AGH DRILLING, OIL, GAS • Vol. 33 • No. 2 • 2016

http://dx.doi.org/10.7494/drill.2016.33.2.341

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EXPERIMENTAL STUDY OF LAYOUTS OF PDC CUTTERS IN CORE BIT DRILLING

1. INTRODUCTION

Drill bits are critical components in the drilling process. Their significant impact over the entire project economics is unquestionably recognized around the world. This key role has demanded a very detailed evaluation of the elements and parameters involving the interaction between the drill bit and the rock. Currently, PDC bits represent the type of fixed-cutter bits where most efforts are being conducted. This is due to new challenging drilling scenarios where Roller-Cone bits are considered as high risk. Notably, PDC cutter arrangements play a major role in bit drilling efficiency and bit stability.

Core PDC bits are PDC bits with reduced cutting area. Core bits are used to recover core samples from the target rock formations. These have to produce smooth and minimally fractured cores that are closer to gauge diameter. As regular drilling bits, the core bits need to ensure a reasonable ROP with a minimum wear of cutters. Because of the reduced cutting structure compared to PDC bits, PDC core bits represent a first step in evaluating drilling efficiency.

The study of drilling efficiency has been broadly documented in the industry and is commonly defined in terms of the mechanical-specific-energy concept or work required to remove a unit volume of rock. This energy consumption can be measured during drilling operations and, consequently, different bit performances can be compared using this concept.

In the past two decades, many studies have been done to understand the interaction between a single PDC cutter and formation rocks [2, 12, 14]. As a result, various single-cutter force models have been developed that consider formation properties, cutter back rake and side rake angles, cutter chamfer size, DOC or cutting area, and pore pressure. These single-cutter force models have been extensively used to model the interaction of a PDC bit with formation rocks. Although the bit models are able to calculate some bit characteristics with acceptable accuracy, such as cutter engagement area and bit force balance conditions, the ability of bit models to predict bit drilling efficiency is usually

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inadequate. Thus far, no conclusions have been drawn experimentally from layouts of PDC cutters for a given formation under a given set of operational parameters. Therefore, more effort is required to understand the influence of cutter arrangements on bit drilling efficiency. In addition, developing experiments with a full-scale test rig is one of the most cost-effective and practical methods to evaluate bit performance.

This study was primarily focused on investigating the effect of the layout of PDC cutters on drilling performance. Therefore, the main objective of this study was to perform an experimental study of PDC cutter arrangements to investigate their effect on core bit drilling efficiency.

2. EXPERIMENTAL FACILITY

TUDRP successfully upgraded its full-scale drill rig between 2013 and 2015. Extensive research on drill bits has been developed using the TUDRP full-scale test rig [3, 7, 9] (Fig. 1). This is located in a 50-ft. tower at the University of Tulsa North Campus facility. The rig is divided into three main systems: the circulating system, the pull-down and rotary system (hydraulic system) and the data acquisition and measurement system. The upgrade work included the design and implementation of a new data acquisition platform. The main purpose was to replace the old PLC-based system with a modern and reliable PC-based data logger that meets the requirements of a laboratory full-scale drilling simulation. As a result, the data acquisition process has been greatly improved, which allows for more accurate interpretation of experimental data.

The current circulating system can work through one of two independent units, a centrifugal pump or a mud duplex pump. The drilling mud flows through the rotary hose, circulating head, Kelly pipe, drill collar and the bit into the high pressure cell located in the drill floor (Fig. 2). Drilling fluid and formation cuttings generated by the bit action exit through a nipple on the side of the pressure cell to a screening assembly. The fluid enters the side of the assembly, deposits the cuttings on the outside surface of a cylindrical sand control screen, and continues through the center of the screen and out of it. The clean mud then flows through the back pressure choke and into the mud tanks, located at the second floor of the tower. The mud is then pulled into the pumps and the cycle is repeated.

The pressure cell can hold a 14-inch diameter core sample with a maximum length of 4 ft. Seal assemblies contained in the top flange of the pressure cell prevent fluid from escaping through the cell's interface with the drill collar. A set of bolts secures the top flange to the rest of the cell assembly. Rotary speed, rotary torque and WOB are controlled by a hydraulic system located on the second floor of the tower. The rotational power is supplied by a hydraulic system (two hydraulic pumps) through a two-speed transmission and a rotary table for speeds up to 120 rpm and a corresponding maximum torque of 3,000 ft-lb. The pull-down force is achieved by the action of a hydraulic pump that applies fluid pressure to pistons in the two pull down cylinders. This hydraulic system that powers the raising and lowering of the drill stem can produce up to 45,000 lbs. of bit load and the drill stem has a 10-ft stroke. The drilling mechanism is supported at different levels in the tower to provide space for different lengths of drilling tools.

