بسم الله الرحمن الرحيم

Sudan University of Science & Technology

College of Petroleum Engineering & Technology

Department of Petroleum Engineering

The Optimum Bit Selection for Hamra Filed

اختيار سكينة الحفر المثالية لحقل حمرا

Submitted as a partial fulfillment for Requirements of the Bachelor Degree in Petroleum Engineering

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A graduation project presented to college of petroleum engineering and technology

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الإستهلال

بسم الله الرحمن الرحيم

قال تعالى:

(وَأَنْزَلْنَا الْحَدِيدَ فِيهِ بَأْسٌ شَدِيدٌ وَمَنَافِعُ لِلنَّاسِ)

سورة الحديد الآية (25)

و قال عز وجل:

(وقُلِ اعْمَلُوا فَسَيَرَى اللَّهُ عَمَلَكُمْ وَرَسُولُهُ وَالْمُؤْمِنُونَ)

سورة التوبة الآية (105)

صدق الله العظيم

Dedication

We lovingly dedicate this thesis to:

Our parent who supported us in each step of the way,

All friends who encourage and support us,

All teachers who teach us about life and light our ways with science,

All colleagues who are go with us in this journey and make it funny.

Acknowledgement

All great thank be to Allah Subhanhu Wa tala for bestowing me with health , opportunity , patience and knowledge to complete this research , may the peace and blessing of Allah Subhanhu Watala be upon prophet mohammed (peace be upon him).

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ABSTRACT

Drilling operation is very important in oil and gas industry, so we must choose an optimum bit with high performance and low cost.

There are many methods used for evaluating bit performance such as:

Cost per foot (CPF), Specific Energy (SE) and Bit Dullness method (BD).

The optimum bit selection of HAMRA formation is PDC because it is soft to medium consolidated and the best method for evaluating this formation is the bit dullness method because it calculated time required for bit inside a well without dullness which equal 90.46 hours.

Key wards: Bits, Roller cone, Diamond, Poly crystalline Diamond

التجريد

عملية الحفر مهمة جدا في صناعة النفط والغاز ،لذلك يجب إختيار حافرة مثالية ذات أدائية عالية و تكلفة أقل.

هناك عدة طرق مستخدمة لتقييم أدائية الحافرة من أمثلتها :

تكلفة حفر القدم الواحد(CPF).

الطاقة المحددة (SE).

طريقة تلف الحافرة(BD).

الحافرة المثالية التي تم إختيارها لحقل حمرة هي البولي كريستالاين وذلك لأن طبقات حمرة هشة إلى متوسطة الصلادة، وأفضل طريقة لتقييم هذه الطبقات هي طريقة تلف الحافرة لأنها تحسب الزمن المطلوب للحافرة داخل البئر دون حدوث أي تلف وهو يعادل 90.46 ساعة.

الكلمات المفتاحية : الحافرات ، ذات الثلاث مخاريط، الماسية، البول كريستالاين

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Chapter One

Introduction

1-1Introduction:

Drilling is considered as the main process in oil and gas industry , the bit is the most essential drilling equipment, the grading of bits and 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 dictate the drilling cost and profit, bit selection is the choosing and using the bit that seems most suitable, so it is carefully designed and evaluated to reach an optimum type of bits with high performance and low cost, The bit that stay along inside the well without dullness is the best bit that decreases drilling time and directly decreases drilling cost .This research discuss the evaluating methods which include cost per foot(CPF), specific energy(SE), and bit dullness method.

1-2 Problem statement:

There are many problems which face drilling bit during drilling operation such as wear and bit dullness, this project aim to solve these problems which related with bit during drilling as wear and tooth dullness to reach an optimum bit with high performance and low cost.

1-3 Project Objectives:

- Evaluation of bits performance in Hamra field.
- Selection of the suitable bit in Hamra field.
- Study an economic bit cost.
- Solve Problems which face bits during drilling (wear , dullness)
- Study application of bits type and select a suitable one.
- Choose an optimum bit with high performance and low cost.

1-4 Methodology:

The following methods could be used for the evaluation of bits which suits the rock to be drilled:

- Cost per foot (CPF)

$$CPF = \frac{C_B + C_R(t_0 + t_1 + T)}{F}$$

- Specific energy(SE)

$$E=W*2pi*R*N$$

- Bit dullness(BD)

$$\tau_H=\frac{tb}{j_2\left(h_f+\frac{H_2h_f^2}{2}\right)}$$

Chapter Two

Theoretical Background and Literature Review

2-1 Bit Types and Selection:

The process of the drilling a hole in the ground required the use of the drilling bits, indeed, the bit is the most basic tool used by drilling engineer, and the selection of the best bit and bit operating conditions is one of the most basic problems that it faces. An extremely large variety of bits are manufactured for different situations encountered during rotary drilling operations. It is important for the drilling engineer to learn the fundamentals of bit design so he can understand fully the difference among the various bits available

1-Roller Cone Bit.

2-Diamond Bit

3-Poly crystalline Bit (PDC)

To select a proper bit some information must be known about the nature of the rocks to be drilled. There are two main types of bits used for rotary drilling. There are several variations within these types, primarily based on the cutting structure used for drilling the rock. The two types are:

- Roller Cone Bit
- Fixed Cutter Bits

2-1-1 Bit Types:

2-1-1-1 Roller Cone Bit:

Roller Cone Bits, commonly called tri-cone bits, are the most common bits used today. They are named tri-cone because the cutting structures are located on three rolling cones attached to the bit body. A variety of types are available depending upon any specific conditions involved. Two main categories of tri-cone bits are milled-tooth and insert bits.
The three cone rolling cutter bit is the most common bit type currently used in rotary drilling operations. This general bit types is available with a large variety of tooth design and bearing types.

The drilling action of a rolling cutter bit depends to some extent on the offset of the cones.

Offset of the cones: a measure of how much cones axes moved so that their axes do not inter act at a common point of the center line of the hole. (Hughes, 1994)

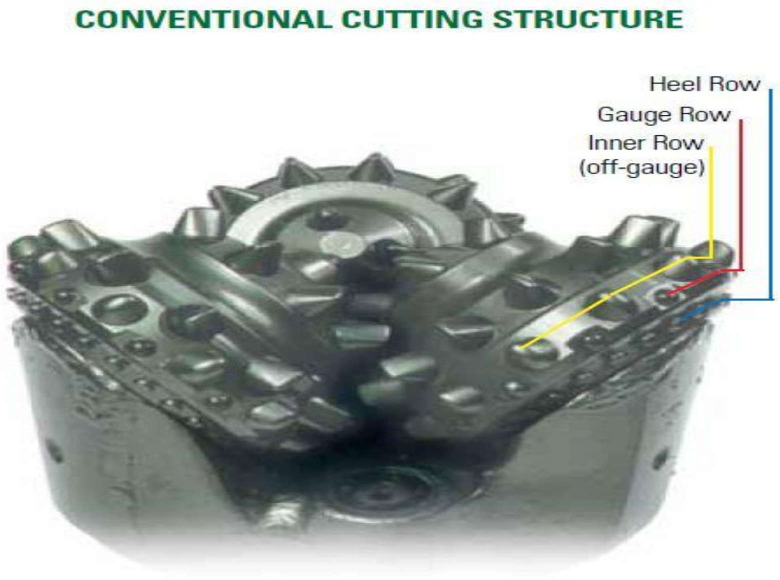


Fig (2-1) Roller cone bit

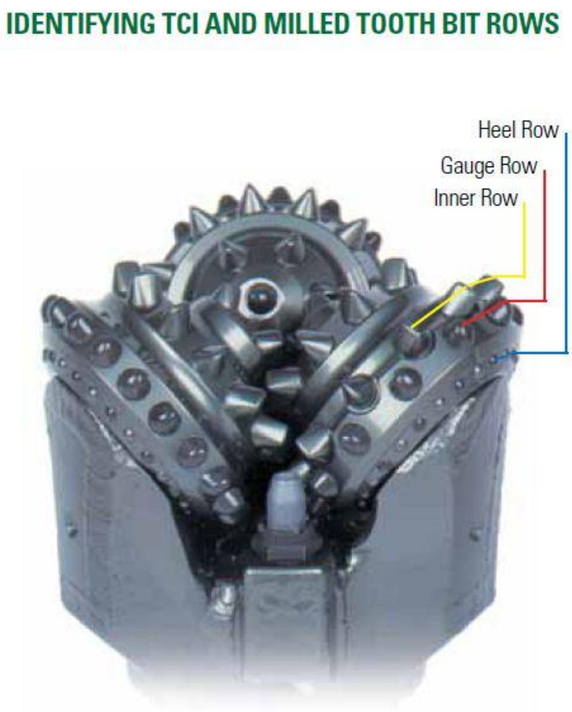


Fig (2-2) milled tooth

Advantages:

Causes the cone to stop rotating periodically as the bit is turned and scrape the hole ottom much like a drag bit. Tend to increase drilling speed in most formation types.

Disadvantages:

Promotes faster tooth wear in abrasive formations cone offset angle 0-4 (hard-soft) Shape of bit teeth also has a large effect on the drilling action of a rolling cutter bit. Long, widely spaced steel- soft formation.

