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## **EXPERIMENTAL AND ANALYTICAL STUDY OF THE SIDE CUTTING ABILITY OF DRILL BITS**

### **1. INTRODUCTION**

Drilling highly deviated wells such as extended reach and horizontal wells is frequently encountered in drilling operations. Drilling a highly deviated wellbore is more expensive compared to conventional vertical well and a substantial portion of drilling operation costs comes from the use of PDC drill bits. Therefore, improving the efficiency of the drill bits would result in a significant reduction of the costs and non-productive time (NPT) of drilling operation. This in turns requires a comprehensive knowledge of bit and rock interaction. Even though several studies have been conducted in this area, they were mainly focused on face-cutting efficiency without much emphasis on the side-cutting ability. The side-cutting ability is an important characteristic of drilling bits, particularly for PDC drill bits. Side-cutting ability directly impacts deviation control, wellbore stability and borehole quality, drilling performance parameters, tripping operations, cuttings transport performance, casing running assurance, real-time data acquisition, drag and torque, etc. Therefore, conducting research on side cutting ability of PDC bits would eliminate/reduce many problems originated by bit-formation interaction.

### **2. OBJECTIVES AND APPROACH**

#### **BHA Modeling**

In the directional drilling process, the Bottom-hole Assembly (BHA) transfers load and torque to the bit which should have the ability to drill both axially and laterally.

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Oil and Gas industry currently lays more emphasis on the axial or face cutting ability of the drill bit and side cutting ability is usually ignored during planning, executing, and evaluating the drilling process and drill bit performance.

A study of the side cutting ability cannot be done without considering the BHA mechanical performance. For the sake of simplicity, we considered a “slick” BHA which consists of drill collars (DC) of constant geometry. Based on the mechanical properties of the DC, the slick assembly can be treated as an elastic beam and analyzed following the theory of solid mechanics. Based on simplifying assumptions, a force and moment equilibrium balance is performed over the elastic beam by assuming free ends. Solving this equilibrium balance, would give us the forces and moments along the BHA which are also called “state variables.” A knowledge of these variables along the BHA makes it easier to understand the effect of the BHA over the drill bit in different drilling conditions.

Nowadays, drilling a directional well requires more complex, so-called directional BHA made of several elements that include drill collars, stabilizers, and bent-sub. Similar assumptions that were considered for a slick BHA are also considered for directional BHA. Thus, the state variables for a directional BHA can be determined. The governing equations can be arranged in a matrix form which can be solved using Transfer Matrix Method (TMM) to enable faster computations. Details of the TMM approach can be found in [8].

Drill bits are divided into two main types: roller cone bits and fixed cutter bits. Roller cone bits have nil side cutting ability while fixed cutter bits have this ability. Considering this contrast in side cutting ability, these two types of drill bits were tested. Drilling tests were conducted using the Tulsa University Drilling Research Project (TUDRP) full-scale drilling rig. The tests considered the use of both the slick and a semi-directional BHAs. The semi-directional BHA simulates the performance of a common directional BHA used in the field. This semi-directional BHA uses a bent sub-element right above the bit. The purpose of the bent-sub is to create an intentional side force in the bit. The results of the mathematical model can be compared with the observed torque measurements during the experiments. The model has the flexibility to use directional data and back calculate the drill bit steerability (side cutting ability) from offset wells. This information can be used for future perfection of drill bit selection and directional performance prediction as part of the well design process.

For a conventional directional BHA (including bent housing + stabilizers), the TMM can be written as below:

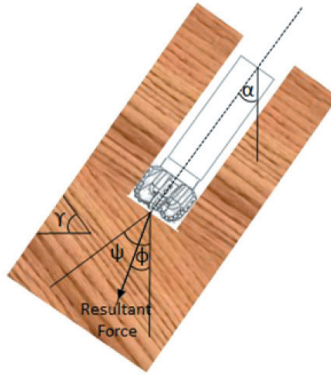
$$\begin{bmatrix} \pm c \\ 0 \\ 0 \\ h_f \\ 1 \end{bmatrix} = [T_n] \left\{ [P_{n-1}] \dots [T_3] [P_2] [T_2] [P_1] [T_1] + [P_{n-1}] \dots [T_3] [P_2] [T_2] [P_1] \begin{bmatrix} 0 \\ C_1 \\ \Delta r_1 \\ 0 \\ 0 \end{bmatrix} \right\} \quad (1)$$

All derivations related to Eqn. (1) are given in reference [8].

## Bit-Formation Interaction

The second factor that influences the side cutting ability of a PDC drill bit is the bit-formation interaction. The term *drilling anisotropy index* ( $h$ ) introduced by Lubinski and Woods (1953) is used for quantitative predictions of drill bit penetration direction while drilling in anisotropic formations. It is defined as the relative difference of drillabilities parallel and perpendicular to bedding planes (Fig 1). More details are provided in reference [4].

$$h = 1 - \frac{\tan(\gamma_f - \phi)}{\tan(\gamma_f - \phi)} \quad (2)$$



**Fig. 1.** Different drilling drill abilities according to the bedding plane angles

When both formation and drill bit are isotropic, the wellbore is drilled in the direction of the resultant force angle. Also, drilling direction tends to reach the hole equilibrium angle if the drilling conditions are kept constant. The equilibrium hole angle is reached for nil side force at the bit. At this condition the resultant force angle equals the inclination angle, leading to  $h = 0$ .

