Results of Extensive RSS Testing With PDC Bits

Steve Jones, SPE, and Junichi Sugiura, SPE, PathFinder Energy Services; and Steve Barton, SPE, ReedHycalog

Rotary steerable systems (RSSs) have made remarkable improvements in reliability since their introduction in the 1990s and have become a standard drilling tool. Today, point-the-bit and push-the-bit RSSs are used on both directional and vertical wells worldwide. No longer limited to high-cost offshore markets, their use is becoming more common in lower-cost land markets.

In the following analysis, the results of an extensive series of test wells are described. The wells were drilled in a controlled, noncommercial environment, allowing single-step changes in the drill bit features and rotary steerable (RS) configurations. The testing was unique in that the specific RSS worked in shop-configurable point-the-bit and push-the-bit modes. Between the two distinct RSS operation modes, consistency in stiffness, weight, force-applying capability, and control systems led to a direct comparison of bit performance.

The advancement of RS technology goes hand in hand with the use of polycrystalline-diamond-compact (PDC) bits. Continual development of advanced modeling software and cutters with significantly increased abrasion resistance have led to PDC designs that can drill faster, further, and with a high degree of stability. These benefits, combined with the appropriate RSS, can also deliver superior directional control, improved borehole quality, higher-quality logging, and easier casing runs. The resultant improvement in economics is particularly attractive in high-cost offshore wells.

The bit-design optimization is key to the success of RS drilling. In directional applications, stability and steerability of the drill bit are critical to performance. Without a smooth torque response or a laterally stable design, drilling will not achieve the desired rate of penetration (ROP) or the durability necessary to drill the required interval. It is also important to match the side-cutting capability of the cutting structure and the gauge geometry to the operating mechanism of the specific tool and the directional objectives. These factors will affect the borehole quality, which has a direct impact on the directional control of the RSS. Maintaining wellbore quality, particularly borehole gauge, is crucial to both push- and point-the-bit systems for obtaining predictable directional response. Also, with any RSS, the directional control and borehole quality is directly linked as to how fast and precise the internal control system can operate.

Rotary Steerable Bits

There are four fundamental characteristics of the fixed-cutter bit: durability, steerability, stability, and aggressivity. Drill-bit designs need to be tuned with respect to bit profile, cutting structure, and gauge design to optimize performance for a given bottomhole assembly (BHA), formation, interval, mud type, and directional requirement. As with most RSSs, gauge hole and good borehole quality are very important in enabling the system to deliver consistent directional response. The lateral stability of the drill bit will play a direct part in this, particularly the cutting structure. Optimal RSS performance is obtained with drill bits that are laterally stable and drill with smooth response in terms of torque and rotation speed. Erratic torque and rotation-speed fluctuations will lead to problems with tool operation, inconsistent steering response, and ultimately to bit and tool failure.

