UNIVERSITI TEKNOLOGI PETRONAS (UTP)

<u>CASE STUDY ON DIFFERENT TYPES OF DRILLING BITS AND THE RATE OF PENETRATION</u>

FINAL YEAR PROJECT II (FYP 2) DISSERTATION

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CERTIFICATION OF APPROVAL

CASE STUDY ON DIFFERENT TYPES OF DRILLING BITS AND THE RATE OF PENETRATION

By

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CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

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CHAPTER 1: INTRODUCTION

1.1Background

Enhancing the field of oil and gas production, safety and without damaging the reservoir, in today's era is the top most priority of each and every operator.

Accurate accounting of the field sustainable capacity, development plans, and strict compliance with good reservoir management guidelines with excellent planning of field activities including but not limited to; operations and maintenance, projects, right choice of drilling equipments will help minimizing the production losses.

In other words, whenever it has been established that a petroleum reservoir probably exists, despite improvements in seismic techniques the only way of confirming the presence of hydrocarbons is to drill an exploration well.

Drilling is very expensive, and if hydrocarbons are not found there is no return for the investment.

1.2Problem statement

In order to start a drilling operation, data must be acquired and analyzed prior to drilling. The drilling efficiency of any operation is directly related to borehole stability and optimized drilling parameters.

Borehole stability is directly related to reactions with the drilling fluid being used. Penetration rate is directly related to the strength of the formation where, the effectiveness of a drill bit varies by formation type. That's because each formation has its own characteristics.

Many active drilling areas around the world have seen the advantage of new drilling fluid systems along with new types of drilling bits.

A major factor in drill bit selection is the type of formation that needs to be drilled. That's because the effectiveness of a drill bit varies by formation type.

Mostly used bits are the PCD (polycrystalline) bits and the use of oil mud, especially the low toxicity oil mud for offshore use. The oil mud drilling fluid has prevented many of the wellbore instability problems that can occur with the use of water based mud.

With the use of oil mud and the PCD bits, considerable savings in drilling costs have been realized.

Being able to choose the right bit type for the right drilling operation is by far one of the most important aspects in minimizing the fluid loss an maximizing the recovery of HC. Since, the choice of the drilling bit will affect the rate of penetration affecting the amount hydrocarbon recovered.

1.3Objectives & scope of study

The objectives of this research project are:

- Discussing different types of drilling bits and their designs.
- Bit selection and evaluation.
- Formation characteristics and their effect on drilling operations.
- Factors affecting bits performance

1.4Relevancy of the Study

The project will focus on drilling operations, drilling bits types, methods, and designs. Bit selection and evaluation, IDAC system, and factors affecting bit performance.
Formation characteristics will be discussed in details, relating with bit selection.
Study of Rate of penetration and the factors affecting it, as well as maximizing the ROP.
Calculations for ROP, Cost per foot, footage calculations and d-exponential.
The project requires hard work through knowledge obtained during the 4 years as an undergraduate student, as well as gathering information.

1.5Feasibility of the project within the scope of study

In order to reach the goals of this research project, research and study has been carried out prior to the submission of preliminary report, acquiring information from a variety of sources, such as the Society of Petroleum Engineers (SPE) Technical Papers, Drilling engineering, and Geosciences Courses learned in UTP.

Since the topic of the project is very wide, so it needs a good effort in organizing the work flow or else the project will be inefficient

2 *Chapter 2: LITERATURE REVIEW*

2.1 Overview

The drill bit is an essential part of the drilling process. Those involved directly with bits as designers, salesmen or applications engineers believe that it is the essential part in the bottom hole assembly (BHA), Yet it is often given slight attention; it may be treated as a product, where price is seen as its most important feature; selection may be made at the last moment, with little regard for earlier lessons learned; there may be minimum evaluation of each run, with a view to improving performance.

Not just any bit can drill a given section, but many bits can, and a few can do so reasonably well. It is easier to pick one of those few bits and even easier to choose one of the many that can complete the section than to search for the best bit for the application. Yet, if we identify that best choice then dramatic savings in drilling cost will be made.

A major factor in drill bit selection is; the type of formation that needs to be drilled, that's because the effectiveness of a drill bit varies by formation type.

There are three main types of formations:

- **Soft Formation**

  A soft formation includes; unconsolidated sands, clays, soft limestone, red beds and shale.

- **Medium Formation**

  A Medium formation includes; calcites, dolomites, limestones, and hard shale.

- **Hard Formation**

  A Hard formation includes; hard shale, calcites, mudstones, cherty lime stones and hard and abrasive formations. [1]

This research project considers how bit design affects bit performance, presents a structured approach to bit selection and considers some of the pitfalls of the selection process. There is an underlying theme of compromise: whether we consider bit design, selection or operation, it is rare that we can have everything from a bit.

When it has been established that a petroleum reservoir probably exists, despite improvements in seismic techniques the only way of confirming the presence of hydrocarbons is to drill an exploration well.

Drilling is very expensive, and if hydrocarbons are not found there is no return for the investment, although valuable geological information may be obtained.

Having decided to go ahead and drill an exploration well proposal is for objective.

The objectives of this well will be:

- To determine the presence of hydrocarbons.
- To provide geological data (cores, logs) for evaluation.
- To flow test the well to determine its production potential, and obtain fluid samples.

The life of an oil or gas field can be subdivided into the following phases:

- Exploration
- Appraisal
- Development
- Maintenance
- Abandonment

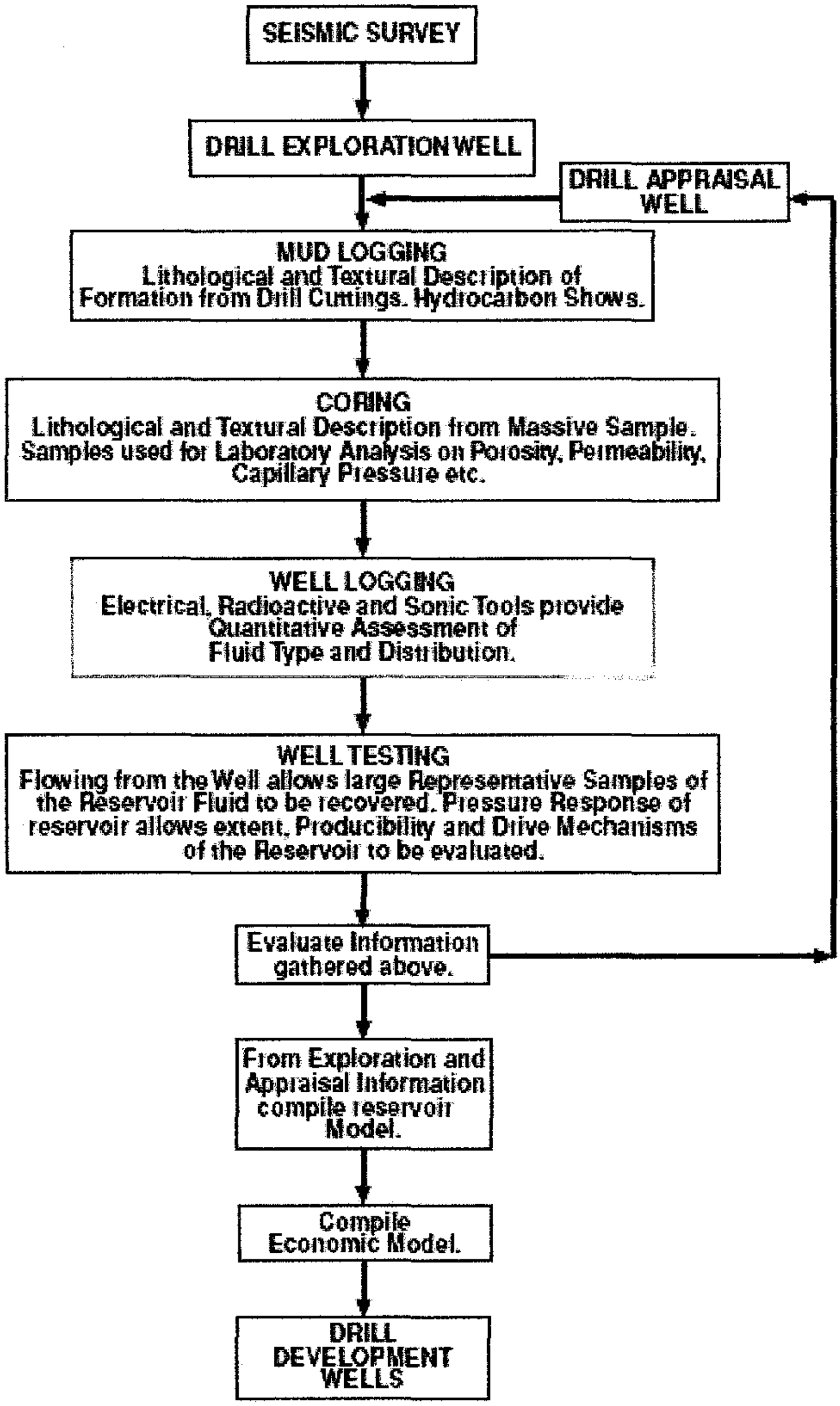


Figure 1 The life of an oil or gas field

2.2Drilling Operations:

The length of the exploration phase will depend on the success or otherwise of the exploration wells. There may be a single exploration well or many exploration wells drilled on a prospect, if an economically attractive discovery is made on the prospect then the company enters the appraisal phase of the life of the field.

During this phase more seismic lines may be shot and more wells will be drilled to establish the lateral and vertical extent of the reservoir.

These appraisal wells will yield further information, on the basis of which future plans will be based. The information provided by the appraisal wells will be combined with all of the previously collected data and engineers will investigate the most cost effective manner in which to develop the field. If the prospect is to be economically attractive a field development plan will be submitted for approval. It must be noted that the oil company is only a licensee and that the oilfield is the property of the country government. The country must therefore approve any plans for development of the field. If the approval for the development is received then the company will drill development wells and constructing the production facilities according to the Development Plan. Once the field is on stream the company commitment continues in the form of maintenance of both the wells and all of the production facilities.

