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Systematic Testing with Push- and Point-the-Bit Rotary-Steerable Systems Leads to the Optimal BHA Design for Stability, Steerability and Borehole Quality

Junichi Sugiura* — PathFinder Energy Services, Inc.

* AADE Member

Abstract

This paper presents the development of bottom-hole assembly (BHA) analysis models using simplified mathematical equations. The predictions of BHA bending moment and directional drilling performance of the Rotary-Steerable Systems (RSS) have been examined with extensive field test data taken in a controlled and non-commercial environment, allowing single step changes in both drill bit features and Rotary Steerable configurations.

The testing is unique in that the specific RSS works in field-configurable push-the-bit and point-the-bit modes. Between two distinct RSS operation modes, consistency in stiffness, weight, force applying capability, and control systems leads to a direct comparison of different BHA models.

A unique sensor system, integrated into the specific RSS, provided real-time measurement of near-bit borehole caliper and near-bit stick-slip and vibration [1,2]. This feature allowed real-time evaluation of bit/BHA stability and borehole quality. After each test run, memory data was retrieved and used for more detailed assessment of bit/BHA performance.

BHA configuration tests were systematically structured in a controlled environment so that the relationship between BHA analysis models and actual BHA behavior could be identified. As a result, the systematic testing and verification lead to the conclusion that the BHA models can be used to effectively optimize Rotary Steerable BHA in both push-the-bit and point-the-bit configurations.

Introduction

The RSS technology has remarkably advanced since the first commercial RSS run was documented [3,4,5]. Today, RSS has become a mature technology, and used in a wide variety of directional drilling applications. Due to this RSS technology advancement, the driving principles and mechanisms used in commercial RSS have become significantly diverse.

There are 2 major schools of RSS design: push-the-bit and point-the-bit configurations. Most readers are familiar with this terminology. Since these terms are used in a broad sense, they do not account for the driving principle diversities in their sub-categories. The following section provides a short discussion of each sub-category of point- and push-the-bit RSS.

Push-The-Bit Mode

The push-the-bit mode consists of two major sub-categories of driving mechanisms; 1) applying dynamic side force from a rotating housing [3] as shown in **Figure 1** and 2) applying static side force from a non-rotating housing as shown in **Figure 2**.

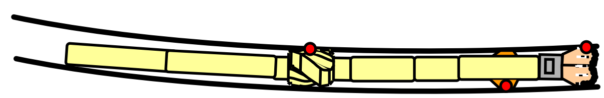

Figure 1: External steering pads on a rotating section

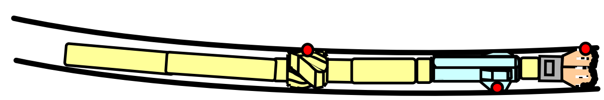

Figure 2: External steering pads on a non-rotating section

In static-side-force push-the-bit tools, a) some RSS steer by computing and setting side force vectors [4,5] with three, four, or five actuator pads, and b) others precisely position the pads to achieve geometrical target with respect to the borehole and its centerline.

The push-the-bit RSS discussed in this paper works in the latter principle (2b), as shown in **Figure 3**.

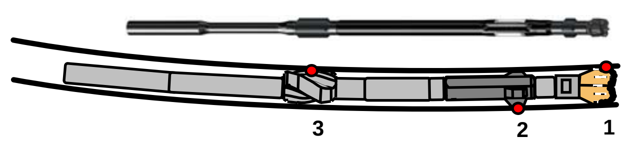

Figure 3: RSS in push-the-bit configuration

Three hydraulically actuated pads in a non-rotating housing position the tool center according to programmed geometrical settings.

Point-The-Bit Mode

In the point-the-bit mode, there are at least 3 major and distinctive ways to tilt the bit; 1) bending a drive shaft inside the non-rotating housing as in **Figure 4**, 2) holding a pre-determined bias with a geo-stationary unit inside a rotating housing as in **Figure 5**, and 3) positioning a non-rotating housing with three pads to tilt a drill bit as shown in **Figure 6**.

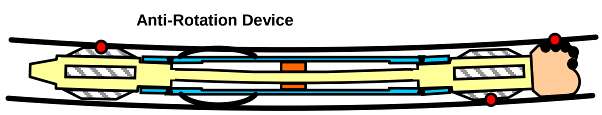

Figure 4: Internally bending driveshaft on a non-rotating housing

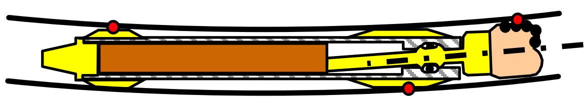

Figure 5: Geo-stationary unit keeps bit tilt angle in a rotating section

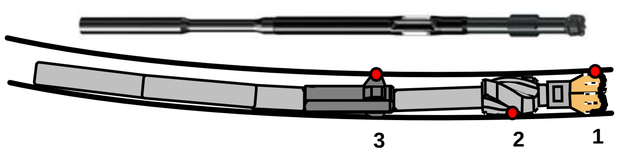

Figure 6: RSS in point-the-bit configuration

The internally deflected shaft used in **Figure 4** can be offset with a pair of eccentric cams in a concentric housing, cams oriented in a pregnant housing, multiple hydraulic pistons, or inflatable packers/hoses. This type of RSS usually includes some sort of anti-rotation mechanism with pads, springs, rollers, hinges and so on, which make contact with the borehole wall.