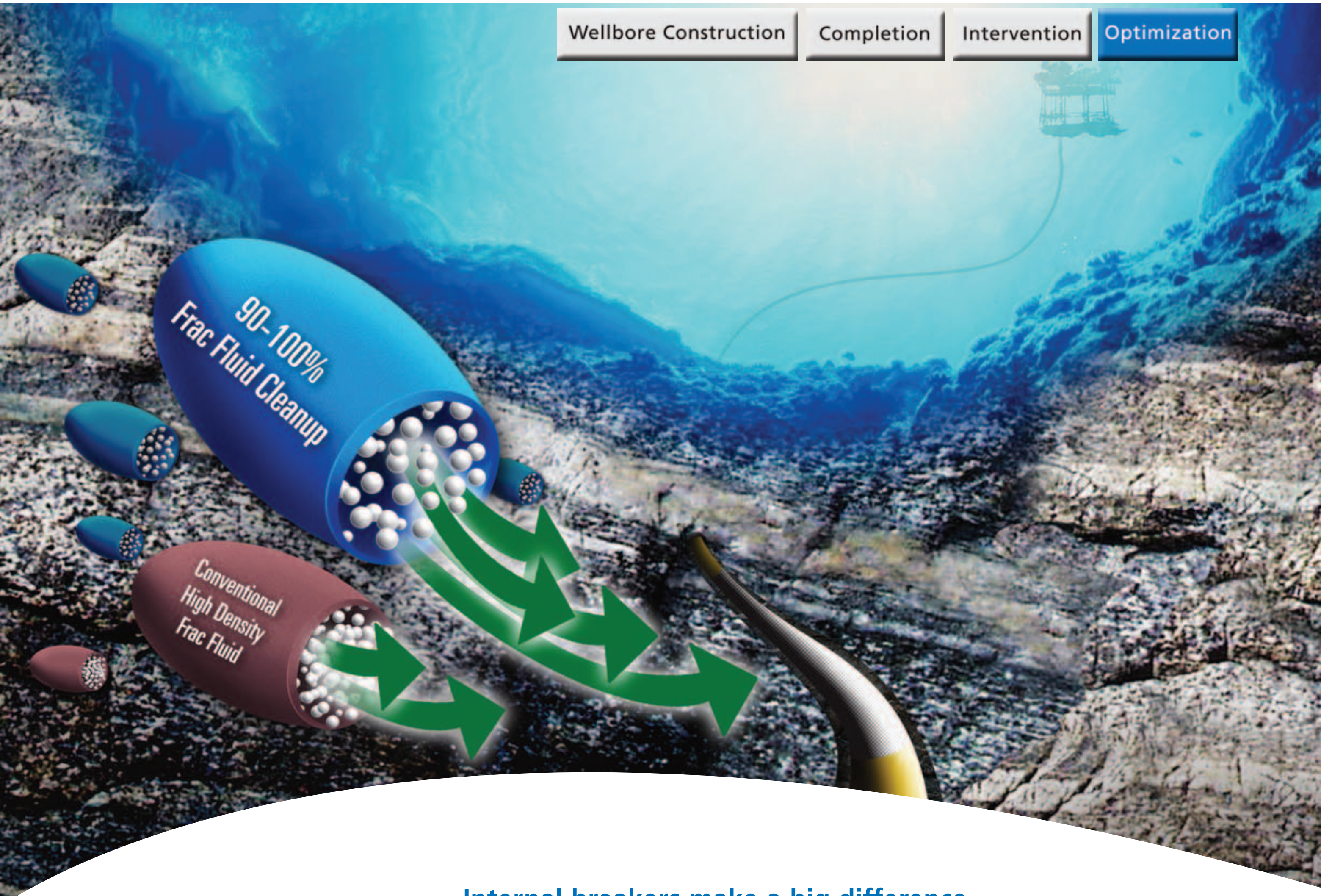
Side-cutting ability is also an important consideration with RS assemblies, and there are two key aspects of a PDC drill bit related to this. One concerns the side-cutting capability of the cutting structure itself and the other is a function of the gauge design, be it length, geometry, or cutter arrangements within the gauge of the bit (Barton 2000). A high degree of side cutting is not necessarily beneficial. However, some directional systems—for example, push-the-bit RSS—can require a high side-cutting ability in certain trajectories to operate most effectively, whereas other systems do not.

One of the key aspects of an RS assembly is the operating mode of the specific tool itself; an in-depth knowledge of the tool and field performance will enable both bit cutting structure and gauge geometry to be matched with a specific RSS drive mechanism. For this series of tests, specific emphasis was applied to the exact effect of gauge geometry. The primary cutting structure was designed by means of proprietary modeling software in order to ensure that the design would be laterally stable in dynamic conditions. As the same primary cutting structure was used, the side cutting capability was also identical between tests. As such, the variance in recorded stability and steerability predictably would be directly related to the variance in gauge geometry used during testing with both push- and point-the-bit RSS configurations. The following section discusses the four primary gauge configurations used in testing.

Active gauge. This geometry has been well documented in several papers (Barton et al. 2002; Romo et al. 2006).

The material in this article was covered by these authors in paper SPE 112579, presented at the 2008 SPE/IADC Drilling Conference, Orlando, Florida, 4–6 March.

Deepwater Fracturing: It's Make or Break Time



Internal breakers make a big difference

Net present value (NPV) of today's assets can depend on the fracture proppant pack. The more conductive the proppant pack, the more productive the well.

Diamond FRAQ™ HD Nonionic Viscoelastic Surfactant (VES) Fracturing Fluid is the only high-density VES fracturing fluid with internal breakers. 100% regained proppant pack conductivity is twice as much as other high-density frac fluids. That's enough to double well NPV.

