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Full Length Paper

Drill Bit Performance Evaluation Using Cost per Foot Analysis and Break-even Model Equation

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Abstract

Performance evaluation of drill bit is very vital to obtain the efficiency of drill bit in mining and oil and gas operation. However, it is paramount to evaluate the performance of drill bits because of the high cost of replacing damaged ones. It is also very important to examine the rocks particle properties as changes in these can affect the performance of a drill bit. This research is focused on the establishment of cost and perform economic evaluation of bit in terms of performance, using cost per foot analysis and breakeven model equation. Sections of a popular petroleum company was used as case study - MOPOL well number A and MOPOL well number B of the oil and gas company was used. Evaluation was conducted by selecting the right type of bit which will give the best performance in a given formation. In MOPOL well number A, four bits were used. The bit with the least cost in terms of cost per foot is the first bit (17½" Volgaburmash Milled Tooth) with $25.85/ft and the highest breakeven penetration rate of 75.48ft/hr. In MOPOL well #B, seven (7) different bits were used. The bit with the least performance in terms of cost per foot is the seventh bit (8½" Volgaburmash PDC) with $422.64/ft and the first bit (16" REED T135) had the highest breakeven penetration rate of 135.86ft/hr.

Keywords: Drill bit, Oil and Gas, Break Even Model Equation, Cost per foot Analysis

1. BACKGROUND OF THE STUDY

Drill bits are useful tools for oil and gas operation. Drill bits are cutting tools used to expunge materials to create holes, almost always of circular cross-sectional shape with a purpose of locating and producing hydrocarbon in commercial quantity [1]. During drilling, a drill bit is essentially used for making or boring the hole into the earth. The drill bit is actually what gouges and crushes the earth's formation, while the drilling mud transports produced cuttings to the surface, cools, lubricate the bits hot surface (due to friction) and stabilizes the well bore pressure. Some other factors which affects drilling rate are: the rotary speed, weight on bit, density of drilling mud, and the strength of connection of drill pipes [2]. Evaluation of drill bit performance is a careful exercise carried out to ascertain the capacity and efficiency of a bit to drill a given section of a hole with optimum suitability. Drilling bit evaluation contributes to the overall efficiency of the drilling program. Criteria used for the evaluation of drilling bit includes rotating hour, footage drilled, maximum penetration rate, weight on bit, rig cost, rotary speed, and bit cost. The aim of this research is focused on studying the method of evaluating bit performance, using cost per foot and break-even analysis. The objective is to suggest best method of comparing the method and select the better approach for effective performance. Finally select the bit with the highest performance and least cost for every foot drilled.

1.1 Importance of Bit Evaluation

Bit evaluation is very important in decision making regarding the choice of bit to be used to drill a particular interval. Since the bit is the tool that actually does the hole making, its performance will have direct effect on how long the rig stays in a location, hence appropriate bit selection becomes very crucial. Bit evaluation helps the driller to determine the cause of bit failure which may be due to poor drilling particle [3]. Evaluation of bit performance is form of bit record, when given to the bit manufacture will assist them improving the design of the bit used for drilling. The bit and how it does its job are very important to rotary drilling. When the bit is at bottom making hole, it is making money. But making hole depends on whether the bit is doing its job as it should. How well a bit drills depends on several things among those are the condition of the bit, the weight applied to make it drill and the rate at which it is rotated [4]. Also, important to drill bit performance is the action of drilling fluid. Drillers want bits that can drill a given hole section at the fastest possible rate. In order words they want a bit that can provide an effective Rate of Penetration (ROP). The nature of the formation to be drilled is the first factor, whether the formation is hard, Soft, medium soft or medium hard formation [5]. The two major categories of bits would be reviewed in this chapter, which includes the drag bit and the roller cone bit.

