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MASTER'S THESIS

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Abstract

The primary object of this thesis is to analyse and optimise the drill bits performance that used to drill on the Norwegian Continental Shelf. The three different types of bits that were utilized under drilling are described in the first part of the thesis. The different aspects of designs and features are discussed and their technological advantages are highlighted.

In the second part of the thesis an experimental tests are conducted. The main purpose of this test is to evaluate the performance, efficiency and stability of 9 ½ inch Kymera (KM623), against 9 ½ inch PDC (6 bladed), and 9 ½ inch (TCI) VMD - 20. The test will compare the drillability (ROP), durability (dullgrade, wear etc) and stability of Kymera vs PDC and TCI. All the bits will be tested in the same formation types and strenghts at the same range of RPM and ROP parameters. Bit response, stability and MSE will be evaluated in order to better understand bit behavior in the subject formation. The analyses and conclusions will be used for future field drilling optimization and advice in offshore operations.

Acknowledgment

First of all I would like to thank Baker Hughes for providing me with all the required data needed for this report. I would like especially to thank my supervisor in the company Regional Drill Bit Engineer – Thorsten Schwefe. My thanks goes to all the drill bit design crew that made experimental testing possible in Houston – Adam Bohanan, Shana Larson.

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At last would like to thank my family for been patient and supportive under this stressful part of my life.

Stavanger, June 2014-06-16

Gergana Nikolova Karadzhova

1 Innholdsfortegnelse

2 Introduction

2.1 History

Drilling for oil and gas is getting more advanced and challenging. New technologies are exploring in order to solve the most crucial technological problems in smart and cost efficient way. There are many parameters related to operations that needs to be planned an evaluated and also modified in order to improve the drilling process.

Drill bit optimization is very important subject in drilling services. The bit is a major tool that has a big impact on the whole drilling process. Bit selection is one of the important parameters for planning and designing new wells. Choosing the wrong bit or damaging the bit in the formation can be of a big cost to an operator companies. Bit selection is a hard task to perform. There are many aspects that need to be considered and evaluated before decision is made. The operator companies are exploring oil and gas areas that were totally impossible to drill for 30 years ago. The need for new bit designs and optimization of those is enormous. Economical savings is one of the main drags for searching new and better solutions.

The first two –cone model bit had cones, which were unable to change. When the bit became worn out, the bit was discarded. In 1917 the Hughes Company presented a cone, which was able to change when required. In 1933 was introduced the first Tricone bit as the type we know today. The bit was primary used for drilling medium to harder formations.

In 1976, Christensen introduced the first Polycrystalline Diamond Compact bit, increasing the capability to drill in softer formations. The market of the diamond bits has grown considerably. PDC are used in longer sections where the seal and bearings of the Tricone bit cannot last long. Another factor that contributes to expanding PDC market is the rig cost. Rig cost has increased significantly the last decade.

In 2010 the first hybrid bit was presented by Baker Hughes. This bit is unique of its type. It combines both the PDC parts and Tricone parts. The Kymera marked has enormously increased the last few years. The bit proved to be a future solution for challenging formation, such as highly interbedded formations, conglomerates and etc.

The main purpose of that document is the optimization and comparison between conventional bits such as PDCs and roller cones with the new hybrid bit Kymera. It involves optimizing the drilling parameters. Increasing the ROP and bit stability will be the major tasks that are going to be addressed.

2.2 Scope and Objective

The scope and objective of this report work contains theoretical, analytical and experimental studies. The thesis contains the following information:

- Presentation of the different types of bit manufactured by Baker Hughes
- Theoretical models and calculations for MSE, DOC, UCS, bit stability, aggressiveness
- Experimental test performance
- Experimental test results
- Results analyses and conclusions

3 Drill Bit Technology Overview

The drill bits are important tool in drilling services. There are three major types of bit that are used in the oil business:

- PDC
- Tricone
- Kymera

3.1 Polycrystalline Diamond Compact bits (PDC)

It is a new generation of old drag bit. PDC bit design is more durable. There are no bearings to wear out or broken cones that may cause junk in hole.

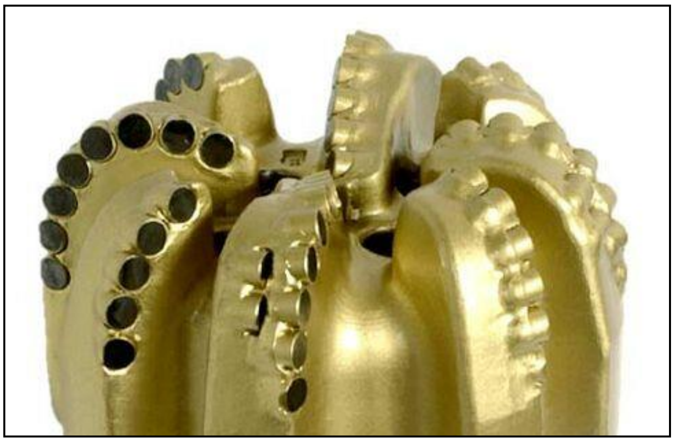

Figure 1 Polycrystaline Diamond Compact

3.1.1 The PDC bit elements

The structure of the PDC bit can be broken down to three major parts:

- Cutting structure,
- Bit body
- Shank.

See the picture below:

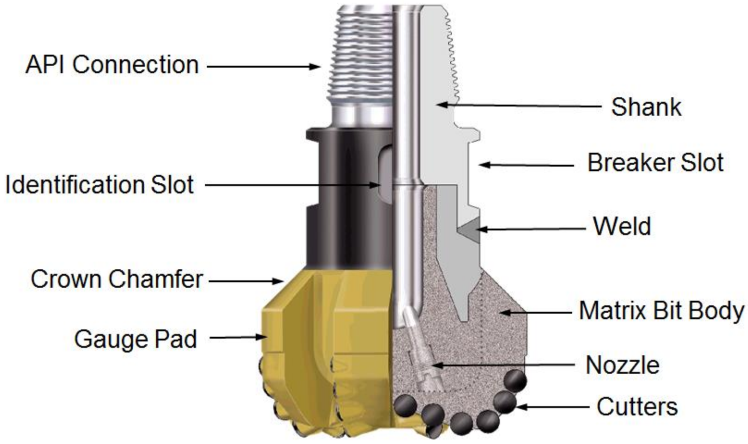

Figure 2 PDC bit components

3.1.2 Cutting structure

This part of the PDC structure can be either synthetic diamonds or natural industrial grade diamonds. The cuttings type used depends on the formation to be cut and the application.

3.1.2.1 PDC Cutters

The PDC cutting structure can either consist of synthetic diamonds or natural industrial grade diamonds.

The diamond is the hardest material that we currently know of. Hardness is described as resistance to scratching and it has a range of 1 (softest) and 10 (hardest). Diamond has the hardness of 10 on the Mohs scale of mineral hardness. There are two mechanical properties that describe the diamond – hardness and toughness. Toughness is the material ability to resist breakage from forced impact.

Industrial diamonds are valued mostly for their hardness and thermal conductivity. The use of diamonds in the industries has been associated with their hardness. The diamonds are used in drill bits cutters especially because of their impact resistance, ability to grind and cut any material.

Synthetic diamonds are diamonds that are produced in the laboratory. The majority of the available diamonds are produced by so called High Pressure High Temperature process. Another popular method is chemical vapor deposition (CVD). The growth occurs under low pressure (below the atmospheric pressure).

Figure 3 Natural Diamond Cutters

PDC cutters are formed from the synthetic diamond crystals (feedstock) and are loaded in a protective holder assembly with a tungsten carbide substrate.
PDC cutters consist of many synthetic diamonds bonded to a cemented tungsten carbide. There are three major parts of cutter design:

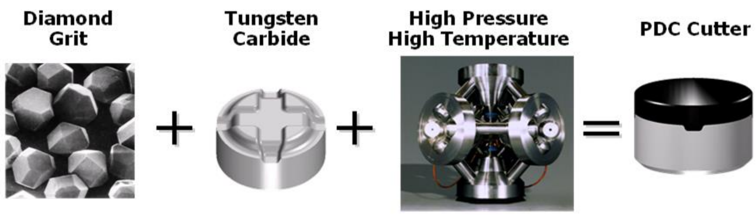

Figure 4 PDC Cutter manufacturing method

- Diamond table
- Diamond Carbide Interface
- Edge Geometry

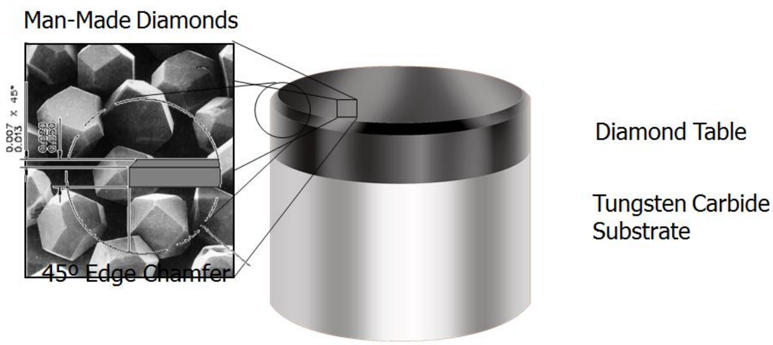

Figure 5 PDC cutters

3.1.3 Diamond Table Properties

The thickness of the diamond table is determined by the application and the diamond table properties. Optimized diamond table properties influence both abrasion resistance and durability.

Thinner diamond table are less durable but maintain better cutting efficiency. When choosing thicker diamond tables we will gain more durability, but the cutting efficiency will not be maintained very well.
(Baker Hughes (2013) – Bit Tech Training – Book)

Figure 6 Diamond Table

3.1.4 Diamond/Carbide Interface

Internal geometry has a very important role in cutter durability and impact resistance. Test studies have shown then planar interface increases the residual stress between the diamond table and carbide substrate hence lower durability and separation of the diamond table from the carbide substrate. The studies showed that non-planar interface allows minimizing this effect of the residual stress.
Residual stress is simply the stress that is residing in the cutter after the cutter manufacturing process.(Baker Hughes,(2008) – Diamond Tech – Student Guide)

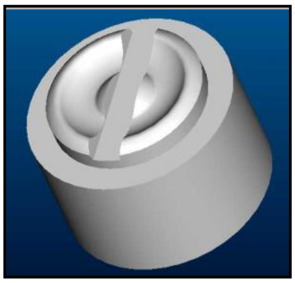

Figure 7 Tungsten Carbide Substrate

3.1.5 Edge Geometry

There are two major features of external geometry:

- Cutter Back Rake
- Edge Chamfer

Cutter back rate is the one feature that provides the aggressiveness of the bit. Larger back rake improve the durability but decrease the aggressiveness.

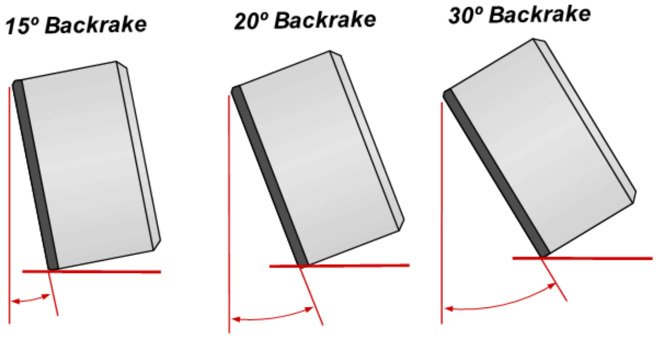

Figure 8 PDC cutter back rake

Cutter chamfer is the feature of a diamond cutter that protects against forced impact. Larger chamfer improves durability but decrease the aggressiveness. The chamfer is a small bevel at the edge of the diamond table. Typical chamfer properties are height and angle of the chamfer. Diamond is a brittle material and crack is very easy to be created and propagated. Reducing these sharp edges leads to high impact resistance. The choice of chamfer on a certain bit is determined by the formation. Smaller chamfers require less force to be broken and damaged. (Baker Hughes, (2008) – Diamond Tech – Student Guide)

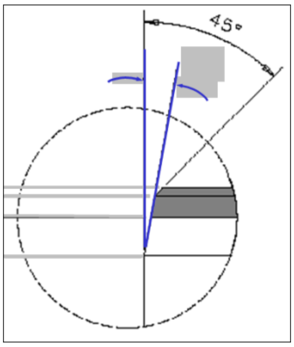

Figure 9 Cutter chamfer

A higher back rake will direct cutting edge forces into the substrate while a lower back rake will direct those through the diamond table. Higher back rake also provides greater resistance to fracture but decrease the efficiency. Smaller back rakes require smaller weight on bit in order to generate a given torque. (Baker Hughes, (2008) – Diamond Tech – Student Guide)

3.1.6 Polished Cutters

Hughes Christensen Company patented polished cutters invention. Polished cutters proved to be more efficient than the non-polished cutters. The polished surface decreases the friction between the cutter and the cuttings. Polished cutters have improved the downhole cleaning issues and minimized the bit balling and bottom balling problems. The cuttings are easily removed from the cutter surface and don't create any additional thermal and frictional issue to the bit. The surface finish of a conventional and polished cutter differs: (Patent, Baker Hughes – Polished Cutters)

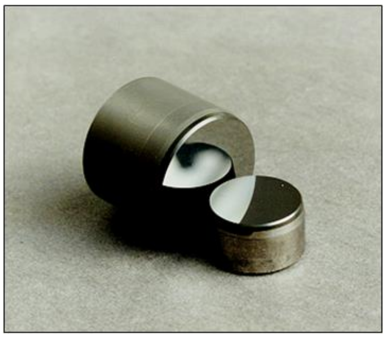

Figure 10 Polished Cutters

- Conventional PDC is 0.5 -1.0 m in
- Polished PDC is 20 – 40 m in

3.1.7 Cutting mechanics

The main purpose with the cutters is to shear the formation in efficient matter, which means use less energy (WOB) per unit volume rock. The cutters needs to remain durable and impact resistant through the whole run. Cutters have to provide the predicted ROP and DOC.

3.1.8 Depth of Cut

It is an important concept connected to the cutting mechanics. DOC is the distance that the cutter is intended into the formation per revolution. (Baker Hughes,(2008) – Diamond Tech – Student Guide)

When the rate of penetration (ROP) and Revolutions per Minutes (RPM) are known, the DOC can be calculated as follows:

$$DOC = ROP/RPM*5$$

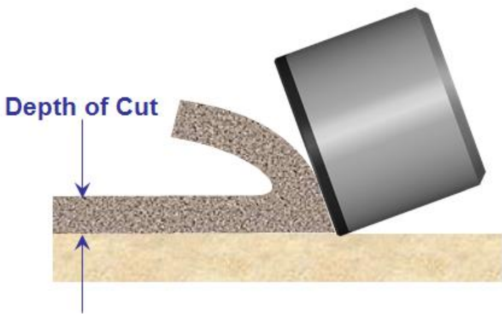

Figure 11 Depth of Cut Control

3.1.9 Cutter size

At Hughes Christensen there are three cutter sizes are used:

- ¾ .inch (19mm)
- 5/8 inch (16mm)

- ½ .inch (13mm)
- 3/8.inch (8mm).

19 mm cutter generates the largest cuttings**.** The most usable diamond height 13mm has the most versatile cutter size. 8 mm they provide design flexibility in small diameter bits. (Baker Hughes (2013) – Bit Tech Training – Book)

3.2 The bit body

This is the part of PDC bit that holds the cutting structure. This part is essential for bit profile, waterway, junk slots, blades and gauge.

3.2.1 The shank

The part is made of hardened steel. The shank contains the identification slots and a bit breaker slot as well as the API threaded connection that connects the bit with the drill string.

3.2.2 Bit body material

Polycrystalline diamond compact bit bodies are made of milled steel or tungsten carbide (matrix bit). The current steel body bit consists of a crown and a shank. The crown starts as a piece of bar stock, which is a piece of steel that requires the bit shape to be milled from scratch to form the bit crown. Cutter pockets and other details are milled into the crown. The material for the bit body is a high alloy steel to obtain good strength and thoughness.
Once the milling is complete the bit crown is welded to a shank at the same time as the cutters are brazed on to the bit.
Steel is much less abrasion and erosion resistant than the tungsten carbide matrix. Therefore, a hardfacing material is applied in critical areas in order to prolong bit body life. Typically, hardfacing is applied to the front of the blades, in between the cutter pockets, behind the cutter pockets and on the gauge pads.

