 sought to establish improvements in design, and Phase 3 aimed to take drill-bit and drilling-fluid improvements to the field for further testing and to commercialize the technology.

Earlier deep-drilling projects have reached a maximum circulating pressure of 7,500 psi. However, to simulate the deeper drilling environments desired for the Deep Trek program, it was necessary to circulate at more than 10,000 psi and generate confining and overburden pressures of 11,000 and 12,000 psi, respectively. To accomplish this, it was necessary to upgrade equipment and increase the pumping capacity of the drilling and completions laboratory.

There are a number of deep productive horizons in the US that present deep-drilling challenges. The test matrix developed for Deep Trek was based on two of these basins: the Tuscaloosa trend in southern Louisiana and the Arbuckle play in Oklahoma and north Texas.

The drill bits selected for Phase-1 testing included a roller-cone bit to establish a baseline, two polycrystalline-diamond-compact (PDC) bits, and a diamond-impregnated bit.

Sixteen tests were run during Phase 1. Test 1 used clean water to provide a baseline for idealized conditions. Tests 2 through 8 were run with 11-lbm/gal water-based drilling fluids with four different drill bits. These tests were designed to simulate conditions in the Arbuckle play. Test 9 provided a baseline test, but with the base oil. Tests 10 through 16 were designed to simulate drilling conditions in the Tuscaloosa trend with 12- and 16-lbm/gal oil-based drilling fluids and three drill-bit designs.

Twenty-one tests that used specially designed drilling fluids and five drill bits were run in Phase 2 of the Deep Trek program. A water-based mud was used in five tests, cesium formate brine was used in five tests, and oil-based fluids were used for the others. Three PDC bits were

tested, along with a diamond-impregnated bit and a roller-cone bit. The rock tested was the same as during Phase 1.

Phase-1 test results, the subject of this paper, are provided in discussion of the penetration rates and mechanical specific energy (MSE) for the various bits, fluids, and rock tested.

Methods and Materials

Test Facilities. All Deep Trek drilling experiments were performed at a drilling and completions laboratory under simulated downhole conditions in a wellbore simulator that applied overburden and confining stresses to the rock. The drill-string loading and rotation were provided by the full-scale laboratory drill rig. This rig is servo-controlled and allowed constant loading of the drill bit.

Rock Samples and Preparation. The rock used for the tests included Crab Orchard sandstone, Carthage marble, and Mancos shale. These rocks were selected to approximate the properties of rock in the Arbuckle play (hard sandstone and hard limestone) and Tuscaloosa trend (hard sandstone and medium-hard shale). Cylindrical rock samples 1 1/2 in. in diameter and 36 in. long were prepared and placed on a steel endcap and enclosed inside a polyurethane polymer jacket. The jacket provided a seal between the rock and the confining fluid when in the wellbore simulator.

Three full-length cylinders of Crab Orchard sandstone and three of Carthage marble were used for Drilling Tests 2 through 7. Two-part composite cylinders were used for the other tests and were configured with 17 in. of Crab Orchard sandstone on the top and 19 in. of either Carthage marble or Mancos shale on the bottom. The composite cylinders were glued together.

Drill Bits. All rock bits tested were 6 in. in diameter (**Fig. 1**). Eight of the 16 tests were run with a seven-blade PDC bit, four with an impregnated bit, two with a four-blade PDC bit, and two with a carbide-insert roller-cone bit. Bit nozzles (and port for the seven-blade bit) were selected to achieve the desired hydraulic horsepower per square inch (HSI).

Drilling Fluids. The drilling fluids used in the study were based on those typical for drilling the Arbuckle play and Tuscaloosa trend. The deep Arbuckle typically is drilled with low-weight fresh-

water dispersed drilling fluids, which was confirmed by mud reports and mud samples provided by industry team members active in drilling the deep Arbuckle. An 11-lbm/gal mud weight was selected from the mud reports as representative of much of the deep slow drilling. Clay/quartz solid dust was added to simulate drill solids. Clear, solids-free fresh water also was used as a drilling fluid in Test 1 to evaluate the effects of mud-up in the subsequent tests. The properties of the drilling fluid, measured before each test, are consistent with this fluid type.

