University of Stavanger

Faculty of Science and Technology

MASTER'S THESIS

Study program/ Specialization: Petroleum Engineering/ Drilling and Well Engineering	Spring semester, 2015 Restricted access
Writer: Dmitriy Belozerov	………………………………………… (Writer's signature)
Faculty supervisor: Dan Sui External supervisor: Sofiane Abdellaoui, Halliburton Drill Bits and Services	
Thesis title: Drill bits optimization in the Eldfisk overburden	
Credits (ECTS): 30	
Key words: PDC drill bits Drilling optimization Drilling parameters ROP model Eldfisk Overburden	Pages: 69………………… + enclosure: 20………… Stavanger, 29.06.2015.. Date/year

Acknowledgements

I would like to express my gratitude to Dan Sui, Associate Professor at University of Stavanger, and Sofiane Abdellaoui, my external supervisor at Halliburton Drill Bits and Services (HDBS), for their guidance and support. They have always been available for discussion. Their ideas and patience were essential for the development of the thesis.

In addition, I would like to thank all HDBS personnel, especially Sindy Kathrin Bru and Sasan Basri for their support and valuable comments regarding drill bits and drilling in general. Also I am grateful to Dianne Tompkins, geologist at ConocoPhillips Norway, for giving me valuable geological information.

Finally, I would like to thank my family and friends, in particular my girlfriend Olga Dovzhenko, for their encouragement, support and care.

Abstract

Drill bits are a part of the well program. It is the major tool that does a cutting/crushing action at the end of the drillstring and highly affects the overall drilling performance. The following aspects can be improved by implementing a better drill bits solution: drilling efficiency, steerability, stability.

Eldfisk is an oil field located in the Norwegian sector of the North Sea. A special interest represents the 12 ¼" section, called "overburden". To a large extent it consists of interbedded formations with highly varying rock strength: soft shales and hard stringers of different origin. A problem that arises is that the bit designed for specific applications will be used to drill formations that it is not completely suited for. Also the overburden is highly overpressured, and these are not the only drilling issues in the section.

The main objectives of this study is to find the ways to optimize drill bits performance in the Eldfisk overburden by introducing a better drill bit solution or better drilling practices.

The group of eight has been analyzed in order to find the best 12 ¼" drill bit solution previously used in the field. It was the matrix-body PDC bit GTD65D which drilled the section with the record overall ROP of 102.8 fph and was pulled out of hole with a minor dull: a few chipped cutters. After evaluating drill bit dynamics relevant for the applications, a new bit design has been proposed: the steel-body bit SFD65D that could potentially increase the bit efficiency due to several features, such as impact shocks damping-effect of the steel, 59% increase in Junk Slot Area, 37% increase in Normalized Face Volume, and some others.

In order to identify the main operational parameters affecting the drill bits performance a multiple regression approach has been utilized. An empirical ROP model has been developed based on the surface mud-logging data from the reference wells. However it has showed only a low correlation with the actual penetration rates: 54%. After adjusting the input data and the model itself the correlation has been improved to 78%. Even though the model has a valid algorithm, the PDC bits performance cannot be easily modelled for such highly-interbedded formations as the Eldfisk overburden. Generally, special transitional drilling procedures should be used whenever a hard stringer is encountered.

Several assumptions have been made in this thesis, such as generalizing formation characteristics and selecting specific offset wells for the study. The drill bits optimization analysis can be performed by different methodologies.

Table of Contents

List of Figures

List of Tables

List of Abbreviations

API	American Petroleum Institute
BHA	Bottom hole assembly
BHP	Bottom hole pressure
CCS	Confined compressive strength
CFD	Computational Fluid Dynamics
CIA	Carbide Impact Arrestors
COPNO	ConocoPhillips Norway
DatCI	Design at Customer Interface
DHT	Down hole tool
DBS	Drill Bit and Services
DLS	Dog leg severity
DrillDOC	Drilling Downhole Optimization Collar
DxD	Direction by Design
EOW	End of Well
HDBS	Halliburton Drill Bits and Services
IADC	International Association of Drilling Contractors
IBitS	Interactive Bit Solutions
JSA	Junk Slot Area
MDR	Modified Diamond Reinforcement
MLFB	Multi-Level Force Balancing
MWD	Measurements While Drilling
MRA	Multiple Regression Analysis
NBR	Near Bit Reamer
NCS	Norwegian Continental Shelf
NFV	Normalized Face Volume
OBM	Oil-based mud
PDC	Polycrystalline Diamond Compact
PWD	Pressure While Drilling
RKB	Rotary Kelly Bushing
ROP	Rate of penetration
RPM	Revolutions per minute
SS	Subsea
TD	Target depth
TQ	Torque
TFA	Total Flow Area
TSP	Thermally Stable Polycrystalline
TVD	True vertical depth
UCS	Unconfined compressive strength
WBM	Water-based mud
WOB	Weight on Bit

1. Introduction

Drilling optimization is defined as a generation and application of an engineering strategy to drill more productive and cost-efficient wells. Obviously, the drilling program cannot be optimized to a hundred percent, because some aspects are always hidden or stay beyond our control, e.g. environmental factors [16].

Drill bits are a part of the well program. It is the major tool that does a cutting/crushing action at the end of the drillstring and highly affects the overall drilling performance. The following aspects can be improved by implementing a better drill bits solution [1]:

1) Drilling efficiency: optimizing penetration rate, maximizing durability, completing the well with the lowest cost per foot.
2) Steerability: optimizing angle-build capability and the force to deviate the bit (directional control)
3) Stability: minimizing stick-slip, bit whirl, and axial vibrations.

If the drill bits program meets these objectives, it results in a good hole quality, good directional and vibrational control. In a simple case where only a homogenous formation being drilled, the bit performance can be predicted and the mentioned requirements will be met. However, due to the challenging characteristics of several lithological units in the Norwegian Continental Shelf (NCS), there were numerous unsuccessful attempts to improve drilling efficiency.

Eldfisk is an oil field located in the Norwegian sector of the North Sea and. It is operated by ConocoPhillips Norway (COPNO). A special interest represents the 12 ¼" section, called "overburden". To a large extent it consists of interbedded formations with highly varying rock strength: soft shales and hard stringers of different origin [2]. A problem that arises is that the bit designed for specific applications will be used to drill formations that it is not completely suited for. Besides that, other drilling challenges, such as high pore pressure (overpressured formations), presence of high gas levels, also affect the bit performance.

This thesis is written in cooperation with Halliburton Drill Bits and Services (HDBS), provider of industry-leading, high efficiency fixed cutter and roller cone drill bit solutions [17]. It is one of the main drill bits suppliers on Eldfisk. Majority of the bits utilized in the 12 ¼" section are PDC (Polycrystalline Diamond Compact) bits. They are especially effective in soft formations, like shales, where ROP (rate of penetration) can achieve 180 fph depending on the rig capacity and mud-logging requirements. However the bit may suddenly stop to progress when a hard stringer (thin sedimentary bed) is encountered. Often the bits are pulled out of hole with severe damages on the cutting structure.

The Eldfisk II development project received approval in 2011. A total of 30 new production wells and nine additional water injection wells will be drilled [18]. Some of them have already been drilled during last three years. Even though the drilling efficiency has been improved, HDBS still experience similar challenges regarding the bits performance.

Rig time is a large portion of the total well cost, especially in offshore operations. Therefore there is a high cost-saving potential in drilling optimization on Eldfisk, and it is a high-importance goal for HDBS and COPNO.

1.1. Objectives

The subject of this paper is the drill bits optimization in the Eldfisk overburden, and the main objectives of this study are:

- Finding possible causes of the insufficient PDC bits performance in this type of lithology
- Analyzing 12 ¼” PDC drill bit designs that have been used on Eldfisk and proposing a potentially better solution
- Determining main operational parameters affecting drill bits performance
- Developing a predictive drilling model and proposing better drilling practices from the drill bits side

1.2. Scope of work

As mentioned above the overburden section on Eldfisk involves several challenges reducing drilling efficiency and causing additional problems, such as well control issues. First of all, the formation characteristics and lithological description will be presented, and associated drilling hazards will be defined. 12 ¼” size PDC bits are used to drill the section from the 13 3/8” casing shoe to TD (target depth) just above the Eldfisk reservoir. A detailed description of different PDC bit designs, features and drilling mechanisms will be discussed.

In order to conduct the study, a group of eight reference Eldfisk wells was chosen based on the following criteria: 1) the wells were drilled from the same platform, 2) a similar BHA (Bottom Hole Assembly) configuration was used, 3) premium drill bits technologies were used.

The analysis of the offset wells will be performed taking into consideration different bit designs. Some software evaluation methods will be also presented, e.g. vibration analysis. Based on the “lessons learned” combined with the interpretation of drill bit mechanics, another 12 ¼” PDC bit design could be proposed.

In addition to selecting a proper bit, we need to ensure that it will be operated as efficiently as possible. Effect of different drilling variables, such as weight on bit (WOB), rotation speed, hydraulics, etc., will be discussed. Based on mud-logging data from the reference wells, we will attempt to create an empirical ROP model using multiple regression analysis (MRA). The question to be answered is whether or not ROP can be easily predicted and controlled in such interbedded formations as the Eldfisk overburden.

1.3. Limitations

Drilling a well is a complex process that includes several disciplines related to each other: drilling fluids, casing design, drill string design, BHA design, bit selection, cementing, etc. Please note that this thesis is written in cooperation with HDBS (provider of drill bits and other drilling tools), and the primary focus of this research is the drill bits optimization. Therefore a large assumption is made from the beginning: what can be optimized in the drill bits program, assuming that other disciplines are already optimized.

A large limitation is that it is hard to generalize the formations drilled in different wells. Even though the reference wells were drilled in the same area from the same platform, the encountered lithology was not completely the same. In each well there was a different amount of stringers, which also vary in thickness and hardness. In addition to that, the pore pressure was different from well to well due to random accumulations of gas. The formations are highly heterogeneous, but in this thesis they will be treated in general, as the overpressured interbedded formations with varying rock strength.

Another challenge is linked to a limited understanding of PDC bits dynamics. HDBS design engineers use IBitS (Interactive Bit Solution) software tool to optimize bit selection or design new bits for specific applications. It enables to design the highest performing bit by simulating the forces that the bit will be exposed to under specific drilling parameters. In addition, a continuous improvement loop process, called DatCI (Design at the Customer Interface), is employed [3]. However in unstable drilling environments (high level of vibrations) or highly heterogeneous formations a bit may perform differently from what it was designed for. Also presence of 13 ½” XR under-reamer (HDBS reaming down hole tool) in BHA makes the drilling dynamics more complex, because the mechanical and hydraulic energy are distributed unequally between the bit and reamer.

Prior to drilling the formation 12 ¼” bits normally drill the 13 3/8” shoe track (it was drilled in six out of the eight reference wells). It is a space between casing or liner shoe and the uppermost collar, which keeps contaminated cement after the cementing operation (a shoe track schematics example is attached in Appendix 7). PDC drill bits (steel- and especially matrix-body) often get damaged just after drilling the shoe, because it includes aluminum parts, darts, setting balls and other components. A problem that arises is that we cannot know the bit dull conditions after the drill-out, because the bit continues drilling (the shoe track drill-out is a wide topic that is beyond this master thesis).

Another challenge is linked to the data quality and consistency. Any drilling data suffer from errors and inconsistency. Several filters have to be applied in order to remove the outliers and noise. On other hand, it will hide some important information [4].

2. Case study: Eldfisk overburden

The Eldfisk field is located at water depth in the block 2/7 in the Greater Ekofisk Area in the Norwegian North Sea. The field is operated by ConocoPhillips Norway (COPNO), and it is the fifth largest by reserves oil filed on NCS. It was discovered in1970 and approved for development in 1975. The reservoir consists of naturally fractured chalks, and the reservoir depth lies between 2,700 and 2,900 meters below the seabed. In December 2012, the field was estimated to contain 37.3 million cubic meters of oil, 5.4 billion cubic meters of gas and 200,000 tons of natural gas liquid in recoverable reserves [18].

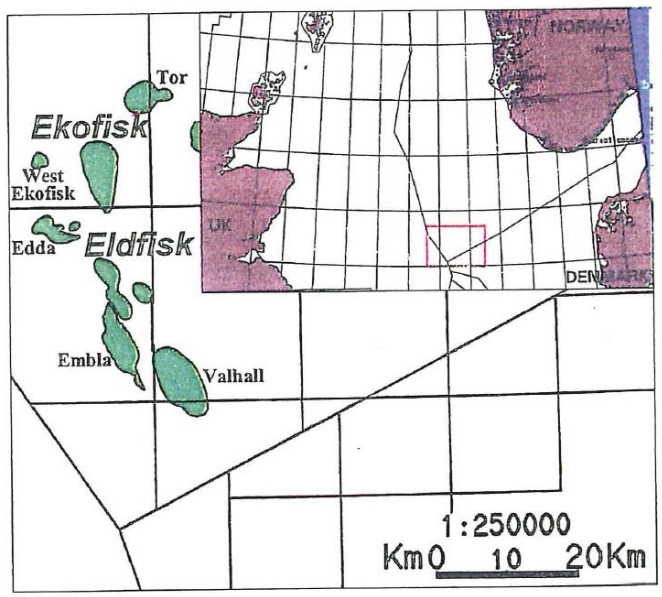


Figure 1. Greater Ekofisk area [5]

Currently the field is produced by 30 wells. The Eldfisk II development project was approved in 2011. It covers the construction of a new accommodation, wellhead and process platform Eldfisk 2/7 S (Eldfisk-S). It was successfully installed in May 2013. Several wells have already been drilled. The overall plan is to drill 30 production wells and 9 water injection wells.

The purpose of the Eldfisk II project is to increase recovery rates and maintain safe and stable production from the field. The objective is to ensure production of about 50,000 barrels per day for many years to come. Production from the field can be extended beyond the license in 2028 [6].

2.1. Overburden section

The formation between the seabed and the top of the reservoir is defined as the overburden. It varies in thickness between 8800 and 9800 ft and shows relatively small differences in lithology. Gamma ray logs, sonic logs and cutting samples show that it predominantly consists of claystones and shales. The overburden is divided into three main lithographic units [5]:

Lithographic unit	Approximate depth (ft TVDSS)	Geological age	Lithology
Nordland group	0-5000	Present - Middle Miocene	Dominated by soft marine claystones, includes silt and sand sediments, pebbles and boulders just below the seabed. Some limestone beds are also encountered in the lower sections. High numbers of faults exists in below the sealing Middle Miocene marker (geological unconformity of low-permeable shales).
Hordaland group	5000-8000	Middle Miocene - Lower Eocene	Consists of marine claystones with minor sandstones. Many thin limestones and streaks of dolomite are presented all over the group. The majority is at the top part. There are many small-scaled faults.
Rogaland group	8000-9800	Lower Eocene - Early Paleocene	Dominated by shales, consists of four lithographic formations: Balder (volcanic tuff), Sele and Lista (claystones with limestone stringers), Våle (marls).

Table 1. ELdfisk overburden lithographic units

2.2. Drilling hazards

Even though the overburden lithology does not seem challenging for the conventional drilling, there are many hazards associated with the well control, cleaning and drilling efficiency issues. A few years ago a special group of COPNO geologists and engineers was made to study causes of these challenges and to improve the wells drilling programs [2].

2.2.1. Drilling environment

The overburden section on Eldfisk-S is drilled using a Rotary-steerable system, Geo-Pilot 9600, with 12 ¼" drill bit and 13 ½" under-reamer, located around 50 ft above the bit (BHA schematics is attached in Appendix 1). The wellbore profile, recently used in this section, is to maintain a 50° inclination angle until approximately 9200 ft TVDSS, and then build the angle to about 70° and slightly turn the azimuth (maximal planned DLS are 3°/100 ft). The section TD is set approximately at 9400 ft TVDSS [7]. Then the 9 5/8" casing shoe is normally placed in the more dense and competent lower Våle formation, approximately 10 ft above the reservoir. The reason is to seal the overlying Lista formation shales and reduce mud weight when drilling the reservoir chalks [5].

The presence of gas migrating from the reservoir is a well-known issue on Eldfisk field. The highest concentration of gas is observed between Lower Miocene and Eocene. Mentioned in the table Middle Miocene marker acts a seal for the rest of the Miocene rocks lying above. Today the observed amount of gas seems to be even higher than before [5]. The presence of gas is one of the primary causes for the wellbore instability: pack-offs and unintentional kicks.

The drilling operational window (mud window) is defined as the difference between the pore pressure and fracture pressure gradients. If the wellbore pressure is less than the pore pressure, it can result in wellbore collapse, pack-offs and consequent kick, accidental influx of formation fluids. If the wellbore pressure exceeds the fracture pressure, it raptures the formation and lost circulation can occur.

A general overburden wellbore stability analysis was conducted by COPNO. The conclusion was that the pore pressure has the greatest influence on the mud window. The rock strength is also an important parameter; however it has only a marginal effect in the mud weight selection [5]. The mud window gets narrow below 5000 ft TVDSS (for example, 14.3 - 17.2 ppg at 8000 ft TVD RKB), because of the steep pore pressure ramp (see the Figure 2). Therefore heavier mud weights are required for drilling this section. In general, increasing mud weight and overbalance conditions have a negative effect on the penetration rates and drilling efficiency.

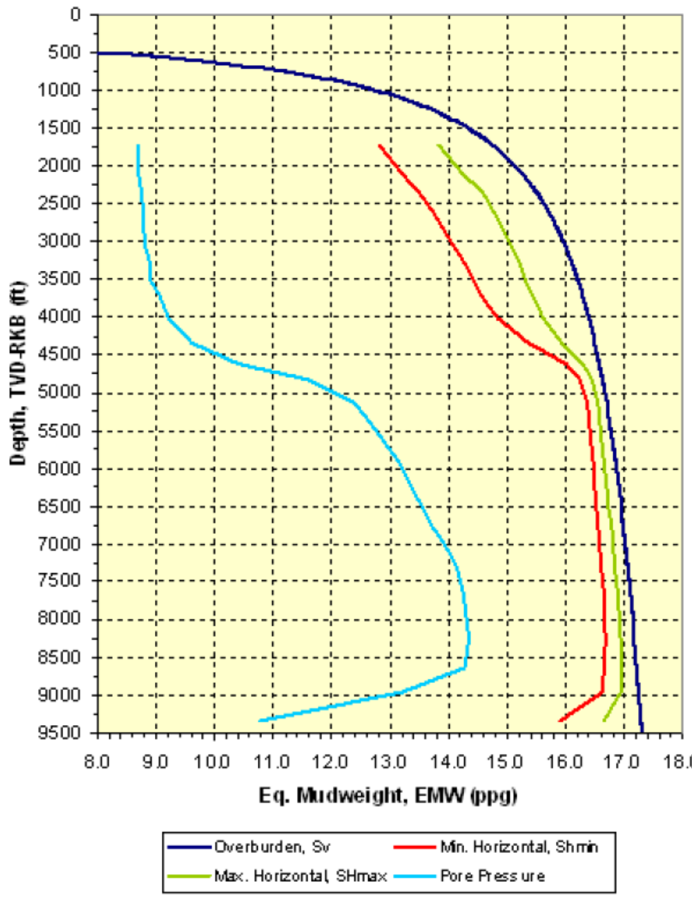


Figure 2. Eldfisk P50 gradient profiles [5]

Geological faults in the overburden represent the main drilling challenges associated with well control. The faults can be of two types: open faults (void space inside the hosting shale rock) or sealing faults (hard calcite cemented rocks). The open fault can results in large mud losses. Even though, the fault depths can be accurately predicted by seismic, it does not specify the fault type. Drilling through the sealing faults is not a challenge for the well control, only a reduction in penetration rates is observed [2].

2.2.2. Stringers

The stringers represent the main challenges associated with the drill bits performance. The stringers are defined as thin sedimentary beds with a parallel to sub-parallel relationship to the bedding planes of the hosting rock. They vary over a great range of lithologies. In the Eldfisk overburden, they vary from silt/clay stone and marl stone to limestone with varying amounts of calcite and dolomite. Chert and diatomite rich stringers are also found. Their thickness varies from 1 to 17 ft, and the mean thickness is about 3 ft. Generally, it is encountered around 70-80 stringers per well, some of them are grouped creating around 15-20 larger accumulations. Most of them are randomly encountered in the Lower Miocene to Eocene age rocks [2].

Carbonate stringers (limestone, limestones with chert, dolomite) are the most common in the section. The density logs indicates the carbonate stringers density about 2.35 g/cc, while the hosting shales are 2.0 g/cc (these values most likely are too low due to the presence of gas). The stringers have much higher compressive strength, the capacity of material to withstand loads tending to reduce the size. Unconfined Compressive Strength (UCS) for shales varies from 877 to 1660 psi, while UCS for the stringers can be as high as 20,000 psi [5].

Figure 3. Core samples of shale (left) and limestone stringer (right) [8]

The overburden can be highly interbedded with formations having different compressive strength. The bit cutting structure often gets severely damaged by the impact loads (nose and shoulder area– when entering the hard stringers, and gauge area – when leaving the stringers). The stringers are not abrasive, but hard formations, that fails mainly by fracturing. The penetration rates can drop dramatically when they are drilling. Generally it decreases below 80 fph, while the controlled ROP in the shales can be up to 180 fph depending on the rig capacity and mud-logging requirements. Occasionally, the bit may even stop progressing through the hard stringer. In this case, the unstable clays above the bit can start intensive swelling that may result in a severe pack-off around the drilling BHA. Over a time interval the packed borehole results in a dramatic increase in the bottomhole and stand pipe pressure. The stand pipe pressure was seen to increase from 150 psi to 750 psi in only 20 seconds. It can fracture the formation and result in severe mud losses. Time needed to circulate out the kick and regain the well control can take several days.

Stratigraphically the stringers can be laterally extensive (possible to correlate them by depth through the entire field) and nodular. The gas is often concentrated below the laterally extensive stringers that act like a semi-seals due to their low permeability. After crossing a stringer, the driller should hold-back the bit and penetrate slowly. Otherwise it can result in a fast uncontrolled influx of gas can and cause well instability.

It is relatively easy to identify the stringers by the logging data after the drilling, but it is hard to predict them ahead of time. The mentioned overburden research group made an attempt to model log-derived stringers indicators. Another idea was to create a stringers data-base and to come up with more statistical data. However these proposals have not been realized. Still the research group has identified “awareness zones” on the Eldfisk field where the stringers are mostly common. Actually, this data was efficiently enough for the drillers on the rig. They do not require a specific depth for each stringer, the “awareness zones” identify intervals where to adjust drilling parameters [2].

2.2.3. Swelling clays

Shale is the dominant lithology in the Eldfisk overburden. It consists of the clay, quartz and carbonate minerals. Their approximate ratio in the shales is 60/20/20 percent respectively. The ratio varies with depth; however the clay minerals are dominant in the composition. The clays minerals include Illite, Smectite, Mica, Kaolinite and Chlorite. The Smectite group is very reactive, especially Montmorillonite minerals that have a high cation-exchange capacity and result in massive swelling when absorbing water. Montmorillonite even swell in oil-based mud (OBM) but less intensively. The presence of this mineral in the shale composition intensifies the pack-off. Balling issues can also be induced in case of inefficient hydraulics [2].

3. PDC drill bits study

Polycrystalline Diamond Compact (PDC) bits are generally used in the Eldfisk overburden. This type of bits is optimal for drilling soft shales and also, by means of special design features, can be applicable for medium-to-hard formations. Even though the overall performance of PDC bits has been improved during last years, it still requires design and technology modifications.

3.1. Rotary drilling bits

A drilling bit is a major tool that does the cutting action at the end of the drillstring. The different types of bits use different drilling mechanics: scrapping, chipping, gouging, or grinding the rock. Drilling fluid is circulated through the bit to remove the drilling cuttings generated inside the wellbore [9, p.311].

The two main classes of the rotary drilling bits are:

1) The roller-cone bits. They are classified as milled-tooth (cutting structure on the cone is milled from the steel) or insert (a series of inserts is pressed into the cone). Both of them have a variety of cone types, tooth design and bearing types. The roller-cone bits remove the rock through gouging/scraping (soft formations) or chipping/crushing action (hard formations). The teeth, cutting elements, rotate about the cone's axis as the bit rotates on bottom around its own axis.
2) The fixed-cutter bits. They are divided in two main groups: PDC bits (use small disks of synthetic diamond) and diamond bits (made up of impregnated, natural diamonds or TSP elements). The PDC bits fail the rock through shearing, while the diamond bits – through the grinding process. The fixed cutter bits do not have any moving parts and consist of fixed blades that are integral with the bit's body rotating as a single unit.

An additional bit class introduced recently is the Hybrid bits, which incorporate PDC blades meeting at the center and rolling cones between the blades.

IADC has developed a system of comparison charts for classifying the bits according to their design characteristics and applications. The IADC classification for the roller-cones includes four characters: 1) bit series, 2) bit type, 3) bearing and gauge arrangement and 4) additional bit features. The IADC classification for fixed-cutter bits is similar and consists of four-characters: 1) body type, 2) formation type, 3) cutting structure and 4) bit profile (IADC code chart for fixed-cutter bits is attached in Appendix 2) [9, p.326].

3.2. Bit selection and evaluation

Bit selection is largely accomplished through trials and errors from previous runs. IADC bit-comparison charts also help in the bits selection process. During the well planning, the following studies should be conducted: in-depth review of offset-wells, review of previous bit runs and their dull grading characteristics. The selection of a bit for a particular application will depend on the following factors [9, p.364]:

1) formation type (hardness, abrasiveness, inter-bedding, presence of hard stringers)
2) Expected operating conditions (drilling parameters, drilling fluid properties, BHA configuration)
3) Wellbore profile (straight or directional drilling, run length)

The main terms describing the formation characteristics are drillability and abrasiveness. The drillability is a measure showing how easily formation can be drilled. It is inversely related to the rock compressive strength. The abrasiveness is a measure showing how fast the teeth wears while drilling [10, p.209].

After the offset data is analyzed and the requirements for the new bit run is understood, the bit can be selected. Generally, aggressiveness and wear resistance (durability) are the two fundamental properties that must be considered [9, p.364].

3.3. PDC drill bits

PDC bits use small disks of synthetic diamond to provide the scrapping/cutting surface. Diamond is the hardest material known, and the popularity of PDC bits has grown steadily during last years.

The PDC bits cut primarily by shearing action. The cutters must have a sufficient axial force to penetrate into the formation and a sufficient torque for the bit rotation. The resulting force defines a plane of thrust for the cutter. The formation is sheared-off at an initial angle that is related to this plane of trust. The energy required to rapture the rock in shearing is less than required by the compressive stress. Therefore PDC bits are efficiently operated under lower WOB [9, p.314]. For example, shearing is the most efficient method for drilling shales.

The depth of cut is determined by the rock strength, applied WOB and the cutting structure type and wear. Different rock failure criteria have been applied to find the ratio between the rock strength and the rotary drilling process. The main theory is the Mohr failure criterion. It says that the fracturing occurs when the shear stress exceeds the sum of the material resistance and the frictional resistance [9, p.338].

PDC bits design and construction includes many parameters. The most important are: 1) the body type material, 2) the number and shape of the blades and 3) the shapes and sizes of cutting elements (PDC cutters, Tungsten Carbide inserts). Several other features, such as metallurgic or material makeup, sizes and locations of hydraulic flow passes, are also considered.