2. REVIEW OF RELEVANT LITERATURE

2.1 Bit Development

In the history of rotary drilling the drag bit is the first to be used. This was used by the Chinese in the year 256 BC. Then, every tool pusher and blacksmith was a bit designer and manufacturer. The bit was enhanced during this time by addition of hard metal to the cutting edge and gauge surface. In 1909, the rock cone bit was introduced from the idea of the drag bit. The rock cone then, comprises of two cones. The rotary drilling technique with the use of two cone bit was then used for hard formation where the drag bit cannot perform. The ineffectiveness of this bit is as seen in the “balling up” effect. Consequently, in 1920 it was redesigned in the rig floor with new cones to prevent balling up. It was designed with meshing teeth (self-cleaning teeth). Furthermore, 1930, the three cone milled teeth bit was introduced, bit record of that time was about 5-10 feet in 4-5 hours at depths below 10,000 feet. The drilling milled tooth bit was not enough for drilling environment encountered [6]. So, the hughes tool company in 1947 introduced the first tri-cone bit using tungsten carbide insert in the cutting edge and named it “chert bit” it was characterised by short space insert (teeth). The 5-10 feet were increased to 50-100 feet at the same time of 4-5 hours just like most dirtily tool, the bit stepped into constant study and experimentation/analysis and enhancement of bit are still being made till today [7]. As a result of constant improvement, modern insert bits are routinely used in many areas from top to bottom. Like recently, in utuama oil field, fire insert bit were used to drill a total depth of 10,565 feet well, unlike a situation where about 20 milled tooth (soft formation) bits would have been used in the past, even tungsten carbide soft formation bits are being introduced to replace the milled tooth bit. This has brought development in bit performance. By this improvement, the bits are able to penetrate an average depth of 1208 feet in unconsolidated formation. Drilling with drag bit requires low Rotation per Minute (RPM), maximum pump speed and moderate weight etc, to prevent balling up [8].

2.2 Types of Bit

Bits can be classified, generally into two types: The drag bit and the Roller cone bit

2.2.1 Diamond Bit

A diamond bit (either for drilling or coring) is composed of three parts: Diamond Ls, matrix and shank. The diamonds are held in place by the matrix which is bonded to the steel shank. The matrix is principally powdered tungsten carbide infiltrated with a metal bonding material [9]. The tungsten carbide is used for its abrasive wear and erosion resistant properties (but far from a diamond in this respect). The shank of steel affords structural strength and makes a suitable means to attach the bit to the drill string. Diamond bits are sold by the carat weight (1 carat = 0.2 grams) of the diamonds in the bit, plus a setting charge. The price will vary depending upon classification (or quality) and size. The setting charge is to cover the manufacturing cost of the bit [10]. A used bit is generally returned to salvage the diamonds and to receive credit for the reusable stones (which materially decreases the bit cost). This credit is frequently as much as 50% of the original bit cost.

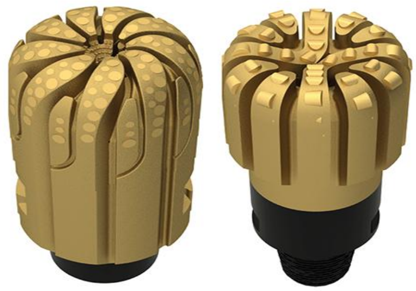

Figure 1: Sample of Diamond Bit

Types of Diamond Bits

There are basically two types of diamond bit the TSP (Thermally stable PDC) and the Polycrystalline diamond Bit.

(i) The TSP (Thermally stable PDC)

A major achievement in enhancing the thermal resistance of polycrystalline diamond cutter was to produce diamond drills PDC types of heat-resistant blades (TSP) in which the space between the grains of diamond inclusions were etched cobalt. These blades have a hard sintered pads, so there are no foreign materials reduce thermal resistance. Thermal resistance drills with cutting TSP is 1148 K (8750C). Due to the increased thermal resistance of the blades TSP bits can be used to drill hard and abrasive formations, in which the operation of a conventional diamond PDC bit is ineffective [11]. TSP is used often in combination with turbines due to their enhanced heat resistance. TSP bits should be used in rotation within 120-160 rpm for medium-hard rocks and 150-200 rpm for soft rocks. Axial thrust should be between 25-30% of the load exerted on roller cone bits of the same diameter.

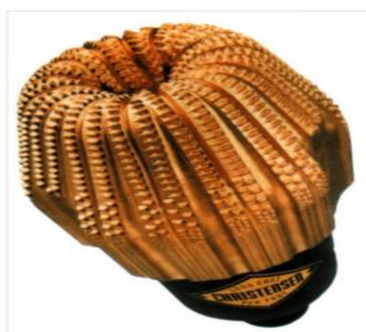

Figure 2: Thermally Stable PDC bit

(ii) Polycrystalline Diamond Compact Bit (PDC)

PDC is one of the most important material advances for oil drilling tools in recent years [12]. Fixed-head bits rotate as one piece and contain no separately moving parts. When fixed-head bits use PDC cutters, they are commonly called PDC bits. Since their first production in 1976, the popularity of bits using PDC cutters has grown steadily, and today they are nearly as common as roller-cone bits in many drilling applications. PDC bits are designed and manufactured in two structurally dissimilar styles: matrix-body bit and steel-body bit. The two provide significantly different capabilities, and because both types have certain advantages, a choice between them would be decided by the needs of the application [13].