A second case can be considered if the formation is assumed to be anisotropic but the drill bit isotropic. For this case, the following equation determines the new hole inclination angle (looking ahead of the bit) given the side force at the bit, WOB, and the resultant force angle.

$$\phi = \gamma_f - \tan^{-1} \left[ (1-h) - \tan(\gamma_f - \phi) \right] \quad (3)$$

A third case considers an isotropic formation but anisotropic drill bit. In this case, the drill bit has a side cutting ability, and its face cutting ability is different from the side

cutting. Typically, the drill bit face cutting ability is higher than its side cutting ability. The relative difference to drill in axial and lateral directions is the so-called *bit anisotropy index (BAI) or bit steer-ability* [1]. By assuming isotropic formation but an anisotropic bit, a third case is generated. This case assumes that there is a difference between axial and lateral bit drill abilities. Commonly, the drill bit face cutting ability is higher than its side cutting ability. The relative difference between drilling in axial and lateral directions is the so-called bit anisotropy index (BAI), introduced by Miska et al [9]. For this case, knowing the side force at the bit, WOB, tilt angle ( $\beta$ ), and an estimated BAI [9], the new hole inclination angle ( $\delta$ ) can be obtained using the Eqn. (4).

$$\delta = \alpha + \beta - \tan^{-1}[(1 - \text{BAI})\tan(\alpha + \beta - \phi)] \quad (4)$$

Based on these three cases, different types of computations can be conducted. Knowing bit and formation characteristics, drilling conditions can be optimized for the desired wellbore angle. On the other hand, if the drilling conditions are known (field data) the drilling anisotropy index can be estimated. Therefore, for deviation control purposes, the BHA mechanics, drilling conditions, and the bit-formation interaction contribute to the directional drilling control.

The last (fourth) case considers anisotropic conditions for both the drill bit and formation. It is understood at this point that a formation is characterized by the drilling anisotropy index ( $h$ ), also known as formation anisotropy index (FAI) when  $\phi = \psi$ . The drill bit is characterized by the bit anisotropy index (BAI). Knowing BAI and FAI, the resultant bit displacement can be determined. The BAI and FAI values can be obtained from already drilled wells. The closest approximation to determine the BAI is as follows:

$$\text{BAI} = 1 - \frac{\tan(\beta)}{\tan(\beta - \phi)} \quad (5)$$

Different concepts are discussed in references [2, 3, 4, 6 and 7].

However, a better determination of BAI and FAI can be obtained by conducting experimental test.

### 3. EXPERIMENTAL DRILLING TESTS

The Tulsa Drilling Research Projects (TUDRP) full-scale experimental drilling rig was used for experimental study. It is called full-scale because it simulates a real drilling rig but in a scale dimension. It includes all the components that are needed to drill with a conventional rig using the rotary drilling principle.

## TUDRP full-scale drilling rig

In the TUDRP full-scale drilling rig, the rotary table, drill bits, and the formation to be drilled are exactly as they are in the field.

The data acquisition system consists of a software that allows controlled drilling while recording the drilling variables. The variables that control the drilling rate are WOB, RPM, and GPM. Once these variables can be controlled, bit torque will be a result of only bit-formation interaction. The variables that are not controlled by the drilling operator but only recorded are torque, bit position, rate of penetration (ROP), and pressure along the drilling fluid system.

Figure 2 shows pictures of the TUDRP full-scale drilling rig.

a)

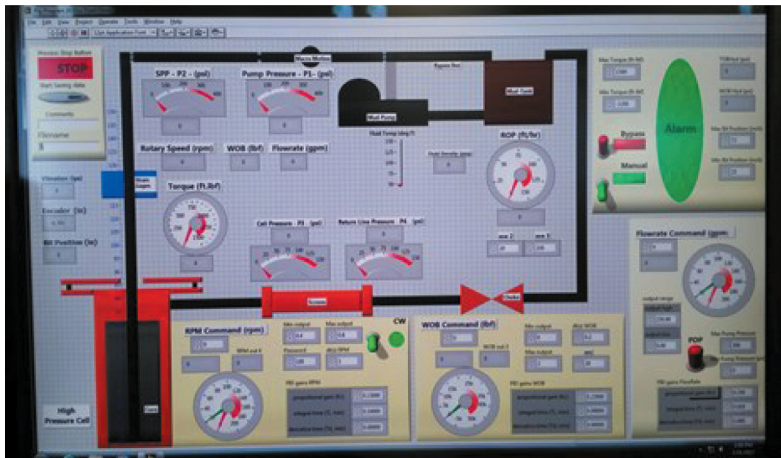


b)



**Fig. 2.** TUDRP full-scale drilling rig

The experimental rig can be manually operated while the data is recorded. If the manual operation mode is used, the drilling occurs, but drilling variables cannot be accurately controlled. To avoid this inaccuracy, the automated drilling mode can be used (Fig. 3).