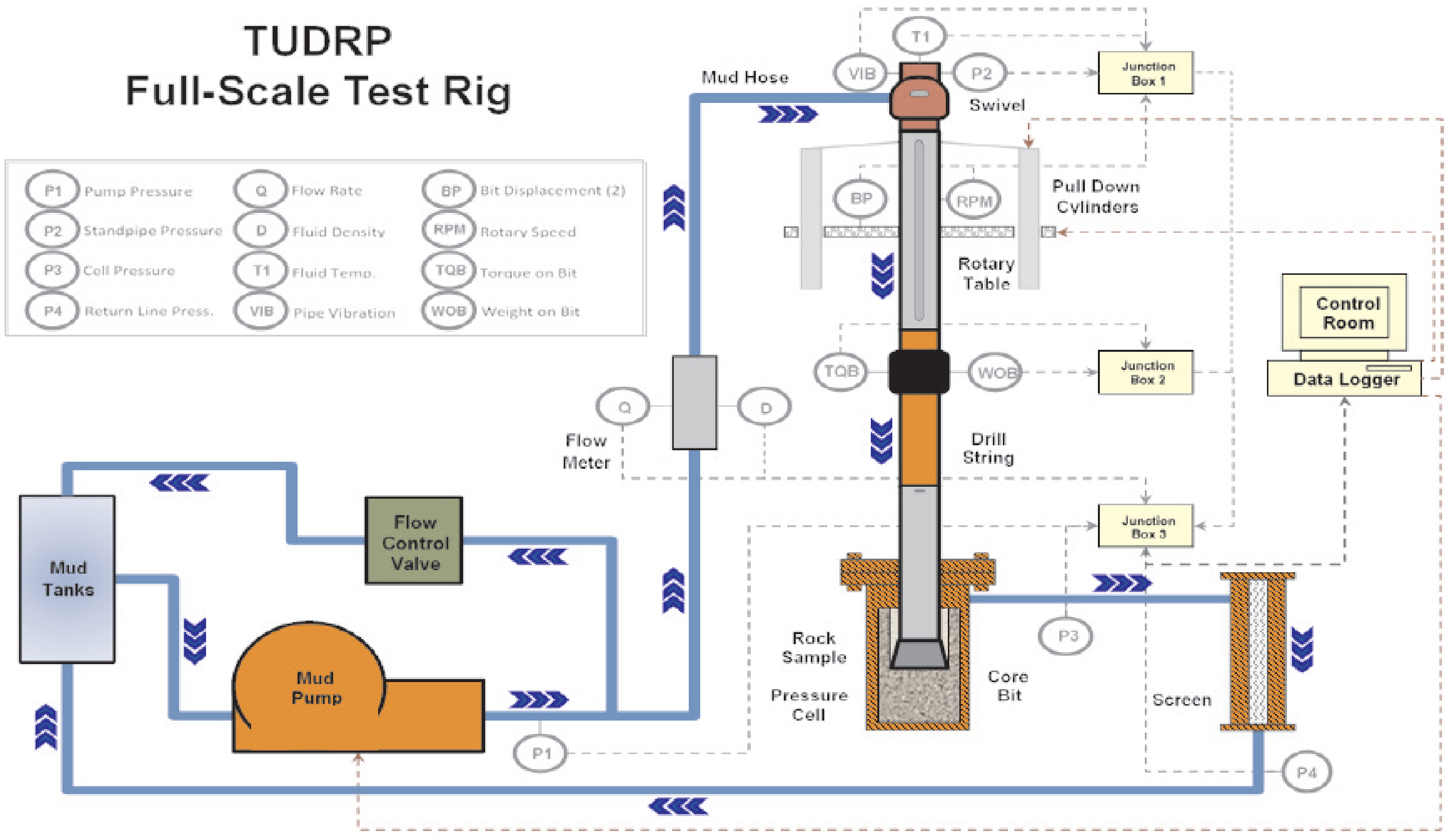


Fig. 1. TUDRP full-scale test rig

Fig. 2. TUDRP Rig. Drill floor: Rig lower level

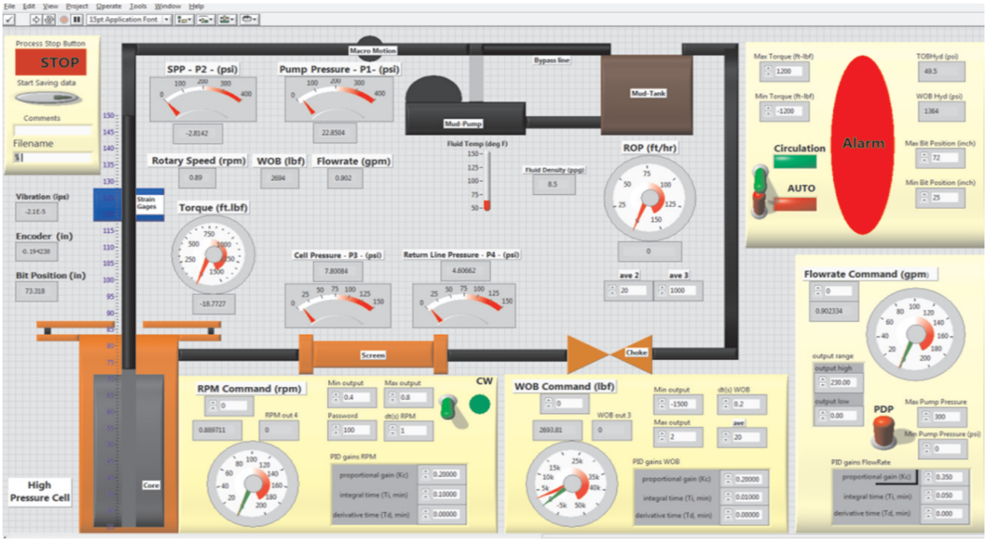
The data acquisition system currently consists of a set of measuring and control devices, junction boxes, wired connections, control panel and a PC-based data logger. Instruments are located around the tower, incorporated into the operating systems (circulating and hydraulic systems) and physically connected to the control room (Fig. 3) to allow monitoring or controlling of all the drilling variables (Tab. 1, Fig. 4).

Fig. 3. TUDRP Rig. Control Room: PC-based data logger and control panel

Table 1

Drilling variables and signal sources

No.	Variable	Unit	Instrument Type	Location
1	Pump pressure	psig	Pressure Transducer	Drill Floor
2	Volumetric flow rate	gpm	Coriolis Flow and Density Meter	Drill Floor
3		%	Pneumatic Flow Control Valve	Drill Floor
4	Fluid density	lb/gal	Coriolis Flow and Density Meter	Drill Floor
5	Fluid temperature	deg F	Resistance Temperature Detector	Top of Drill string
6	Drill string vibration	ips	Vibration Transmitter	Top of Drill string
7	Standpipe pressure	psig	Pressure Transducer	Top of Drill string
8	Rotary speed	rpm	Magnetic Pulse Tachometer	Rotary Table
9		psig	Pressure Transducers (Control)	Hydraulic Floor
10	Bit position	in	Linear Position Gauge	Rotary Table
11		in	Rotary or Shaft Encoder	Rotary Table
12	Weight on Bit	lbf	Strain Gauges	Drill string
13		psig	Pressure Transducer (Control)	Hydraulic Floor
14	Torque on Bit	ft-lbf	Strain Gauges	Drill string
15	Cell pressure	psig	Pressure Transducer	Drill Floor
16	Screen pressure	psig	Pressure Transducer	Drill Floor
17	Time	sec	PC	Control Room
18	Rate of penetration	ft/hr	Calculated	Control Room



SPP - P2 - (psi) -2.8142
Pump Pressure - P1- (psi) 22.8504
Rotary Speed (rpm) 0.89
WOB (lbf) 2694
Flowrate (gpm) 0.902
Fluid Temp (deg F)
Fluid Density (ppg) 8.5
ROP (ft/hr) 0
Vibration (ips) -2.1E-5
Encoder (in) -0.194238
Bit Position (in) 73.318
Torque (ft.lbf) -18.7727
Cell Pressure - P3 - (psi) 7.80084
Return Line Pressure - P4 - (psi) 4.60662
ave 2 20
ave 3 1000
Max Torque (ft-lbf) 1200
Min Torque (ft-lbf) -1200
TOBHyd (psi) 49.5
WOB Hyd (psi) 1364
Max Bit Position (inch) 72
Min Bit Position (inch) 25