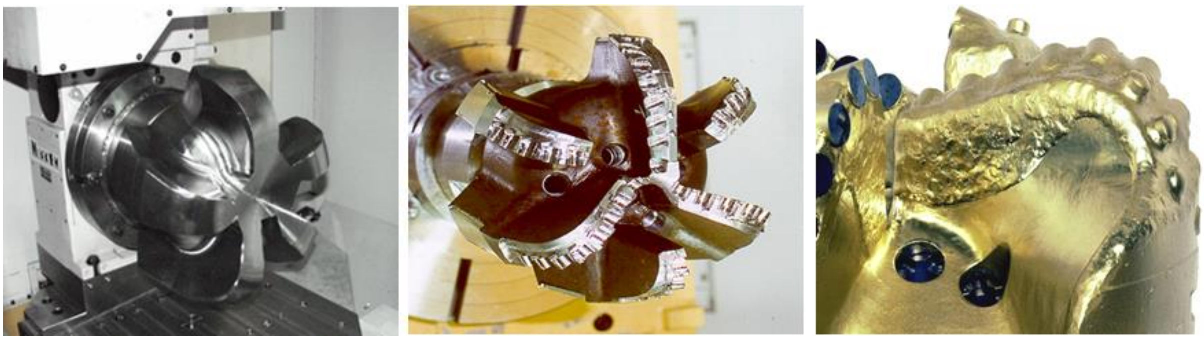

Figure 12 PDC Manifacturing Process

3.3 PDC Design Technology

Profile – the certain shape of the bit when viewed from the side.The shape of the profile can be of significant importance for bit performance. The objective of every profile is to provide balanced wear to the cutting structure and optimize the bit stabilization.

3.3.1 Profile Theory

This is one of the factors that are determining the number of the cutters that will fit on a blade. The longer the length of the profile and the more cutters can be placed on the blades. The design of the profile is very essential for determine bit balance and durability. A long profile will have more cutters, slower wear but less stable. A shorter profile will have fewer cutters. It will wear more quickly, but will be more stable in directional control.

3.3.2 Profile Components

The PDC profile composite curve consists of:

- cone
- nose
- shoulder

3.3.2.1 Cone

The section of the profile between the centerline and the nose radius is called the cone. The cone provides stabilization of the bit and helps it prevent from moving sideways. The cone provides some cutters redundancy due to more surface area available to be set with cutters. (Baker Hughes (2013) – Bit Tech Training – Book)

3.3.2.2 Nose

This is the lowest point on the profile. The nose radius is the radius of the arc between the cone and the shoulder/gage. The nose location is the distance from the centerline of the bit to the nose radius center point. (Baker Hughes (2013) – Bit Tech Training – Book)

3.3.2.3 Shoulder

Shoulder area on the bit profile is the distance between the nose radius and the gage.

3.3.2.4 PDC bit profiles

There are three major PDC bit profile types:

- Short parabolic
- Long parabolic
- Shallow cone

Figure 13 PDC bit profiles

3.3.2.5 Cutter density

Cutter density is the number of cutters per length of the profile.

3.3.2.6 Bit density

The bit density is a function of a blade count, profile length and cutter size. It can be classified as light, medium or heavy and refers to the blade count.

There are two basic profile designs used for PDC bits, the shallow cone and parabolic profile.
Experience has proven the flat profiles are more stable. Parabolic profiles have two radii (nose and shoulder). They are divided into three groups long, medium or short.
Long profiles are best suited for higher RPM ranges. The short parabolic profile is essentially provides the best compromise of stability and cutter coverage. (Baker Hughes (2013) – Bit Tech Training – Book)

3.3.3 Blade design

Blades need sufficient strength to withstand drilling stresses for the various applications. There are several blade designs are used in PDC bits:

- Pie-Shaped

It is an older design that is not in production any more.

- Straight Blades – they allow for wider junk slots and better place for the nozzles
- Curved Blades – they can inhibit effective cleaning and cooling of cutters on the shoulders

(Baker Hughes (2013) – Bit Tech Training – Book)

3.4 Hydraulics

3.4.1 Hydraulic Design

This is a method that is used to control the flow of drilling fluid across the face of the bit. The scope of any hydraulic design is to maximize the efficient drilling cuttings evacuation and provide cooling. Different methods for hydraulic optimization designs are implemented.

3.4.1.1 Junk slots

Junk slots are the area between the blades of the bit that are used to evacuate cuttings into the annulus. Their purpose is to carry formation cuttings away from the cutters. The number of the blades and the shank diameter can limit the junk slots.

3.4.1.2 Junk Slot Area/Ratio

It is measured of the total cross-sectional area from each junk slot if the bit were viewed face-on, expressed in square inches (in2). Larger junk slot area is used in soft formations with a higher penetration rate. When large JSA is used it is easier to evacuate a large volume of cuttings away from the cutters and avoid bit balling. The junk slot ratio is a ratio of a junk slot area to the total face area (hole area) of the bit. The junk slot is used to compare different types of bit sizes and designs. (Baker Hughes, (2008) – Diamond Tech – Student Guide)

3.4.1.3 Face Volume/ratio

Face volume is a measurement for hydraulic capacity. The face volume considers the volume in between the blades from the center of the bit and across the entire profile.

3.4.1.4 Gauge

The bit gauge is an essential factor of stabilization and steerability.

3.4.2 Hydraulic Efficiency

There are two aspects of hydraulic efficiency:

- Cutting removal
- Cutter cooling

Cutting removal – this property is verified by through a simulator-balling test. Cutter cooling is the ability to maintain a certain fluid velocity across the cutter face to cool the cutter during drilling. (Baker Hughes, (2008) – Diamond Tech – Student Guide)

3.5 PDC Cutter Failure Modes

The PDC bit can be exposed to one or more failure modes: fracture, wear and delamination.

3.5.1 Fracture

Cutter fracture comes as a result of an impact loads due to vibration and has two sub-categories:

- chipping
- spalling

3.5.2 Chipping

Chipping is a result from impact loads in the direction of cut, essentially parallel to the borehole bottom. The vibration that cause the impact loads is usually lateral or stick-slip. This is the most often seen PDC failure. (Baker Hughes, (2008) – Diamond Tech – Student Guide)

3.5.3 Spalling

Spalling, is caused by high axial impact loads. It represented by the separation of a partial thickness of the total diamond layer from the face of the substrate

3.5.4 Wear

Hard and abrasive formations will cause wear on the cutters. Due to long and continuous rotating despite that the diamond is very hard material, it is often seen wear on the cutters when the bit is pulled out of the hole.

3.5.5 Heat Checking

Hard but not abrasive formations often cause heat checking on the cutters. Heat checking occurs when the cutter substrate is rubbed against the formation. It is not that often seen failure compared to some other failures. (Baker Hughes,(2008) – Diamond Tech – Student Guide)

3.5.6 Diamond lip

This is the failure which will harm less the drilling process due to its low impact on the penetration rate. The diamond lip is a slight and smooth wear with little or no fracture of the cutter.

3.5.7 Delamination

Delamination is very rare seen in the new diamond cutters. This is identified as a separation of the diamond table and the tungsten carbide substrate. This is a quite serious failure which can cause low Rate of Penetration and high torque. (Baker Hughes, (2008) – Diamond Tech – Student Guide)

3.5.8 PDC bit Nomenclature

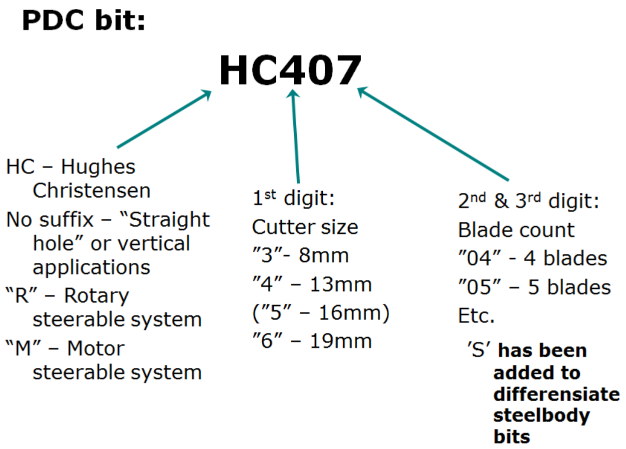

Figure 14 PDC Bit Nomenclature

3.6 Tricone bits

The roller cone bits consist of three main parts:

1. Roller Cone Legs
2. Bearings
3. Seals
4. Cones
5. Nozzles
6. Cutting structure

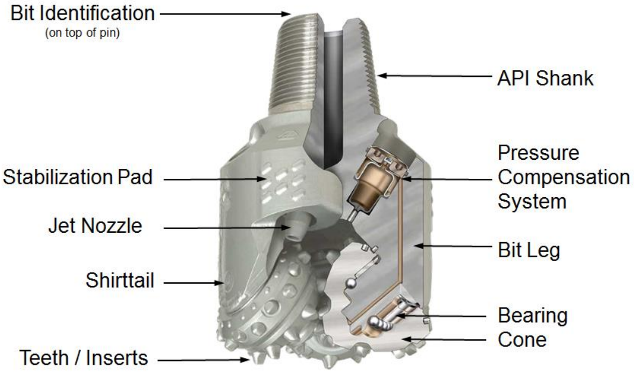

Figure 15 Roller cone bit components

3.6.1 Roller cone legs

This is the part of the Tricone body that holds the cone, bearings, seals and the nozzles. It is steel body that is milled and machine. The three legs are welded afterwards and hold the most of the weight of the bit.

Figure 16 Roller Cone legs

3.6.2 Roller cone bit types

As mentioned earlier it the thesis the first generation Tricone bits were the two cone bits. It was Howards Hughes, Jr who invented it in 1909. The technology behind this type of roller cone was revolutionizing. It was not only scraping the rock but the hard rock was powdered. This allowed the drillers to drill faster and deeper.

In 1925 new Acme self-cleaning cones were introduced. These new solutions manage to double the penetration rate and increased the footage with 80 %. (Tricone Technologies, Student Guide, Baker Hughes (2008)
8 years later Tricone bit was introduced to the drilling operators. The bit ran smoother and longer. In 1951 Hughes introduced the first Tungsten Carbide Insert (TCI). These are specially designed for harder and challenging formations.

The bit technology has improved a lot the last decades. The bearings and seals has been improved and new technologies are implemeted. Seal lifetime is significantly increased. Tricones can drill longer and advanced well paths. Steel tooth and TCI are still leading technology in shorter sections where boulders and other hard rocks are present. (Tricone Technologies, Student Guide, Baker Hughes (2008)

3.6.2.1 Steel tooth

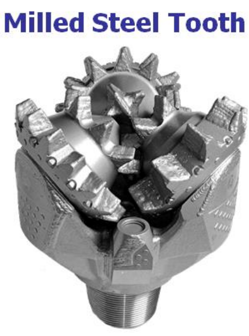

Figure 17 Steel Tooth Bit

Steel tooth cones are machined from forgings of an alloy steel. The cones are milled to form the shape of the steel tooth. The shape of the actual teeth will depend on the purpose of the bit. To protect the steel tooth, hardfacing is welded on the cutting structure. The hardfacing contains of tungsten carbide particles designed to maximize the cutting life of a tooth. The shape and density of the teeth depends on the formation application. Larger teeth with bigger space between are much suitable for soft to medium formations. Large teeth can grab and crush bigger volume of rock, thus drilling faster.
Smaller teeth with small space between are designed for medium to harder formation. Harder formation drilles slowly with low ROP and RPM. In order to drill this fomation the bit has to be able to carry a high weight on bit and resist to damage. Thats is the main reason small teeth are applied. They are able to grind the formation slowly with high weight on bit.

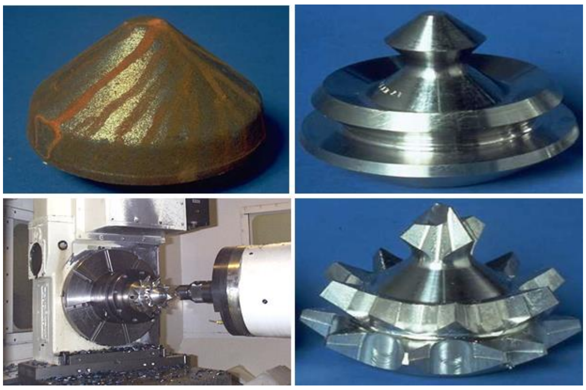

Figure 18 Steel tooth cones milling process

3.6.2.2 Tungsten Carbide Insert

The main difference between these two bits is that the teeth in Tungsten Carbide Insert (TCI) bits are pressed into the cones and not milled into them. The insert teeth are milled and machined and then mount on the cones. The amazing thing here about this type of bit technology is that the only force that holds the tungsten carbide inserts pressed in the bit cone, is the friction between the insert and the body.
The size and type of the components in the bit depends on the formation hardness. Bits for soft formation require smaller weight, smaller bearings, smaller cone shell thickness and thinner legs. That gives more room for long, thin cutters. Drilling in hard formations requires weight, bigger bearings, steadier body and stubbier cutters.
The roller cone bits consist of different types of bearings. TCI are the drilling solution for hard and challenging formations.

Figure 19 The process of manufacturing TCI cones and cutters

3.6.3 Bearings

The two main types of rock bit bearings are journal bearings and roller bearings. Both types of bearings are designed to carry large radial loading:

3.6.3.1 Journal bearings

Journal bearings (« friction bearings») have high load capacity due to their large load area. These types of bearings are space efficient and that make them especially used in small bit sizes. Journal bearings have RPM limitations due to friction. (Tricone Technologies, Student Guide, Baker Hughes, 2008)

Figure 20 Journal Bearings

Advantages:

- High Weight Capacity
- Relatively Space Efficiency

Disadvantages:

- RPM limitations
- Runs " Hot"

3.6.3.2 Roller bearings

Temperature is not an issue for roller bearings since they are anti-frictional bearings. Compared to journal bearings, roller bearings need more space in the cone of the bit. This is the main reason that these types of bearings are used in rock bits of larger sizes. Roller bearings are weight limited due to rolles impose line loading on the roller races.

Figure 21 Roller Bearings

Advantages

- High RPM capability
- Runs «Cool»

Disadvantages

- Requires more space
- Weight limitations

3.6.4 Seals

There different types of seal systems that are used in the different bit sizes. There is O-Ring seals and Metal Face Seals. The seal function is to separate the internal greased bearing from the drilling mud.

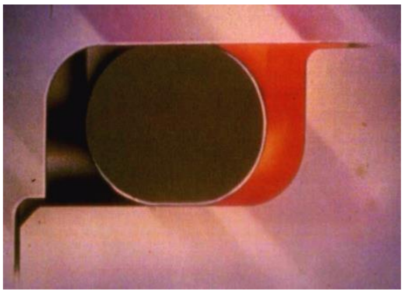

Figure 22 The seal function is to separate the cone grease from the oil

The O-ring is held under compression between polished surfaces between the head and the cone. The seal helps to isolate the greased section from the drilling mud system.

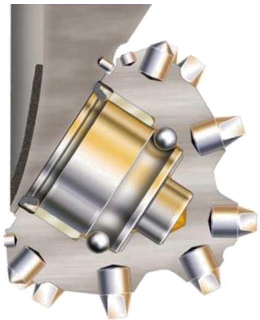

Figure 23 Metal Face Seal

Single Energizer Metal (SEM) seal system has fewer sealing components and silver plated insert:

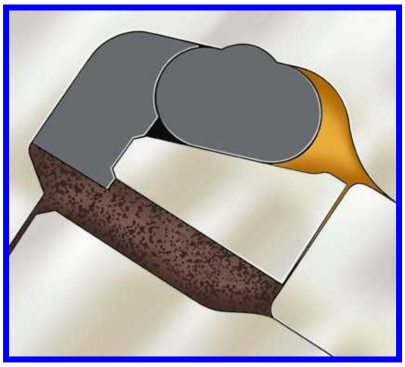

Figure 24 Seal Energizer Metal (SEM)

Metal face seal consist of elastomer that is used to “energize” metal seal surfaces.

Figure 25 O-ring seal

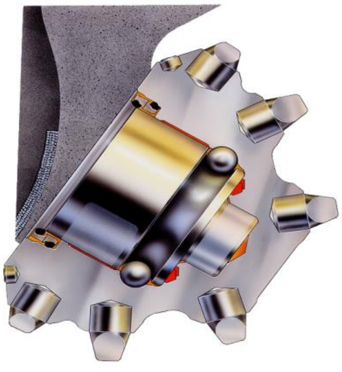

Figure 26 Dual Metal Face Seal Dual Energizer

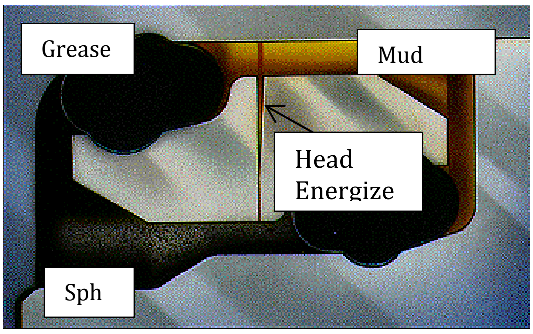

Figure 27 Dual Metal Face Seal System

The Metal Face Seal comprises polished metal rings retained by static elastomer ‘energisers’. A dynamic seal is created across the highly wear resistant metal faces. The advantages with this seal system are that it has high RPM potential, high temperature capacity, and obtain longer life. (Tricone Technologies, Student Guide, Baker Hughes (2008))

3.6.5 Nozzles and center jets

Nozzles are manufactured of Tungsten carbide material. Their main function is to provide sufficient cleaning and cooling to the bit in order to avoid downhole bit problems. Nozzles size and position are determined by the bit formation application. The orientation of the nozzles streaming direction is computed and modeled in order to assure best cleaning and cooling effect of the bit.