The long teeth easily penetrate the soft rock, and the scraping action provided by alternate rotation and plowing action of the offset cone removes the material penetrate.

The wide spacing of the tooth on the cone promotes bit cleaning.

Teeth cleaning are mainly provided by the intermeshing of teeth on different cones.

As the rock type gets harder, the tooth length and cone offset most be reduced to prevent tooth breakage.

The metallurgy requirements of the bit teeth also depend on the formation characteristics

These two primary types used are:

1-milled tooth

2-Tungsten carbide inserts cutters.

Milling the teeth out of a steel cone.

a) Milled-Tooth Bits:

(Figure 2-3): These bits have steel teeth which have been milled on the cones. The teeth vary in size and shape, depending on the formation they are expected to drill. Long, slender teeth are used in soft formations and short, broad teeth are used in harder formations.

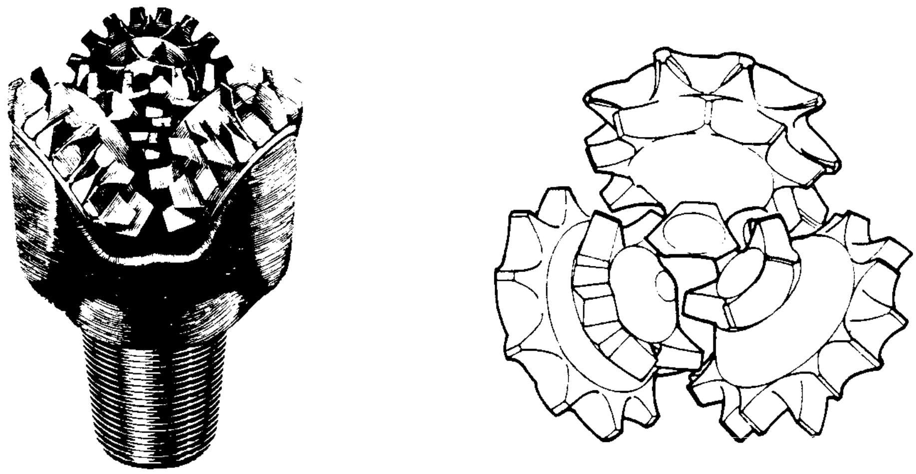


Figure 2-3: Milled Tooth Drill Bit

The teeth on a mill tooth bit are sometimes “hard-faced” using tungsten carbide. This hard-facing can be on the gauge teeth (for hard formations), the inner teeth (for soft formations), or on both rows. Hard-facing is applied in such a way so that, as the teeth dull, the hard-facing causes a self-sharpening of the tooth

b) Insert Bits:

(Figure 2-4): These bits differ from milled-tooth bits in that the cones do not have steel teeth milled into them; instead, tungsten carbide inserts (teeth) are pressed into the cones. These are very much harder and last longer (and much more expensive

Over the past ten years, most of the progress in rolling cutter bits has been made in the design of insert bits. Although the merits of tungsten carbide bits has long been accepted, it was not until recently that bit manufacturers obtained enough experience with the carbide material and design to make it possible to consider this type of bit for application in virtually all formations - soft, medium and hard.

The chief advantage of this concept is that there is virtually no change in the configuration of the cutting structure due to wear. In addition, any bit often finds good application in a variety of formations. Thus, the limiting factor on performance is usually the life of the bearing assembly (providing formation changes do not cut short the bit run).

When drilling hard formations. The inserts can come in a variety of shapes, from long chisel shapes for firm formations to short round buttons for hard, brittle formations.

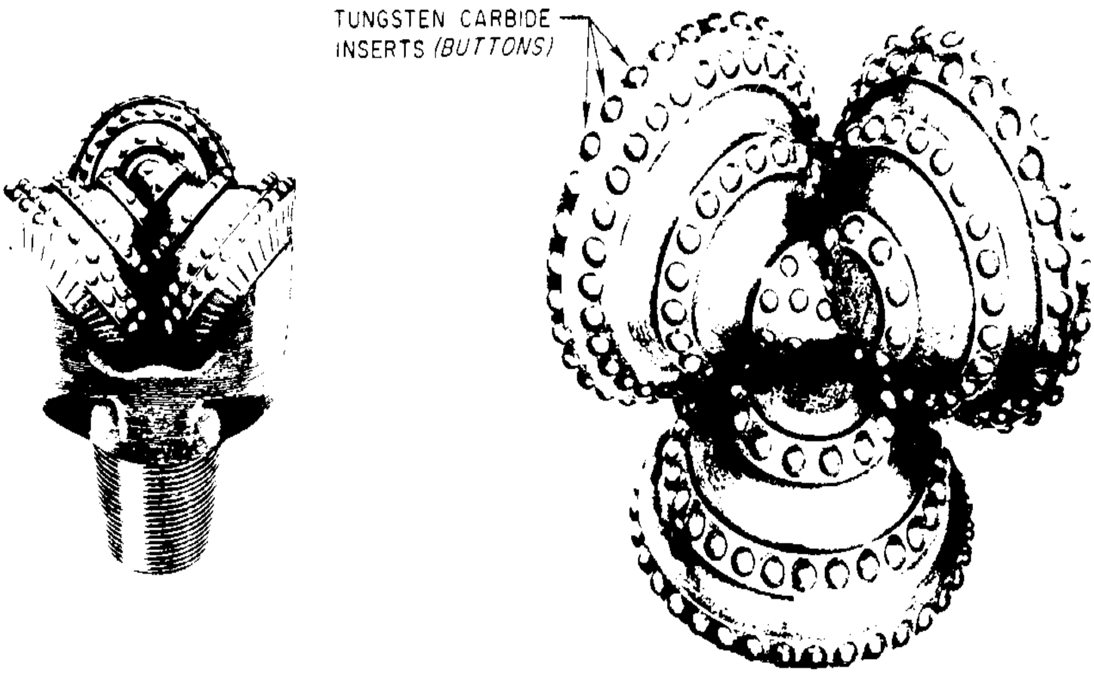


Figure 2-4: Tungsten Carbide (Insert) Drill Bit

Though the cutting structures may differ, tri-cone bits have many common features:

1. Fluid Courses: (Figure 2-5): These allow for the drilling fluid to leave the bit and carry away the cuttings. The earliest arrangement was a "conventional" water course, where the fluid passed through holes drilled in the center of the bit body. As wells were drilled deeper, more hydraulic force was necessary to carry the cuttings from the bottom of the hole. "Jet nozzles" were introduced and have been used ever since. Present nozzles come in various sizes which can be changed to match the pressure and flow requirements of the well. Jet nozzles are described in thirty-seconds of an inch (a #10 nozzle is 10/32-inch in diameter).