After many years of production, it may be found that the field is yielding more or possibly less hydrocarbons than initially anticipated at the development planning stage and the company may undertake further appraisal and subsequent drilling in the field.

At some point in the life of the field the costs of production will exceed the revenue from the field and the field will be abandoned. All of the wells will be plugged and the surface facilities will have to be removed in a safe and environmentally acceptable way.

THE DRILLING PROPOSAL AND DRILLING PROGRAM:

The proposal for drilling the well is prepared by the geologists and reservoir engineers in the operating company and provides the information upon which the well will be designed and the drilling program will be prepared.

The proposal contains the following information:

- Objective of the Well
- Depth (m/ft Subsea), and Location (Longitude and Latitude) of Target
- Geological Cross section
- Pore Pressure Profile Prediction

The drilling program is prepared by the Drilling Engineer and contains the following:

- Drilling Rig to be used for the well
- Proposed Location for the Drilling Rig
- Hole Sizes and Depths
- Casing Sizes and Depths
- Drilling Fluid Specification
- Directional Drilling Information
- Well Control Equipment and Procedures
- Bits and Hydraulics Program [2]

2.3DRILLING METHODS:

2.3.1 Cable tool drilling:

This was the method used by pioneer wildcatters in the nineteenth and early twentieth century and is still used today for some shallow wells. This method employs a heavy steel drill stem with a bit at the bottom, suspended from a cable.

The falling steel weight above the bit provides energy to break up the rock, pounding a hole through it. The hole is kept empty, except for some water at the bottom. After drilling a few feet, the drill stem (with its bit) is pulled out and the cuttings are removed with a bailer (an open tube with a valve at the bottom).

The cable tool method is simple, but it is effective only for shallow wells.

Progress is slow because of the inefficiency of the bit and the need to pull the tools frequently to remove out cuttings.

2.3.2 Rotary drilling:

Rotary rigs are used for variety of purposes drilling oil, gas, water, geothermal and petroleum storage wells; mineral assay coring; and mining and construction projects. The most significant application, however, is oil and gas drilling. In the rotary method (introduced to oil and gas drilling in about 1900)' the drill bit is suspended on the end of a tubular drill string (drill stem) which is supported on a cable pulley system held up by a derrick. Drilling takes place when the drill string and bit are rotated whiles the weight of the drill collars and bit cuts down in the rock.

To keep the bit cool and lubricated, and to remove the rock cuttings from the hole, drilling fluid (mud) is pumped down inside of the drill string. When it reaches the bit, it passes through nozzles in the bit, impacts the bottom of the hole and then moves upward in the annulus (the space between the drill string and the wellbore wall) with the cuttings suspended in it.

At the surface, the mud is filtered through screens and other devices that remove the cuttings and then pumped back into the hole. Drilling mud circulation brought efficiency to rotary drilling that was missing from cable tool drilling.

2.4DRILLING BITS

2.4.1 INTRODUCTION:

A drilling bit is the cutting tool which is made up on the end of the drill string. The bit drills through the rock by scraping, chipping, gouging or grinding the rock at the bottom of the hole. Drilling fluid is circulated through passageways in the bit to remove the drilled cuttings. There are however many variations in the design of drill bits and the bit selected for a particular application will depend on the type of formation to be drilled. The drilling engineer must be aware of these design variations in order to be able to select the most appropriate bit for the formation to be drilled. The engineer must also be aware of the impact of the operating parameters on the performance of the bit.

The performance of a bit is a function of several operating parameters, such as:

- Type and Condition of a bit
- Weight on bit (WOB);
- Rotations per minute (RPM);
- Drilling fluid used for Circulation
- Hydraulic efficiency
- Type of Rock/Formation to be drilled

When a section of hole has been drilled and the bit is pulled from the wellbore the nature and degree of damage to the bit must be carefully recorded. A system, known as the Dull Bit Grading System has been devised by the Association of Drilling Contractors (IADC); to facilitate this grading process.

In addition to selecting a bit, deciding upon the most suitable operating parameters, and then describing the wear on the bit when it has drilled a section of hole, the drilling engineer must also be able to relate the performance of the bit to the performance of other bits which have drilled in similar conditions.

2.4.2 Bit History and technology

Around 1906, Mr. Hughes began to conduct experiments on a rock bit designed to replace the fishtail bit. In 1908, Mr. Hughes and Mr. Sharp built the first wooden model of a roller type bit with two cone shaped cutters.

They tested this experimental bit in Goose Creek, Texas; the pipe twisted off, but a second bit test proved successful. According to a Hughes Tool Company biography, Mr. Hughes "drilled fourteen feet of hard rock in eleven hours, brought in a well, and thus discovered the Goose Creek field, which became one of the greatest oil fields in the Gulf Coast region."

Immediately following the successful drill bit tests, the partners founded the Sharp Hughes Tool Company in 1909; the first shop to manufacture the bit occupied a 20-foot by 40-foot rented space. Later that year, on August 10, 1909, the US Patent Office affirmed and protected the intellectual property rights of the invention with a patent granted to Mr. Hughes.

The Hughes Two Cone Drill Bit comprised two removable cone shaped cutters of hardened steel. The cones, each with 166 cutting edges, revolved on bronze pin bushing bearings shaped to provide a large surface with reduced friction. The bushings were lubricated by means of oil holes drilled through the head and run to an oil valve on the lubricator.

The removable cutters could be removed for sharpening or replacement when dull. Unlike the fishtail bit, the Hughes Two Cone Drill Bit rolled in a true circle, crushing and grinding the rock.

This rolling motion allowed the cutting edges to chip the rock, one edge after another. Significantly, the cutting edges were designed so they would avoid falling into previous cuts, preventing what is known as tracking. This enabled each edge to continuously crush a new portion of the rock. The absence of pure scraping of the fishtail bit allowed the Hughes Two Cone Drill Bit to drill faster and further before sharpening.

The bottom of the drill hole, as formed by the operation of the bit, was a perfect seat for a water-tight joint, preventing leakage after the casing had been set.

2.4.3 *Types of Drilling Bits*

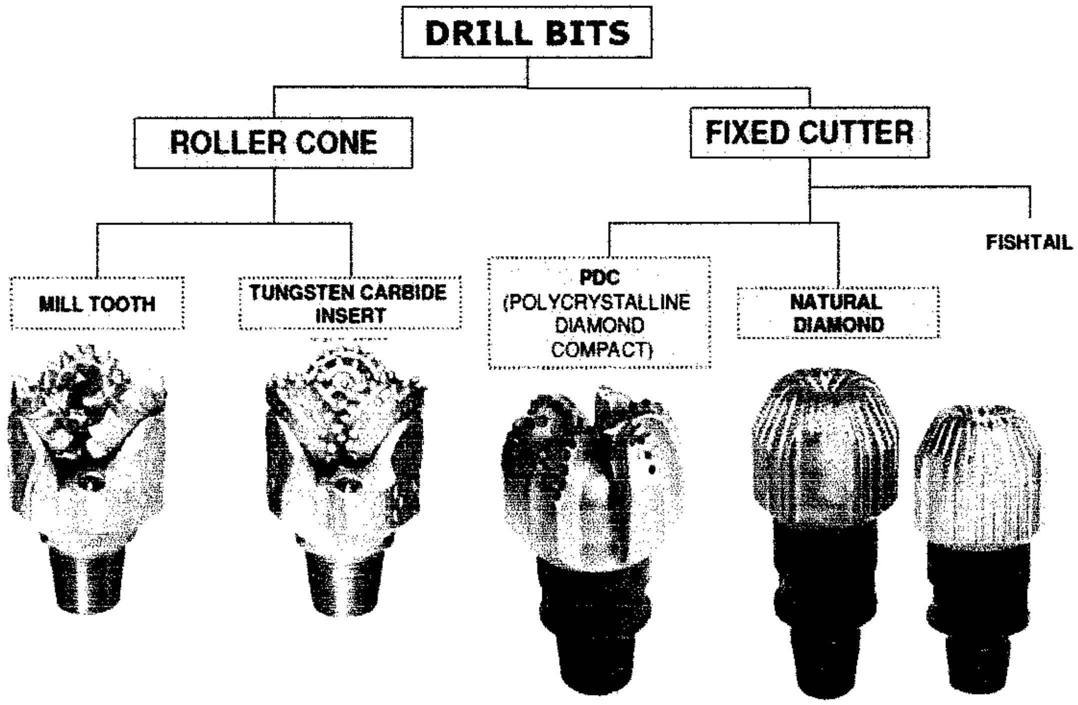


Figure 2 Types of Drill Bits

2.4.3.1 *Roller Cone Bits:*

Roller cone bits are still the most common type of bits used worldwide. The cutting action is provided by cones which have either steel teeth or tungsten carbide inserts.

These cones rotate on the bottom of the hole and drill the hole mainly with a grinding and chipping action. Rock bits are classified into **milled tooth bits** and **insert bits** depending on the cutting surface on the cones.

At mill tooth bits, which are also known as steel tooth bits, the teeth are milled out of the same body the cones consist of. These bits are very forceful and accept severe drilling conditions but wear out relatively quickly. From this reason they are not well suited for deeper wells where tripping constitutes a large time factor.

2.4.3.1.2 Insert bit:

Insert bits, also called tungsten carbide bits, have teeth made of tungsten carbide which are fitted on the cone bodies. These bits do not tolerate shock loadings but they can drill long sections before being worn out. In general, insert bits of the same bit size are more expensive than mill tooth bits.

2.4.3.2 Fixed cutter bits:

Diamond has been used as a material for cutting rock for many years. Since it was first used however, the type of diamond and the way in which it is set in the drill bit have changed.

2.4.3.2.1 PDC Bits:

New generations of diamond bits known as polycrystalline diamond compact (PDC) bits were introduced in the 1980's. These bits have the same advantages and disadvantages as natural diamond bits but use small discs of synthetic diamond to provide the scraping cutting surface. The small discs may be manufactured in any size and shape and are not sensitive to failure along cleavage planes as with natural diamond. PDC bits have been run very successfully in many areas around the world. They have been particularly successful (long bit runs and high ROP) when run in combination with turbo drills and oil based mud.