The deep Tuscaloosa trend is almost always drilled with high-weight oil-based drilling fluids because of the temperatures and pressures experienced. A 16-lbm/gal mud weight was selected as representative of much of the slow drilling in the deep Tuscaloosa, but the industry team also was interested in a few tests at 12 lbm/gal to evaluate the effect of mud weight. Clear, solids-free base fluid also was used in Test 9 to evaluate the effects of mud-up in later tests.

Testing

The test parameters for each Deep Trek test are listed in Table 5 in the full-length paper. Tests 1 and 9 provided baseline trials to determine the idealized conditions of drilling with an unweighted, clear fluid (water and base oil, respectively) with the seven-blade PDC bit. Tests 2 through 8 provided performance data on four drill-bit designs (roller-cone, seven-blade PDC, four-blade PDC, and impregnated) in a hard sandstone (Crab Orchard sandstone) and a hard limestone (Carthage marble), and all were conducted with an 11-lbm/gal water-based drilling fluid. Tests 10 through 16 simulated drilling conditions in the Tuscaloosa trend using hard sandstone (Crab Orchard sandstone) and medium-hard shale (Mancos shale). Drilling fluids used in these tests were 12- and 16-lbm/gal oil-based fluids and measured the performance of three bit designs (seven-blade PDC, four-blade PDC, and impregnated). Test 14 was run to determine the effectiveness of increased HSI (increased bit and hole cleaning) on bit performance with a 16-lbm/gal oil-based drilling fluid. Test 16 was run to determine the effect of reduced borehole pressure on performance of the seven-blade PDC bit.

At the completion of each drilling test, the bits were inspected for wear and balling (rock material sticking to the

bit); drill cuttings were examined, and a sample was frozen for later analysis; the borehole and bottomhole were examined, and the borehole was measured; and core plugs were taken from the borehole and bottomhole for later analysis.

Data were collected for rotary speed, weight on bit (WOB), penetration, fluid flow rate, swivel and borehole pressures, mud temperature, overburden stress, and confining stress. Low-data-rate data were collected at a frequency of one parameter set per second during the entire test. High-speed data were collected at 2,000 data sets per second for 2 seconds at each test interval (predetermined suite of rotational speeds and WOB settings).

Conclusions

- Penetration rates seen in these laboratory tests correspond reasonably well with those seen in field applications at high bottomhole pressures (BHPs).
- The test protocol adopted gave a reasonable simulation of field drilling conditions encountered in applications that involve penetrating hard rocks at high BHPs.
- “Mudding up” at high BHP causes penetration-rate reductions in the range of 30 to 80%.
- PDC bits have substantially higher penetration-rate potential than do impregnated and roller-cone bits, even when allowing for the lower operating weights typical of PDC bits. Impregnated and roller-cone bits are typically 60 to 80% slower than PDC bits at equivalent WOB in the environments studied.
- The relationship between ROP and confined rock strength is not a simple function of BHP alone.
- The relationship between ROP and drilling-fluid weight is not a simple linear relationship.
- The MSE when drilling at high BHP often is substantially higher than the compressive strength of the rock when confined at the BHP, even when the bit apparently is drilling efficiently.
- Fluid invasion of intact rock and of rock destroyed by the cutting structure of the bit seems to play a major role in controlling ROP at these high BHPs.
- Drilling-fluid compositions and properties that promote invasion without provoking formation damage and bit-design features that facilitate the removal of rock debris from the hole bottom both hold promise for improving drilling efficiency in hard rock drilled at high BHPs.

JPT

A Bit-Based Data-Acquisition System for Hard-Rock PDC Bits

The full-length paper describes the development and use of a bit-based module designed to monitor accelerometer and magnetometer sensors and to record selected data. The authors also describe the effort to infer dynamic dysfunctions from the data in the fast-growing hard-rock polycrystalline-diamond-compact (PDC) -bit application and to mitigate them by modifications to drilling parameters and bit designs.

Introduction

Drill bits are developed iteratively for specific applications to meet performance objectives such as aggressiveness, durability, stability, and steerability. The transition from one iteration to the next occurs when dull bits are examined, run data are analyzed, and the inferences are implemented as revisions to the bit design and/or the operating parameters. Experience has shown that the efficiency of the process depends strongly upon the appropriateness and significance of the data collected. If, for example, a dominant cutter-failure mechanism is characterized incorrectly as abrasive wear and is, in fact, impact wear, then both the proposed solution and the development time will be affected significantly.