The figure and the table below demonstrate and describe general components of a PDC bit [1]:

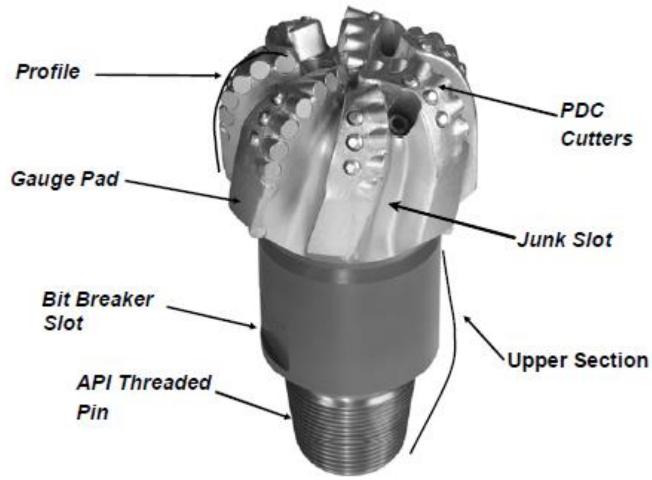


Figure 4. PDC bit basic components [1]

Upper section	Includes the shank, which has the bit breaker slot and the pin connection, which are made according to American Petroleum Institute (API) standards.
Gage section	Located above the profile and implies as an extension to it. The vertical cylindrical shape of the gage provides bit stabilization and maintains the hole size
Junk Slot Area	Includes face recesses, fluid courses, and defined as a void space of the bit. It is designed to help formation cuttings to move freely from the bottom and across the bit face and gage.
Bit profile	Defines the shape of the bit from a side-view. The profile covers the area from the gage and to the center of the bit, including location of cutters, fluid courses and void areas. There are different bit profiles for a variety of drilling applications.
PDC cutters	The cutting elements of a PDC bit. There are many different PDC cutter designs, varying in shape, material, manufacturing process, etc.

Table 2. PDC bit basic components

Two main types of PDC bits are: matrix-body and steel-body bits. The figure and the table below compares demonstrate the differences between them [1]:

Figure 5. Matrix-body (left) and Steel-body (right) PDC bits [1]

Matrix body	Steel body
Made from tungsten carbide material.	made of steel plus “hard facing” coating
Provides improved resistance to the body wear and erosion, because the material is extremely hard and wear resistant, and typically a heavier set of cutting structure is chosen. They last longer in the abrasive formations (high sand content) or in drilling with extensive circulations (high HSI applications).	Steel is less wear resistant than tungsten carbide. The “hard facing” is applied to the critical areas of the steel bit to improve the abrasion resistance.
Matrix is a more brittle material and it can be broken under high impact shocks.	The main advantage of the steel is a superior impact and transverse rupture strength. It allows placing longer blades with a higher stand-off. It increases the face volume and junk slot area providing better cleaning and reducing bit balling. These bits are perfect for shales or other soft formations where high ROPs are expected.
More flexible in design: easier to place additional features and require less designing time.	Less flexible in design, however the steel-body bits are generally less expensive in sizes 12 ¼ inches and greater.

Table 3. Matrix-body vs. Steel-body PDC bits

3.4. PDC bit design

As mentioned before, there is a large variety of PDC bit designs, many components of the bit can be adjusted for different purposes. However the main bit characteristics are always specified in the IADC code and the consigned bit name (nomenclature for HDBS PDC drill bits is attached in Appendix 3).

3.4.1. Bit profile

The profile shape is one of the most important characteristics of the PDC bits. It represents the bit shape from the gauge to center. It has an influence on stability, steerability, cutter density, durability, rate of penetration, cleaning efficiency and cooling of the cutters.

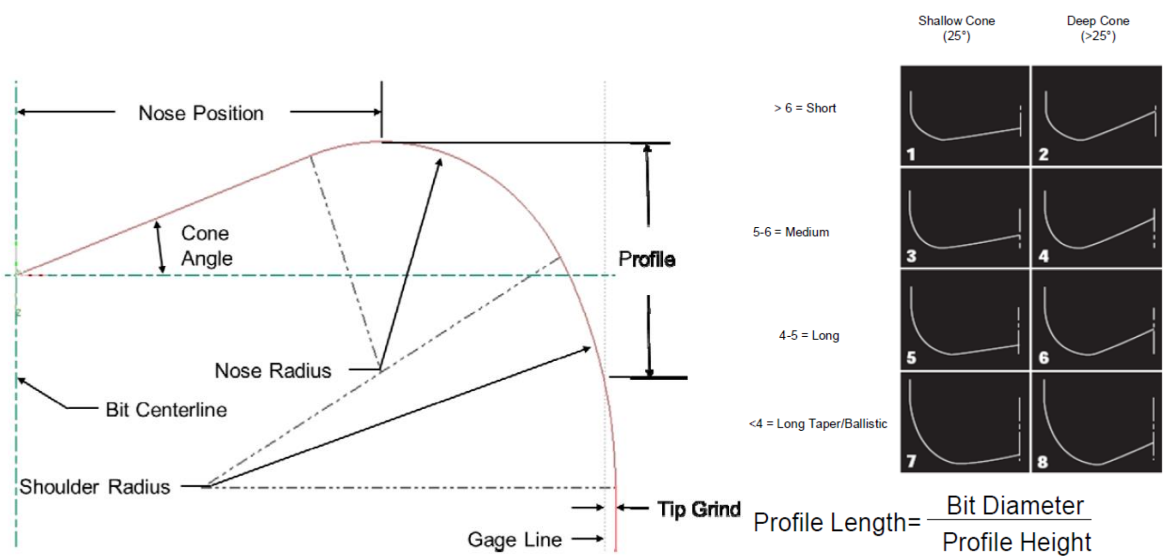


Figure 6. PDC bit profile layout and profile types [1]

The profile shape has a major influence on the bit aggressiveness and stability. The general rule is the following:

- Aggressive/less stable is short profile with shallow cone angle
- Non-aggressive/more stable is longer profile with deeper cone, large nose radius

The deeper cone increases the cutters volume and creates a deeper formation cone at the center ("mechanical lock") that helps to stabilize the bit. A larger nose radius increase the cutters volume at the nose and better distributes the forces across the cutters, making it less aggressive. Profile and shoulder length increase the bit durability and stability. Halliburton DBS recognize eight different profile types shown on the Figure 6 [1].

3.4.2. PDC cutters

PDC cutters are the major element of a PDC bit. They can vary in size, shape, hardness [1]:

a) Increasing PDC cutter size increases the bit aggressiveness, but reduces durability and the cutter count. It is opposite for the decreasing cutter size. The most utilized sizes in HDBS are 10.5, 13, 16 and 19 millimeters.
b) There are different variations in shape: cylindrical and bullet, round and scribe. Different shapes have different load-distribution that affects the depth of cut, stability and drilling action. For example scribe cutters are often placed at the bit cone to increase the point-load if the cutting torque at the center is not high enough to shear the formation.
c) Chamfer is the tapered area of the PDC cutter. It determines the aggressiveness of the cutter. The higher chamfer has a smaller depth of cut and is less aggressive, but more durable.

Figure 7. PDC cutter types [1]

Position of the cutters and their orientation also vary. They are distributed between face, nose, taper, shoulder and gage of the bit. Back-rake and side-rake angles orient the cutter about its center in 3D coordinates. Normal side-rake angle is set to +5°, but can vary for force and energy balancing purposes. The back-rake angle defines the cutter aggressiveness. A smaller angle is more aggressive and can be used in softer formations where impact damages are not common. Opposite, back-rakes above 15° increase the impact and wear resistance but decrease the drilling efficiency. See the figure below.

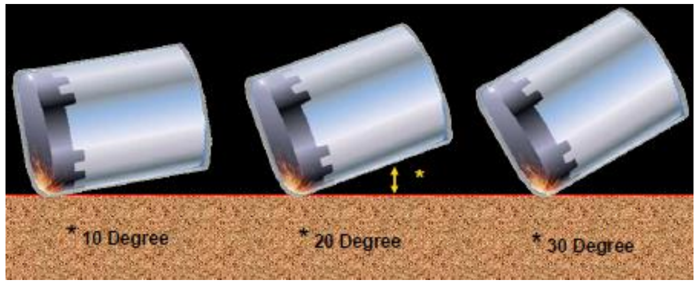


Figure 8. Back-rake angles of PDC cutters [1]

The overall cutting structure can be oriented in two different layouts: single-set and track-set. The single-set cutting structure has no cutters in the same radial or longitudinal position, while the track-set has at least two cutters at the same radial and axial position on different blades. Normally the secondary blade PDC cutters follow the tracks from the primary blade. The track-set PDC bits form a more ridged bottomhole pattern, while the single-set creates a smoother pattern. The track-set layout makes the bit more stable and protects it from lateral instability due to the restoring force, pushing the bit to its original path. However the single-set is more efficient and aggressive due to the exposure of all cutters.

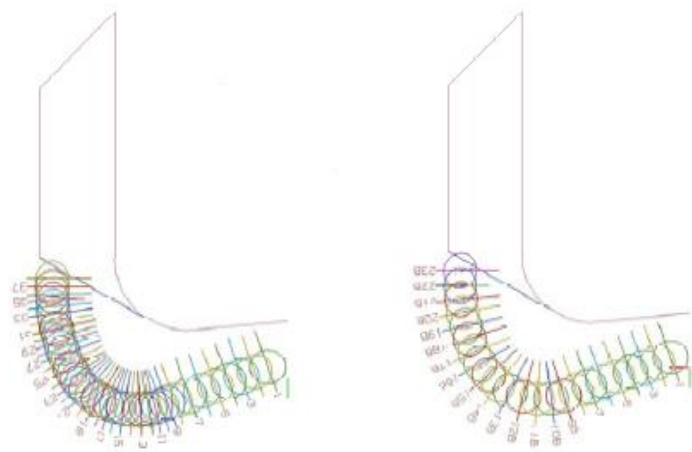


Figure 9. Single-set (left)t and Track-set (right) cutters layout [1]

A special feature available in PDC bit design is the dual row back-up cutters (previously it was applicable only for matrix-body PDC bits). It is recommended to use a second row of premium cutters in highly abrasive conditions. It is an effective way to add diamond volume and increase durability. The back-up row cutters can be under-exposed (shear the formation when the primary cutters are worn) or exposed (cut the formation and control the depth of cut). The disadvantages of the dual row cutters are placement limitation, poorer cleaning and relatively high cost.

Figure 10. Dual row back-up cutters [1]

Besides that, HDBS have several other options for the depth of cut control. It is used to limit over engagement of the primary cutting structure and to damp axial vibrations, smooth torques and to limit stick-slip related damage.

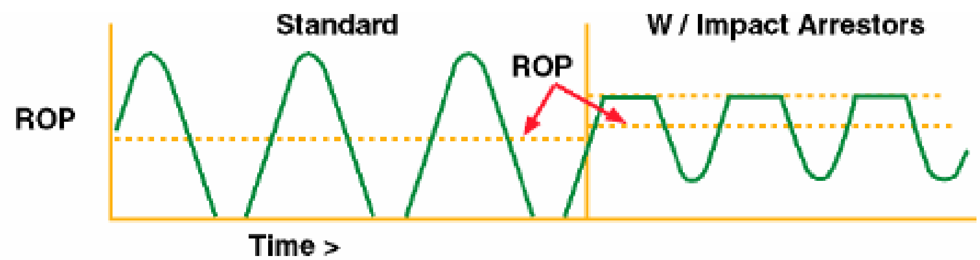


Figure 11. Axial engagement management [1]

All impact arrestor types are protrusions from the bit body which are aligned directly behind the preceding PDC cutter and set below its tip. They are split into two groups: active and passive elements. The following features are available in HBDS solution catalog:

1) Passive elements: a) Impact arrestors and Carbide Impact Arrestors (CIA) are used when little wear is expected but impact damage is observed; b) Modified Diamond Reinforcement (MDR) cutters are more “wear resistant” axial arrestors, but have relatively high cost.
2) Active elements (cutting the formation): a) Backup R1 cutters are generally recommended in interbedded formations with highly varying rock strength; b) Impreg discs are the secondary cutters enabling dual cutting action in intermediate hard/abrasive formations; they are especially beneficial in reducing both axial and lateral vibrations.

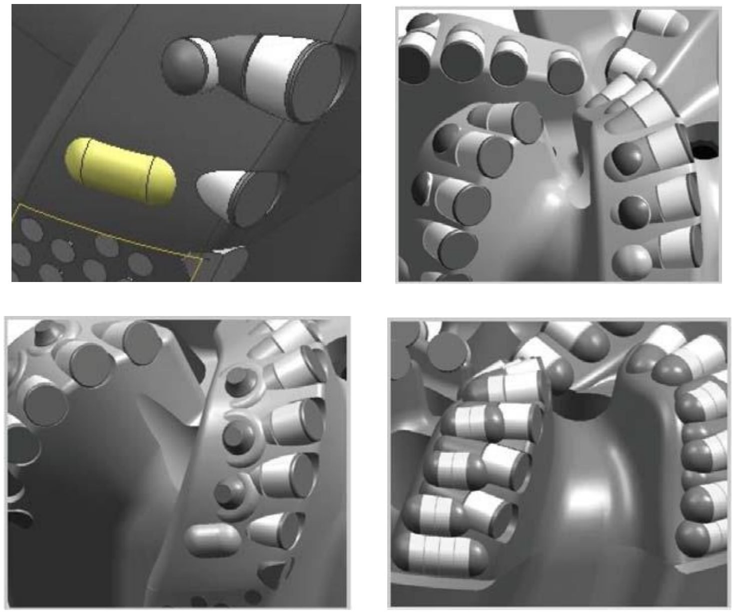


Figure 12. Depth of cut control elements. Impact Arrestors and Carbide Impact Arrestors (top left), Modified Diamond Reinforcement (top right), R1 cutters (bottom left), Impreg discs (bottom right) [1]

3.4.3. Blades layout

The blades layout determines initial aggressiveness, stability, and durability of the bit [1]:

a) Bits with a high blades count generally have a greater cutter density, which increases durability and stability. The increased cutter volume at the bit face makes the bit less prone to pivoting about any point or blade, whirling. However the increased blade count makes the bit less aggressive. Also it decreases the cleaning ability at higher ROPs, because the Junk Slot Area (JSA) and the nozzle count are reduced.
b) Blades asymmetry refers to the spacing between the blades. The symmetric blades have an equal spacing between them, and asymmetric have unequal spacing. Asymmetry is one of the main approaches to reduce bit whirling tendency when bit creates a harmonic bottomhole pattern, lobes. HDBS design asymmetric bits for the majority of drilling applications.

Figure 13. Symmetric (left) and Asymmetric (right) blades layout [1]

c) The degree of blade spiraling has a direct effect on the bit stability: a better stability is achieved with spiraling due to a more even distribution of load between the cutters. Blade spiraling also provides better wall contact, making the bit more stable at the gauge. However spiraling reduces bit cleaning efficiency due to elongated water ways. Therefore the extensive spiraling is not proper for all applications and should be evaluated.

Figure 14. Straight (left) and Spiral (right) blades and pads layout [1]

3.4.4. Gauge design

The gauge design has an effect on bit performance in different BHA types: rotary, motor or rotary-steerable system. The gauge design is basically divided in two parameters: the gauge cutting structure and the gauge pad [1].

a) The gauge cutting structure refers to the furthermost cutters at the blades. Their primary function is to provide adequate wear protection and ensure that the hole is not under-gauged. Normally, one gauge cutter per blade is enough if the formation is not abrasive. The gauge cutters are tip grinded to increase contact area with borehole wall. Their secondary function is to improve bit steerability in directional applications, making the bit more responsive.
b) The gauge pads are passive component of the gauge and are used for bit stabilization. Different gauge pad geometries are suitable for different applications, basically depending on steering requirements. They can be straight, spiral and MEG (modified extended gage). In terms of the diameter, they can be in-gaged with the bit diameter, fully relieved, step or EDL (for Geo-Pilot point-the-bit applications).

3.4.5. Force and energy balancing

An important step towards a stable running bit is the cutting structure that does not attempt to translate laterally during drilling [1]. This is accomplished primarily by adjusting it in order to reduce the imbalance force which is determined through summation of drag forces acting on each cutter around the bit axis of rotation. In addition to that, the global force balancing is applied. It considers all force types (drag, radial, axial) in the same manner.

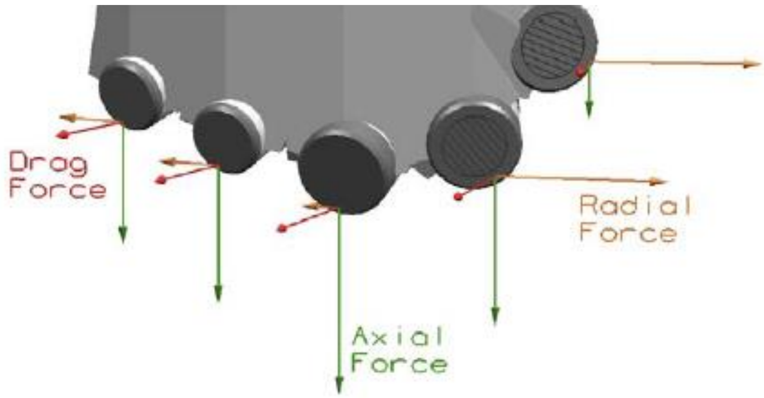


Figure 15. Forces acting on PDC cutters [1]

On other hand, the energy balancing is looking at the distribution of the individual forces across the bit face instead of the axis of rotation. The idea is to have an even torque distribution between the adjacent cutter to avoid cutters breakage.

Force balancing extremely reduces downhole vibrations, resulting in more efficient drilling, because less mechanical energy is discharged in vibrations. However the traditional force balancing is only effective when all cutters are engaged within a uniform formation.

When drilling transitional zones, different cutters cut formations with different rock strength. It changes engagement of the cutters and makes the bit imbalanced. Therefore to compensate for these distortions, the bits used in transitional drilling could have a Multi-level force balancing (MLFB). It provides balancing at three different levels: 1) cutter group level, 2) cutter set level and 3) all cutters level.

Figure 16. Standard (left) and Multi-Level Force Balanced (right) PDC bits [1]

3.4.6. Bit hydraulics

The overall hydraulic efficiency of the rotary drilling is partly dependent on the bit design. Computational Fluid Dynamics (CFD) theory predicts fluid velocity and direction. CFD is applied when designing a new bit or modifying an existing bit with a hydraulic dysfunction.

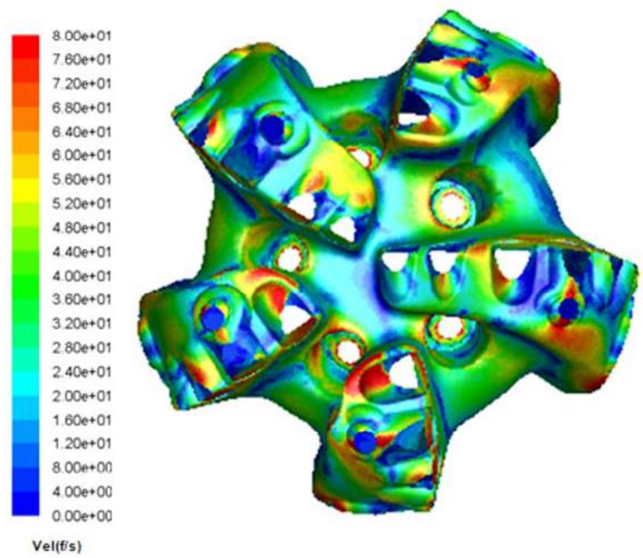


Figure 17. Computational Fluid Dynamics approach [1]

In order to enhance hydraulic performance of a bit, a bit design engineer can modify two parameters:

a) Normalized Face Volume (NFV) is the rational amount of the open space measured from the bit body to the cutter profile. The Junk Slot Area (JSA) should be accurately designed to improve cuttings removal without compromising blade strength. A general ratio between the blade height and width is 1:1 for matrix-body bits and 3:1 for steel.
b) Nozzles layout should be designed to improve bit cleaning and hydraulic efficiency and to mitigate bit-body erosion. However their placement at the bit face is often limited. The nozzles themselves have different variations, such as side-port nozzles, micro nozzles, extended nozzles and others.

3.5. PDC cutters wear

The wear on PDC cutters can be divided in two categories, depending on their basic cause. The steady-state wear results in a flat-wear on the cutter tips, and it is the function of operating parameters applied to the bit, cutter temperature, formation properties and cutter properties. Another type of wear, impact damage is associated with impact loads on the cutters. It can be caused by dynamic shock through whirling or transitional drilling. Different types of PDC cutter wear are presented below.

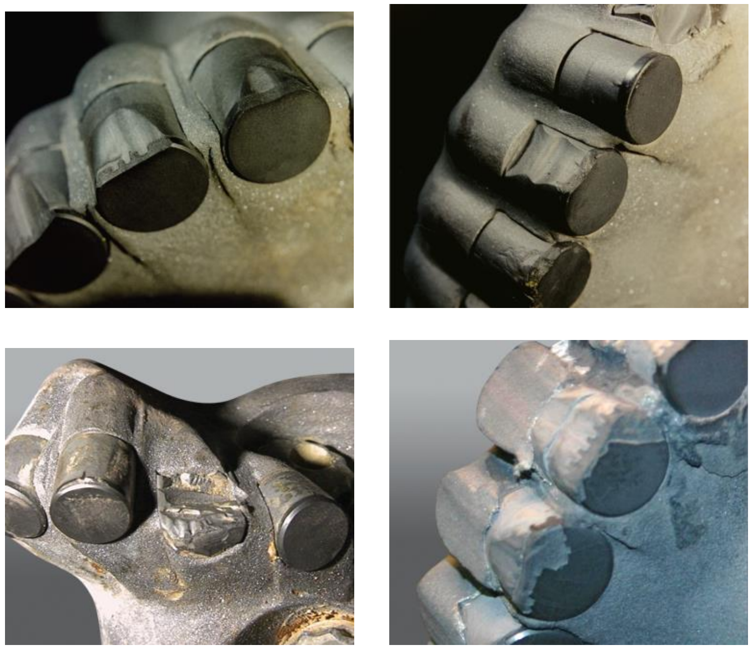


Figure 18. PDC cutters wear: worn (top left), chipped (top right), broken (bottom left), spalling (bottom right) [1]

The circular shape of PDC cutter defines the relation between the fractional tooth wear h and the cutter contact area. Generally the tooth wear rates, dh/dt, decreases with increasing fractional tooth wear between 0 and 0.5 and increases with the increasing fractional tooth wear between 0.5 and 1. The following equation applies for zero back-rake angles (for different back-rake angles the relation is more complex) [10, p.216]:

$$\frac{dh}{dt} \propto \left(\frac{dh}{dt}\right)_s 1/d_c \sin(\beta/2) \tag{3.1}$$

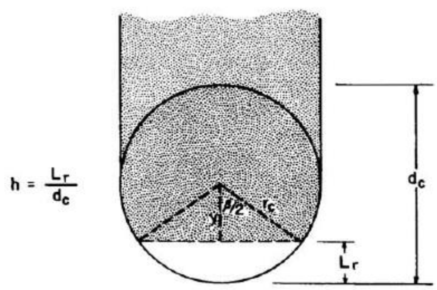


Figure 19. PDC blank geometry as a function of fractional cutter wear [10, p.216]

IADC created a dull-grading system that represents a systematic method for communication of bit failures. It indicates seven characteristics for fixed-cutter bits and provides a mechanism for systematic evaluation of bit appropriateness and drilling parameters (IADC dull grading chart is attached in Appendix 4). The PDC dull grading review three main bit-wear categories: cutting structure, gauge, and remarks. The system is closely associated with the IADC bit-classification system. After evaluating the bit, engineers can identify successful and unsuccessful design features that can be either reapplied or corrected in the future applications [9, p.331].

3.6. PDC bits vibration mechanisms

Generally, bit and drillstring vibrations and shock loads are among the main factors causing a poor drilling performance and creating a non-productive time. The following vibrations modes are the most common for the dynamic behavior of the PDC bits [11]:

Mechanism	Mode of vibration	Frequency	Description	Typical Environment	Consequences
Stick-slip	Torsional	0.1-5 Hz	Non-uniform drillstring rotation in which the bit stops rotating momentarily at regular intervals causing the string to periodically torque and then spin free.	High-angle or deep wells, hard formations or salt, use of aggressive PDC bits with high WOB	Surface torque fluctuations, can cause PDC bit damage and stabilizers wear, lower ROP, drillstring twist-offs
Bit whirl	Lateral/ Torsional	10-50 Hz	Occurs when bit cut itself a hole larger than its own diameter. The bit moves around the wellbore and not around its natural center. The cutters move faster, backward and sideways.	Excessive side cuttings on the bits, softer washed out formations	Damage to the bit cutting structure accelerated by impact loadings. Over gauge reinforce tendency for the bit and BHA to whirl.
Bit chatter	Lateral/ Torsional	20-250 Hz	High frequency resonance of the PDC bit, caused by impacts of each blade or even each cutter.	PDC bits drilling in high compressive strength rocks where they lose shearing cutting action.	Damage to the bit cutting structure, bit dysfunction, failure of downhole electronic equipment due to vibrations.

Table 4. Downhole vibration mechanisms

There are more vibrations mechanisms downhole associated with the roller-cone bit type (bit bouncing) and the entire drillstring (BHA whirl, lateral shocks, torsional and parametric resonance).

4. Offset wells study

The main drilling hazards in the Eldfisk overburden section were mentioned previously in this paper. The detailed description of PDC bit types and design was also given. A successful drill bit performance is mainly recognized through the trial runs in real drilling applications. In this section we will compare performance of PDC bits used in the reference wells.

The bit runs included into the analysis were completed in 12 ¼" x 13 ½" section on Eldfisk-S from the year 2013 to 2015. A group of eight wells was chosen by several criteria:

1) The wells were drilled from the same platform, Eldfisk-S.
2) The similar BHA configuration was utilized: 12 ¼" bit, Geo-Pilot 9600, 13 ½" XR1200 under-reamer, and near bit reamer (NBR) on some of the wells (NBR or TDReam, modification of NBR, are HDBS drilling tools which normally activated after the section is drilled to TD to eliminate the residual rat-hole, therefore their contribution to drilling efficiency can be neglected).
3) The premium bit technologies were utilized (specification sheets are attached in Appendix 5).

4.1. Offset summary

The end-of-well reports (EOW) for all wells were reviewed to find valuable information [7]. The drilling and logging data were downloaded using Halliburton InSite Studio Software. Then the collected raw data were filtered by several filters using MATLAB (the filtering process will be described later). The time spent for drilling the shoe track was taken out, such that the analyzed data refers only to the overburden formations.

The Figure 20 shows the offset wells summary: the footage drilled from depth to depth and the average ROP, fph. The headers are reference well name, bit type and their dull grading characteristics. The same diagram is made to compare the runs by TVDSS, ft, (Figure 21). Just by looking at the figures we can see, the fastest ROP was achieved in the well #8 with the matrix-body bit GTD65D, 102.8 fph, only with a minor dull on the bit cutting structure (1-1-BT). The longest bit run was performed in the well #7 with the matrix-body bit MMD65DH, 8222 ft, but the bit was severely damaged (3-4-BT). Analysis and comments for all bit runs will be given in this section.