That's not all. Diamond FRAQ also offers these value-added benefits.

- Up to 50% less surface treating pressure and hydraulic horsepower
- Up to 50% less fluid cost from cost-effective brines
- Seawater solubility and disposability

Contact us to learn how Diamond FRAQ HD Fracturing Fluid can increase your deepwater asset NPV.

www.welltreatment.com

BAKER HUGHES Baker Oil Tools

THE Completion and Intervention Company

Full-round PDC cutters, set with an aggressive backrake, are placed along the entire leading edge of the gauge pad. The gauge pad itself is recessed to allow lateral exposure of these cutters. This arrangement increases the lateral cutting ability of the bit design and is optimal when used in conjunction with a push-the-bit RSS.

Dual-action gauge (DAG). This gauge geometry incorporates a full diameter gauge pad with a PDC cutter selectively placed at the back angle of the gauge pad. This cutter is set in a recess of the pad. The design is such that when the bit is tilted in the hole, the cutter can remove formation and allow the system to move in the direction required (Barton et al. 2002). However, when in a neutral or tangential setting, the cutter is actually set lower radially than the gauge pad and thus will not undercut the low side of the hole.

Circumferential ring gauge. This gauge design features a continuous ring at the gauge diameter, rather than discrete pads as seen on conventional bits. These features are described in more detail in a previous paper (Roberts 1998). Ring bits were designed to improve directional response by improving the lateral stability of the bit, reducing the propensity of the bit to whirl. By minimizing lateral vibration, the ring bit reduces torque fluctuations that can occur due to bit whirl. This reduces the potential of the bit to overengage the formation laterally, which can cause issues with the directional tool. In addition, as the ring bit limits lateral vibration, it will tend to drill a smoother borehole. The majority of ring-gauge designs used commercially feature partial ring geometry, and that was used within the test program.

Tapered gauge. The gauge pad of the drill bit is tapered at an angle that is matched to the tilt imposed by the RSS. All tools apply a tilt to the bit. With a push-the-bit system, pad contact against the wellbore results in the bit tilting, forcing the high side of the gauge into the formation. This also occurs with point-the-bit systems, where the deflected shaft points the drill bit and the gauge pad is forced against the low side of the hole. This contact with a conventional parallel gauge can result in high/erratic torque, instability, inefficient steering, and overgauge hole. The specific geometry of the proprietary tapered gauge avoids the frictional resistance produced in directional drilling, thus lowering torque and instability (Niznik et al. 2006). This gauge geometry can be coupled with any of the other three gauge geometries mentioned earlier.

Test Results

Confidential drilling-rig test facilities were used to conduct the controlled RSS directional test program. Because a limited number of test facilities were available in North America, the tests were split between two locations: the Gas Technology Institute (GTI) Catoosa Test Facility near Tulsa, Oklahoma, and the U.S. Department of Energy Rocky Mountain Oilfield Test Center (RMOTC) near Casper, Wyoming.

Throughout 2006 and 2007, the point-the-bit and push-the-bit RS systems were extensively tested with different drill bits in controlled, noncommercial environments at GTI and RMOTC. To allow comparison of the directional response from the formations at both facilities, similar assemblies were run. The results showed comparable response for build rates at both locations when the rev/min, weight on bit (WOB), and gallons per minute (GPM) were maintained relatively constant. The surface parameters used throughout testing in 8½- and 12¼-in. holes are shown in **Table 1.** For optimal test results, it was necessary to drill the same formation at exactly the same true vertical depth, angle and direction. This was done by setting cement plugs when required to sidetrack the well and track the original test hole as closely as possible.

The main objective of the controlled tests was to establish the maximum dogleg by means of various bit-gauge configurations and at the same time evaluate the system for stability, steerability, and borehole quality. The test results herein are categorized by hole size and RSS configuration. The exact contact-point spacings and outer diameters (ODs) of stabilizers and steering unit remain confidential. However, changes in length are disclosed.

The RSS test tools were designed to allow touch-point stabilizer spacing and OD changes to be made at the test site. Software modeling was used to evaluate the best possible configurations, and these assemblies then were tested to confirm and update the computer model. The BHA modeling and subsequent analysis will be covered in a separate paper.