The geo-stationary unit used in **Figure 5** can include an electric motor or continuously variable transmission (CVT) to internally maintain the tilted shaft steady and geo-stationary, relative to the earth magnetic field or gravity field. The internal geo-stationary unit is housed in a rotating member and the outer housing of the RSS rotates while drilling.

The non-rotating housing with the three pads in **Figure 6** is geometrically biased in a borehole and the drill-bit is tilted, using a full-gauge near-bit stabilizer as a pivoting point. The point-the-bit RSS discussed in this paper works in the latter principle (3), using three hydraulically actuated pads in a non-rotating housing and a pivot stabilizer. In addition to providing a pivoting point, the use of a full-gauge near-bit stabilizer dampens some of the vibrations originating from the drill bit [6].

Thus far we have reviewed the mainstream steering mechanism found in the majority of commercial RSS. In reality, there is no "pure" system that relies solely upon "pushing" or "pointing" the bit. Rather, each system uses both push- and point-the-bit principles. For example, a certain push-the-bit RSS generates bit tilting angle to optimize for steerability and borehole quality. Similarly, the point-the-bit RSS induces bit tilting; however, without the side force at the bit, the bit cannot be tilted or pointed to the steering direction. Whether it is push- or point-the-bit system, the side force and side cutting structures are required at the bit [7].

This paper describes the BHA optimization process of the particular RSS that has field-configurable push-the-bit and point-the-bit modes. The BHA analysis model relies on the unique control mechanism of the RSS, which is a position-based steering.

Rotary Steerable System Tested

This RSS controls drilling trajectory by making all three pads contact with the borehole wall and offsetting/maintaining direction and distance of the tool center from the borehole center [2,7,8]. This trajectory control method is geometry-based (as opposed to force-vector-based) and unique to this particular RSS. This section discusses the advantages of the geometry-based control algorithm in rotary steerable drilling both in push- and point-the-bit configurations.

Unique Steering Mechanism

The advantages of the geometry-controlled steering mechanism are 1) real-time mechanical caliper [2,8,9] can be obtained close to the bit; 2) these pads also act as an anti-rotation device, to hold the steering unit stationary while drilling ahead; and 3) the exact position of the steering unit respective to the borehole is always known.

There are several commercially available push-the-bit RSS that rely on the amount of force applied to a designated toolface in order to steer. Whether the pad force is applied dynamically or statically, the amount of drilling course change is not predictable since the side-cutting depth (or tilting angle) is dependent upon the formation strength.

In the point-the-bit RSS with the internally deflected shaft, the amount of the deflection could be precisely known; however, the geometrical relationship between the outer housing and the borehole wall is unknown. This ambiguity in position hinders the precise prediction of the dogleg severity (DLS). The steerability of this RSS type might tend to be sensitive to borehole gauge.

For example, in a vertical hole, the anti-rotation mechanism might secure the housing in the center of the borehole and, on the contrary, in horizontal wells, the tool housing might lay against the low side of the borehole due to the tool weight.

This scenario might result in the tendency where the maximum build rate is highly proportional to the well angle. For example, a maximum build rate at 10° inclination might be half of the maximum build rate at 90° inclination as shown in **Figure 7** (Excerpted from other literature [10,11]).

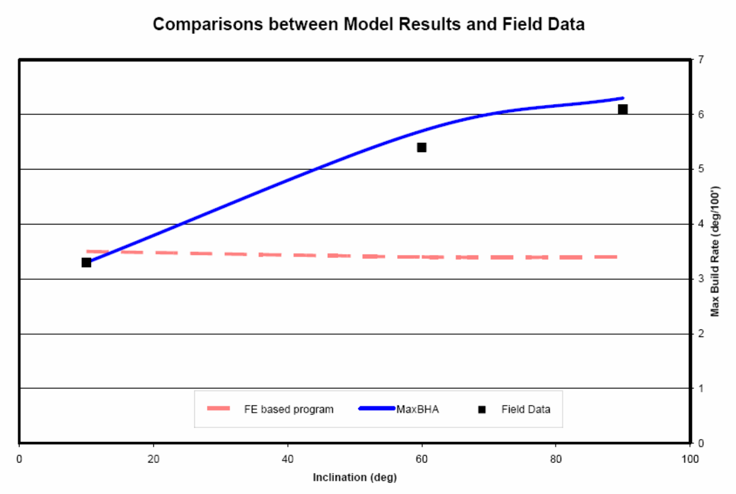

Figure 7: Maximum build-rate changes depending on the hole inclination with the third-party 8 ½"-hole-size point-the-bit RSS. (Excerpted from SPE 101186)

The geometry-based RSS described in this paper has a clear advantage in producing a predictable DLS regardless of the formation strength (or softness) or borehole inclination. The geometry-controlled algorithm prevents the drill bit from excessively side-cutting or bit-tilting when the formation becomes soft. On the contrary, in a hard formation, the RSS applies the maximum actuation force in attempting to achieve the pre-determined offset (or the geometrical target position).

