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Abstract

Shoe track is a space between casing or liner shoe and the uppermost collar, which keeps contaminated cement after cementing operation has been performed. This term is also used to describe the whole downhole cementing configuration, which consists of wiper plugs, collar or collars, cement and a shoe. These components have to be drilled out to proceed with drilling of new formation. The process is often time-consuming and damaging for the drilling tools. At the same time shoe track drilling is a difficult operation to analyze due to big variety in float equipment design and materials used. Therefore, oil companies often rely on “best practices”, developed throughout years of experience.

This thesis presents analysis of shoe track drillouts data obtained from several wells, which are categorized into two major groups. The groups were chosen based on presence of common features, for example section size, bit and equipment used. All shoe track components were analyzed separately with respect to their design and drilling parameters used. Different shoe track components require customized drilling strategy. It was found, that design and number of wiper plugs, collars and float valves are the major factors that affect drillout time of float equipment, which includes plugs, collars and shoe. Drilling parameters and materials used also play an important but secondary role during shoe track drillout. Variations in drill bits specifications, as number of cutters and nozzles, have minor influence on shoe track drillout efficiency.

Cement drilling greatly depends on operational parameters. As a part of the analysis, parameters used for drilling out cement in shoe track were considered and compared with the existing practice. Drilling optimization models have been used to determine drilling efficiency, carry out sensitivity analysis for drilling parameters and forecast penetration rate. Averaged drilling efficiency factor for cement was found using MSE concept. Penetration rate was modeled using Brourgoyne and Young method. Calculated penetration rate was then compared to logged feet-to-feet ROP values, and significant correlation was observed. Cement drillout study was completed with cuttings transport analysis, which was performed in WELLPLAN software to determine critical flow rate for successful drillout.

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List of abbreviations

AFC	AUTOFILL FLOAT COLLAR
API	AMERICAN PETROLEUM INSTITUTE
BHA	BOTTOM HOLE ASSEMBLY
BYM	BOURGOYNE AND YOUNG MODEL
CCS	CONFINED COMPRESSIVE STRENGTH
ECD	EQUIVALENT CIRCULATING DENSITY
FC	FLOAT COLLAR
HB	HALLIBURTON
HSR	HIGH SULFATE RESISTANCE
IADC	INTERNATIONAL ASSOCIATION OF DRILLING CONTRACTORS
JIF	JET IMPACT FORCE
JSA	JUNK SLOT AREA
LC	LANDING COLLAR
LCM	LOSS CIRCULATION MATERIAL
MPT	MUD PULSE TELEMETRY
MSE	MECHANICAL SPECIFIC ENERGY
MSR	MODERATE SULFATE RESISTANCE
MW	MUD WEIGHT
MWD	MEASUREMENT WILE DRILLING
NCS	NORWEGIAN CONTINENTAL SHELF
ODC	ONSHORE DRILLING CENTRE
ODR	OUTSIDE DIAMETER RADIUS
OPC	ORDINARY PORTLAND CEMENT
PDC	POLYCRYSTALLINE DIAMOND COMPACT
RC	ROLLER CONE
ROP	RATE OF PENETRATION
RPM	REVOLUTION PER MINUTE
RSS	ROTARY STEERABLE SYSTEM
SDL	SURFACE DATA LOGGING
SSR	SUBSURFACE RELEASE
SWP	SINGLE WIPER PLUG
TFA	TOTAL FLOW AREA
TSP	THERMALLY STABLE PDC
TVD	TOTAL VERTICAL DEPTH
UCA	ULTRASONIC CEMENT ANALYZER
UCS	UNCONFINED COMPRESSIVE STRENGTH
WOB	WEIGHT ON BIT
WOT	WEIGHT ON TARGET
WTF	WEATHERFORD

1. Introduction

This thesis is a comprehensive study of shoe tracks drillout with focus on the drilling efficiency evaluation and its optimization.