Designing RSS test tools with rigsite-changeable touch points allowed the system to be tested to optimize performance characteristics based on the control system, geometry, and drill-bit type. Having the flexibility to change tool configurations at the rigsite saved considerable time during the evaluation phase of the RSS. Real-time and memory data were used to evaluate tool performance. The memory data were recorded at 1-second intervals, allowing the steering control system to be evaluated between runs. This analysis was used to understand whether the geometry and drill-bit changes influenced the internal control system.

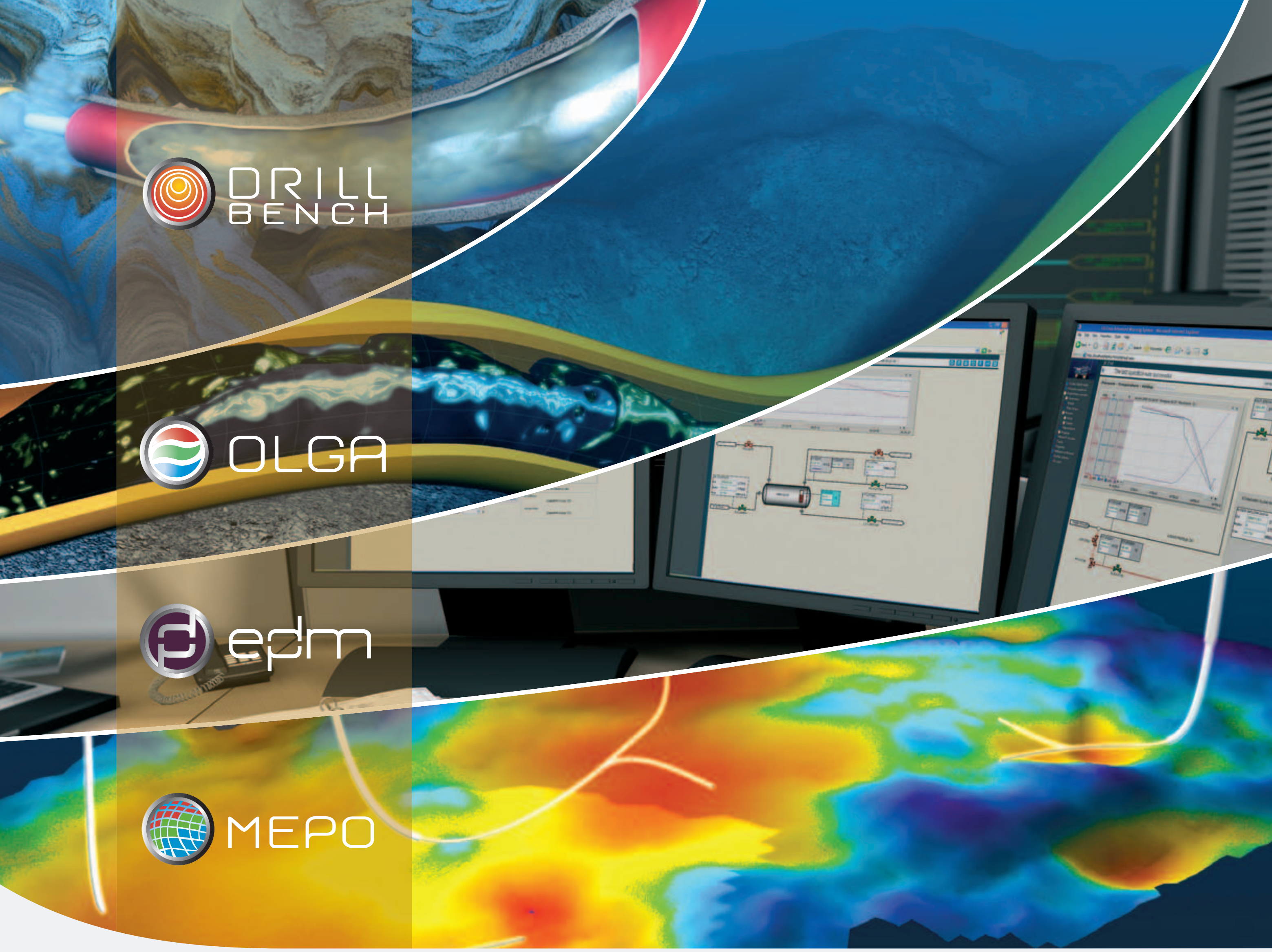
6¾-in. Tool With 8½-in. Drill Bits

Push-The-Bit Results

Tool setup: An experimental push-the-bit RSS was designed exclusively for this test. To optimize the 6¾-in. push BHA for maximum build rate, different spacings were tested with various bit-gauge configurations. The distance between the steering unit and bit face was varied, as was the distance between the steering unit and the third touch-point stabilizer. The four different configurations that were tested have been named long push (long-shaft push-the-bit), short push (short-shaft push-the-bit), long push + spacer, and short

TABLE 1—SURFACE PARAMETERS USED DURING CONTROLLED TESTING

Parameter	12¼-in. hole	8½-in. hole
WOB (klbm)	15–25	10–20
Rotation speed (rev/min)	100–120	100–120
Flow rate (GPM)	800	450



Work with world leading simulators!

SPT Group is the leader in dynamic modelling for the oil and gas industry, employing highly skilled professionals worldwide. SPT Group provides a combination of software and consulting services in flow assurance, drilling and reservoir engineering.

- DRILLBENCH® - comprehensive suite for design and evaluation of all drilling operations
- OLGA® - leading simulator for dynamic multiphase production in wells, pipelines and process facilities
- edpm® - e-field dynamic production management for operational support and optimisation
- MEPO® - reservoir production forecasting, history matching and uncertainty assessment

be dynamic®

Bergen - Cairo - Dubai - Guildford - Hamburg - Houston - Kuala Lumpur
Mexico City - Milan - Moscow - Oslo - Perth - Rio de Janeiro

SPT GROUP
www.sptgroup.com