If, for some reason, the drill bit lacks side-cutting ability in a given formation strength or the RSS does not supply the required actuation force, the RSS operator will be aware of these limitations while drilling since the achieved offset is transmitted up to the surface and monitored in real-time. From the real-time achieved offset, the operator can predict the output DLS before the MWD survey data is even transmitted.

The new DLS computation algorithm takes advantage of this unique feature of this RSS control mechanism – a geometry-based steering control in both point- and push-the-bit configurations.

Geometry-Based Build Rate Prediction

As described in the previous section, the side-force vector or duty cycle does not accurately define the borehole geometry. The position of the RSS with respect to the borehole defines the steering course and consequently the drilled and projected borehole geometry. First, this section discusses the DLS prediction based on simple 2-point-contact and 3-point-contact geometries in the push-the-bit mode. The second half of the section explains the DLS capability and side force at the bit in the point-the-bit mode.

2-Point-Contact Geometry – Push-the-Bit

In the push-the-bit mode, a drilling course is changed when pads are extended to achieve a desired offset and the tool center is moved away from the borehole center as shown in **Figure 8**.

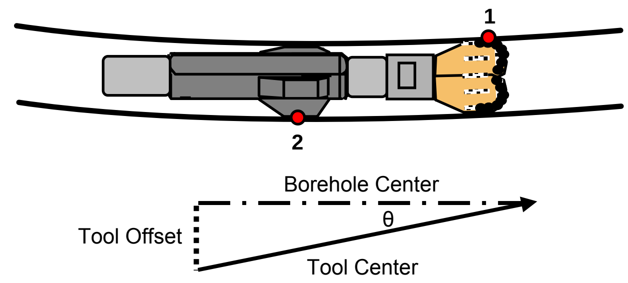

Figure 8: The 2-point-contact geometry in push-the-bit mode

The angle θ indicates the borehole deviation angle. In the figure, touch points are labeled as 1 (at the bit) and 2 (at the pad) respectively. The deviation angle θ can be derived in terms of the tool offset (OS) and the distance between the pads to the bit (d_{12}).

$$\theta = \arcsin\left(\frac{OS}{d_{12}}\right)$$

An expected dogleg severity (DLS) in °/100ft can be derived using the above deviation angle θ and the distance d_{12} in feet.

$$DLS = \frac{360 \cdot 100}{\pi} \cdot \frac{\cos\left(\frac{\pi - \theta}{2}\right)}{d_{12}}$$

Or, more simply, the DLS can be approximated in terms of OS and d_{12} as follows:

$$DLS \approx \frac{180 \cdot 100}{\pi} \cdot \frac{OS}{(d_{12})^2}$$

For example, if OS is 0.3 inches and d_{12} is 4 feet, the deviation angle θ and the predicted DLS will be 0.358° and 8.95°/100ft respectively. The above equation suggests that in order to obtain high DLS, the d_{12} of the RSS must be short with a large OS. The fundamental design of the tool (d_{12}) has more influence on the maximum DLS capability than the amount of OS since the DLS is inverse-proportional to $(d_{12})^2$.

3-Point-Contact Geometry – Push-the-Bit

In a similar way to the 2-point-contact method, a simple 3-point-contact model is constructed. In this model, the geometry of the RSS BHA (between the bit and the sleeve stabilizer) is considered as a maximum DLS constraint. In a high DLS borehole, the RSS body starts to interfere with the borehole wall and limits the maximum DLS. **Figure 9** illustrates this constraint. The touch points are labeled as 1 (at the bit), 2 (at the pad) and 3 (at the stabilizer) respectively. The fourth touch point (at the RSS body) has been introduced in the high dogleg application.

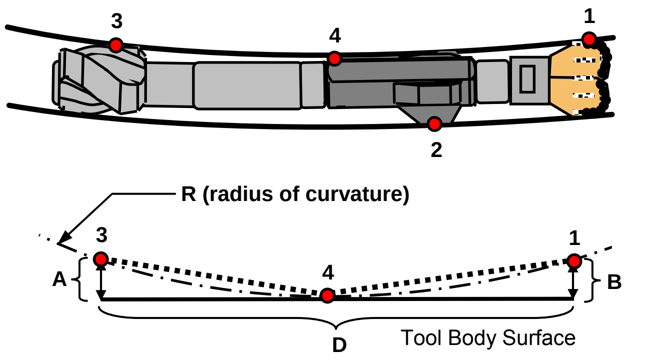

Figure 9: The 3-point-contact geometry in push-the-bit mode

Let us denote the outer diameters (OD) of the bit, tool body, and the sleeve stabilizer as OD_b, OD_t, and OD_s. Dimension D shown in **Figure 9** is the distance between the bit and the string stabilizer (between contact points 1 and 3). Dimensions A and B shown in **Figure 9** can be expressed as follows:

$$A = \left(\frac{OD_s - OD_t}{2} \right)$$

$$B = \left(\frac{OD_b - OD_t}{2} \right)$$

Since the stabilizer OD is smaller than the drill-bit OD but larger than tool OD, the following relationship is known:

$$0 \le A \le B \text{ and } B \ne 0$$

The radius of the borehole curvature denoted R, defined by the touch-points 1, 4 and 2, can be approximated as follows:

$$R \approx \frac{B^2 + \left(\frac{B \cdot D}{A + B} \right)^2}{2 \cdot B}$$

The expected maximum dogleg severity (DLS) in °/100ft can be derived using the above equation with all parameters A, B, and D in feet.

$$DLS \approx \frac{360}{\pi} \cdot \frac{100 \cdot B}{B^2 + \left(\frac{B \cdot D}{A + B} \right)^2}$$

For example, if the bit-stabilizer distance, bit size, tool OD, and the stabilizer OD are 14ft, 10", 9.2", and 9.75" respectively, the predicted maximum DLS (restricted by the tool body profile) will be 5.55°/100ft. The above equation suggests that, in order to obtain high maximum DLS, the RSS OD must be small, and the overall tool length between the bit and the stabilizer should be short.

Bit Side Force – Push-the-Bit

In the push-the-bit configuration, the sleeve stabilizer at the third touch point can provide the BHA with a pivoting point as illustrated in **Figure 10**.

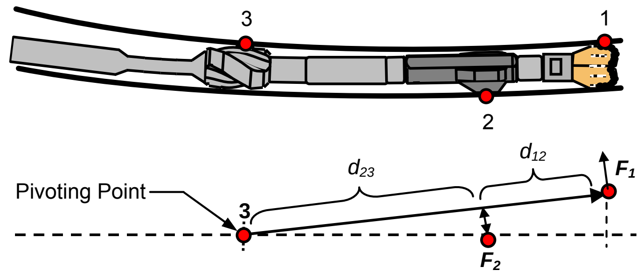

Figure 10: The pivoting point in push-the-bit mode

Let us denote d_{12} and d_{23} as the distance between the bit and pads and the distance between the pads and stabilizer. The RSS tilt angle ϕ can be expressed as follows:

$$\phi = \arcsin \left(\frac{OS}{d_{23}} \right)$$

For example, if OS is 0.3" and d_{23} is 8 ft, The RSS tilt angle ϕ will be 0.188°. The above equation suggests that more pivoting angle can be obtained with more OS and shorter d_{23}.

Let us denote F_1 and F_2 as side forces at the bit (1) and at the pad (2). If we assume the RSS body is rigid and the stabilizer provides a perfect pivoting point, the side force at the bit is expressed as:

$$F_1 = \frac{d_{23}}{d_{12} + d_{23}} \cdot F_2$$

For example, if d_{12} is 4 feet, d_{23} is 8 feet, and F_2 is 10klbs, the side force at the bit F_1 will be 6.67klbs. If d_{12} is 1 feet, d_{23} is 8 feet, and F_2 is 10klbs, the side force at the bit F_1 will be 8.89klbs. The shorter the distance between the bit and the pad, the more side force at the bit can be applied with the same amount of the pad force at the steering unit.

2-Point-Contact Geometry – Point-the-Bit

Many point-the-bit systems take advantage of "pivoting" to tilt the drill bit in the desired direction. For example, the back side of a long passive gauge bit (typically used in point-the-bit configuration) provides the pivoting point, and its drilling course can be easily changed through the use of "mechanical advantage."

Similarly, a full-gauge near-bit stabilizer is used in this particular RSS to provide necessary pivoting to the lower part of the BHA. Pads are extended to achieve a desired offset and the tool center is moved away from the borehole center, which in turn tilts the drill bit with the near-bit stabilizer, as illustrated in **Figure 11**.

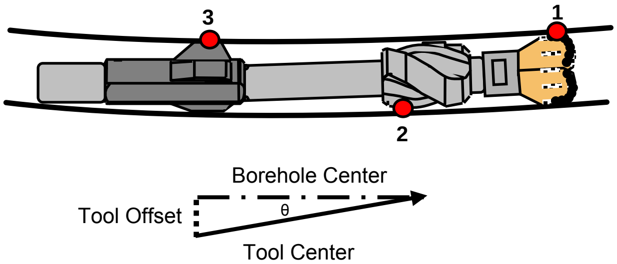

Figure 11: The 2-point-contact geometry in point-the-bit mode

The angle θ indicates the borehole deviation. In the figure, touch points are labeled as 1 (at the bit), 2 (at the stabilizer), and 3 (at the pad) respectively. The deviation angle θ can be derived in terms of the tool offset (OS) and the distance between the pads to the near-bit stabilizer (d_{23}).

$$\theta = \arcsin\left(\frac{OS}{d_{23}}\right)$$

An expected dogleg severity (DLS) in °/100ft can be derived using the above deviation angle θ and the distance d_{23} in feet.

$$DLS = \frac{360 \cdot 100}{\pi} \cdot \frac{\cos\left(\frac{\pi - \theta}{2}\right)}{d_{23}}$$

Or, more simply, the DLS can be approximated in terms of OS and d_{23} as follows:

$$DLS \approx \frac{180 \cdot 100}{\pi} \cdot \frac{OS}{(d_{23})^2}$$

For example, if OS is 0.3 inches and d_{23} is 4 feet, the deviation angle θ and the predicted DLS will be 0.358° and 8.95°/100ft respectively. The above equation suggests that in order to obtain high DLS, the d_{23} of the RSS must be short with a large OS.