Shoe track (Fig.1) is a space between float or guide shoe and landing or float collar. Primary function of this space is to provide accommodation for contaminated cement and prevent it from filling the space around casing shoe and annulus. Above the shoe track, float collar is placed. It provides seat for wiper plugs used during cementing operations. A float shoe with non-return valve is placed at the bottom to prevent reverse flow of cement slurry back into the casing after placement.

This thesis work presents field case analysis of shoe track drilling both in cement and plug setting. Main goal of this study is to evaluate the ROP (rate of penetration) with respect to various drilling parameters such as RPM (revolution per minute), torque, WOB (weight on bit) and well hydraulics. In addition, ROP optimization studies along with drillability issues are presented. The float equipment drillout efficiency is analyzed basing on field data.

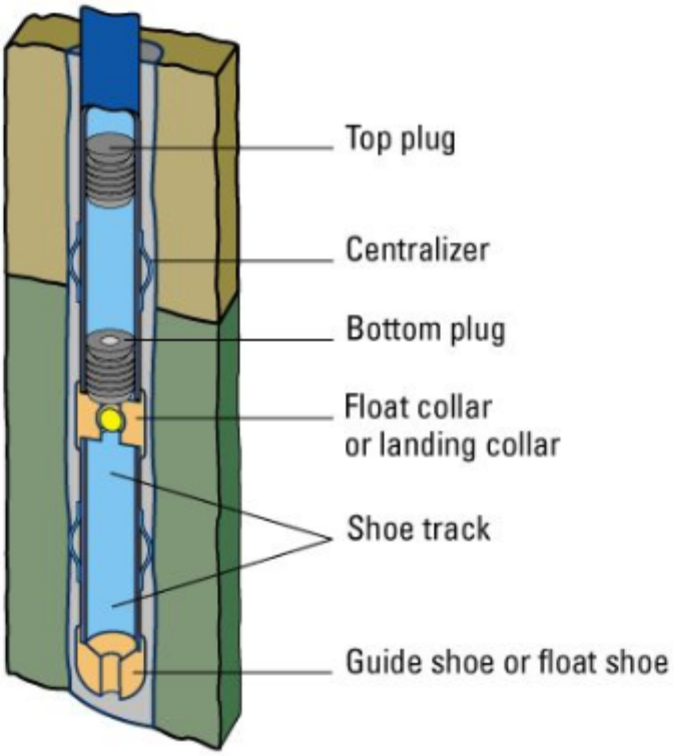

Figure 1: Shoe track components [24]

1.1 Background

Typically shoe track drillout study is an internal analysis within a service company. By trying different bit configurations and drilling parameters, drill bit and float equipment suppliers look for the most optimal way of shoe track drillout.

Early study of *PDC* (Polycrystalline Diamond Compact) bit performance while drilling shoe tracks was performed by J.G.A. Punnel *et al*. in 1996 [43]. The earlier designs of PDC bits were unable to drill new formation after shoe track drillout due to severe bit damage while drilling through float equipment. According to Punnel *et al*. area between landing collar and float valve is the most damaging for the bit. The landing collars contained funnel-shaped aluminum parts, darts, and the setting ball. The float configuration was comprised of float, shoe track and shoe.

Tests were carried out to assess bit performance while drilling out shoe track. Bit used during the tests was conventional for that time PDC bit with IADC (International Association of Drilling Contractors) number M332. Please refer to Appendix D for IADC bits' classification. The shoe track was drilled with slowly increasing WOB from 1.5 ton to 5 ton (3 klbs to 10 klbs). The system was constantly getting plugged up and had to be cleaned regularly. After the test had been finished, the drill bit was inspected. The inspection showed broken blades. Firstly, the authors thought that the reason for this was the float equipment, partially made of aluminum and bronze. However, after the materials were changed to rubber, the problems repeated. In addition to being severely damaged, blades were also plugged off with rubber. In the end it was decided to change the M332 bit configuration. Main idea was to reduce space for junk accumulation and minimize its impact on the cutting structure. A new bit with IADC number M433 was designed. It had two small openings instead of three to reduce available for junk space. Tapered blades were introduced instead of parallel ones. It was done to redistribute the loads from the weaker tops onto stronger base of the blades. Backrake angle was also increased to aid loads redistribution. After all changes have been done, the weak points were no longer on the cutters, and the bit strength was increased with 70%.