2.4.3.2.2 Natural Diamond Bits:

The hardness and wear resistance of diamond made it an obvious material to be used for a drilling bit. The diamond bit is really a type of drag bit since it has no moving cones and operates as a single unit. Industrial diamonds have been used for many years in drill bits and in core heads.

The cutting action of a diamond bit is achieved by scraping away the rock. The diamonds are set in a specially designed pattern and bonded into a matrix material set on a steel body. Despite its high wear resistance diamond is sensitive to shock and vibration and therefore great care must be taken when running a diamond bit.

Effective fluid circulation across the face of the bit is also very important to prevent overheating of the diamonds and matrix material and to prevent the face of the bit from becoming smeared with the rock cuttings (bit balling).

The major disadvantage of diamond bits is their cost (Roughly 10 times more expensive than a similar sized rock bit). There is also no guarantee that these bits will achieve a higher ROP than a correctly selected roller cone bit in the same formation.

They are however cost effective when drilling formations where long rotating hours (200-300 hours per bit) are required. Since diamond bits have no moving parts they tend to last longer than roller cone bits and can be used for extremely long bit runs.

This results in a reduction in the number of round trips and offsets the capital cost of the bit. This is especially important in areas where operating costs are high (e.g. offshore drilling). In addition, the diamonds of a diamond bit can be extracted, so that a used bit does have some recover value.

2.4.3.2.3 Fish-Tail (Drag Bits):

Drag bits were the first bits used in rotary drilling, but are no longer in common use. A drag bit consists of rigid steel blades shaped like a fish tail which rotate as a single unit. These simple designs were used up to 1900 to successfully drill through soft formations. The introduction of hard facing to the surface of the blades and the design of fluid passageways greatly improved its performance. Due to the dragging and scraping action of this type of bit, high RPM and low WOB are applied.

The decline in the use of drag bits was due to:

1- The introduction of roller cone bits, which could drill soft formations more efficiently
2- If too much WOB was applied, excessive torque led to bit failure or drill pipe failure
3- Drag bits tend to drill crooked hole, therefore some means of controlling deviation was required
4- Drag bits were limited to drilling through uniformly, soft, unconsolidated formations where there were no hard abrasive layers.

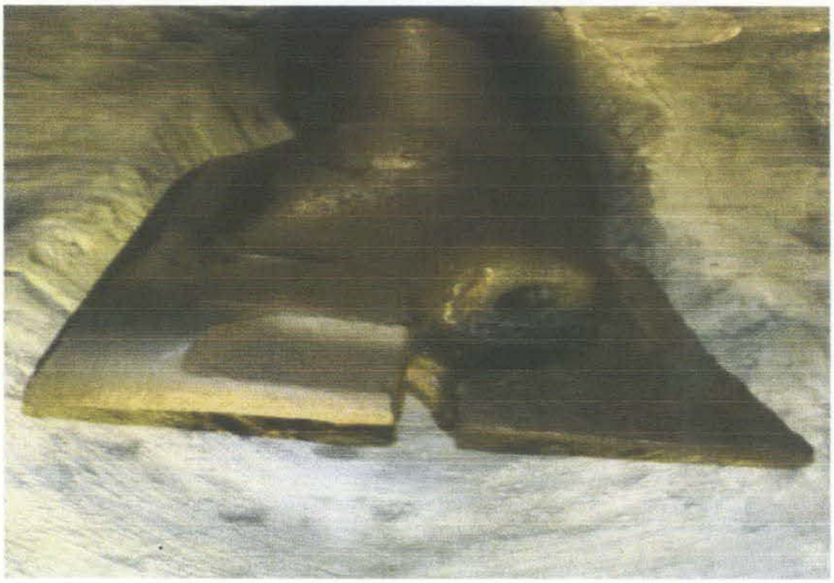


Figure 3 drag bit

2.5 *Bit Design*

The drilling engineer is seeking a bit that will deliver a certain performance in his planned application. [3]

Performance mean:

- How fast the bit drills? (Rate of Penetration)
- How durable it is?
- How far it cans drills?
- What is its final dull condition?
- How stable it is?
- Does it suffer vibration easily?
- What kind of vibration?
- Does it hold angle in a tangent or deliver the necessary dogleg?
- How adaptable it is?

Each application places different demands on the bit; the relative importance of the performance factors listed above varies but bit design involves matching the features of the bit to the demands of the application and to the relative importance of these performance factors.

2.5.1 Roller Cone Bit Design:

The design of roller cone bits can be described in terms of the four principle elements of their design.

The following aspects of the design will be dealing with in details:

1. Bearing assemblies
2. Cones design
3. Fluid circulation

2.5.1.1 Bearing Assembly:

The cones of a roller cone bit are mounted on journals. There are three types of bearings used in these bits:

- **Roller bearings**: which form the outer assembly and help to support the radial loading (or WOB)
- **Ball bearings**: which resist longitudinal or thrust loads and also help to secure the cones on the journals
- **Friction bearing**: in the nose assembly which helps to support the radial loading. The friction bearing consists of a special bushing pressed into the nose of the cone. This combines with the pilot pin on the journal to produce a low coefficient of friction to resist arrest and wear.

Details of bearing structure:

All bearing materials must be made of toughened steel which has a high resistance to chipping and breaking under the severe loading they must support. As with all rock bit components, heat treatment is used to strengthen the steel.

The most important factor in the design of the bearing assembly is the space availability. Ideally the bearings should be large enough to support the applied loading but this must be balanced against the strength of the journal and cone shell which will be a function of the journal diameter and cone shell thickness. The final design is a compromise which ensures that ideally, the bearings will not wear out before the cutting structure (i.e. all bit components should wear out evenly).

However, the cyclic loading imposed on the bearings will (in all cases), eventually initiate a failure. When this occurs the balance and alignment of the assembly is destroyed and the cones lock onto the journals.

There have been a number of developments in bearing technology used in rock bits:

Sealed Bearing bits:

The bearing assemblies of the first roller cone bits were open to the drilling fluid.

(Sealed bearing bits) were introduced in the late 1950s, to extend the bearing life of insert bits. The sealing mechanism prevents abrasive solids in the mud from entering and causing excess frictional resistance in the bearings. The bearings are lubricated by grease which is fed in from a reservoir as required. Some manufacturers claim a 25% increase in bearing life by using this arrangement. [9]

2.5.1.2 Cones Design:

All three cones have the same shape. One of the basic factors to be decided in the design of the cones is the journal or pin angle (Figure 12). The journal angle is formed between the axis of the journal and the horizontal. Since all three cones fit together, the journal angle specifies the outside contour of the bit. The use of an oversize angle increases the diameter of the cone and is most suitable for soft formation bits. Although this increases cone size, the gauge tip must be brought inwards to ensure the bit drills a gauge hole.

One important factor which affects journal angle is the degree of meshing or inter-fit (i.e. the distance that the crests of the teeth of one cone extend into the grooves of the other).

The amount of inter-fit affects several aspects of bit design.

- It allows increased space for tooth depth, more space for bearings and greater cone thickness
- It allows mechanical cleaning of the grooves thus helping to prevent bit balling
- It provides space for one cone to extend across the centre of the hole to prevent coring effects
- It helps the cutting action of the cones by increasing cone slippage.

The cutting structure for insert bits follows the same pattern as for milled tooth bits. Long chisel shaped inserts are required for soft formations, while short voided shaped inserts are used in hard formation bits.

Tungsten carbide hard facing is applied to the teeth of soft formation bits to increase resistance to the scraping and gouging action. Hard formation bits have little or no hard facing on the teeth, but hard facing is applied to the outer surface (gauge) of the bit. If the outer edge of the cutting structure is not protected by tungsten carbide hard facing two problems may occur. [9]

The outer surface of the bit will be eroded by the abrasive formation so that hole diameter will decrease. This under gauge section of the hole will have to be reamed out by the next bit, thus wasting valuable drilling time

If the gauge area is worn away it causes a redistribution of thrust forces throughout the bearing assembly, leading to possible bit failure and leaving junk in the hole (e.g. lost cones)

2.5.1.3 Fluid Circulation:

Drilling fluid passes from the drill string and out through nozzles in the bit. As it passes across the face of the bit it carries the drilled cutting from the cones and into the annulus. The original design for rock bits only allowed the drilling mud to be ejected from the middle of the bit. This was not very efficient and led to a buildup of cuttings on the face of the bit (**bit balling**) and cone erosion. A more efficient method of cleaning the face of the bit was therefore introduced. The fluid is now generally ejected through three **jet nozzles** around the outside of the bit body. The turbulence created by the jet streams is enough to clean the cutters and allow efficient drilling to continue.

Jet nozzles:

Jet nozzles are small rings of tungsten carbide and are available in many sizes. The outside diameter of the ring is standard so that the nozzle can fit into any bit size. The size of the nozzle refers to the inner diameter of the ring.

Nozzles are available in many sizes although diameters of less than 7/32" are not recommended, since they are easily plugged. The nozzles are easily replaced and arefitted with an "O" ring seal. The nozzles are made of tungsten carbide to prevent fluid erosion.

2.5.2 *Fixed cutters drilling bit design*

2.5.2.1 Design factors:

A polycrystalline diamond compact (PDC) bit employs no moving parts(i.e. there are no bearings) and is designed to break the rock in shear and not in compression as in roller cone bits.

Rock breakage by shearing requires significant less energy than in compression, since less weight on bit can be used resulting in less wear on the drill string.

A PDC bit employs a large number of cutting elements, each called a PDC cutter, the cutter is made by bounding a layer of polycrystalline diamond to a cemented tungsten carbide in a high pressure and high temperature process, the diamond layer is composed of many tiny diamonds which are grown together at random orientation for maximum strength and wear resistance.