Bit Side Force – Point-the-Bit

In the point-the-bit configuration, the full-gauge near-bit stabilizer at the second touch point can provide the BHA with a pivoting point as illustrated in **Figure 12**.

Let us denote d_{12} and d_{23} as the distance between the bit and stabilizer, and the distance between the stabilizer and pads. The RSS tilt angle ϕ can be expressed as follows:

$$\phi = \arcsin\left(\frac{OS}{d_{23}}\right)$$

The above equation suggests that a greater pivoting angle can be obtained with more OS and shorter d_{23}.

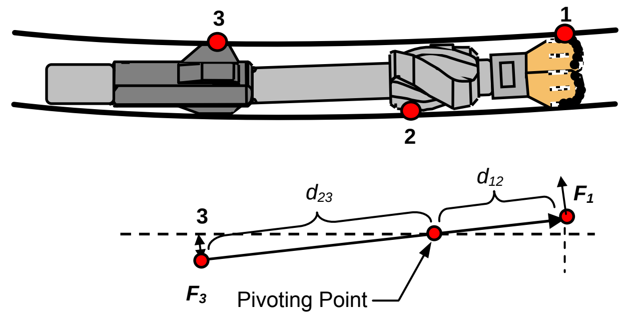

Figure 12: The pivoting point in point-the-bit mode

Let us denote F_1 and F_3 as side forces at the bit (1) and at the pad (3). If we assume the RSS body is rigid and the stabilizer provides a perfect pivoting point, the side force at the bit is expressed as:

$$F_1 = \frac{d_{23}}{d_{12}} \cdot F_3$$

For example, if d_{12} is 2 feet, d_{23} is 4 feet, and F_3 is 10klbs, the side force at the bit F_1 will be 20klbs. If d_{12} is 1 feet, d_{23} is 4 feet, and F_3 is 10klbs, the side force at the bit F_1 will be 40klbs. The shorter the distance between the bit and the pivoting point, the more side force at the bit can be applied with the same amount of the pad force at the steering unit. This is an effective use of "mechanical advantage" in the RSS application. For this reason, some point-the-bit RSS prefer to use long passive gauge bits [12] (gauge length between 8" and 16") as shown in **Figure 13**.

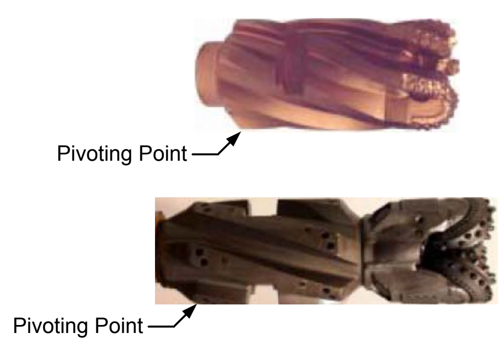

Figure 13: Examples of the long-gauge bits (Excerpted from SPE 77218)

These bits are known to produce a high-quality borehole and utilize "mechanical advantage" to intensify the side force near the bit face. Though a long-gauge PDC bit can generate high dogleg in a gauged hole, the dogleg capability quickly diminishes in an overgauged hole [13]. The resultant dogleg is very sensitive to the slightest borehole enlargement (between 0.010" and 0.050").

Rotary Steerable Bits

Systematic drill-bit testing with the particular RSS in both push- and point-the-bit modes has been well documented in other literature [14]. Extensive PDC bit testing was conducted to identify the best gauge designs for this RSS in both push- and point-the-bit configuration because subtle differences in gauge design can lead to significant changes to the directional drilling response of the given RSS configuration.

One aspect of bit design quality that influences wellbore quality is the ability to stabilize the lower part of BHA since lateral and torsional vibration will contribute to wellbore enlargement. BHA instability can have a significant negative effect on the RSS performance.

Another aspect of the important bit design quality is the steerability, which affects the amount of response to a bit side force. Some RSS require a high-side cutting ability of a bit for particular high DLS applications. In general, an optimized bit gauge design, matched with a given RSS, provides effective side cutting and gauge stabilization that leads to best steerability, BHA stability and borehole quality.

Jones et al. reported that an active gauge PDC bit, in combination with this push-the-bit RSS, produces highest build rate while providing the highest lateral, axial, and torsional stability [14].