Figure 28 Bit nozzles

In certain applications a center jet is mounted in the center of the bit body. This feature is specially used when extra efficient cleaning is needed. The subject features is a hydraulic optimized feature in order to assure better cleaning and cooling of the bit.

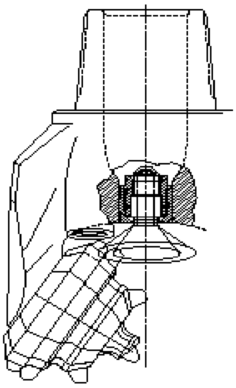

Figure 29 Center Jet

3.6.6 Cutting structure components

In this section the main components of the cutting structure will be presented. On the Fig.30 below are shown the different components of the cutting structure. As can see there are certain differences between the components of the Steel Tooth bit and TCI bit.

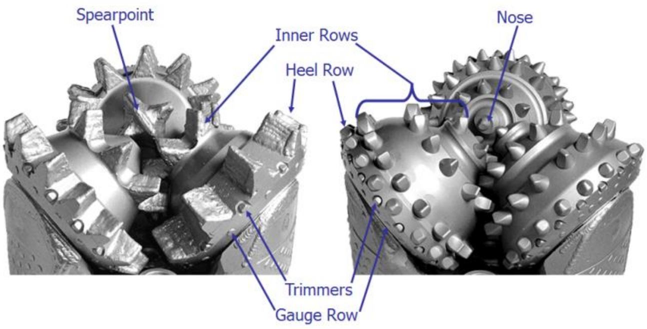

Figure 30 Cutting Structure Components

3.6.7 Steel Tooth Components

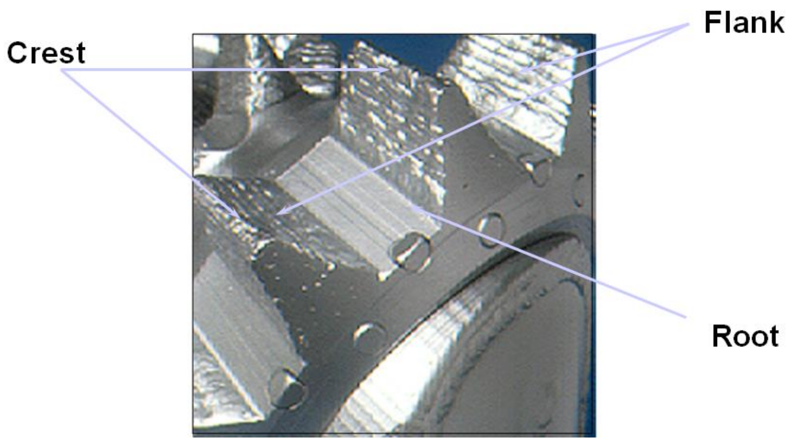

Figure 31 Steel Tooth Components

Different formation applications require different type of cutting structure. In soft formation high projection tooth structure is used with long crest. The cutting structure is with bigger teeth and wide space. Medium projections and short crest are usually used in medium formations. In soft formations rock failure can be easily achieved by long steel tooth. The teeth can easy grab and crush the formation in more efficient way. In soft formations usually balling is very often seen issue. When using a bit with long teeth, balling potential will be minimize and avoid.
On the other side when drilling through hard formations TCI bits are usually applied. Due to their durability, stability and wear resistance those bits are the most preferred ones when drilling in challenging formations. Small, wear resistance tungsten carbide cutters help to grind the hard formation and mill it carefully.

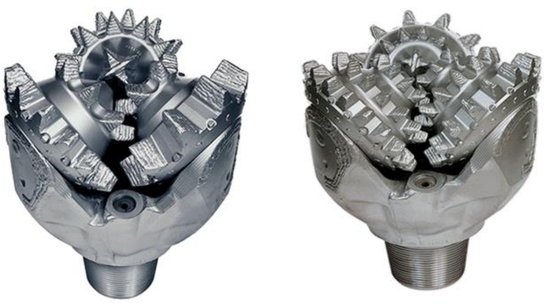

Figure 32 Soft formation vs medium formation

3.6.8 Compact shapes

There are four main compact shapes that are used according to the application requirements**.**

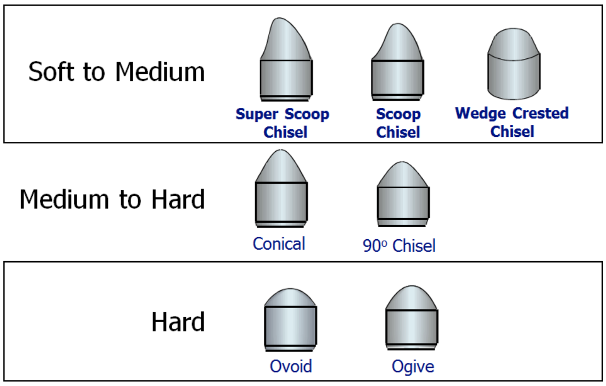

Figure 33 Compact shapes

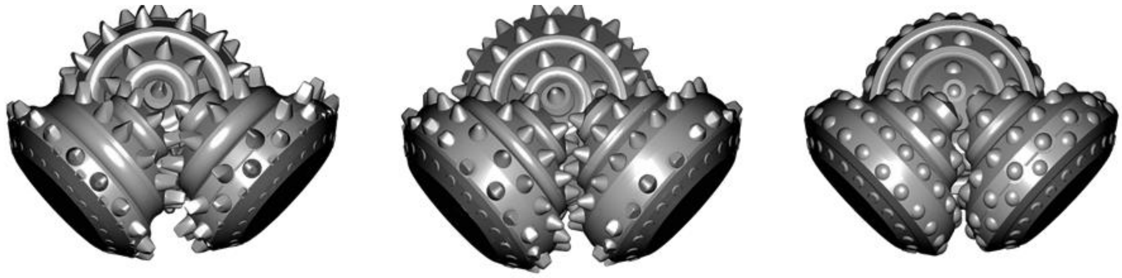

Figure 34 Soft Formation vs Medium Formation vs Hard Formation

3.7 Kymera bits

Kymera is the new generation hybrid bit. It combines roller cone bit and PDC bit in one. The design of hybrid bit is based on the very well proven and tested (up to six blades) PDC design where the secondary blades are replaced by roller cones. Kymera bit combines the best of two worlds. It combines the formation crushing action of the Tricone and the shear cutting action of the PDC bit. The rolling cones are positioned partially towards the back of the blades in order to open up a bigger junk slot for cutting evacuation. Kymera can drill four times faster in softer and plastic formations compared to roller cone bit. It drills faster in hard formations compared to a PDC bit. Hybrid bit is uniquely suited for heterogeneous formations with hard abrasive stringers by achieving higher ROP values compared to roller cones without sacrificing the durability. While drilling Kymera shows lower torque fluctuations compared to PDC bit. In directional applications the hybrid bit has tool face control of the roller cone bit and the ROP potential of the PDC. Low torque fluctuations contribute to better bit resistance to stick slip vibrations. Kymera bit is more likely to suffer fewer whirls due to its lower aggressiveness**.**

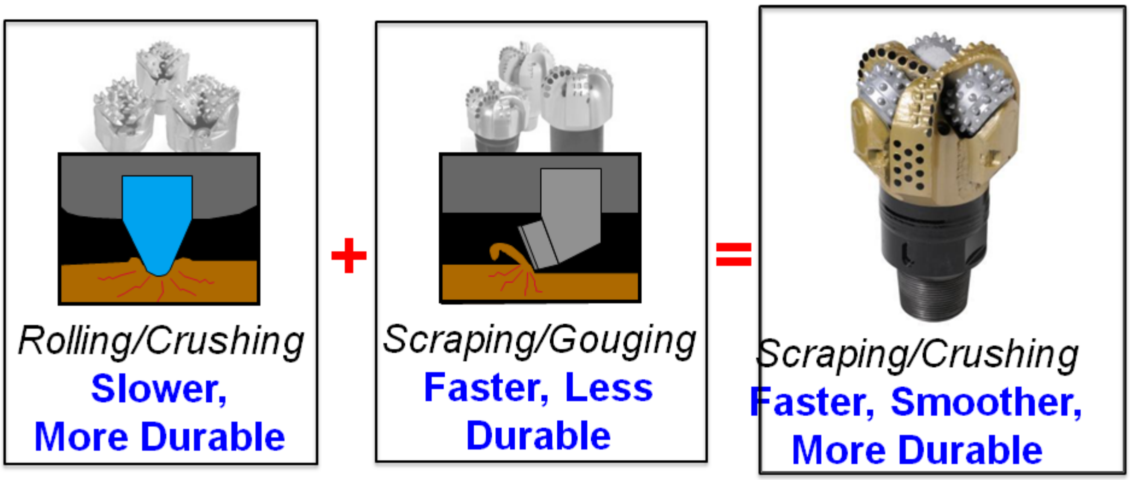

Figure 35 Kymera Cutting Action

3.7.1 Kymera Manufacturing

The body is made of steel. The steel body is machined. Then the shank is attached and welded to the PDC body. The next step is to apply the hardfacing. The cutters are brazed and grind afterwards.The cone is attached onto the head. And finally place the PDC body into assembly fixture with shank down. Both the head/cone body should be positioned into the correct pockets. Last weld the all the parts, add the grease in order to provide lubrication and decrease the frictions in the cone rotation.

3.7.2 Kymera Optimization Features

3.7.2.1 Seal type

Both elastomer seals and Metal Face Seals are available for Kymera. For elastomer seals the most commonly used are High Aspect Ratio seal (HAR). For metal faced seals (SEMII).For Kymera as for the other roller cones bit, the type of seal that is going to be used depends on the space possibility in the cones.

3.7.2.2 Inserts:

On the roller cone cutting structure inserts that are used in Kymera designs are chisel and conic. Ovoid inserts are used in the heel row. There are no steel teeth that are dressed on Kymera. The bit is designed to be durable and impact resistant.

3.7.2.3 Fixed Cutter Optimization

The PDC cutters that are mounted on the Kymera blade have the same manufacture technology as for the PDC bits. Kymera always is dressed with the last diamond technology cutters. The density and size of the cutters depends on the number of PDC blades that on a particular hybrid design. The space availability of the blade limits the cutter variety.

3.7.2.4 Nozzles:

The choice of nozzles is quite depending on the size of the bit and its formation application Small bit sizes has as well space limitations. There are different size of nozzles which can be dressed on a Kymera in order to achieve the required horse power for sufficient hole cleaning and bit cooling.

3.7.3 The Hybrid bit formation applications

The range of application of the hybrid bit technology continues to expand into more complex drilling well profiles. Overall Kymera has shown increased efficiency in applications were conventional bit struggle to achieve any progress at all. Despite its short history (only 4 years), the hybrid bit has already proven its value and contribution in challenging formations. Kymera is highly recommended for applications as:

- Interbedded formations
- Nodular formations
- Directional applications
- Stick slip problems
- Large diameter bits
- Poor hydraulics

3.8 Drill bit properties

Selecting the correct drill bit is a very important and uneasy task. The right bit choice can affect the drilling performance of the whole Bottom Hole Assembly. The wrong choice can be crucial both mechanically and economically. Bit performance can be affected by sudden downhole conditions. It is proven that better knowledge of the formation, has a huge impact on the bit choice. Other objectives as directional control, borehole quality, expected ROP, cost reduction are just a small part of the risks that need to be evaluated under bit choice consideration.
Good field offset analysis and formation knowledge could avoid any wrong decision in the future. There are certain models that are used in the oil company in order to execute drill bit evaluation.

3.8.1 Mechanical specific energy model (MSE)

Drillers can use the model in order to evaluate the efficiency of the drilling parameters. MSE can be used under well planning phase in order to adjust the parameters. R.Teale introduced this formula in 1964. MSE is defined as the amount of energy required to remove 1cm3 of rock. Teale then performed lab test that demonstrated the energy per volume of rock destroyed to be relatively constant, regardless in ROP, WOB and RPM.

MSE ≈(Input Energy)/(Output ROP)

Teale also observed that the value of MSE was approximately equal to the compressive strength of the rock. The tests that he conducted were done under atmospheric conditions where the rock failed in a highly efficient, brittle failure mode. In field conditions the peak bit efficiency are usually much lower, often in the 30-40% range. For operational reasons MSE was adjusted so that the value would be closer to the known rock strength. The EFFm that the operators are using them is 0.35:

MSE adj = MSE x EFFm

When the bit is operating at its peak efficiency, the ratio of energy to rock volume will remain relatively constant. When varying the different drilling parameters such as weigh on bit (WOB) and rotary speed (RPM) we can evaluate the bit efficiency. If despite the increasing of WOB the MSE stays constant one can still assume that the bit is drilling efficiently. If the MSE increases significantly, the bit has foundered. Then the parameters need to be adjusted accordingly in order to minimize the MSE again. MSE equation is expressed as follows:

$$MSE = \frac{WOB}{A_B} + \frac{120\pi \times N \times T}{A_B \times ROP}$$

Figure 36 MSE equation formula

Ab – bit surface area (inch2)
WOB – Weight on bit (lbs)
N – Rotary Speed (Round per minute)
T – Torque (lbf x ft)
MSE – psi
ROP – Rate of Pentration (ft/hr)

(Dupriest, Fred E., ExxonMobil Corp. Witt, Joseph William, Remmert, Stephen Mathew, ExxonMobil Qatar – Maximizing ROP with Real-Time Analysis of Digital Data and MSE)

3.8.2 Bit aggressiveness

Compared to roller cones, PDC bits have high aggressiveness. PDC shear the formation and they cause a higher torque. The cones on the tricone bits are freely rotating and hammer away the formation. The torque generated by the tricones is less than that of the diamond bits.
Aggressiveness and wear resistance are fundamental properties that need to evaluate for the specific application where the bit is going to be applied.

The aggressiveness of a bit is determined as mentioned earlier in the thesis by the depth of cut the bit is designed to remove. In roller cone bits the aggressiveness is determined by the projection, pitch of the teeth and cone offset. For the PDC bits the aggressiveness is determined by cutters exposure and cutter angle (Backrake)
Bit wear resistance is on the other hand determined by the cutter density of the cutters.

For roller cone bits in order to improve the wear resistance one have to add more cutter on the gauge, more durable shapes of cutters. Applying diamond on the gauge cutter could be another solution to increase resistance. Making the cutters more brittle and increasing the number of carbide inserts.

PDC wear resistance can be improved by increasing the length of the gauge so that more cutters can be placed on and near the gauge and as well as the roller cones increase the carbide and the diamond content. The features that make the bit more resistant at the same time make it more susceptible to cutter breakage. (Spaar, J.R., Ledgerwood, L.W., Hughes Christensen, Goodman, R.L. Graff, Moo, T.J., Chevron Petroleum Technlogy Co. – Formation Compressive Strenght Estimates for Predicting Drillability and PDC Bit Selection)

The aggressiveness of the bit can be calculated by the following formula: (Pessier and Fear 1992)

$$Mu = \frac{36 \times \text{Torque}}{\text{WOB} \times \text{Diameter}}$$

Figure 37 Specific Coeffcient of Sliding

Specific coefficient of sliding expressed a torque as a function of the WOB. This coefficient will be further used to derive the mechanical specific energy. (Pessier and Fear 1992).
Higher Mu means that the bit can generate more torque with lower weight on bit but it can suffer from impact damage in abrasive formations. “Mu” is determined as a measurement for bit aggressiveness.

3.8.3 Drill Bit Stability

Up until 1980s it was not that obvious that bit stability could be of a big issue. Thermal stability of the cutters triggered many researches and lab testing through the years.

Bit Performance depends on BHA Performance. Drill collars tend to vibrate when rotated. BHA design and operation controls the severity of this vibration. The resulting BHA vibration loads the bit unevenly. Bits that are “stable” in the laboratory can become unstable because of these effects.

Bit stability is the ability of the bit to resist to drilling vibrations. There are different types of drilling vibrations that cause inefficient drilling and bit damage impact. I am going to explain shortly the main types of vibrations. Drilling vibrations sometimes can be easily detected by string movement, twisting, and irregular rotation. But sometimes it is undetected by the drilling team and thus can cause a lot of damages.