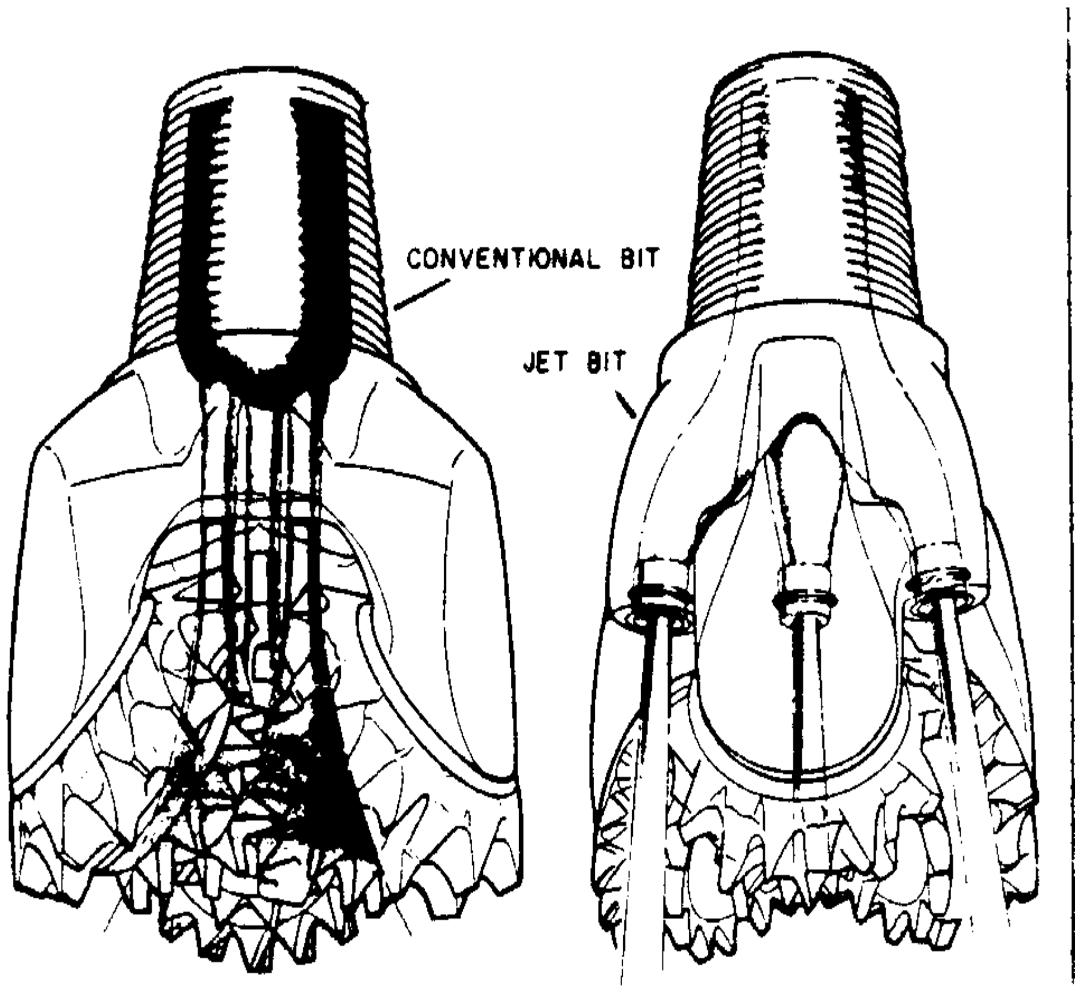


Figure 2-5: Drill Bit Fluid Courses

2. Gauge Protection: (Figures 2-6): The outer rows of teeth a receive the greatest wear. This is because, if the bit drilled an in-gauge hole, then the outer rows are always in contact with the formations. To compensate for this, bits “protect” these outer row cutting structures. One method is to “hard-face” the bit's teeth with an outer layer of tungsten carbide; another is to “T-shape” a bit tooth to give it a much larger surface. Another method is to press tungsten carbide inserts into the outer row teeth.

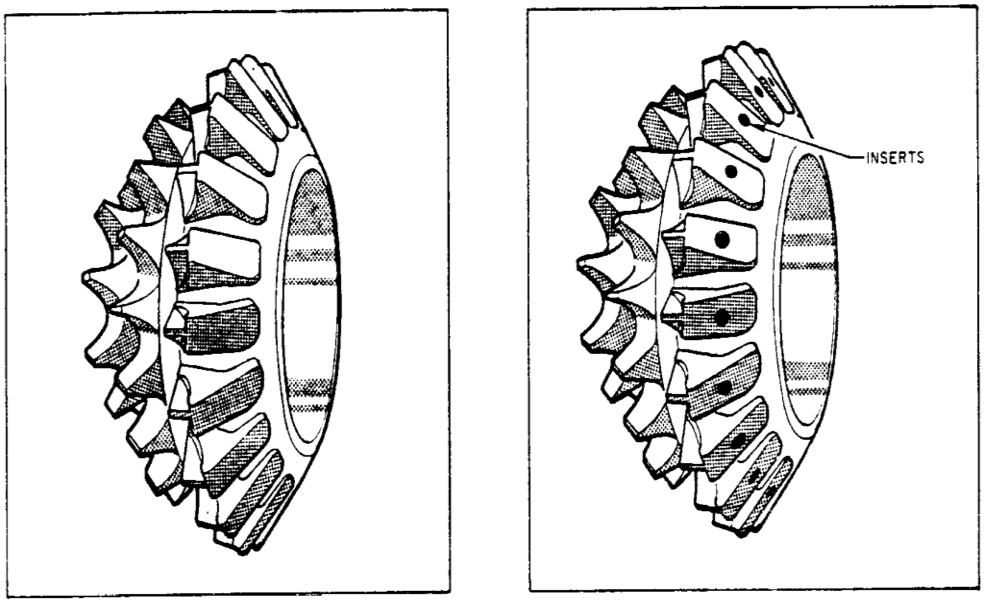


Figure 2-6: Gauge Protection on Bits

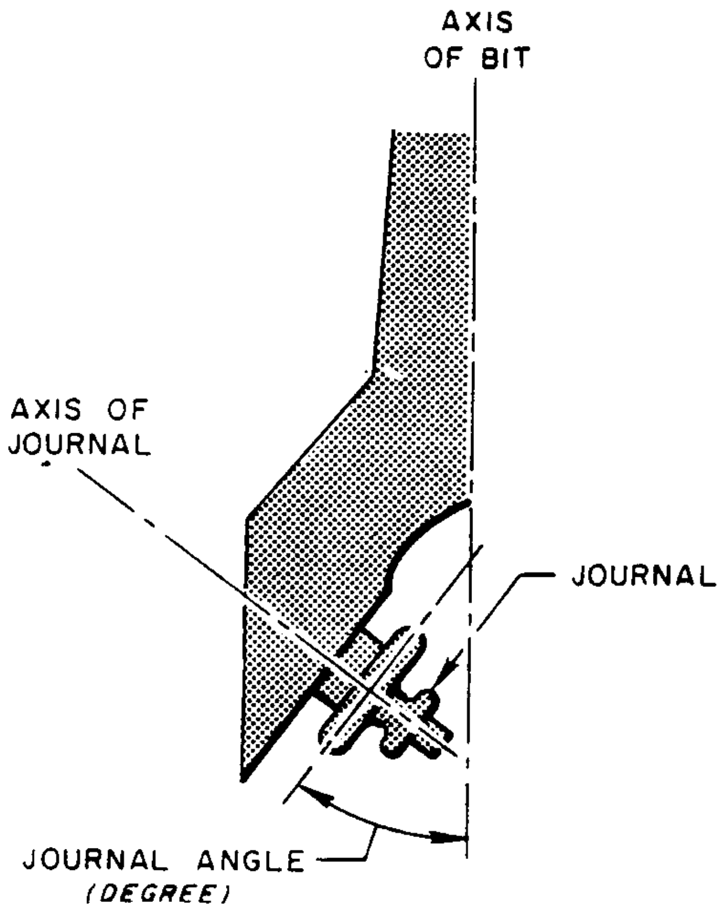


Figure 2-7: Journal Configuration

3 . Journals: (Figure 2-8): The journal is the metal shaft upon which the cones are set. They are manufactured for the insertion of bearings, which allow the cones to rotate. The angle, from horizontal, will dictate which type of formation the bit will be used in; 33 to 34 degrees for soft formations, 36 degrees for medium formations, and 39 degress for hard formations.

4. Bearings: Two types of bearings are used in tri-cone bits. Roller/ ball bearings are used when bit life is not a problem. Journal/ friction bearings, a specialized metal ring, enhance the drilling performance because they will last longer. To withstand the pressures and temperatures of drilling, the bearings have to be lubricated. Two types of lubrication are used:

Non-sealed bearings: This type of lubrication used the drilling fluid to cool the bearings. However, because of the solid content of the drilling fluid, the bearings do not have a particularly long life.

Sealed bearings: This lubrication system uses a graphite-type lubricant sealed in a reservoir to cool the bearings. Pressure changes cause the lubricant to be pumped around the bearings.

Offset: An off-center alignment of the cones makes the teeth scrape and gouge the formation as the cones rotate. The amount of scraping depends on the offset. Figure 3.8 shows the cone offset of a soft formation bit. For soft bits, a 1/4-inch to 3/8-inch offset is common. The offset decreases, until hard formation bits have no offset.

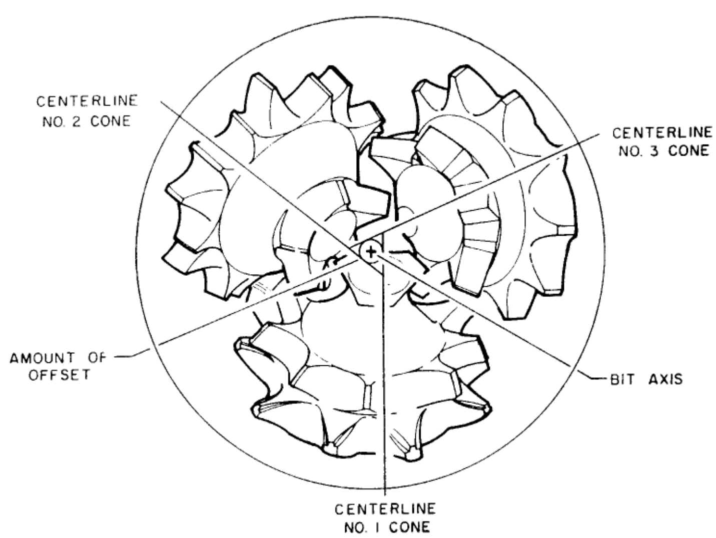
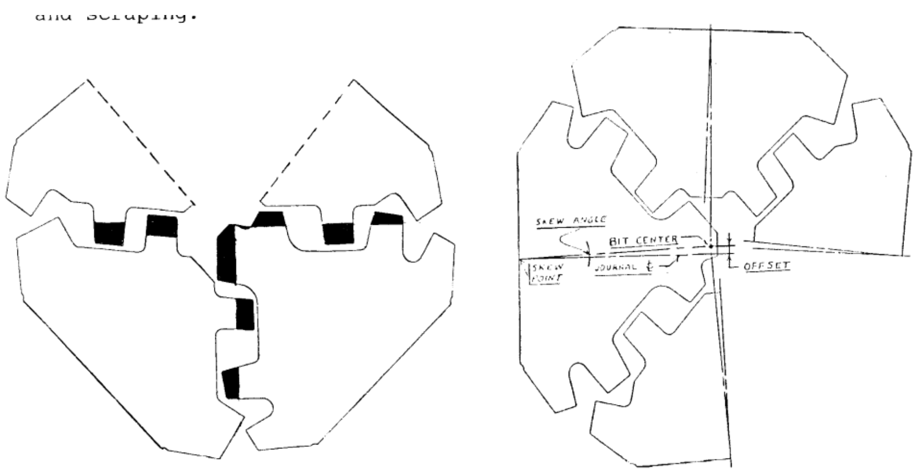


Figure 2-8: Cone Offset

Fixed Cutter Bit:

Fixed Cutter Bits have no moving parts. The bit body and cutting structures rotate as one (i.e. there are no cones). These were the earliest type of bits, with the cutting structure still evolving. The main categories of fixed cutter bits are drag bits, diamond bits, PDC (Polycrystalline Diamond Compact) bits, and TSP (Thermally Stable PDC).