Test Facilities

Confidential, neutral test sites were selected for evaluating different rotary-steerable BHA configurations in both push-the-bit and point-the-bit modes. The systematic BHA testing was conducted in two different facilities: 1) the GTI Catoosa Test Facility near Tulsa, Oklahoma and 2) the Rocky Mountain Oilfield Test Center (RMOTC) near Casper, Wyoming.

Both facilities provided adequate geological variations and rig/pump capabilities for the RSS tests in 8 ½" and 12 ¼" hole sizes [15,16]. With no directional constraints at either of the facilities, they both offered a perfect test ground for controlled BHA testing.

Test Results

Since 2004, the point-the-bit and push-the-bit RSS have been extensively tested with various hole sizes (8 ½", 8 ¾", 12 ¼", and 16 ½") and different BHA configurations. The BHA tests have been conducted in controlled and non-commercial environments both at the GTI Catoosa and RMOTC Wyoming facilities. For optimal test results, it was necessary to drill the same formation at exactly the same TVD, 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 using various RSS configurations and at the same time evaluate the system for stability, steerability and borehole quality. Due to the confidential nature of these test results, the exact contact-point spacings and outer diameter (OD) of stabilizers and steering units will not be published. However, changes in length are published.

BHA Optimization – Push-the-Bit

To optimize the 6 ¾" push-the-bit BHA for maximum build rate, different spacings were tested with a 1 ½" active gauge bit. The distance between the steering unit and bit face was varied, as was the distance between the steering unit and the 3rd touch point (at the sleeve 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 Push + Spacer. These configurations are shown in **Figure 14**.

Figure 14: Various push-the-bit BHAs tested in RMOTC: 1) Long Push, 2) Short Push, 3) Long Push + Spacer and 4) Short Push + Spacer

The difference between Long Push RSS and Short Push RSS was a 1.5ft length increase between the steering unit and the 3rd touch point stabilizer. Both long-shaft and short-shaft versions were then tested with and without a 7" spacer sub inserted between the steering unit and the bit.

All build-rate tests were carried out on an 88% deflection (offset) setting. As an initial benchmark test, the 1 ½" active gauge bit was run on the Short Push RSS. Reducing the spacing from steering unit to 3rd touch point stabilizer by 1.5ft had the effect of increasing the build rate to 11.4°/100ft. 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" spacing increase between the steering unit and the bit. From the results shown in **Table 1**, it is quite clear that this extra spacing had a drastic effect on reducing build rate. The build rates were reduced by approximately 4°-5°/100ft.

Table 1: 6 ¾" Push-the-Bit Configurations – Average Build Rates in °/100ft steering High Side with 88% offset

8 ½" Bit Type	6 ¾" LONG	6 ¾" SHORT	6 ¾" LONG + 7"	6 ¾" SHORT + 7"
Results	9.9	11.4	5.0	7.5
FEA Model	11.4	14.9	3.4	6.78
New Model	9.5	10.0	4.0	7.0

The FEA-based model predicted higher build rates on Long and Short tools without a spacer. On the contrary, the geometry-based model predicted lower build rates on these tools.

BHA Optimization – Point-the-Bit

To optimize the 6 ¾" point-the-bit BHA for maximum build rate, different spacings were tested with a 3" passive gauge bit. The distance between the near-bit stabilizer and bit face was varied, as was the distance between the steering unit and the near-bit stabilizer. The three different configurations that were tested have been named Short Point (short-spacing point-the-bit), Long-2-3 Point (long-spacing between 2 and 3), and Long-1-2 Point (long-spacing between 1 and 2). These configurations are shown in **Figure 15**.

Figure 15: Various point-the-bit BHAs tested in RMOTC: 1) Short Point, 2) Long-2-3 Point, and 3) Long-1-2 Point

The difference between Long-2-3 Point RSS and Short Point RSS was a 2.8ft length increase between the steering unit and the near-bit stabilizer. The difference between Long-1-2 Point RSS and Short Point RSS was a 2.8ft length increase between the bit and the near-bit stabilizer.

All build-rate tests were carried out on an 100% deflection (offset) setting. Short Point RSS produced 10°/100ft while two other Long Point systems yielded 5-7°/100ft as shown in **Table 2**.

Table 2: 6 ¾" Point-the-Bit Configurations – Average Build Rates in °/100ft steering High Side with 100% offset

8 ½" Bit Type	6 ¾" SHORT	6 ¾" LONG-2-3	6 ¾" Long-1-2
Test Result	10.0	5.5	7.0
FEA Model	11.1	5.4	7.3
New Model	9.0	4.0	6.5

It is clear that this extra spacing between the steering unit and the near-bit stabilizer had a drastic effect on reducing build rate. The build rates were reduced by approximately 4°-5°/100ft. The extra spacing between the bit and near-bit stabilizer did not have as much drastic effect as the other configuration. This extra spacing reduced the build rate by 3°/100ft. The FEA-based model predicted higher build rates on most tools. The geometry-based model predicted lower build rates on all tools.