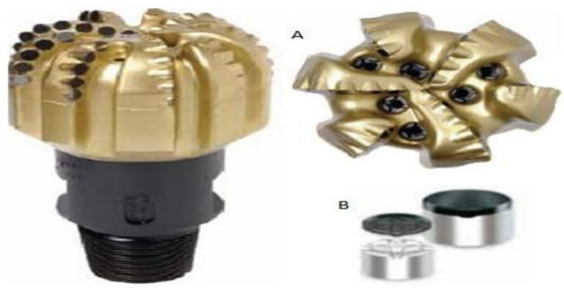

Figure 3: Polycrystalline diamond Compact Bit

2.2.2 Roller Cone Bits

Roller cone bits are the most commonly used type of rotary drilling bits. The first such constructions have been made in the beginning of 20th century. They have undergone several improvements since then so are still very useful tools. This comprehensive bit type is accessible with wide variety of tooth design and bearing types. Thus is suitable for drilling various types of rock formations. The drill bit design depends on the rock formation properties and the hole diameter [14]. Taking into consideration diversification of drill ability of the rocks, roller cones bits are produced in many different configurations. The crushing comes from the high weight utilized driving the teeth into the rock as the cones and the bit rotate [15]. A roller cone bit consists of three major elements: the cones, the bearings and the body of the bit. Roller cone bits can have one, two, three or even four cones. Three equal – sized cones solution is the most often applicable form. Each cone has teeth sticking out of them in the rows that collaborate and fit into the teeth from adjacent cones. The cones are fixed on bearings which operate on a pin that are a part of the leg of the bit. The body is forged and welded object consisting of three legs. The body is forged from a nickel-chrome-molybdenum steel alloy and is then treated. Cones are forged too from a nickel-molybdenum alloy steel and treated. Nozzles and Tungsten Carbide Insert teeth are made of sintered tungsten carbide. The bearings are made of suitable tool-steel grade alloy. Figure 4 shows a typical Milled tooth bit and Tungsten Carbide Insert bit.

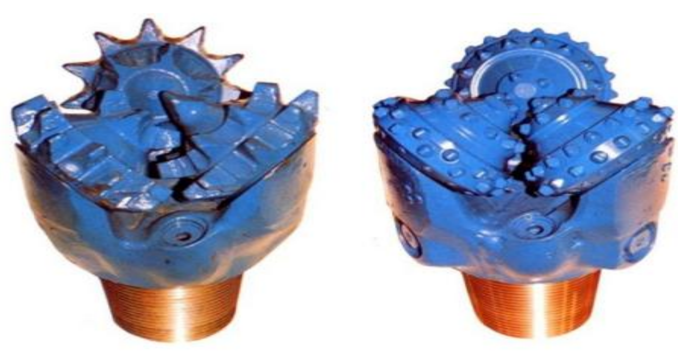

Figure 4: Milled Tooth Bit and Tungsten Carbide Insert Bit

IADC Roller-Cone Bit Classification Method:

The IADC Roller-Cone Bit Classification Method is an industry-wide standard for the description of milled-tooth and insert-type roller cone bits. This coding system is based on key design- and application-related criteria. The currently used version was introduced in 1992 and incorporates criteria cooperatively developed by drill bit manufacturers under the auspices of the Society Engineers.

Milled Tooth Bits

he milled tooth bit has a rolling sealed bearing structure. The cylinder rolling element is placed within the groove of roller cone, thus enlarging the journal size and ensuring a better performance of roller bit. The secondary surface of thrust bearing of roller bit has been handled with antifriction and hardening treatment so as to decrease the frictional force of bit for protecting its hardening resistance. The roller bit uses new type lubricating grease which can bear the high temperature of 250ºC and boasts abrasion resistance and the full rubber oil reservoir uses limitable differential pressure and can prevent drilling fluid from entering lubricating system so as to provide qualified lubrication for bearing system. The milled tooth bit are also designed to have a self-cleaning characteristics which makes the bit drill effectively on formation, to prevent “balling up”. The milled tooth bit is made in such a way that it has producing tooth length and offsetting of the cone slightly so that the cone does not rotate about the true centre of the hole