(a) (b)

Figure 2-9- a: Inter fitting Teeth, b: Cutter Offset Skew Angle

Advantages:

1- Have no rolling parts.
2- less chance of bit breakage.

Formation:

Steel cutter elements-(fishtail bit) uniformly soft, unconsolidated.

Diamond bit –non-brittle formations with plastic mode of failure

Design feature:

The number and shape of the cutting stones, the size and location of the water course, and metallurgy of the bit and cutting elements.

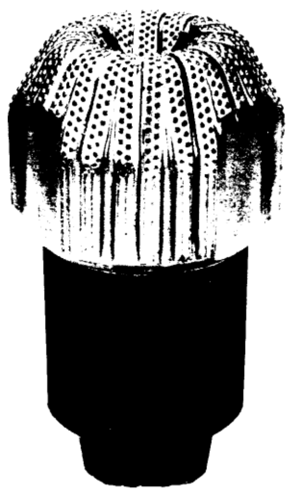
For diamond bit:

Important design – crown profile. The size and number of diamond bit depends on the hardness of the formation.

- Hard (0.07-0.125) carat
- Soft (0.75-2) carat

2-1-1-2 Diamond Bits:

These bits use natural diamond (the hardest substance known) as the cutting structure. They are usually slightly smaller than tri-cone bits to prevent diamond damage while being run into the borehole. The design of diamond bits (Figure 2-10) varies greatly in the shape of the head, the size and setting of the diamonds, and the water courses for cooling. The main advantages of diamond bits is that, with no bearings, they can be run for long periods of time and they can drill almost any formation.(Hughes, 1994).



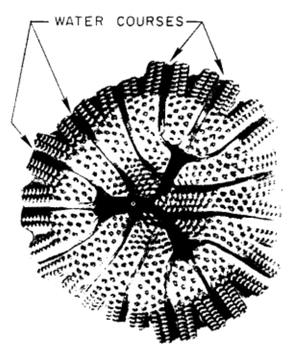


Figure 3-21. Diamond Drill

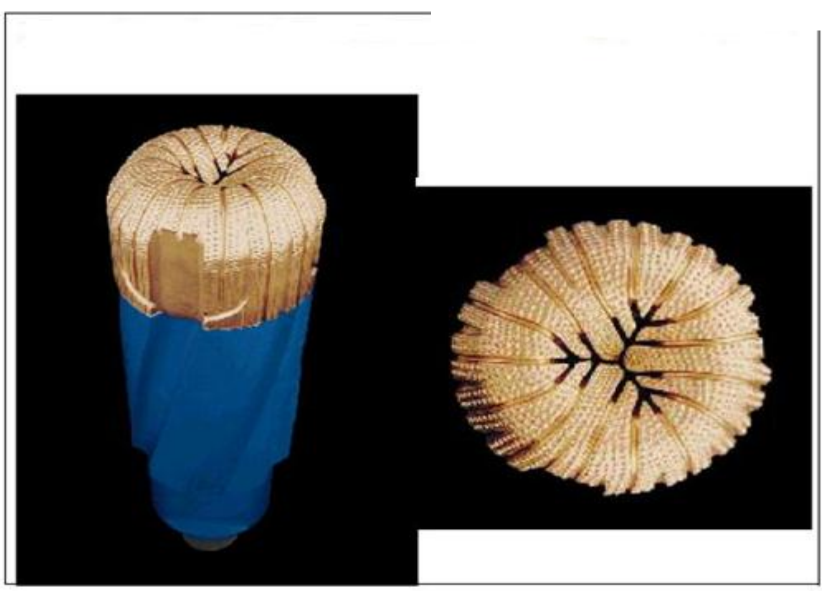


Fig (2-10) Diamond bit

2-1-1-3 Polycrystalline Diamond Bits:.

PDC Bits:

The cutting structure of these bits is composed of man- made diamond dust/crystals bonded to a tungsten carbide stud. These studs are then either pressed or molded into the bit body. Because of the crystal structure in the cutter, it is self-sharpening (exposing new crystals while others are broke new generation of bit technology began in1973 when general electric company introduced the layer drill blank. This technology has been license to drill manufactures that now produce their own property PDC (poly crystalline diamond compact) bits. Crystalline, diamond and cemented tungsten carbide produce as an integral blank by high temperature, high pressure technique. The resulting blanks nearly the hardness and greater abrasion resistance of cemented tungsten carbide. Blanks are used as drag cutting elements to bits for drilling and mining application. The cutters attached to the bit by proprietary, matrix bodies appear to be more erosion resistance. Figure of PDC cutter is becoming an important consideration. PDC designs are generally based on high or low RPM applications for example turbine is rotary drilling. Turbine applications use more blanks to consideration. The bit tapered to allow placement of the cutters PDC bit for rotary applications have fewer cutter and a somewhat flat design .However; effort is being given to research and development of alternative shapes to PDC bits do not have the benefit of the self-fluid-cleaning action between rows of teeth like roller cone bits, so they must rely on the bit's hydraulics to flush the cuttings from under the bit to prevent balling. This is accomplished with strategically positioned converging-diverging nozzles which maximize cleaning while minimizing erosion of the body near the nozzle area. Optimum hydraulic range is between 2.0 to 4.0 hydraulic horsepower per square inch. The interchangeable jet nozzles come in standard sizes from 8/32's to 14/32's.

Bit life is controlled by the cutting structure. As stated earlier, the PDC cutting elements provide a self-sharpening edge with the wear resistance of diamonds. This combination is very effective in soft to medium formations such as shale, chalks, lime stones, clays, salts and anhydrite. These formations have been drilled at excellent penetration rates with weights between 1000 and 2500 pounds per inch of bit diameter and rotary speeds of 85 to 140 rpm. Economic performance has also been achieved with rotary speeds of 750 rpm and weights 1000 pounds per inch of bit diameter using down hole motors, High rotary speeds provide better drill rates and reduce the chances of deviation. Optimum rotary speed varies with formation hardness. A *soft* plastic formation would require higher rpm; a hard formation, lower rpm. Most applications require rotary speeds less than 120 rpm, Lighter weight-on-bit means lower stress on the drill string, with increased string life as a result. There's less drag in directional holes because fewer drill collars are required, These bits have made economical runs in both oil and water base mud. Oil base mud and the addition of lubricants to water base mud will enhance PDC bit performance in Lighter weight-on-bit means lower stress on the drill string, with increased string life as a result. There's less drag in directional holes because fewer drill collars are required, reducing the These bits have made economical runs in both oil and water base mud. Oil base mud and the addition of lubricants to water base mud will encourage Formations which should be avoided with PDC bits are soft stick off). They are used in soft to medium-hard formation.

Fig (2-11) PDC Bit length

Fig (2-12) PDC Bits

Fig (2-13) Different Types of PDC Bits

TSP Bits:

A TSP cutter is composed of the same man-made diamond dust/crystals as a PDC bit. The difference being that the cutters are used by themselves and not bonded to a stud. It has been found that the bonding material is the weakest part of the cutting structure, and under the extremely high temperatures associated with fixed cutter bit drilling, the bonding material loses some its strength and the PDC cutter is broken away from the stud. (Houston, 2011).