2.5.2.2 Bit Design elements:

- **Geometry of Bit**

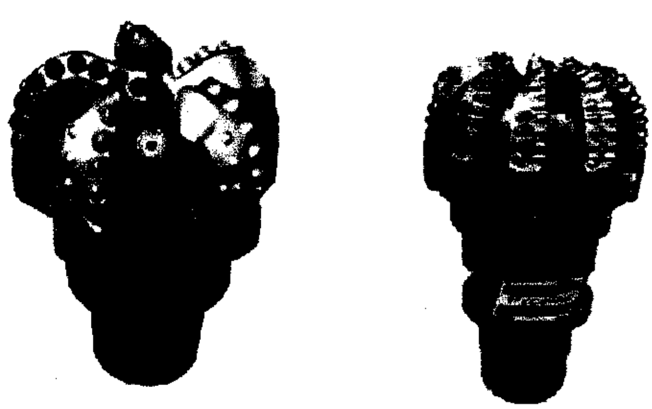
1. Number of Blades
2. Blade Height
3. Blade Geometry

- **Body Composition**

1. Matrix
2. Steel
3. Hard facing

- **Cutter Character**

1. Number of Cutters
2. Spacing of Cutters
3. Size of Cutters
4. Back Rake
5. Side Rake



a b

Figure 4 hard formation PDC bit with many tiny cutters

- **Diamond Table**

1. Substrate interface
2. Composition
3. Shape [9]

Geometry of bit:

Number of blades:

A polycrystalline diamond compact (PDC) bit designed for **soft formations** will have **few blades** while the other one designed for **hard formations** will have **many blades.**

Two aspects determine this:

1. Junk slot area requirement
2. Number of cutters

Junk Slot Area Requirement:

The soft formation PDC bit will there for have a large junk slot area to remove the large volume of cutting rocks and to reduce the bit balling in sticky formations. (Figure a)

Blade Height:

Blade height is an important consideration because a soft formation bit will benefit from tall blades, giving the bit maximum open face volume. Higher blades will typically be made with steel rather than with matrix, because of the greater strength of steel.

Blade Geometry:

PDC bits can be manufactured with a variety of blades shapes ranging from straight to curved shapes.

Experience has shown that curved blades provide a greater stability to bit especially when the bit first contact with the formation rock.

Bit profile:

Bit profile affects cleaning and the stability of the bit, there are two bit profiles which are most used:

1. Double cone
2. Shallow cone

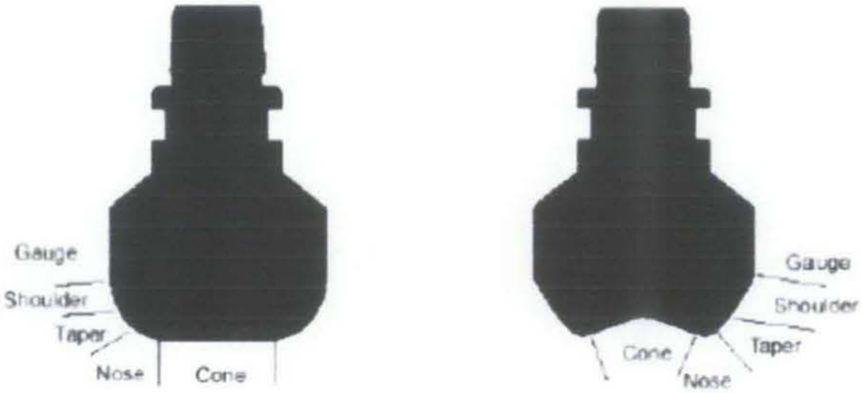


Figure 5 bit profile (double cone)

Double cone shallow cone

The double cone profile allows more cutters to be placed near the gauge protection and allowing better directional control, while the shallow cone gives faster penetration but has less area for cleaning.

In general, a bit with a deep cone will tend to be more stable than a shallow cone.

Bit length:

This is important for steer-ability. Shorter bits are more steerable, as they reduce the radius of the possible turn. (See the diagram)

The two bits on the left of figure () are sidetrack bits, with a short, flat profile

While, The 'Steering Wheel'' bit on the right is designed for general directional work.

Figure 6 PDC bit length

For hard rocks, PDC bits will have more blades, with smaller and more numbers of cutters

Cutter Characters

Number of cutters:

The hard formation PDC bit needs many tiny cutters, each removing a small amount of formation rock (figure b).

a b

Figure 7 hard formation PDC bit with many tiny cutters

Cutter size:

Large cutters are used in case of soft formation bits while; smaller cutters are used in case of harder formation bits.

Usually a range of size is used, from 8mm to 19mm on any one bit

Back Rake

Cutter orientation is described by back rake an side rake angles;

Back rake is the angle presented by the face of the cutter to formation and is measured from the vertical.

The magnitude of the rake angle affects penetration rate and cutter resistance to wear

As the rake angle increases, ROP decreases but the resistance to wear increases as the applied load is spread over larger are.

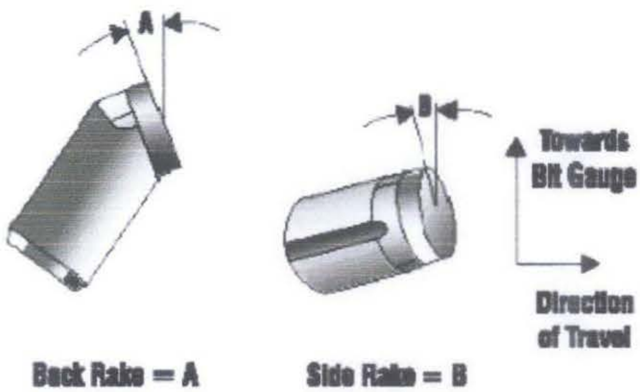


Figure 8 back rake , side rake

PDC cutters with small back rakes take large depths of cut and are therefore more aggressive, generate high torque, and subjected to accelerated wear and greater risk of impact damage while, cutters with high back rake take less depths of cut and are therefore less aggressive, generate less torque, and subjected to less wear and less risk of impact damage.

Side rake

Side rake is an equivalent measure of the orientation of the cutter from left to right, where angles are usually small. Side rake angle assists in hole cleaning by mechanically directing toward annulus

Cutter shape

The edge of the cutters may be beveled or chamfered to reduce the damage caused by impacts

Bit selection and evaluation

IADC DULL BIT GRADING SYSTEM:

Objectives of Dull Grading:

1. Aid optimum bit selection
2. Help avoid catastrophic failure
3. Identify bits that are suitable for re-run
4. Suggest optimum operating parameters
5. Provide insights for improving bit design

These are the individual objectives of dull grading. Each can help to lower drilling costs, which is the underlying purpose of dull grading.

Dull grading is an important element of bit evaluation. A proper run evaluation will consider three things:

1. What was (reasonably) expected of the bit
2. What the bit actually achieved
3. What is its dull condition

Thus, a bit with a bad dull condition may have made an excellent run: it may have exceeded expected performance (interval, R.O.P., steerability etc) in all respects. Equally a bit with a good dull condition might be considered a bad run: based upon that condition a more aggressive bit might have been chosen, that would have delivered higher R.O.P.

IADC SYSTEM FOR ROLLER CONE BITS:

IADC classification system is a valuable aid in bit selection, and a useful tool for comparing the general features and formation applicability of various bit types

The IADC has created a system for grading dull roller cone bits which consists of eight characters and letters describing the wear on the cutting structure plus bearing, gage and reason pulled [4].

Table 1 system for grading dull

Cutting Structure				Bearing	Gage	Remarks	
Cutting St. Inner	Cutting St. Outer	Cutting St. Dull Char.	Cutting St. Location	Bearing / Seal	Gage	Other Dull Char.	Reason Pulled
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)

First and second column:

Inner and Outer Teeth:

In column 1 and 2 a linear scale from 0 to 8 is used to describe the condition of the cutting structure according to the following:

For steel tooth bits:

A measure of lost tooth height due to abrasion or/and damage

0 – No loss of tooth height

8 – Total loss of tooth height

For insert bits:

A measure of total cutting structure reduction due to lost, worn or/and broken inserts

0 – No loss of tooth height

8 – Total loss of tooth height

For cutter bits:

A measure of total cutting structure reduction due to lost, worn or/and broken structure

0-No loss of tooth height

8-Total loss of tooth height

Third column:

Using only cutting structure related codes such as BC for Broken cone, CC for cracked cone, ER for erosion, JD for Junk damage, FM for formation change...etc.

Fourth column:

Location for roller cone and fixed cutter

Fifth Column

Bearing and seals

For non-sealed bearing;

A linear scale estimating bearing life used

0-No life used

8-All life used, meaning no life remaining

Sealed bearing

E-Seals effective

F-Seals Failed

N-Not able to grade

X-Bearing-less (since fixed cutter bit)

Sixth column:

Out of Gage measured in fractions of an inch

Seventh column:

Other dull characteristics

Eights column:

Reasons pulled or run terminated such as; BHA for change of BHA, RIG for rig repair, LOG for run logs…etc.

Factors Affecting Bit Performance

Work of the bit on the bottom of the bore hole is the principal element of the whole complex of drilling operations, as the main aim of the complex making a hole in the earth crust is archived as a result of rock disintegration by the bit.

Drilling cost depth to a considerable extent on bit performance, if a bit drill fast and it makes a long section of the bore hole, it will secure low drilling cost.

Many factors affect the performance of a bit on bottom of the bore hole. Close studying of suck factors and proper selection of those, which can be controlled by the operator, are essential for the most economical drilling.

Factors affecting the bit performance:

Many variables factors affect the bit performance; they may be divided into several large groups as follows:

1. Rig Capabilities/ Personal efficiency
2. Formation properties
3. Drilling fluid properties
4. Hydraulic factors
5. Mechanical factors

Rig Capabilities/ Personal efficiency

In the process of drilling a well in a particular oil field by a particular drilling crew with a particular drilling rig are the factors of the first three groups which remain unchanged (rig efficiency, personal efficiency and formation properties).

The drilling engineer must answer the following rig-related questions when deciding whether to run a particular bit type:

1. Can the rig provide the bit weight and rotating speed (determined from vendor specifications) required to obtain the optimum penetration rate from this bit?
2. Can the mud pumps provide the rates and pressures necessary to provide adequate hydraulics with this bit?

   Since the rig's characteristics are not easily changed, a "no" answer to either of these questions requires selecting a different bit and/or changing the hydraulics program.