TABLE 2—6¾-IN. LONG PUSH-THE-BIT—AVERAGE BUILD RATES, STEERING HIGH SIDE WITH 88% OFFSET

8½-in. bit type	Inclination range tested (°)	Average build rate (°/100 ft)
1½-in. active gauge	30–45	9.9
1½-in. partial ring	30–45	5.5
3-in. tapered	45–60	6.1

TABLE 3—6¾-IN. PUSH-THE-BIT CONFIGURATIONS—AVERAGE BUILD RATES IN °/100 FT, STEERING HIGH SIDE WITH 88% OFFSET

8½-in. bit type	6¾-in. long	6¾-in. short	6¾-in. long +7 in.	6¾-in. short +7 in.
1½-in. active gauge	9.9	11.4	5.0	7.5

TABLE 4—8½-IN. BIT COMPARISON WITH AN 8½-IN.-HOLE-SIZE AND LONG-SHAFT, PUSH-THE-BIT RSS

8½-in. bit type	MWD lateral (CPS)	RSS lateral	RSS axial	RSS stick-slip severity (SS)%	DLS (°/100 ft)
1½-in. active	0	2	1	0.61	9.9
1½-in. DAG	0	3	1.9	1.22	6.0
3-in. tapered	0	4	2	1.16	6.2

push + spacer. The difference between short push RSS and long push RSS was a 1.5-ft length increase between the steering unit and the third touch-point stabilizer. Both long-shaft and short-shaft versions were then tested with and without a 7-in. spacer sub inserted between the steering unit and the bit.

Settings: All build-rate tests were carried out on an 88% deflection (offset) setting. As an initial benchmark test, the long push RSS assembly was run with three bit-gauge configuration types. The bit that produced the highest build rate was then tested on the short push configuration. This same bit was then used for both assemblies with the 7-in. spacer.

Steerability: **Table 2** shows the test results from the various gauge configurations. The long push results clearly showed that the full active gauge produced the highest build rates, whereas the rates produced by the partial ring gauge and tapered gauge bits were notably lower.

Optimized steerability: The active-gauge bit was then run on the short push RSS. Reducing the spacing from steering unit to third touch-point stabilizer by 1.5 ft had the effect of increasing the build rate to 11.4°/100 ft. While producing these high build rates, the assembly was very stable and no drillabililty problems were encountered. Both short and long push assemblies were then tested with a 7-in. spacing increase between the steering unit and the bit. From the results shown in **Table 3,** this extra spacing had a dramatic effect—reducing build rates by approximately 4°–5°/100 ft.