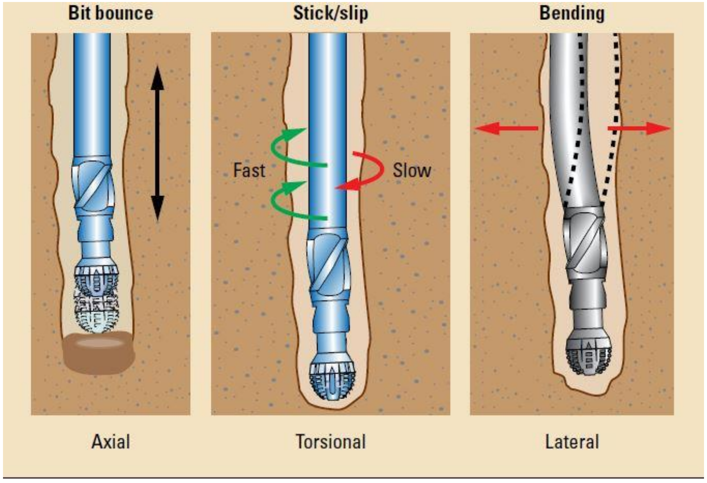

Figure 38 Drillstring Vibrations

3.8.3.1 Axial Vibrations

When the string is moving up and down it creates forces that can damage the string and the bit. The bit movement initiated by axial vibrations is called bit bounce. Bit bounce damages the cutters and bearings. These type of vibrations can be detected from surface and can be mitigated. (http://www.slb.com/~/media/Files/drilling/brochures/drilling_opt/drillstring_vib_br.pdf)

3.8.3.2 Torsional Vibrations

Torsional vibration can cause irregular downhole rotation. Stick-slip is one type of torsional vibration which very common for PDC bit. The rotation of the bit becomes stationary and then followed by sudden quick rotation. As the downhole conditions get more and more severe the stick slip can increase more. the stick slip can lead to drill string buckling, bit cutter damage, BHA faulire due to high vibration level etc. These vibrations are easy to detect by the downhole drilling data. (http://www.slb.com/~/media/Files/drilling/brochures/drilling_opt/drillstring_vib_br.pdf)

3.8.3.3 Lateral Vibrations

Lateral vibrations are the type that can cause severe damage on the BHA and the bit. Whirl is the most severe form of vibration. The whirl can create a bending moment that can result to connection fatique. (http://www.slb.com/~/media/Files/drilling/brochures/drilling_opt/drillstring_vib_br.pdf)

Bit stability is basically the bit interaction with the formation. There are two factors that prompt bit instability, they are the profile shape and the cutting structure. The main purpose is to find the profile that will minimize the bit stability and increase bit durability at the same time. There are different methods and feature that can be applied for that matter.

3.8.4 Compressive Strength and Drillability

Compressive strength and the drillability have been linked and observed in the laboratory and in the field for many years. Rock strength is found to correlate well with overall measurements with the bit drillability.

3.8.4.1 Compressive strength

The compressive strength is qualified as a function of confinement stress. With Mohr`s failure technique, it is very important to understand that inherent rock strength properties (cohesion and angle of internal friction) must be known before compressive strength can be calculated. The unconfined compressive strength is defined as the load per unit area at which cylindrical specimen of standard dimension of soil fails in a simple compression test. (Rao and Ranjan, “Basic and Applied Soil Mechanics”
In order to determine the compress strength we need to be supplied with shear sonic real time data. The strength of the rock is very important value in bit selection and evaluation. The UCS is measured in psi. High values of UCS are the most critical challenges in well objectives. Hard rocks can severly damage most of the bit types and cause well instability and hole cleaning issues. High compressive strength can uncover any hidden harmful formation rocks.
In order to evaluate if a certain bit has achieved the efficiency that was predicted in the prognosis, MSE and UCS correlation can be plotted. It will show drill bit efficiency at the various drilling parameters that were applied at the certain formation strengths.

3.9 Test Locations and Wells

All the laboratory work for the thesis purpose was conducted in the test facility of Baker Hughes in Woodlands, USA. All the bits that were used were shipped from Norway to USA for that purpose. PDC bit was first repaired in the Baker Hughes PDC Repair Facility in Celle, Germany. A high pressure test rig was used to simulate downhole conditions, enabling testing in controlled, yet realistic environment (Ledgewood and Kelly 1991). The surface pressure rig was used to measure vibrations and bit whirl (Cooley, et al,.1992)

3.9.1 Test Work Flow

Test request is filled out through the LabQ. That is laboratory database software. The input information is listed below:

- Type of test, rock used, work description and other pertinent information filled out
- Multiple tests require their own test request to be filled out
- Tests are then scheduled by priority, urgency, rock availability and bit availability
- When test is completed the data and photos are compiled and stored on the server

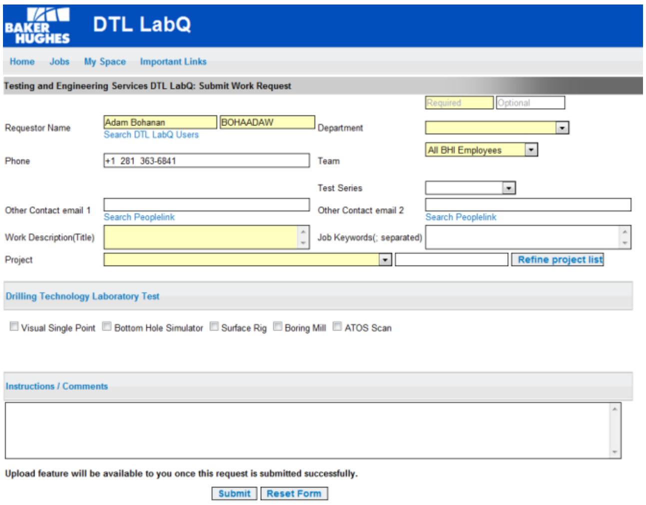

Figure 39 LabQ software where bit test request is submitted

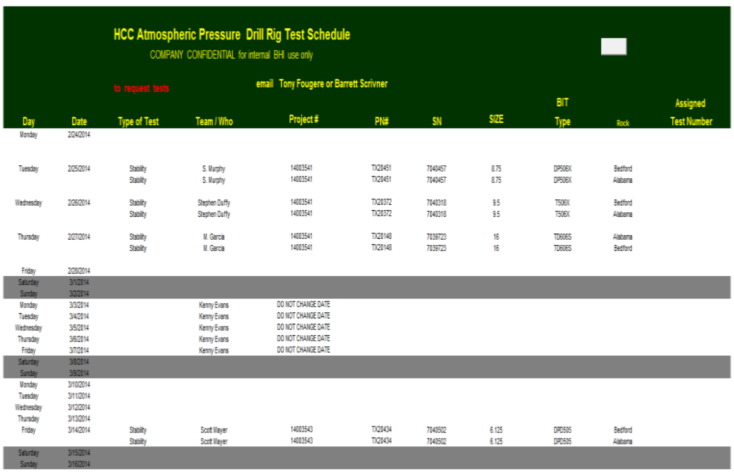

Figure 40 Lab Test Queue overview in Baker Hughes system

3.9.2 Test Equipment

Surface Rig, also known as Atmospheric Pressure Rig is located in the Drilling Technology Laboratory. The Baker Hughes Drilling Technology Laboratory, located at The Woodlands Technology Center in The Woodlands, TX, is the world`s premiere bit and cutter testing facility. The Laboratory is equipped with Bottom Hole Simulator, the Visual Single Point Cutter, the Atmospheric Surface Rig and Boring Mills.

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Figure 41 Surface Rig Laboratory in Woodlands, USA

3.9.3 Rock types used on Surface Rig fir that test:

Alabama Marble was the first rock that was drilled. It is a marble that is found in a belt running to Talladega County, Alabama. It is famous with its pure white color and its crystalline structure. Alabama marble is considered as one of the finest stone.
It is metamorphic rock that derives from limestone (sedimentary rock). It is subjected to high heat and thus has changed its structure. Alabama marble is more durable than the limestone. The marble is as well very fine grained. (http://www.encyclopediaofalabama.org/face/Article.jsp?id=h-2047)
Alabama Marble can be white, grey, pink, red and black depending on the impurities in the original limestone and dolomite.(http://archives.alabama.gov/emblems/st_rock.html).
Alabama Marble was chosen for the experimental test. The reason for that is the high rock strength of the rock and its properties are close to the properties of rocks which are very challenging to drill in the Norwegian Continental Shelf. There were many bit failures while drilling in hard limestone in Norway. This issue is the main reason for conducting these tests.
On the table below are described the rock properties of the subject Alabama Marble.

Table of rock properties:

Rock	Alabama Marble
Density	2.71 g/cc
UCS	12 – 14 ksi
Porosity	65%
Permeability	0.00015

Figure 42 Alabama Marble

3.9.4 Bits that were used for that test are:

Bit size	Bit name	Bit type	Manifacturer
9 ½ inch	QT406X	PDC	HCC
9 ½ inch	VMD-20	TCI	HCC
9 ½ inch	KM632	Hybrid	HCC

Figure 43 Overview of the bit that were tested in this experiment

3.9.5 Depth of rock that was drilled:

- Rock samples are typically 4`x4`x4`cubes
- Bits drill into the rock sample to a depth of 30-36 inches

3.9.6 Routine types that were tested in this particular experiment:

- Stability
- Efficiency
- Performance

3.9.7 General Information of the parameters used under the experiments:

- 100 000 lbs WOB
- 10,000 ft-lbs TOB
- 500 rpm max rotary speed
- 200 ft/hr
- 5120Hz data acquisition rate
- Axial and Torsional load cell
- 3 Axis accelerometers
- 2 Axis Laser Ranging of drill stem

3.9.8 Surface Rig – Bit test search page

On this page is possible search for bit tests by bit size, bit type, rock type, test type, etc. The test that have been performed before are stored for future references and guidelines. This search gives the option to compared tests with different bits.

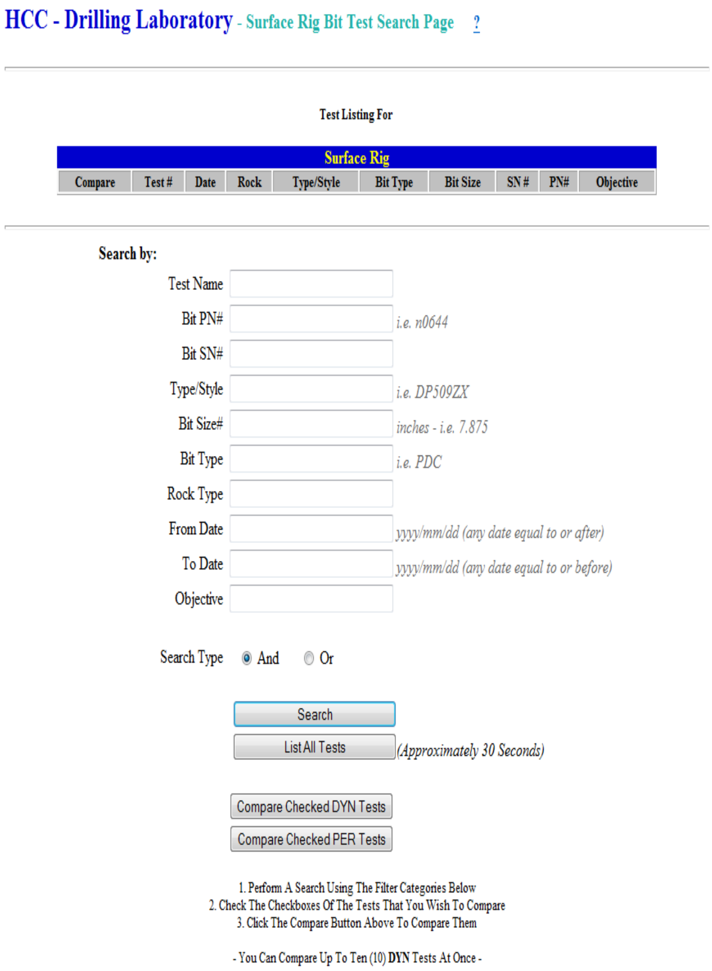

Figure 44 Hydraulic Laboratory software page

Figure 45 Surface Rig Lab Facilities in Woodlands, USA

The picture above shows basically typical test that is conducted in the surface rig. It is shown the rock bit that is drilled. On the right side it is easy to see the control room where the operator is monitoring and controlling the drilling unit. Over the rock, there is hydraulic pipe. The drill bit is mounted on it.

3.9.9 Surface Rig – Real –Time Camera

The surface rig is also equipped with camera. The real time camera makes it possible for engineers, operators in Baker Hughes to see and follow up the test remotely. It is possible to take screen shot of a real time camera. Most of the screen shots are saved in internal database archive for future references.

Figure 46 Screenshot from the Surface Lab Web Camera

Figure 47 Photos taken under a test in the Surf Lab Facilities

3.9.10 Surface Rig – Photos

While performing the tests the entire process is documented with pictures. These kinds of documentations are quite important under drill bit evaluation. Fig. 37 is an example of typical experimental pictures taken. Damages and impacts can be revealed and studied. Drill bit failures can be avoided and new optimization techniques could be implemented.

3.10 Data Analysis

This chapter will present the results of the test in two stages. I will then discuss the influence of the drilling parameters and variables on the rate of penetration, stability and efficiency of the certain bit.

Three different technology bits will be tested. For that purpose we have chosen TCI, PDC and Kymera bit. For more detailed see the table attached below:

Bit size	Bit type	Bit Manifacture	SN	PN
9.5	QT406FX	HCC	7133296	X15940
9.5	KM623	HCC	7033208	
9.5	VMD-20DVHX	HCC	5198816	TRH2129400

Figure 48 Overview of the test drill bit

3.10.1 Surface Rig Lab Data Analysis

In this laboratory test two matrixes were chosen. Both of them covered common parameters along with considered operating range of the testing equipment. The formation was the same in both stages. The tests were conducted in Alabama Marble rock.
Different drilling parameters were applied at the both stages and stability and efficiency will be evaluated at the different scenarios.

3.10.1.1 Bit Test Stage One

The stability test was conducted in Alabama Marble at 60 ft/hr ROP, in RPM controlled with six different RPM steps. The ROP is a result of the applied WOB. The formation is the same this allows to keep the WOB constant. For each RPM/ROP step the weight on bit applied was respectively (rage from 0 to 40 000lbs). The drilling data was recorded throughout the test

3.10.1.2 Bit Test Stage Two

The second stage of the test was executed as well in the Alabama Marble with the following parameter:

- **Appliying constant RPM 80rpm**
  Varying the level of ROP: 30, 60, 120, 180 ft/hr

- **Applying constant constant RPM 240rpm**
  Varying the level of ROP: 30, 60, 120, 180 ft/hr

The high RPM test was conducted to observe how the bit behavior is influenced by different values of rpm. It will be evaluated bit stability and efficiency at the different rpms. In order for a bit to be considered as stable, all the energy that is applied by the RPM need to be transferred in higher values of ROP.