3. Bit Run Economics

As with other aspects of well design, drilling and production, bit programs are ultimately based on **economics**, with their most basic objective being to minimize the overall cost per foot of drilling the well.

Cost per Foot

The equation can be used in order to identify the cost of a bit per foot to be drilled. It is beneficial in:

- Post drilling analysis:

In order to compare one bit run with another in a similar well.

- Real-time analysis:

To decide when to pull the bit – theoretically when cost/ft typically reaches a minimum, and then begins to increase as the bit wears and the penetration rate decreases.

By periodically calculating cost/ft throughout the bit run, an engineer can determine when it would be more economic to run a new bit [5]

$$C = \frac{C_b + (R_t + T_t)C_r}{F}$$

Equation 1

C = Overall drilling cost per foot ($/ft)

Cb = Cost of bit ($)

Rt = Rotating time with bit on bottom (hrs)

Tt = Round trip time (hrs)

Cr = Cost of operating rig ($/hrs)*

F = Length of the bit run (ft)

It is simple in concept. The cost of drilling an interval is governed by: the cost of the bit with which we drill the interval; the time it takes to drill the interval; and the cost (the operating cost of the rig) over the time it takes to trip the bit into the hole, to start drilling, and out of the hole, once drilling is complete.

If we divide that total cost by the interval drilled, we have the cost per foot.

*Note that ***Cr*** includes all costs associated with the actual drilling of the well, including rig rate, mud logging and conditioning, equipment rentals, transportation, and all other supporting materials and services

While knowing how to calculate ***C*** (Overall drilling cost per foot) during a bit run is important, it is only the first step in analyzing bit economics. We need to take Equation a step further so that we can select bits based on comparative performance.

For example, the cost of a diamond bit can be up to four times the cost of a tungsten carbide insert bit, and up to twenty times the cost of a mill tooth bit. For the diamond bit to be economical, its performance (footage, drilling time) must justify this extra cost. To determine whether this is the case, we can conduct a break-even analysis.

The break-even point is simply the combination of footage and drilling time needed for the cost per foot of one bit to equal the cost per foot that we could obtain if we used a different bit (or bits) for the same interval. To find the break-even point, we need a bit record from an offset well,

When performing a break-even analysis, the bit performances in the offset well are known, but bit performance in the new well must be estimated. Thus, we must assume either the footage that the new bit will drill or the penetration rate it will attain. [5]

If we assume that the bit will drill certain footage, then we can calculate the break-even penetration rate using the following formula, which can be derived from **Equation 1.**

Formation characteristics

Improvements in drilling efficiency and economics are continuously being achieved with drilling bits, specifically in medium and hard formations.

The formation hardness; abrasiveness and heterogeneity have a great effect on bit performance. In addition, Drilling efficiency will be affected by; operational parameters, vibration behavior, durability equivalency (DEQ) and lithology differences.

Formation Properties

With respect to bit programs, formation properties are constant-that is, they are not subject to control. Knowing formation properties, however, is the first step in determining which bit to use in a given interval.

Formation properties that figure prominently in bit selection include:

- Compressive strength;

  Refers to the intrinsic strength of the rock, which is based on its composition, method of deposition and compaction. For a bit to "make hole," the driller must apply enough drill string weight to overcome this compressive strength, and the bit must be able to perform under this applied weight.

- Elasticity;

Elasticity affects the way in which a rock fails a rock that fails in a plastic mode will deform rather than fracture, this occurs most often under high confining pressures. Under such conditions, a bit utilizing a gouging/scraping action would be preferable to a bit designed to chip and crush the rock.

- Abrasiveness;

Abrasive formations require bits with extra gauge protection. Under-gauge holes result in extra reaming and wasted rig time, and increase the chances of the drill string sticking.

- Overburden pressure;

Overburden pressure is the pressure exerted on a formation by overlying formations. Under normal conditions, overburden increases with depth, compacting formations and making them harder.

- Stickiness;

Sticky formations (i.e., "gumbo") can result in bit-balling and reduced penetration rate.

- Pore pressure;

Pore pressure is a measure of the pressure exerted by the formation fluid on the rock matrix.

Pore pressure affects mud weight requirements, which in turn can affect penetration rates.

- Porosity and permeability.

Porosity is a measure of the void space contained within a unit volume of rock. One cc of sandstone with a porosity of 20%, for example, contains 0.20 cc of void space. Permeability is a measure of a rock's fluid flow properties. In general, penetration rates would be expected to be higher in a highly porous, permeable formation than in a low-porosity, "tight" formation.

There are a number of resources available for determining the locations, depths and properties of formations. Most of these resources consist of information from offset wells, which may include some or all of the following:

- Formation name and age;
- Open-hole logs (i.e., SP/resistivity, gamma ray, neutron, sonic);
- Mud logs;
- Core analyses;
- Drilling and production records;
- Stratigraphic cross sections

Formation hardness:

According to the IADC, bits are generally categorised by the hardness of the formation they can drill, however these classifications are vague but unfortunately no superior classification method exists.

Some formations such as 'medium to hard' are sometimes wrongly defined because they had previously experienced low drilling rates although this was actually due to wrong bit selection or operating parameters used.

Where a number of bits can be used, say to drill a soft formations, the bit selected will depend on other conditions such as mud type and hole size.
Therefore, bit selection in soft formations becomes a matter of defining the conditions that produce the lowest drilling costs.

Bit action in **hard and abrasive formations** is by failure in the compressive mode and as a result bits which use shear action are not very successful. In this case, **roller bits** are usually more successful as they have been designed for abrasive wear which may be very damaging to shear failure action bits.

Formations with sticky characteristics, often resulting from clay rocks that are hydratable, the cuttings stick to the teeth or bit structure and impede drilling efficiency. Bits designed for sticky formations have a high degree of teeth inter-fit and hydraulics such as centre jetting capabilities. PDC, diamond and short tooth roller cone bits have been particularly unsuccessful unless when PDCs are used with oil based mud. [6]

In general, PDC bits drill faster than mill tooth or diamond bits in soft to medium-soft rocks unless they are sticky. This is substantiated by numerous results test reports.

Table 2 formations

Group Number	Formations
Mill Tooth Bits	
1	Soft formations of low compressive strength and high drillability
2	Medium to medium-hard formations with high compressive strength
3	Hard semi-abrasive or abrasive formations
Insert Bits	
4	Very soft formations
5	Soft to medium formations with low compressive strength
6	Medium-hard formations with high compressive strength
7	Hard semi-abrasive or abrasive formations
8	Extremely hard and abrasive formations

Drilling fluid properties:

Drilling fluid properties can be selected and changed within certain limits so as to secure the best possible bit performance

Properties of the drilling fluid which affect the bit performance are:

1. Density
2. Viscosity
3. Water loss

4. Solids content
5. Composition

Hydraulic factors:

1. Circulation rate
2. Hydraulic horse power

Mechanical factors:

1. bit type
2. weight on bit
3. rotating speed

Type of bit is selected before the bit is run into the well. It remains constant during the work of the bit on bottom. Weight on bit and rotary speed can be changed by the driller deliberately so that the best bit performance can be achieved.

Weight on bit, rotary speed and circulation rate are the principal variable factors which affect the bit performance and can be changed by the operator during the process of the bit operation on bottom. An optimum combination of these factors secures such penetration rate and met-rage per bit which correspond to the minimum drilling cost.

Effect of drilling fluid properties on the bit performance:

Effect of drilling fluid density:

Drilling fluid density has a big significant effect on the rate of penetration. Penetration rate and bit output decrease after weighting the mud, and vice versa, replacement of mud by water improves both penetration rate and matrage per bit. Application of air drilling secures the highest bit performance.

Effect of drilling fluid density on bit performance is mainly attributed to the deferential pressure between the hydrostatic pressure of the mud and the reservoir pressure of the rock drilled.

The differential pressure existing on the bottom tends to keep the rock cuttings passes through up heavily. Thus prevent quick removal of them which prevent direct interaction between the bit working elements and the rock to be drilled.

Effect of drilling fluid water loss:

In the process of disintegration of porous and permeable formations, filtration takes place on the bottom of the hole and a filter cake is deposited almost instantly on the fresh surface of the rock. This filter cake has three unfavourable effects on the process of rock breaking down.

1. It prevents the differential pressure, thus promoting the unfavourable effect of drilling fluid density
2. It interferes with the bit rock interaction by preventing direct contact of bit working elements with the formation.
3. If forms a pasty mixture on the bottom in which loosened cutting may be trapped.

These three effects decrease the efficiency of the drilling bit process.

Effect of drilling fluid viscosity:

The effect of drilling fluid viscosity on the bit performance results mainly from worsening the bottom cleaning process when mud viscosity increases.

Effect of solid contents:

Effect of solid contents on bit performance is widely proved by industrial application of low solids mud which secure high rate of penetration and a greater metrage per bit.

Effect of drilling fluid composition:

The most important type of drilling fluid is the oil base mud.

Oil which is present in the mud, improves lubrication of the bit, decrease ball up trend and helps to keep the bit clean.

These factors are believed to be responsible for the improvement of the bit performance in the presence of oil in the drilling fluid.

The other reason of increasing the rate of penetration in the presence of oil is the decrease in the friction between the drilling string and the wall of the hole.

Hydraulic factors:

It would be ideal if any cutting when it was torn off the formation by the drilling bit be removed sudden its cut, but unfortunately some cutting stay on the bottom for some time and are reground by the bit to be drilled again. This reduces the bit output and the rate or penetration.

Circulation rate:

In the process of drilling with a given bit model and a given drilling fluid there is only one factor which can be changed to improve the hole cleaning, this factor is circulation rate.

It was known long ago that in rotary drilling an increase in flow rate resulted in a corresponding increase in a bit penetration rate and metrage rate. Such improvement in the bit performance was usually attributed to better cleaning of the bottom of the hole during drilling.

Bit Hydraulic Horsepower (BHHP):

Significant increase in the rate of penetration is mainly due to better bottom cleaning action provided by high velocity streams of drilling fluid discharge from the nozzles, this process is function of hydraulic horsepower utilized by the bit nozzles.

So to illustrate; the rate of penetration increase with increasing the bit hydraulic horsepower.