Overall, the short push RSS produced the best build rates and still delivered good drillabililty. The torque and drag values, and weight application to the bit were normal. No hanging up or hole problems were encountered when drilling 11.5°/100 ft with a 6¾-in. RSS assembly. As a further test to evaluate the hole quality with the push-the-bit system, a point-the-bit system with full-gauge near-bit stabilizer was run through the same hole. Only occasional light reaming was required to get the point assembly to bottom, indicating the high doglegs generated by the push-the-bit system were created with good hole quality.

Stability: Further testing was performed to evaluate the stability of the active-gauge design, compared with both the DAG and tapered-gauge geometries. The three bits drilled in the same formation (Steele) with the same deflection (offset) rate and similar surface parameters (WOB=10~12 klbm, rotary speed=100 rev/min, and flow rate=420~450 GPM) at 43°~45° inclination. After each test, memory data were retrieved and the near-bit (NB) stick-slip and vibration data were used to analyze lateral, axial, and torsional stability of the drill bit. **Table 4** shows the comparison of the three gauge geometries in terms of vibration and dogleg severity (DLS). In the table, RSS lateral and axial vibration levels are computed by taking an average of maximum acceleration (in 9.8 m/s^2) over a predetermined period. The detailed computation process is not disclosed, as it is proprietary information. In the following sections, vibration levels are treated as unit-less numbers (severity levels).

The test results indicate that the active-gauge bit provides the highest DLS with the lowest lateral, axial, and torsional vibration at the RSS. The DAG and tapered-gauge bits have less side-cutting capability at the gauge and thus produced lower DLS with the same amount of RSS side force. Moreover, the inability to achieve offset at the steering unit (or to side cut to the target position at the bit) induced lateral and torsional instability. The active gauge will remove rock efficiently, when side force is applied, thus achieving smoother drilling. With the less aggressive gauge geometries, the bit is less efficient at cutting laterally. Thus, friction and drag are generated, and slightly higher vibration levels result. The stick-slip is lower for the 3-in. tapered gauge, compared with the 1½-in. DAG, because the tapered geometry reduces the friction. This results in smoother drilling even when the overall gauge length is doubled.

Point-the-Bit Results

Tool setup: Previous tests had been performed to determine the optimum touch-point spacing for maximum build rate in a point-the-bit mode.

Settings: 98% offset.

Steerability: **Table 5** depicts the build rates obtained with different bit-

TABLE 5—6¾-IN. POINT-THE-BIT—AVERAGE BUILD RATES, STEERING HIGH SIDE WITH 98% OFFSET

8½-in. bit type	Inclination range tested (°)	Average build rate (°/100 ft)
1½-in. active	40–60	9.8
1½-in. partial ring	40–60	10.0
3-in. tapered	40–60	8.9

TABLE 6—A COMPARISON OF ROP, BUILD RATE, BOREHOLE CONDITIONS, AND VIBRATION BETWEEN 8½-IN.-HOLE-SIZE POINT-THE-BIT AND PUSH-THE-BIT MODES

Parameters	Point-the-bit	Push-the-bit
Drill bit	partial ring gauge	full active gauge
Formation	shale	shale
Flow rate	440 GPM	400 GPM
Rotation speed	100 rev/min	100 rev/min
WOB	12 klbm	10 klbm
Tool offset	0.39 in. (98%)	0.35 in. (88%)
ROP	49.3 ft/hr	49.0 ft/hr
DLS	10.2°/100 ft	11.5°/100 ft
Build rate	10.0°/100ft	11.4°/100ft
Mean caliper	8.536 in.	8.544 in.
Caliper deviation	0.020 in.	0.022 in.
Housing roll	0.84 rev/hr	1.25 rev/hr
Lateral vibration	6.6	6.5
Axial vibration	2	1
3-in. tapered	40–60	8.9

TABLE 7—8-IN. PUSH-THE-BIT—AVERAGE BUILD RATES, STEERING HIGH SIDE WITH 91% OFFSET

12¼-in. bit type	Inclination range tested (°)	Average build rate (°/100 ft)
2-in. active	10–30	5.8
2-in. partial ring	30–50	5.4
3¼-in. tapered DAG	10–30	5.4

gauge configurations. From the data, it is clear that the 1.5-in. ring gauge drill bit produced the highest build rates. However, there was not a significant difference overall in build-rate response between the various gauge geometries. The hole quality was marginally better with the longer gauge bit.