3.10.2 Bit Test Results Stage One

3.10.3 9.5 inch KM623 (Kymera) Test Photos

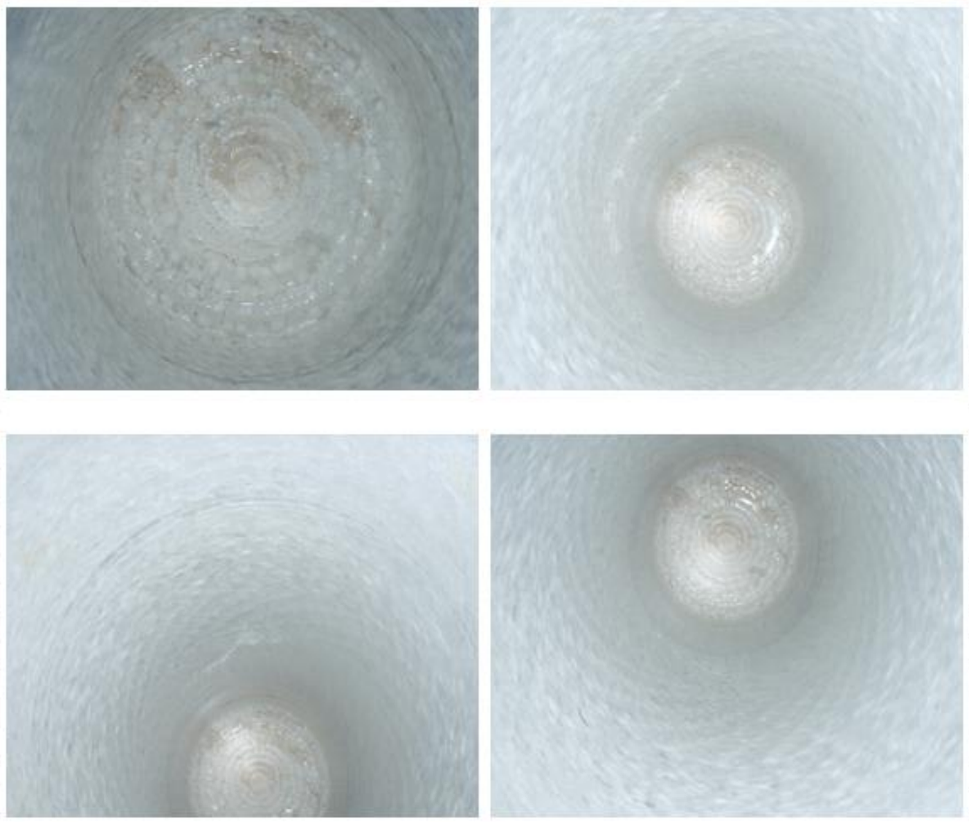

Figure 49 9.5 inch Kymera Bottomhole picture

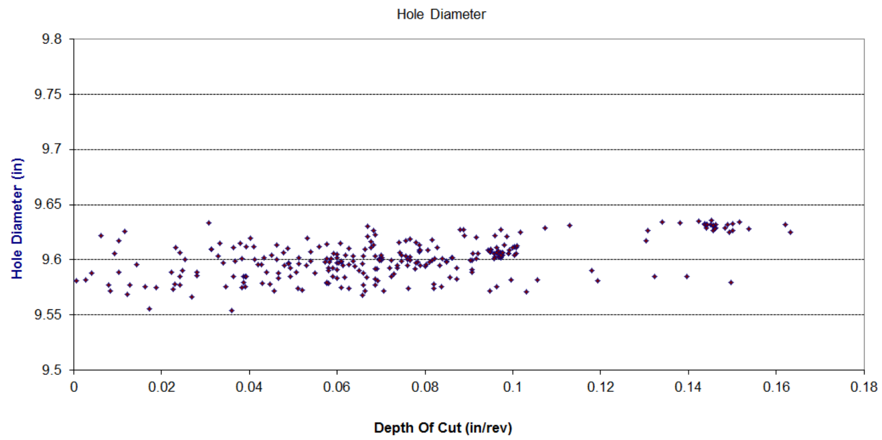

Figure 50 Hole diameter vs DOC for 9.5 inch Kymera

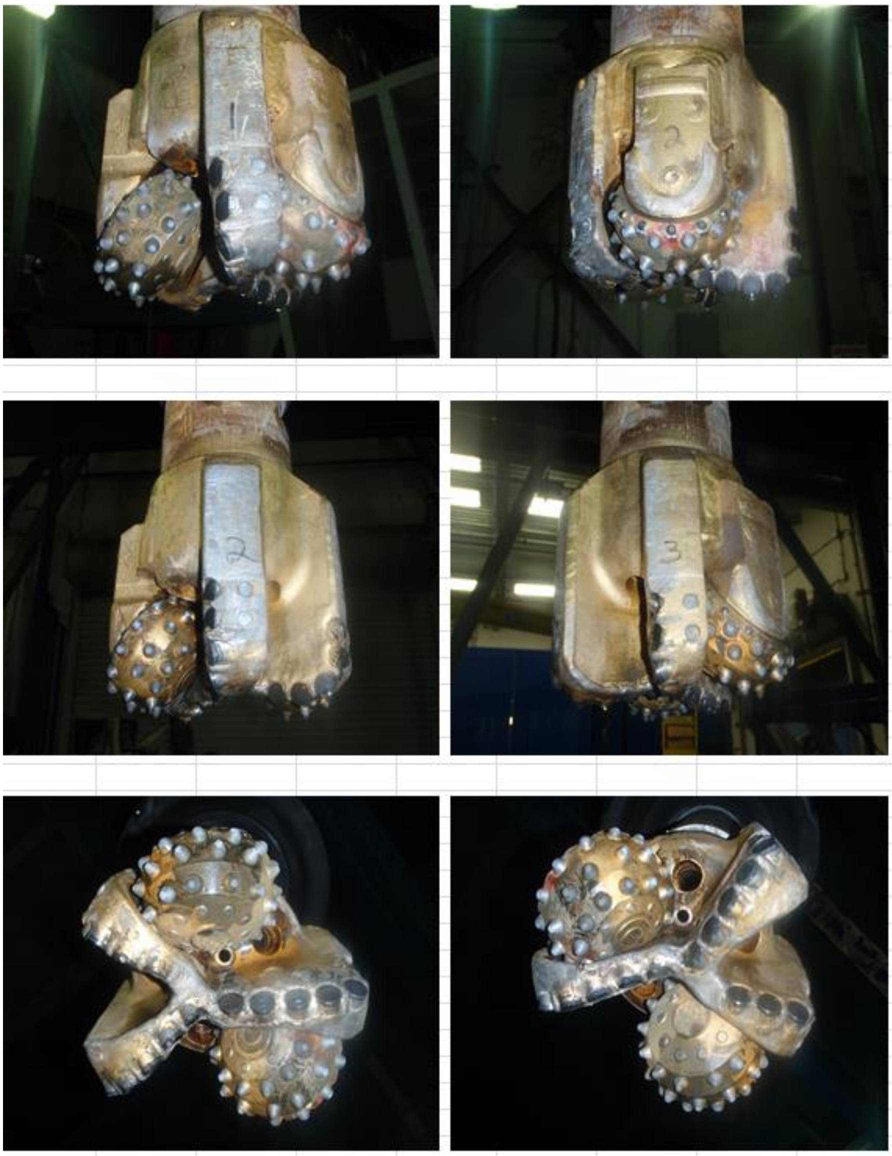

Figure 51 9.5 inch Kymera photos after the test was conducted

9.5 inch QT406XF Photos

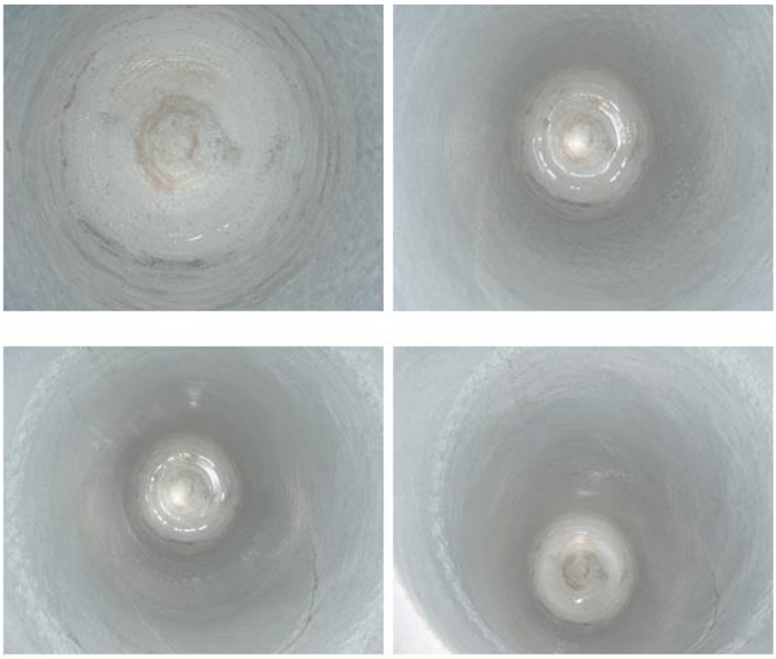

Figure 52 9.5 inch QT406XF Bottomhole pictures

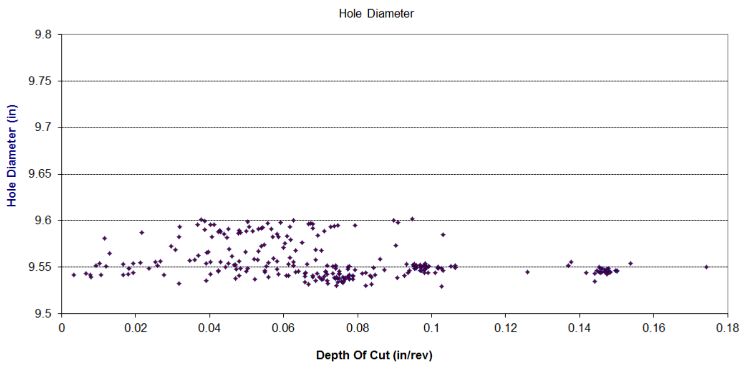

Figure 53 9.5 inch QT406X Hole diameter vs DOC

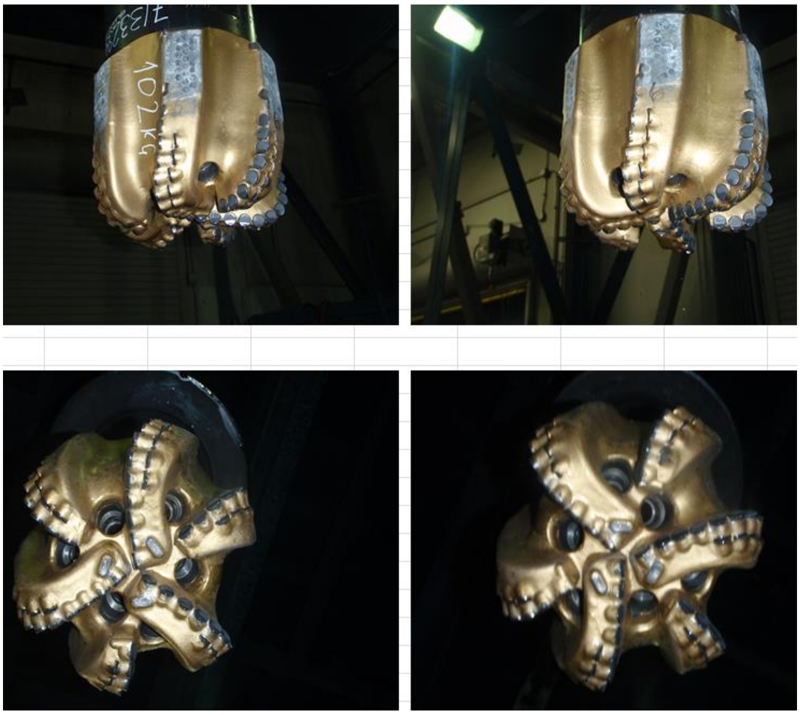

Figure 54 9.5 inch PDC photos after the test was conducted

3.10.4 9.5 inch VMD-20 (TCI) Photos

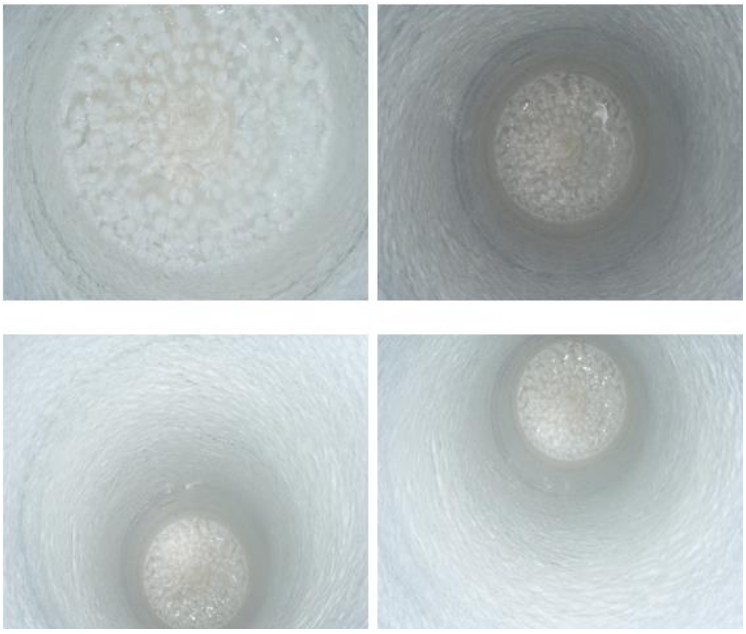

Figure 55 9.5 inch TCI Bottomhole Photo

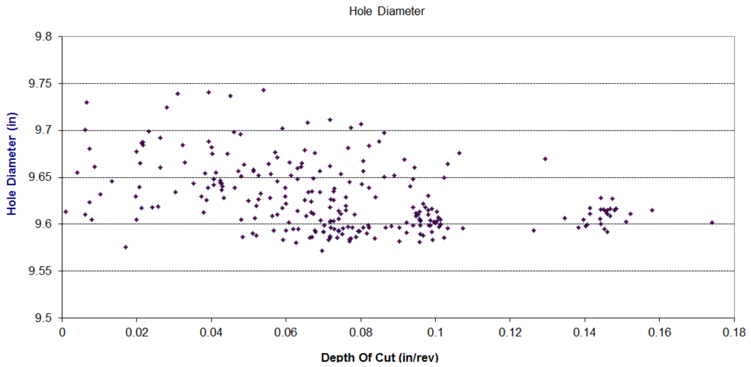

Figure 56 9.5 inch TCI Hole diameter vs DOC

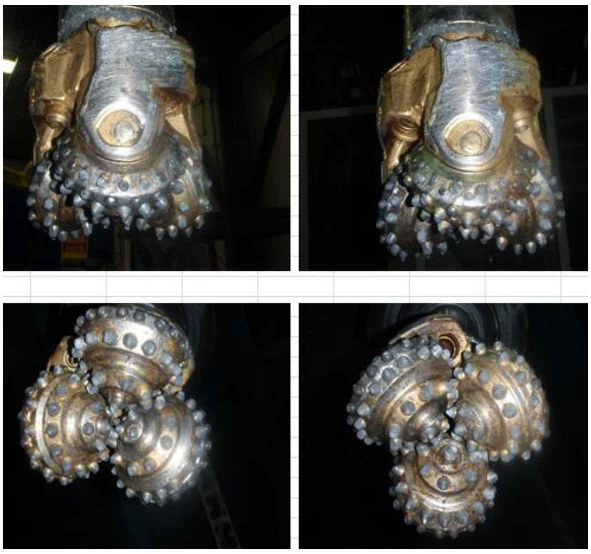

Figure 57 9.5 inch TCI Photos after the test has been conducted

3.10.5 Bit Stability and Agressiveness at 60 ft/hr with Increasing RPM

In order to evaluate the bit aggressiveness, a test with constant ROP of 60 ft/hr and in steps increasing RPM was conducted. The three bits were tested in the same Alabama Marble rock.

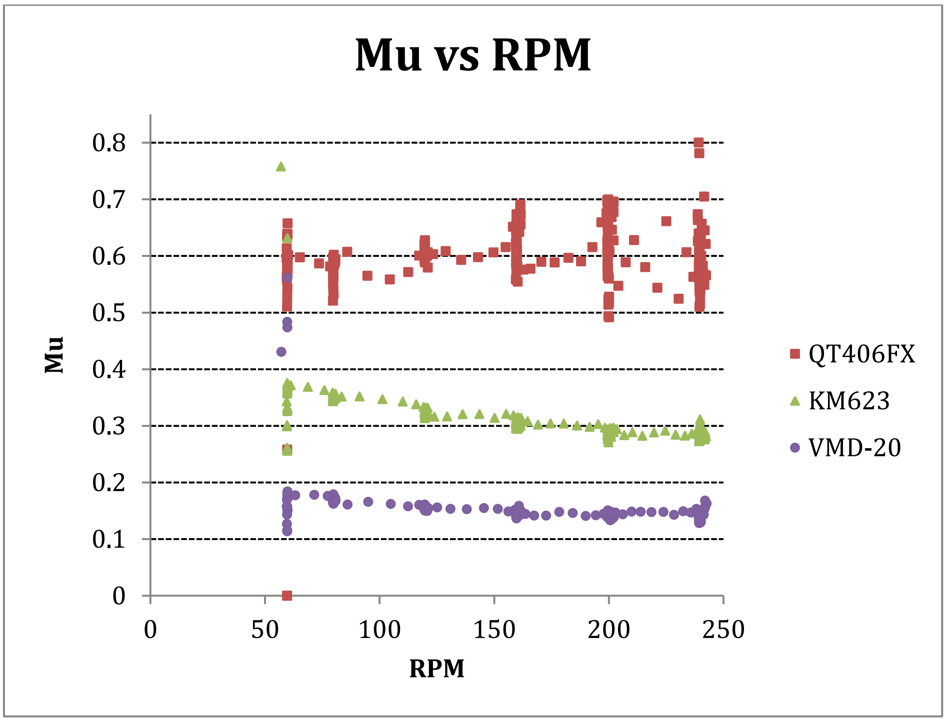

Figure 58 Mu vs RPM - test stage one

From **Fig. 55** it is observed that the PDC bit has the highest aggressiveness value, as expected. Although aggressiveness is good property, here it is important to remark that PDC bit aggressiveness is very much uncontrolled. The Mu value can vary from 0.5 to 0.8 for the same ROP and RPM values. This type of behavior could be quite disastrous in the field. A bit with uncontrolled aggressiveness could generate uncontrolled torque and hence uncontrolled ROP. Uncontrolled ROP could lead to hole cleaning and pack off issues which in the other hand can jeopardize the drilling section.
I can further elaborate that Kymera has shown stable and controlled aggressiveness. Another phenomena that is observed as well is that with increasing RPM at constant ROP, at certain WOB values, the Mu values for Kymera and Tricone are declining. Hence the drilling efficiency will be reduced respectively.

Drilling efficiency is very important parameter that needs to be discussed. From **Fig. 56** I have plotted the test results for efficient energy and how this energy varies with increasing RPM, at constant ROP of 60 ft/hr. The specific energy needs to be around the same value as the UCS of the Alabama Marble rock that was drilled. The rock in this case has 15 ksi UCS. From this graph I can see that the PDC and Kymera are most efficient when spinning from 75 to 150 rpm. For RPM higher than those values the efficiency of the bits starts to vary a lot.