**Fig. 3.** Scaled rig automatized system screen

This mode helps the operator to set constant drilling variables such as GPM, RPM, and WOB and allows the user to record 15 different measurements, each of which is recorded ten times per second. The drilling data is stored as long as the drilling test last. Regarding the data acquisition system, the next image shows the screen of the automated drilling mode.

### Drilling test preparations

Previous research related to bit side cutting ability included moving parts that push the bit laterally. The purpose of this pushing is to create a side force at the bit, which results in the lateral drilling. In contrast, the TUDRP drilling rig has a rigid and static pressure cell. The pressure cell is the device that holds the formation core to be drilled. Because of the simplicity of the TUDRP experimental setup, the more complex pushing lateral force setup was discarded. To create a bit side force, a bent-sub was placed above the bit with the expectation that bent-sub will distribute the WOB in axial and lateral forces. The lateral force component at the bit is the lateral WOB transferred through the bent-sub that makes lateral drilling possible.

Based on field experience, a common bent housing sub deflection ranges from 1.15 to 3.0 degrees; thus, based on this criterion, a 2 degrees bent-sub deflection was used in our experimental tests. Figure 4 shows the setup for the two stages of the planned drilling tests.

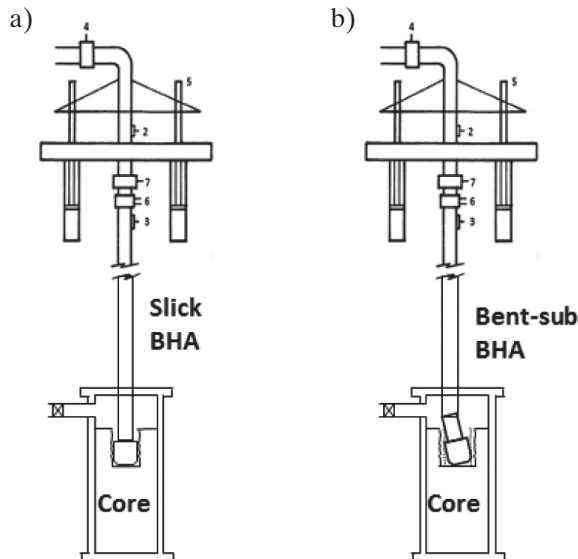


Fig. 4. TUDRP experimental drilling test setup

Figure 4a shows the experimental setup for a slick BHA, which does not include the bent-sub. In Figure 4b a bent sub is included in the BHA.

To test our objective, the drill bits must be tested in two drilling configuration – and without a bent sub. If drilling variables (WOB, RPM and GPM) remain constant, we expect, the only variable that may change between these drilling tests would be the torque on bit.

### Drilling bits and bent-sub

Based on the TUDRP bit inventory, four 8.5 in. bits were selected; two PDC and two tri-cone bits. Figure 5a presents an 8.5 in. PDC bit with five blades having the primary cutters of 13 mm in diameter. Figure 5b shows an 8.5 in. PDC bit with nine blades and primary cutters of 13 mm size. Figure 5c shows an 8.5 in. tri-cone bit with insert teeth. Figure 5d presents a 7.375 in. tri-cone bit with milled-tooth. All these bits have the same type of connector i.e. 4.5 in. REG pin. An advantage of TUDRP experimental rig is that the shaft or drill collar has a 4.5 in. REG box type of connector. Thus, both the bit and drill collar (DC) can be directly connected to each other with no need of an intermediate connector sub.

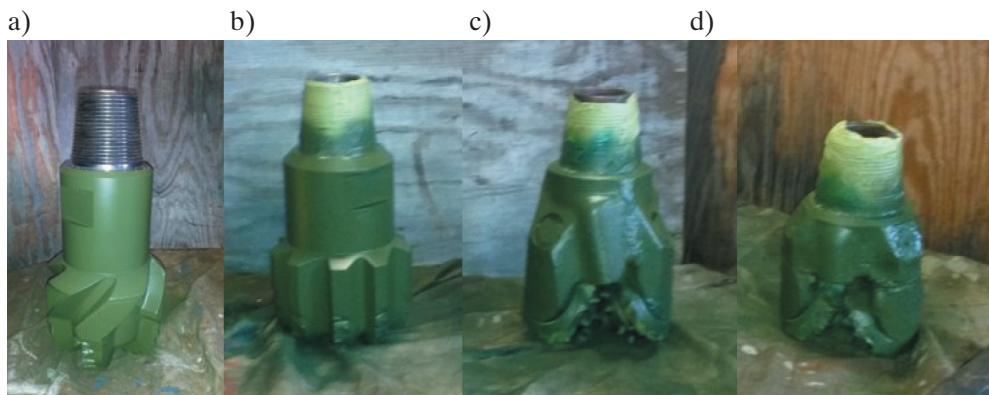
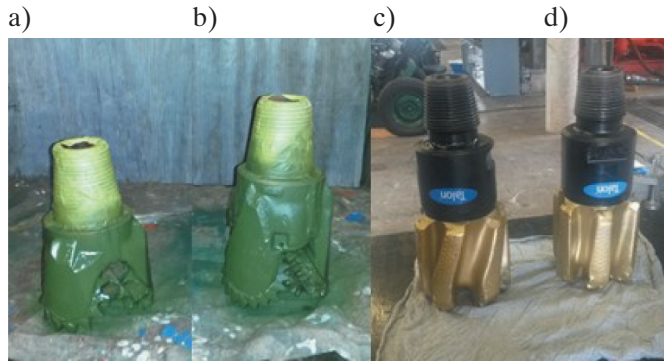