H. Rogers *et al.* [46] have evaluated shoe track drillouts using the conventional (motor) and RSS (rotary steerable system) drilling assemblies. They have concluded that most float equipment and wiper plugs can be drilled out with PDC bit, even though their aggressive nature may cause large debris creation. If not transported out properly, these large pieces can pack off the string and result in bit pump off[1].

H. Rogers *et al.* provided an example of conventional drilling, where extended drillout due to increased flow rate was experienced. Only after flow rate had been reduced, penetration through plugs was initiated. Next example showed us rotary system performance. This method is often preferred to the conventional one due to its improved ROP. *Point the bit* method aids better borehole quality. This technology allows using more PDC bits than conventional motors.

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[1] Pump off – plugging and bridging of cuttings, hampering the work string loads transfer to the bit, leading to reduced ROP.

[2] Rotary kiln – pyro processing device to bring materials to high temperature in a

The authors also discussed importance of ROP and WOB restriction to avoid creation of big pieces of plugs and collars, which are difficult to transport out of the borehole. Too high penetration rate might initiate spinning of some parts of the float equipment. Using non-rotating plugs makes the drillout process easier. Other solutions to avoid rotation are available, for example interlocking tooth profiles of float equipment and plugs, covering wiper plug with cement etc.

H. Rogers *et al.* gave general recommendations for shoe track drilling, which include following points:

- Record rotary torque before spudding to establish a bench mark,
- Monitor the torque: zero torque might mean spinning of the target,
- Do not allow fast penetration due to creation of large debris,
- Reciprocation can be allowed only if penetration stops.

Service companies create their own recommendations and procedures for shoe track drillout. Procedures, developed by ODC (Onshore Drilling Centre) in Halliburton, can be found in Appendix A. Its summary is presented in the table below:

Table 1: Summary of procedures for shoe track drillout by Halliburton ODC, citation [31]

PDC Drillout Procedures	Tri-cone Drillout Procedures
Plugs/Landing Collar: – Note free rotating torque before drilling wiper plugs – Tag gently with low flow/no rpm – DO NOT SPUD the bit – Low WOB, 0.5-1 klbs per inch of bit – High Flow Rate – Low RPM: 20 - 80 – Pick up every 15 - 30 min to clear debris. *Float collar/Cement/Shoe:* – 40-60 rpm – 2 klbs per inch of bit – 40 gpm per inch of bit – Don't excess WOB when the plugs\float collar is drilled.	– Take free rotating torque – 40 gpm per inch of bit – 40-60 rpm – 6-10 klbs WOB – Need to see 1 to 3 kftlbs torque over free rotation to see bit working – If not working, parameters must be changed – more WOB and flow rate.

1.2 Problem statement

Shoe track drilling is often a troublesome and time-consuming operation that has to be performed to start drilling a new section. Few studies of this issue have been carried out due to lack of common criteria for drillout assessment. As a rule, the operator company wishes for fastest drillout, which usually implies higher penetration rate in both cement and float equipment. Penetration rate is a function of operational parameters, drill bit specifications and drilling target properties. It is also well known, that high penetration rate has to go along with sufficient hole cleaning, which makes hydraulics an important part of efficient drillout. The main problem of drillout time estimation is complexity of shoe track composition. Typical 13 3/8" shoe track consists of wiper plugs, float collar, cement and casing shoe. 7 ¾" liner has landing collar and sometimes stage collar in addition. Float collars and landing collars are used to aid control during cementing, and their number greatly depends on planned length of shoe track and formation properties. There is a large variety of mechanical components that differ in design and materials. Casing shoe typically contains a non-return valve, which also has to be drilled out. As a result, minimum three different components have to be studied separately to estimate how long time it will take to drill a particular shoe track using predefined drilling parameters and drill bit.