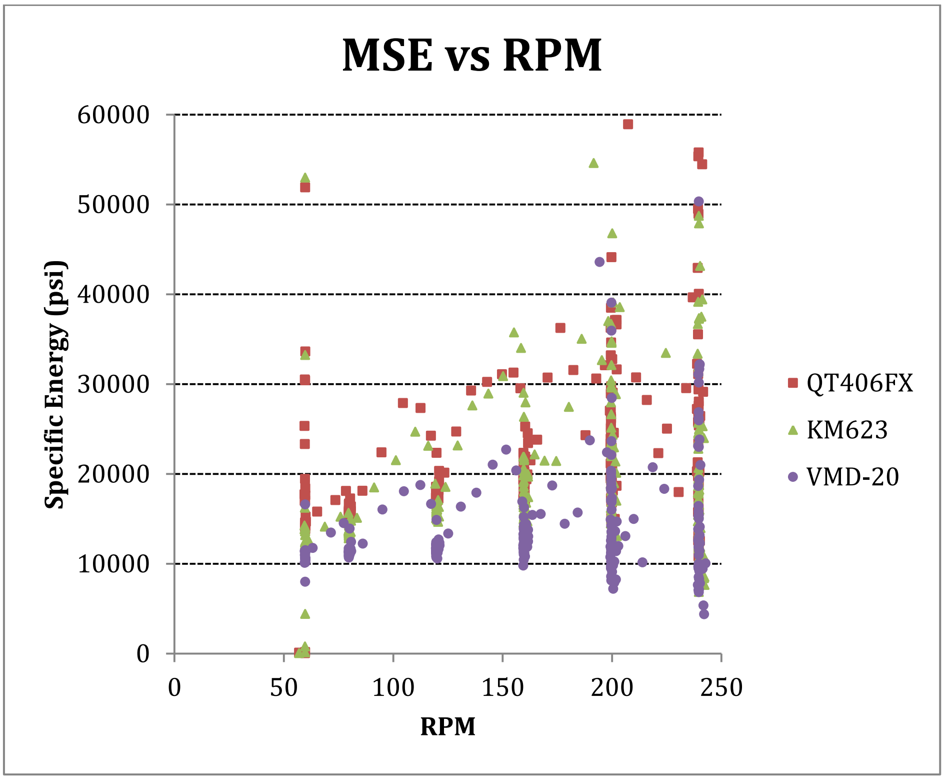

Figure 59 MSE vs RPM - test stage one

Fig 61 shows the magnitude of vibrations that all three bits encountered at increasing RPM and constant ROP.

Whirltraction Value	Stability Indicator	Description
0.00 - 0.06	1	Very Stable – Preferred
0.06 - 0.10	2	Somewhat Stable - Acceptable
0.10 - 0.15	3	Somewhat Unstable – Marginal/Unacceptable
0.15 - 0.255	4	UnStable – Potentially Damaging
0.255 - 1.00	5	Very Unstable – Potentially Catastrophic Damage

Figure 60 Whirl Traction

It is desired to have a whirl traction value under 0.10 for all ranges of RPM. When the whirl traction remains under 0.10, the bit is thought to be stable. All of these bits show to be stable. The PDC bit shows lowest level of whirl at 50 to 150 rpm. After increasing the RPM further than 150, PDC shows increasing of vibration level. Kymera on the other hand shows more stable drilling vibration level. It starts with 0.4 to 0.6 whirl traction at 50 rpm and declines to 0.2 at 250 rpm. Tricone shows also generally low whirl traction below 0.1 but the vibration levels variations are bigger. Tricone has declining vibration level as well as the Kymera, which is expected due to roller cone technology on both of the bits.

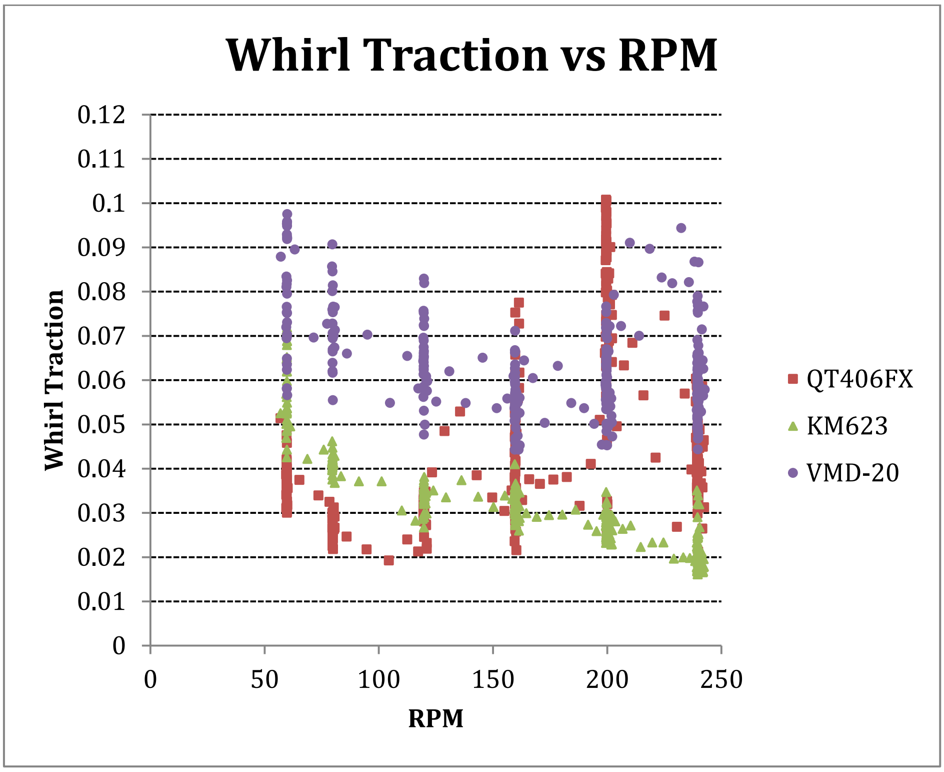

Figure 61 Whirl Traction vs RPM - test stage one

The next **Fig.62** shows how the aggressiveness of the bit influence the torque generated by each of the bit. PDC are expected to generate more torque because they are more aggressive (Mu). Tricone require more weight to produce a given ROP than PDCs and Kymeras. Higher slopes (Torque vs WOB) indicate higher aggressiveness (μ). On this figure as well we can see the same pattern that we discussed earlier. The PDC bit is more aggressive but as well not controlled aggressive. The Torque fluctuations are higher and hence the ROP variations are expected to be bigger. This feature again needs to be considered when applying PDC bit in this type of formation. Not only the ROP could be jeopardize but bit integrity as well.

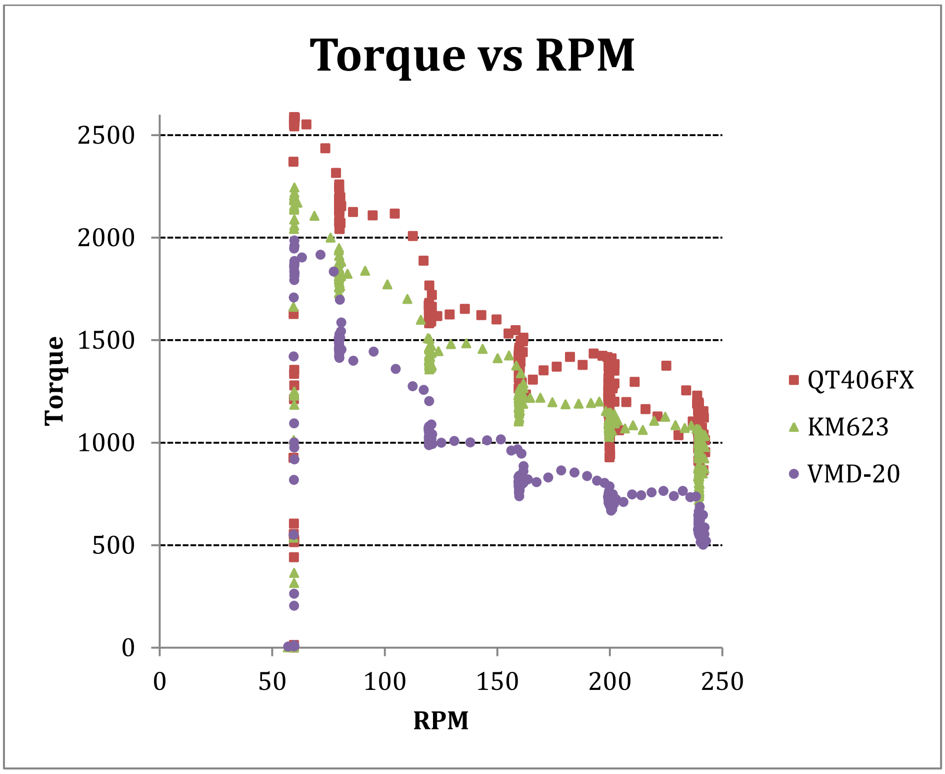

Figure 62 Torque vs RPM

Aggressiveness of the bits versus the depth of cut is ploted on **Fig.63** below. This shows that the PDC is by far the most aggressive bit. The Kymera is in between like expected and the Tricone has the lowest aggressiveness. It is obvious that in the range 0.15 of depth of cut and higher (which represents softer formation), the bit aggressiveness is well controlled. All the bits show constant increasing slope. When looking further on the range below 0.15 DOC, respectively harder formations, PDC shows higher but unstable and scattered aggressiveness values. Kymera shows higher and stable values compared to tricone hence Kymera will deliver higher ROP and stable efficient drilling.

Each bit type torque decreases as the RPM increases because the bit is taking a smaller bite of the formation. DOC is calculated by ROP/ 5*RPM which would mean the higher the RPM the smaller the DOC. Since the bits are not removing as much rock they are not generating as much torque.

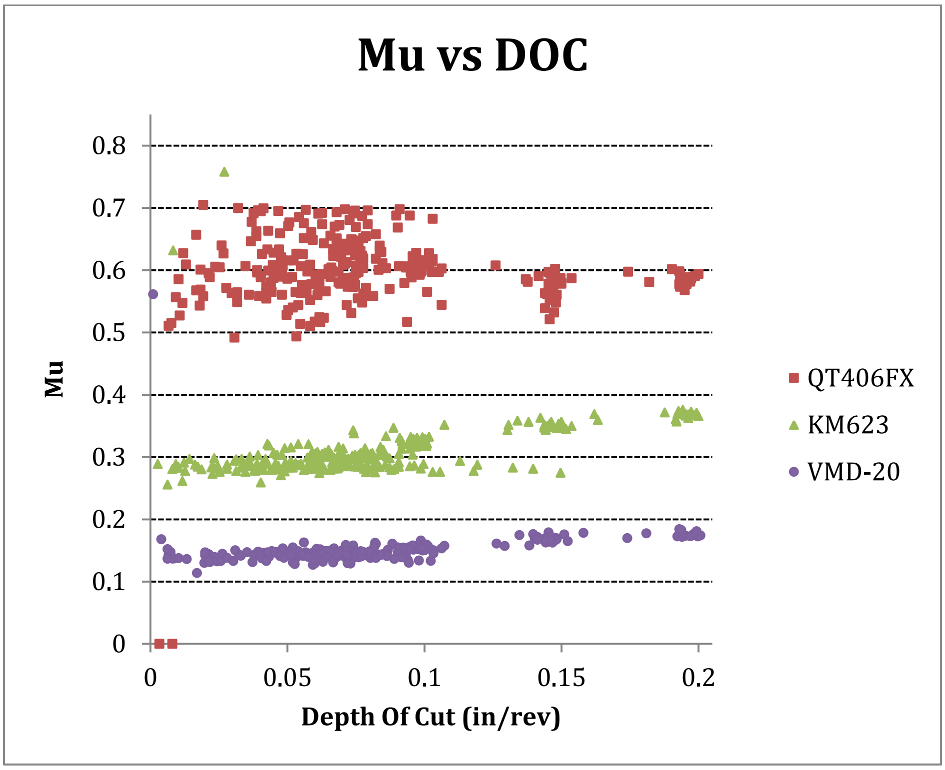

Figure 63 Mu vs DOC - test stage one

Fig.64 shows drilling efficiency of the three bits versus the depth of cut. The specific energy needs to be around the 15 ksi which is the UC strength of the rock. For the same ROP, WOB and increasing RPM the bits perform differently in the same formation. Tricone shows to be more efficient when DOC is lower than 0.15 which reperesents hard formation. This pattern is expected, tricones are by far the most efficient bits in hard formations. Further studying on the Kymera performance we can see that hybrid bit shows as well good efficiency in hard formation. While in higher DOC values we can see that PDC efficiency is increasing. But still Kymera and Tricone shows better and more sufficient drilling performance in this formation.

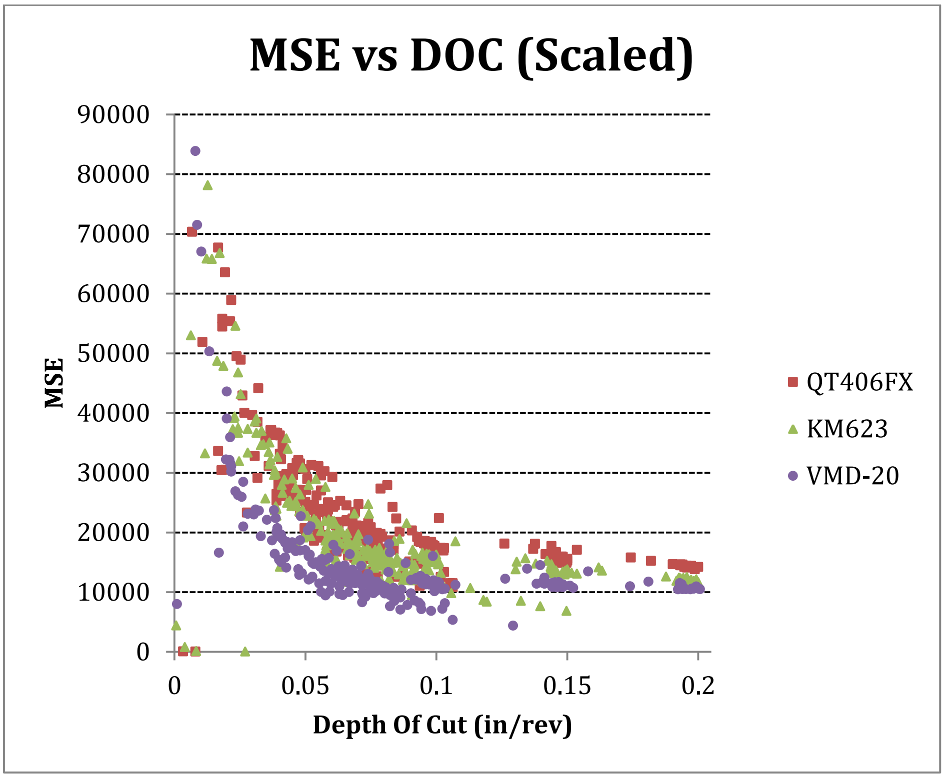

Figure 64 MSE vs DOC - test stage one

By looking at the results on **Fig. 65** it is easily seen why the PDC bit is inefficient at DOC lower than 0.15. By plotting the vibration level versus depth of cut at constant ROP and increasing RPM, it is obvious that when encountering harder formation PDC bit experiences higher vibration level. The energy transferred to the system by RPM is lost in vibration and less energy in transformed in ROP. Kymera shows low vibrational level over all with small fluctuations. Tricones appears to be overall stable with whirl traction level lower than 0.1, but as the PDC, Tricone also shows higher vibration fluctuations which can cause bit instability on bottom.