RPM Command (rpm) 0
0.889711
RPM out 4 0
Min output 0.4
Max output 0.8
Password 100
dt(s) RPM 1
PID gains RPM
proportional gain (Kc) 0.20000
integral time (Ti, min) 0.10000
derivative time (Td, min) 0.00000

WOB Command (lbf) 0
2693.81
WOB out 3 0
Min output -1500
Max output 2
dt(s) WOB 0.2
ave 20
PID gains WOB
proportional gain (Kc) 0.20000
integral time (Ti, min) 0.01000
derivative time (Td, min) 0.00000

Flowrate Command (gpm) 0
0.902334
output range
output high 230.00
output low 0.00
Max Pump Pressure 300
Min Pump Pressure (psi) 0
PID gains FlowRate
proportional gain (Kc) 0.350
integral time (Ti, min) 0.050
derivative time (Td, min) 0.000

Fig. 4. TUDRP Rig. LabView front panel: Data acquisition platform

3. TEST CORE BITS AND LAYOUTS OF PDC CUTTERS

The core PDC bits were provided by Halliburton DBS. The initial concept of an eight-blade PDC core bit, with radially movable cutters for laboratory tests, was modified slightly to better fit the actual application and evolved to a core bit design with a common body and replaceable heads (Tab. 2, Fig. 5).

The study included experiments to evaluate different layouts of PDC cutters. Regarding the cutter arrangements, the PDC cutters are laid out in six different ways: Single Set or Base, Behind Track Set, Opposite Track Set, Track Loc, Pair-Cutter Groups (Single Set) and Two-Cutter Groups (Single Set) (Figs 6–12). These layouts allow a constant maximum DOC per cutter of 0.25 in.

For a flat bit profile, a Single Set cutter layout is defined as having no cutters at the same radial position after cutters are rotationally projected into the bit profile. On the other hand, a Track Set layout is defined as having at least two cutters at the same radial position but on different blades. Track Loc is an extreme version of Track Set, in which there is only one primary blade and cutters on all others are redundant to those on the primary blade. The major difference among these three configurations is the engagement area or width of indentation of cutters while drilling. The Single Set cutter has the smallest indentation width while drilling, and the Track Loc has the largest indentation width.

Table 2

Core PDC bit characteristics

Bit Profile		Flat
Body Material		Steel
Bit Dimensions	OD	7 in
	ID	2 1/4 in
	Core Size	2 in
	Length	8.5 in
Cutters	Type	PDC
	Size	5/8 in (16 mm)
	Chamfer	0.01 in
	Quantity	14
	OD Gage	4
	ID Gage	2
Weight		70 lbs
Maximum Depth of Cut		0.25 in
Back rake Angle		20 deg
Side rake Angle		2 deg
Nozzles		None
Special Feature		Replaceable heads