Point-the-Bit and Push-the-bit Comparison. Both the point- and push-the-bit configurations drilled in the same formation (Steele) with similar surface parameters (WOB=10~12 klbm, rotary speed=100 rev/min, and flow rate=400~440 GPM). The offsets were set at 98% and 88%, respectively. In the tests, concurrent NB caliper and vibration data enabled the engineers and researchers to make comparative analysis of bit and BHA stability and borehole quality between the two distinct RSS configurations. The detailed information on the NB caliper and vibration sensors integrated in the particular RSS is described in a previous paper (Sugiura and Jones 2008).

Both BHAs exhibited similar ROPs, good lateral and axial stability, and borehole quality (consistent gauged borehole) as shown in **Table 6.** There were no signs of borehole ledging or spiraling with either configuration. The only notable difference between the two was the average build rate, which was 10.0°/100 ft in point-the-bit mode, with 98% deflection, and 11.4°/100 ft in push-the-bit mode, with 88% deflection.

8-in. Tool With 12¼-in. Drill Bits

Push-the-Bit Results

Tool setup: Previous testing had already proved the optimal spacing for the touch points. The standard commercial spacing was used to perform the controlled bit tests.

Setting: 91% offset.

Steerability: The results from testing are shown in **Table 7.**

Because operational issues occurred at surface during testing, the results for the active gauge were invalidated at RMOTC. Prior testing with gauge geometries at GTI did reveal that the active-gauge geometry produced the highest doglegs in push-the-bit mode, following the trend identified earlier with the 8½-in.-bit test results.

Stability: In addition to the PDC drill bit tests, a third-party 12¼-in. milled-tooth drill bit also was run with the push-the-bit configuration. All drill bits were within the same formation (Steele) with the same deflection (offset) rate and similar surface parameters (WOB=10~20 klbm, rotary speed=100 rev/min, and flow rate=720~750 GPM). With the milled-tooth bit, the memory data indicated that the steering housing rotated nonuniformly and that the borehole caliper was erratic with an average borehole size of 12.5 in. (¼ in. overgauge). The resultant average DLS was 4.2°/100 ft as shown in **Table 8.** The measurements-while-drilling (MWD) tool detected high lateral vibration count in real time, approximately 200 counts per second (CPS) on average. The lateral and axial vibration levels at the RSS were 6 and 3, respectively. In summary, the NB data showed that the bit and BHA were highly unstable.

In the following runs, the bit and BHA instability were eliminated by the use of RS PDC bits. The memory data indicated that actual toolface and offset, as well as NB inclination, were all steady and smooth with both PDC bits used. In addition, the steering housing rotated smoothly at a uniform rotational speed, and the borehole caliper was consistent, with an average borehole size of 12.27 in., indicating a high-quality borehole. Both tests, with the tapered gauge and partial-ring gauge, drilled a smooth borehole, indicating no signs of hole spiraling, with an average DLS of 5.4°/100 ft. The MWD later-

TABLE 8—12¼-IN. DRILL BIT COMPARISON FROM THE RMOTC TEST

12¼-in. bit type	MWD lateral (CPS)	RSS lateral	RSS axial	RSS (SS)%	DLS (°/100 ft)
Milled-tooth	200	6	3	0	4.2
Tapered	0	2	1	0	5.4
Ring	0	3	0.5	0	5.4

TABLE 9—8-IN. POINT-THE-BIT—AVERAGE BUILD RATES, STEERING HIGH SIDE WITH 91% OFFSET

12¼-in. bit type	Inclination range tested (°)	Average build rate (°/100 ft)
2½-in. active	10–30	3.8
2-in. partial ring	30–50	4.0
3¼-in. tapered	10–30	3.9

al vibration count was 0, and the lateral and axial vibration levels at RSS were 2–3 and 0.5–1, respectively. There were no signs of lateral, axial, or torsional vibration problems at the RSS.