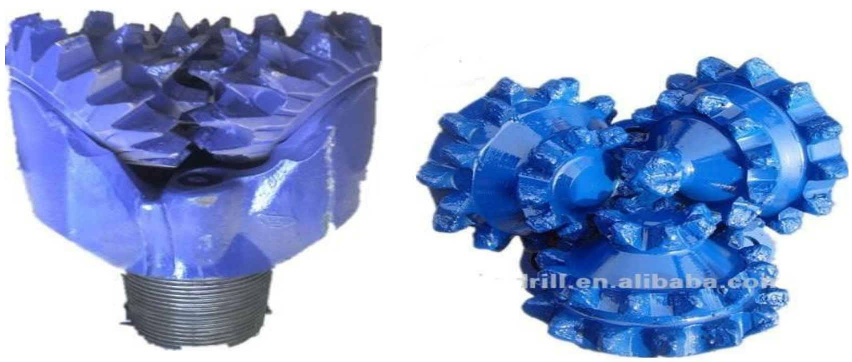

Figure 5: Milled Tooth Tricone Bit

Tungsten Carbide Insert Bit

In recent years, many improvements have been made in sealed bearing tungsten carbide insert bits [16]. The tungsten carbide is recommended for hard formations. Hence, it can be called hard formation bit. Modern tungsten carbide insert bit run in hole at high speeds, of up to 180 Revolutions per Minute (RPM) or more, as compared to the 45 RPM used with older ones. Its main action is to destroy the rock by crushing and chipping. This is followed by extreme and at a low RPM [17]. Its teeth are usually made of tungsten carbide, which makes it hard enough to drill hard formations [18]. The cone offset meet in a common point, thus, rotating about its true centre

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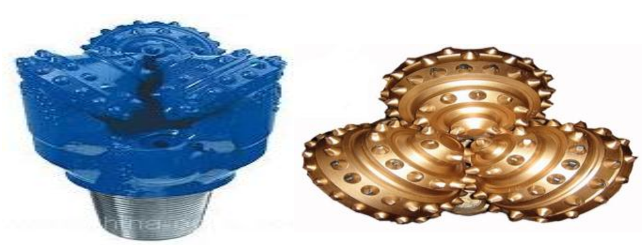

Figure 6: Tungsten Insert Carbide Tricone Bit

3. METHODOLOGY AND COST ANALYSIS

As earlier complained, the recent trend toward deeper and costlier holes has led to the development of various rock bits which can stay in the hole longer, drill more footage and eliminate expenses. As a result there is a need for bits that can perform to enhance these qualities, ever increasing types of bit have

Become available, these are the milled tooth bit and the insert bit which are designed to have either sealed or non-sealed bearing. The various design have made the various bits to have different prices, footage drilled, penetration rate, and rotary hour. But all these factors have lost their significance, the only factor considered in drilling or selecting a bit is the cost per foot comparison.

3.1 Cost per Foot Model Equation

The most realistic and approved method for evaluation of drilling bit performance by IADC was for cost of foot. Using this parameter, it is possible to achieve an optimum relationship between penetration rates bit cost. The drilling cost per foot as related to these variables can be determined by the equation.

$$CT = \frac{B+CR(T+t)}{F} \quad (1)$$

CT = Drilling cost per foot ($/ft), B= Bit cost ($); CR = Rig operating cost ($/hr), T= Rotating or drilling time, t = Trip time (hr), F = Footage drilled by bit (ft). From the equation, it shows that cost per foot is controlled by a number of variables. The principle for evaluation of bit on the basis of cost/ft in a given formation of a hole section is usually comparative where a bit with the minimum value of cost per foot deemed to have the best performance. This formula can be used to ascertain the best bit on minimum cost per foot analysis. So bit performance is not judged by the footage drilled, penetration rate, bit cost, etc. But it is based on the cost per foot.

3.2. Break Even Calculation

This method of bit selection based on minimum cost analysis from an offset wells. The procedure for this technique is simply as following (Rob March 2002): Select the offset control wells, obtain bit records from the offset wells. Determine the rig cost for the prospect wells; elect the condition that gave the lowest cost per foot result using the breakeven calculating equation to determine the best bit with minimum cost per foot to be run on a given interval using the formula.

$$ROPBE = \frac{RR}{(C-(RR \times T) + B)/F} \quad (2)$$

Where; ROPBE = Breakeven Penetration Rate (ft/hr); RR=Hourly Rig Rate ($/hr)
F= Assumed footage for breakeven (ft); T=Trip Time (hour); B= Bit cost ($); C=Bit cost per foot ($/ft). With this equation, it is possible to determine the possible performance by a different bit to give cost per foot performance equal to that achieved with the current bit selection.

3.3. Specific Energy Equation

This method provides a simple and practical method for evaluation of drill bits. The specific energy of a drilling bit can be defined as the energy requires for it to remove a unit rock volume. The equation for specific energy can be derived by considering the mechanical energy E, expended by the bit in one minute.

$$E= W \times 2\pi R \times N \quad (3)$$

Where, E= Mechanical Energy; W= Weight on bit (lb); N= Rotary speed (rpm); r = Radius of the bit. The volume of rock removed in 1min is

$$V= (\pi R^2) \times PR \text{ (ft/hr)} \quad (4)$$

Where
PR = Penetration rate; Specific energy = E/V

This implies $S.E= \frac{W \times 2 \times \pi \times R \times N}{\pi \times R^2 \times PR}$