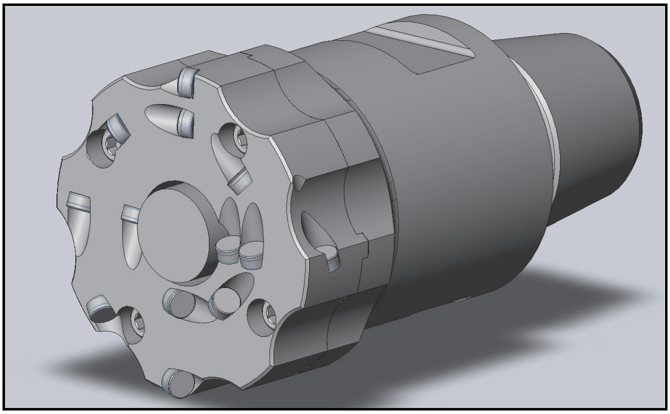


Fig. 5. Core bit design

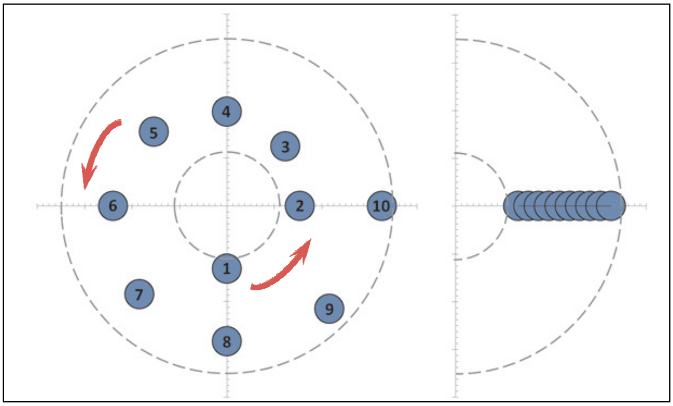


Fig. 6. Single Set or Base layout

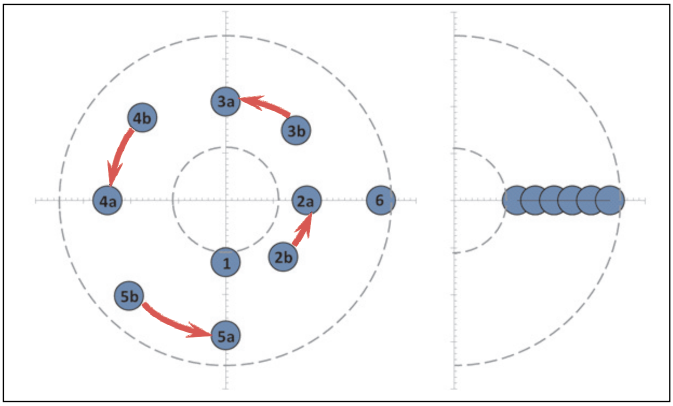


Fig. 7. Behind Track Set layout

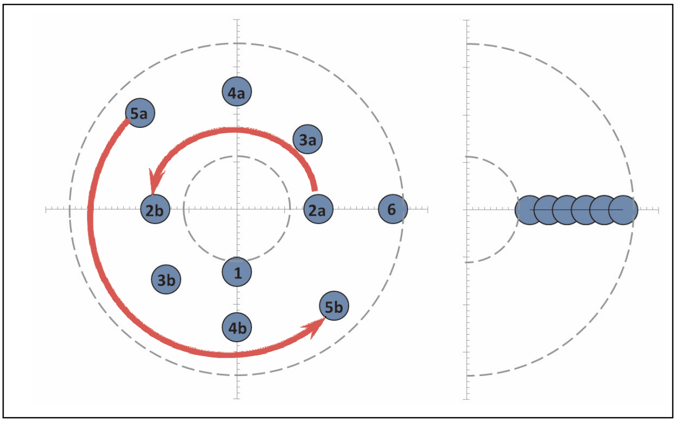


Fig. 8. Opposite Track Set layout

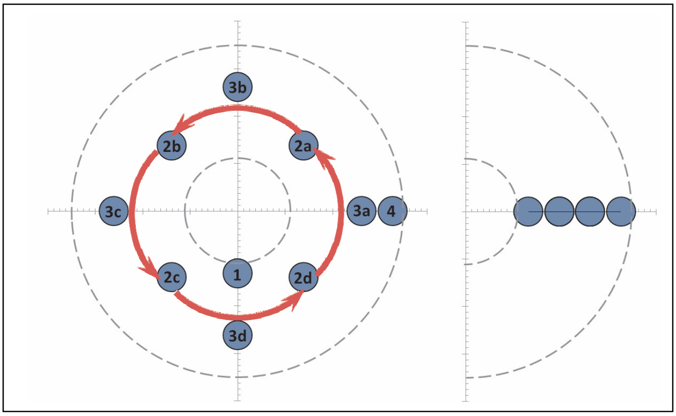


Fig. 9. Track Loc layout

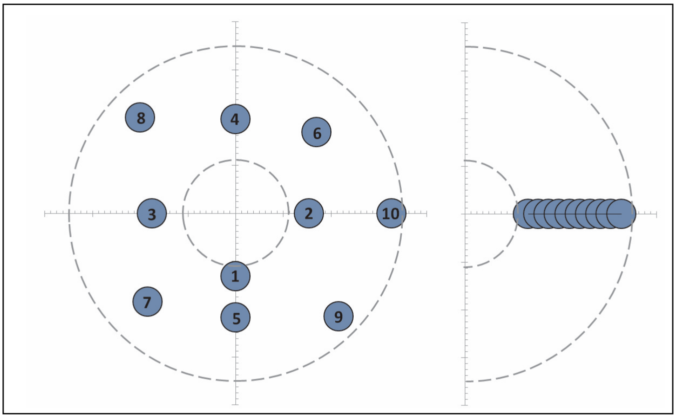


Fig. 10. Pair-Cutter Groups, Single Set layout

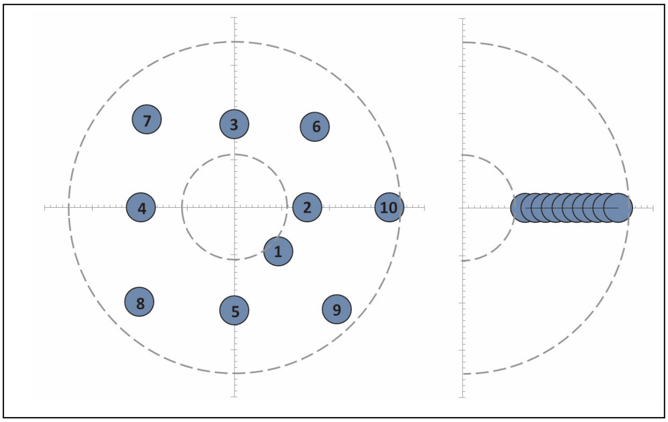


Fig. 11. Two-Cutter Groups, Single Set layout

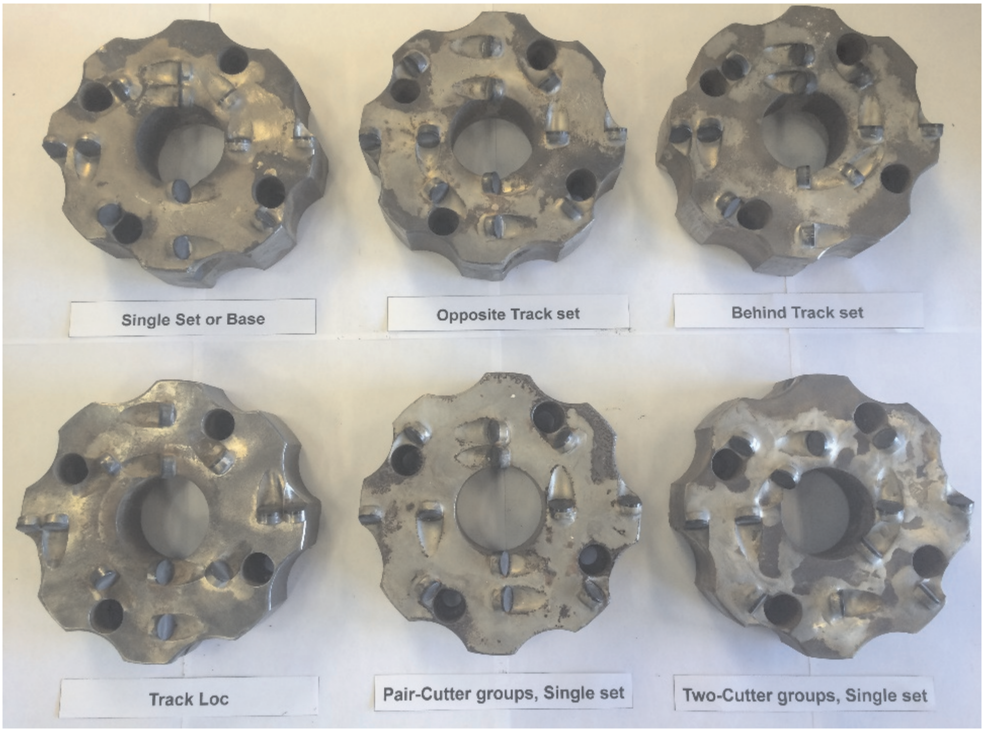


Fig. 12. Core heads: Layouts of cutters

Two of the proposed PDC cutter arrangements are in correspondence with the theory published by Chen et al. [4] for improving PDC bit performance in hard and transit formation drilling. The authors, based on experimental results, propose that cutters are laid out in force-balanced groups, with each group designed to remove a ring of rock independently and efficiently.

4. ROCK SAMPLES AND ROCK CHARACTERIZATION

Originally, it was proposed to prepare concrete samples for this study. Although they are not real formations in drilling operations, they may reproduce mechanical properties of interest, such as the unconfined compressive strength. However, because a good supply of cores was available, it was decided to change to Bedford (Indiana) and Carthage limestones.

