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DETERMINATION OF DRILLING BIT PERFORMANCE USING COST PER FOOT AND BREAKEVEN EQUATIONS

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ABSTRACT

This paper is to determine the drilling bit performance, using cost per foot and breakeven equations.Opukushi-38 well of Shell Petroleum Development Company(SPDC) was used as a case study.Nine drill bits were used to drill this well to a total depth of 13,500ft.They were evaluated using cost per foot and breakeven equation base on their makers and their average cost per foot was calculated.From the results obtained, the average cost per foot for Hughes security, smith and redhcal bits were $34.57/ft,$11.441/ft,$36.35/ft and $39.77/ft respectively.Base on evaluation of bit performance using cost per foot,it could be said that Hughes bit with $34.57/ft has better performance than the other bits since it has the lowest cost per foot.If Hughes bit were used in Opukushi-38 to drill to total,a total cost$6,000 will drill for 75.3hours to produce forage of 2,455.2ft in order to breakeven the cost per foot or less of Hughes with the best performance in the offset well.

Key words: Bit, Drilling, Performance, Holes

INTRODUCTION

Drilling is a process of making or boring holes into the earth for the purpose of producing hydrocarbon in a commercial quantity. During drilling, the tool called the BIT performs the basic function of making or boring hole into the earth. The drill bit is what actually cut into the rock in an oil or gas well located at the tip of the drill string, below the drill collar and drill pipe. The drill bit may consist of two or three cones made up of the hardest of materials (usually steel, tungsten carbide and or synthetic or natural diamonds) and sharp teeth that cut into the rock formation. In contrast to percussion drilling, which consist of continuously dropping a heavy weight bit in the well bore to chip away the rock rotary drilling uses a drill bit to grind, cut scrap and crush the rock at the bottom of the well. The most popular choice of drilling for oil and gas (rotary drilling), includes a drill bit, drill collar, the rotary equipment and the pressure control equipment. The vital part of the rig (the bit) must be in a good condition. There must be weight on it, which is the function of the drill collar, to enable it drill through rocks. And it must get a helping hand from the drilling fluid due to its hydraulic power it provides (**Estes**, J. **C**, November 1971). The drilling fluid must be a good condition to ensure proper bottom cleaning, lubricating the drill string and to cool the bit. These factors and many more enhance better bit performance. If we have bits that would not wear out, or that would drill perfectly no matter how operated we would not need a drillers and tool pushers. Unfortunately, bit do wear out, often too quickly and sometimes unanticipated problems do occur.

The grading of bits and subsequent evaluation plays an important role in the drilling operation. Bit evaluation is particularly critical today because of the high drilling cost and severe drilling conditions encountered in wells. As drilling companies are in the business to maximize profit, the drilling bit performance also dictates the drilling cost and profit. Bit selection is the choosing and using of the bit that seems most suitable or likely to make the greatest contribution to the progress of drilling to the total depth. Evaluation of bit is a careful exercise carried out to ascertain the capacity and efficiency of bit to drill a given hole section. This will enable the right choice of bit referred to as bit selection to be made for overall drilling efficiency. Bit evaluation is based often on some performance criteria such as total rotating hours, total footage or maximum penetration rate. To make efficient use of newer bits will require that more emphasis be placed on cost per foot as a basis for performance evaluation. The use of this parameters provide a possible way to achieving an optimum relationship between penetration rate, rig cost, trip time and bit cost **(**Peter J. Martins ,February 2007). The aim of this paper is to evaluate drill bit performance using cost per foot and breakeven equation to establish cost saving as the economics evaluation of bit. In this paper, opukushi-038 well will be used as a case study.This well is located 65km south of Warri in the Western swamp depo-belt of Niger-Delta, was drilled on may 20,2003. the well was proposed to be drilled to a depth of 13870ft but was later drilled to 13500ft, where hydrocarbon was found. The well was spunded on May 22nd, 2003 and was drilled to the total depth with ten drilling bits.