To optimize shoe track drillout we should be able to answer following questions:

- Which plugs and collars design should be preferred?
- Which bit should be chosen for efficient drillout of both mechanical components and cement?
- How operational parameters affect the drillout?
- What operational parameters should be used for different shoe track components?
- How does cement quality affect the drillout?
- What effect operational parameters exert on cuttings transport?

A thorough analysis of several shoe tracks has to be performed in order to answer questions stated above. In addition to this, we would like to model and predict effect of operational parameters on cement drillout. Therefore, we formulate two more questions:

- What effect variation in operational parameters will have on cement drilling?
- Can we predict penetration rate in cement using existing ROP models?

In this work we try to answer these questions, what automatically divides the thesis into two parts: (1) analysis and optimization of float equipment drillout, and (2) cement drillout evaluation and penetration rate modeling. In the first part we conduct an extensive analysis of float equipment used for 7 ¾" liner and 13 3/8" casing cementing. The second part is devoted to modeling of penetration rate in cement and determining how different operational parameters influence ROP in cement.

1.3 Objectives

The objectives of this thesis are formulated basing on main questions to be answered:

- Analyze float equipment drillout discriminating between different designs,
- Determine how different bit designs affect float equipment and cement drilling,
- Determine the most important operational parameters affecting float equipment drillout and study their influence on drillout time,
- Propose operational parameters for fastest float equipment drillout,

– Model penetration rate in cement using existing ROP models (include bit hydraulics and cement strength into study),
– Perform sensitivity analysis using ROP models,
– Compare results of sensitivity analysis and make conclusions,
– Perform cutting transport analysis in WELLPLAN to determine minimal flow rate for proper cuttings removal,
– Give general recommendations about shoe track drillout and compare them to existing ones.

1.4 Methodology

As specified above, the shoe track drillout analysis is split into two parts: mechanical components drillout and cement drillout. To conduct a quality analysis of mechanical components drillout, we need to focus on details: describe components and sub-components, order they are placed in, preferred materials and overall design. Moreover, depending on the shoe track, we might have one, two or more collars; plug system may consist of several plugs and darts; shoe might have zero, single or double float valve. These parts have different functions and properties; therefore, they will be analyzed separately from each other.

We tried to choose shoe tracks with similar configuration to have common reference point: this way the effect of variables on drillout time can be easily seen. The variables can be either operational parameters, drilling tools (drill bit, bottom hole assembly (BHA)) or float equipment design.

For our analysis we have chosen two sets of wells, we call them “H” wells and “K” wells. Analyzed shoe tracks in “H” wells had diameter of 13 3/8” and were drilled out with PDC bit. Shoe tracks in “K” wells were part of 7 ¾” liner and were drilled through with roller cone bit. Due to similar float equipment configurations and bit design within both groups, the main focus of analysis will be drilling parameters. We, however, will also see few cases, where alternative float equipment and drill bits with different IADC code were used.

Cement drillout will be analyzed just for “H” wells. Main focus here is analysis of operational parameters. Firstly, we will see how operational parameters affect penetration rate separately and in combination. For this purpose we use MRA in Excel (multiple regression analysis) (see section 5.2.2). After having done that, we will apply ROP optimization models and ROP prediction models that have been chosen among the existing ones for this analysis (see chapter 5.2). We will also conduct sensitivity analysis to see how operational parameters influence cement drillout according to different models. Since hole cleaning is one of the crucial aspects of successful drilling, we will also perform cuttings transport simulation to calculate the minimum flow rate required for proper hole cleaning. It will help us to recognize whether cuttings transport was an issue in the analyzed well.