The objective of measuring mechanical rock properties per sample was to correlate any considerable change in rock properties with drilling behavior. Experiments were performed using cylindrical rock samples with a length-to-diameter ratio of two. The specimens were loaded axially to failure, with no confinement (lateral support). Conceptually, the peak value of the axial stress is taken as the UCS of the sample. In view of the variability of rock properties, when adequate samples were available, repeat testing was performed to determine average values. To adjust to experimental conditions, characterization tests were conducted on dry samples. Although the rock is submerged in water into the pressure cell while testing in the drill rig, there is not enough time for the rock to become fully saturated. Dry conditions are assumed to be closer to the actual setup.

Experimental results are usually represented as stress-strain curves, and tabulated average values of elastic constants and strength (Tab. 3). Again, the purpose was to evaluate the variability in UCS measured among the samples. This variability was found to be small for the samples tested.

Table 3

Measured Unconfined Compressive Strength

Rock sample	Average density, lb/cf	Average Poisson's ratio	Average Young's modulus, psi	Average Unconfined Compressive Strength, psi
Bedford (Indiana) limestone	~142	0.23	$3.9\ (10^6)$	4353
Carthage limestone (Carthage marble)	~168	0.14	$6.9\ (10^6)$	13570

5. TEST MATRIX AND DATA COLLECTION

The definition of the experimental test matrix (Tab. 4) required taking into account the core bit design, the current facility capacities and analysis of the recorded data in preliminary tests. From the data recorded, the focus was on those intervals where the rate of penetration remained constant for a certain set of drilling parameters. This is directly evaluated on the curve of bit displacement as function of time. For the purpose of comparing the performance among the layouts of cutters, the interest was in doing experiments on a maximum of four different DOC, which correspond to four different weights on bit. There is a maximum DOC of 0.25 in per cutter. Water is the drilling fluid for the entire experimental phase.

Table 4

Summary of test matrix

Rock sample	Bedford (Indiana) limestone
	Carthage limestone
Drilling fluid	Water
Rotary speed, rpm	60 and 100
Flow rate, gpm	120
Weight on bit, lbs	Up to 7000
Back pressure	No

Operating parameters such as N and WOB were varied and the performance parameters ROP and TQB were measured at each time step. ROP is calculated as a function of bit displacement over time. DOC is calculated from ROP, as well as the average WOB and TQB values are calculated at each depth.

Adjustments on WOB and TQB measurements were required to account for the combined effect of pump-off force, cell pressure and friction forces between the top flange and the drill string. To remove these forces from the actual measurements, the base condition was established at zero rate of penetration. This is set right after a 2.5-in pilot hole was drilled that allows full bit engagement at the top of the samples. This condition was measured per sample per rotary speed and then averaged to estimate the initial WOB and TQB values. This is under the assumption that pump-off force does not depend on DOC.

6. DATA ANALYSIS

While WOB was gradually varied and the other operating parameters were kept constant (bit rotational speed and flow rate), all the performance parameters were measured at each time step. Since there is no specific control over the rate of penetration, the data analysis was performed over intervals of time at which both WOB and ROP remained constant. Under these conditions, the TQB is proportional to bit mechanical specific energy. Therefore, it is also valid to use TQB to compare the drilling efficiency. Bit mechanical specific energy at each DOC is calculated from the group of measurements. The results show how the MSE changes with different layouts under the test operating conditions. They also show how different rock samples (Bedford and Carthage limestone) perform under the same conditions.

The data obtained from the set of Bedford samples included a total of 12 tests conducted as per the test matrix. Expressions describing linear relationships between WOB and DOC as well as between TQB and DOC (Figs 13 and 14) were found. Similarly, the data obtained from the set of Carthage samples included a total of 12 tests conducted for Carthage marble. Expressions describing linear relationships between WOB and DOC as well as between TQB and DOC were also found (Figs 15 and 16). The maximum ROP achieved was limited to the breakability of the rocks.

For the case of Bedford samples, it is noticeable that the linear relationships observed in the range of DOC in this study are not valid for a low interval of DOC. It has been documented [1, 2] that there is a higher energy consumption at extremely shallow DOC due to minimum cutter-rock contact required to develop a desirable rate of penetration.

From data obtained in Bedford samples, it is important to note that the maximum DOC at which all layouts were able to perform was around 0.15 in./rev. For the case of Carthage samples, the range of DOC was considerably smaller, up to only 0.05 in./rev. This was because of the high breakability of the rock. Linear relationships were calculated from the curves of DOC vs. TQB at different conditions.

By comparing through the concept of Mechanical Specific Energy among Bedford samples (Figs 17 and 18), it is observed that the drilling efficiency of Track Set layout is up to 97% higher than that of other layouts for DOC from 0.05 to 0.15 in./rev. It is important to note that this performance difference is due to the cutter layouts because nothing is changed except the cutter angular locations. This performance is more remarkable at higher rotational speeds. There is one layout (Pair-cutter Groups) which equals in energy consumption to the Opposite Track Set layout at a rotary speed of 100 rpm.

From Carthage samples (Figs 19 and 20), it is observed that the drilling efficiency of the Pair-Cutter Groups layout is up to 112% higher than that of other layouts for DOC from 0.01 to 0.04 in./rev. Again, the performance difference is thought to result from the differences in the cutter angular locations. There is only one layout (Two-Cutter Groups) at 100 rpm that consumes less energy with respect to the Pair-Cutter Groups layout.

From the set of experiments in Bedford and Carthage limestone, there is no evidence to confirm whether the drilling-efficiency improvement is decreased or not with increase in depth of cut. More laboratory and field tests should be conducted to better understand the conditions under which the cutter layouts benefit the most.