Effect of mechanical factors:

Effect of bit type:

A great variety of formation may be encountered in drilling a well. This makes it uneconomical to drill the whole well with one type of bits only. Formations with different hardness, plastics and abrasive properties will be drilled with the highest efficiency only with bits which geometry fits properly the mechanical properties of the formation drilled. Analysis of the bit performance recorded obtained from previous drilled wells and analysis of dull grading should be the basis for bit selection.

Effect of weight on bit:

Effect of weight on bit on rate of penetration can be expressed in three steps:

First if the contact pressure between the bit working teeth and the rock is lower than the hardness of the rock, therefore the bit working teeth cannot penetrate into the rock and crush it.

After some revolutions a bit tooth strike the spot of the bottom and more fractures may appear and some old fractures may become deeper, as a result of this impact the rock becomes weaker and finally the rock is crushed.

Second if the contact pressure between the bit working teeth and the rock is equal to the hardness of the rock. So no fatigue failure of the rock can happen.

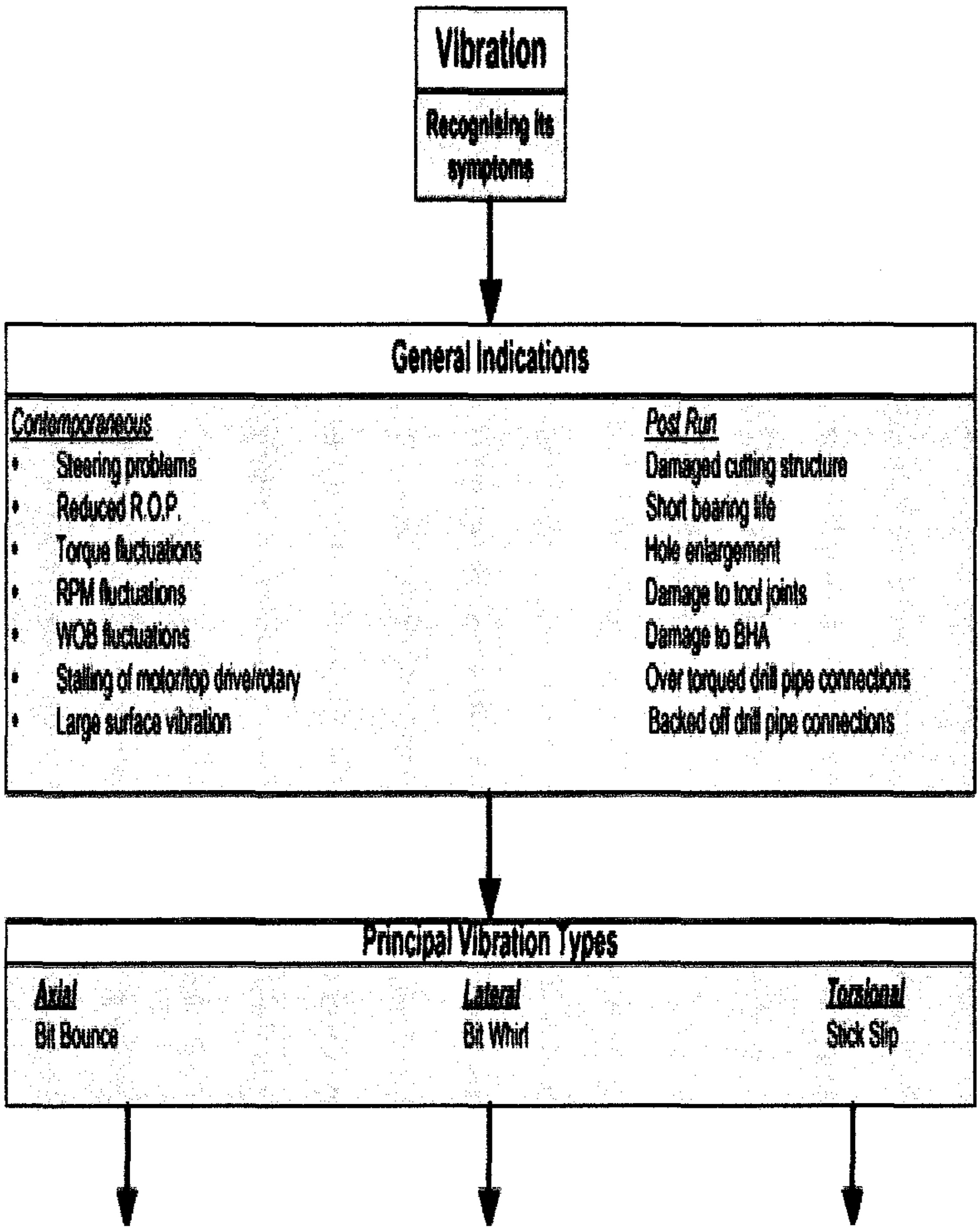
Third if the contact pressure between the bit working teeth and the rock is higher than the hardness of the rock, when this application is occurred so weight on bit value is accepted and if the weight on bit is doubled the penetration rate will be doubled too to a maximum value that cannot be exceeded.

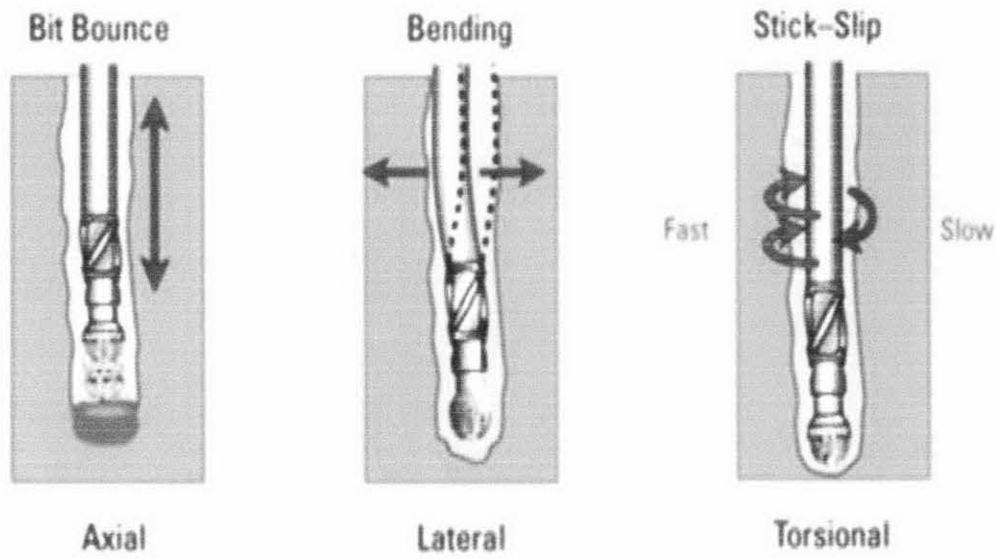
Effect of rotary speed:

An increase of the rotary speed causes several effects related to the bit performance:

1. Corresponding increase of the number of tooth impacts
2. An increase of the speed of impact
3. Decrease of time of contact between the teeth and the rock. [7]

Table 3 Vibration





Evidence	Evidence	Evidence
Contemporaneous Large W.O.B. fluctuations Rig vibrations Loss of tool face Reduced R.O.P. *Post Run* Broken/chipped cutters/inserts Early bearing failure MWD failure	*Contemporaneous* High frequency downhole vibrations. Increase in mean downhole on-bottom torque Erratic toolface control Reduced R.O.P. *Post Run* Broken/chipped cutters - shoulder & gauge of PDC bits. Broken blades Worn hybrids - minimal cutter wear. Overgauge hole Localised tool joint wear Flat spots on stabilisers/BHA	*Contemporaneous* Torque 'cycling' RPM fluctuations Increased range of torque Increase in MWD shock counts Reduced R.O.P. Drive stall *Post Run* Broken/chipped cutters - nose/ shoulder. Connection over torque. Twist offs/wash-outs

Vibration Measurement

The string vibration is measured as a "shock". A transverse shock is a sideways motion of the downhole tool that results in an impact, which accelerates the tool at a rate 25 times greater than the acceleration of gravity, i.e. 25g.

The MWD tools contain a solid state accelerometer (completely different from the type used for surveys) that can measure such shocks. The number of shocks is accumulated then an average value is sent to surface as shocks per second (cps). No differentiation is made between a shock of 25g and one of 500g they are both recorded with the same weight.

The rate of shocks has been classified to better help the importance of action.

- Shock level (0) zero: 0 - 7 cps, Monitor try to reduce but not necessary serious
- Shock level (1) one: 8 - 14 cps, after 30 min. inform company man and take some action to reduce to level zero.
- Shock level (2) two: 15 - 22 cps, After 15 min. inform company man and take some action to reduce to level zero.
- Shock level (3) three: > 22 cps, after 5 min. the tool is in imminent peril of failure immediate action should be taken.

Rate of penetration (ROP):

Drill-bits break the rock by combination of several process including Compression (weight on bit), Shearing (rpm), and sometimes jetting action of drilling fluid. The speed of drilling is described as the rate of penetration (ROP) and is measured in ft/h.

Factors affecting the rate of penetration (ROP);

Weight on bit (WOB), Revolutions Per Minute (RPM), Bit Type, Bit Wear, Hydraulic Efficiency, Degree of overbalance, Drilling fluid properties, Hydrostatic pressure, Hole size.