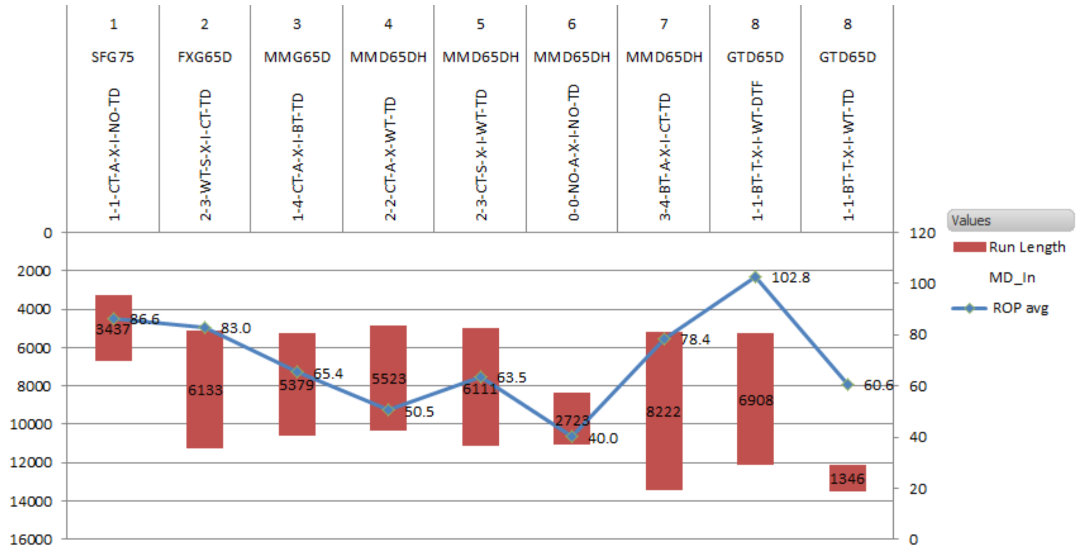


Figure 20. Offset wells summary by measured depth (MD), ft

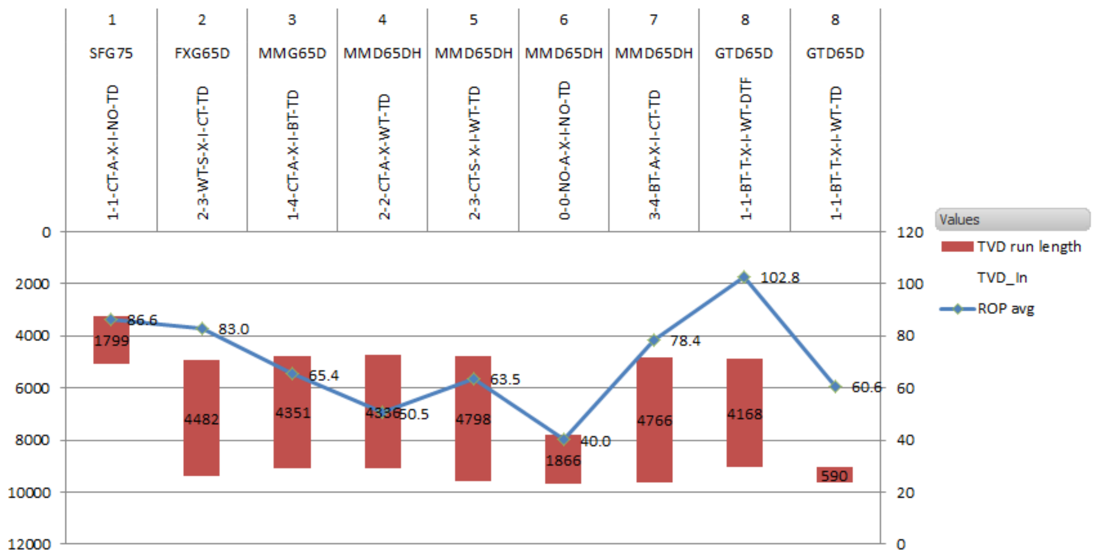


Figure 21. Offset wells summary by TVDSS, ft

The table below shows other relevant data that will be useful in the analysis:

Well #	MD In, ft	MD Out, ft	Length, ft	ROP, ft/hr	Bit model	Material	IADC	TFA	Incl In	Incl Out	DLS
1	3290	6727	3437	86.6	SFG75	778427	S222	1.3744	20.3	69.78	1.45
2	5127	11260	6133	83.0	FXG65D	663251	M223	1.353	25.81	69.48	1.47
3	5216	10595	5379	65.4	MMG65DH	836757	M324	1.353	35.01	70.61	1.96
4	4835	10358	5523	50.5	MMD65DH	866233	M324	1.353	15.85	72.49	1.48
5	5009	11120	6111	63.5	MMD65DH	866233	M324	1.353	27.19	73.97	0.89
6	8357	11080	2723	40.0	MMD65DH	836757	M324	1.353	25.59	72.67	2.37
7	5205	13427	8222	78.4	MMD65DH	783199	M324	1.353	52.57	71.63	0.24
8	5230	12138	6908	102.8	GTD65D	941512	M324	1.353	52.32	53.05	0.05
8	12138	13484	1346	60.6	GTD65D	941512	M324	1.353	53.05	72.95	1.72

Table 5. Offset wells additional data

One large limitation that was mentioned in the introduction to this thesis is that we do not know the bit dull-conditions after it has completed drilling the shoe track. PDC bits (steel- and especially matrix-body bits) often get damaged just after drilling the shoe, because it includes aluminum parts, darts, setting balls and other. PDC bit wear has a large effect on the depth of cut and the penetration rates. For example, some PDC bits were unable to drill new formation after the shoe track drill-out (example is not from the Eldfisk well). In the group of selected wells, in two of them the shoe-track drill-out was not performed: the well #6 and 8 were sidetracks from the main wellbores, wells #5 and 7 respectively.

4.1.1. Density log comparison

To verify that all bits drilled formations with approximately the same hardness, the density log comparison is made (density-logs were not used in the sidetrack runs). The measurements were made by the Halliburton Sperry Drilling tool, Azimuth Lithodensity (ALD) Sensor, it combine density and photoelectric measurements with azimuthal bringing of data and an acoustic standoff sensor.

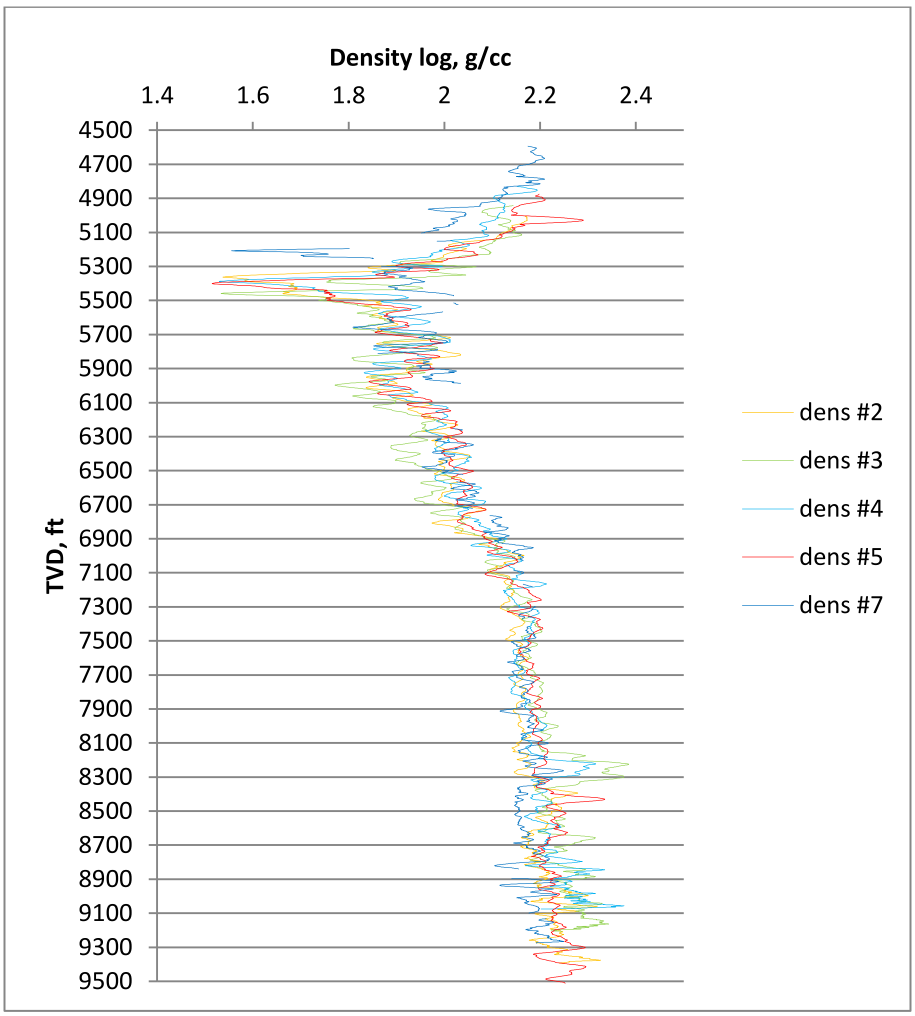


Figure 22. Composite density logs

There were some variations in the density between the wells because of the formation heterogeneity (dominated shales with random hard stringers), but generally the wells are comparable. High density fluctuations in each well also correspond to the formation heterogeneity. The density log might be too low, because of high gas concentration in the overburden section. The average density log decreases from 2.2 g/cc at the shoe towards 1.5 – 1.7 g/cc at 5400 ft TVD. This is the transition from Nordland to Hordaland groups (Middle Miocene age), the area with several geological faults. Below that the density naturally increases under the increasing overburden stress and approaches 2.3 g/cc at the section TD.

4.2. Bit in the well #1

In the wellbore #1 the bit SFG75 (SteelForce class) drilled at lower depths: 3255 – 5054 ft TVDSS, mainly the Nordland group. However it was the only steel-body bit recently used on the Eldfisk-S overburden. The bit also drilled several hard stringers and had only a small dull: a few chipped cutters (1-1-CT-A-X-I-NO-TD). 16 mm PDC cutters (at face and gauge) and some 13 mm cutters (at gauge) were used on all the bits. SFG75 also had Carbide Impact Arrestors (CIA) reducing axial vibrations. The rest of bits had the Double row cutters instead.

Figure 23. Bit dull-picture, SFG75, well #1 [12]

Steel was not eroded neither by the formation or the drilling fluid, even though the bit was operated at the same WOB as the matrix-body bits (up to 14,000 lbs), higher RPM (up to 160 rpm) and higher flow rates (up to 1170 gpm). See the parameters plot below.

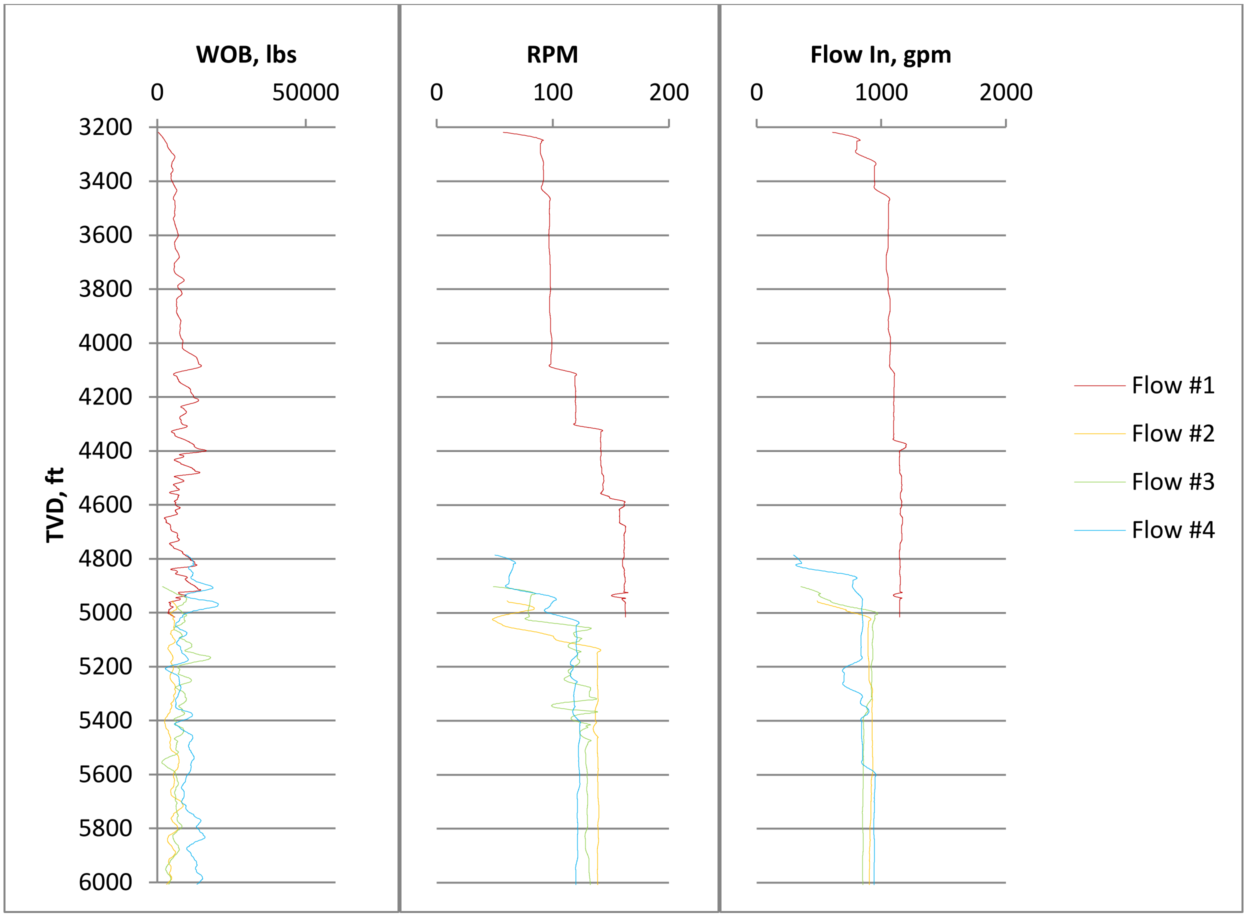


Figure 24. Drilling parameters: WOB, RPM, Flow In; wells # 1-4

A significant improvement in the steel abrasion resistance has been achieved during the last years due to innovative technologies in the "hard-facing" (now it can be applied even in the small gaps between the cutters) and enhanced Computational Fluid Dynamics. The overburden section is not abrasive, and the bit gets damaged by the impact shocks in the hard stringers. Therefore I suggest that there is a window for testing 12 ¼" PDC steel-body bits in these applications.

4.3. Bits in the wells #2, 3 and 4

It is wise to compare wells # 2, 3 and 4, because they were drilled close to each other on the Southern part of Eldfisk. The well profile for #2 and 3 was also similar with high building angles in 12 ¼" section: from 25-35° to vertical and then building in the opposite direction to 70° at the section TD.

The high-spiraling bit with a long full-drift Geo-Pilot sleeve, FXG65D, was used in the well #2. It was a successful run to TD with the second best overall ROP (83.0 fph) even though the applied WOB was lower (average around 10,000 lbs). The bit IADC code is M223: applicable for soft formations, medium-profile length. It was chosen for a better steerability. Some hole-cleaning issues reducing ROP were experienced. Probably, it can be partly addressed to the high blades spiraling. After the run the bit was damaged at the nose and taper area. This bit did not have MLFB feature while all the other bits had it.

Figure 25. Bit dull-picture, FXG65D, well #2 [12]

The matrix-body bit MMD65DH (MegaForce class) was used in the well #3. IADC code is M324: applicable for medium-hard formations, long profile. The blades on the bit were less spiral and thicker. It allowed placing more 16 mm PDC cutters at the bit face (65 versus 60 on the previous bit). The diamond volume was increased, aggressiveness was reduced, however the bit still got impact damages: chipped cutters, mostly at the shoulder. Also this bit drilled harder formations according to the density log (see Figure 22).

Figure 26. Bit dull-picture, MMD65DH, well #3 [12]

The bit center and the cone are the most ineffective areas of any PDC bit, because there cutters produce the lowest torques due to the small radius of rotation. These cutters were not damaged on the previous runs. It was proposed to try the same bit design, but with "scribe" PDC cutters at the cone: 9 circumferential cutters at the cone were replaced. The new bit design was used in the well #4, but it was operated at too high WOB (up to 32,000 lbs in the Rogaland group) and was severely damaged all over.

Figure 27. Bit dull-picture, MMD65DH, well #4 [12]

The drilling parameters for these three wells are presented below:

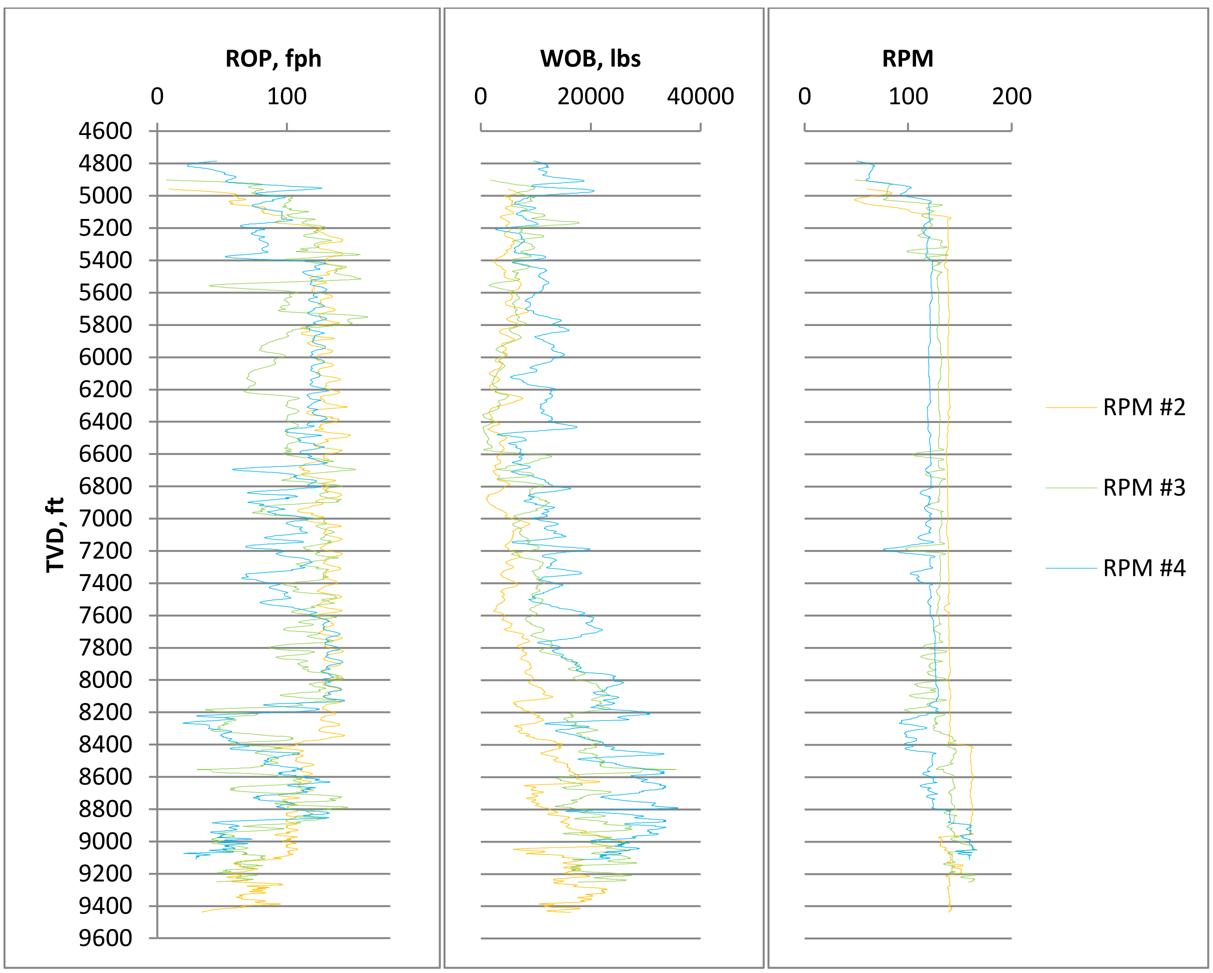


Figure 28. Drilling parameters: ROP, WOB, RPM; wells #2-4

4.4. Bits in the well #5 and the sidetrack #6

A beneficial performance of the scribe cutters at the cone was partly recognized by bit specialists and drilling engineers. It was decided to repeat this feature on the next runs in the Eldfisk-S overburden. The wellpath was different from the well #4 and less steering was required: maintaining the sail angle 27° until approximately 8200 ft TVD and then build to 74° towards the section TD. The bit was operated with similar WOB and higher RPM (140-150 rpm versus 120). After the run the bit was severely damaged.

Figure 29. Bit dull-picture, MMD65DH, well #5 [12]

A sidetrack, well #6, was drilled with the similar MMD65DH bit, but without the scribe cutters. As discussed before, the bits used in the sidetracks did not drill the shoe track. It is only drilled firm cement from 8290 ft to 8357 ft MD, where the sidetrack depth was defined. The both bits showed very close ROPs, even though the mainbore bit prior to this drilled the shoe track and 3920 ft of the mostly interbedded formations (Lower Nordland and Upper Hordaland groups). That is why the sidetrack bit was pulled with a very small dull comparing to the mainbore bit: one chipped cutter at the shoulder.

Figure 30. Bit dull-picture, MMD65DH, well #6 [12]

The WOB measured at surface is not effective, because a large part of it is absorbed by the drillstring torque (especially in deviated holes) and the under-reamer. Both BHAs had the Drilling Downhole Optimization Collar Tool (DrillDOC). It is located approximately 25 ft above the bit and measures real-time downhole weight, torque and bending moment. The first bit was operated under a higher downhole WOB (average 12,000 lbs versus 8,500 lbs) and approximately the same RPM (150-170 rm). The drilling parameters plots are presented below.

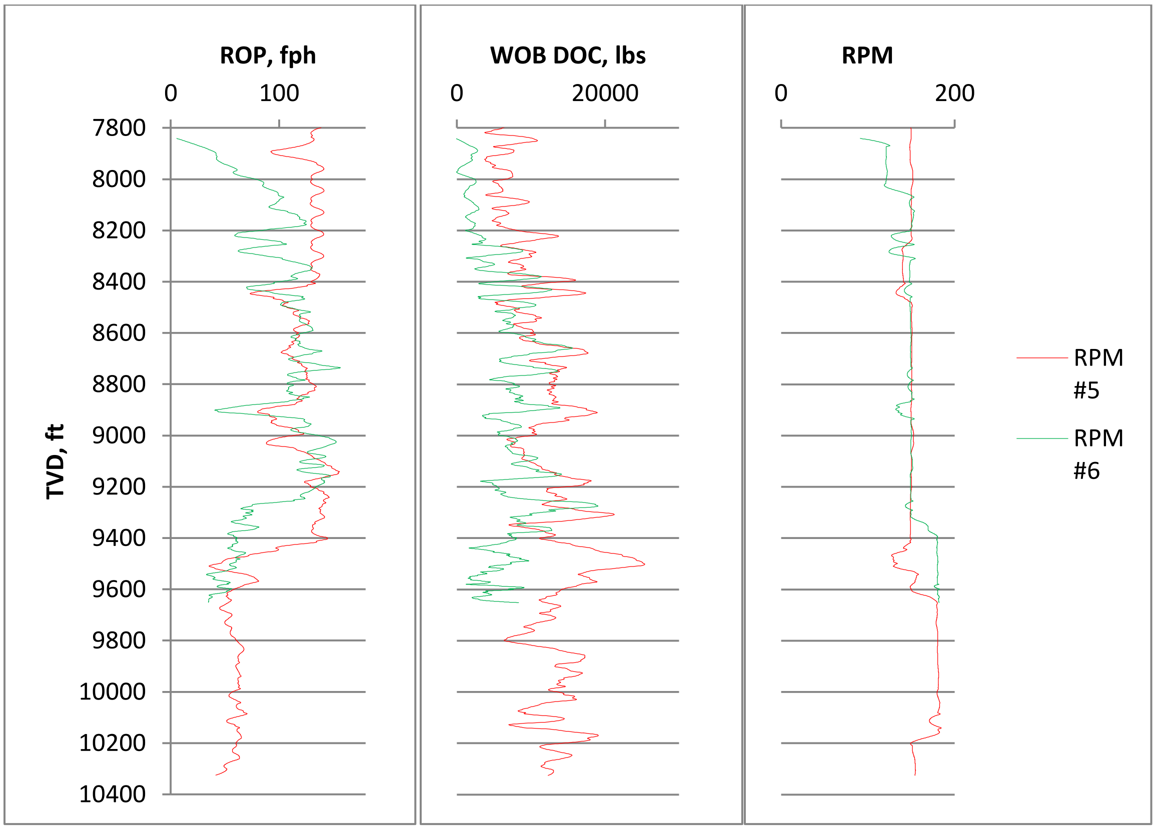


Figure 31. Drilling parameters: ROP, downhole WOB, RPM; wells #5, 6

4.5. Bits in the well #7 and the sidetrack #8

The profile of the well #7 was similar to #5 but with a higher sailing angle at the beginning, 52° instead of 27°. Due to the less steerability requirements the bit, MMD65DH with a longer gage, 4”instead of 1”, was used. The bit cutting structure was the same as on the previous run, without the scribe cutters at the cone. The problem is that the bit was operated at very erratic weights producing very erratic ROPs (even the smoothed data did not seem reliable). Average applied WOB was too high for such applications (interbedded formations with highly varying rock strength): 20,000 lbs before 7000 ft TVD and much higher after that , up to 40,000 lbs towards the end of the run. Consequently the bit was extremely dull: 3-4-BT-A-X-I-CT-TD. It was the most damaged bit among the all analyzed. However this bit also drilled the longest section, 8222 ft MD.

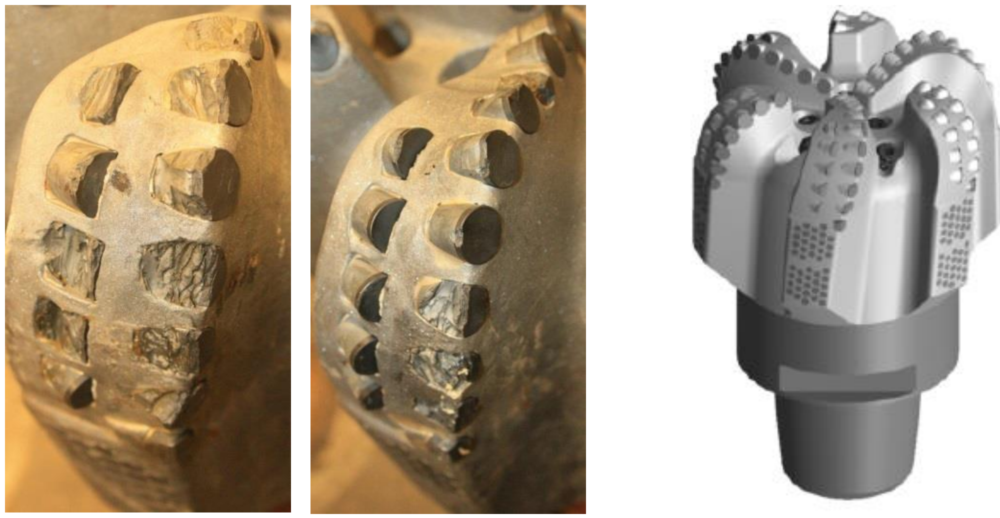


Figure 32. Bit dull-pictures, MMD65DH, well #7 [12]

The last offset well is the sidetrack, well #8. A new generation bit was used here, GT65D, GeoTech class drill bits, industry's most robust matrix body bits [3]. It employs the most impact resistance (do not mix with abrasion resistant) PDC cutters available in HDBS, type CT404. It is highly recommended for such heterogeneous formations as on the Eldfisk overburden. The bit profile and cutters layout was similar to what had been previously used: long profile bit (IADC code M324) with the scribe cutters in the center. The GTD65D bit showed the best overall ROP on the field, 102.8 fph, while the MMD65DH bit from the main wellbore achieved only 78.4 fph. At the depth 12138 ft MD, after drilling 6908 ft, the communication with the pulsar was lost and BHA was pulled out of hole. The GeoTech bit had only a few chipped cutters. However we should take into account that that bit did not drill the shoe track. Regarding the formations, this bit drilled all lithological units (Nordaland, Hordaland and Rogaland groups) including the hazard zones with the faults and hard stringers. This bit was rerun on the next BHA to complete the section to TD at 13484 ft MD without any issues.