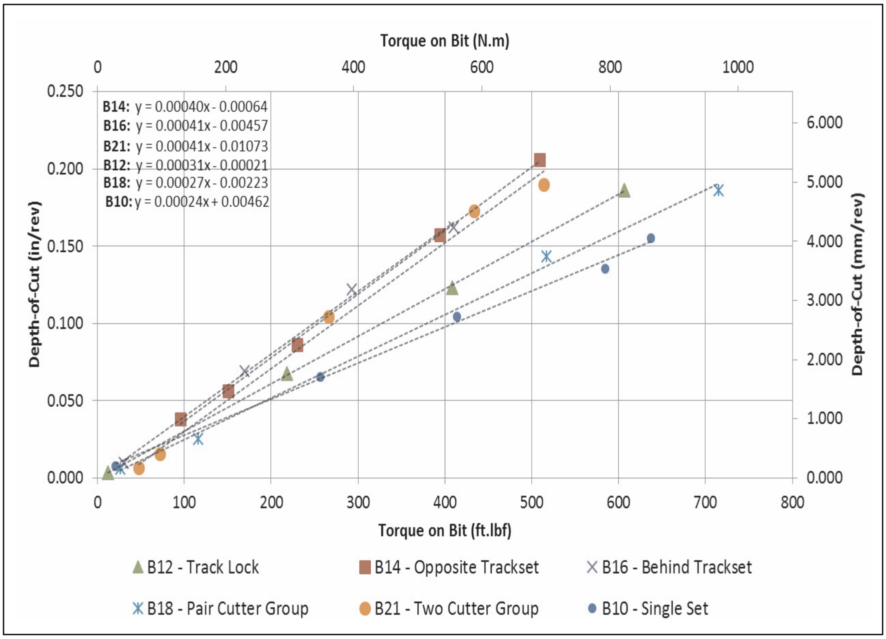


Fig. 13. Depth of Cut vs. Torque on Bit for Bedford samples at 60 rpm

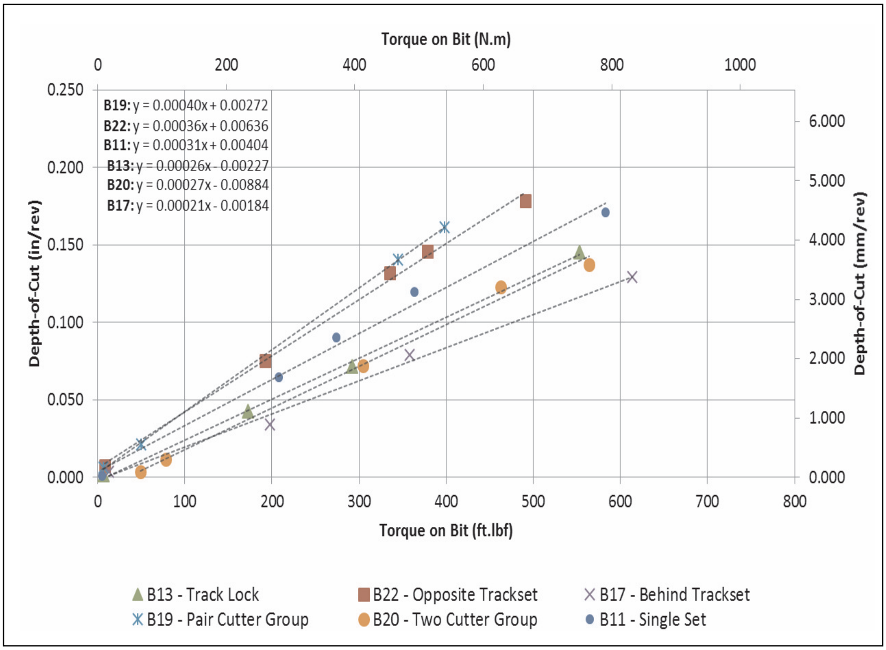


Fig. 14. Depth of Cut vs. Torque on Bit for Bedford samples at 100 rpm

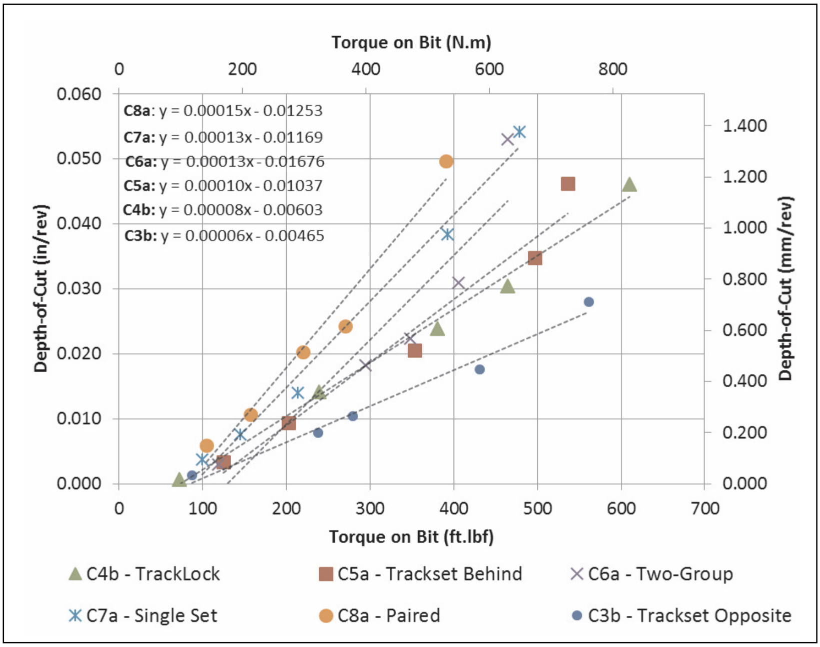


Fig. 15. Depth of Cut vs. Torque on Bit for Carthage samples at 60 rpm

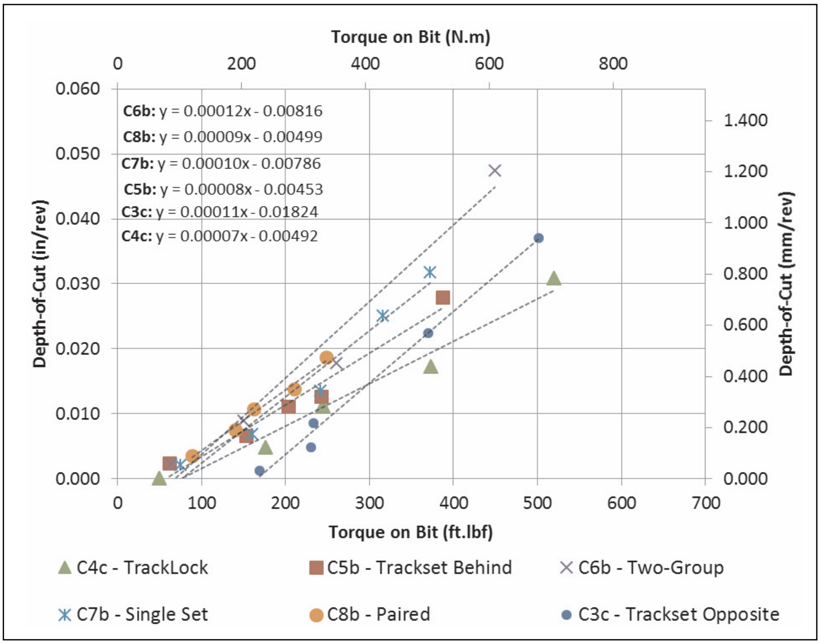


Fig. 16. Depth of Cut vs. Torque on Bit for Carthage samples at 100 rpm

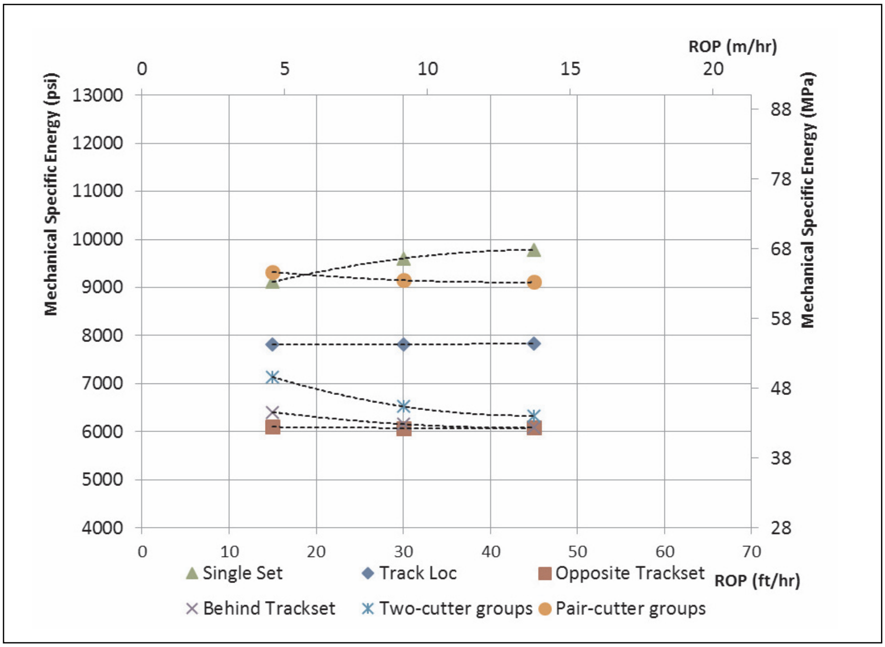


Fig. 17. Mechanical Specific Energy for Bedford samples at 60 rpm

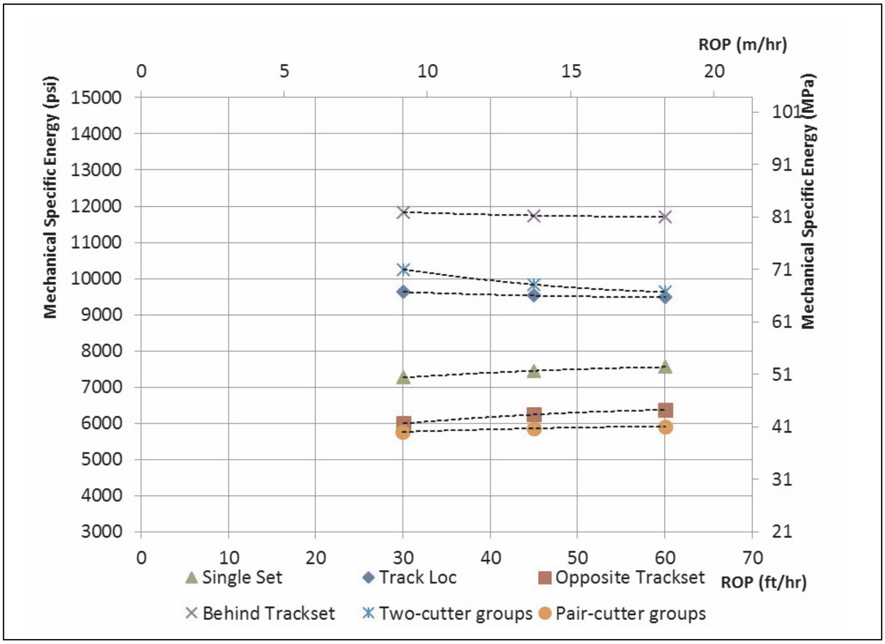


Fig. 18. Mechanical Specific Energy for Bedford samples at 100 rpm

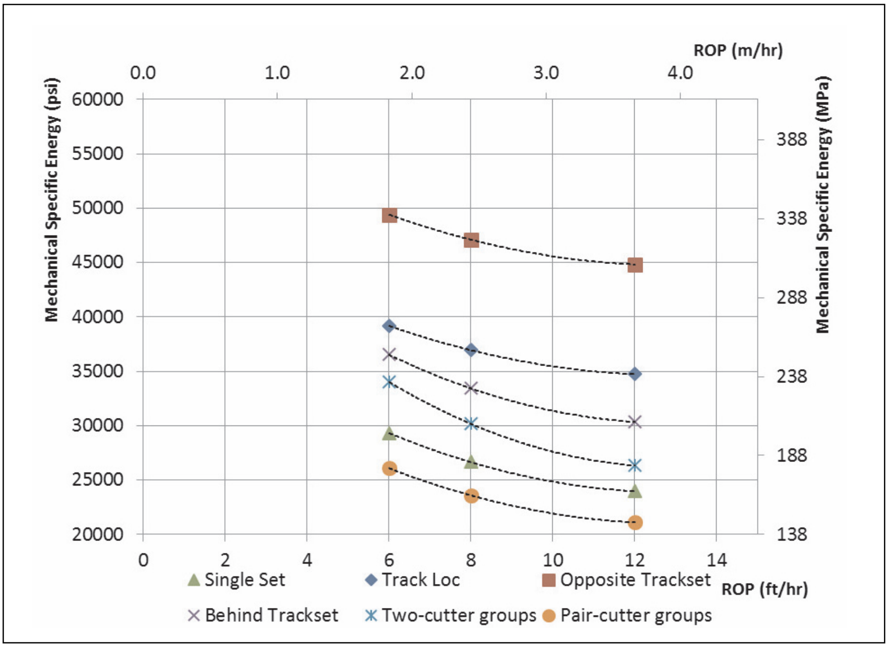


Fig. 19. Mechanical Specific Energy for Carthage samples at 60 rpm

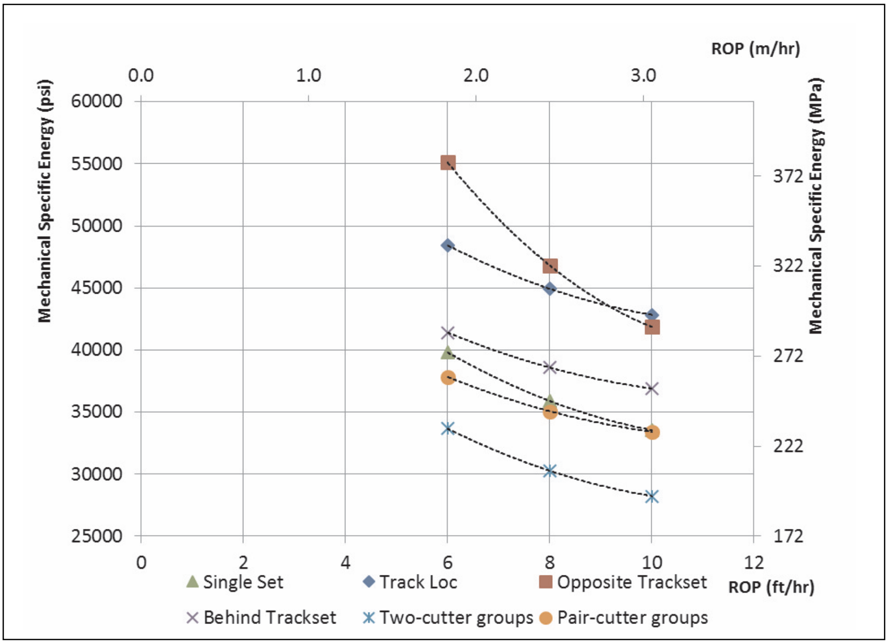


Fig. 20. Mechanical Specific Energy for Carthage samples at 100 rpm

7. DISCUSSION

Chen [4] pointed out that the extent to which drilling efficiency can be improved by a certain cutter layout may depend on the type of rock and drilling parameters. By analyzing the drilling performance per cutter arrangement, it is seen that particular layouts perform better at certain rotary speeds: Behind Track Set layout at 60 rpm, and the Pair--Cutter Groups and the Single Set layouts at 100 rpm.

Similarly, Chen [4] suggested that the extent to which drilling efficiency can be improved by a certain cutter layout depends on the type of rock. There is also evidence in our study to state that the relative drilling performance among the different layouts of cutters varies according to the type of rock. It is observed that the drilling performance of the six layouts in Bedford samples is considerably different than the corresponding performance in Carthage samples. While the Opposite Track Set performed the best in Bedford rocks, it developed the highest energy consumption in Carthage limestone.