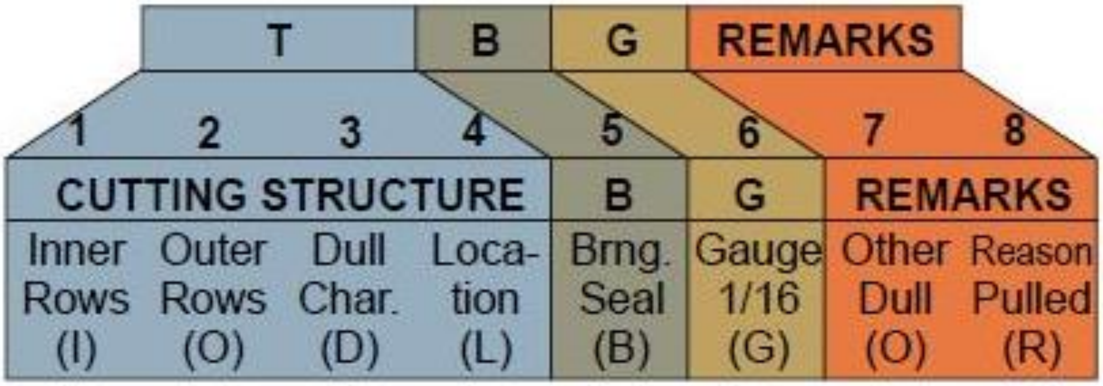


Fig (2-14) system of tooth structure

- Reduction due to lost, worn and/or broken cutting elements.
- (O) = Outer Rows
- Used to report the condition of the cutting elements that touch the
- Wall of the hole.
- Linear scale from 0 - 8 measuring the combined cutting structure
- Reduction due to lost, worn and/or broken cutting elements.
- Smith Bits guide line Do not include heel elements

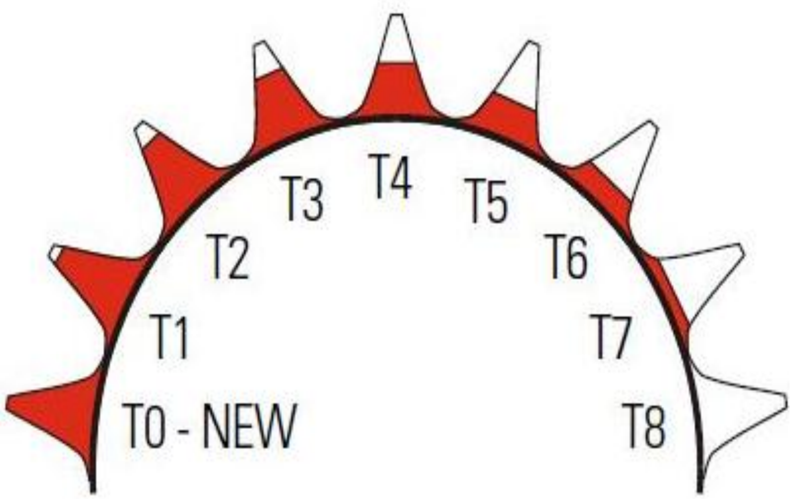


Fig (2-15) Tooth Height Measurement

2-1-2 Tooth wear:

2-1-2-1 Factors effecting of tooth wear:

The rate of tooth wear depends on:

1-Formation abrasiveness

2-Tooth geometry

3-Bit weight

4-Rotary speed

5-Cleaning and cooling action of the drilling fluid

2-1-2-2 Effect of tooth height on rate of tooth wears steel:

1- Steel tooth abrade rate directly proportional to the area of the tooth in contact with the grinding wheel.
2- Bit Tooth Contact Area:

$$A_i = W_X * W_y \ldots\ldots(2.1)$$

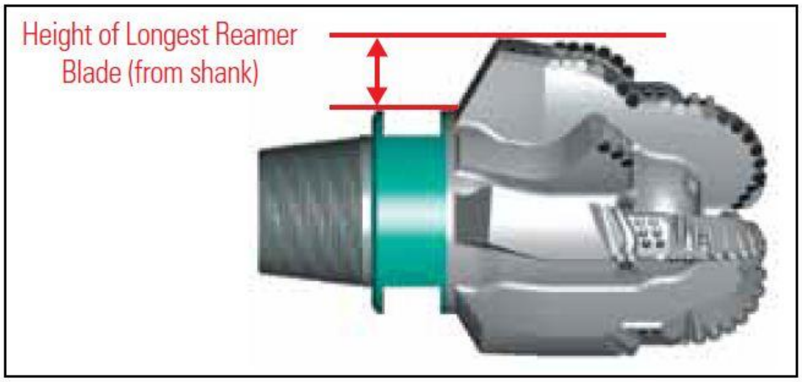


Fig (2-16) height of longest reamer blade (from shank)

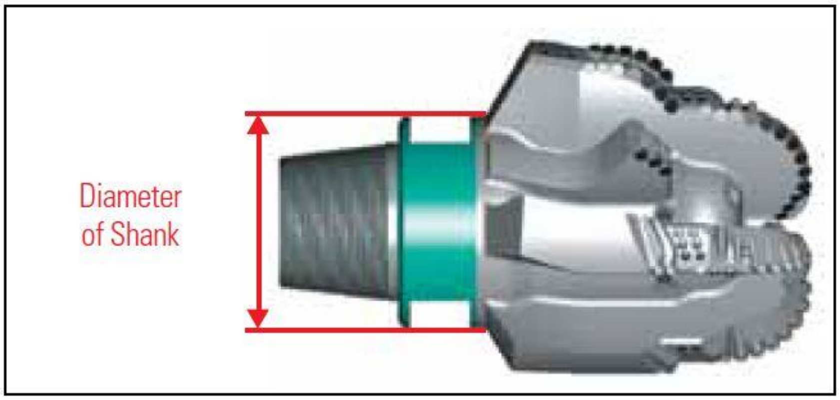


Fig (2-17) Diameter of Shank

If we define the geometry constant G1, and G2 by:

G1=[Wy1(Wx2-Wx1)+Wx1(Wy2-Wy1)]-Ai………….…………..…(2.2)

G2=[(Wx2-Wx1)(Wy2-Wy1)]*Ai……………..…………..………..…(2.3)

Then contact area A can be expressed by:

A=Ai(1+G1h+G2h^2)area……………….……….………………..…(2.4)

dh/dt α (dh/dt)s*(1/dc sin(β/2)) ……………….……..………………..…(2.5)

dh/dt α (0.3979(dh/dt)s/(1-log(w/db)…….………..………………..…(2.6)

dh/ dt α (dh/dt)s[(w/db)m-4/(w/db)m-w/db)………………………….(2.7)

3-Hydraulics:

The effective of the cooling cleaning action of the drilling fluid on the cutter wear rate is much more important for diamond or PDC bit than the rolling cutter bit, but no mathematical models.

Tooth wear equations:

dh/dt=1/τ(N/60)^H1[(w/db)m-4/(w/db)m-(w/db)m][(1+H2/2)/(1+H2h)]

$$\tau_{H}=\frac{tb}{j_{2}(h_{f}+\frac{H_{2}h_{f}^{\wedge}2}{2})} \text{…………………………………….(2.8)}$$

Tooth wear equation can be expressed by:

$$\int_{0}^{t_b} dt = J_2\tau_H \int_{0}^{h_f} (1+H_2)dh$$

Integration of this equation yield:

$$\tau_b = J_2\tau_H\left(h_f+\frac{H_f h_f{}^{\wedge}2}{2}\right) \text{ …………………………………….(2.9)}$$

A numerical code for reporting the degree of bit wear relative to:

1- tooth
2- bearing

3-bit diameter structure

There are three grading:

1- Grading tooth wear
2- Grading bearing wear
3- Grading gauge wear

1-Grading tooth wear:

For milled tooth bits:

In term of the fractional tooth height that has been worn away , and is reported to the nearest eight. (t-4: the tooth are 4/8 worn).

For insert bit:

The tooth wear usually is reported as the friction of the total number of inserts that have been broken or lost to the nearest eight.

T-4, 4/8 of the inserts are broken or lost.

2- Grading bearing wear:

Usually depend on the number of hours of bearing life that the drilling engineer thought the bearing will lost.

3- Grading gauge wear:

A ring gauge and a ruler

G-O-4: lost 4/8 in.

This type of wear occurs when:

1-the drill fluid contains a high concentration of abrasive solids

2-the circulation rate is extremely high

Worse for regular bit than for jet bit .

Eliminated through the operation of the drilling fluid de -sander.

This type of wear occur when the nose areas of the cones are worn a way or lost . this frequently occur because of successive loads being applied to the cone tips.

Low bit weight and high rotary speeds.

2-1-3 Factors effecting bearing of a wear:

The prediction of bearing wear is much more difficult than the prediction of tooth wear. Like tooth wear, the instantaneous rate of bearing wear depend on the current condition of the bit. After the bearing surface become damage, the rate of bearing wear increase s greatly. However, since the bearing surface cannot be examined rapidly during the dull bit evaluation, a linear rate of bearing wear usually is assumed. For a given applied face, the bearing life can be expressed in term of total revolution as long as the rotary speed low enough to prevent an excessive temperature increase. Thus, bit bearing life usually

The effect of bit weight on bearing life depends on the number and type of bearings used.

The hydraulic action of drilling fluid at the bit is also thought to have some effect on bearing life, as flow rate increases, the ability of the fluid to cool the bearings also increase, it is believed the flow rate sufficient to life cutting will also be sufficient to prevent excessive temperature build up in the bearing.

Steel Tooth Cutting Structures:

There are three basic design features incorporated in steel tooth cutting structures, teeth spacing, tooth hard facing, and tooth angle (Figure 2-18). Using variations of these parameters, bits are separated into formation types.