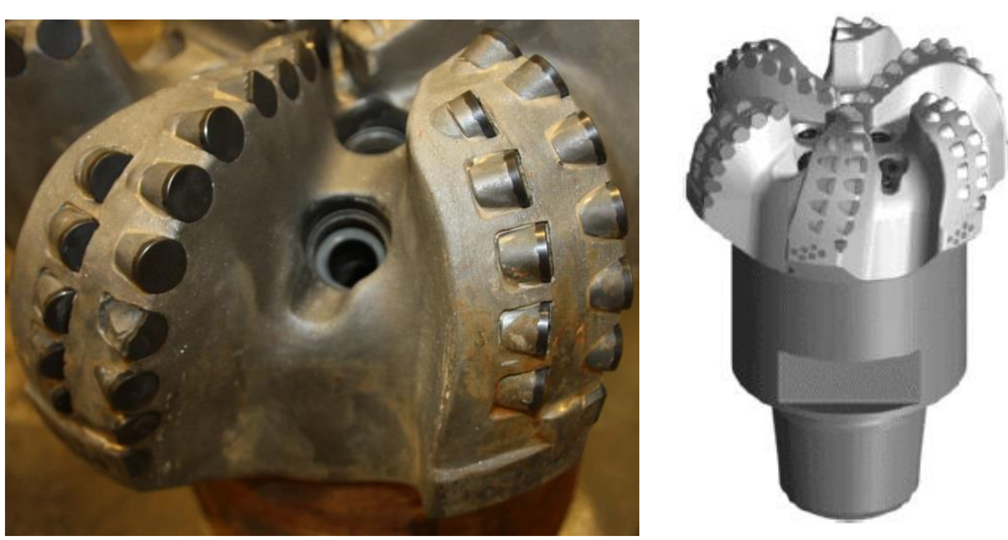
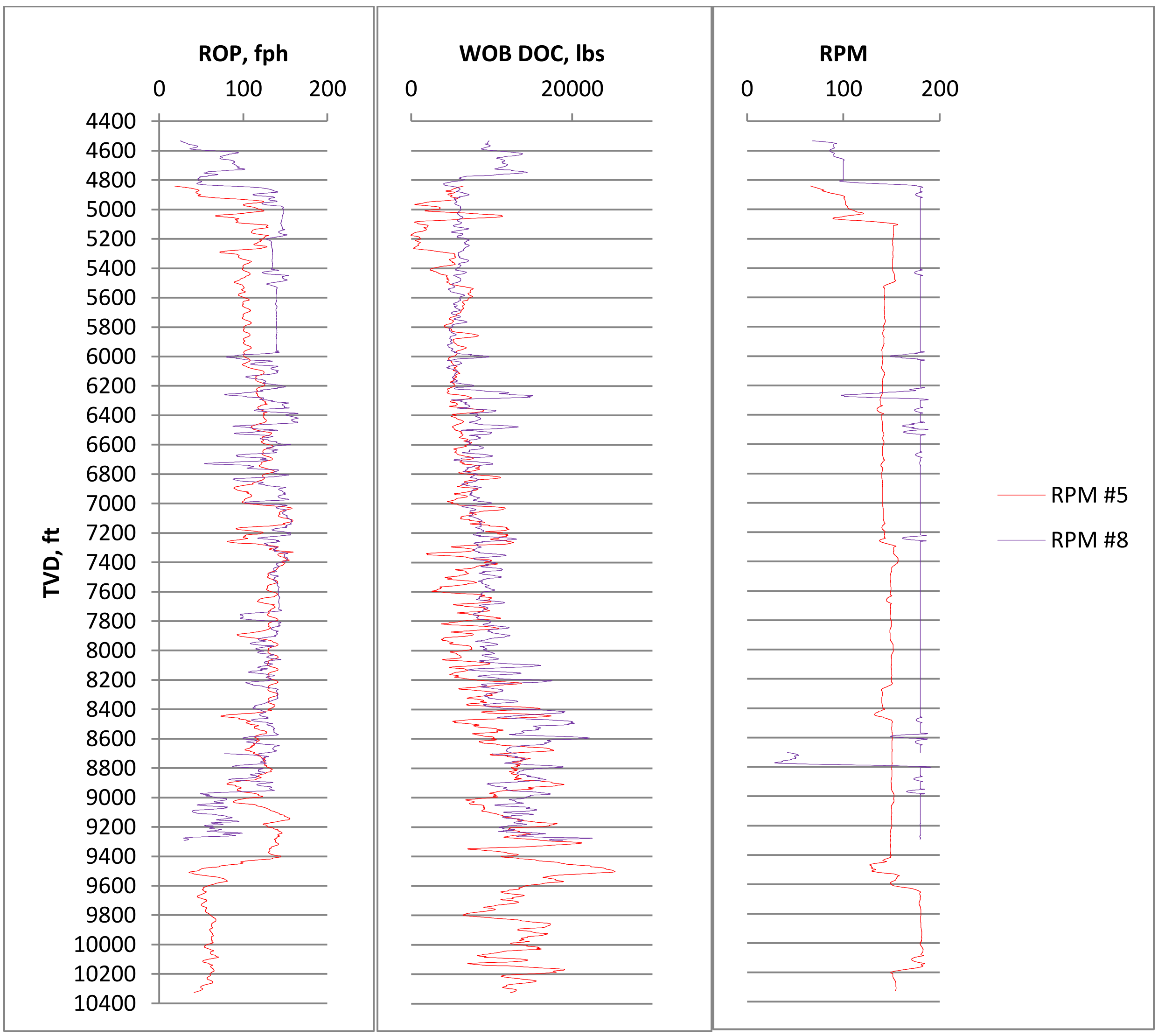


Figure 33. GT65D, well #8 [12]

Since the data from the mainbore, well #7, was not reliable, the GeoTech bit run can be compared with the well #5, where the similar bit, but the MegaForce class, was used. The overall average ROP for the GeoTech bit was better: 102.8 fph (drilled 6908 ft) versus 63.5 fph (drilled shoe track plus 6111 ft).As can be seen from the plots below, the bits were operated with similar downhole WOB (ranging from 5,000 lbs to approximately 16,000 lbs in the denser Rogaland group). The GeoTech bit was rotated faster, 180 versus 145 rpm, and produced lower downhole torques measured by DrillDOC, average 1500 f-p versus 2500 f-p. The main difference that the GeoTech bit was operated at higher flow rates, 1100 gpm versus 800 gpm, before reaching 7200 ft TVD. It resulted in much higher hydraulic jet impact force (JIF), average 4.3 versus 1.8 hsi.



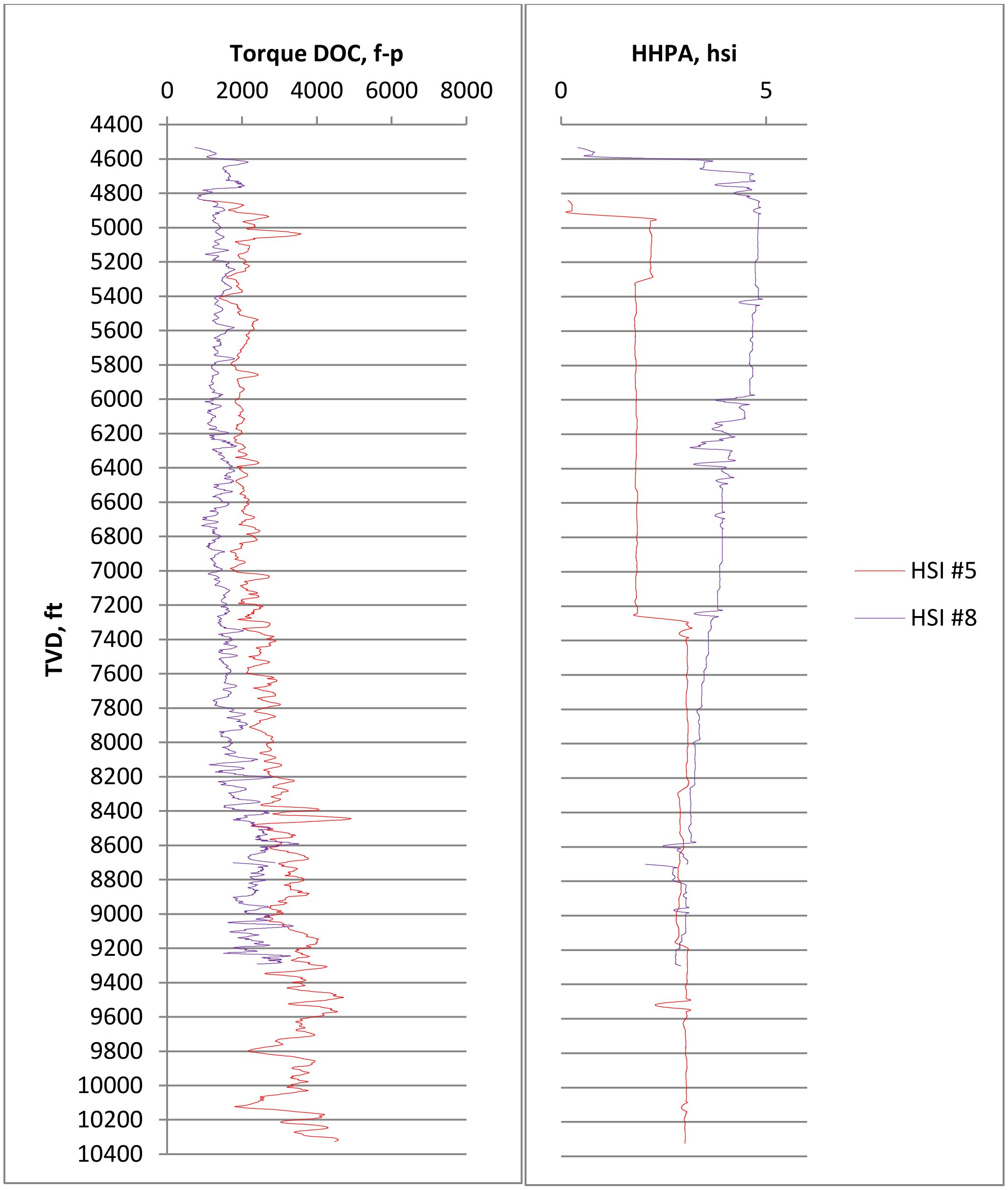


Figure 34. Drilling parameters: ROP, downhole WOB, RPM, downhole TQ, HIS (hydraulic impact force); well # 5, 8

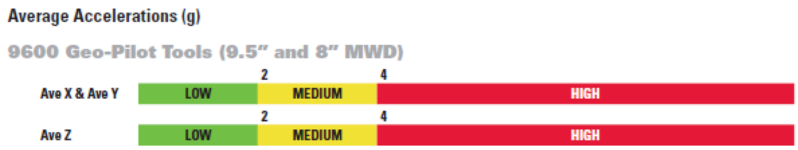
Excellent performance of the GT65D bit was recognized by bit specialists and drilling engineers. The bit had a good combination of the features recommended for both soft and hard formations and the similar design is considered for the future use in the Eldfisk overburden. It showed the best average ROP in all lithological units, except for the Upper and Middle Miocene age formations, where ROP was controlled to mitigate pack-offs issues experienced in the main wellbore.

4.5.1. Vibration analysis, well #8

The vibrations analysis of the GTD65D bit run was made using Vibration Level Analyzer, InSite Studio software. Based on the downhole data (DrillDOC measurements) the 9600 Geo-Pliot drilling BHA most of the time was under low level of vibrations, average X, Y, Z bins less or equal to 2·G, where G is gravitational acceleration. Only for the 6.6 minutes of the entire drilling run (67.2 drilling hours on bottom) the downhole vibrations exceeded the low range. See the analysis results in the figure below.

Vibration Analysis Detail Information

Vibration Tool	DDSr-DOC1
M/LWD Tool Size	8" + Geo-Pilot
Rotary Steerable Tool Size	Geo-Pilot 9600
Activity Code	Drilling
Depth Range selected	5230 to 12138
Date/Time Range selected	to
Run Number selected	800
Report Generation Date and Time	2015-06-21T16:00:36



Average X Bins

Band (G)	Bit Run (Mins)
0 to 1	2641.6
1 to 2	54.6
2 to 3	5
3 to 4	0.8
4 to 5	0.2
5 to 6	0.4
6 to 7	0
7 to 9	0
9 to 12	0
12 to 15	0.2
> 15	0

Average Y Bins

Band (G)	Bit Run (Mins)
0 to 1	2691
1 to 2	11.2
2 to 3	0.6
3 to 4	0
4 to 5	0
5 to 6	0
6 to 7	0
7 to 9	0
9 to 12	0
12 to 15	0
> 15	0

Average Z Bins

Band (G)	Bit Run (Mins)
0 to 1	2702.8
1 to 2	0
2 to 3	0
3 to 4	0
4 to 5	0
5 to 6	0
6 to 7	0
7 to 9	0
9 to 12	0
12 to 15	0
> 15	0

Figure 35. Vibration Analysis, well #8 [13]

4.5.2. Drilling efficiency analysis, well #8

Historically, Mechanical Specific Energy (MSE) has been used to evaluate and improve drilling results. It is defined as the mechanical work done to excavate a unit volume of rock. Teale proposed the following MSE equation [14]:

$$MSE = \frac{WOB}{A_B} + \frac{120 \cdot \Pi \cdot RPM \cdot TQ}{A_B \cdot ROP} \tag{4.1}$$

Where WOB – weight on bit (lbs), Ab – bit area (sqin), RPM – rotations per minute (rpm), ROP – penetration rate (fph), TQ – torque on bit (f-p)

MSE cannot be easily correlated with the rock strength: MSE is usually much higher than the unconfined compressive strength (UCS) even if the bit drills efficiently. A more comprehensive approach to estimate efficiency is the Drilling Specific Energy (DSE). It is defined as the work done to excavate and remove, underneath the bit, a volume of rock. The hydraulic related term is added to the Teale equation [14]:

$$DSE = \frac{WOB}{A_B} + \frac{120 \cdot \Pi \cdot RPM \cdot TQ}{A_B \cdot ROP} - \frac{1{,}980{,}000 \cdot \lambda \cdot HP_b}{ROP \cdot A_b} \tag{4.2}$$

Where λ – dimensionless bit-hydraulic factor (equals 0.0875 for 12 ¼” bit diameter), HPb – bit hydraulic power (hp).

Normally, the DSE data, calculated at downhole conditions, can be correlated with the Confined compressive strength (CCS). DSE for the well #8 was calculated using the DrillDOC downhole measurements. The CCS data is also available from Halliburton SPARTA software analysis, which delivers advanced rock-strength analysis and modelling. CCS was estimated for the well #7, because the drilling BHA in the sidetrack #8 did not have a minimum required set of LWD tools (the first page of the SPARTA analysis is attached in Appendix 8). Then the CCS values were correlated for the well #8 using linear interpolation method, curve fitting using linear polynomials [15]:

$$y = y_0 + (y_1 - y_0)\frac{x - x_0}{x_1 - x_0} \tag{4.3}$$

Where (x_0, y_0) and (x_1, y_1) are two known points, and y values are calculated by the corresponding values of x, where $x_0 < x < x_1$.

The estimated DSE and CCS curves are shown in the figure below:

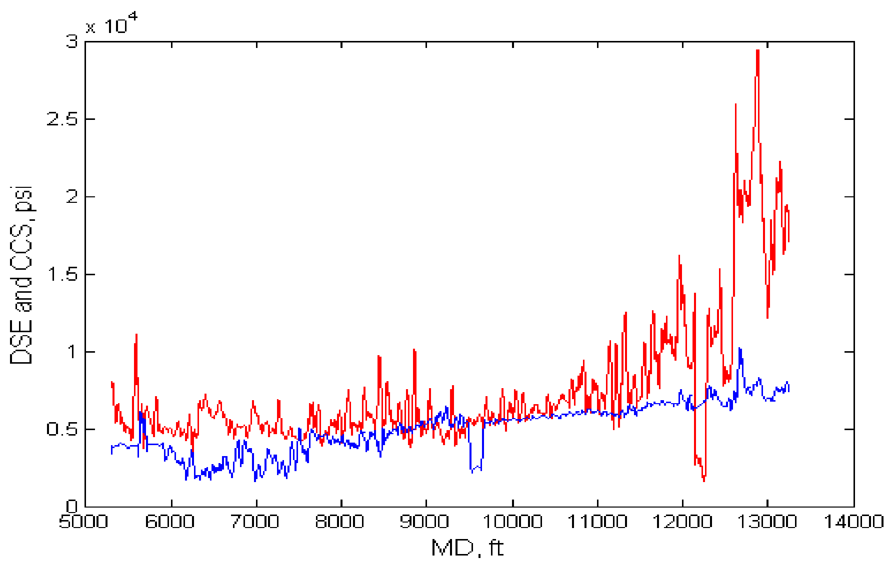


Figure 36. DSE versus CCS, well #8 [25]

The ideal drilling practices is when DSE is equal to CCS through the entire bit run. It means that all energy from the bit is efficiently transformed to shear and remove the rock.

$$Efficiency = \frac{CCS}{DSE} \cdot 100\% \tag{4.4}$$

In our case, the bit was quite efficient until approximately 10,500 ft MD (7719 ft TVD - Lower Hordaland group) – 74% efficiency. Then it dropped and resulted in 66% overall efficiency. The values were calculated in MATLAB by the area under the DSE and CCS curves (energy.m code is attached in Appendix 10). These values are only approximations, due to the measurement uncertainties (the data was filtered and correlated from the main wellbore).

5. Drill bit design optimization

PDC bits performance in the reference wells has been evaluated. This section will focus on the drilling dynamics in the challenging formations. Particularly, drill bit performance in deep overpressured shales and interbedded formations with highly varying rock strength. At the end of this section at attempt will be made to propose a modified bit solution.

5.1. PDC bits performance in deep shales

The PDC bits seem to be the most suitable for shale drilling. However they may perform unsuccessfully in deep overpressured shales. Very slow penetration rates, less than 25 fph, may appear when drilling deeper than 10,000 ft with weighted water-based mud, above 13 ppg. This is called the "plastic shale problem". The PDC bits in combination with oil-based mud are the most cost effective technology to drill these overpressured shales. The penetration rates may increase two or three times using OBM, but the plastic shale problem would still exist [19].

The Eldfisk overburden shales are not as deep and drilled faster. However the sections interbedded with hard stringers are not drilled efficiently. The suggestion might be that not only the hardness of stringers but also the effect of overpressured shales can cause ROP to drop.

5.1.1. Proposed causes of the problem

None of the main drilling variables can explain this problem alone. The shales are sensitive to the fluid properties and the bit specifications. Moreover, PDC bit performance in the overpressured shales is inconsistent, and a successful drill bit run cannot be easily duplicated [19].

The "global balling" refers to a massive balling or any large-scale packing or jamming of cuttings between the bit and the bottom of the hole. It significantly reduces the bit performance, because the forces applied to the bit (axial and torsional) are largely transmitted to the rock through the mass of cuttings rather than by the sharp cutters. In this case the bit acts like a bearing. It limits depth of cut and consequently the penetration rates.

Figure 37. Global balling of a PDC bit [1]

Oil-based muds generally prevent the global balling. The Eldfisk overburden section is drilled with the MI Swaco EMS-4600 oil-based mud. There are no indications of the global balling at the bit interface neither while drilling or when the bit is pulled to surface. Pressure While Drilling (PWD) tools only detect occasional pack-offs around drilling BHA. XR™ reamers were also observed being balled-up with the formation cuttings (wells #5 and 6).

The cutters balling is a phenomenon reducing penetration rates. It is described as an accumulation and adhesion of formation cuttings to the diamonds. They can accumulate in the form of sheared and deformed chips or as pulverized rock. Low effective pore pressure below the cuttings results in a high differential pressure pushing them to the bottom. Similar to the global balling, it reduces the sharpness of the bit and bit acts like being very dull. The minimal required force to remove the cuttings and sweep them away can be quite large due to the presence of friction forces. OBM is less prone to the cutters balling phenomenon, however does not totally prevent it. Even if the bit is pulled out of hole clean, the adherent cuttings could have been washed away while tripping out.

The wellbore pressure and overbalance conditions have its own effect on the penetration rates. The effective confining stress is the difference between the wellbore pressure and the local pore pressure in the rock in front of the bit. Laboratory research pointed that in impermeable rocks the effective confining stress is just equal to the wellbore pressure. The dilation of the shales during failure causes the local pore pressure to drop close to zero. It increases confining rock strength and reduces the penetration rates [19].

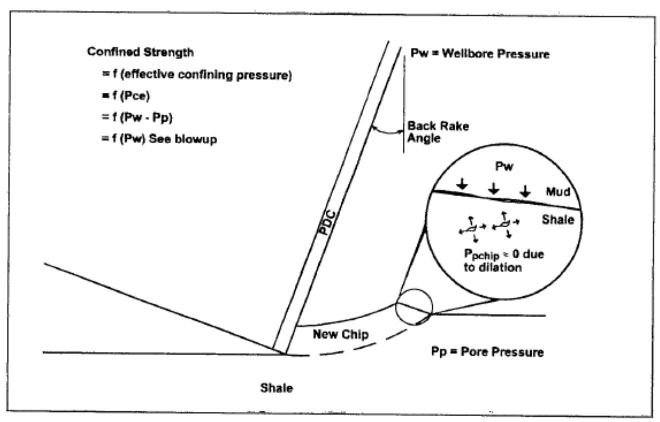


Figure 38. Wellbore pressure acting as confining pressure [19]

In addition, overbalance conditions induce the “chip hold-down” effect. It occurs when a chip, just being fractured, is hold against the bottom by the wellbore pressure. The effective pressure below the chip is low. In impermeable rocks the drilling fluid does not have enough time to pass through the chip and equalize the pressure. The chip deforms plastically under the applied weight without being ejected from the bottom. It forms a flour-like substance. The PDC cutters become much less effective, and this can result even in a zero drilling progress.

5.1.2. Proposed solution

- Smoothing of the diamond surface finish is an approach to improve PDC cutters. The normal PDC finishing is 20-40 microinches. Some experiments were conducted with the extra-polished cutters, approximately 0.5-1.0 microinches (surface becomes highly reflective). It showed much lower coefficient of friction, reducing cuttings adhesion to the diamond tables and keeping them sharp; required less axial and tangential forces to cut shales, limestones and sandstones in high-pressure conditions [20].

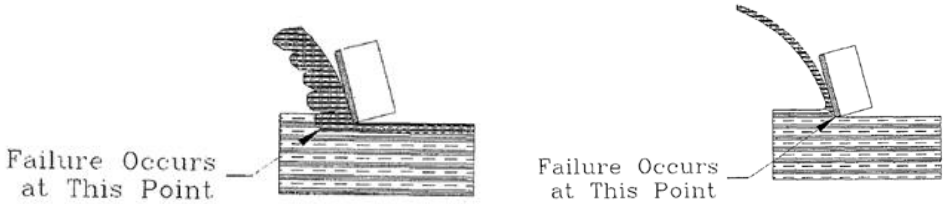


Figure 39. Cutting process with a non-polished (left) and highly-polished (right) PDC cutter [20]

- The steel-body PDC bits with a higher blade stand-off can improve cleaning around the junk slot area and prevent the cuttings jamming between the blades. The Computational Fluid Dynamics (CFD) must be applied to design the blades layout and nozzles in order to achieve the best possible cleaning.
- Even in the perfect cleaning case, the reactive clays (like Montmorillonite) would still adhere to the diamond tables, reducing the diamonds' sharpness. In addition, PDC cutters at the bit cone have much lower torques (the most ineffective part of the bit). This issue can be partly solved by utilizing "scribe" cutters which has a higher point-load at the cutter tip. It will provide a better vertical contact with the formation and induce a crushing action in addition to shearing. The scribe cutters have already significantly improved penetration rates on the Eldfisk-S overburden.

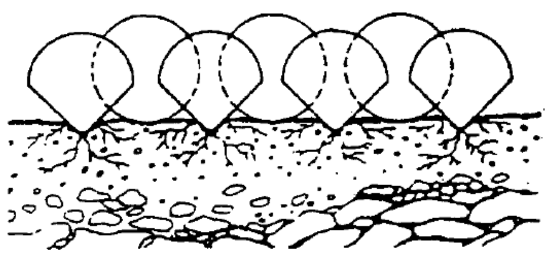


Figure 40. Scribe cutters effect [1]

- A heavy-set bit is not required because the formations are not abrasive. 6-bladed PDC bits with 16 mm cutters at the face and double row back-up cutters seem to be suitable for the applications. It is more important to ensure that the bit is stable and do not whirl. The Multi-Level Force Balancing is the "must have" feature of the cutting structure, because the bit drill highly interbedded formations with varying rock strength.
- Lower back-rake PDC cutters can be placed at the nose (10-15°) to increase the bit aggressiveness (can be slightly manipulated for purposes of Energy and Force balancing) and higher back-rake angles at the gauge (20-30°) to improve impact resistance.

5.2. Drilling interbedded formations

A drill bit for interbedded formations with varying rock strength should employ features suitable for both, soft and hard formations. However they are often in conflict: heavy-set bits reduce penetration rates in the soft formations, while light-set bits can get damaged in the hard formations. The goal is to find a combination of the PDC bit technologies that provide a solution to consistently drill interbedded formations without compromising bit selection [21].

5.2.1. Proposed causes of the problem

Impacting hard stringers with an unstable drill bit or fluctuating drilling parameters can lead to the bit failure: chipped/broken PDC cutters or broken blade. When drilling a deviated well, the nose and taper cutters are the first to collide with the hard rock. They accept the most of the weight on bit and become overloaded, while the other cutters are still in the soft formation. When leaving the stringer, it is opposite. The shoulder and gauge cutters become overloaded. This is even worse, because the gauge cutters have the largest radius of rotation increasing the inertia of the impact [21].

In addition to that, the bit whirling in hard rocks (frontward and backward) can also cause a premature failure. The worst case if a critical failure occurs close to the section TD, then it will require a longer tripping time out & in to complete the section.

Majority of the 12 ¼" PDC bits utilized in the overburden section on Eldfisk-S were very dull after the runs: chipped and broken cutters all over (mostly on the shoulder and gage), the wear flat was not regular. This shows that the bit suffer from the impact damages in the hard, but not abrasive formations.

5.2.2. Proposed solution

- Bit profile should be designed to reduce probability of cutter damage when entering or leaving hard stringers. This effect can be minimized by designing the profile cone to be the same depth as the profile height. This makes the load distribution between all cutters more even in the transitional drilling. See the figure below [21].