One method for improving the significance of the data collected is to implement a special-purpose data-

acquisition system within the bit. Such a device has at least three significant advantages over available subassembly-based data-acquisition systems: (1) Its bit-based sensors will detect bit-based events more accurately, (2) it can be deployed economically over many bits, and (3) it is relatively transparent to the user.

Objective

The objective of the project was to develop an inexpensive battery-powered programmable data-acquisition system sized to fit within a bit and sufficiently robust to function under typical downhole-service conditions to monitor and record data for post-well analysis. The device is intended to support bit design, drilling-parameter development, and validation of laboratory simulation software and tests.

A device has been designed, manufactured, and tested that is an integrated battery-powered dynamic-behavior sensor and data-acquisition module. The module typically is implanted within the pin portion of a downhole tool, (e.g., within the shank portion of a bit). Modules are being run currently in bits in selected applications.

Form. The sensor/data-acquisition module is sized and constructed so that it can be implanted within an annular recess machined between the inside diameter (ID) and outside diameter of the end of a rock-bit shank. The electronics are implemented with rigid/flex circuit boards to minimize the number of failure-prone wire interconnects. The board, a temperature-measuring device, three orthogonal (x, y, z) accelerometers, three orthogonal (x, y, z) magnetometers, and the batteries are attached

to a rigid “backbone” to form the integrated (standalone) module. An end cap with O-ring seals and backup rings forms the ID and bottom of the sealed-module cavity when installed and protects the device from moisture and hydrostatic pressures.

Vibration

In the ideal case, a PDC drill bit and bottomhole assembly (BHA) will drill smoothly, on center at a constant angular velocity. However, there are three types of vibration that often occur and are potentially damaging to the bit and the BHA. They are the following.

- Axial vibration.
- Lateral vibration.
- Torsional vibration.

Axial vibration is not considered to be a significant cause of damage for PDC bits. An examination of field data collected with the module and the associated bits seems to confirm that fact.

Vibration at the bit may be characterized as various combinations of axial- and whirl-induced lateral vibration and torsional oscillation. Lateral vibration is induced by backward whirl (i.e., when the position or whirl vector describing the bit centerline in the hole reference frame rotates in a sense opposite the bit).

Typically, vibration damage to the bit is minimized when the bit center of rotation is fixed at the center of the hole (i.e., when there is little lateral vibration). However, if the bit center rotates about the hole center in the same sense as the bit rotation, there will be moderate vibration as a result of the eccentric motion and mass of the bit and the attached BHA. A more severe lateral vibration occurs when the whirl vector rotates opposite the bit rotation (i.e., the bit whirls

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For a limited time, the full-length paper is available free to SPE members at www.spe.org/jpt. The paper has not been peer reviewed.

backward). Backward or reverse-whirl angular velocity can be a multiple of bit angular velocity. There has been considerable effort in the industry to understand and eliminate bit whirl.

Low-speed torsional oscillation (vibration) can range from mild to severe. The frequency is determined by the drillpipe stiffness and BHA mass. In the mild form, the variation of the bit angular velocity about average is small. Small changes in bit angular velocity do not appear to affect the performance of PDC bits, though they can affect the quality of azimuthal logging-while-drilling readings. Large swings in rotational speed can manifest as angular-velocity-dependent transitions to whirl, particularly at higher velocities.

As bit angular-velocity variations increase, the minimum value can fall to zero, referred to as “stick/slip.” During the stick portion of the cycle, the resultant load direction on the cutters approaches vertical, and in hard formations spalling of the diamond table can result. The stick/slip frequency will be lower than less-severe torsional oscillation with greater maximum velocity because of the stick time for the bit.

Low-frequency torsional oscillation may be critical when the bit reverses direction after each stick event (i.e., the bit rotates backwards or counterclockwise when viewed from above for a portion of the cycle). During backward bit rotation, forces can develop that act to pull the diamond table off the substrate in tension and to spall the diamond. This can be catastrophic to a PDC bit in hard formations.

In addition to the low-frequency torsional oscillation stick/slip events, there are several examples of high-frequency torsional oscillation shown. High-frequency oscillations ranging from 40 to 90 Hz and beyond have been observed. The vibration mode has not been documented or studied as well as stick/slip and whirl have been, and yet it seems to be common when drilling hard formations with PDC bits.