To introduce reader to the analysis structure, we illustrate it in the flow-chart:

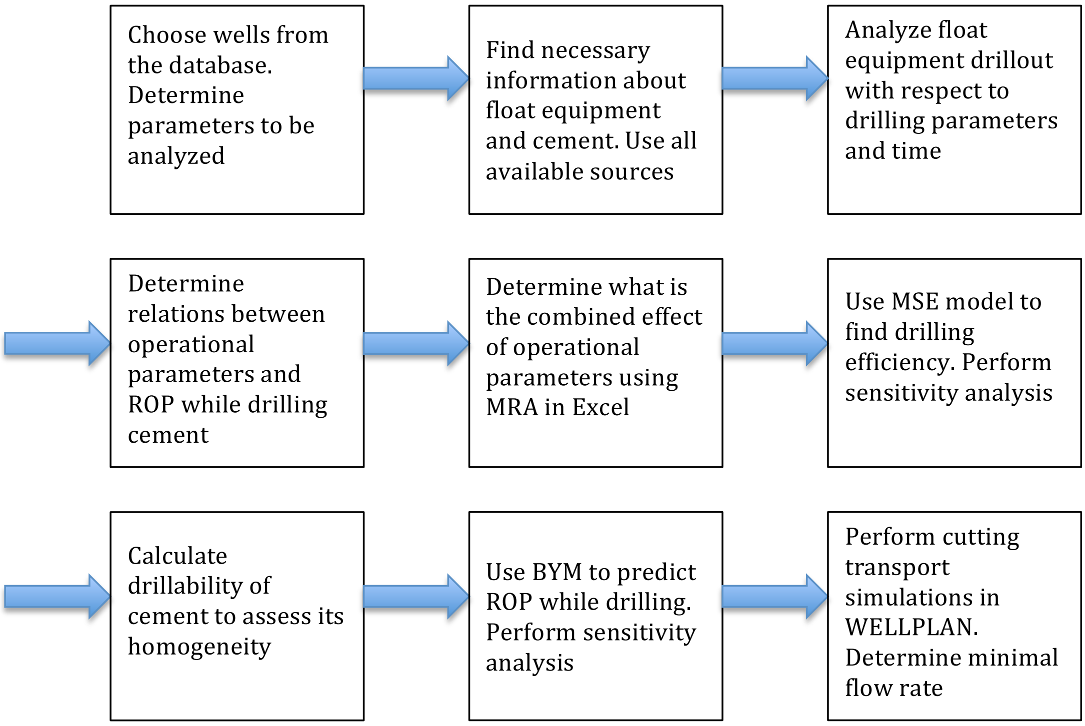

Figure 2: Main steps of shoe track analysis

1.5 Challenges and assumptions

It is hard to generalize shoe tracks due to their complex design. It is even more challenging to find the way to evaluate the shoe tracks that already have been drilled. Bits characteristics, mud rheology, operational parameters, cement quality and plugs and collars design vary from well to well. Typically an oil company would get proposal from service companies on how to design a shoe track and how to drill it out. The issue is that there are often 2 or 3 service companies involved, and then a question about compatibility of equipment arises. For most cases, the choice will be based on the experience with particular equipment. This approach may or may not work due to plenty of factors involved. In this work we try to combine the existing "best practice" with data analysis to provide more specific recommendations for successful shoe track drillout.

Another challenge is linked to data quality and consistency. Drilling performance analysis is highly dependent on good quality input data. It was observed that in some cases reported drilling parameters differ somewhat from the logged ones, and surface data deviates from downhole data to some extent. In this study we used surface logging data provided by Sperry Drilling Services. More information about data acquisition and transmission can be found in sections 4.2-4.3.

Finally, human factor plays important role in any work. Database quality highly depends on how well thought through is the way of storing historical data. Our experience showed that better database structure and better reporting routines could aid the process of data extraction for analysis like one conducted in this thesis.

In this study main assumptions are as follows:

1. Cement within one shoe track is homogeneous. Mud contamination and micro cracks were not taken into account,
2. Pore pressure in cement is equal normal hydrostatic pressure (1.03 sg): when cement has hardened, the only mobile phase in it is salt water [1],
3. Surface logging data is assumed to be reliable,
4. Tooth wear is negligible, if not specified otherwise. Shoe track length is short in comparison to the whole section, therefore it would be incorrect to base bit grading after shoe track drillout on general bit grading, performed after the bit has been pulled out to the surface,
5. Main criterion for cement drillout analysis is ROP, for plugs and collars – time.