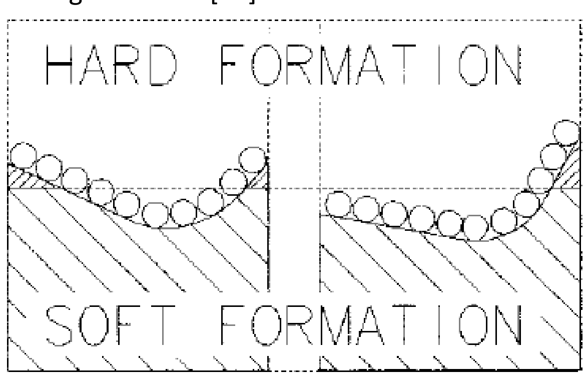


Figure 41. Matched cone and short external profile [21]

- Longer profiles are more stable, but have a lower weight per cutter. It reduces the bit aggressiveness. MMD65DH and GTD65D bits had a long profile (IADC code M324) and Dual Row Backup Cutters (exposed) – 83 PDC cutters in total. The diamond volume was relatively high. Even then the primary row cutters were severely damaged. Probably, CIA or MDR cutters could reduce impact shocks. However they are passive elements, and bit would drill much slower if the primary PDC cutters suddenly get broken or chipped.
- Larger cutters are more prone to impact damages in hard formations. The cutter count is reduced, and the failure is more critical since there are less redundant cutters to compensate for it. The bits with medium-size PDC cutters are recommended, 16mm. They were used in the Eldfisk overburden. A lower cutter size can increase the impact resistance but will definitely reduce the bit efficiency in the shales.
- The cutters technology and materials are highly important. The GeoTech bit with the new generation “non-leached” cutters, type CT404, recently drilled the section with the record ROP (102.8 fph) and showed a very little dull (only a few chipped cutters). Actually, development of new more wear and impact resistant PDC cutters is the most essential goal in the drill bits market.
- Steel is a stronger and tougher material than the tungsten carbide. It should be more appropriate for the environments where high shock loads are expected. There is a theory that, due to the steel elasticity, the impact loads get transmitted from the cutters and absorbed by the body (tungsten carbide does not have such damping effect). This, in combination with controlled WOB and RPM, should reduce the PDC cutters damage.
- Lateral and torsional bit vibrations (stick-slip, whirling and chattering) damage PDC cutters. But according to the vibration analysis (Figure 38), only low levels were detected on the GTD65D bit which is similar to the rest of the MMD65DH bits.

5.3. Proposed drill bit design

The integration of multiple features in a single bit design is a challenging task: some bit features may be difficult to combine with others. Therefore a compromising bit design should be chosen.

After the performed offset analysis and study of drilling challenges, I assume that the following bit type should be more suitable for the Eldfisk overburden section: SFD65D, SteelForce class, material number 958508 (specifications sheet is attached in Appendix 6).

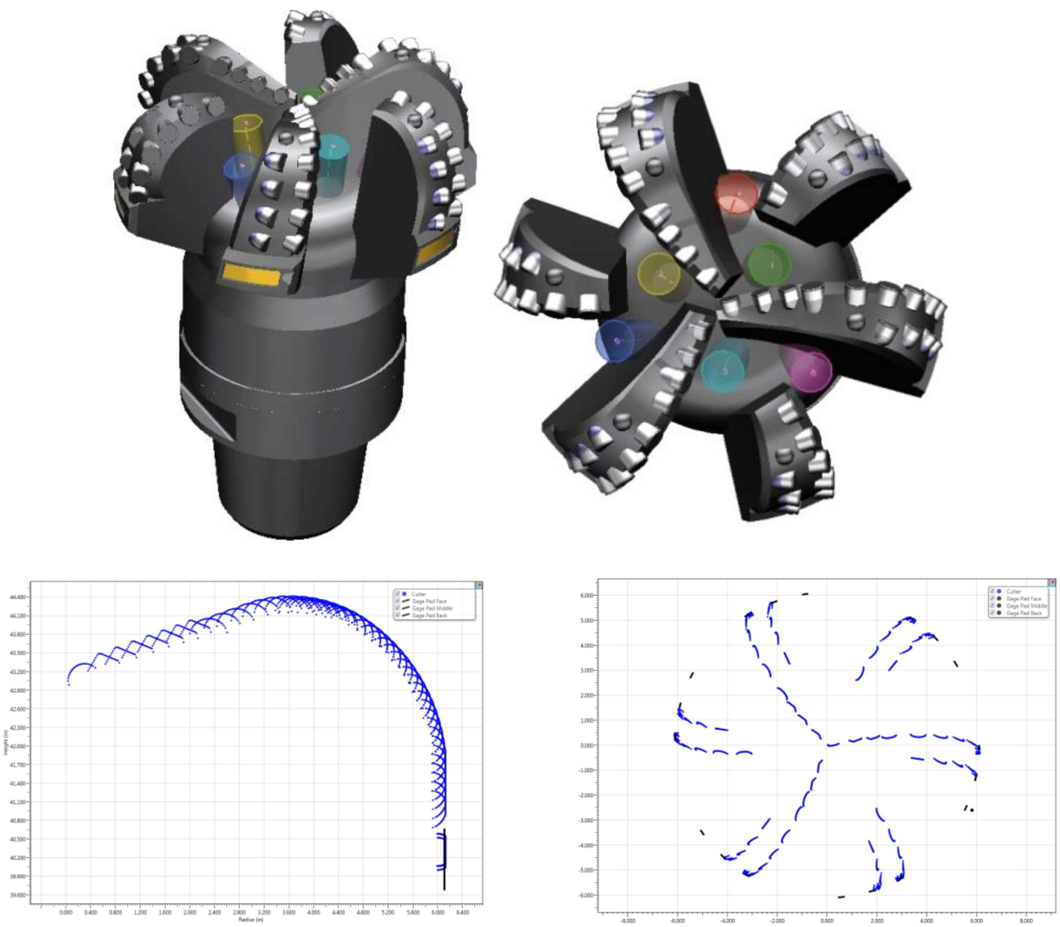


Figure 42. bit pictures, section view (left) and top view (right), SFD65D [22]

The 12 ¼” SFD65D steel-body PDC bit design (958508) is based on the matrix-bofy bit GTD65D (941512) used in the well #8. I assume that the change from matrix to steel should solve mentioned drilling issues and improve drilling efficiency. The two bits are compared in the table below and advantages of the proposed bit design are outlined.

	GTD65D (941512)	SFD65D (958508)	Advantages of SFD65D
Body material	Tungsten carbide + welded steel pin connection	single steel piece with applied "hard facing" and anti-balling coating	More strong and ductile material : • Absorb shocks from the cutters • Less prone to cracks propagation and breakage Reduce bit balling by producing an electronegative charge
Cutters • Primary face • Secondary face • Primary gage • Secondary gage • Drop-ins	CT404 type (total 83 cutters) • 41 x 16 mm • 24 x 16 mm • 6 x 16 mm • 6 x 16 mm • 6 x 13 mm	CT404 type (total 75 cutters) • 45x16 mm • 18x16 mm • 6 x 16 mm • 6 x 16 mm • 6 x 13 mm	Similar cutting structure, however with less back-up cutters due to smaller blades width.
Gauge configurations	1" long at 1/32" undercut	1" long at 1/32" undercut	
Make-up length	12.74"	9.26"	Results in smaller tilt length (using Geo-Pilot 9600) and better steerability
Blades • Height • Width	6-blades • 2.26" • 2.02"	6-blades • 4.26" • 1.72"	Blades height increases 88.5%, width decreases 15%
Hydraulics: • Junk Slot Area (JSA) • Normalized Face Volume (NFV) • Nozzles	CFD is applied • 31.65 sqin • 50.1% • 9 sideport nozzles	CFD is applied • 50.35 sqin • 68.81% • 6 Sideport nozzles	JSA Increase 59%, NFV increases 37% (more area and volume for cuttings removal). Improve cleaning and mitigate bit/cutters balling. Less count of nozzles allow to place Larger-size nozzles with the same TFA. It is less prone for nozzles plugging and reduces bit pressure drop.
Other features	• Scribe cutters at cone • MLFB	• Scribe cutters at cone • MLFB • 6 x CIA at nose	• Improve efficiency by adding crushing action • Reduce imbalance force and bit vibrations • Depth of cut control reduce impact shocks

Table 6. Comparison of SFD65D with GTD65D

In addition, based on the performed DxD analysis (Direction by Design) the SFD65D bit should produce lower torques and have a better steerability. The imbalance force will be slightly higher under the simulated conditions, 107.1 lbf versus 104.4 lbf. See the analysis results on the figure below:

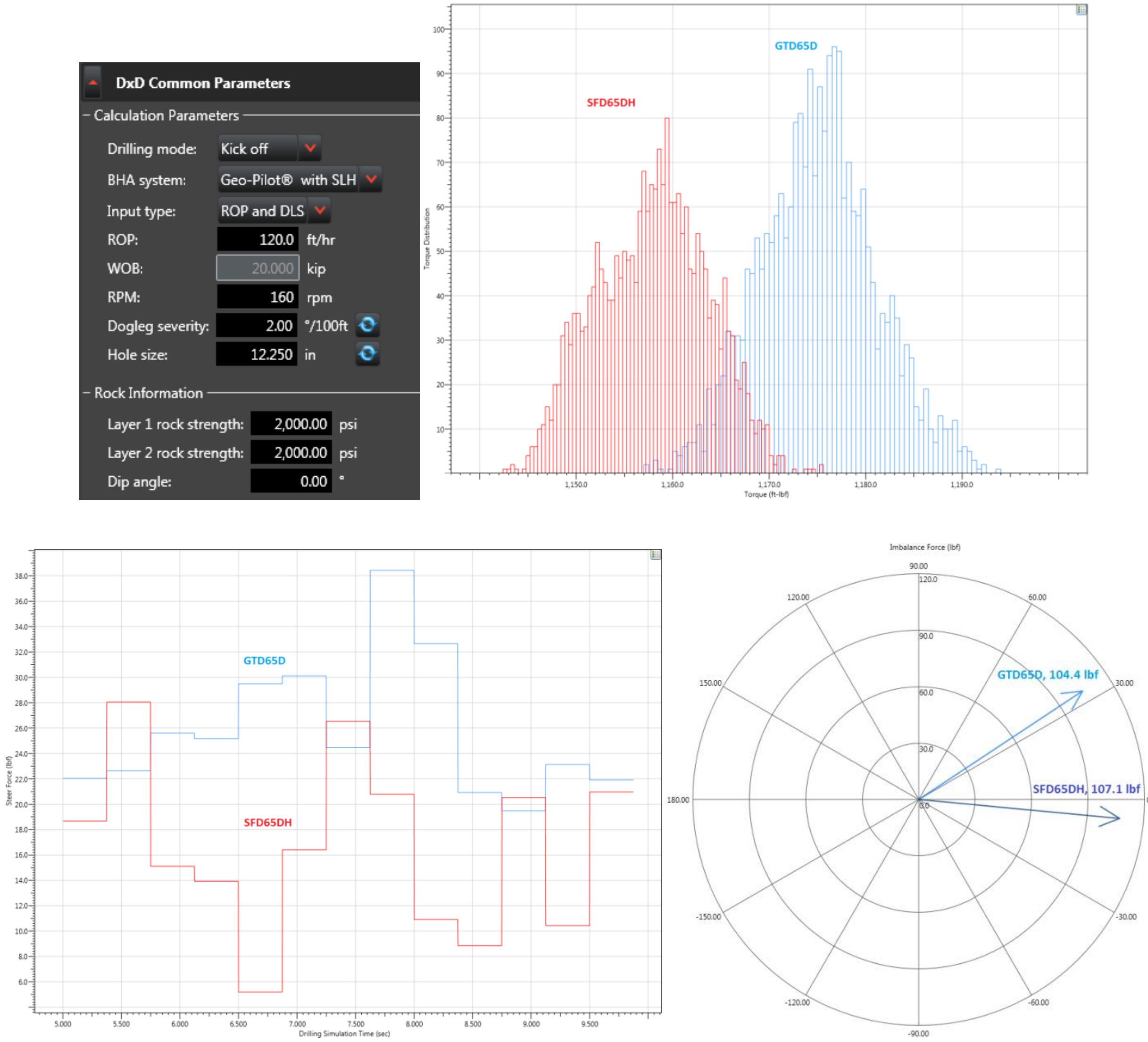


Figure 43. DxD analysis: Input parameters (top left), Torque distribution (top right), Bit steerability (bottom left), Imbalance force (bottom right) [DrillingXpert software]

However the SFD65D bit (958508) is a new design and was used only once in the Ekofisk field (the overburden section on Ekofisk is less hazardous than on Eldfisk: softer stringers, smaller count, less gas concentration and less pack-off issues). From the beginning of the run a wash-out in the drilling BHA was detected. Therefore the bit was operated not at the optimal hydraulic level. At 10575 ft MD, the run was terminated due to the suspected washout. The bit drilled 5169 ft (vertical depths 5187 – 9504 ft TVDSS) with overall ROP of 66 fph and was grades as 2-2-CT-S-X-I-BT-DTF.

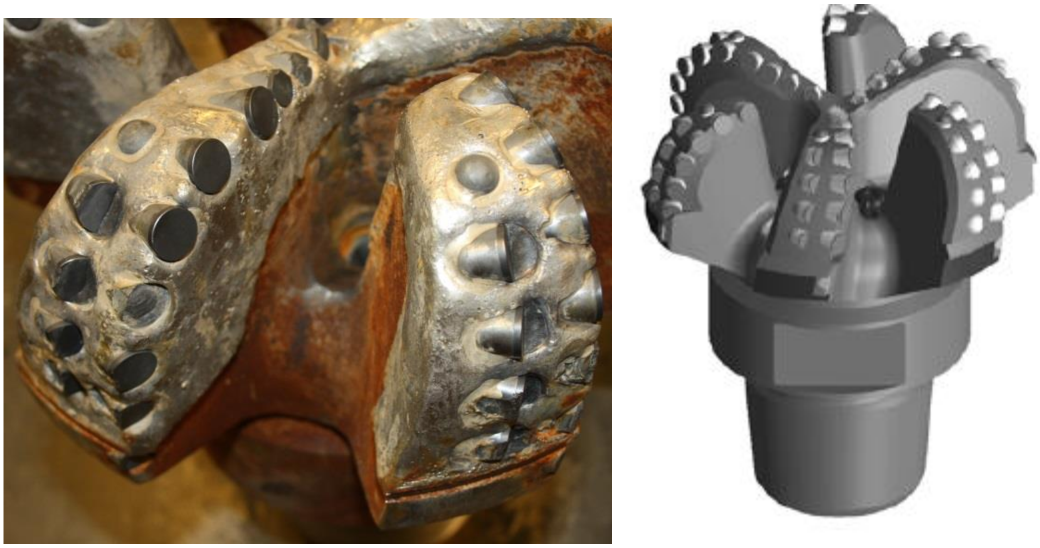


Figure 44. Bit dull-picture, SFD65D, used on Ekofisk overburden [12]

In addition, the steel-body bits are recognized to be more efficient for the shoe track drill-out due to the higher JSA and NFV that is beneficial for cleaning and removing junk aluminum and other debris of the shoe track system [22].

6. Drilling parameters optimization

As has been mentioned previously, performance of PDC bits in the overbalanced shales interbedded with hard stringers is very inconsistent and a successful drill bit run cannot be easily duplicated. There are no clear routines to identify the most valuable parameters in optimizing drilling efficiency. Therefore an idea of fitting drilling data to an empirical ROP model seems challenging and requires a high accuracy data. An attempt to filter the data and to develop an ROP model for the Eldfisk overburden will be made in this section. The question to be answered is whether or not ROP can be easily predicted and controlled in such interbedded formations as the Eldfisk overburden.

The steel-body PDC bit, SFD65D, proposed for the Eldfisk-S overburden in the last section, employs the cutting structure similar to the bits MMD65DH and GTD65D (scribe-cutters at the cone) used in the wells # 4,5 and 8. Therefore these bit runs are chosen as the offset wells for the development of the ROP model.

6.1. Rate of penetration

Rate of penetration is the most valuable drilling optimization objective. Rig time is a large portion of the total well cost. There is a high cost saving potential in improving ROP, especially in expensive offshore drilling operations. Despite this, the bit-rock interaction is not well understood. The drilling data and predictive models cannot provide definitive values for penetration rates. There are high uncertainties even in well-known formations. For example, other aspect of rotary drilling, torque & drug phenomena can be easily managed by means of quantitative modelling [23].

A.T. Bourgoyne identified six the most important variables affecting the penetration rates [9, p.352]:

1) Bit type, as discussed previously in this paper, has a large effect on drilling efficiency, stability and steerability. The two most important bit factors are aggressiveness and durability (light-set and heavy-set bits).Also mechanical- and hydraulic-design modifications can improve the bit performance.
2) Formation characteristics: the elastic limit and ultimate strength are the most important parameters. Permeability also has an effect. In impermeable rocks drilling-fluid does not penetrate through formation ahead of the bit and does not equalize the pressure differential. The overbalance conditions tend to reduce ROP. The minerals composition is also important. Hard and abrasive minerals can cause rapid bit dulling, and clay minerals – bit balling.
3) Drilling-fluid properties: penetration rates tend to decrease with increasing mud density, viscosity, solid content and decreasing filtration rate. They control the pressure differential across the crushed rock and the viscosity controls parasitic frictional forces. In addition the fluid chemical composition effects bit-balling.
4) Operating conditions: increasing weight on bit and rotation speed normally increase penetration rates until a certain point (see figure below). There are several theoretical equations relating

operational conditions to changes in ROP. Generally, fixed cutter bits require lower WOB and higher RPM than Roller-cone bits.

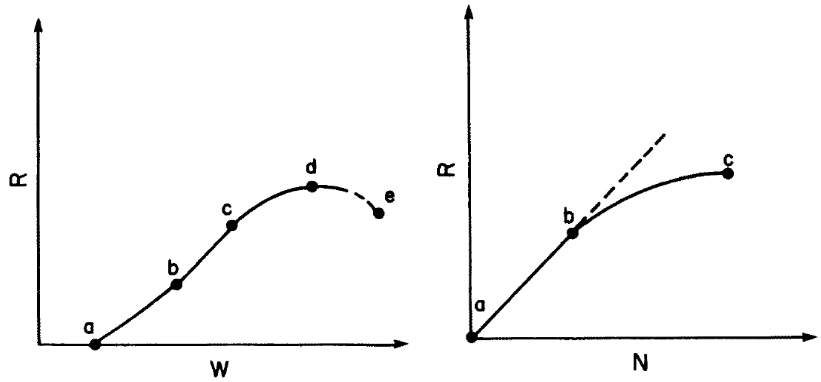


Figure 45. Relation between ROP and WOB, ROP and RPM [9, p.355-356]

5) Bit tooth wear: bits tend to drill slower with increasing cutting structure wear. Two main types of PDC cutters wear are worn teeth or chipped/broken teeth.
6) Bit hydraulics: higher penetration rates can be achieved with an improved jetting action through bit nozzles. It can promote better cleaning of the cutters and junk slots and increase jet impact force on formation.

6.2. Limited use of mud-logging data

Mud logging involves rig-site monitoring and assessment of information coming to surface while drilling and data from downhole sensors. The drilling parameters that are collected and stored in the mud log include rate of penetration, pump rate, stand pipe pressure, weight on bit, rotary speed, rotary torque and some others [24].

The traditional mud logging data suffers from errors and poor quality. Before the quality is improved, it is difficult to make a quantitative use of the mud-logging data, for example to fit the data to an ROP model. It would be very difficult to quantify the effect of different variables on the penetration rates [4].

The quality of the mud-logging data is directly dependent on the accuracy of the sensors measuring physical quantities and transforming them to a digital signal. For example, the hookload sensor is mounted on the dead line anchor and represents only an indirect measurement of the hook load. It is disturbed by changes in travelling mass, accelerations of travelling block, wire cables vibrations. The torque sensor is another example of a sensor that suffers from poor quality. It provides indirect torque measurements by multiplying the current in the top-drive motor by a converting factor, where non-linear motor characteristics are neglected.

The weight on bit is a key variable for understanding drilling process and interpreting ROP. A high accuracy WOB data is essential for developing an ROP model. The current way of determining WOB is not very accurate. It is calculated as the difference between a reference and an actual hook loads. The reference load is the sum the buoyed string weight and the travelling mass when rotating off bottom. There is a lack of procedures updating this reference value that cause uncertainties in the recorded WOB [4].

Accuracy of measurement depth data is directly related to the accuracy of the short term ROP. There are three main error sources in the depth measurements: 1) errors in the pipe tally, 2) errors in the swivel height and 3) lack of correction terms for the drillstring elongation (tensional stretch, ballooning effect, thermal expansion). Neglection of these errors requires strong filtering or long averaging intervals [4].

The data acquisition includes filtering, sampling, scaling, post processing and storing the data. If the signal contains significant frequency components, it can cause an aliasing effect. Therefore a proper filtering is necessary. Although not every signal contains high frequencies, it is important to apply the identical filters to all variables to be stored. This is required because an occasional filter will always introduce a phase shift between the recorded variables.

6.2.1. Data-filtering

Feet-by-feet surface mud logging data was collected using Halliburton InSite Studio software (data-set example is attached in Appendix 10).

The raw data contained high-frequency components, mainly in ROP and WOB values. Several filters were applied to the entire data-set for the outliers and noise removal (MATLAB code smooth.m is attached in Appendix 11) [25]:

1) Median filter: filters the values by going through the chosen list of values and replaces each value with the median of the current value and its neighbors. It is most efficient for the outliers' removal, because it does not mix the values, but simply delete them. The filter with a 3-values range was used to remove single outliers.
2) Average filter (mean filter): filter the values by going through the chosen list of values and replaces each value with an average of the current value and its neighbors. The average filter with 5-values range was applied in order to smooth smaller outliers left after the median filter.
3) Low-pass filter (exponentially weighted moving average filter): filters by letting the low-frequency signal to pass and attenuates the higher-frequency signals (gradual loss in intensity). The Savitzky-Golay filter (type of low-pass filter) was applied in MATLAB to remove the noise and smooth the data. This is achieved, in a process known as convolution, by fitting successive sub sets of adjacent data points with a low-degree polynomial by the method of linear least squares [26]. Inputs used for the filter are: polynomial order = 2, frame size = 65.

The quantitative use of mud-logging data was significantly improved. However the information about the high-fluctuations that may also contain valuable data was lost. The original and filtered data plots for the well #8 are presented below:

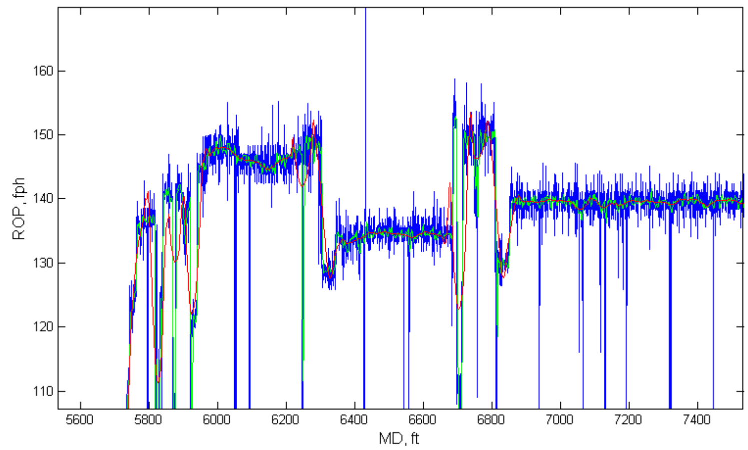


Figure 46. Data filtering: raw data (blue), outliers' removal (green), noise removal (red); well #8

As mentioned before, the WOB and torque values estimated at surface are not the direct measurements. The effective downhole measurements were recorded with the DrillDOC tool located approximately 25 ft above the bit. These values are normally lower, because they are measured at the bit interface and do not cover the entire drillstring. The differences between the surface and downhole readings are presented on the figure below.

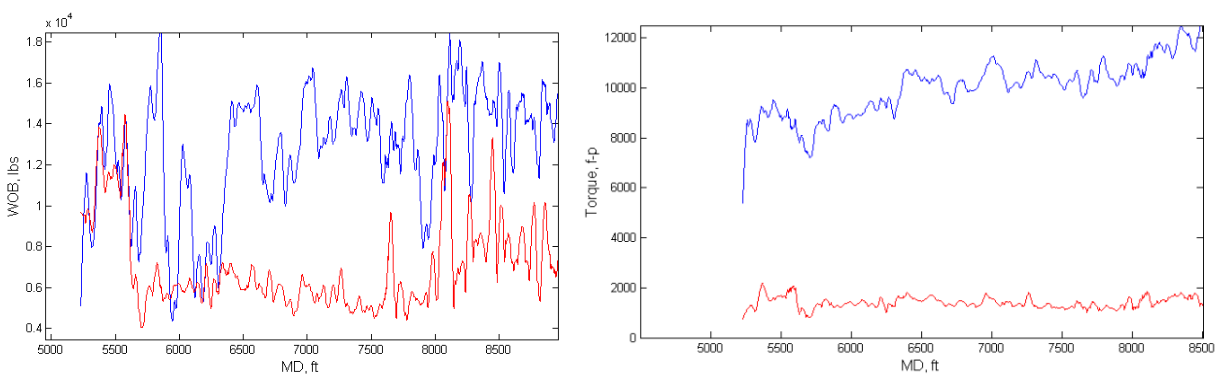


Figure 47. weight on bit (left) and Torque (right): surface (blue) and downhole (red) readings; well #8

6.3. Development of drilling model

Over the past decades variety of different models has been proposed for the rotary drilling optimization. They made possible to select better operational conditions. Perhaps, the most complete mathematical model so far is the one designed by A.T. Bourgoyne and F.S. Young. It is an empirical model derived through a multiple regression analysis (MRA) of the drilling data taken over short intervals [27]:

$$ROP = Exp(a_1 + \sum_{J=2}^{8} a_i x_i) \tag{6.1}$$

Where Exp indicates exponential function, a_i – constants, x_i – drilling parameters

The modelling of penetration rate in a given formation type is completed by selecting constants a_1 through a_8 using a linear multiple regression analysis (MRA) technique. It attempts to model the relationship between two or more explanatory variables and a response variable by fitting a linear equation to the observed data.