Point-the-Bit Results

Tool setup: The 8-in. point-the-bit RSS also had been optimized for spacing touchpoints during initial development (Moody et al. 2004). The standard commercial spacings were used to conduct the bit tests.

Setting: 91% offset

Steerability: The results from testing are shown in **Table 9.** As per the push-the-bit results, the data for the active gauge were invalidated at RMOTC. Prior testing with gauge geometries at the GTI facility did disclose that the active-gauge geometry produced an average DLS of 3.8°/100 ft in the point-the-bit configuration. This reveals that gauge geometry has limited effect on steerability in point mode with the 8-in. tool.

Conclusions

The selection of optimum gauge structure for an RSS drill bit varies widely, depending on the RSS driving mechanism, application, and rock type. Because each RSS on the market is different, the design of an optimum drill bit should be customized for each system.

Systematic testing is required to evaluate the DLS and drillability of the RSS. Achieving high DLS from an RSS is relatively easy, but balancing stability and drillabililty requires more involved testing.

Active gauge produced the highest build rates in the push-the-bit mode testing with both tool sizes. It also delivered high-quality, gauged borehole. The active-gauge testing (in the push-the-bit mode) produced the lowest levels of vibration because of its increased lateral cutting efficiency to the side force applied by the tool.

The tapered gauge lowered the recorded stick-slip because of less friction and drag, compared with conventional parallel-gauge geometry.

Reducing the spacing from the steering unit to stabilizer did increase the maximum build rate in the push-the-bit mode. Increasing spacing between the steering unit and bit in the push-the-bit mode led to a drastic decrease in build rate.

Push-the-bit mode delivered higher dogleg capability than point-the-bit mode, with both size tools.

The gauge geometry had limited effect on steerability in point-the-bit mode, with both tool sizes.

Testing with milled-tooth bits produced high vibration and resulted in wellbore enlargement and low doglegs. In comparison, the RS PDC bits tested displayed very low vibration, gauged borehole, and efficient steering.

Matching the appropriate drill bit and RSS for the specific application results in optimized drillabililty, stability, steerability, and borehole quality.

Acknowledgments

The authors wish to thank PathFinder Energy Services for its willingness to publish the data obtained with the 8½-in.- and 12¼-in.-hole-size PathMaker RSS. We are grateful to PathFinder and ReedHycalog for permitting the publication of this work.

References

Barton S. 2000. Development of Stable PDC Bits for Specific Use on Rotary Steerable Systems. Paper SPE 62779 presented at the SPE/IADC Asia Pacific Drilling Conference, Kuala Lumpur, 11–13 September.

Romo L., Bert D.R., and Richard C. et al. 2006. Optimizing Drilling Operations in the Arkoma Basin: Building on Success. Paper SPE 104598 presented at the SPE Eastern Regional Meeting, Canton, Ohio, 11–13 October.

Barton S., Russell R., and Brooks T. 2002. Specifically Engineered Gauge Structures to Enhance Directional Performance on Rotary Steerable Tools. Paper SPE 77531 presented at the SPE Annual Technical Conference, San Antonio, Texas, 29 September–2 October.

Roberts T. 1998. Development of a New Concept of Steerable PDC Bit for Directional Drilling. Paper SPE 39307 presented at the SPE/IADC Drilling Conference, Dallas, 3–6 March.

Niznik M.R., Carson, A.D, Wise K.J., and Carson F. 2006. New Approach to Stick-Slip Management Integrating Bit Design and Rotary Steerable System Characteristics. Paper SPE 98962 presented at the SPE/IADC Drilling Conference, Miami, 21–23 February.

Sugiura, J., and Jones, S. 2008. Integrated Approach to Rotary-Steerable Drilling Optimization Using Concurrent Real-Time Measurement of Near-Bit Borehole Caliper and Near-Bit Vibration. Paper SPE 112163 presented at the SPE Intelligent Energy Conference and Exhibition, Amsterdam, 25-27 February.

Moody M., Jones S., and Leonard P. 2004. Development and Field Testing of a Cost-Effective Rotary Steerable System. Paper SPE 90482 presented at the SPE Annual Technical Conference and Exhibition, Houston, 26–29 September. JPT