Burst-File Examples

The in-bit module can be programmed before service to monitor

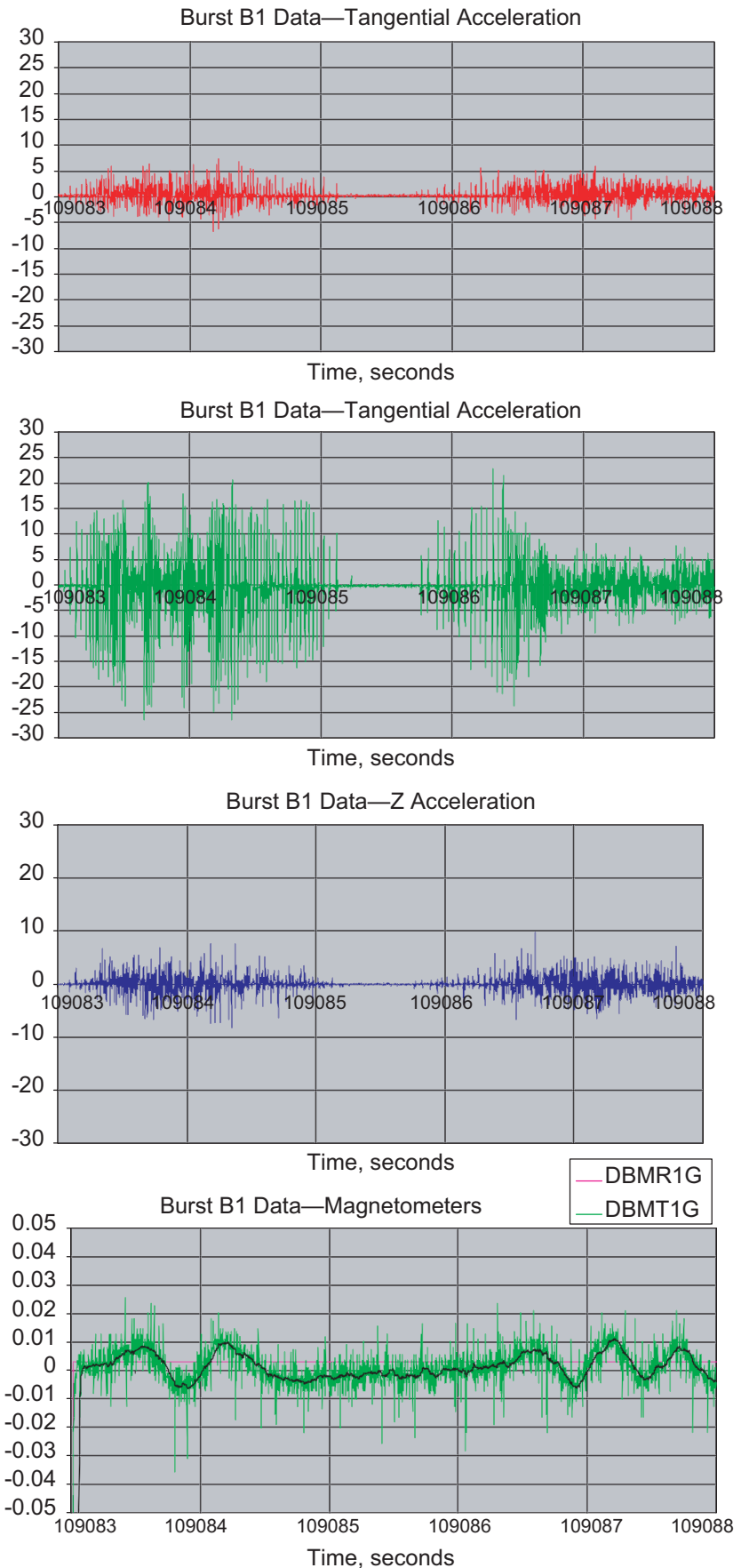


Fig. 1—Stick/slip below a motor with chatter on startup.

the accelerometers and when certain threshold vibration conditions are met, to record high-frequency (250 Hz) accelerometer data in "burst" files. The full-length paper details several examples of these 5-second-interval burst files.