While drilling; formation fluids are prevented from entering the wellbore due to the differential force. However, the overbalance also keeps the rock cutting held in the bottom of the well-bore. The effects of bit rotations and hydraulics offset this force and ensure that cuttings are lifted from the bottom of the hole. The differential force has one of the most effectson the ROP especially in soft medium formation

If all factors affecting ROP are kept constant while drilling a uniform shale thus the ROP will decrase with depth, this is due to natural increased compaction with depth reflecting a decrease in prosoity and increased shale density and increased in shale compressive strength

When entering abnormally pressured shale, the drill bit recognizes the shale section which is uncompacted. The increased porosity and decreased density of the under-compacted shale section results in formation becoming more drillable since, there is less rock matrix to be removed. Consequently; ROP increases, assuming all drilling parameters haven't changed as mentioned before. In addition, the reduced differential pressure between the mud hydrostatic and pore pressure further increased the ROP

The increase in ROP upon entering an abnormally pressured zone is showed in figure below, as we can notice from the figure a sharp drill-bit would pick up the onset of the transation zone much faster than a dull bit. [8]

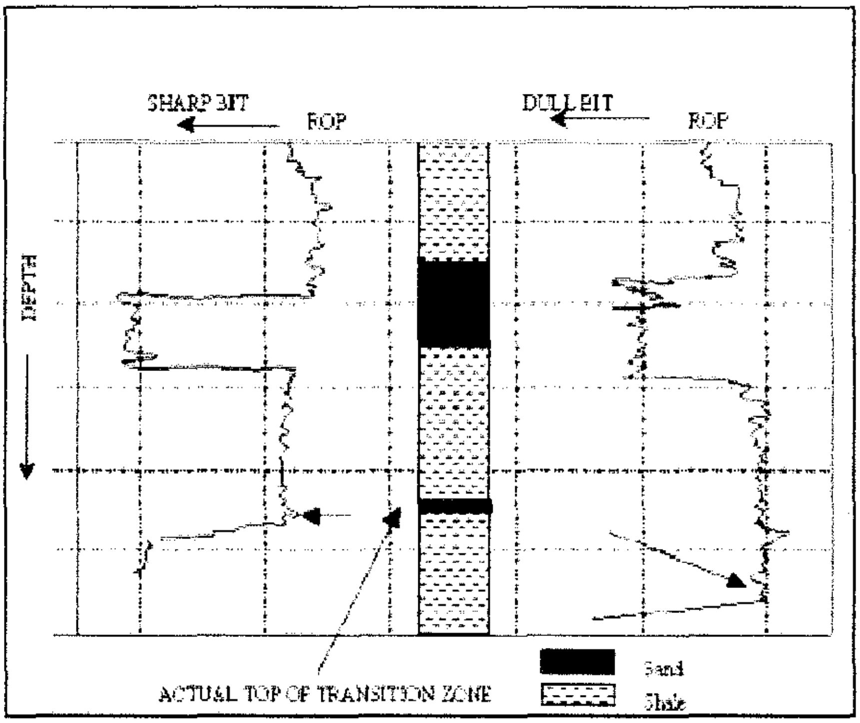


Figure ROP as an indicator of overpressure

Drill ability:

The rate at which a formation can be drilled is determined by a number of factors, some of which are: force applied rotary speed, tooth efficiency, differential pressure, drilling hydraulics and matrix strength.

Thus with same drilling conditions in a uniform lithology, it can be seen that the rate of penetration can be controlled by differential pressure alone. Rate of penetration would decrease uniformly with depth as compaction increases. Upon entering a geo-pressure transition zone, decreasing compaction and increase differential pressure across bottom would lead to an increase in penetration rate.

A number of "drill-ability" or normalized drill rate formulations have been proposed to remove the effects of many drilling variables. For the best application of these formulations, direct data monitoring and computation equipment are necessary. However, field application has shown that, when such equipment is not available, the easiest and most reliable method is the "d-exponent." This formulation allows control of the major drilling variables, and has proved so successful that most of the more complex ***drill ability*** formulations are extensions and refinements of the basic "d-exponent"

3 *CHAPTER 3: METHODOLOGY*

In order to reach the goals of this research project, research and study has been carried out prior to the submission of preliminary report, acquiring information from a variety of sources, such as the Society of Petroleum Engineers (SPE) Technical Papers, Drilling engineering, and Geosciences Courses learned in UTP.

Since the topic of the project is very wide, so it needs a good effort in organizing the work flow or else the project will be inefficient. So in order to organize the work flow for such a wide topic, these points are to be followed:

For final year project it will be all research based.

1. Research on the topic itself as a whole.
2. Divide the main topic into sub-topics.
3. Research on each subtopic on its own, for a given time that is suitable for each subtopic, to cover it.
4. Evaluate each of the subtopics.
5. Searching for case study available for the techniques.
6. The advancement in each technique.
7. Reaching conclusion.

The Aims of Bit Selection:

Optimum ROP and Durability:

Bit selection commonly involves choosing a bit that offers the right balance between durability and Rate of Penetration. We cannot get maximum rate of penetration and maximum durability in the one bit. The right balance between the two will yield an Optimum ROP and an Optimum Durability for the application.

Avoiding Catastrophe:

It is not sufficient to select a bit that seems to offer the desired balance between ROP and durability. We must also be confident that there is little likelihood of major bit failure. We need to be assured that the risk of cone loss through early bearing failure is acceptably low, or that an expensive PDC bit will not be destroyed in a hostile formation before reaching its target.

Rolling cutter bits, also known as *roller cone bits,* consist of cutting elements arranged on cones. The principle types of rolling cutter bits are *milled steel tooth,* or "rock" bits (Figure 1 , *soft formation type*, and Figure 2 , *medium formation type*), and *tungsten carbide insert,* or "button" bits (Figure 3 , *soft formation type*, and Figure 4 , *hard formation type*).

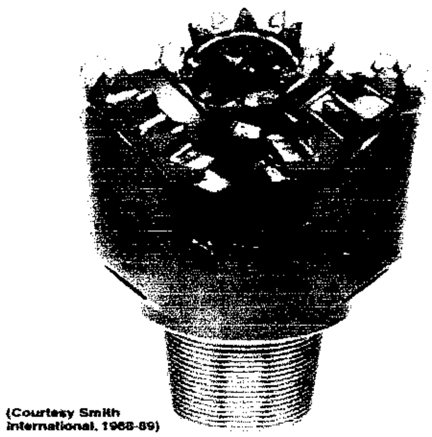


Figure 9 soft formation type

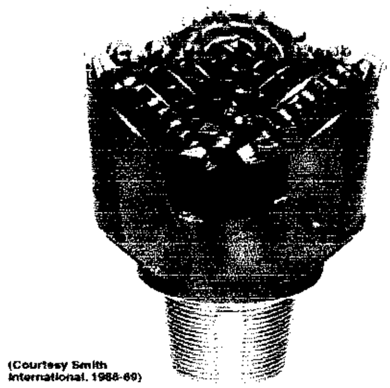


Figure 10 Medium formation type), and tungsten carbide insert

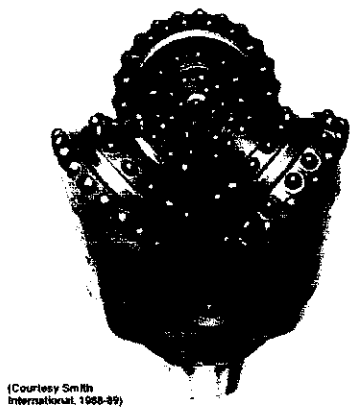


Figure 11 soft formation type

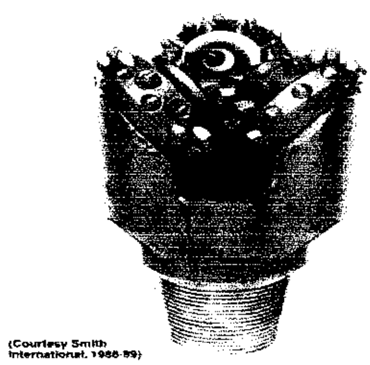


Figure 12 Hard formation type

Fixed cutter bits, also known as *drag bits,* consist of stationary cutting elements that are integral with the body of the bit and are rotated directly by the turning of the drill string. The principal types of fixed cutter bits are

— steel cutter (i.e., "fishtail" bits)

— Natural diamond

— Polycrystalline diamond compact (PDC)

While steel cutter drag bits have some use in soft, unconsolidated formations, this discussion focuses mostly on diamond fixed-cutter bits, which have a much wider range of applications. Examples of these bits are shown in Figure 5 (*natural diamond*) and Figure 6 (*PDC*).

(Courtesy Smith International, 1988-91)

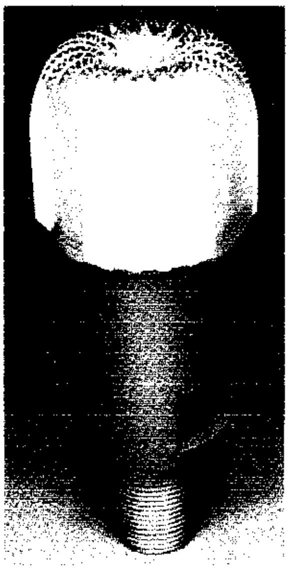


Figure 13 Natural diamond

(Courtesy Smith International, [redacted]

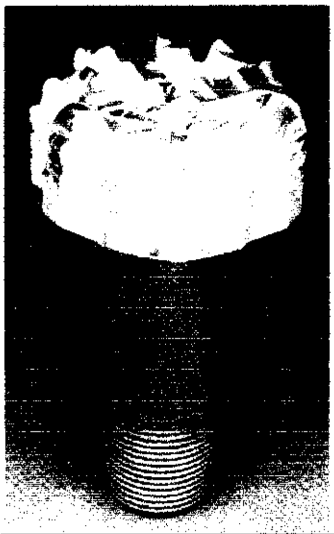


Figure 14 polycrystalline diamond compact (PDC)

Both rolling cutter and fixed cutter bits are designed for a wide variety of formation types. Certain bit types, however, are best suited to a particular range of formations.

Table 4 PDC applications and non-applications.