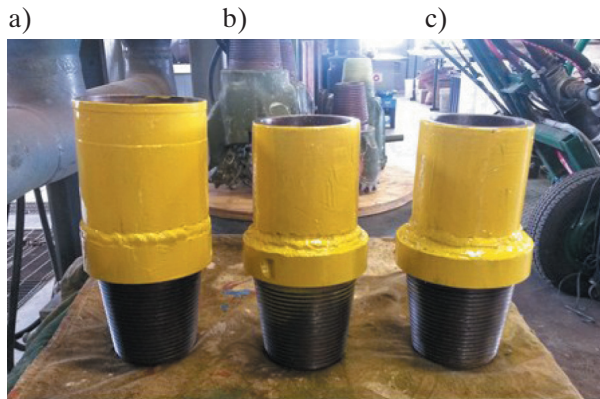
Fig. 5. TUDRP refurbished 8.5 in. drill bits

The next set of drilling tests includes drill bits with 6 in. diameter (Fig. 6). For this bit size, a couple of them were refurbished from TUDRP bit inventory; additionally, two more bits were provided by Baker Hughes. Figure 6a and Figure 6b the 6 in. tri-cone bits with milled-tooth, which were refurbished. Figure 6c and Figure 6d shows the two 6 in. PDC bits with 13 mm primary cutters size. The all four 6 in. bits have a 3.5 in. REG pin type of connector.





**Fig. 6.** The 6 in. drill bits



**Fig. 7.** Manufactured sub and bent-subs

The connector sub and bent-subs were manufactured in TUDRP. Figure 7a shows the bent-sub needed

to connect the 8.5 in. bits to the drill collars (DC); this bent-sub has 2 degrees of deflection. Figure 7b shows the connector sub required to connect the 6 in. bits to the drill collar (DC); this sub is not deflected as the other two bent-subs from the same figure. Figure 7c shows the smaller bent-sub required to connect the 6 in. bits with the drill collar (DC); this bent-sub has 2 degrees of deflection. Notice that the deflection angle is perceptible in Figure 7a and Figure 7c.

### **Drilling test setup**

To conduct drilling tests with appropriate drilling conditions, test matrix (Tab. 1) was implemented. As mentioned in the previous section, torque on bit is the only variable that is expected to change with different types of BHAs. The constant variables include the flow rate of 120 gpm, WOB equal to 6000 lbf., and the rotational speed of 60 RPM.

Every drill bit was tested twice making a total of eight drilling tests.



**Table 1**  
Test drilling matrix

Variable	Value	Unit
Flow rate	120	gpm
Angular Velocity	70	rpm
Weight on bit	6 000	lbf
Drilled length	15	in

The final bit selection is shown in Table 2.

**Table 2**  
Selected drill bits

Type of drill bit	Type of teeth	Primary cutter Size [mm]	Diameter [in]	Bit height [in]	Size of REG pin connection [in]	Bit provider
Tri-cone	Inserted	–	8.5	10.25	4.5	TUDRP
PDC	–	13.4	8.5	14	4.5	TUDRP
Tri-cone	Milled	–	6	5.25	3.5	TUDRP
PDC	–	13.4	6	10.625	3.5	Baker Hughes