High-Frequency Torsional Oscillation. Fig. 11 in the full-length paper shows a 5-second burst that captured the transition from smooth to severe high-frequency torsional vibration. The sudden appearance of this vibration mode suggests that it is driven by changes in formation and/or operating environment and it is not the result of gradual dulling. The fact that later bursts during this bit run did not show the high levels of torsional vibration suggests that this is a reversible effect and not a result of catastrophic cutter damage.

Stick/Slip Below a Motor. Often it is hard to place subassembly-based sensors below a motor because this adds

length to the BHA and additional bending loads to the bearing housing. However, because this module is integral to the bit and adds no length, it is possible to study vibration signatures below the motor without interfering with other drilling objectives.

In this case, the module recorded a stick/slip event below the motor with 13,000 ft of 5-in. drillpipe (**Fig. 1**). Note that there is a 2-second period of no bit rotation. Other bursts show periods of stick that are more than 4 seconds long. With a 30-rev/min surface speed and 90-rev/min motor speed, there would be 8 wraps of the drillpipe for 4 seconds of stick. While this is a deep well, the long stick times suggest that the motor stalled during at least some of these events.

Also, note the severe torsion spikes at the start and stop of the stick phase. Other burst records in the run showed that there were no whirl or other torsional dysfunctions during this run except during the stick/slip events. This suggests that the dys-

function was BHA-related in this case and not bit-induced.

The character of this stick-phase startup chatter has not been noted before, and it is unknown how common this is.

Summary

Full 3D models of the bit with a limber BHA have reproduced the stick/slip and chatter events observed at the restart of each rotation. Simulations also have been run showing the normal stick/slip and whirl described in many prior papers. By using this in-bit module in unexplored hard-rock applications, significant insights are being gained that can be translated into fewer dynamic dysfunctions and lower drilling costs. While there is significantly more work to be done to compare the models to actual field data, these results have added insights into less-explored high-frequency dynamic dysfunctions and methods that can be used to suppress them. **JPT**



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A ROP-Management Process in Qatar North Field

In March 2005, the operator implemented a rate-of-penetration (ROP)-management process in Qatar's North field. The ROP-management process uses real-time, customized surveillance technology to maximize continuously both drill-bit-cutter efficiency and transmission of energy to the bit. To date, the development program has been accelerated by 1 year, and USD 54 million has been saved while drilling 470,000 ft of hole. More than 440 personnel have been trained in mechanical specific energy (MSE) analysis, and 50 new field drilling records have been set.

Introduction

The Qatar operator currently conducts drilling operations at eight platform locations across six very-large producing blocks. The majority of wells are drilled in batch mode by section. Over the years, the operator gained extensive field knowledge and developed many efficient operating practices. Thus, the introduction of any new ROP-management process would be examined against solid baseline operating performance. At the same time, 2005 to 2006 has been a period of transition, as the company increased rig count from three to nine. The addition of many new support personnel in a multicultural working environment presented a significant challenge in terms

of maintaining or improving drilling efficiency.

In the midst of these challenges, the decision was made to pilot test the ROP-management process, with its first application in such an extensive carbonate-field environment. The focus of the program was four-fold: (1) Conduct extensive customized field training in MSE analysis, (2) implement a standard surveillance program, (3) introduce new practices in a phased manner concurrent with measurement of energy efficiency, and (4) communicate learning systematically across all rigs using MSE curves as the basis for discussion.

Field Background

Aside from one vertical data well at each platform, all wells drilled are 55-to-65° S-shaped directional wells with an abbreviated drop section into the Khuff reservoir. Although platforms are miles apart, many wells are quite similar in terms of lithology, hole size, casing configuration, and casing-setting points. An important reference data set when discussing MSE is rock unconfined compressive strength (UCS). The MSE recorded while drilling should vary as the bit traverses rock of various strengths. However, it should vary only by the amount of change in rock strength. In field operations, a baseline MSE is established, and any increase above this that exceeds the change in rock strength is likely to be an indication of bit dysfunction.

Learning Cycle

To begin the learning cycle, the operator analyzed historical information with hindcast MSE curves (i.e., curves generated from offset wells using existing data). Intervals of significant energy waste (high MSE) were identified

and became opportunities for improvement. MSE increases beyond baseline were discussed in relation to change in rock strength. The actual energy waste visible even on the best offset was significant.