Nevertheless: R is inch (in)
W is in pounds (lb)
PR is in ft/hr

This implies $S.E= \frac{W \text{ (lb)} \times 2 \times \pi \times R \text{ (in)} \times N}{\pi \times R^2 \text{ (in}^2) \times PR \text{ (ft/hr)}}$

$$S.E= \frac{20WN \quad (IN\text{-}LB)/IN^3}{D \times PR} \quad (5)$$

The specific energy is highly dependent on weight on drill bit, rotating speed, time and fundamental rock property (density). This infer that for a given formation; a soft formation would have value of its specific energy different from that of the hard formation. The specific energy method thus affords operators with the accurate means of evaluating bit performance within a section of hole. The bit that is given the least value of specific energy in a given hole section is the most economic bit.

3.4 Drilling Index

The drilling index approach method of evaluation draws on the strength of the methods that have been discussed earlier. It captures the variations of rock removal mechanism of different rock bit types and distinguishes the relationship between technology and performance. It permits the evaluation of bit performance according to operators specific needs, as dictated by the well profile and drilling program.

4. CASE ANALYSIS

4.1 Brief History of Wells Mopol well #A and well #B

The record data for this research was obtained from a popular Oil and Gas company in Nigeria. The data contain the bit record of MOPOL WELL#A and MOPOL WELL#B. MOPOL WELL #A is a horizontal well drilled with BOGEL's durg – 2 rig to a total depth of 9,66eff (MORT), 589, TVD with maximum inclination of 90.40deg, All depth reference in this report are made with respect to Rotary Kelly Bushing (RKB) of the rig which is 36.84 for the MOPOL drilling sequence, a 24" conductor pipe was pre-piled to refusal at 307ft with 250BPF. The 17½" hole section was drilled to a depth of 4930ft – MDRT initially with spud mud and high viscous (hi-vis) fills which was changed to KCL polymer mud as drilling progressed beyond 1500ft. The $13^{3}/_{8}$" casing was run and cemented with a shoe at 4,920ft-MDRT. The12¼" hole section was drilled to a depth of 8164ft-MDRT and the $9^{5}/_{8}$" intermediate casing was run and cemented with the shoe at 8,153ft-MDRT. The 8½" drain hole section was drilled to a depth of 9,664ft – MD to penetrate the reservoir.

MOPOL Well #A was planned to be drilled, evaluated and handed over for completion in 34days. However, the well was drilled in 27days. The well was completed and concluded at 2:00hrs of January 02, 2015 using four (4) different bit.

MOPOL #B was a well coordinate of 172724.550m South and 431024.340m East in Warri, Delta State Nigeria. The well was initially proposed to drilled a total depth of 11,000ft with the 8½" hole section. The $9^{5}/_{8}$" casing intermediate was run and cemented with the shoe at 10374ft-MDRT, but for further production to cover deeper pay zones, it was decided to drilled a total vertical depth of 11,265ft with the 8½" hole section. The well was spudded on 6th January 2014 using seven (7) different bit.

Table 1: Drilling Bit Record used for Drilling MOPOL WELL #A

BIT NO.	BIT SIZE	BIT MAKE	BIT TYPE	DEPTH IN	DEPTH OUT	FOOTAGE DRILLED	IADC CODE	ROTATE	TRIP TIME (HR)	BIT COST ($)	AROP (FT/HR)
1.	17½"	Volgabumash	Milled Tooth	307	4181	3874	137	51.36	4.81	30,000	37
2.	17½"	Security	Tricone	4181	4390	749	137	41.5	9.93	45,000	32
3.	12¼"	Volgabumash	PDC	4930	8164	3234	437	48.7	8.16	73,000	23
4.	8½"	Volgabumash	PDC	8164	9664	1500	423	27.25	9.66	60,000	45

Table 2: Drilling Bit Record for Drilling MOPOL WELL #B

BIT NO	BIT SIZE	BIT MAKE	BIT TYPE	DEPTH IN	DEPTH OUT	FOOTAGE DRILLED	IADC CODE	ROTATE	TRIP TIME (HRS)	BIT COST ($)	AROP (FT/HR)
1.	16”	Reed	T125	190	3660	3470	135	10	5	20,000	34.020
2.	16”	Reed	T135	3660	6250	2590	135	99.5	6	20,000	26.211
3.	12¼”	Smith	Dsjc	6250	7947	1697	M442	6.41	7	45,000	32.765
4.	12¼”	Smith	Dsjc	7947	9847	1900	M442	5.41	7	45,000	32.074
5.	12¼”	Smith	MGGH +CDC	9847	10374	527	135	17	9	48,000	36.751
6.	8½”	Volgabumash	PDC	10374	11,000	626	437	15	8	65,000	7.190
7.	8½”	Volgabumash	PSC	11,000	11,265	265	423	12	10	73,500	5.900