2. Literature study

In this thesis we use specific for cementing operation terms, which may be not well known for all readers. Therefore, in this chapter we define these terms and briefly explain process of primary cementing and equipment used. We also discuss cement types that are currently used for cementing operations offshore Norway. We then define and describe parameters that are deemed to affect drilling in general, and shoe track drillout in particular. Finally, we will describe two main types of drill bits, explain main design features and see how they might affect drilling.

2.1 Primary cementing techniques

"Primary cementing is a technique for placing cement slurries in the annular space between the casing and the borehole" [37, p. 459]. It is one of the important barrier elements that separates formation from casing and prevents migration of formation fluids. This operation is compulsory for all casings and liners in the well. The only exception can be reservoir section with openhole completion. Primary cementing has a few supplementary functions: it supports casing or liner weight, keeps it in one position and protects it from unwanted effects of contact with formation.

2.1.1 Casing cementing techniques

There are a few methods of primary cementing used nowadays. The method selection depends on formation strength, total well length and cement properties. One of the unconventional ways of primary cementing is so-called *reverse circulation cementing*. It is used sometimes when thief (lost circulation) zones or fragile formations are expected near the shoe. Since in this case the shoe is never cemented, float equipment selection has particular importance [37, p. 466]. Another method of primary cementing is called *grouting.* It is sometimes used for cementing large diameter casings. During grouting several pipes of small diameter are placed in the annulus, and cement is pumped down through them. Two abovementioned techniques are used sometimes for intermediate and production casings cementing.

Cementing technique used for wells in our study is called *single-stage* cementing. The operation starts with running in casing and setting it in slips. Then mud circulation is established. Circulation lasts for as long as it is required to ensure clean hole and stable gas reading. To obtain good quality cementing, we must ensure to separate mud from cement. Even small amount of mud might contaminate cement, what will lead to reduction in cement's strength. Two methods are usually used to separate cement from mud: spacer, which must be compatible with both cement and mud, or wiper plug system (different configurations are possible here), which is a mechanical barrier between these two phases. Often both spacer and wiper plugs are used to avoid contamination. Cementing operation starts with pumping drilling mud, spacer, and finally a bottom wiper plug. Then a slug of cement slurry is pumped into casing, followed by a top plug and finally drilling mud. Ideally the phases move down in sequence, without intermingling. In reality, spacer and drilling mud are being mixed to some extent due to higher density of spacer. This is exacerbated by wiper plug, which goes after the spacer and scraps pipe walls, this way pushing leftovers of drilling mud into spacer column. When the bottom plug reaches the float collar it cannot move further and its membrane breaks under hydrostatic pressure of liquids being pumped. The cement flows through the collars and float equipment, reaches casing bottom, flows out and up along annulus between outside casing wall and formation. When all cement has been displaced, the top plug lands on the bottom plug, surface pressure increases, indicating end of cementing operation [7, p.18].

2.1.2 Liner cementing techniques

Liner cementing equipment includes cement head, which contains dart-releasing stem mechanism. Plug system may contain one or two wiper plugs and one or two darts. Liner cementing starts with rigging up cementing lines and pumping spacer down the drillpipe. Cement slurry follows the spacer, and pumpdown dart is deployed just behind the slurry. The dart is then displaced to the special seat in the wiper plug. When pressure rises due to fluid pumping, pins holding the plug in place are sheared and the whole assembly moves down to the landing collar. Then pressure is increased again, indicating end of cementing job.

In case of two-plug system, the plugs are preinstalled in the liner. The lower pumpdown dart is launched, and cement is pumped. The dart under hydrostatic pressure will move down into the lower plug and the whole plug-dart configuration will be displaced to the landing collar. After cement has been pumped, it is displaced by spacer. The upper dart is then launched, and it lands into the upper plug. The whole arrangement is then moved down just above the bottom plug in the landing collar. This system of two plugs, two darts and inner parts of landing collar will be drilled out in the next run [37, p. 480].