To facilitate learning, the operator customized the surveillance package so that MSE data were captured in a standard manner and made accessible to all relevant project personnel. MSE real-time displays were located on the rig floor, in service cabins, and in the company representative's office, as well as the onshore offices of the project engineer and manager. Initially, real-time downhole vibration data were displayed to complement MSE interpretation. There were initial concerns that wells would be "drilled from the office," but drillers did what they do best, which was to optimize parameters on the rig, and engineers leveraged their expertise to analyze MSE information in the context of future well plans.

Changes were made in the standard surveillance package as learning progressed. For example, after several wells in an area had been drilled with both MSE and vibration analysis, the value of real-time vibration data could be reassessed, especially because MSE was always the primary trending tool. MSE generally provided a better indication of drilling dysfunction than vibration data. The transfer onshore of real-time MSE data was scrutinized, with the result that frequent posting of MSE data to the local-area network was deemed an effective substitute for continuous real-time display to onshore personnel.

Lithology

On the basis of observations of approximately 170 sections drilled under the ROP-management process,

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it was learned that the generalized lithology information could be further subdivided into approximately 40 subunits according to rock type and characteristic ROP limiter (e.g., the issue responsible for bit founder). Many intervals drilled in the North field consist of very heterogeneous, highly laminated rock sections.

The UCS of rock in the North field generally ranges from 5,000 to 35,000 psi. At the lowest end of the UCS scale, bit-structure cleaning (BSC) was observed to be the dominant limiter, particularly in the argillaceous limestones or limestones of high clay content. In higher-UCS dolomites and anhydrites, bits exhibited lateral-vibration tendencies. As heterogeneity increased, especially in hard-to-soft sequences, there was a shift toward axial vibrations. It is recognized that ROP limiters rarely occur one at a time. However, it also was observed that a significant improvement in overall MSE level (and drilling performance) can be realized if the dominant limiter is managed properly.

One of the unique aspects of the ROP-management process was the integration of lithology into the MSE-drilling parameter log. Standard programs and procedures incorporated learning on the basis of expected ROP limiter by lithology and provided general mechanical parameters to address expected limiters.

Managing Drilling Efficiency

Inherent to the ROP-management approach is the philosophy that MSE is of primary importance. Minimizing MSE generally means that operations would be in the desired range. Conversely, focus on maximizing instantaneous ROP likely would result in operations with a higher MSE signature and the risk of premature bit damage. This project used MSE analysis to manage drilling efficiency, and specific attention was given to maintaining a MSE level less than 100,000 psi throughout the entire section. A North field record run length was achieved. One of the most problematic intervals from this bit run was a highly laminated dolomite sequence very prone to severe axial vibrations. Axial vibrations in this interval can result in a very erratic MSE signature, with potential for

200,000- to 300,000-psi MSE increases and bit ringout. Here, frequent weight-on-bit (WOB) adjustments were required to produce a relatively smooth MSE curve, and the bit drilled the entire section. Importantly, the final bit grade was reflective of excellent vibration management, with relatively balanced wear between inner and outer cutters. During this specific bit run, many ROP limiters were experienced.

ROP Limiter—BSC

With MSE analysis, it became apparent that certain intervals were subject to BSC issues or incipient bit balling. Argillaceous limestone and claystone were particularly susceptible to BSC. Sudden cuttings accretion to the bit cutting structure would interfere with efficiency, as evidenced by a sudden increase in MSE. Intervals of competent limestone, perceived in the past as “hard-drilling” streaks, actually were limited by BSC, and MSE information was used to quantify the relationship between energy waste and applied WOB. In claystone intervals, BSC issues were expected and confirmed by MSE analysis. Of the 40 major subunits identified, BSC was a major issue in 15 of these intervals and was present in several more.

MSE analysis can highlight the onset of BSC before the problem becomes severe. The point at which a bit will founder can be quite low even in limestone with moderate bit hydraulic horsepower.

The relationship between bit hydraulic horsepower and performance for polycrystalline-diamond-compact (PDC) bit runs in 12¹/₄- and 8¹/₂-in. intervals was examined. The trends in both hole sections are similar. There is benefit with increased hydraulic energy at least to 6 hhp/in² (HSI) and indications of continuing benefit beyond this level. Maximizing hydraulic horsepower at the bit is emphasized in the design stage. In the 17¹/₄-in. section, similar trends have been observed, and the design guideline for HSI is 5 to 6 or more, when possible.