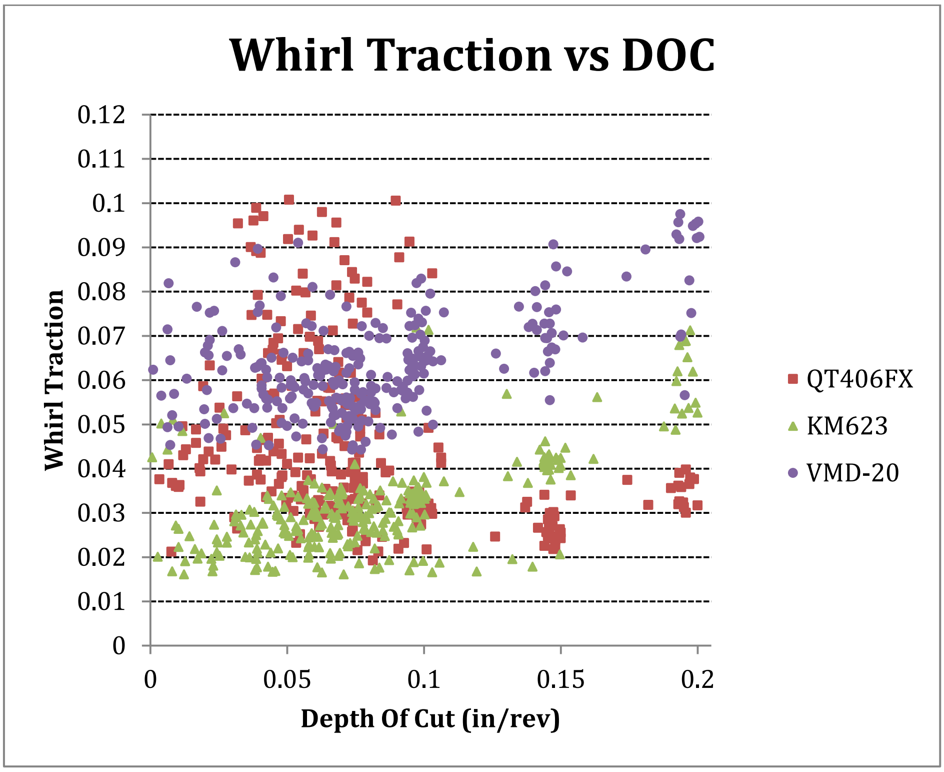

Figure 65 Whirl Traction vs DOC - test stage one

In order to see torque behavior of the bits with constant ROP and increasing RPM versus the depth of cut prorogated in the formation, I will have look at **Fig.66.** As expected from the prevous figure which represented the vibration level, I observe here the same phenomenon. The torque for PDC bit is quite scattered for harder formation. It means that the bit generated higher and uncontrolled torque fluctuations. Kymera and Tricone here should be mentioned that they deliver more stable control torque. Smaller DOC means that the bit is taking smaller volume of the formation per revolution hence generating lower torque as well.

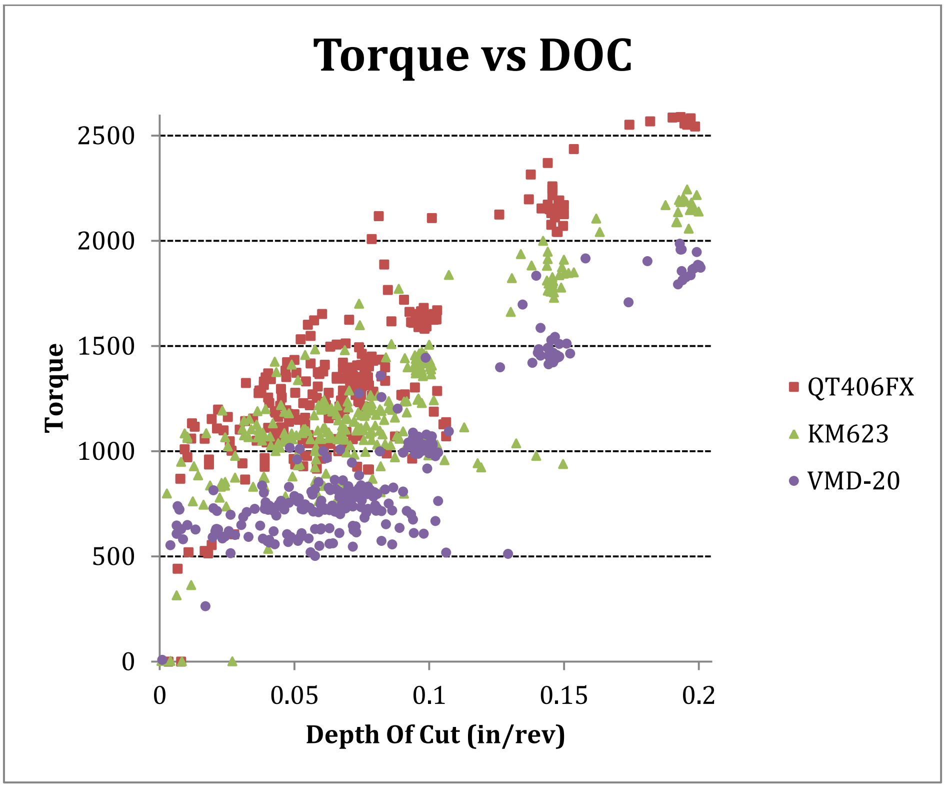

Figure 66 Torque vs DOC - test stage one

From **Fig.67** below we can conclude that while operating with low RPM and WOB the three bits delivere unstable and uncontrolled ROP. That behavior is expected since the bits need higher RPM to mitigate the generated vibration levels. As the WOB was increased at 20000 lbs as shown on the **Fig. 68** and the RPM was respectively increased the bits appeared to deliver more stable and controlled ROP. Kymera and Tricone managed to keep almost constant ROP throughout the rest of the run. The PDC on the other hand delivered more fluctuating ROP, varying from 30 to 60 ft/hr.

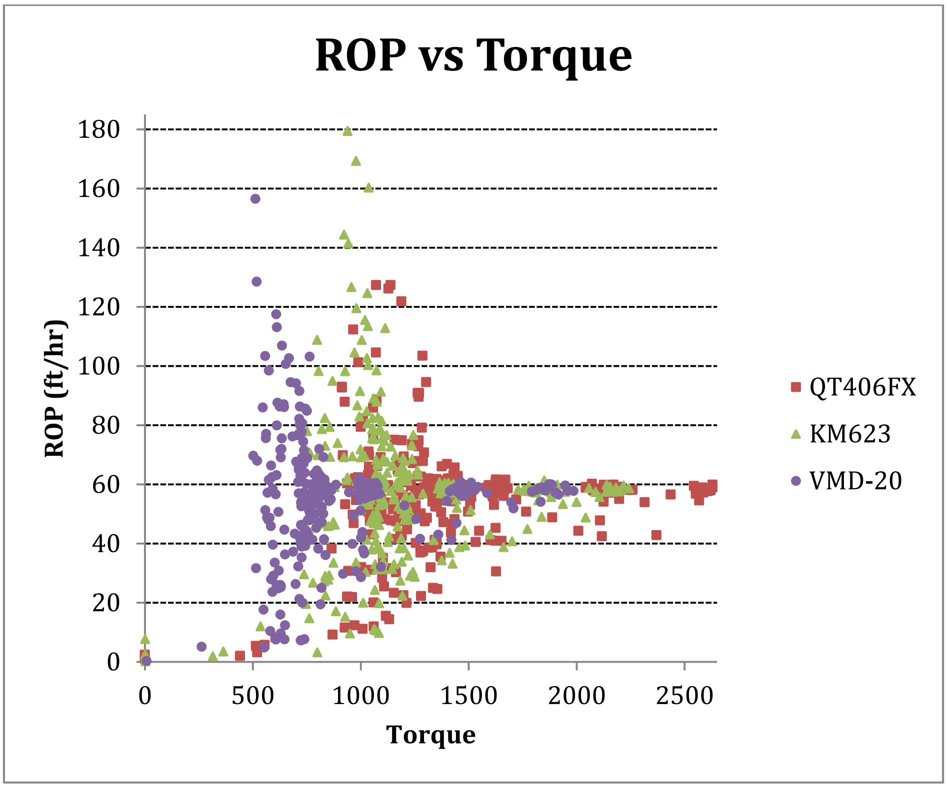

Figure 67 ROP vs Torque - test stage one

PDC are expected to generate more torque because they are more aggressive (Mu). Tricone require more weight to produce a given ROP than PDCs and Kymeras. When drilling with Kymeras that is one thing that has to be considered about the drilling system on whether it is stiff enough to provide the extra weight needed to the Kymera or Tricone. Higher slopes (Torque vs WOB) indicate higher aggressiveness (μ).

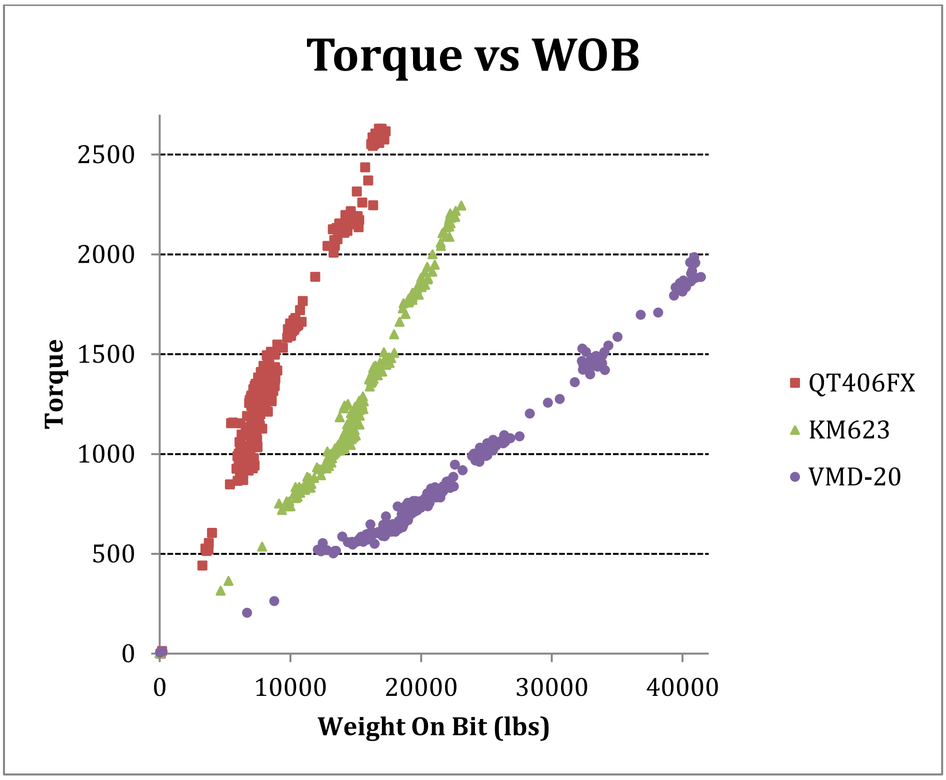

Figure 68 Torque vs WOB - test stage one

3.10.6 Effect of RPM on Bit Stability and Effciency

There have been done a lot of experimental work on this subject. Langeveld described that with increasing RPM bit has greater tendency to whirl. (Langeveld, 1992).
The main purpose of this test was to follow the development of the bit stability at constant low RPM (80rpm) and constant high RPM (200rpm) in Alabama Marble.
From **Fig.69** shows that PDC is most aggressive of all the bits. It has Mu value of 0.6 at the beginning of the test from 0-60 ft/hr. With increasing ROP and WOB, but constant RPM the aggressiveness of the bit start to decline and gets equal to the aggressiveness of the Kymera at 180 ft/hr. This behavior is expected since PDC bits need less WOB compared to Kymera and Tricone.
Tricone and Kymera on the other hand show lower Mu values but inclining behavior. Kymera increased the Mu values from 0.3 to 0.45 with constant RPM of 80.

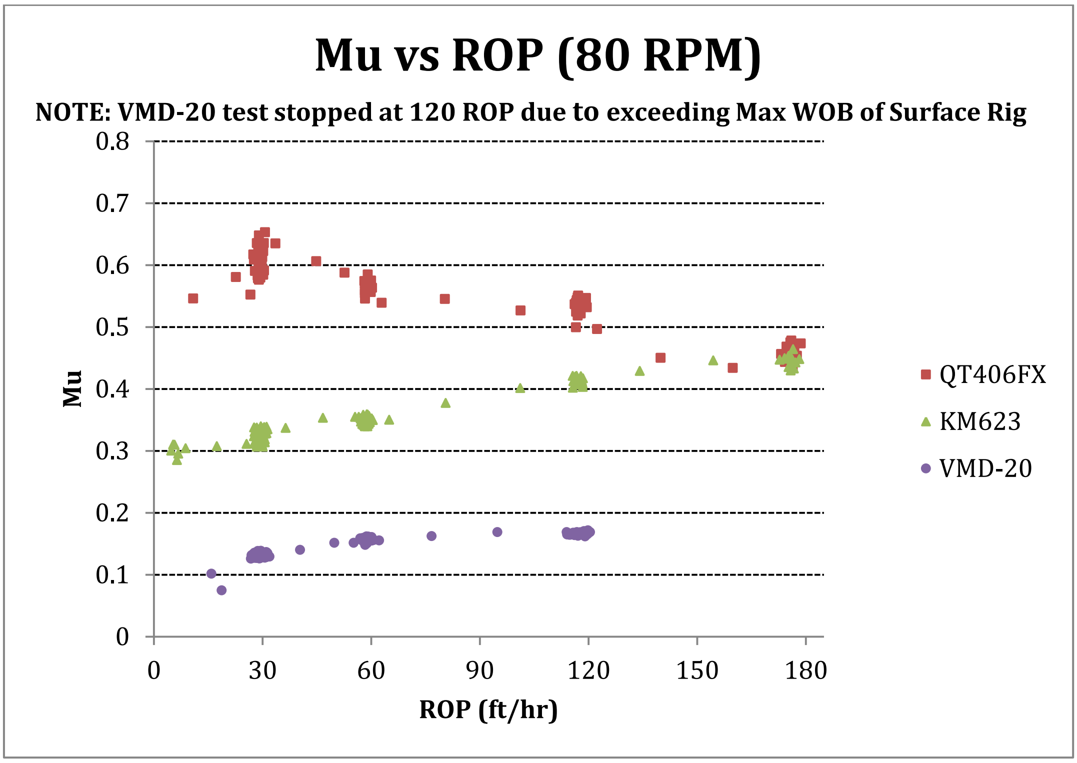

Figure 69 Mu vs ROP - test stage number two

The second test was conducted with 200rpm for the same ROP values as the first one. Diamond bit shows quite high and unstable Mu values, which varies from 0.45 to 0.75. Kymera shows lower aggressiveness but much more controlled and stable throughout the whole run. Tricone shows much lower and stable aggressiveness and Mu values of 0.1 to 0.15.

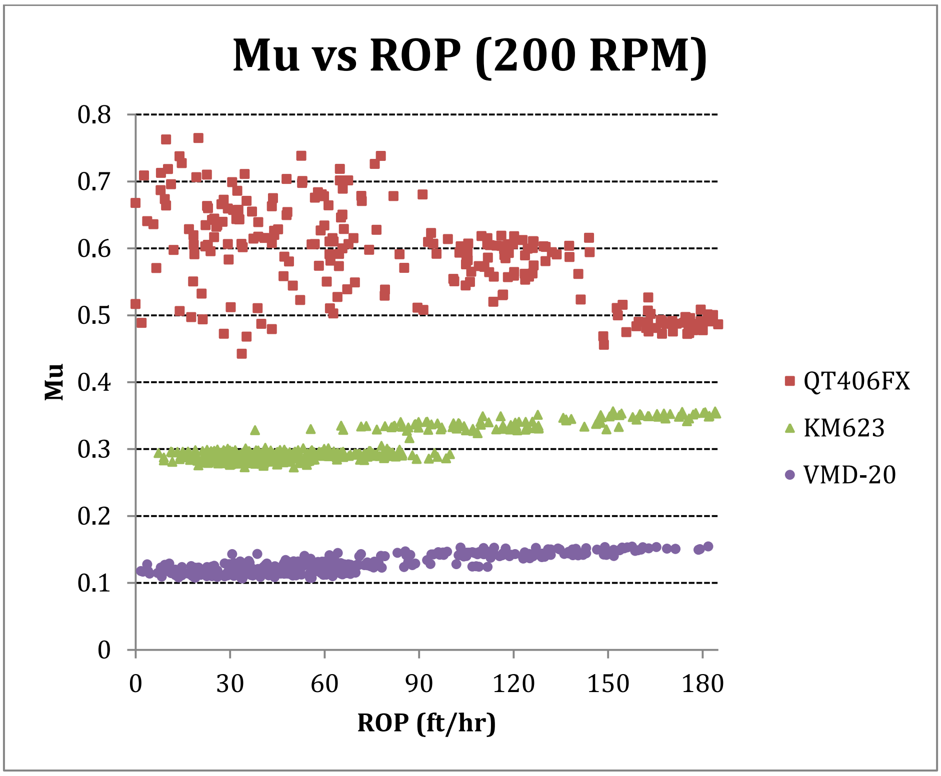

Figure 70 Mu vs ROP - test stage two

In order to look into the drilling efficiency of the bits we correlated MSE values to the ROP at constant RPM of 80. See **Fig.71** below, describes clearly that at this RPM and 15ksi USC of the rock, Kymera and Tricone are the most efficient of all tested bits. With increasing the WOB and the ROP, the efficiency of these two bits is even improving.