BIT DEVELOPMENT

These deals with the various stage of advancement in the different types of bits used in oil and gas wells. These advancements include such items, which include:
(a) Development of the roller cone bit (b) Multiple cone (c) Diamond bit drilling (d) Polycrystalline (PDC) bit

DRAG BIT (fishtail)

The drag bit is the oldest rotary tool still used by the drilling industry. In 1947, this bit was later modified by bringing watercourse through the blade of the bit to the outlet. This was done by the inventor of the bit prototype. A drag bit usually designed for use in soft formation such as sand, clay or more soft rock. However, they will not work well in course gravel not hard rock formation. Whenever possible, they should be used to drill pilot holes because they produce cuttings that are easiest to log(Gatline C. ,May 1957).Fig 1 below is a drag bit

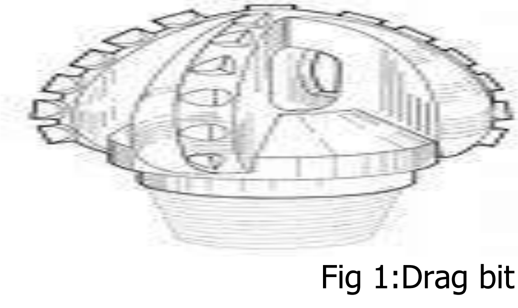

Fig 1:Drag bit

DIAMOND BIT

Diamonds embedded in a matrix have been used since the early Chinese dynasties. However, modern usage for mineral exploration came into common use in the early 1900's.The diamond natural wear resistance makes it competitive in today's drilling practices even at their higher prices. Diamond bits are use in conventional rotary, turbine and coring operations. Diamond bit designs and applications must be understood to obtain optimum result at economical rates. The combinations of fluid hydraulic blended with selection and arrangement of diamonds enables this goal to be met in most formation types. A matrix structure is embedded with diamond and contains waterways from the bit throat to the exterior of the bit. The drilling fluid should flow across the faces of the bit to clear the cuttings and cool the diamonds. Rock failure mechanism with a diamond bit is slightly different from the milled tooth or insert bit. The diamond is embedded in the formation and then dragged across the face of the rock without being lifted and re-embedded, as would be the case with roller cone bit. The diamond bit can be design for soft, medium and hard rock formation.

POLYCRYSTALLINE DIAMOND BITS (PDC)

A new generation of bit technology began in 1973 when general electric company introduced the stratapax drill blank. This technology has been licensed to drill manufactures that now produce their own proprietary PDC (polycrystalline diamond compact) bits,as shown in fig2 below. Drill blank consist of a layer of polycrystalline, man made diamond and cemented tungsten carbide produce as an integral blank by a high temperature, high pressure technique. The resulting blank nearly the hardness and greater abrasion resistance of natural diamond and is complemented by the strength and impact resistance of cemented tungsten carbide. Blanks are used as drag cutting elements to bits for drilling and mining application.

Fig2: Polycrystalline diamond compact

The cutters attached to the bit by proprietary techniques, matrix bodies appear to be more erosion resistant. Shape of the PDC cutter is becoming an important consideration. PDC designs are generally based on high or low RPM applications i.e turbine is rotary drilling. Turbine applications use more blanks to compensate for friction related wear consideration. The bit is tapered to allow placement of the cutters PDC bit for rotary applications have fewer cutter and a somewhat flat design. Most manufacturers use the original circular design. However, effort is being given to research and development of alternative shapes to enhance the design and improve drilling performance.

BIT CLASSIFICATION

Bits are classified into soft, medium and hard formation drill bit. Because of the varying nature of the formation being drilled, bit is designed to have drilling optimum performance for different formation. Under the classification of bit into soft, medium and hard formation bit.

Soft formation drill bits

These drill bit are constructed with widely spaced teeth, low bearing capacity with large setoff, which makes them to be very effective in soft formation. These bits are usually used with high pump velocity, and less weight to enhance good performance. They are usually used in formation such as shale, soft limestone and unconsolidated formations.

Medium formation drill bit

The medium formation bit is similar to the soft formation bits but with shorter bit streaks and little or relatively closely spaced teeth compared to the soft formation bit.

Hard formation bits

They are made of tungsten carbide button like insert teeth are widely spaced. They are constructed using heavy-duty bearing, hard shell. Some soft formation tungsten carbide inserts bit have been currently designed and being used in the oil industry for soft formations. It is just a matter of designing a large offset (En. Wikipedia Org/Wiki/Drilling-rig).