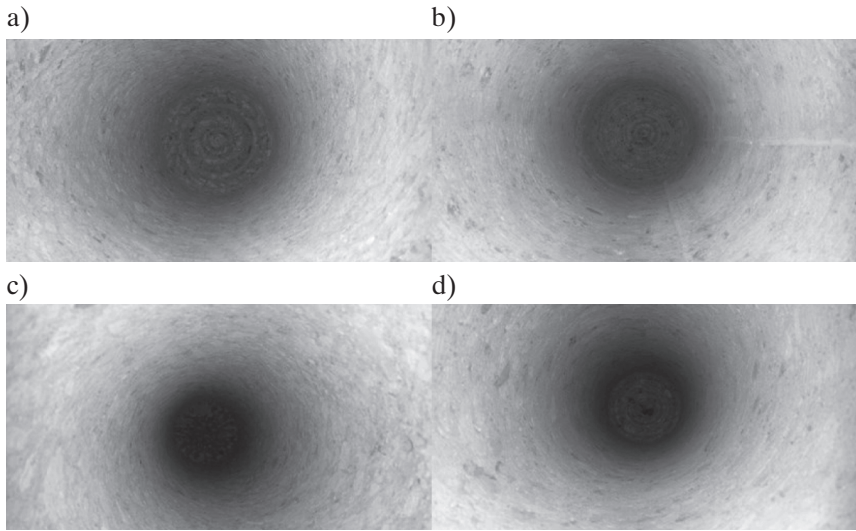
## 4. RESULTS AND DISCUSSION

### Qualitative drilling test results

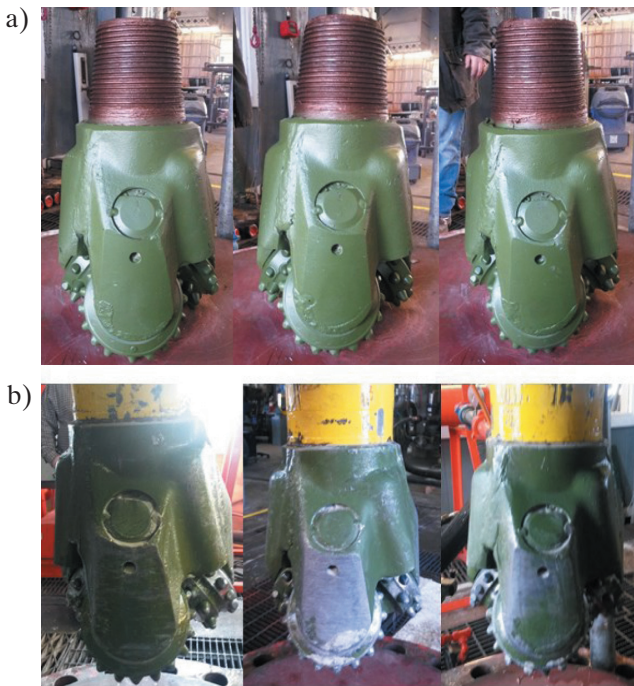
The experimental setup can be used for simulating drilling conditions for typical drill bits used by the drilling industry to qualitatively determine the severity of the bit wear. The bits were painted with an opaque green color. Pictures of bent sub and drill bit before and after the test were taken. Pictures of the wellbore were also taken as shown in Figure 8.

Careful observation of the pictures shows a difference in wellbore roughness for wells drilled with a PDC bit and tri-cone bit. Clearly, the tri-cone bits produce the wellbore wall rougher as compared to PDC bits. Therefore, in our opinion, one can expect better quality of cementing jobs in wells drilled with PDC bits as compared to roller cone bits.

The observed bits wear is shown in Figure 9.



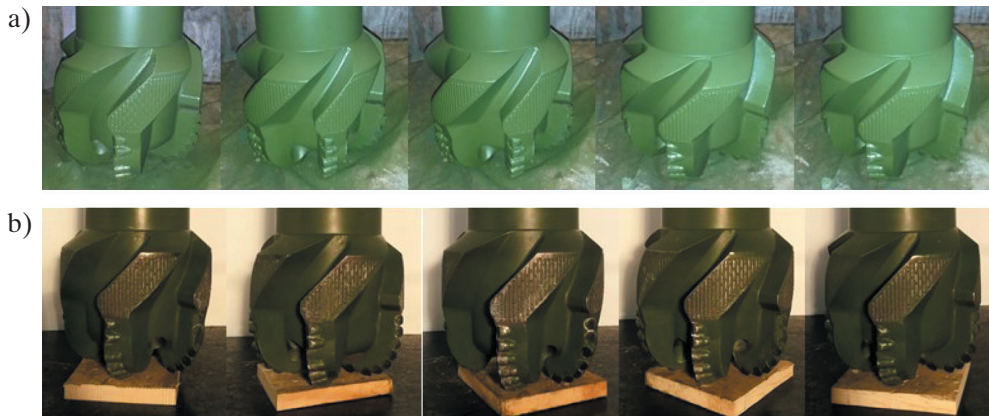
**Fig. 8.** Wellbore wall quality from drilled wellbores: a) 8.5 in. tri-cone bit – insert teeth; b) 8.5 in. PDC bit – 5 blades; c) 6 in. tri-cone bit – milled teeth; d) 6 in. PDC bit – 6 blades



**Fig. 9.** The 8.5 in. tri-cone drill bit wearing condition. Bit shoulders are numbered (1–3) from left to right: a) 8.5 in. tri-cone bit before the drilling test with bent-sub BHA; b) 8.5 in. tri-cone bit after the drilling test with bent-sub BHA

Figure 9a shows the bit shoulders for the 8.5 in. tri-cone bit. The bit wearing exposed after the drilling test was completed, is shown in Figure 9b. It can be observed that bit shoulder number 2 has the maximum worn area, which depends on the bit – bent-sub alignment.