In addition to the analysis of drilling performance, there are some observations regarding the coring operation. For the Bedford samples drilled, the percentage of recovery was 100%. It was possible to retrieve full cores after every drill test involving Bedford limestone. The quality of the core surface is a measure of the rate of penetration. Therefore, the bottom sections of the samples were exposed to higher rates of penetration and, thus, greater roughness was observed.

On the other hand, the Carthage samples were found to be highly fractured. Natural fractures are observed on the samples and their locations match the breaking points while drilling the Carthage rocks. Due to the limited rate of penetration, the core surface was not significantly affected by the cutting action.

Although the performance of Track Loc layout was low when compared to the others under the same conditions, it was found to be suitable for the purpose of coring. This is based on the physical observation of higher stability or lower vibrations while drilling. This observation cannot be supported with data because the current setup is unable to directly measure vibrations at the core bit.

8. CONCLUSIONS

The experiments on core PDC bits revealed that the cutter layout has a significant effect on MSE. Under the same drilling parameters, the layout plays a key role in drilling efficiency. Experimental results show strong linear relationships between DOC, WOB and TQB at different conditions for the specific bit characteristics. Similarly, there is evidence to validate that the type of rock affects the relative drilling performance of the different cutter arrangements.

The experiments on Bedford samples revealed that the Track Set layout performs better than other layouts for depth of cut from 0.05 to 0.15 in./rev at the two rotational speeds in this study. This is under the assumption that variability in rock properties is not decidedly affecting the performance. The experiments on Carthage samples revealed that the Pair-Cutter Groups layout performs better than other layouts for depths of cut from 0.01 to 0.04 in./rev at the two rotational speeds in the study. This is under the assumption that slight variations in individual rock properties do not significantly affect bit performance.

NOMENCLATURE AND CONVERSION FACTORS TO SI UNITS

Ab – Bit area, in^2 ($1\ in^2 \approx 645.2\ mm^2$)
AOC – Area of Cut, in^2 ($1\ in^2 \approx 645.2\ mm^2$)
DOC – Depth of Cut, in/rev (1 in./rev ≈ 25.4 mm/rev)
Drill string vibration, ips (1 in./s ≈ 25.4 mm/s)
E – Young's modulus (drained), psi (1 psi ≈ 6894.8 Pa)
Fluid density, lb/gal (1 lb/gal ≈ 119.8 kg/m^3)
Fluid temperature, deg F (deg C = [deg F – 32] × 5/9)
Fn – Normal or vertical force (single cutter), lbf (1 lbf ≈ 4.45 N)
Fs – Shear or horizontal force (single cutter), lbf (1 lbf ≈ 4.45 N)
Fh – Normal force (full bit), lbf (1 lbf ≈ 4.45 N)
ID – Inner Diameter, in (1 in. ≈ 25.4 mm)
MSE – Mechanical Specific Energy, psi (1 psi ≈ 6894.8 Pa)
N – Rotary Speed, rpm (1 rpm ≈ 0.105 rad/s)
n – Number of cutters
OD – Outer Diameter, in (1 in. ≈ 25.4 mm)
PDC – Polycrystalline Diamond Compact
r – Cutter radial position, in (1 in. ≈ 25.4 mm)
ROP – Rate of Penetration, ft/hr (1 ft/hr ≈ 0.085 mm/s)
TQB – Torque on Bit, ft-lbf (1 ft-lbf ≈ 1.356 N-m)
TUDRP – Tulsa University Drilling Research Projects
UCS – Uniaxial Compressive Strength, psi (1 psi ≈ 6894.8 Pa)
Volumetric flow rate, gpm ($1\ gpm \approx 6.309 \cdot 10^{-5}\ m^3/s$)
WOB – Weight on Bit, lbf (1 lbf ≈ 4.45 N)
WOC – Width of cut, in (1 in. ≈ 25.4 mm)
β – Side rake angle (1 deg ≈ 0.0175 rad)
ε – Intrinsic specific energy
ζ – Ratio of vertical to horizontal force
θ – Back rake angle (1 deg ≈ 0.0175 rad)
μ – Friction coefficient
ν – Poisson's ratio
ψ – Interface friction angle (1 deg ≈ 0.0175 rad)

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