- The coefficient a_1 primary represents the effect of formation strength, and also takes into consideration effects of some drilling parameters not included to the model, e.g. mud type, solids content. This coefficient is commonly called formation drillability.
- The functions x_2 and x_3 are used to model the effect of compaction. $x_2 = 8000 - D$, assumes an exponential decrease in ROP with increasing depth in a normally compacted formation (8000 ft TVDSS is chosen as normalized depth for the Eldfisk overburden). $x_3 = D^{0.69}(p_p - 13.5)$, assumes an exponential decrease in ROP with increasing pore pressure gradient. These two functions produce 1.0 for pore pressure gradient of 13.5 ppg at depth of 8000 ft.
- The function x_4 describes the effect of the differential pressure: $x_4 = D(p_p - p_c)$. It assumes an exponential decrease in ROP with an overbalanced bottomhole pressure. The function x_4 has value of 1.0 with a zero-overbalance.
- The function x_5 models the effect of WOB and the bit diameter. Bourgoyne and Young considered the use of their model for roller-cone bits. In order to fit the model for PDC bits the term x_5 should be corrected. The relation between mechanical and critical weights for PDC bit can be presented as following [28]:

$$x_5 = \ln\left(\frac{\left[\frac{W}{d}\right]_m}{\left[\frac{W}{d}\right]_c}\right) = \ln\left(\frac{C_r\left[\frac{W}{d}\right]_a - 0.942 \cdot \Delta P_b \frac{d-1}{d}}{\left[\frac{W}{d}\right]_c}\right) = \ln\left(\frac{C_r W_a - 0.942 \cdot \Delta P_b (d-1)}{d\left[\frac{W}{d}\right]_c}\right) \tag{6.2}$$

$$\Delta P_b = \frac{q^2 \rho}{12031 \cdot A_n^2} \tag{6.3}$$

  The coefficient C_r represents the weight split between the 12 ¼" drill bit and 13 ½" under-reamer. It is calculated for different rock strength and applied weight and equals to 93±3%. It is calculated using Halliburton software, Precise Bit Reamer (analysis results are attached in Appendix 9). The mechanical weight on bit is composed of the measured weight minus the hydraulic pump-off force. This force is resulted from the hydraulic differential pressure across the bit and significantly unloads the cutting structure [28]. The chosen normalized WOB value for PDC bits is 800 lbs/in. The coefficient 0.942 appeared to be too high, probably due to hydraulic friction losses and flow split at XR-reamer; therefore it was reduced by 1/3.
- The function x_6 represent the effect of rotary speed and is defined as $x_6 = \ln(N/160)$. The chosen normalized rotary speed is 160 rpm. It means that the functions x_5 and x_6 will produce 1.0 under the normalized drilling parameters: 8,00 lbs/in estimated mechanical weight and 160 rpm rotary speed.

- The function $x_7 = -h$. It is the tooth height that has been worn away. The worn out height can be predicted by a separate model described later in this paper.
- The term x_8 represents the effect of hydraulics. Hydraulic power per square inch (hpsi) is chosen as the main parameter and the normalized value is 2.0 hpsi. Actually, the hydraulic effect can be linked to other parameters such as the jet impact force or nozzle Reynold number.

$$x_8 = \ln\left(\frac{P_H/A_b}{2.0}\right) \tag{6.4}$$

$$P_H = \frac{\Delta P_b q}{1{,}714} \tag{6.5}$$

Where D – depth (ft TVDSS), p_p – pore pressure (ppg), p_c – equivalent circulation density (ppg), W_a – average surface WOB (lbs), W_c – critical/normalized WOB (lbs), W_m – mechanical WOB (lbs), d – bit diameter (inch), A_n – Nozzles total flow area (sqin), A_b – Bit area, ΔP_b – bit pressure drop (psi), P_H – Hydraulic power (hp)

The functions presented above define the general relations between the penetration rate and other variables. The constants a_1 through a_8 must be determined based on the offset drilling data using MRA technique.

Theoretically only eight data points are required to compute the eight coefficients. However they will not be accurate if the data contain uncertainties. Therefore a larger number of data points is necessary. Practically a depth interval of 2 to 5 ft gives appropriate data and keeps it in a reasonable range. The number of the data points is dependent on the amount of the input values [27], see the table below:

Parameter	Minimum range	No of parameter	Minimum No of points
X2	2,000	8	30
X3	15,000	7	25
X4	15,000	6	20
X5	0.40	5	15
X6	0.50	4	10
X7	0.50	3	7
X8	0.50	2	4

Table 7. Recommended Minimum data ranges for Regression analysis.

6.3.1 Bit wear model

PDC bits often get damaged after drilling the shoe track. The main objective of this Master thesis is the drilling optimization of the overburden formations. Therefore one important assumption is made: bits have a 0.2 rational wear on the cutting structure after drilling the shoe track.

Bourgoyne and Young developed a model for the Roller-cone bits tooth wear predicting the bit conditions at any time. The model combines the effect of tooth geometry, bit weight and rotary speed. The instantaneous rate of tooth wear is given by [27]:

$$\frac{dh}{dt} = \frac{H_3}{\tau_H}\left(\frac{N}{100}\right)^{H_1}\left[\frac{\left[\frac{W}{d}\right]_{max} - 4}{\left[\frac{W}{d}\right]_{max} - \frac{W}{d}}\right]\left(\frac{1 + H_2/2}{1 + H_2 h}\right) \tag{6.6}$$

Where h – fractional tooth wear, $H_{1,2,3}$ – bit related coefficients, τ_H – formation abrasiveness constant.

To make this model applicable for PDC bits some adjustments should be made:

$$\frac{dh}{dt} = \frac{H_3}{\tau_H}\left(\frac{N}{160}\right)^{H_1}\left[\frac{\left[\frac{W}{d}\right]_c}{\left[\frac{W}{d}\right]_m}\right]\left(\frac{1 + H_2/2}{1 + H_2 h}\right) \tag{6.7}$$

To estimate the formation abrasiveness factor τ_H, a parameter J_2 is introduced:

$$J_2 = \frac{1}{H_3}\left(\frac{160}{N}\right)^{H_1}\left[\frac{\left[\frac{W}{d}\right]_m}{\left[\frac{W}{d}\right]_c}\right]\left(\frac{1}{1 + H_2/2}\right) \tag{6.8}$$

Then the equation (6.7) can be expressed by:

$$\int_0^{t_b} dt = \tau_H J_2 \int_{hi}^{h_f} (1 + H_2 h)\, dh \tag{6.9}$$

Where t_b – bit hours on bottom (hr), h_f – final tooth wear ratio

Integrating this equation results in:

$$t_b = \tau_H J_2 \left(h_f - h_i + \frac{H_2}{2}\left(h_f^2 - h_i^2\right)\right) \tag{6.10}$$

Then the abrasiveness constant can be calculated as:

$$\tau_H = \frac{t_b}{J_2\left(h_f - h_i + \frac{H_2}{2}\left(h_f^2 - h_i^2\right)\right)} \tag{6.11}$$

During a rotary drilling process the drilling parameters can vary. Therefore, to calculate the formation abrasiveness constant, the sum algorithm should be used over time intervals Δt_{bj}:

$$\tau_H = \sum \frac{\Delta t_{bj}}{J_{2j}\left(h_f - h_i + \frac{H_2}{2}\left(h_f^2 - h_i^2\right)\right)} \tag{6.12}$$

Also assume that the H-coefficients from Inserts bits can be used for PDC bits: $H_1 = 1.50$, $H_2 = 1$ and $H_3 = 0.02$ [27]. Then from equation (6.12) it is possible to compute the PDC cutters wear at any time:

$$h_j = \sqrt{1 + \frac{2 \cdot t_{bj}}{\tau_H \cdot J_{2j}} + 2h_{j-1} + h_{j-1}^2} - 1 \tag{6.13}$$

Where h_j – tooth wear at point j, h_1 – initial tooth wear (equals zero, if shoe track was not drilled)

6.3.2 Formation abrasiveness constant

Prior to estimating the Formation abrasiveness constant τ_H, we need to define the final rational PDC bits wear, h_f, based on the dull-characteristics and dull grading pictures. Then the formation abrasiveness constant is estimated using equation (6.12) (MATLAB code wear.m is attached in Appendix 14).

Well	Bit type	Dull characteristics	Initial toot wear	Final tooth wear, hf	abrasiveness constant, τ_H
#4	MMD65DH	2-2-CT-A-X-I-WT-TD	0.2 (drill-out)	0.35	12.0
#5	MMD65DG	2-3-CT-S-X-I-WT-TD	0.2 (drill-out)	0.30	25.2
#8	GTD65D	1-1-BT-T-X-I-WT-TD	0	0.10	38.0

Table 8. Rational tooth wear

The tooth wear plots for each run are presented below:

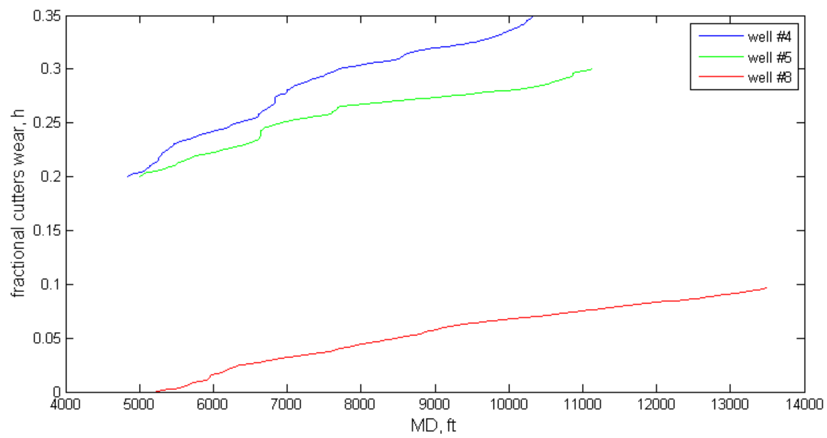


Figure 48. Fractional tooth wear, wells 4, 5 and 8

The average formation abrasiveness factor is equal 25±13.

6.3.3 Model simulations

The set of parameters x_1 through x_7 has been calculated using the equations presented in the paragraph 6.3.1. The data for the wells #4, 5 and 8 contained 5510, 6107 and 8251 data points correspondingly. As recommended by Bourgoyne, the data was then sampled with 5 ft interval, and the predictors x_1 through x_8 were calculated. MRA was performed in MATLAB using the function *lsqlin* (code regress.m is attached in Appendix 15), which solves least-squares curve fitting problems with bounds or linear constraints [29]. This function was used instead of the standard *regres* function, because it allows limiting the a-coefficients ranges. It is required because the negative or positive effects of the different variables are already included into the predictors x_1 through x_8. The coefficients a_1 through a_8 were obtained: 4.38, 0.00019, 0.00067, 0, 0, 0.13, 0, 0.32.

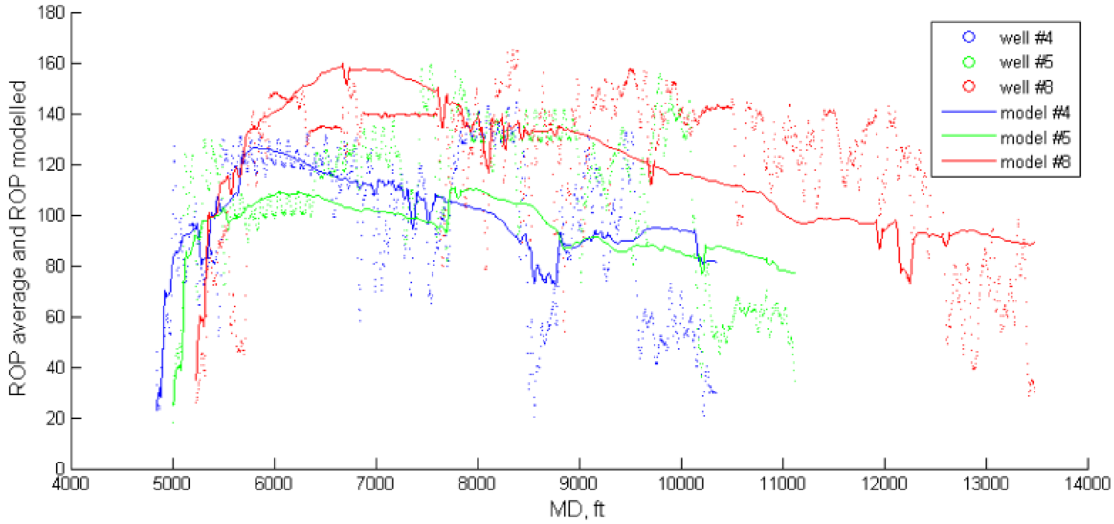


Figure 49. Average ROP (dots) and modelled ROP (curves) for the wells #4, 5, 8

The model accuracy can be evaluated using the regression index of correlation G, given by [27]:

$$G = \sqrt{1 - \frac{\sum[ROP_{observed} - ROP_{calculated}]^2}{\sum[ROP_{observed} - ROP_{average}]^2}} \tag{6.14}$$

The closer the index to 1.0 the more correlated the data is. For our data-set G equals 0.54. It means that the data is not strongly correlated. Also some of the obtained coefficients appear to be not realistic, e.g. the coefficient a_5 is equal 0, meaning that the Mechanical weight on bit does not affect the penetration rates.

It could be better to narrow MRA to similar lithological units. The following formation tops and markers exist in the Eldfisk overburden [2]: Upper Miocene Marker, Miocene Middle Top, Middle Miocene Marker, Miocene Lower Top, Oligocene Top, Upper Oligocene 1 Top, Upper Oligocene 2 Top, Eocene Top, Balder Fm Top, Sele Fm Top, Lista Fm Top, Våle Fm Top.

Many attempts were made to run the MATLAB simulations with different inputs: single geological units / adjacent units, single well / all wells, all data points / sampled data points. However these set-ups were producing many zero-coefficients because the minimum recommended range of x-descriptors was not fulfilled (see table 7) even though the input data was smoothed. Therefore a decision was made to run MRA with the following set-up only for the Middle Miocene to Oligocene age formations (mostly shales interbedded with stringers):

Well #	4		5			6		
MD, ft	5500-6810		550-7230			5830-7610		
Averaging interval	25 ft							
Coefficients	A1	A2	A3	A4	A5	A6	A7	A8
Minimum value	0	0	0	0	0.05	0.05	0	0.05

Table 9. Settings for multiple regression analysis

The chosen set-up gave 190 data points from the three wells and satisfied five out of the seven minimum predictor ranges.

Predictor	Recommended minimum range	Actual range
X2	2,000	1,991
X3	15,000	614
X4	15,000	8685
X5	0.40	3.4
X6	0.50	0.4
X7	0.50	0.3
X8	0.50	1.0

Table 10. predictors ranges

The following coefficients were obtained: $a_1 = 4.91, a_4 = 0.147 \cdot 10^{-4}, a_5 = 0.050, a_6 = 0.162, a_8 = 0.215$. The index G is equal 0.78. It was improved for 40%, but an excellent correlation still was not achieved.

Then the equation 6.1 becomes:

$$ROP = Exp\left(4.91 + 0.147 \cdot 10^{-4} D(p_p - p_c) + 0.050 \cdot \ln\left[\frac{0.93W_a - 1.60 \cdot 10^{-4} q^2 \rho}{9800}\right] + 0.162 \cdot \ln\left[\frac{N}{160}\right] + 0.215 \cdot \ln\left(\frac{q^3 \rho}{8.90 \cdot 10^9}\right)\right) \quad (6.15)$$

Where Exp – exponential function, D – depth (ft TVDSS), p_p – estimated pore pressure (ppg), p_c – equivalent circulation density (ppg), W_a – average surface WOB (lbs), N – rotation speed (rpm), q – flow rates (gpm), ρ – mud density (ppg).

The modelled ROP can be calculated for the analyzed drilling interval based on the operational conditions from the actual wells. The plot below shows the calculated ROP versus the average sampled ROP.

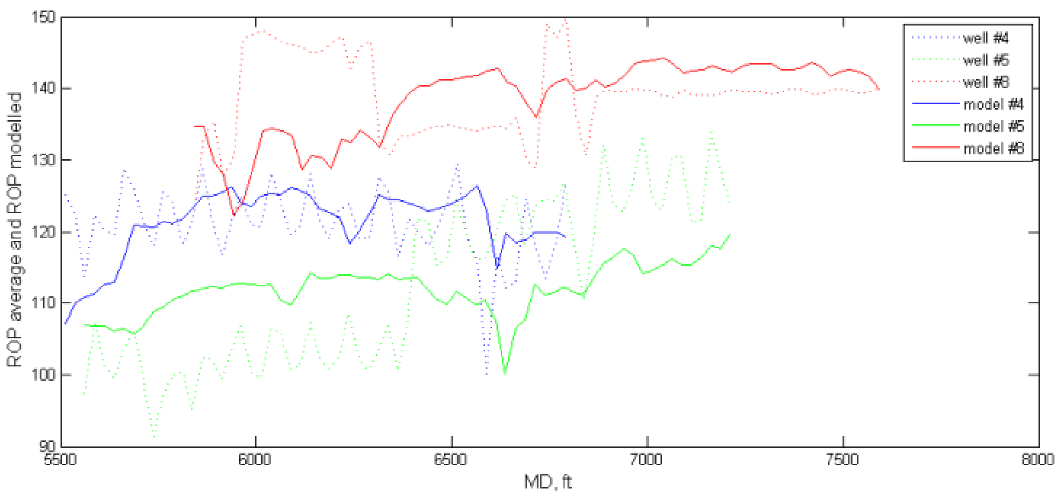


Figure 50. Average ROP (dashed lines) versus modelled ROP (solid lines), wells #4, 5 and 8

One of the main reasons why the data is not easily correlated is the formation heterogeneity. The shales are dominant lithology in the selected range (Middle Miocene, Oligocene ages), but they are highly interbedded with limestone stringers. It can be seen by high density log fluctuations from 1.6 to 2.0 g/cc even in the smoothed and averaged data.

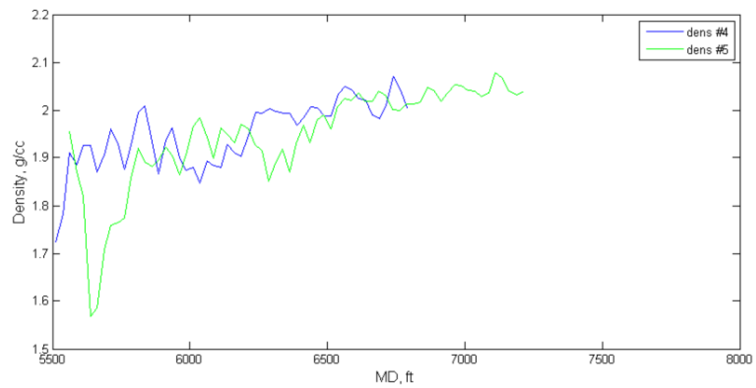
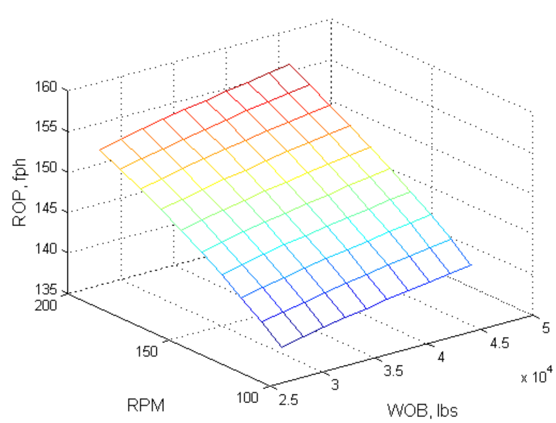


Figure 51. Composite density logs, Middle Miocene, Oligocene; well #4, 5

Even though the model does not show a strong correlation, we can illustrate how ROP can be predicted by simply adjusting the input parameters in the equation (6.15). Such parameters as the flow rates and mud density are dictated by the drilling operational window (mud window), hole cleaning requirements and BHA configuration (e.g. TDReam has a restricted operational window due to the activation shear pins). Instead ROP can be improved by increasing WOB and RPM inside the reasonable ranges. For example, in the well # 8 the matrix-body bit GTD65D was used which has recommended operational parameters: $33 < RPM < 200, 6 < WOB(klbs) < 46$.

At 7130 ft MD, ROP was 140 fph under 12.9 klbs WOB and 180 RPM. According to the obtained model in order to increase ROP to 150 fph, the minimal drilling parameters should be adjusted to the following (the values are obtained through a simple sensitivity analysis by keeping all variables unchanged and adjusting only WOB and RPM magnitudes):



WOB,lbs	RPM
27000	190
29000	185
32000	180
34000	175
37000	170
41000	165
45000	160

Figure 52. Increasing ROP by WOB and RPM

6.4. Transitional drilling procedures

Hard stringers have unpredictable nature and vary in thickness and hardness. Creating a comprehensive drilling model for the interbedded formation is challenging regardless of the data quality. However the drilling operational parameters for PDC bits can be adjusted locally every time a hard stringer is penetrated [22]:

1) When a PDC bit hits a stringer, ROP slows down quickly. Then gradually back-off some WOB (avoid breaking the formation into lumps). After five minutes gradually reduce the flow to an acceptable level (for the hole cleaning and downhole signals detection) in order to prevent hole washout resulting in a ledge formation, and gradually lower ROP. When entering the stringer drilling vibrations are likely to occur due to sudden changes in WOB, RPM and Torque that can result in drilling BHA instability. Additionally, sudden change in bit/rock engagement destroys the bottomhole pattern developed by the bit in the softer formation. Bit can start chattering (high frequency resonance up to 250 Hz). If severe vibrations are detected, pick off bottom and shut the drilling to discharge the energy accumulated in the drillstring.
2) Once the bit head is inside the hard formation (about 1.5 feet), first, gradually increase WOB and, if necessary , RPM in order to find an optimum combination which will result in acceptable ROP and will not induce bit vibrations. Generally, WOB in hard formation should be higher than in soft formations, and RPM – slower. After these two parameters are tuned, re-establish the full flow rates if required for the hole cleaning. But be aware of potential wash-outs above the stringer and the bit pump-off effect.
3) When the bit is breaking through the stringer, ROP will increase and fluctuations in drilling parameters can occur. Do not immediately increase the drilling parameters to push the bit faster. Instead, reduce the flow rates to avoid wash-outs in the softer formation below the stringer and gradually reduce RPM to prevent shoulder/gauge cutters damage until the bit head is fully entered the soft formation. Then the drilling parameters can be re-established towards the original. But keep watching for sudden fluctuations because large BHA components, such as BHA stabilizers, are still in the hard formation.

7 Discussion and Conclusion

In this master thesis we have carried out an extensive analysis of a potential drill bits optimization in the 12 ¼" x 13 ½" Eldfisk overburden section. The main objectives, defined at the beginning of this study, have been fulfilled to a different extent. Some of them were easier to understand and to propose a solution, while others were not as easily achievable and probably require a more comprehensive study or a different methodology.

The first objective was to find possible causes of insufficient PDC bits performance in the Eldfisk overburden section. The challenges have been defined as the high count of hard stringers of different origin (mostly carbonates) through the entire section (especially in the Middle Miocene to Eocene rocks), overpressured formation requiring higher mud weights, high gas concentrations causing pack-offs, open faults causing lost circulation, swelling clays inducing PDC cutters balling and intensifying pack-offs.

The group of eight wells have been analyzed in order to find the best 12 ¼" drill bit solution previously used in the Eldfisk-S. It was the premium GeoTech class PDC bit GTD65D. It drilled the section with the record overall ROP of 102.8 fph and was pulled out of hole with a minor dull: a few chipped cutters. However, the major limitation was that the study was conducted for both: drill-out runs (drilling shoe track) and post drill-out runs (the GeoTech bit was used in a sidetrack where the shoe track was not drilled). The vibration analysis showed that the bit was stable in the challenging heterogeneous formations and fell out of the acceptable vibrations range only for 6.6 minutes out of 67.2 total drilling hours on bottom (0.16%). The drilling efficiency of this bit run was approximately 66% as concluded from DSE and CCS comparison. The special bit features, such as the new type impact-resistant cutters CT404, scribe cutters at the cone, MLFB have been recognized as efficient in the current applications.

Drill bit dynamics in overpressured shales and interbedded formations with varying compressive strength have been studied, and based on the outcomes a new PDC bit design has been proposed. The SteelFoce class bit SFD65D should be a better solution in the similar applications due to bit balling mitigation, impact resistance, bit stability (vibration resistance) and steerability (directional control). This bit employs the cutting structure similar to the GeoTech bit, but has several advantages due to the steel-body type: impact shocks damping-effect, 59% increase in JSA, 37% increase in NFV. A detailed comparison was given in the paragraph 5.3.

The next objective of the drilling optimization problem was to identify the main operational parameters affecting drill bits performance. The six most important variables have been described in the section 6.1. However, the problem that was known from the beginning is that performance of PDC bits in the overbalanced shales interbedded with hard stringers is very inconsistent. Despite this we have tried to answer the question whether or not ROP can be easily predicted and controlled in the Eldfisk overburden.

The idea was to use a multiple regression analysis (MRA) based on the mud-logging data from the offset wells in order to identify how different drilling variables are related to the changes in ROP. First the data was smoothed by median filter, averaging filter and Savitzky-Golay low-pass filter. Then the empirical model has been developed taken into consideration main drilling variables and, in addition, bit dull-conditions at any time of the run (the model development was described in the paragraph 6.3). Unfortunately, the final model showed a low correlation with the observed ROP: 54% for all data points and 78% for the best reasonable selection when a long averaging interval, 25ft, was used. The average stringers thickness is 3 ft and therefore this ROP model cannot be applied at that level.

The developed model has a valid algorithm and can be for example applied to homogenous formations. However it cannot find strong data correlations in highly interbedded formations where the drill bits performance is inconsistent. In order to optimize drill bits efficiency, the transitional drilling procedures described in the paragraph 6.4 have to be implemented whenever penetrating a hard stringer. In general, the parameters used in the well #8 resulted in a good bit run: WOB of 10 – 20 klbs at Nordland/Hordaland groups and 20 – 30 klbs in the Rogaland group, RPM of 170-180, Flow rates of1000 – 1100 gpm.

A large assumption was made in this thesis: to treat the overburden formations in general. Another approach could have been chosen: to evaluate feet-by-feet drilling data instead and identify every formation being drilled. However the capacity of collecting a high number of data points will be reduced.

Also another group of offset wells could have been chosen, that would result in a different analysis. The proposed steel-body PDC bit, SFD65D, has not been used yet in the Eldfisk overburden. But the best way to prove the bit appropriateness is a trial drilling run in the field. Therefore the solution proposed in this paper should be tested before it can be considered as beneficial.

Another limitation of this research is that in the future ConocoPhillips Norway plan extended-reach drilling wells, where the overburden section will be around 12,000 ft long. Therefore steel-body PDC bits might be less appropriate for these applications due to possible body-erosion by extensive hydraulic circulations and by formation friction.