4.2 Evaluation of Bit Performance at MOPOL #A WELL

Cost Per Foot Analysis of Bits used in MOPOL #A Well – Recall equation 1

$$CT = \frac{B + CR\,(T + t)}{F}$$

CT=Cost Per Foot; B = Bit Cost; t= Rotation Hours (Drilling Time);T =Trip Time in Hours (Round trip); CR=Rig Cost; F=Footage Drilled

1. Drilling Cost per foot of bit run 1, 17½” Volgaburmash Milled tooth bit
B=$30,000; CR=$1250 hour; t=51.36hours; T = 4.81hours; F=3874ft; CT=$25.85 /ft

2. Drilling Cost per foot of bit run 2, 17½” security Tricone bit
B =$45,000; CR =$1250 hour; t=41.5hours; T=9.93hours; F=749ft; CT =$145.91/ft

3. Drilling Cost per foot of bit run 3, 12¼” Volgaburmash PDC bit
B=$73,500; CR=$1250hour; t=48.7hours; T=8.16hours;F=3234ft;CT =$44.70/ft

4. Drilling Costper foot of bit run 4, 8½” Volgabumash PDC bit
B=$60,000; CR=$1250 hour; t=27.25 hours; T= 9.66hours; F=1500ft; CT=$70.76/ft

4.3. Breakeven calculation of Bit used in MOPOL # A Well

$$ROPBE = \frac{RR}{[C - (((RR \times T) + B)/F)}$$

Parameters already defined in section 3.

1. Breakeven calculation for 17½” Volgaburmash Milled tooth bit

$$ROPBE = \frac{RR}{[C - (((RR \times T) + B)\,(F)]}$$

RR=$1250 /hr; F=3874ft; T=4.81hr; B=$30,000;C=$25.85/ft; ROPBE=75.48 ft/hr

2. Breakeven Calculation for the 17½” Security Tricone Bit

$$ROPBE = \frac{RR}{[C - (((RR \times T) + B)\,(F)]}$$

RR=$1250/hr; T=9.93ft; B=$45,000; F=749ft; C=$145.91/ft; ROPBE=18.05 ft/hr

3. Breakeven calculation for the 12¼” Volgaburmash PDC Bit

$$ROPBE = \frac{RR}{[C - (((RR \times T) + B)\,(F)]}$$

RR=$1250/hr; T=8.16hr;B=$73,500; F=3234ft; C=$44.70/ft; ROPBE=66.42 ft/hr

4. Breakeven calculation for the 8½” Volgabumash PDC Bit

$$ROPBE = \frac{RR}{[C - (((RR \times T) + B)(F)]}$$

RR=$1250/hr; T=9.66; B=$60,000; F=1500ft; C=$70.76/ft; ROPBE=55.04ft/hr

4.3 EVALUATION OF BIT PERFORMANCE IN MOPOL #B WELL

4.3.1 Cost Per Foot Analysis of Bits Used In MOPOL #B Well

1. Drilling cost per foot of bit run 1, 16" reed T135 Bit
   B=$20,000; CR=$1750/hr; t=10hours; T=5hours; F =3478ft; CT= $13.33/ft

2. Drilling Cost per foot of bit run 2, 16" Reed T135 Bit
   B=$20,000; CR=$1750/hr; t=99.5hours; T=6hours; F=2590ft; CT=$79.00/ft

3. Drilling Cost Per Foot of bit run 3, 12¼" Smith Dsjc Bit
   B=$45,000; CR=$1750/hr; t=6.41hours; T=7hours; F=1697ft; CT=$40.42/ft

4. Drilling Cost Per Foot of Bit run 4, 12¼" Smith Dsjc Bit
   B=$45,000; CR=$1750/hr; t =6.41hours; T=7hours; F=1697ft; CT=$40.42/ft

4. Drilling Cost Per Foot of Bit run 4, 12¼" Smith Dsjc Bit
   B=$45,000; CR=$1750/hr; t= 5.41hours;T= 7hours; F=1900ft; CT = $35.11/ft

5. Drilling Cost Per Foot of Bit run 5, 12¼" Smith MGGH+CDC Bit
   B=$48,000; CR=$1750/hr; t=17hours; T=9hours; F=527ft; CT = $177.42/ft

6. Drilling Cost Per Foot of Bit run 6, 8½" Volgaburmash PDC Bit
   B=$68,000; CR=$1750/hr; t=15hours; T=8hours; F=626ft; CT=$172.92/ft