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METHOD OF EVOLUTION OF DRILLING BIT PERFORMANCE

The performance of a drilling bit in a hole or a given formation can be evaluated by using the following methods below:-

1. Bit dullness 2. Well bit record and geological information 3. Cost per foot
4. Breakeven calculation

BIT DULLNESS GRADING

Grading the condition of a dull bit means estimating how much wear it has received. The wear a bit had received can be judge in terms of tooth wear bearing and gauge condition.

WELL BIT RECORDS AND GEOLOGICAL INFORMATION

The drilling from an offset and geological information can given useful guides for the evaluation of drill bits since logs from such wells can logs be used to provide an estimate of the strength of rock, which in turn provides a guide for evaluating and selecting the proper bit type. In addition to toxic data, cation exchange capacity (CEC) derived from gamma logs can help in bit evaluation. The cation exchange capacity (CEC) is a measure of shale reactivity estimated by dividing gamma ray API units by four. Value above 28 indicate a potential for bit balling in hydra table clays or shale for (CEC) of 20 or above, a fish tail design is recommended, while reading between 28 and 10 indicate a large cutter bit will made hole best. In the absence of sample sand shale limestone, dolomite and anhydrite percentage can be calculate from gamma ray, sonic density and neuron porosity curve.

COST PER FOOT

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.

$$C = \frac{B+R(T+t)}{F} \text{--------} 1.0$$

Where C=Drilling cost per foot ($/ft)

B=Bit cost ($)

R=Rig operating cost ($/hr)

T=Rotating or drilling time

t=Trip time (hrs)

F=Footage drilled by bit (ft)

from the equation, it shows that cost per foot is controlled by a number of variable for a given bit cost (B) and hole depth (ft), cost per foot will be highly sensitive to change in rig cost per hour (R), trip time (t) and rotating time (T).

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.

BREAK EVEN CALCULATION:

This is a method of bit selection based on minimum cost analysis from an offset wells. The procedure for this technique is simply as following (Rob Arfele, March 2002):-

i. Select the offset control wells

ii. Obtain bit records from the offset wells

iii. Determine the rig cost for the prospect wells

iv. Select the condition that gave the lowest cost per foot result using the breakeven calculation equation to determine the best bit with minimum cost per foot to be run on a given interval using the formula

$$T_2 = \frac{B_2 + R(t)}{C\left(\frac{F}{t}\right) - R} \text{-------------------} 2.0$$

Where

T_2 = Rotating time for replacement bit (hrs)

B_2 = Cost price of replacement bit ($)

R = Rig cost ($/hr)

t = trip time (hrs)

C = Cost per foot for prior bit ($ ft)

Once the breakeven hour "has been calculated (T_2) the footage drilled by the replace bit can then be determined using the formula

$F_2 = (F/t) * T_2$

Where

F_2 = Footage for replacement bit
F/t = Penetration rate for prior bit
T_2 = Breakeven hours

RESULTS

COST PER FOOT CALCULATIONS

1. Cost per foot calculation for 16" MAXGT-03 (HUGHES) bit used for the well opukushi-038

$$C = \frac{B+R(T+t)}{F} \text{--------------}1.0$$

Where B = \$ 6500, R = \$ 935/hr, T = 75 hrs, t = 9 hrs and f = 2541ft

$$C = \frac{6500+935(78+9)}{2541}$$

=\$34.57/ft

2. Cost per foot calculation for 12¼" MGGH + CDL (SMITH) bit used for the well opukushi-038

Where B = \$ 4577, R = \$935/hr, T = 34hrs, t = 10.4hrs and F = 1261

$$C = \frac{4577+935(34+10.4)}{1261}$$

= \$36.55/ft

3. Cost per foot calculation for 12¼" MGGH + ODC (SMITH) bit used for the well opukushi 038.

Where B = \$ 4577, R = \$ 935/ft, T = 50 hrs, t = 14hrs and F = 1353ft

$$C = \frac{4577+935(50+14)}{1353}$$

= \$ 47.61/ft

4. Cost per foot calculation for 12¼" SS82 (SECURITY) bit used for the well opukushi-038

Where B = \$ 6000, R = \$ 935/ft, T = 40.3 hrs, t = 16. 3hrs and F = 515ft

$$C = \frac{600+935(40.3+16.3)}{515}$$

= \$ 114.41/ft

5. Cost per foot calculation for 12¼" GEODM40HPX (SMITH) bit used for the well opukushi-038

Where B = \$2500 R = \$ 935/ft, T = 38.5 hrs, t = 18hrs and F = 1209ft.