References

[1] Halliburton Drill Bits and Services, Training nomenclature

[2] Dianne Tompkins, Geologist at ConocoPhillips Norway, interview notes, 2015

[3] Halliburton Drill Bits and Services, Solutions catalog

[4] Å. Kyllingstad, J.L. Horpestad, S. Klakegg, A. Kristiansen (Rogaland Research), B.S. Aadnøy (Rogaland University Centre), " Factors Limiting the Quantitative Use of Mud-Logging Data", SPE-25319, 1993

[5] R.W. Mitchel, N.B. Nagel, E.C. Onyia, P.E. VanDeVerg (ConocoPhillips Upstream Technology), "A Wellbore Stability Evaluation of the Overburden above the Eldfisk Reservoir with Special Emphasis on the Våle Formation", 2006

[6] ConocoPhillips, "Eldfisk II. Increased recovery, new platform and modifications"

[7] Halliburton Sperry Drilling, End of Well Reports for Eldfisk-S wells

[8] ConocoPhillips, Core samples pictures

[9] R.F. Mitchel, S.Z. Miska, "Fundamentals of Drilling Engineering", SPE textbook series vol. 12, 2011

[10] A.T. Bourgoyne, K.K. Millheim, M.E. Chenevert, F.S. Young, SPE textbook series vol. 2, 1986

[11] Halliburton Sperry Drilling, Vibration Sensors and Vibration Mitigation Guidelines

[12] Halliburton Drill Bits and Services, Dull grading pictures

[13] Halliburton Sperry Drilling, InSite Studio software

[14] M. Armenta, "Identifying Inefficient Drilling Conditions Using Drilling-Specific Energy", SPE-116667, Shell EPT-WT, 2008

[15] Wikipedia, Linear Interpolation. Available from https://en.wikipedia.org/wiki/Linear_interpolation/ (read 28.06.2015)

[16] Gerard Soubervielle, Drilling Optimization and Perform Drilling. Available from: http://oilpro.com/post/1582/drilling-optimization-and-perform-drilling-basic-seminar-1-of-3/ (read 28.06.2015)

[17] Halliburton Drill Bits and Services. Available from: http://www.halliburton.com/en-US/ps/drill-bits/ (read 28.06.2015)

[18] Offshore-technology.com, Eldfisk Oil and Gas Field, North Sea, Norway. Available from http://www.offshore-technology.com/projects/eldfisk-oil-gas-field-north-sea/ (read 28.06.2015)

[19] J.R. Smith, "Addressing the Problem of PDC Bit Performance in Deep Shales", SPE-47814, Louisiana State University, 1998

[20] R.H. Smith, J.B. Lund, M. Anderson, R. Baxter, “Drilling Plastic Formations Using Highly Polished PDC Cutters”, SPE-30476, 1995

[21] S. Taylor, A. Besson, D. Minto, I. Mampuk, “Unique PDC Bit Technologies Combine to Consistently Reduce Drilling Time in Interbedded Formations”, SPE-47778, 1998¨

[22] Halliburton Drill Bits and Services, internal documents

[23] M.J. Fear, “How to Improve Rate of Penetration in Field Operations”, SPE Drilling and Completion, Vol. 14, No. 1, March 1999

[24] Wikipedia, Mud Logging. Available from https://en.wikipedia.org/wiki/Mud_logging/ (read 28.06.2015)

[25] R.A. Boiten, “Drilling data and its quality control”, Bachelor’s Thesis, University of Stavanger, 2015

[26] Wikipedia, Savitzky-Golay filer. Available from https://en.wikipedia.org/wiki/Savitzky%E2%80%93Golay_filter (read 28.06.2015)

[27] A.T. Bourgoyne, F.S. Young, “A Multiple Regression Approach to Optimal Drilling and Abnormal Pressure Detection”, SPE Journal, August 1974

[28] C.P. Duklet, T.R. Bates, “An Empirical Correlation to Predict Diamond Bit Drilling Rates”, SPE-9324, 1980

[29] MathWorks, MATLAB function “lsqlin”, Available from http://se.mathworks.com/help/optim/ug/lsqlin.html (read 28.06.2015)

Appendixes

Appendix 1. BHA configuration, well #7

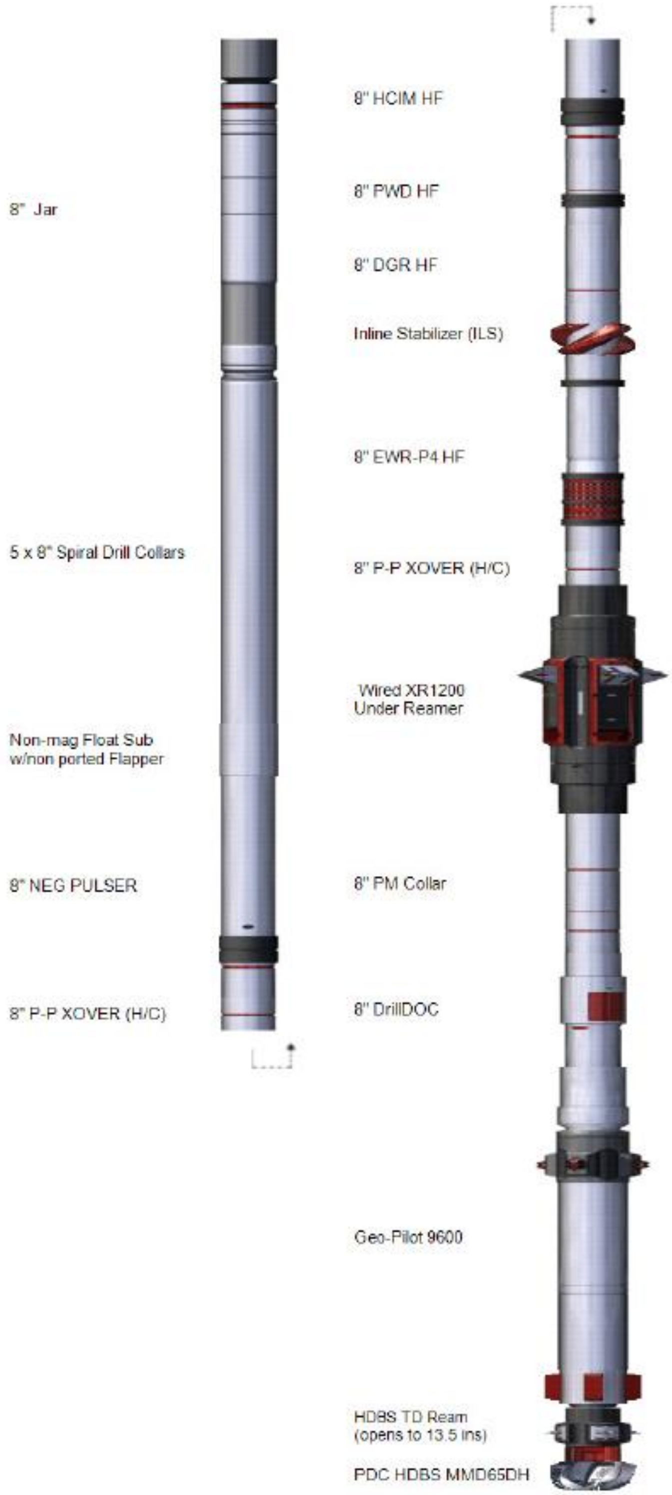
BHA Schematic

ConocoPhillips

COMPONENT DATA

OD (in)	Length (ft)	Description
8.000	1.07	PDC HDBS MMD65DH (Gauge: 12.250 in)
8.000	2.53	HDBS TD Ream (opens to 13.5 ins) (Gauge: 11.875 in)
9.625	23.58	Geo-Pilot 9600
		Ref Housing Stabilizer (Gauge: 12.188 in, Pos: 2.35 ft)*
		Ref Housing Stabilizer (Gauge: 12.125 in, Pos: 15.26 ft)*
8.219	7.39	8" DrillDOC
8.000	9.11	8" PM Collar
10.000	14.84	Wired XR1200 Under Reamer (Gauge: 12.000 in)
8.000	1.86	8" P-P XOVER (H/C)
8.000	12.16	8" EWR-P4 HF
8.000	3.92	Inline Stabilizer (ILS) (Gauge: 12.188 in, Pos*: 2.33 ft)
8.000	5.02	8" DGR HF
8.000	4.36	8" PWD HF
8.000	7.83	8" HCIM HF
8.000	1.72	8" P-P XOVER (H/C)
8.000	14.34	8" NEG PULSER
8.375	3.50	Non-mag Float Sub w/non ported Flapper
8.250	151.39	5 x 8" Spiral Drill Collars
8.125	30.04	8" Jar
8.250	89.22	3 x 8" Spiral Drill Collars
8.125	33.29	Accelerator
8.250	29.80	1 x 8" Spiral Drill Collar
8.000	3.72	X-Over Sub
5.875	401.02	13 x 5-7/8" HWDP - DSTJ ST58
5.875	12575.29	5-7/8" X 5.045" - 31.8# ST58

*Pos: Measured as distance from bottom of the component.



Appendix 2. IADC codes for fixed-cutter bits

IADC CLASSIFICATION FOR PDC AND DIAMOND BITS

IADC code consists of four characters, indicating bit body, formation type, cutting structure and bit profile. First character is literal, others – numerical.

First literal code character designates the bit body material (**S**teel, **M**atrix or **D**iamond).

Second numerical code character (1-8) designates the formation type being drilled. Category 5 has no code.

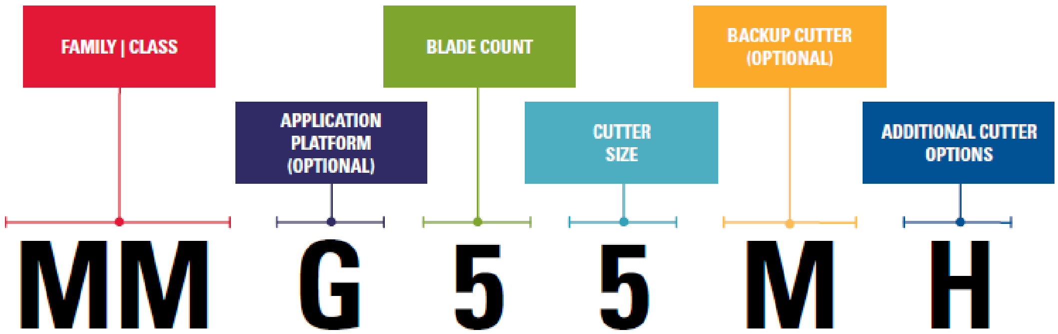
Third numerical code character designates drill bit cutting structure (PDC cutter size, diamond cutter type). Drill bits are equipped with 8-19 mm PDC cutters for 1-4 formation type categories and with natural diamonds, thermally stable polycrystalline diamonds (TPS), their combination or impregnated diamonds for 6-8 formation type categories. .

Fourth numerical code character – bit profile.

1	2		3				4			
Bit body	**Formation type**		**Size of PDC cutters**				**Bit profile**			
			1	2	3	4	1	2	3	4
S – steel M – matrix D – diamond	Very soft	1	-	19	13	8	Short fishtail	Short profile	Medium profile	Long profile
	Soft	2								
	Soft to medium	3								
	Medium	4								
	no code	5	**Diamond cutters type**							
	Medium hard	6	Natural diamond	Thermally stable (TSP)	Combination	-				
	Hard	7								
	Extremely hard	8		-	-	Impregnated diamond				

Reference: http://burintekh.com/upload/iblock/d51/d5160461ef4a840e5a038956f77ea242.pdf

Appendix 3. Halliburton PDC bits nomenclature



FAMILY | CLASS

MM = MegaForce Drill Bits
GT = GeoTech Drill Bits
SF = SteelForce Drill Bits

APPLICATION PLATFORM (OPTIONAL)

D = Directional (all other directional systems)
G = Geo-Pilot® Rotary Steerable
E = Geo-Pilot® EDL Rotary Steerable
T = Turbine High Rotational Speed

BLADE COUNT

The blade count indicates the number of blades on the bit.

3 = Three Blades
4 = Four Blades
5 = Five Blades
6 = Six Blades
7 = Seven Blades
8 = Eight Blades
9 = Nine Blades

CUTTER SIZE

The cutter size digit describes the size of the PDC cutters on the bit. On bits with multiple cutter sizes, the predominant size is indicated.

2 = 8 mm (3/8 in.)
3 = 10.5 mm (13/32 in.)
4 = 13 mm (1/2 in.)
5 = 16 mm (5/8 in.)
6 = 19 mm (3/4 in.)
8 = 25 mm (1 in.)

BACKUP CUTTER (OPTIONAL)

D = Dual Row Backup
M = Modified Diamond Round
R = R1™ Backup Cutters
I = Impreg Backup Discs
C = Carbide Impact Arrestor

ADDITIONAL CUTTER OPTIONS

H = Highly abrasive wear

OPTIONAL FEATURES

Not listed in nomenclature but found on marketing spec sheet. For more information, please contact your local Halliburton Drill Bits representative.

b = Back Reaming
c = Carbide Reinforcement
e = SE - Highly Spiraled
f = Full PDC Gauge Trimmers
k = Kerfing - Scribe Cutters
p = PDC Gauge Reinforcement
u = Updrill

Appendix 4. IADC dull-grading

IADC Dull Grading

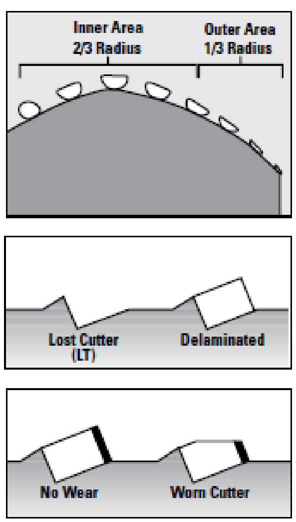
CUTTING STRUCTURE							
INNER ROWS	OUTER ROWS	DULL CHAR.	LOCATION	BEARINGS/ SEALS	GAUGE	OTHER DULL CHAR.	REASON PULLED
1	2	3	4	X	6	7	8

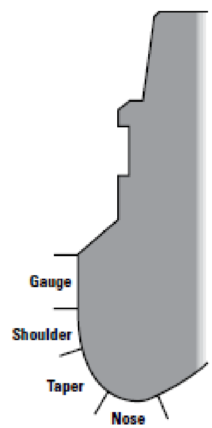
1 INNER CUTTING STRUCTURE

2 OUTER CUTTING STRUCTURE

A measure of lost, worn, and/or broken cutting structure.
Linear Scale: 0-8

- 0 - No lost, worn and/or broken cutting structure
- 8 - All of cutting structure lost, worn and/or broken





Halliburton's fixed cutter bits are tip ground to exacting tolerances at gauge O.D. per API spec 7. Depending on the specific design and application, as much as .080 of an inch of the cutter diameter may be ground flat. This can be mistaken for gauge wear if unfamiliar with our products. Please ensure that the dull bits are in gauge with a calibrated No Go ring gauge.

3 DULL CHARACTERISTICS

BF - Bond Failure
BT - Broken Cutters
BU - Balled Up
CR - Cored
CT - Chipped Cutters
DL - Delaminated Cutters
ER - Erosion
HC - Heat Checking
JD - Junk Damage
LM - Lost Matrix
LN - Lost Nozzle
LT - Lost Cutters
NO - No Dull Characteristics
NR - Not Rerunnable
PN - Plugged Nozzle/Flow Passage
RO - Ring Out
RR - Rerunnable
WO - Washed Out
WT - Worn Cutters

4 LOCATION

C - Cone
S - Shoulder
N - Nose
G - Gauge
T - Taper
A - All Areas

5 BEARINGS/SEALS

N/A

6 GAUGE

I - In Gauge
1 - 1/16" Out of Gauge
2 - 1/8" Out of Gauge
4 - 1/4" Out of Gauge

7 OTHER DULL CHARACTERISTICS

(Refer to column 3 codes)

8 REASON PULLED OR RUN TERMINATED

BHA - Change Bottom Hole Assembly
CM - Condition Mud
CP - Core Point
DMF - Downhole Motor Failure
DP - Drill Plug
DSF - Drill String Failure
DST - Drill Stem Test
DTF - Down Hole Tool Failure
FM - Formation Change
HP - Hole Problems
HR - Hours on Bit
LH - Left in Hole
LOG - Run Logs
PP - Pump Pressure
PR - Penetration Rate
RIG - Rig Repair
TD - Total Depth/Casing Depth
TQ - Torque
TW - Twist Off
WC - Weather Conditions
WO - Washout in Drill String

Appendix 5. Drill bits specification sheets, offset wells

Well #1

HALLIBURTON | Drill Bits & Services

12-1/4" (311mm) SFG75

PRODUCT SPECIFICATIONS

Cutter Type		Select Cutter
IADC Code		S222
Body Type		STEEL
Total Cutter Count		51
Cutter Distribution	13mm	16mm
Face	0	37
Gauge	7	7
Number of Large Nozzles		7
Number of Medium Nozzles		0
Number of Small Nozzles		0
Number of Micro Nozzles		0
Number of Ports (Size)		0
Number of Replaceable Ports (Size)		0
Junk Slot Area (sq in)		48.67
Normalized Face Volume		76%
API Connection		6-5/8 REG. BOX
Recommended Make-Up Torque*		50,958 Ft*lbs.
Nominal Dimensions**		
Make-Up Face to Nose		19.13 in - 486 mm
Gauge Length		1 in - 25 mm
Sleeve Length		9 in - 229 mm
Shank Diameter		7.625 in - 194 mm
Break Out Plate (Mat.#/Legacy#)		181978/44757
Approximate Shipping Weight		704Lbs. - 319Kg.

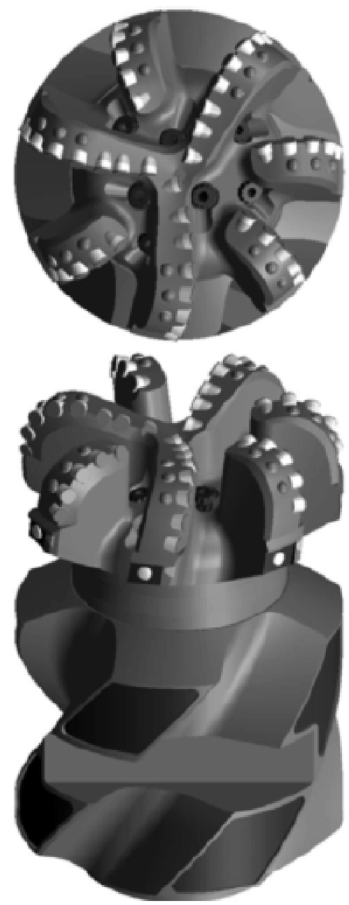
SPECIAL FEATURES

Anti-Balling Coating, (MEG) Modified Extended Gage Sleeve - 4 Blade, 1/16" Undergage Sleeve, Carbide Impact Arrestor, Side Port Nozzles, Multi Level Force Balancing

RECOMMENDED OPERATING PARAMETERS

(Recommended operating parameters are based on global guidelines and should always be validated with local application specific data)

Rotary Speed: 33 - 200
WOB: 6 - 46



Material #778427

*Bit specific recommended make-up torque is a function of the bit I.D. and actual bit sub O.D. utilized as specified in API RP7G Section A.8.2.

**Design dimensions are nominal and may vary slightly on manufactured product. Halliburton Drill Bits and Services models are continuously reviewed and refined. Product specifications may change without notice.

www.halliburton.com

Well #2

HALLIBURTON | Drill Bits & Services

12-1/4" (311mm) FXG65D

PRODUCT SPECIFICATIONS

Cutter Type			X³
IADC Code			M223
Body Type			MATRIX
Total Cutter Count			78
Cutter Distribution		13mm	16mm
	Face	0	60
	Gauge	6	12
Number of Large Nozzles			9
Number of Medium Nozzles			0
Number of Small Nozzles			0
Number of Micro Nozzles			0
Number of Ports (Size)			0
Number of Replaceable Ports (Size)			0
Junk Slot Area (sq in)			32.23
Normalized Face Volume			48.86%
API Connection			6-5/8 REG. BOX
Recommended Make-Up Torque*			58,885 Ft*lbs.
Nominal Dimensions**			
Make-Up Face to Nose			20.63 in - 524 mm
Gauge Length			2.5 in - 64 mm
Sleeve Length			12 in - 305 mm
Shank Diameter			8.75 in - 222 mm
Break Out Plate (Mat.#/Legacy#)			181978/44757
Approximate Shipping Weight			688Lbs. - 312Kg.

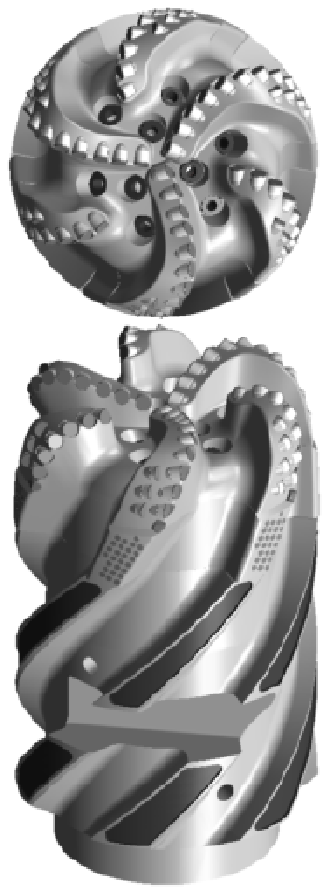
SPECIAL FEATURES

1/16" Undergage Sleeve, 1/32" Relieved Gage, Optimized Dual Row - "D" Feature, 6 Bladed Sleeve

RECOMMENDED OPERATING PARAMETERS

(Recommended operating parameters are based on global guidelines and should always be validated with local application specific data)

Rotary Speed: 33 - 200
WOB: 6 - 46



Material #663251

*Bit specific recommended make-up torque is a function of the bit I.D. and actual bit sub O.D. utilized as specified in API RP7G Section A.8.2.

**Design dimensions are nominal and may vary slightly on manufactured product. Halliburton Drill Bits and Services models are continuously reviewed and refined. Product specifications may change without notice.

www.halliburton.com

Well #3 and 6

12-1/4" (311mm) MMD65DH

PRODUCT SPECIFICATIONS

Cutter Type			Select Cutter
IADC Code			M324
Body Type			MATRIX
Total Cutter Count			83
Cutter Distribution		13mm	16mm
	Face	0	65
	Gauge	6	12
Number of Large Nozzles			9
Number of Medium Nozzles			0
Number of Small Nozzles			0
Number of Micro Nozzles			0
Number of Ports (Size)			0
Number of Replaceable Ports (Size)			0
Junk Slot Area (sq in)			31.65
Normalized Face Volume			50.1%
API Connection			6-5/8 REG. PIN
Recommended Make-Up Torque*			37,119 – 43,525 Ft*lbs.
Nominal Dimensions**			
Make-Up Face to Nose			11.96 in - 304 mm
Gauge Length			1 in - 25 mm
Sleeve Length			0 in - 0 mm
Shank Diameter			8 in - 203 mm
Break Out Plate (Mat.#/Legacy#)			181978/44757
Approximate Shipping Weight			430Lbs. - 195Kg.

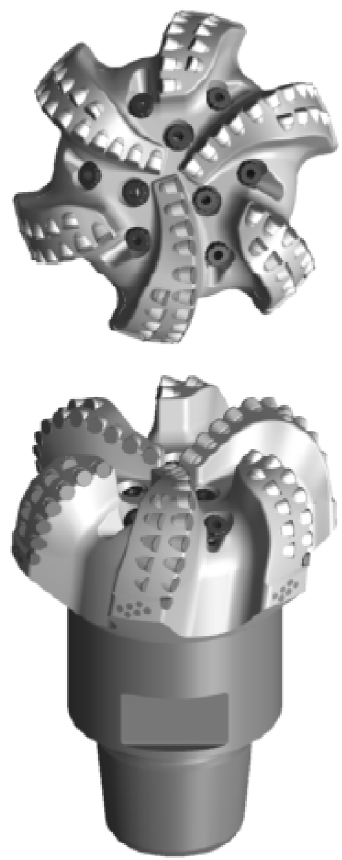
SPECIAL FEATURES

Optimized Dual Row - "D" Feature, 1/32" Relieved Gage, Multi Level Force Balancing, Sideport Nozzles, , Non-standard Bit Bevel

RECOMMENDED OPERATING PARAMETERS

(Recommended operating parameters are based on global guidelines and should always be validated with local application specific data)

Rotary Speed: 33 - 200
WOB: 6 - 46



Material #836757

*Bit specific recommended make-up torque is a function of the bit I.D. and actual bit sub O.D. utilized as specified in API RP7G Section A.8.2.

**Design dimensions are nominal and may vary slightly on manufactured product. Halliburton Drill Bits and Services models are continuously reviewed and refined. Product specifications may change without notice.

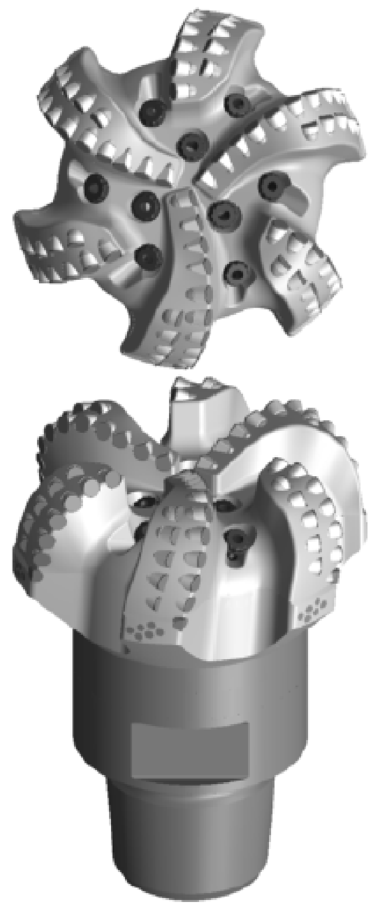
Well #4 and 5

HALLIBURTON | Drill Bits & Services

12-1/4" (311mm) MMD65DH

PRODUCT SPECIFICATIONS

Cutter Type			Select Cutter
IADC Code			M324
Body Type			MATRIX
Total Cutter Count			83
Cutter Distribution		13mm	16mm
	Face	0	65
	Gauge	6	12
Number of Large Nozzles			9
Number of Medium Nozzles			0
Number of Small Nozzles			0
Number of Micro Nozzles			0
Number of Ports (Size)			0
Number of Replaceable Ports (Size)			0
Junk Slot Area (sq in)			31.65
Normalized Face Volume			50.1%
API Connection			6-5/8 REG. PIN
Recommended Make-Up Torque*			37,119 – 43,525 Ft*lbs.
Nominal Dimensions**			
Make-Up Face to Nose			11.96 in - 304 mm
Gauge Length			1 in - 25 mm
Sleeve Length			0 in - 0 mm
Shank Diameter			8 in - 203 mm
Break Out Plate (Mat.#/Legacy#)			181978/44757
Approximate Shipping Weight			430Lbs. - 195Kg.



Material #866233

SPECIAL FEATURES

Optimized Dual Row - "D" Feature, 1/32" Relieved Gage, Multi Level Force Balancing, Sideport Nozzles, Non-standard Bit Bevel, Scribe Cutters

RECOMMENDED OPERATING PARAMETERS

(Recommended operating parameters are based on global guidelines and should always be validated with local application specific data)

Rotary Speed: 33 - 200

WOB: 6 - 46

*Bit specific recommended make-up torque is a function of the bit I.D. and actual bit sub O.D. utilized as specified in API RP7G Section A.8.2.

**Design dimensions are nominal and may vary slightly on manufactured product. Halliburton Drill Bits and Services models are continuously reviewed and refined. Product specifications may change without notice.

Well #7

HALLIBURTON | Drill Bits & Services

12-1/4" (311mm) MMD65DH

PRODUCT SPECIFICATIONS

Cutter Type			Select Cutter
IADC Code			M324
Body Type			MATRIX
Total Cutter Count			83
Cutter Distribution		13mm	16mm
	Face	0	65
	Gauge	6	12
Number of Large Nozzles			9
Number of Medium Nozzles			0
Number of Small Nozzles			0
Number of Micro Nozzles			0
Number of Ports (Size)			0
Number of Replaceable Ports (Size)			0
Junk Slot Area (sq in)			31.65
Normalized Face Volume			50.1%
API Connection			6-5/8 REG. PIN
Recommended Make-Up Torque*			37,119 – 43,525 Ft*lbs.
Nominal Dimensions**			
Make-Up Face to Nose			13.51 in - 343 mm
Gauge Length			4 in - 102 mm
Sleeve Length			0 in - 0 mm
Shank Diameter			8.75 in - 222 mm
Break Out Plate (Mat.#/Legacy#)			181958/44071
Approximate Shipping Weight			430Lbs. - 195Kg.