7. Drilling Cost Per Foot Bit run 7, Volgaburmash PDC Bit
   B=$73,500; CR=$1750/hr; t=12hours; T=10hours; F=625ft; CT= $422.64/ft

4.4 Breakeven Calculation of Bit used in MOPOL #B Well

1. Breakeven Calculation for 16: Reed T135 Bit

$$ROPBE = \frac{RR}{[c - (((RR \times T) + B)/F)]}$$

RR=$860/hr; F=3470ft; T=5hours; B=$20,000;C=$13.33/ft

ROPBE= 135.86ft/hr

2. Breakeven Calculation for 16" Reed T1355 Bit

$$ROPBE = \frac{RR}{[c - (((RR \times T) + B)/F)]}$$

RR=$860/hr; F=2590ft; T=6hours; B =$20,000; C =$74.00/ft

ROPBE= 12.41ft/hr

3. Breakeven Calculation for 12¼" Smith Dsjc Bit

$$ROPBE = \frac{RR}{[c - (((RR \times T) + B)/F)]}$$

RR= $860/hr; F=1697ft; T =7hours; B=$45,000; C=$40.42/ft

ROPBE= 83.01ft/hr

4. Breakeven Calculation for 12¼" Smith Dsjc Bit

$$ROPBE = \frac{RR}{[c - (((RR \times T) + B)/F)]}$$

RR=$860/hr; F=1900ft; F=7hours; B =$45,000;C=$35.11/ft

ROPBE= 104.121ft/hr

5. Breakeven Calculation for 12¼" MGGH+CDC Bit

$$ROPBE = \frac{RR}{[c - (((RR \times T) + B)/F)]}$$

RR = $860/hr; F=527ft; T=9hours; B=$45,000; C =$177.42/ft

ROPBE= 12.00ft/hr

6. Breakeven Calculation for 8½" Volgaburmash PDC Bit

$$ROPBE = \frac{RR}{[c - (((RR \times T) + B)/F)]}$$

RR=$860/hr; F=626; T=8hours; B=$68,000; C=$172.92/ft

ROPBE= 16.14ft/hr

7. Breakeven Calculation for 8½" Volgaburmash PDC Bit

$$ROPBE = \frac{RR}{[c - (((RR \times T) + B)/F)]}$$

RR=$860/hr; F=265; T=10hours; B= $73,500; C=$422.64/ft

ROPBE= 7.62ft/hr

Table 3: Cost Per Foot and Breakeven Calculation in Well MOPOL #A

BIT NO	BIT SIZE	BIT TYPE	COST PER FOOT ($/FT0	BREAKEVEN ANALYSIS (FT/HR)
1.	17½”	Volgaburmash Milled Tooth	$25.85/ft	75.48ft/hr
2.	17½”	Security Tricone	$145.91/ft	18.05ft/hr
3.	12¼”	Volgaburmash PDC	$44.70/ft	66.42ft/hr
4.	8½”	Volgaburmash PDC	$70.76/ft	55.04ft/hr

Table 4: Cost per Foot and Breakeven Analysis in Well MOPOL#B

BIT NO	BIT SIZE	BIT TYPE	COST PER FOOT ($/FT)	BREAKEVEN ANALYSIS (FT/HR)
1.	16”	REED T135	$13.13/ft	135.86ft/hr
2.	16”	REED T135	$79.00/ft	12.41ft/hr
3.	12¼”	Smith Dsjc	$40.42/ft	83.01ft/hr
4.	12¼”	Smith Dsjc	$35.11/ft	104.12ft/hr
5.	12¼”	Smith MGGH+CDC	$177.42/ft	12.00ft/hr
6.	8½”	Volgaburmash PDC	$172.92/ft	16.14ft/hr
7.	8½”	Volgaburmash PDC	$422.64/ft	7.62ft/hr

4.5. Final Analysis and Result

4.5.1 BIT Performance in Well MOPOL #A

According to the analysis of the data from Well MOPOL #A, the first section was drilled with (17½” Volgaburmash Milled Tooth) bit, which drilled footage of 3874ft at a rotation hour of 51.36hours and the average trip time of 4.81hours, it drilled a cost per foot of 25.85ft and a breakeven penetration rate of 75.48ft/hr.The second bit (17½” Security Tricone), drilled footage of 749ft at a rotation of 41.5hours and an average trip time of 9.93hours. it frilled at a cost per foot of 145.91/ft and a breakeven penetration rate of 18.05ft/hr. In the second section, the third bit (12¼” Volgaburmash PDC), drilled footage of 3234ft at a rotation hour of 48.7hrs and an average trip time of 8.616hr. It drilled at a cost per foot of 44.70ft and a breakeven penetration rate of 66.42ft/hr.