6 ¾" Point-the-Bit BHA Build-up Tendency

In 2005 and 2006, 6 ¾" point-the-bit RSS was tested at the GTI Catoosa to identify its build-up tendency from near-vertical to near-horizontal hole angles. The point-the-bit RSS BHAs that we tested had a very similar BHA to the optimized one that we use commercially today. The RSS was tested with both 8 ½" and 8 ¾" PDC bits for continuous build-up.

Figures 16 and 17 show the continuous build-up tendency in 8 ½" and 8 ¾" holes respectively.

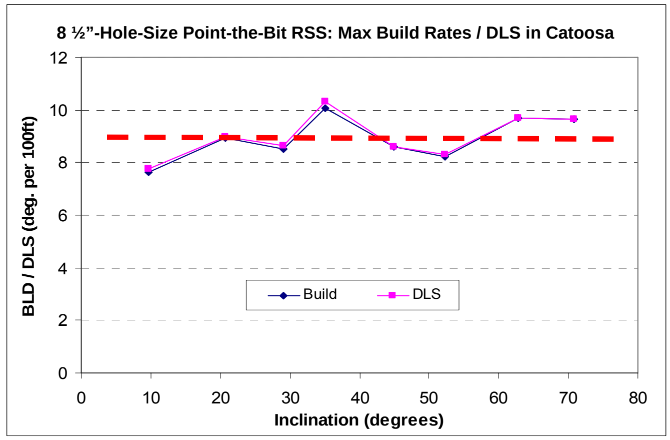

Figure 16: The 8 ½"-hole-size point-the-bit RSS: Continuous Build-up Test in Catoosa.

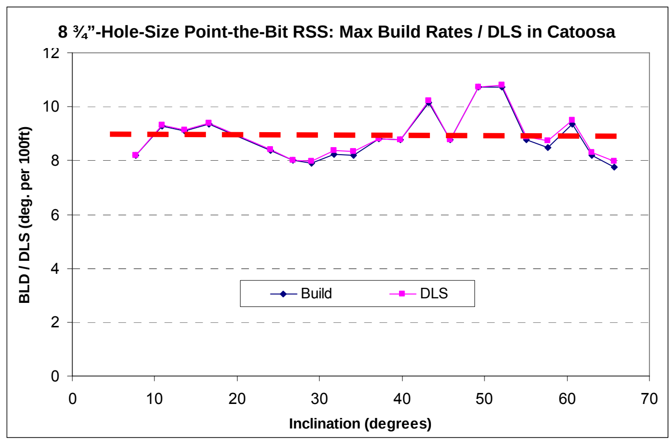

Figure 17: The 8 ¾"-hole-size point-the-bit RSS: Continuous Build-up Test in Catoosa.

Since the static survey was taken only once in a continuous run, no averaging over several runs was applied. Even though the build rate data was influenced by statistical errors and formation tendencies, we can clearly see the near-flat build-up response of the RSS at inclinations from 10° to 70°. Also, the toolface control (resultant toolface) was very accurate and, consequently, the build rate was very close to the DLS.

6 ¾" Point-the-Bit and Push-the-Bit Comparison

In RMOTC, both the point- and push-the-bit configurations drilled in the same formation (Steele) with similar surface parameters (WOB = 10 ~ 12 klbs, rotary speed = 100 RPM, and flow rate = 400 ~ 440 GPM). The offset was set at 98% and 88% respectively. In the tests, concurrent near-bit 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 [2,14,17]. **Figures 18 and 19** show the memory data retrieved from the two optimal assemblies.

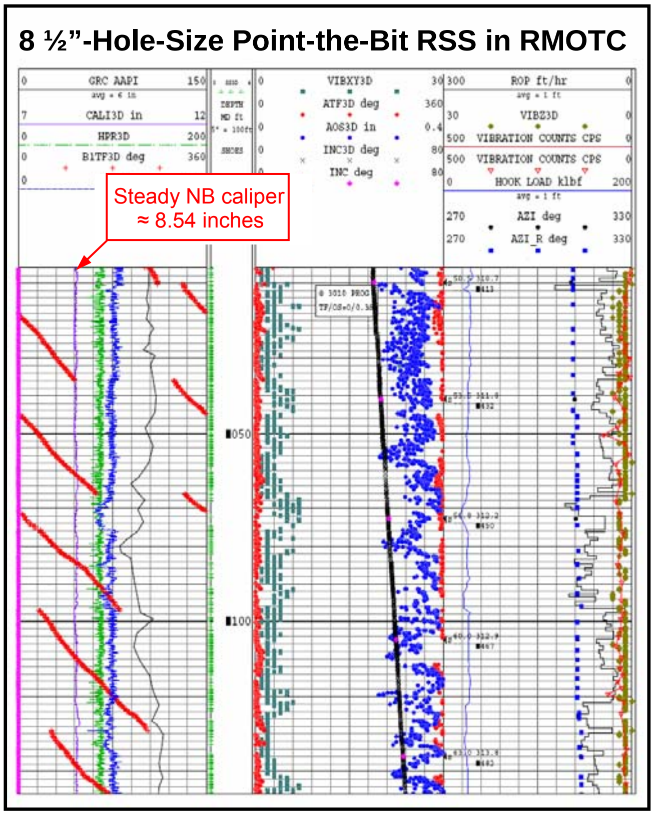

Figure 18: The maximum build rate test with an 8 ½”-hole-size commercial point-the-bit BHA (w/ 98% deflection).