ROP Limiter—Vibrations

Axial vibration was a major limiter in 15 of 40 subunits and was present as a secondary limiter in 10 other zones.

Higher-UCS zones with alternating sequences of lower-strength rock are prone to axial vibration, especially where softer limestone is interbedded with dolomites and anhydrites. The hypothesis is that a ±55° bit orientation relative to flat bedding planes results in eccentric and severe loading of the PDC bit cutting structure at formation-transition points, with very high risk of bit-shoulder damage. It is known that rock strength varies only ±20,000 psi in these intervals, yet energy curves increase by a factor of 10 to 20 times that level if vibrations are not addressed through proper WOB and rotary-speed adjustment. A prompt reduction in WOB is required to minimize MSE in the presence of axial vibrations. Constant-WOB practices can hasten the ringout process.

Lateral Vibration. Lateral vibration, or bit whirl, has been identified as the major ROP limiter in 10 of 40 lithology subunits. In relatively clean, higher-strength rock, it has been observed that lateral vibration is the primary ROP limiter, as evidenced by MSE improvement with increased WOB and reduced rotary speed. Lateral vibration leads to significant energy waste and premature bit damage if not addressed properly by prompt mechanical adjustment. Insufficient engagement of bit cutters allows the bit to rotate off center, pivot off gauge pads, and overdrill the hole. The resultant cutting pattern can be quite irregular and damaging to PDC-bit cutters not designed for sideloads. When MSE analysis is used to mitigate whirl, ROP typically increases by 100% or more and shoulder damage to the bit is reduced. Of the 5,764-ft section drilled, approximately 1,400 ft of the interval was diagnosed as whirl-prone anhydrite and hard dolomite. Mechanical practices mitigated this damaging form of vibration effectively.

Torsional Vibration. Torsional vibration, or stick/slip, was present in all sections of the North field. Torsional vibration has not been damaging to PDC bits, in sharp contrast to axial and lateral vibrations. However, it has been observed that reducing high levels of stick/slip is essential to achieving peak efficiency.

Bottomhole Assembly Optimization

Like most North field operators drilling wells with similar architecture, efforts have been made to optimize 2D directional-drilling systems. Trailing stabilizers have been configured to accomplish build, hold, or drop objectives. Adjustable kickoff (AKO) settings on the lower motor have been reduced to 0.6° to mini-

mize downhole vibrations in rotary mode. The exception to this is the use of a 0.8° AKO set motor in the 17¹/₂-in. build section. Here, inclination is built from 30° to the final angle of 55° and a lead is built in the well path for azimuth walk in lower sections.

17¹/₂-in. Hole Section. In the 17¹/₂-in. interval, a key objective

was to minimize slide drilling to perform MSE analysis while rotary drilling. This change in philosophy was driven by the ROP-management process itself. Because MSE is calculated from surface torque, MSE essentially drops to zero while sliding. Hence, the MSE-optimization process was used only during rotary drilling. In the initial wells, rotary drilling was used in approximately 70% of the 17¹/₂-in.-section footage. To accommodate MSE analysis, directional-drilling practices were changed from a “drill the line” approach to one of “drill the zone.” Directional assemblies were redesigned to facilitate stronger rotary build rates, and “no-slide guides” were developed for each project. Sliding was highly discouraged if the well remained in the designated zone. With this approach, rotary drilling increased to the 80-to-97% range.

12¹/₄- and 8¹/₂-in. Hole Sections. A similar “no-slide-zone” philosophy was adopted for both the 12¹/₄- and 8¹/₂-in. sections. Initial rotary-drilling percentage in these sections was high, 90 to 95%. Because hold or drop is critical in these sections, an adjustable-gauge stabilizer typically is used behind the motor. One of the critical variables in the 8¹/₂-in. section was optimizing motor length and torque output to achieve more-consistent directional performance. Longer high-performance motors introduced too much variability in drop performance when compared to shorter high-performance motors.

Conclusions

The new ROP-management process has improved drilling performance and has ensured more-consistent results within a rapidly expanding, major development program. MSE analysis in particular has been an effective tool for identifying ROP limiters and providing a technical framework for optimization of drilling practices. Cross-referencing ROP limiters to lithology has been an important part of that framework. **JPT**

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