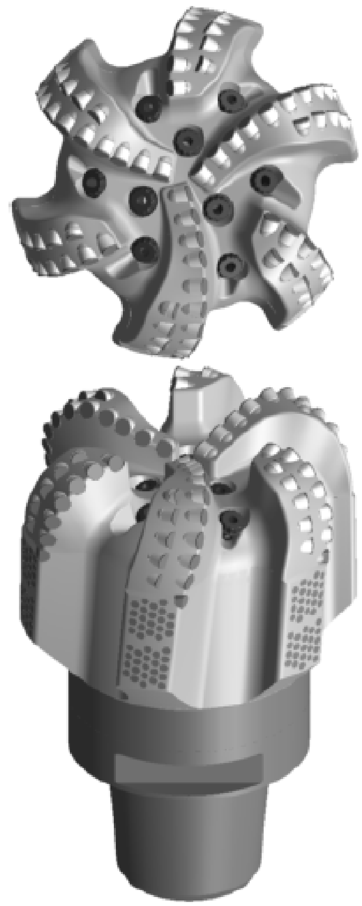
SPECIAL FEATURES

Optimized Dual Row - "D" Feature, 1/32" Relieved Gage, Short Shank, 1/16" Stepped Gage, Multi Level Force Balancing, Sideport Nozzles

RECOMMENDED OPERATING PARAMETERS

(Recommended operating parameters are based on global guidelines and should always be validated with local application specific data)

Rotary Speed: 33 - 200
WOB: 6 - 46



Material #783199

*Bit specific recommended make-up torque is a function of the bit I.D. and actual bit sub O.D. utilized as specified in API RP7G Section A.8.2.

**Design dimensions are nominal and may vary slightly on manufactured product. Halliburton Drill Bits and Services models are continuously reviewed and refined. Product specifications may change without notice.

Well #8

12-1/4" (311mm) GTD65D

PRODUCT SPECIFICATIONS

Cutter Type			Select Cutter
IADC Code			M324
Body Type			MATRIX
Total Cutter Count			83
Cutter Distribution		13mm	16mm
	Face	0	65
	Gauge	6	12
Number of Large Nozzles			9
Number of Medium Nozzles			0
Number of Small Nozzles			0
Number of Micro Nozzles			0
Number of Ports (Size)			0
Number of Replaceable Ports (Size)			0
Junk Slot Area (sq in)			31.65
Normalized Face Volume			50.1%
API Connection			6-5/8 REG. PIN
Recommended Make-Up Torque*			37,119 – 43,525 Ft*lbs.
Nominal Dimensions**			
Make-Up Face to Nose			12.74 in - 324 mm
Gauge Length			1 in - 25 mm
Sleeve Length			0 in - 0 mm
Shank Diameter			8 in - 203 mm
Break Out Plate (Mat.#/Legacy#)			181955/44050
Approximate Shipping Weight			430Lbs. - 195Kg.

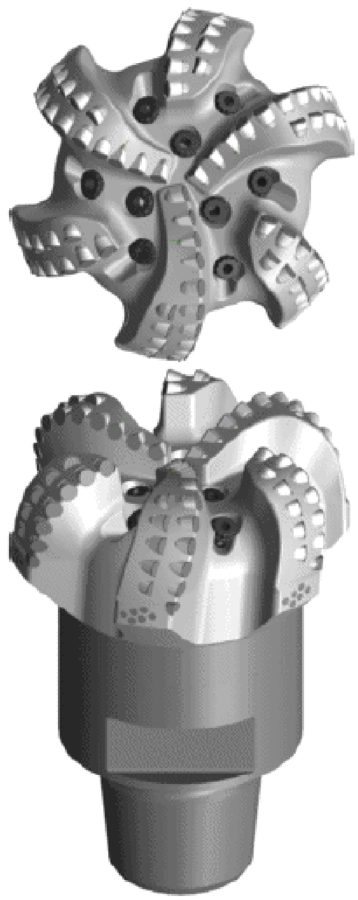
SPECIAL FEATURES

Optimized Dual Row - "D" Feature, 1/32" Relieved Gage, Multi Level Force Balancing, Sideport Nozzles, Scribe Cutters

RECOMMENDED OPERATING PARAMETERS

(Recommended operating parameters are based on global guidelines and should always be validated with local application specific data)

Rotary Speed: 33 - 200
WOB: 6 - 46



Material #941512

*Bit specific recommended make-up torque is a function of the bit I.D. and actual bit sub O.D. utilized as specified in API RP7G Section A.8.2.

**Design dimensions are nominal and may vary slightly on manufactured product. Halliburton Drill Bits and Services models are continuously reviewed and refined. Product specifications may change without notice.

Appendix 6. Drill bit specification sheet, SFD65D (958508)

HALLIBURTON | Drill Bits & Services

12-1/4" (311mm) SFD65D

PRODUCT SPECIFICATIONS

Cutter Type			Select Cutter
IADC Code			S224
Body Type			STEEL
Total Cutter Count			75
Cutter Distribution		13mm	16mm
	Face	8	49
	Gauge	6	12
Number of Large Nozzles			6
Number of Medium Nozzles			0
Number of Small Nozzles			0
Number of Micro Nozzles			0
Number of Ports (Size)			0
Number of Replaceable Ports (Size)			0
Junk Slot Area (sq in)			50.35
Normalized Face Volume			68.81%
API Connection			6-5/8 REG. PIN
Recommended Make-Up Torque*			37,119 – 43,525 Ft*lbs.
Nominal Dimensions**			
Make-Up Face to Nose			9.26 in - 235 mm
Gauge Length			1 in - 25 mm
Sleeve Length			0 in - 0 mm
Shank Diameter			7.75 in - 197 mm
Break Out Plate (Mat.#/Legacy#)			181955/44050
Approximate Shipping Weight			300Lbs. - 136Kg.

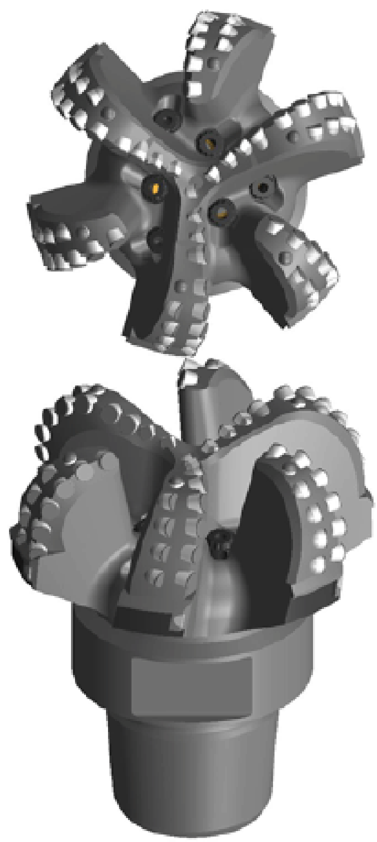
SPECIAL FEATURES

Anti-Balling Coating, Side Port Nozzles, Multi Level Force Balancing, Dual Row Cutting Structure - "D" Feature, 1/32" Relieved Gage, Scribe Cutters

RECOMMENDED OPERATING PARAMETERS

(Recommended operating parameters are based on global guidelines and should always be validated with local application specific data)

Rotary Speed: 33 - 200
WOB: 6 - 46



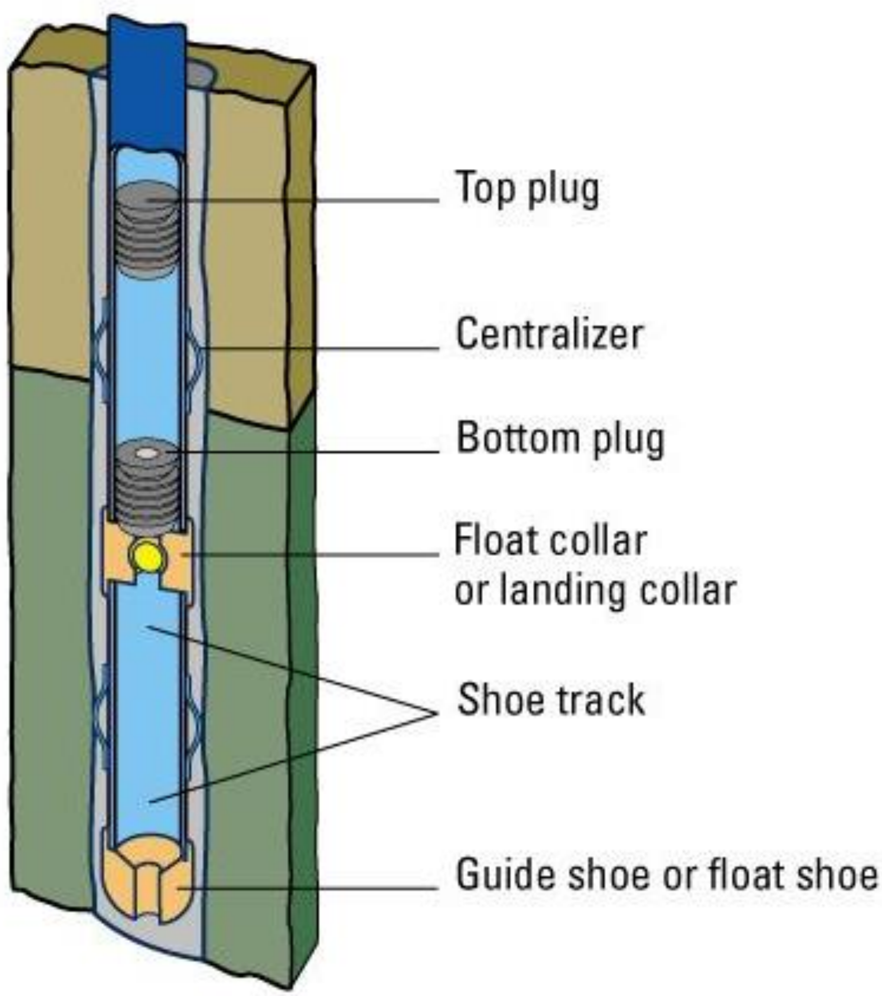
Material #958508

*Bit specific recommended make-up torque is a function of the bit I.D. and actual bit sub O.D. utilized as specified in API RP7G Section A.8.2.

**Design dimensions are nominal and may vary slightly on manufactured product. Halliburton Drill Bits and Services models are continuously reviewed and refined. Product specifications may change without notice.

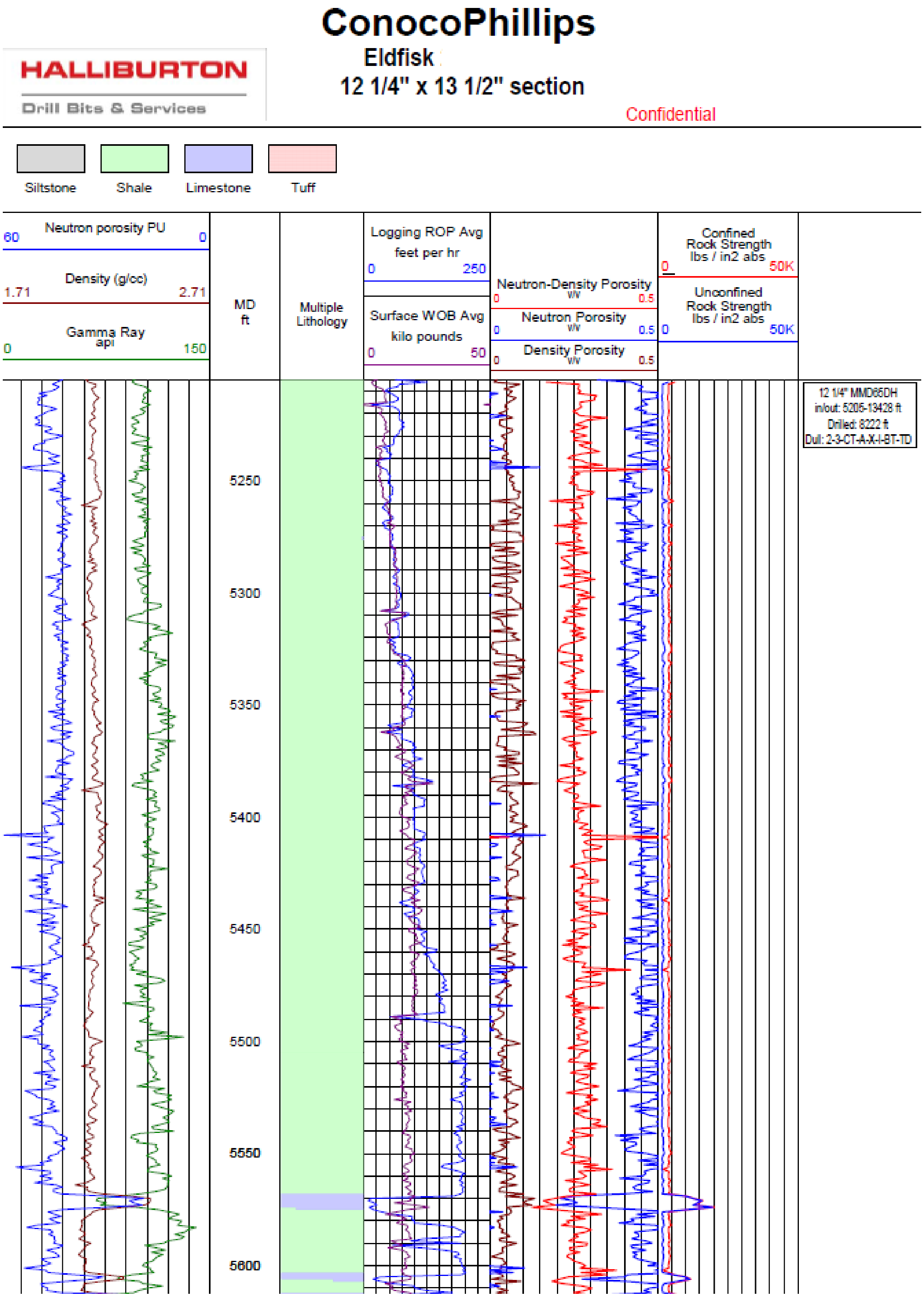
www.halliburton.com

Appendix 7. Shoe track schematics



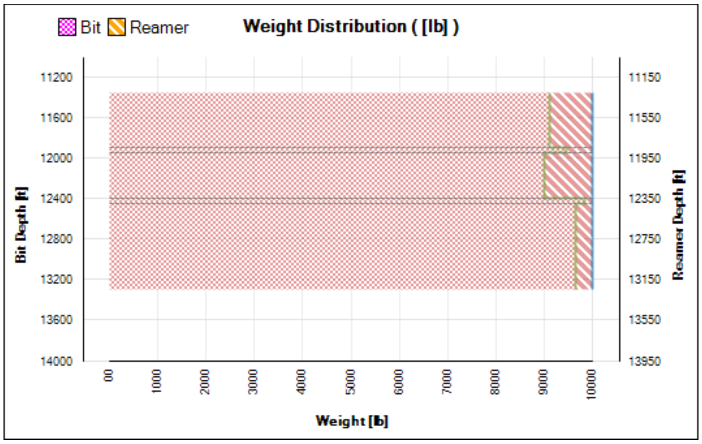
Reference: http://www.glossary.oilfield.slb.com/en/Terms/c/casing_shoe.aspx

Appendix 8. SPARTA analysis (first page only), well #7

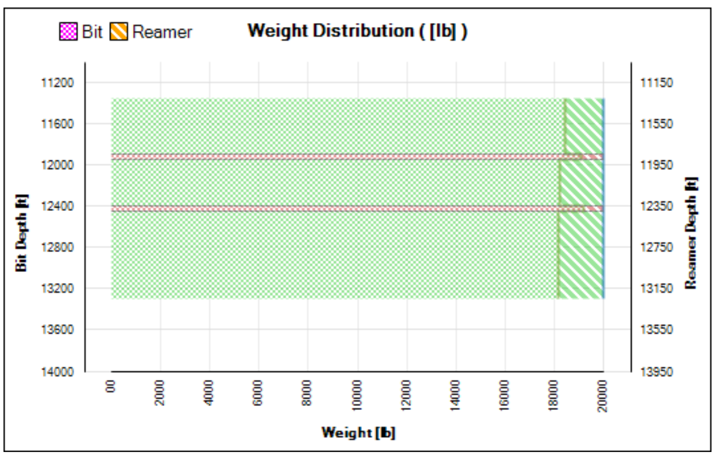


Appendix 9. Precise Bit Reamer, weight split analysis

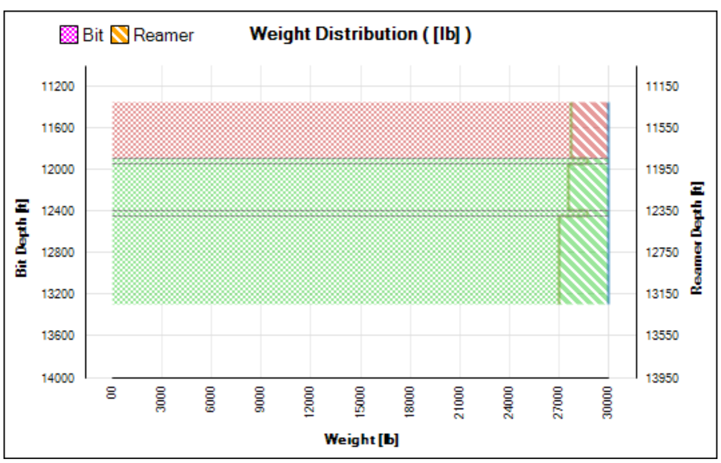
Low weight: 10,000 lbs



Middle weight: 20,000 lbs



High weight: 30,000 lbs



Appendix 10. Non-processed data example, well #1

DEPT	ROPA	BWAV	RSAV	TAAV	FIPA	DMIA	SPPA	ECDA	PPE	BPL	HHPA	HOB	ROB	LOTV	DCWAE	DCTAB	ALCDA
3291	31.64	1000	89.5895	3678.613	805.2537	10.4597	2028.015	10.7126	8.9	329.9633	1.3153	0.0267	0.1433	3218.26	695	276.375	1.597
3292	42.0533	1000	89.5517	3701.185	805.3879	10.446	2021.328	10.6877	8.9	329.64	1.3142	0.05	0.2687	3219.194	795.7143	290.2857	1.5983
3293	46.1739	1000	80.6915	3660.994	805.0473	10.466	2019.966	10.7146	8.9	329.9934	1.3151	0.0717	0.3739	3220.128	725.1429	291.1429	1.6124
3294	46.0038	1000	71.9902	3784.844	805.6954	10.4626	2025.002	10.7074	8.9	330.4173	1.3178	0.0933	0.4675	3221.062	1087.333	418	1.6465
3295	45.9139	1000	71.713	4229.027	805.082	10.4613	2020.197	10.7055	8.9	329.8716	1.3147	0.115	0.5606	3221.996	2093.143	790.2857	1.66
3296	49.5053	766.1959	71.856	4177.34	805.556	10.4721	2017.056	10.7174	8.9	330.6034	1.3184	0.1358	0.6504	3222.929	2715	819.5	1.8206
3297	50.2662	1137.458	71.8399	4135.263	805.0363	10.4812	2012.472	10.7277	8.9	330.4637	1.317	0.1558	0.7367	3223.863	3350.333	862.5	2.1528
3298	49.9832	1653.319	71.8245	4369.306	805.2408	10.4757	2021.585	10.7197	8.9	330.4558	1.3173	0.175	0.8191	3224.797	3669	1034.167	2.2202
3299	50.5382	1352.394	71.7816	4234.973	805.8977	10.4773	2017.601	10.7206	8.9	331.0468	1.3207	0.195	0.9053	3225.731	3488.667	887.5	2.2437
3300	50.26	1414.821	71.7301	4200.21	804.8656	10.4628	2020.115	10.7141	8.9	329.7428	1.3138	0.215	0.9913	3226.664	2851.714	807.8571	2.2468
3301	34.137	1694.644	82.7182	4070.266	805.1451	10.4967	2026.952	10.7414	8.9	331.0414	1.3194	0.2442	1.1359	3227.598	3368.75	716.25	2.2415
3302	47.0908	256.8264	88.2884	4339.083	805.1195	10.493	2034.112	10.7403	8.9	330.9028	1.3188	0.2658	1.2507	3228.531	3359	825.3333	2.2379
3303	48.2969	497.3216	88.4681	4208.024	803.7565	10.4851	2038.228	10.7301	8.9	329.5359	1.3112	0.2858	1.357	3229.465	3248.857	759	2.2349
3304	48.9229	677.0823	88.4135	4268.075	804.8843	10.4955	2033.575	10.7422	8.9	330.7895	1.318	0.3067	1.4674	3230.398	3162	761.8333	2.2262
3305	48.546	440.4882	88.4818	4224.071	804.184	10.5004	2034.661	10.7475	8.9	330.3677	1.3152	0.3275	1.5782	3231.332	3021	767	2.2302
3306	50.0171	666.4205	88.4811	4237.413	804.9965	10.4527	2039.626	10.6925	8.9	329.5322	1.3132	0.3475	1.6843	3232.265	2965.333	776	2.2341
3307	46.4822	353.5448	88.4841	4153.719	804.1128	10.5149	2036.853	10.7555	8.9	330.7661	1.3166	0.3692	1.7994	3233.199	2811	720.1667	2.1924
3308	43.0884	1674.95	88.5327	4122.323	804.7655	10.4979	2033.345	10.7417	8.9	330.7667	1.3177	0.3917	1.9188	3234.132	2740.286	716.1429	2.1948
3309	54.4331	1141.52	88.7553	4250.983	804.2606	10.524	2042.768	10.7652	8.9	331.173	1.3185	0.41	2.0164	3235.065	2299	671.6667	2.181
3310	57.0323	1673.095	88.8128	4343.602	804.758	10.4766	2048.025	10.7235	8.9	330.0902	1.315	0.4275	2.1097	3235.999	2664.8	869.4	2.1558
3311	56.5483	2066.278	88.8837	4418.577	804.5002	10.5023	2060.445	10.7437	8.9	330.6856	1.317	0.4458	2.2075	3236.932	2894.4	946.4	2.1076
3312	56.7938	2736.495	89.0649	4325.76	804.799	10.5262	2064.625	10.7719	8.9	331.687	1.3214	0.4625	2.2965	3237.865	3535.667	889.3333	2.0921
3313	56.7938	2736.495	89.0649	4325.76	804.799	10.5262	2064.625	10.7719	8.9	331.687	1.3214	0.4625	2.2965	3237.865	3653.333	920	2.1056
3314	194.9987	2670.78	89.1699	4420.534	804.3257	10.4846	2065.986	10.7286	8.9	329.9856	1.3139	0.4742	2.3589	3239.731	-999.25	-999.25	2.1251

Appendix 11. Smooth.m (MATLAB code)

```
%delete zeros%
[row,col] = find(data(:,[2:8])<=0);
data(row, :)=[];

figure
plot(data(:,1), data(:,2),'b');% plot original ROP
%%
%filtering%
filt=[2 3 4 5 6 7 8 9 10 11 12 16 17 18];%columns in "data" to
be filtered

%median filter%
data(:,[filt])=medfilt1(data(:,[filt]),3);

%average filter%
B = ones(1,5)/5;
data(:,[filt])=filter(B,1,data(:,[filt]));
hold on
plot(data(:,1), data(:,2),'g');%plot ROP

%Lowpass filter%
data(:,[filt])=sgolayfilt(data(:,[filt]),2,65);
hold on
plot(data(:,1), data(:,2),'r');%plot ROP
xlabel('MD, ft', 'FontSize',12);
ylabel('ROP, fph','FontSize',12);
```

Appendix 12. Energy.m (MATLAB code)

```
%name variables%
run('params')
ccs=rock(:,1);
ucs=rock(:,2);
rocktvd=rock(:,3);
ab=pi*12.25^2/4;% bit area
ccsnew=interp1q(rocktvd,ccs,tvd);%linear interpolation

%Drilling specific energy%
dse1=dcwoba./ab;
dse2=(120*pi/ab).*(rpma.*dctqa./ropa);
dse3=1980000*0.00875*hpsi./ropa;
dse=dse1+dse2-dse3;

figure
plot(dept, dse, 'r');
hold on
plot(dept, ccsnew, 'b');
xlabel('MD, ft', 'FontSize',12);
ylabel('DSE and CCS, psi','FontSize',12);

%total efficiency%
eff=trapz(dept(2:end), ccsnew(2:end))/trapz(dept(2:end),
dse(2:end));
```

Appendix 13. Params.m (MATLAB code)

```
%name parameters%
dept=data(:,1);%MD, ft
ropa=data(:,2);%ROP avg, ft/hr
woba=data(:,3);%WOB avg, lbs
rpma=data(:,4);%RPM avg, rpm
tqa=data(:,5);%TQ avg, f-p
flowa=data(:,6);%Flow-in pump avg, gpm
mwa=data(:,7);%MW in, ppg
sppa=data(:,8);%SPP average, psig
ecda=data(:,9);%ECD avg, ppg
ppe=data(:,10);%Pore pressure, ppg
bpl=data(:,11);%Bit pressure loss, psig
hpsi=data(:,12);%Hydraulic power, hpsi
hob=data(:,13);%Hours on bottom, hr
rob=data(:,14);%Rotations on bottom, krev
tvd=data(:,15);%TVD, ft
dcwoba=data(:,16);%WOB avg from DrillDoc, lbs
dctqa=data(:,17);%TQ avf from DrillDoc, f-p
adldens=data(:,18);%Composite density from ADL, g/cc
```

Appendix 14. Wear.m (MATLAB code)

```
%Load data%
run('params');
d=12.25;

%mechanical weight on bit%
wobma=0.93*woba-1/3*0.942.*bpl.*(d-1);
o=find(wobma<0);%check for negative values
data(:,19)=wobma;%add wobma to data-set

%delta hours on bit%
dhob=hob(1);
for i=2:size(data)
    dhob(i,1)=hob(i)-hob(i-1);
end

%estimate formation abrasiveness constant%
J2=1/0.02*((160./rpma).^1.5).*(wobma./(d*1200))*(1/1.5);%estimat
e J2 for each dhob intervals
hi=input('initial bit dull from 0 to 1, hi: ');
hf=input('final bit dull from 0 to 1, hf: ');
toh=sum(dhob./(J2*(hf-hi+0.5*(hf^2-hi^2))))%calculate formation
abrasiveness factor

%calculate tooth wear:
ht=hi;
for i=2:size(data)
    ht(i)=sqrt(1+2.*dhob(i)./(toh*J2(i))+2*ht(i-1)+(ht(i-
1)).^2)-1;%estimated tooth wear
end
data(:,20)=ht;%add ht to data-set
```

Appendix 15. Regress.m (MATLAB code)

```
%Load data%
run('params')
wobma=data(:,19);
ht=data(:,20);
d=12.25;

%Model predictors%
x2=8000-tvd;%normalized TVD = 8000 ft
x3=tvd.^0.69.*(ppe-13.5);%normalized ppe = 13.5 ppg
x4=tvd.*(ppe-ecda);%overbalance
x5=(log(wobma/(d*800)));%normalized WOB = 800 lbs/in
x6=log(rpma/160);%normalized RPM = 160
x7=-ht;
x8=log(hpsi/2);%normalized hpsi = 2

%check the minimum range of predictors%
range=[max(x2)-min(x2); max(x3)-min(x3); max(x4)-min(x4);
max(x5)-min(x5); max(x6)-min(x6); max(x7)-min(x7); max(x8)-
min(x8)];

%%
%regression analysis%
y = log(ropa);
X = [ones(size(y)) x2 x3 x4 x5 x6 x7 x8];%predictors

%Non-negative coefficients%
A=ones(1,8);
lb=[0 0 0 0 0 0 0 0];%minimum values
ub=[9 9 9 9 9 9 9 9];%maximum values
a = lsqlin(X,y,A,10, [], [], lb, ub);%MRA

%Index of correlation%
G=sqrt(1-sum((ropa-ropm).^2)/sum((ropa-mean(ropa)).^2));
```