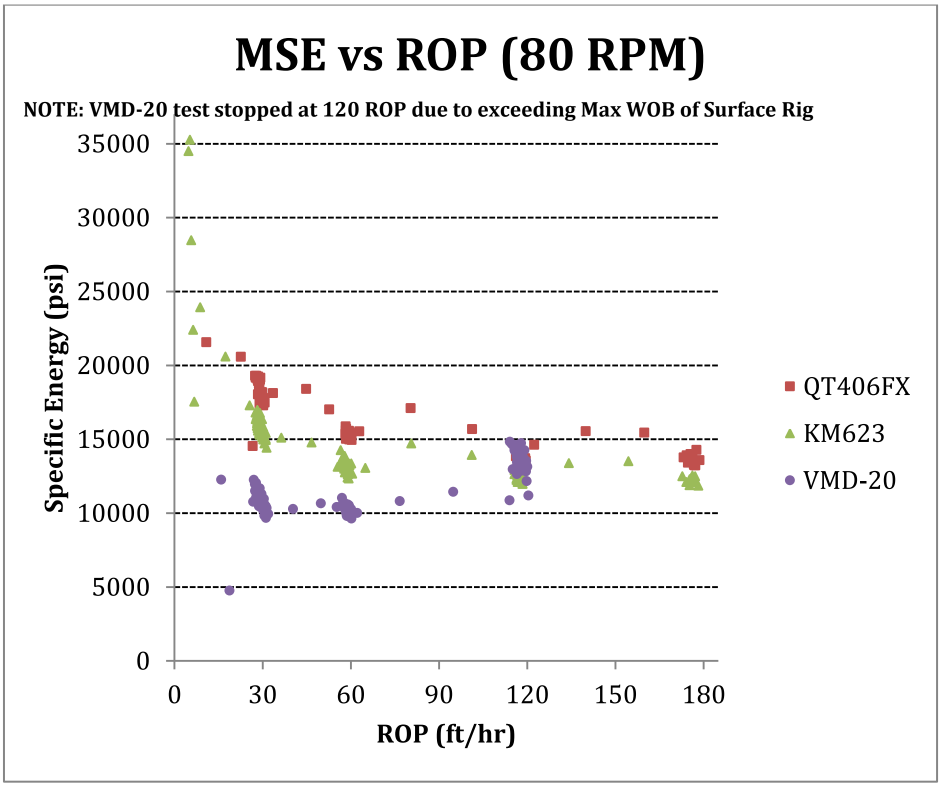

Figure 71 MSE vs ROP at 80 rpm - test stage two

Fig.72 shows how the efficiency of the bits has changed after RPM has been increased to 200 rpm. Kymera that was most efficient at 200rpm now have changed place with Tricone. Roller cone bit seems to be the one that delivered the most efficient drilling at 200 rpm. But overall the bits delivered more unstable and uncontrolled drilling efficiency compared to 80 rpm. With increasing ROP Tricone and Kymera shows significant efficiency improvement.

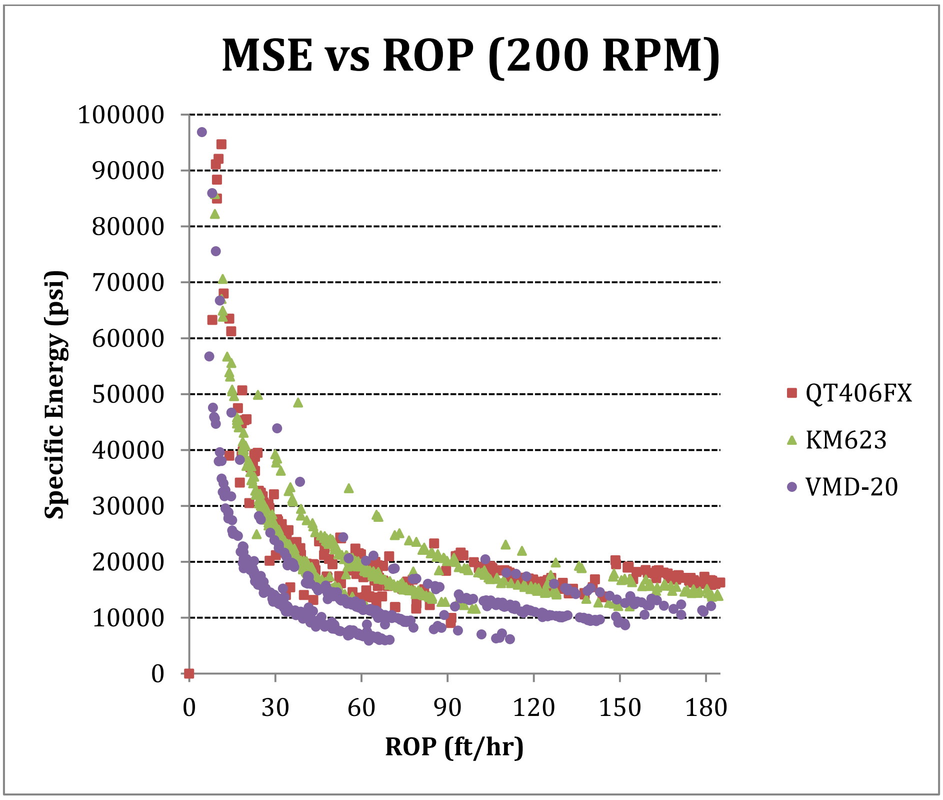

Figure 72 MSE vs ROP at 200 rpm - test stage two

Next step is to discuss how the bit stability is influenced by the constant low and constant high RPM. **Fig. 73** below presents the vibration level suffered by each bit at different values of ROP and WOB. **Fig.74** shows the same phenomenon but with constant RPM of 200. By comparing the two figures I can first conclude that while drilling with lower RPM all the three bits experienced higher whir traction but with more stable and controlled drilling. When drilling with 200rpm the bits whirl traction is much lower but more unstable and fluctuating this causes bit damage and failure. PDC bit shows to induce less whirl vibration while drilling with 80 rpm. Kymera on the other hand proved to be more stable and induce less vibration when drilling with 200rpm nad ROP up to 130 ft/hr. Kymera aslo showed unstable vibration level when drilling with ROP higher than 130 ft/h.

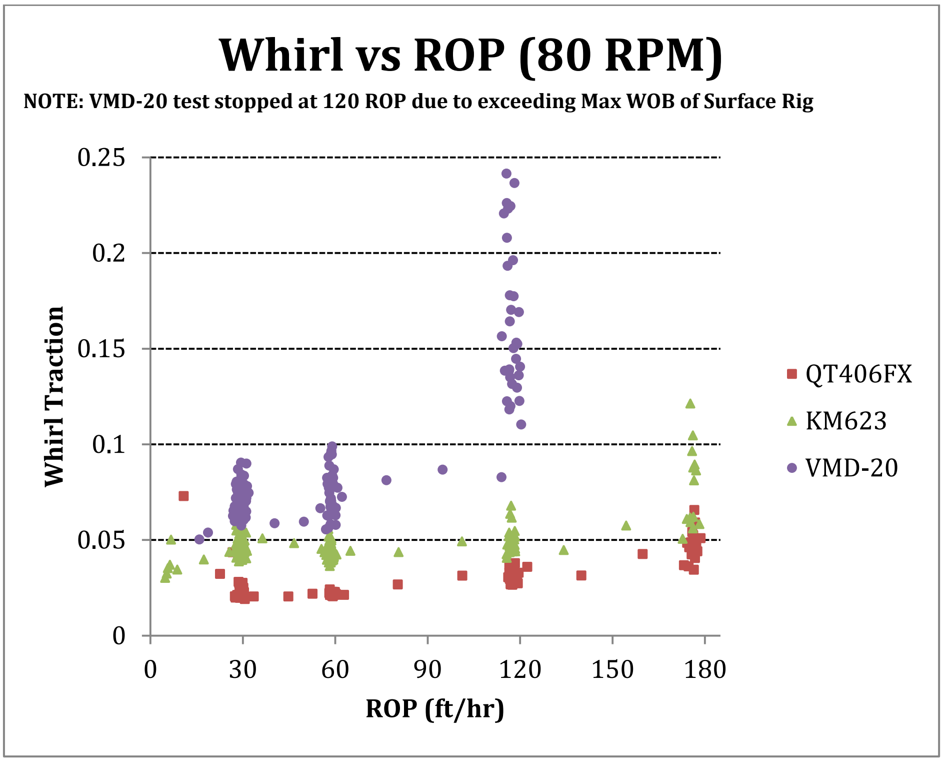

Figure 73 Whirl Traction vs ROP at 80 rpm - test stage two

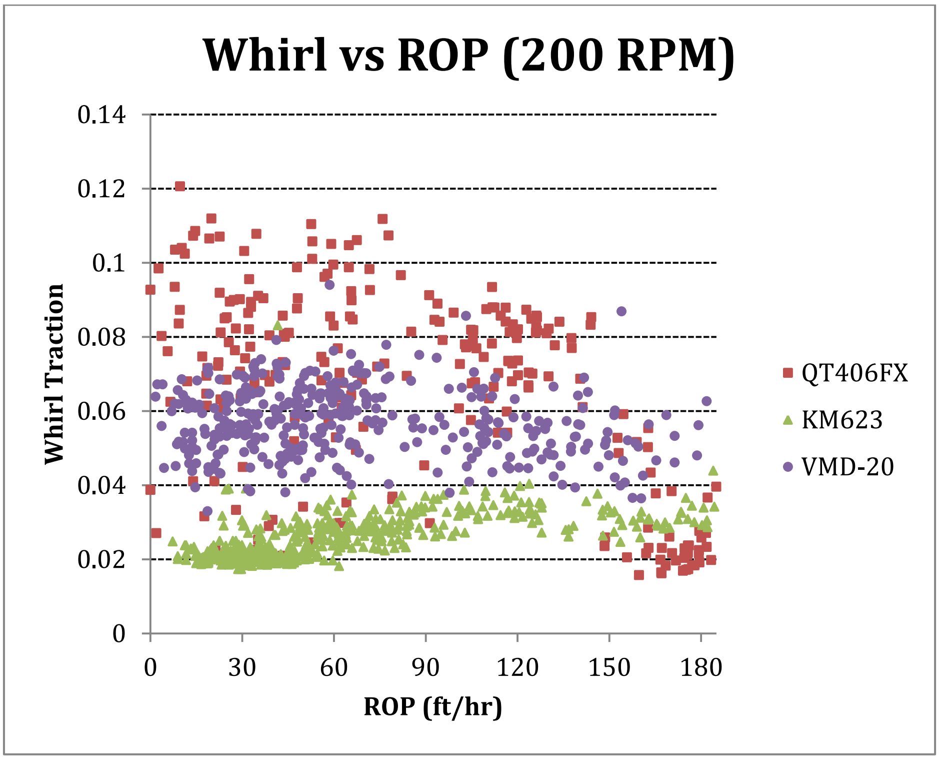

Figure 74 Whirl Traction vs ROP at 200 rpm - test stage two

Fig. 74 and Fig 75 are representing the torque results from drilling with constant RPM of 80 and 200 rpm. As expected the PDC bit generates more torque due to their aggressiveness. They create a high torque slope. While

Kymera and Tricone need more weight on bit to generate more torque. When spinning with 200 rpm it is shown that all the three bits generated lower torque compared to the one generated with 80 rpm. This is explainable with the depth of cut being smaller when spinning with higher RPM, hence lower torque generated.

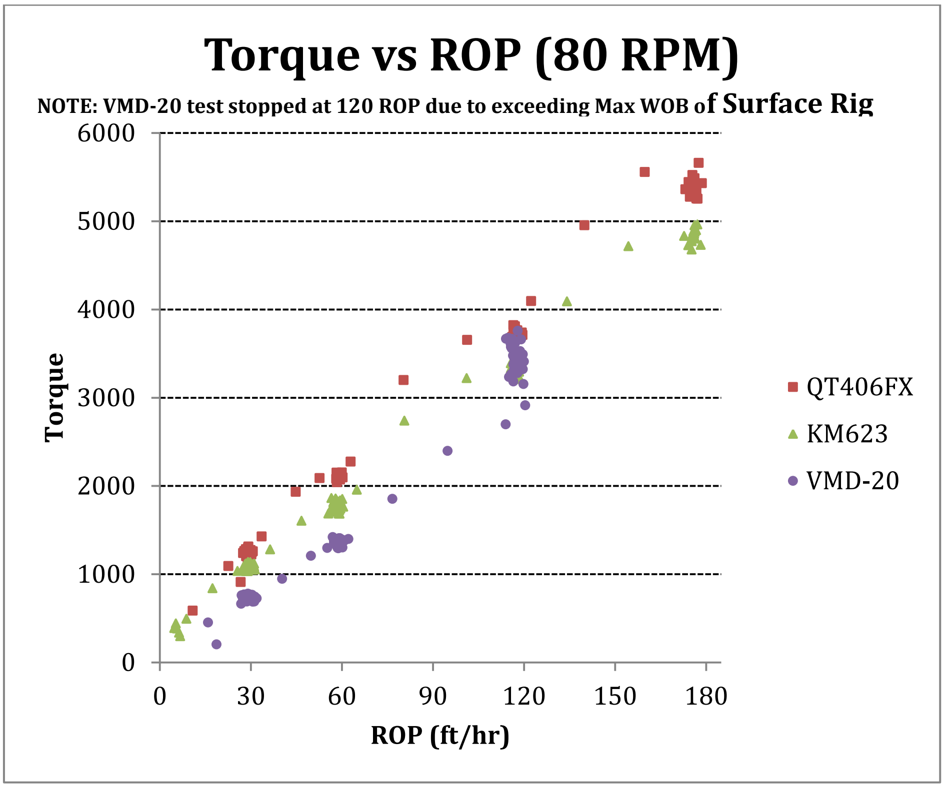

Figure 75 Torque vs ROP with 80 rpm- test stage two

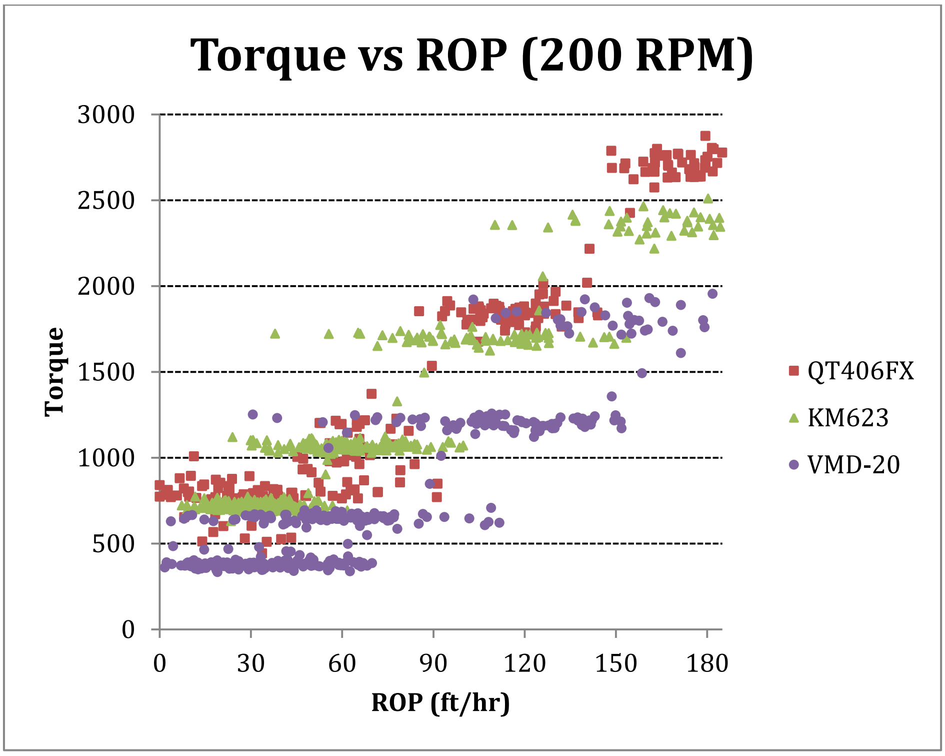

Figure 76 Torque vs ROP with 200 rpm- test stage two

3.10.7 Conclusion

The experimental test conducted proven to be very knowledgeable. They showed that overall the bit drilling technology is performing as expected in the subject formation. Alabama Marble is hard formation that generates challenging drilling process for most of the bits that will be applied.

All the three bits show good response and efficiency in this hard formation. Things that need to be considered when choosing the right bit for the next formation with the same hardness, is that PDC bits deliver high ROP and high torque values. They are generally good for long sections, but they tend to generated more unstable drilling and uncontrolled ROP in this subject formation. This behavior can cause potential cutting structure damage and failure. PDC bits are perfectly suitable for softer formation (higher than 0.15 DOC). There they can deliver extreme ROP and good stable drilling.

TCI proved to deliver good and stable drilling in Alabama Marble formation. They are perfectly suited for that kind of formation. They don not deliver the highest ROP but they have the best durability properties from of all the bits. TCI showed very good response and efficiency at DOC below 0.15 which means harder formations, while in softer they showed to tend to be more unstable and deliver lower ROP. If formation is represented of hard rocks, TCI is the best solution for those types of applications.

Kymera has proven to be the key drilling tool for formations with varying hardness. It has shown that it can deliver the same or better ROP efficiency and stability in harder formations as the TCI bits. At the same time can drill efficiently softer formations without jeopardizing the ROP and stability as the PDC bits.

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