A similar wearing is generated when the PDC bit is tested; the wearing of this bit is showed in Figure 10. Notice that the biggest worn area occurs in the blade number 5, the rest of the blades show lower wearing based on the original bit paint coat.



**Fig. 10.** The 8.5 in. PDC drill bit wearing condition. Bit shoulders are numbered (1–5) from left to right: a) 8.5 in. PDC bit before the drilling test with bent-sub BHA; b) 8.5 in. PDC bit after the drilling test with bent-sub BHA

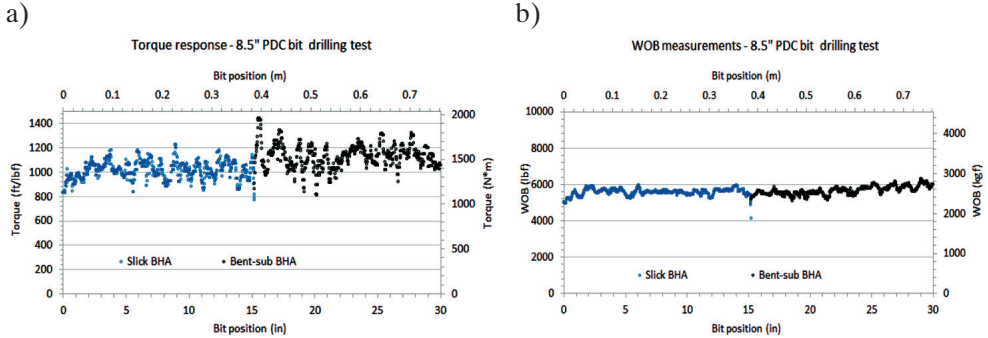
## Experimental drilling test results

As mentioned before, four drill bits were tested which required eight drilling tests. Every drilling test records 15 drilling variables which are stored in the data acquisition system. Among these variables, the bit position is a reference variable for all tests; any other recorded variable during the test can be plotted with respect to bit position. Notice that bit position is related to the rate of penetration (ROP) variable; this is because ROP is the drilled footage in a determined time. Some of the interesting results are presented below:

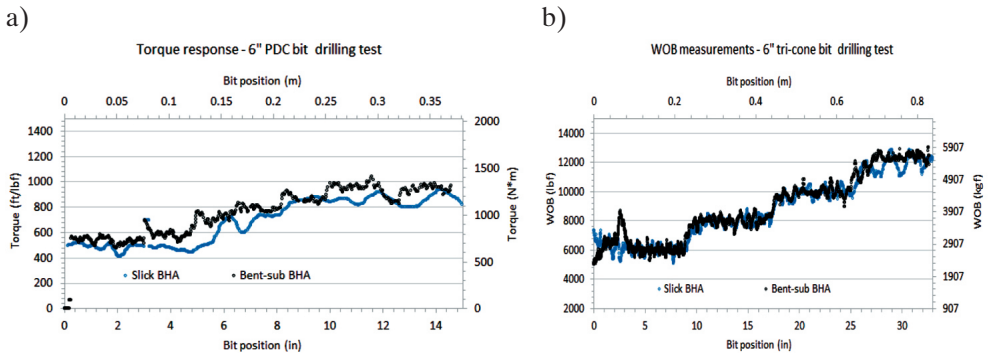
### 1. Torque vs bit position for slick BHA and bent-sub BHA, constant WOB and changing WOB.

As shown in Figure 11, for a constant WOB of about 6000 lbf. and a constant RPM of about 65, the torque values for a bent-sub BHA is higher than that of slick BHA in case of 8.5 in. PDC drilling bit. Similar results were observed for same operating

conditions in case of 8.5 in tri-cone bit. However, the values for PDC drill bit were approximately three times higher than tri cone roller bit. When the WOB was varied, as shown in Figure 12, the Torque value increased with the increase in WOB. However, the values were higher for bent-sub BHA as compared to slick BHA.



**Fig. 11.** Torque response for 8.5 in. PDC bit drilling test (a) and WOB measurements for 8.5 in. PDC bit drilling test (b)



**Fig. 12.** Torque response for 6 in. PDC bit drilling test (a) and WOB measurements for 6 in. PDC bit drilling test (b)

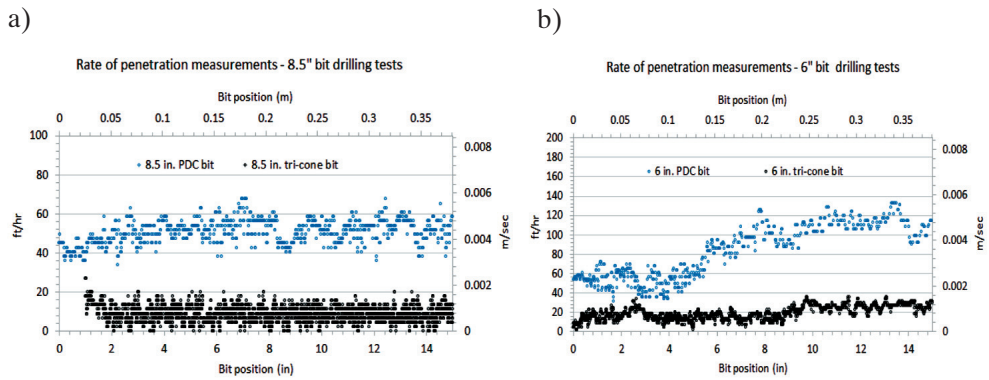
## 2. Computed torque – application of Warren Equation.