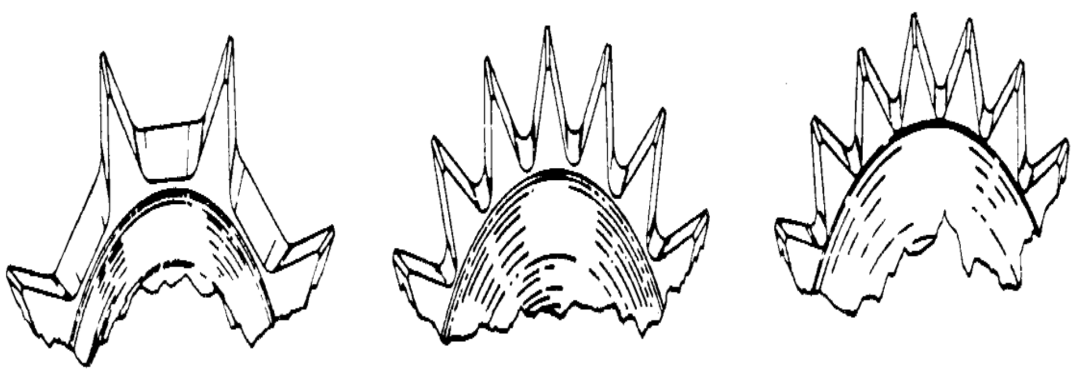


Figure 2-18: Tooth Spacing on Milled-Tooth Bits

Soft Formation Cutting Structures:

Teeth on this type of bit are few in number, widely spaced, and placed in a few broad rows. They tend to be slender, with small tooth angles (39 to 42). They are dressed with hard metal.

Medium Formation Cutting Structures:

Teeth on medium formation bits are fairly numerous, with moderate spacing and depth. The teeth are strong, and are a compromise between hard and soft bits; with tooth angles of 43^{o} the inner rows as well as the gauge rows are hard faced.

Hard Formation Cutting Structures:

There are many teeth on this type of bit. They are closely spaced and are short and blunt. There are many narrow rows with tooth angles of 46^{o} to 50^{o}. The inner rows have no hard facing, while the gauge row is hard faced.

BIT CLASSIFICATIONS:

1- Soft formation drill bit.
2- Medium formation drill bit.
3- Hard formation drill bits.

1- Soft Formations: Increasing the rotary speed can improve the penetration rate with little effect on bit cutter wear. Relatively low WOB is recommended.
2- Medium Formations: Increased RPM will not have the same result as in soft formations. Moderate RPM with moderate WOB should maximize the drill rate and reduce bit wear. As the cutters begin to wear, the WOB should be increased to maintain the drill rate.
3- Hard Formations: Increased WOB is more important than increased RPM. Moderately high WOB with minimum RPM yields the most optimum drill rates.

2-2 Literature Review:

This research is focuses on drilling engineering specifically the optimum bit selection of HAMRA field.

There are many papers have been writing about this subject, for example .

At 2008, Delta state university department of petroleum engineering, study Determination of Drilling Bit Performance Using Cost Per Foot and Breakeven Equation, study the determination of the drilling bit performance, using cost per foot and breakeven equations.Opukushi-38 well of Shell Petroleum Development Company, They found that Hughes bit with 34.57$/ft has better performance than other bits because it has a lowest cost per foot.

At 2008, Al-Qadisiya University, College of Engineering, study the Bit dullness evaluation for three drilled wells In zubair field by using dimensionless parametersI, This study deals with using a useful method to monitor the wear of the teeth of milled tooth bits during drilling. This approach is done by using two dimensionless parameters T (dimensionless torque) and RD (dimensionless rate of penetration) . By plotting T , The constants a 1 and a could be determined and both used to calculate the two other dimensionless parameters E D 2 (bit efficiency) and F (bit dullness) as a bit dullness evaluation indicators , which could be used rather than other traditional echniques. This approach applied on three wells , Zubair #166 , Zubair #162 and Zubair #174 in Zubair field Southern Iraq .The obtained results could be useful to detect bit wear and according to that, the decision of pulling and using new bits could be determined easily and therefore drilling operations will be actively done with lowest costs and efforts.

At 2014 Stanford University, Stanford, California Thirty-Ninth Workshop on Geothermal Reservoir Engineering, study the Bit Performance Evaluation in Geothermal Well Drilling, This study geothermal, as a new potential renewable source of energy, has been developing in all over the world rapidly. One of the ways in developing geothermal energy is by increasing the number of exploration and exploitation drilling wells. However, the need of appropriate and careful design is very important in geothermal well drilling operation due to harsh environment generally encountered. The design need to consider the holes condition, the well geometry, production rate, well lifetime and also other economic factors. In addition to that, one of the crucial factors is the bit selection method which will contribute to effective and low cost drilling operations. An appropriate bit design will result in an effective penetration rate, since it is common in geothermal field that the formation is consist of igneous or metamorphic rock, which has high compressive strength and not easy to penetrate by using normal bit. Therefore, the bit performance analysis of a geothermal well is very important because it gives information, evaluation, and recommendation in selecting suitable bit for the next operations. This study will cover cost per foot (CPF) method which are very common used to evaluate the bit. Nevertheless, some modifications will be used to adjust evaluation methods toward geothermal conditions. The aim of this study is to analyze and to compare bit performance from geothermal drilling data in a field. Analysis of the factors affecting the bit performance in geothermal wells drilling will be discussed as well. As a result, performance analysis can be made for various kinds of bit in geothermal wells which will lead to suggestions and recommendations in selecting bit effectively and efficiently for future geothermal well drilling operation.

Chapter Three

Methodology

3.1 Bit Selection:

The following methods could be used for the evaluation of bit which suits the rock to be drilled:

3.1.1 Cost per foot:

The distinction basis among the available bits and the selection of the suitable one by this method on the basis of the cost per foot through using the equation (3-1) to each bit and then selecting one which provides less drilling cost to specific layer or particular section of the rock. (Martin, 2007).

$$CPF = \frac{C_B + C_R(t_0 + t_1 + T)}{F} \dots\dots\dots\dots\dots\dots\dots\dots \quad (3.1))$$

CPF=Cost per foot which scaled by USD per foot.

CR=Cost of bit operation by USD units per hour to include bit actual cost , various step duration during drilling, stop duration during pipes transformation and maintenance stop duration and other.

T=Drilling time per hours that to be taken as the time of which the bit actually operating inside the well.

t_1=Pipes transformation time per hours.

t_0 =Pipes link time per hours.

$C_B = \text{Bit cost}, \$$

In ordered to use cost per foot method in selecting the suitable bit there should be provision of prices information , completed and updated (renewable in time) about bit costs based on its types, sizes and availability of it and about rig cost.

3.1.2 Specific Energy:

The specific energy method prepares an easy tool and practical for the selecting the right bits. And it can be defined by (SE) as an abbreviation to it's the required energy to eliminate a unit volume from the drilled rock with the possibility to take any of the homogeneous units.

The SE equation could be derived through adopting the known mechanic energy of bit per minute. Therefore the equation:

E=W*2pi*R*N……………………………………… (3-2)

Where:

E=Mechanic Energy, pound (node)

W=Bit Weight , pound

N=Circulation Speed

R=Bit Radius, Node

And the rock size equation could be written in one (V) minute through node cubic units as bellow:

$$V=pi*(R\ \ )\ \hat{}2*PR\ldots\ldots\ldots.(3\text{-}3)$$

Where:

PR=Penetration Rate. Foot per hour .

And by divided the equation (3-2) on the equation (3-3)

We get the specific energy Equation in terms of size by field units as following:

$$SE=10*WN\ \ /(D*R)\ldots\ldots\ldots(3\text{-}4)$$

Therefore, (SE) by pound units . Node / Cubic node.

And the equation becomes (3-4) by metric units as:

$$SE=2.35*WN/\ (P\ *R)\ldots\ldots\ldots(3\text{-}5)$$

Where by:

W, D, PR in the equation (3-5) measured by (Kg) and (mm)

Unit and (m/h) respectively .

And as long as the Penetration Rate (PR) is the amount of FOOT (F) divided on actual circles times (T) Thus equation (3-5) becomes as follow:

$$SE=20*W*N*T\ \ /\ (D*F)\ldots\ldots\ldots(3\text{-}6)$$

The specific SE is not considered as core. Basic property to rock Energy therefore m it depends on large degree on type and design of the bit. And this means that to drill a layer of rock known resistance, the soft bit-class will give a value to (SE) totally different of SE value resulted from using the hard bit- class. This property of SE presents a precise tool to select the suitable bit.

3.1.3 Bit Dullness Method:

We can use dullness as attest for selecting a suitable bit, as generally the bits which dull quickly it considered less efficiency than other, bit dullness described with tooth wear and bearing condition , tooth dullness known as the remaining tooth height from the total tooth height and it is given a sample change from T_1toT_8 , T_1 refer to (1/8) tooth height was dulled as the result of using , and T_4 refers to (1/2) tooth height was dulled as the resut of using.

As the same bearing life described with eight codes from B1 to B8, the sample B1 indicate to 1/8 bearing life was consumed, B8 indicate that all bearing lf was consumed or the bearing has been locked or lost .The table (3-1) describe of full teeth dullness and bearing condition (as a part of eight bearing) with the practical measurement of for two bits.