$$C = \frac{2500+935(38.5+18)}{1209}$$

= \$45.76/ft

6. Cost per foot calculation for 12¼" GEOD4HPX (SMITH) bit used for the well opukushi-038

Where B = \$2500 R = \$ 935/ft, T = 70 hrs, t = 21.3hrs and F = 2300ft.

$$C = \frac{2500+935(70+21.3)}{2300}$$

= \$ 38.20

7. Cost per foot calculation for 12¼" DS130HG (REEDHYCAL) bit used for the well opukushi-038

Where B = $1000 R = $ 935/ft, T = 91.8hrs, t = 23.5hrs and F = 1757ft.

$$C = \frac{1000+935(91.8+23.5)}{1757}$$

= $61.93/ft

8. Cost per foot calculation for 8½" DSI65DG (REEDHYCAL) bit used for the well opukushi-038

Where B = $5200, R = $ 935/ft, T = 33.4hrs, t = 25HRS, and F = 1388ft.

$$C = \frac{5200+935(33.4+25)}{1388}$$

= $43.09/ft

9. Cost per foot calculation for 8½" DSI65DG (REEDHYCAL) bit used for the well opukushi-038

Where B = $5200, R = $ 935/ft, T = 62hrs, t = 28.3hrs, and F = 1176ft.

$$C = \frac{5200+935(62+28.3)}{1176}$$

= $76.22/ft

BREAKEVEN CALCULATION

Another approach is required for evaluation if only the record for one bit is available. This involves setting up a breakeven calculation to determine what would be required by another type of bit to obtain the same cost/ft or less as that of the bit with the best performance a terms of cost per foot.

Performance data of the offset well bit No. 1 (Hughes)
Total rotating time = 78 hours
Trip time = 9 hours
Rig operating cost = $ 935/ft
Bit cost = $ 935/ft
Footage drilling = 2541ft
Using the drilling equation, the cost per foot achieved this section of the offset well is calculated to be $ 34.5/ft. if a bit can result in the same value it will breakeven.

Breakeven formula

$$T_2 = \frac{B_2 + R(t)}{C\left(\frac{F}{t}\right) - R}$$

T_2 = Rotating hours for replacement bit (hrs)
B_2 = Replacement bit cost ($)
R = Rig operating cost ($/hr)
t = trip time (hrs)
C = Drilling cost per foot ($/ft)
(F/t) = Percentage rate of bit
$F_2 = (F/t) * T_2$
F_2 = footage needed to be drilled by replacement bit to breakeven for example

Estimating a breakeven for a $8^1/_2$" B*445 (Hughes) bit which cost $6000 for replacement at a trip time of 9 hours. Using the breakeven formula for rotation hours of replacement bit (T_2)

From equation above

$T_2 = \frac{6000 + 84.5}{1126.2906 - 935}$

= 75.36 hrs

CONCLUSION

It was concluded that Hughes bit was quite better than the security bit, four smith bits and three Reedhycal bits used in Opukushi 038 well. The Hughes bit has the best performance due to the fact that Hughes bit the lowest cost per foot amongst all the bits used to drill the same well. From a breakeven analysis made for a new bit $8^1/_2$" B*445 (Hughes) bit which cost $ 6000 will drill for 75.3 hours to produce a footage of 2455.2ft in order to breakeven the cost per foot or less of Hughes bit run no.1 in the bit offset well

RECOMMENATION

This project research is seizing this opportunity to call on both the bit manufacturer and icon to try and digitize a program for the bit so as to be able to drill alternatively through different formation. By bringing forward the soft formation teeth of the bit when it encounters soft formation. Medium formation bit teeth for medium formation and hard formation teeth for a hard formation. And this can be properly done if the formation is geologically study very well. It is also recommended that the various drilling companies/manufactures should not hide their data most especially from student on research work, because the end result is for the betterment of the world at large. The world is now a global village in which we need one another to develop our society, for the benefit of all. The mind should be reoriented from the age long random selection of bit base only on experience but on a proper guard of bit selection to have the best drilling bit performance for minimum cost and maximum profit.

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