The computed torque was originally referred as empirical torque and derived by Warren (1984); his purpose was to determine the factors that affect bit torque [10]. Despite the fact that this research was conducted for tri-cone bits, it can also be applied to PDC bits. To determine the computed torque, a normalization of drilling variables is needed. The computed torque is determined by the following equation:

$$M = \left[ a + b \sqrt{ROP / (RPM \cdot d)} \right] WOB \cdot d \quad (6)$$

where:  $d$  is the bit diameter in inches, WOB is measured in thousands pounds force, ROP is measured in feet per hour, and RPM is measured in revolutions per minute (RPM). The parameters  $a$  and  $b$  are obtained from the normalized drilling variables plot. This normalization is obtained by plotting  $\frac{M_{real}}{WOB \cdot d}$  on the vertical axis with respect to  $\sqrt{ROP/(RPM \cdot d)}$  on the horizontal axis. The variable  $a$  is the intercept point when the squared root term is zero. On the other hand, the  $b$  variable is the slope of the plotted curve. In addition to these variables,  $M_{real}$  term represents the measured bit torque.

Since ROP is involved in the torque computation, it would be helpful to study the ROP response from previous drilling test. The next figures show the ROP response for each bit test. These plots give a physical sense to the reader of how fast or time consuming this type of drilling test are. From Figure 13, it can be observed in both drilling cases that ROP from PDC drill bits is higher than the ROP from tri-cone bits.

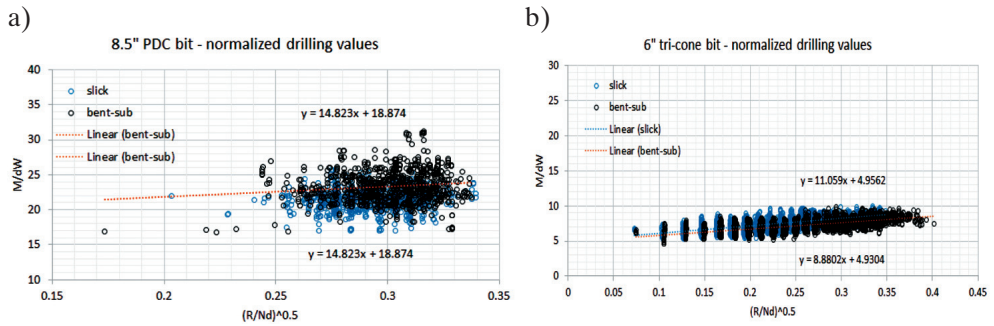


**Fig. 13.** ROP performance of the 8.5 in. drill bits (a) and ROP performance of the 6 in. drill bits (b) for slick BHA assembly

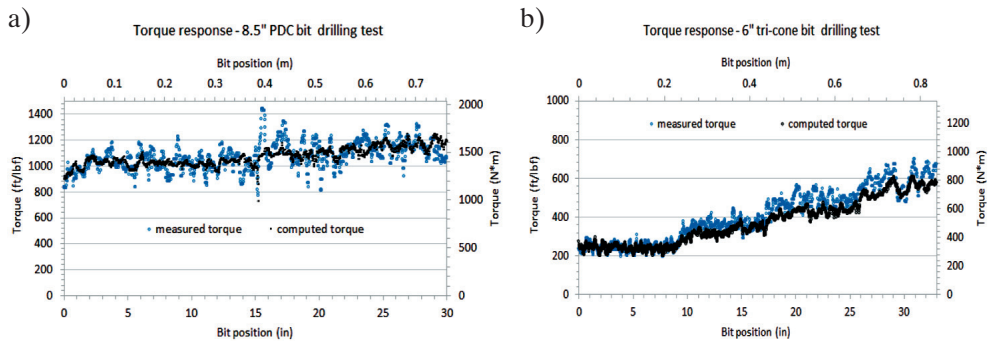
### 3. Computed torque vs measured torque.

The parameters  $a$  (intercept) and  $b$  (slope of the plotted curve) from the Warren equation (6) were obtained by plotting normalized variables (Fig. 14). Then, the parameters were substituted in the Warren equation to compute the torque values. Subsequently, the computed torque values were plotted against the measured torque, as shown in Figure 15.

It can be seen from Figure 15 that a very good match was observed between measured torque and computed torque for PDC bits. Similar results were observed for tri-cone roller bits.