PDC bits are generally <u>applicable</u> to	PDC bits are generally <u>not applicable</u> to
Very weak, unconsolidated hydrateable sediments (sand, shale, clay)	Hard cemented sandstones (angular porosity less than 15 %)
Low strength, poorly compacted, nonabrasive precipitates, evaporates (salt, anhydrite, marls, chalk)	Hard carbonates (low porosity limestone or dolomite)
Moderately strong, somewhat abrasive ductile sediments (claystone, shales, porous carbonates)	Pyrite, chert, granite, and basalt

Table 5 Diamond Bits Application:

Diamond bit is generally <u>applicable</u> to	Diamond bits are generally <u>not applicable</u> to
Hard abrasive formation such as quartzite, composites, siltstones sections, hard lime-stones, sandstones particularly useful in Turbine drilling	Low abrasive formations Soft carbonates
Hard carbonates (low porosity limestone	

Gantt chart

For FYP-1

No.	Details / week	1	2	3	4	5	6	7		8	9	10	11	12	13	14
1	Selection of project topic	■	■													
2	Preliminary research work		■	■	■											
3	Submission of prelim report				●											
4	Project work					■	■	■	■	■						
5	Submission of progress report										●					
6	Project work continues									■	■	■	■	■	■	
7	Submission of Interim Report													●		
8	Oral Presentation														●	

● Milestone

■ Progress

For FYP-2

No.	Details / week	1	2	3	4	5	6	7		8	9	10	11	12	13	14
1	Project work continues															
2	Submission of progress report									●						
3	Project work continue															
4	Submission of Final report												●			
5	Poster exhibition/ PRE-EDX												●			
6	Submission of dissertation/EDX													●		
7	Final Oral Presentation															●
8	Submission of hardbound copies															●

● Milestone

Progress

4 *Results and discussion:*

Effect of drilling fluid viscosity on ROP

Experiments and field practice showed that viscosity of drilling fluid affect adversely the bit performance.

It is showed by the chart that the penetration rate decreases with viscosity increasing. The most considerable changes takes place in the region of 0 – 40 cp. At higher viscosity the penetration rate changes insignificantly

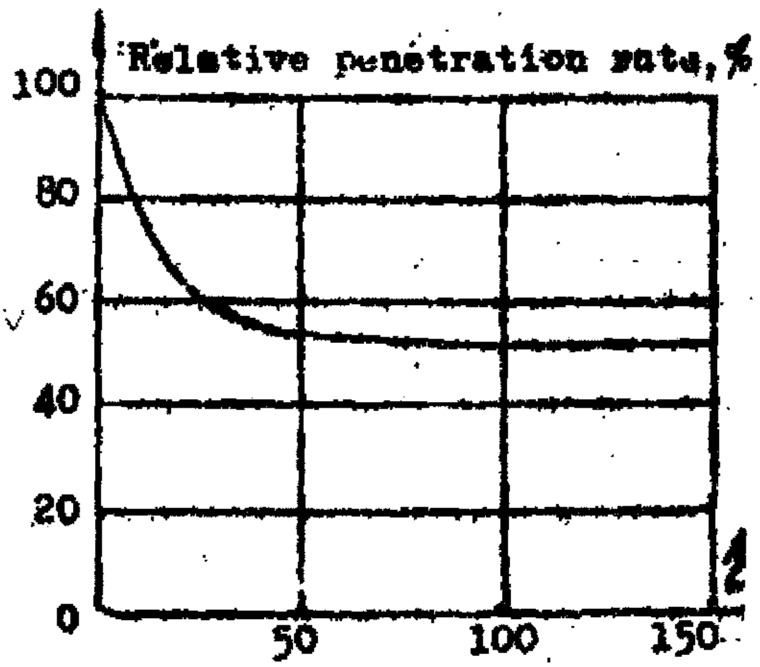


Figure 15 Relative Penetration Rate

Circulation Rate

It was learned by field experience that in rotary drilling an increase in the rate of penetration result from higher circulation rate tends to slow and approach a certain maximum value.

$$Q = (0.057 - 0.065) \times AB \qquad l/sec$$

This value can be considered as the maximum value which is not advisable to exceed because exceeding this value has no useful effect.

Rotary speed recommendation:

According to recommendations given by Hughes Tool Company, the average weight on bit, rotary speed and (Wb / n) criteria vary with the bit type.

Table 6 Bit Criteria Variation

Bit type	***Bit weight / unit dia. W_b, t/cm***	***Rotary speed, n rpm***	***W_b n, t*rpm/cm***
Soft formation Bits	0.53 – 1.07	100 – 250	107 – 134
Medium soft formation Bits	0.53 – 1.25	60 – 180	75 – 96
Medium hard formation Bits	0.71 – 1.43	40 – 90	57 – 64
Hard formation milled tooth Bits	0.89 – 1.78	35 – 70	62
Tungsten carbide compact Bits	0.71 – 1.43	35 - 70	50

Limitations for Rate of Penetration (ROP):

As mentioned before ROP is affected by Weight on bit (WOB), Revolutions Per Minute (RPM), Bit Type, Bit Wear, Hydraulic Efficiency, Degree of overbalance, Drilling fluid properties, Hydrostatic pressure, Hole size. Consequently, a sudden increase in ROP does not have to be due to penetrating an abnormal pressure zone, as a matter of fact maybe caused by changes in any one of previously mentioned parameters.

D-exponent Calculation:

Bingham (1965) proposed that the relationship between penetration rate, weight on bit, rotary speed, and bit diameter may be expressed in the following general form:

$$\left(\frac{R}{N}\right) = a\left(\frac{W}{B}\right)^{d}$$

Where:

d = drilling exponent (dimensionless)
R = rate of penetration (ft/hr)
N = rotary speed (rpm)
W = weight on bit (lbs)
B = bit diameter (inches)
A = matrix strength constant (dimensionless)

Jorden and Shirley (1966) [8] solved the previous equation for "d", inserted constants to allow common oilfield units to be used, and plotted the output on semilog paper which produced values of d-exponent in a convenient workable range. Most important, however, they let "a" be unity, removing the need to derive empirical matrix strength constants, but made the d-exponent lithology specific:

$$D = \frac{\log\left(\frac{R}{60N}\right)}{\log\left(\frac{12W}{10^6 B}\right)}$$

Where:

d = drilling exponent (dimensionless)

R = rate of penetration (ft/hr)

N = rotary speed (rpm)

W = weight on bit (lbs)

B = bit diameter (inches)

Rehm and McClendon (1971 &1973) proposed this correction:

$$Dxc = dx \; \frac{N.\,FBG}{ECD}$$

Where:

d = drilling exponent

Dxc = corrected d-exponent

N. FBG = normal formation balance gradient-EQMD (lb/gal)

ECD = effective circulation density (lb/gal)

In a certain lithology, the d-exponent should increase as the depth, compaction and differential pressure across bottom increase (Figure.3).Upon penetration of a geopressured zone, compaction and differential pressure will decrease and will be reflected by a decrease in the d-exponent (Bowers,

Limitations of D-Exponent:

It can only be used to calculate pore pressure in clean limestones

Large increase in mud weight cause lower value of dc

Dc Exponent values are affected by lithology, poor hydraulics, type of bit, bit wear, unconformities in formation

Cost per foot calculation:

The following partial bit record is available:

Bit Size	Type	Bit Cost	Depth Out	Ftg.	Hrs.	ROP, ft/hr
8 "	OSC-1G	$1,000	8,650 ft	650	16	40.6
8 "	OSC-1G	$1,000	9,175 ft	525	15	35.0
8 "	X3A	$1,000	9,600 ft	425	15	28.3
$8\frac{1}{2}$ "	J22	$4,350	10,150 ft	550	20	27.5
$8\frac{1}{2}$ "	J22	$4,350	11,000 ft	850	30	28.3

Offset well performance (interval 8,000' to 11,000'):

Total rotating time = 96 hours; Total trip time = 48.5 hours; Rig operating cost = $300/hour; Total bit cost = $11,700; Total footage = 3,000 feet.

Therefore, the offset cost for the interval 8,000'-11,000' is

$C = [300\ (96+48.5) + 11{,}700] / (3{,}000) = \$18.35/\text{ft}$

When performing a break-even analysis, the bit performances in the offset well are known, but bit performance in the new well must be estimated. Thus, we must assume either the footage that the new bit will drill or the penetration rate it will attain.

If we assume that the bit will drill certain footage, then we can calculate the break-even penetration rate using the following formula, which can be derived from **Equation 1.**

Rate of penetration calculation:

$$ROP = \frac{R}{\left[C_1 - \left(Rt + B_2\right)/F_2\right]} \qquad (2)$$

Where:

ROP = break even penetration rate, ft/hr

R = rig operating cost, \$/hr

C_1 = offset cost per foot, \$

t = trip time for new bit

B_2 = new bit cost, \$

F_2 = assumed new bit footage, ft

To determine the break-even performance of a PDC bit costing \$14,800

R = \$300

C_1 = \$18.35/ft

t =11 hours

B_2 = \$14,800

F_2 = 3,000'

Thus, the break-even penetration rate is

ROP = 300/[18.35 - (300 × 11 + 14,800)13,000] = 24.4 ft/hr

If we instead assume a penetration rate, we can calculate the break-even footage as follows:

Footage Calculation based on rate of penetration:

$$F = \frac{Rt + B_2}{C_1 - R/ROP_2} \qquad (3)$$

Continuing with the preceding example,

If we assume a penetration rate of 30 ft/hr, the break-even footage is

F = [(300 × 11) + 14,800]/[18.35 - (300/30)] = 2,168 ft

The PDC bit needs to drill only 2,168 feet to attain the break-even point if it can maintain an average penetration rate of 30 ft/hr.

Although this illustration involves a comparison between a PDC bit and rolling cutter bits, break-even analysis can be applied to any bit types.

We can see from this discussion that economic analysis of bit performance involves a certain amount of guesswork. Our bit selection based on break-even analysis is only as valid as our estimates of footage or penetration rate. These estimates, therefore, must be as accurate as possible, which is why the drilling engineer must become as familiar as he or she can with bit types, formation characteristics, mud properties, hydraulics, rig operating conditions and other factors that influence bit performance.

5 CHAPTER 4: CONCLUSION

The drill bit is an essential part of the drilling process although; it is often given slight attention. Depending on many factors such as the formation type, economic wise, efficiency required; a drilling bit should be chosen. Accordingly, if we identify that best choice then dramatic savings in drilling cost will be made.

This research project considers how bit design affects bit performance, presents a structured approach to bit selection and considers some of the pitfalls of the selection process. There is an underlying theme of compromise: whether we consider bit design, selection or operation it is rare that we can have everything from a bit.

As an engineer, knowledge and skill must be available in order the make the right decision of which equipment to be used thus, minimizing drilling cost and maximizing the Hydrocarbon recovery.

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