Table (3-1) explain tooth dullness and bearing condition for eight part (PDC)

Bearing condition	Tooth dullness
B1…….1/8 the bearing life lost	T1…..1/8 the height of tooth dulled
B2…….2/8 the bearing life lost	T2…..2/8 the height of tooth dulled
B3…….3/8 the bearing life lost	T3 …..3/8 the height of tooth dulled
B4…….4/8 the bearing life lost	T4…..4/8 the height of tooth dulled
B5…….5/8 the bearing life lost	T5…..5/8 the height of tooth dulled
B6…….6/8 the bearing life lost	T6…..6/8 the height of tooth dulled
B7…….7/8 the bearing life lost	T7…..7/8 the height of tooth dulled
B8…….all bearing life completely (locked) or lost	T8……all teeth has been dulled

Observation:

For broken teeth we use these two letters (BT)

I: inner gauge of the bit

O: outer gauge of the bit

Example (3-1):

Description of bit condition (T3-B5-2).

(Bit tooth 2/5 the height has dulled, medium bearing, as the same inner gauge).

The bit which gives big dull in the teeth and little edge bearing it is not suitable for drilled layer. If this bit from type (1-1-1), we must use bit with the largest number code for less tooth dullness so increase edge bearing.

Symbols using in bit dullness depend on height:

T0……. No break or lost

T1……. less than 1/8 of teeth are broken or lost

T2…….nearly 1/4 of teeth were broken or lost

T3…….more than 3/8 of teeth were broken or lost(less than half)

T4……. Nearly 1/2 of teeth were broken or lost (less than half)

T5…….. Tooth were broken or lost (less than 3/4)

T6…….. Nearly 3/4 of teeth were broken or lost

T7……. More than 3/4 of teeth were broken or lost

T8……. all teeth were broken or lost.

Chapter Four

Results and Discussions

Company Name: GNPOC Well Name: Hamra E-16

Drilling Contractor: PPS Rig Name: Rig 101

Application

Table (4-1) Examined bit data

RUN NO	BIT NO	SIZE (in)	IADC	TYPE	Nozzels	Depth (m) IN	Depth (m) OUT	METRES DRILLED	HOURS	ACCUM ssssHOURS	ROP (M/HR)	WOB KdaN	RPM	RPM Flow Rate (lpm)	D C IODL
1	1	14.75		TRY	3x16 1x14	31.0	543.0	512	46		11.00	10	100	700	1 2 WT N
2	2	14.75	S117C	TRY	3x16 1x14	543.0	598.0	55	10.75	5.11	5.11	10/15	110	700	0-0-NO-A
3	2RR	14.75	S117C	TRY	3x16 1x14	598.0	845.0	247	22	27.21	11.18	10	100	630	1-1-wt-A
4	RR2	14.75	S117C	TRY	3X16 1X14	845.0	909.0	64	10	37.21	6.40	10	100	700	2-2-WT-A
5	3	9.875	436	VTD 619DXU	8 x 13	909.0	1900.0	991	77	113.96	12.91	10	100	700	1-0-CT-O

Bit: Reference

Table (4-2) Reference Bit Data

BIT	Bit size(in)	Type	Depth out (ft)	H (ft)	Hours	ROP(ft/hr)	WOB(Ton)
1	14.7	DSJ	1538	1538	26.25	56.5	7
2	14.7	DSJ	2302	764	22.75	33.6	7
3	9.88	EHT-11	4867	2564	34.25	75	8
4	9.88	HP-11	6012	1308	23.5	55.7	8
5	9.88	HP -11	6320	308	6.75	45.6	8

Application cost per foot method:

$$\text{CPF} = \frac{C_B + C_R(t_t + t_c + T)}{F}$$

C_B=*Bit price*

$C_R = Rig\ cost$

t_t=*Trip time (hr)*

t_c=*Time to joint pipe (hr)*

T=F/ROP

ROP=penetration rate (foot/hr)

F=drilled foot

Wt (in mud)= DC(weight on air)(1-0.015$\boldsymbol{\rho_m}$*)*

$\boldsymbol{\rho_{m=}}$*mud density(Ib /gallone)*

Wt=Weight of drill collar in mud (Ib/ft)

Wt Dc=Heavy weight drill collar in air (Ib /ft)

$$\boldsymbol{l_{DC}} = \frac{WOB}{90t_{DC(in\ mud)}}$$

l_{DC}=*Heavy weight lengh (ft)*

WOB=weight on bit (Ib)

*Wt Dc=28.7(1-0.015*9.50)=24.61*

$\boldsymbol{l_{DC}}$ *=10,000/(90*24.61)=4.5 Stand.*

$$l_{DP} = 1538 - (90 * 4.5) = 1133\ ft$$

$\boldsymbol{t_c} + \boldsymbol{t_t}$*=0.5+0.1333/DC + 0.5 / DP(1000 Ft)=0.5+0.1333*4.5+0.5*0.908=1.55 hr*

T=F/ROP

T=512/11=46.54

CPF=(4000+100(1.55+46.54))/512=111.13$/ft

If assumed that:

Rent of rig =100$/hr

Bit cost=4000$

FOR BIT NO 2:

T=F/ROP=55/5.11=10.76 hr

CPF=4000+100(1.55+10.76)/55=95.1$/hr

FOR BIT NO 3:

T=247/11.18=209.3hr

CPF=4000+100(1.55+209.3)/247=101.5$/ft

FOR BIT NO 4:

T=64/6.40=10hr

CPF=4000+100(1.55+10)/64=80.54 $/ft

FOR BIT NO 5:

T=991/12.91=76.7hr

CPF=4000+100(1.55+76.7)/991=11.93$/hr

Table No (4-3) cost per foot for Investigated bit

	Investigated Bit
Bit No	*CPF*
1	*11.1*
2	*95.1*
3	*101.5*
4	*80.54*
5	*11.93*

Table No (4-4) cost per foot for Bench mark Bit

	Bench mark Bit
Bit No	*CPF*
1	*8.5*
2	*3.04*
3	*5.182*
4	*16.62*
5	*6.84*

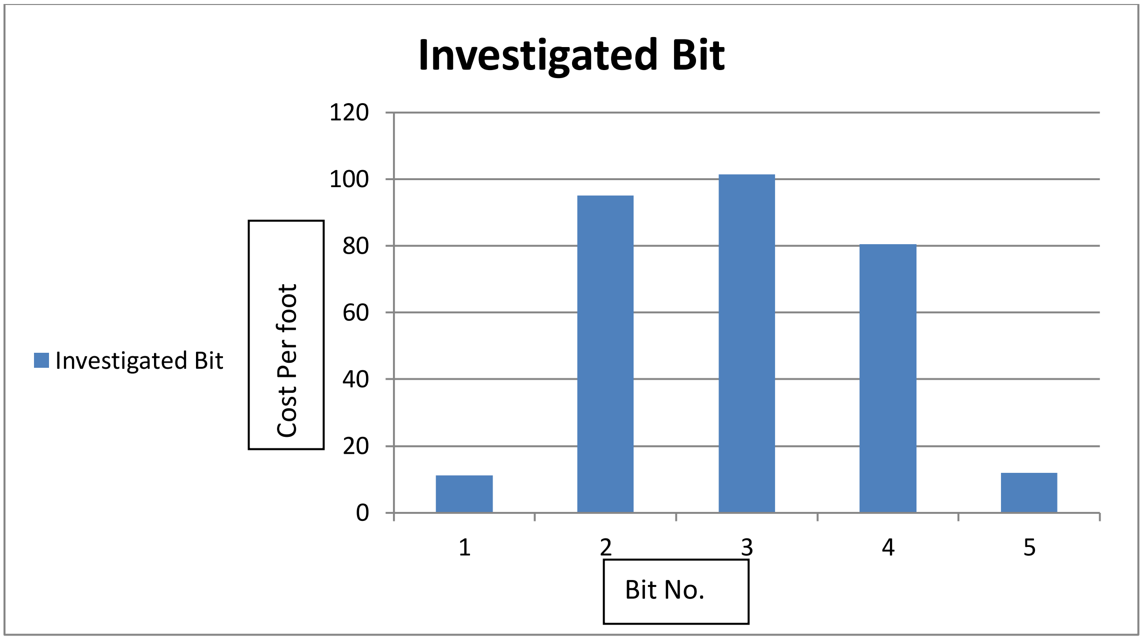


Fig (4-1) Cost per foot for Investigated Bit

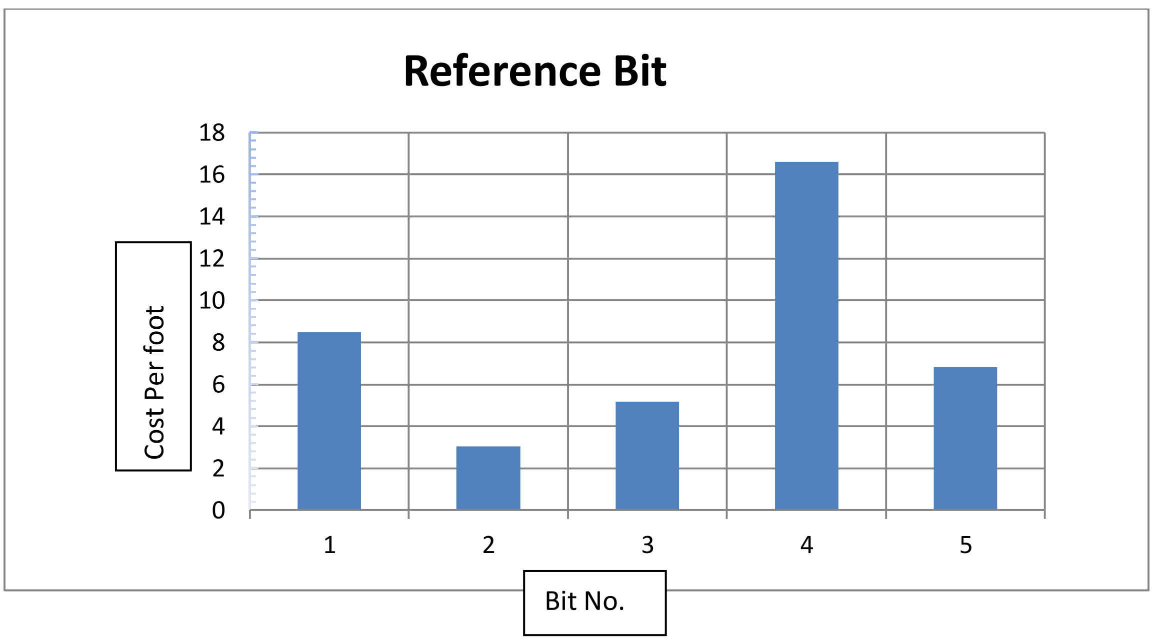


Fig (4-2) Cost per Foot for Reference Bit

Application of Specific Energy Method:

*SE=2.35*W*N /(D*PR)*

W=Weight on bit (kg)

N=Rotary speed (Revolution mm per minute)

PR=Penetration rate (m/hr)

D=Bit diameter (in)

Table no (4-5) Data of examined bit

BIT NO	W(Kg)	N(rpm)	D(in)	RP(m/hr)	SE (Kg-m/m^3)
1	10000	10s0	14.75	11.00	36
2	66.67	110	14.75	5.11	106.1
3	10000	100	14.75	11.18	409
4	11000	100	14.75	6.40	1093.5
5	10000	100	9.875	12.91	333.4

Table no (4-6) Reference Bit Data

BIT NO	W(KG)	N(rpm)	D(in)	RP(m/hr)	SE(kg-m/m^3)
1	7000	150	375	17.86	368.4
2	7000	150	375	10.24	642.6
3	8000	140	251	22.91	457.7
4	8000	140	251	16.89	617.6
5	10000	140	251	13.92	753.3

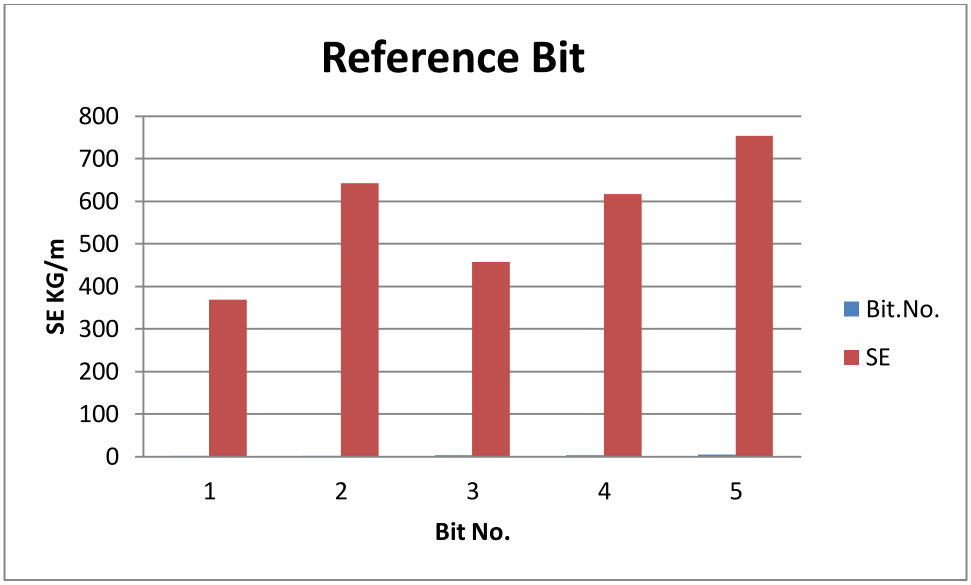


Fig (4-3) Specific Energy for Reference Bit

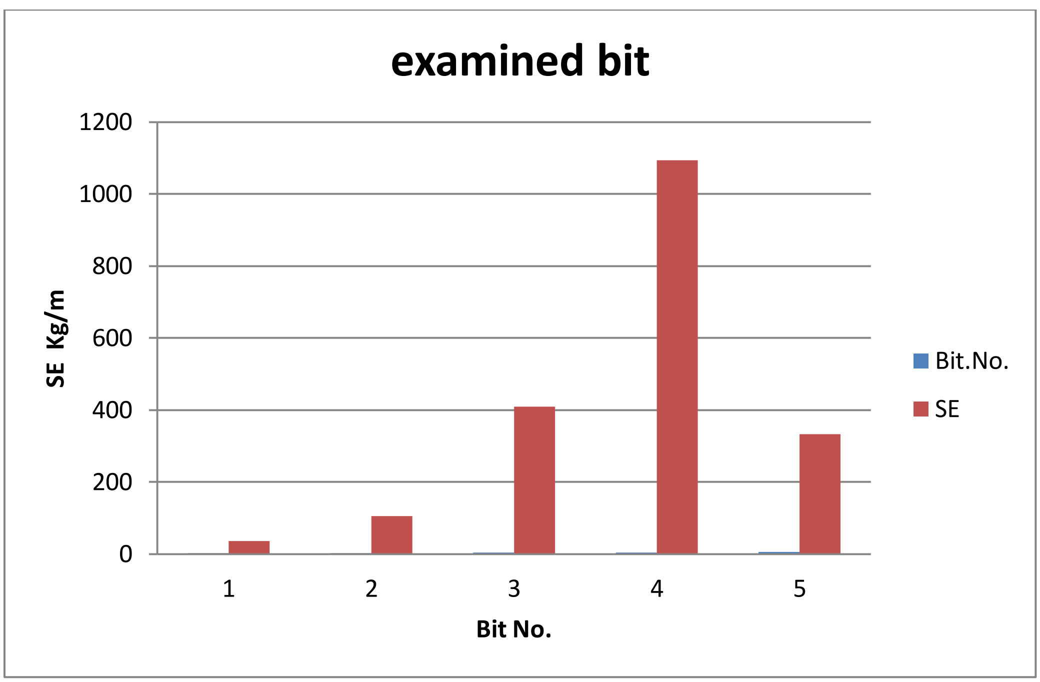


Fig (4-4) Specific Energy for examined Bit

Bit dullness method:

An 14.875 in. class 2-2 bit drilled from a depth of 845-909m in 10 hours, The average bit weight and rotary speed use for the run was10000kg 100 rpm, respectively. when the bit was pulled, it was graded T-5, B-4, G-1compute the average formation abrasiveness for this depth interval. Also estimate the time required to dull the teeth completely using the same bit weight and rotary speed.

Table (4-7) Tooth wear parameter for drilling PDC bit

Bit Class	H_1	H_2	$(W/d)_{max}$
1-1 to 1-2	*0*	*7*	*7.0*
0-0	*1.84*	*6*	*8.0*
1-1	*1.80*	*5*	*8.5*
2-2	*1.76*	*4*	*9*

Solution:

, $(w/db)_m = 8.0$ *By using table we obtain*

$$H_1 = 1.84, H_2 = 6$$

$$J_2 = \frac{8.0-\frac{45}{8.5}}{8.0-4.0}\left(\frac{60}{100}\right)^{1.84} * \left(\frac{1}{1+\frac{6}{2}}\right) = 1.05$$

$$t_b = \frac{10\ hours}{1.05(0.60+6*\frac{0.6^2}{2})}$$

$$t_b = 90.46 \text{ hours.}$$

Chapter Five

Conclusion and Recommendation

5.1 Conclusion:

Comparing Between Bit Evaluation Methods:

- When using cost per foot or cost per meter method we found that the cost per foot for drilling index bit is high , so the best choice is using the examined bit(8.5$) for the same layer in another well.
- When using specific energy method we found that the specific energy for a reference bit is too high, so we prefer to use the examined bit (36Kg-m/m^3) for the same layer for third well.
- We found that the time required dulling the tooth is90. 46 hours), so it is the best choice of bit because of staying long time inside a well without tooth dullness.

5.2 Recommendations

- Drilling operation improvement as the result of bits improvement.
- The means of bit performance and evaluation it is not suitable in oil industry
- Bit performance estimation must establish on user requirement and technical ability.
- Specific energy used for treating factors which less of drilling efficiency.
- A suitable bit choice increase of ROP, and less drilling time in addition to low drilling cost.
- The main aim of bit evaluation is to obtain optimum bit with high performance and low cost, so all companies advised to make bit evaluation.
- We are advised for using bit dullness method because it is very important to know the time required for bit down hole without dullness.
- Bit dullness Method is the best choice for less cost & time, because it is use for evaluating tooth wear and time required for tooth dullness, so it is the most economical method.

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