**Fig. 14.** Calculating variables  $a$  and  $b$  for 8.5 in. PDC drill bit (a) and for 6 in. tri-cone drill bit (b)



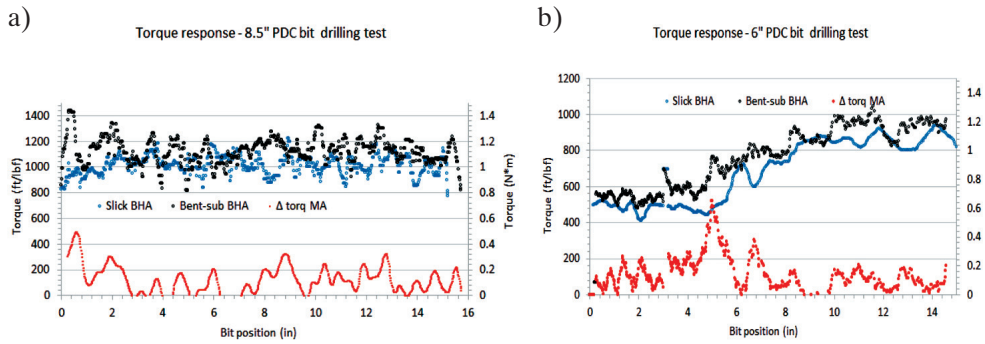
**Fig. 15.** Torque comparison for 8.5 in. PDC drill bit (a) and for 6 in. tri-cone drill bit (b) slick BHA assembly

#### 4. Relative difference in torque values.

Based on this unique experimental setup and the conducted drilling tests, it can be concluded that the relative difference in torque response between the slick BHA and the deflected BHA indicates a quantitative contribution to the side cutting ability of a drill bit. To visualize this relative difference, a plot that shows the magnitude of two drilling cases for the same type and size of drill bit is shown in Figure 16.

Figure 16a shows the relative difference in torque measurements (in red color) for 8.5 inch PDC bit. This difference ranges between 0 and 0.2 with a mean value of 0.13. A similar analysis is conducted for the drilling test with 6 in. PDC bit size, as shown in Figure 16b. The relative difference in this second drilling test ranges from 0 to 0.2 with a mean value of 0.16. Notice that Figures show results for PDC type of bit only. No torque difference was observed while testing tri-cone bits.





**Fig. 16.** Relative difference in torque measurements of slick and deflected BHA for 8.5 in. PDC (a) and 6 in. PDC bit drilling test (b)

Of the many state variables determined from BHA mechanical analysis, the magnitude of the side force at the bit is of relatively large importance. Since the torque required is directly related to the side forces/contact forces, the relative difference in bit side force magnitude is proportional to the relative difference in torque measurements. As shown in Figure 15, the relative difference of torque measurements from drilling test with PDC bits and different types of BHA is within the range of 0 to 0.3. This difference is the result of the observed torque while drilling with a slick BHA and drilling with a bent-sub BHA.

The relative difference of bit side force computed by transfer matrix method averages 0.15. The magnitude of this relative difference approximates the magnitude of the relative difference from torque measurements. In fact, both results show that there is a difference in bit side force and bit torque that can be related to the bit side cutting ability.

## 5. SUMMARY

The experiments conducted for this research work are unique and has no precedent in TUDRP. Although previous research in bit side cutting ability involved different types of experimental drilling tests, none of those test included a bent-sub to study this subject before. The conclusions presented in this research are limited by these type unique experimental setup. This means that the obtained results are not generalized and do not apply for any other type of experimental drilling test. However, they can be used as reference value if similar drilling conditions are reached.

Experimental drilling tests produced interesting drilling performances using different types of drill bits and different types of BHAs. The drilling performance of tri-cone

bits does not change for different types of BHAs. In the case of PDC drill bits, different torque response was observed for different types of BHAs. Based on the drilling performances, the 8.5 in. PDC bit with medium parabolic profile and combined gauge design presented a positive relative difference in torque measurements that varies from 0 to 20%. This means that higher torque measurements were observed with the use of this type of bits with the bent-sub BHA. Regarding the Warren equation validation, a very good match was observed between the drilling measurements and the computed torque values. The normalized plots included in this analysis can be used as reference values for drilling tests with similar drilling conditions.

## NOMENCLATURE

### List of abbreviations:

- BAI – Bit Anisotropy Index
- FAI – Formation Anisotropy Index
- BHA – Bottom Hole Assembly
- ROP – Rate of Penetration
- RPM – Revolution per Minute
- WOB – Weight on Bit

### Greek letters:

- $\alpha$  – wellbore inclination angle
- $\beta$  – tilt angle
- $\gamma_f$  – formation dipping angle
- $\Delta r$  – dimensionless deflection
- $\varphi$  – weight on bit angle or hole equilibrium angle
- $\phi$  – resultant force angle

### Other notations:

- $M$  – computed torque
- $a, b$  – variables in Warren Equation
- $h$  – anisotropy index
- $d$  – bit diameter

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