Finally, the four bit (8½” Volgaburmash PDC), drilled footage of 1500ft at a rotation hour of 27.25hours and an average trip time of 9.66hours, it drilled at a cost per foot of 70.76/ft and a breakeven penetration rate of 55.04ft/hr.

4.5.2. BIT Performance in Well MOPOL #B

From the analysis of Well MOPOL #B, the first section of the well drill was drilled with two (16” REED T135) bit of the same make and type. The first bit use to drill footage of 3,470ft at a rotation per hour of 99.5hours and an average trip time of 6hours. It drilled at a cost per foot of 13.13/ft and a breakeven penetration rate of 135.86ft/hr. A footage of 2,590ft was drilled by the second at a rotation of 99.5hours using an average trip time of 6horus, It drilled at a cost per root of 813.13/ft and breakeven penetration rate of 12.41ft/hr. The third bit (12¼” SMITH Dsjc), drilled footage of 1697ft at a rotation of 6.41hours and an average trip time of 7hours. it drilled at a cost per foot of 840.42/ft and a breakeven penetration rate of 83.01ft/hr.

The fourth bit (12¼” SMITH Dsjc), drilled footage of 1900ft at a rotation of 5.41hours and an average tip time of 7hours. It drilled at a cost per foot of $35.11/ft and a breakeven penetration rate of 104.12ft/hr. The fifth bit (12 ¼“ SMITH MGGH + CDC), drilled footage of 527ft at a rotation of 17hours and an average trip time of 9hours, I drilled at a cost per foot of $177.42/ft and breakeven penetration rate of 12.00ft/hr. The third section of the Well was drilled with two (2) (8½ Volgaburmash PDC) bit of the same make and type. The sixth bit was used for conditioning of the hole, it drilled footage of 626ft at a rotation of 15hours and an average trip time of 8hours. it drilled at a cost per foot of $172.92/ft and breakeven penetration rate of 16.14ft/hr.

The seventh bit (8½” Volgaburmash PDC),

drilled footage of 265ft at a rotation of 12hours and an average tip time of 10hours. It drilled at a cost per foot of $422.54/ft and breakeven penetration rate of 7.62ft/hr.

5. DISCUSSION OF RESULT

With regards to the bit record of Well MOPOL #A , a total of four (4) bits were used but the actual number of bits that drilled the well to its to total depth of 9664ft were three (3) bit and the well was drilled in two section of different diameter. The first section was drilled with a (12¼" Volgaburmash PDC) bit with footage of 3234ft. The last section of the hole was drilled with (8½" Volgaburmash PDC) diameter bit to the total depth of 9,664ft with a footage of 1500ft. For Well MOPOL #B, according to the bit record a total of seven (7) bits are sued to drill the well of its total depth of 11,265ft, there are different sizes of bit used, (three sizes of bits to be precise) and it shows that it was three section of the well drilled. The first section was drilled with a (16"REED T135) diameter bit within has a footage of 3470ft. two of this bit (REED T135) which are of the same make and type were used. The first run gave the best performance for drilling that section for the hole having the lowest cost per foot and the highest breakeven rate. The next section of the hole, which was (8½" Volgaburmash PDC) in diameter make and type was drilled to a depth 11,000ft and a rotation of 626ft the first bit run (REED T135) gave the best performance with the lowest cost per foot and the highest breakeven rate. The (8½" Volgaburmash PDC) diameter bit was used to drill lost section of hole to 11,265ft and a footage of 265ft.

6. CONCLUSION

In this study, the evaluation of drill bit performance using cost per equation compared with breakeven calculation gave a better bit performance, it can be seen that a total of four (4) bit were used to drill well MOPOL #A to a total depth of 9,664ft, also a total of seven (7) bits were used to drill well MOPOL #B to a depth of 11,265ft. This is due to good bit optimization. The evaluation of drilling bit using cost per foot and breakeven calculation provide a better bit performance evaluation. Most of the bits are good but quite expensive. The Volgaburmash bit in Well MOPOL #A had the best performance also, due to the cost and economic viability. The result analysis proved that Volgaburmash and REED T135 bit used in Well MOPOL #A and Well MOPOL #B respectively can be used for more substitute oil Wells. It is recommended that to attain best result when comparing drilling bit optimization, the drilling engineers should always evaluate their bit using cost per foot compared and breakeven analysis for better bit performance. In such process, care should be taken to ensure accurate measurement of variables such as footage drilled, time trip, weight on bit, gauge diameter, rotation hour. From the bits use to drill Mopol well #A and #B, It is recommended that drillers should consider the first bit 17½" Volgaburmash, in Mopol well #B because it has the lowest cost per foot and obtained the highest breakeven point which will optimize the cost of drilling operations.

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