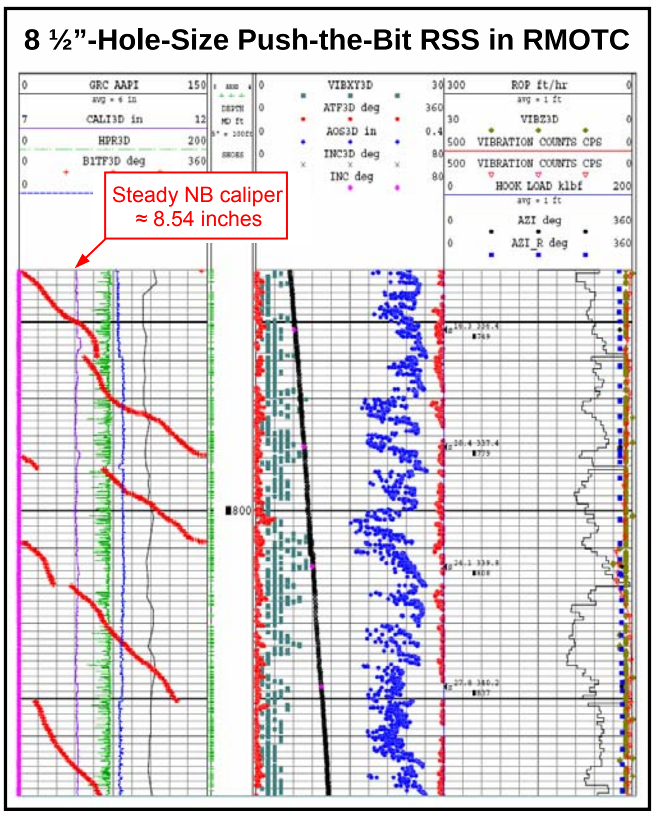

Figure 19: The maximum build rate test with an 8 ½”-hole-size prototype push-the-bit BHA (w/ 88% deflection).

Both BHAs exhibited similar ROPs, good lateral and axial stability, and borehole quality (consistent gauged borehole) as shown in **Table 3**.

Table 3: A comparison table of ROP, build rate, borehole quality and vibration between 8 ½”-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
RPM	100	100
WOB	12Klbs	10 Klbs
Tool Offset	0.39” (98%)	0.35” (88%)
ROP	49.3 ft/hr	49.0 ft/hr
DLS	10.2°/100ft	11.5°/100ft
Build Rate	10.0°/100ft	11.4°/100ft
Mean Caliper	8.536”	8.544”
Caliper Deviation	0.020”	0.022”
Housing Roll	0.84 rev/hr	1.25 rev/hr
Lateral Vibration	6.6	6.5
Axial Vibration	2	1

There were no signs of borehole ledging or spiraling with either configuration. The only notable difference between the two is the average build rate, which was 10.0°/100ft in point-the-bit mode with 98% deflection, compared to 11.4°/100ft in push-the-bit mode with an 88% setting. In the point-the-bit configuration, the maximum build rates tend to be higher with a partial ring gauge bit than that with a 3” passive gauge bit.

Conclusions

- 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.
- Increasing spacing between the steering unit and the full-gauge near-bit stabilizer in the point-the-bit mode led to a drastic decrease in build rate.
- A simple BHA model has been developed to predict maximum DLS capability of the particular RSS in push- and point-the-bit configurations. Its DLS prediction closely matched with the field test data taken in a controlled environment.

- A simple BHA model simulated optimum rotary steerable BHAs for maximum DLS in both push- and point-the-bit configurations.

- Push-the-bit mode delivered higher dogleg capability than point-the-bit mode with this particular RSS.

- Systematic testing is required to evaluate the dogleg and drillability of rotary steerable systems. Achieving high dogleg from an RSS is relatively easy, but balancing stability and drillability requires more involved testing.

Acknowledgments
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Nomenclature

BHA	=	*Bottom-Hole Assembly*
DLS	=	*Dogleg Severity (degrees per 100 feet)*
GPM	=	*Gallons Per Minute*
LWD	=	*Logging While Drilling*
MD	=	*Measured Depth*
MWD	=	*Measurement While Drilling*
NB	=	*Near Bit*
OD	=	*Outer Diameter (or Outside Diameter)*
PDC	=	*Polycrystalline Diamond Compact*
ROP	=	*Drilling Rate Of Penetration*
RPM	=	*Revolutions Per Minute*
RS	=	*Rotary Steerable*
RSS	=	*Rotary Steerable System*
SS%	=	*Stick-slip Severity in Percentage*
TD	=	*Target Depth*
TVD	=	*True Vertical Depth*
VS	=	*Vertical Section*
WOB	=	*Weight On Bit*

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