2.2 Cement types and testing

2.2.1 Regular cement

Regular cement or OPC (Ordinary Portland Cement) is the most broadly used binding material in oil industry. Such cement is called *hydraulic cement,* because it sets due to chemical reactions between cement components and water. The compressive strength develops with time as a result of *hydration* process. Raw materials that are needed to make a mixture for cement are *calcareous* and *argillaceous* materials. Calcareous materials can be limestones, corals, shells or artificial calcareous materials. They contain calcium. Argillaceous materials like clays, shales, schist, marls and etc. contain alumina, silica and iron oxide. If these minerals are not present in clay or shale, they are added separately. Other compounds, like salts, normally do not exceed 5 % of total composition.

Cement manufacturing is a multistage process. Row materials are first blended and reduced in size. They then go through heating in a rotary kiln[2]. The ready mixture is called cement *clinker*. Clinker then undergoes cooling and grinding before the prepared cement can be stored for future use [41].

Important property of cement is its ability to develop compressive strength when it interacts with water. It keeps this ability even when fully submerged into water. Cement hydration is a series of complex chemical reactions that happen at the same time and influence each other. The primary components of OPC (C_3S, C_2S, C_3A and C_4AF) have different hydration phases and reaction products. Cement hydration is an exothermic process, i.e. heat is released after cement has been brought into contact with water. The *absolute volume* of cement decreases, because hydration products have higher density than initial components. The *bulk volume*, however, stays the same due to increase in porosity. Higher temperature quickens cement hydration. However, according to some researches, temperature above 110^0 C may decrease stability of some components [37, p. 37].

The most typical cement classification is API (American Petroleum Institute) classification [3]. It divides cement into 8 classes based on downhole conditions, namely pressure and temperature and depth at which they are positioned. Some classes specify the sulfate resistance. The resistance levels to sulfate are 0, MSR (moderate sulfate resistance) and HSR (high sulfate resistance). The classes are defined below:
Classes A, B and C consist mainly of hydraulic calcium silicates with one or more forms of calcium sulfate.
Class A: No special properties are required. It is only available in 0-grade sulfate resistance.
Class B: Conditions require moderate or high sulfate resistance. MSR and HSR grades are available.
Class C: Conditions require high early strength. Cement is available in all three grades.
Classes D, E and F have similar composition to abovementioned classes, but allow for more options. They are used for moderately high temperatures and pressures and are available in both MSR and HSR grades. These three types have good retarding properties, which means they need more time to set and can be used in longer wells.
Class G: No other additives, but sulfate and water can be mixed with the clinker. This class is available in both MSR and HSR grades.
Class H: No other additives but calcium sulfate or water can mixed with the clinker. This class is available in both MSR and HSR grades.
Classes G and H are the ones most often used in well cementing.

[2] Rotary kiln – pyro processing device to bring materials to high temperature in a continuous process [53]

2.2.2 Foamed cement

Construction industry was the first to use foamed cement, already in 1950's. Oil industry has adopted this technique in 1979 and has been using and developing it since then. Such cement is often used to avoid lost circulation problems. Due to its low density, foamed cement will exert less pressure on weak formation [37, p. 248].

In our study we do not analyze foamed cement, therefore detailed description will be given as supplementary information in Appendix B.

2.2.3 Compressive strength testing

Needless to say that cementing is a very important aspect in well construction. The Macondo accident in 2010 showed that mistakes in cement composition could lead to fatal consequences. Therefore, cement testing has to be performed for all slurry compositions under simulated downhole conditions. The compressive strength test is the utmost important test applied to the concrete, which gives a good picture of its quality. Compressive strength depends on several factors, including type of raw material and additives, slurry design, method and time for curing and temperature [22]. To perform the test, cement slurry specimens have to be prepared first. Cement of measured weight is added water and other components. The mixture is blended using a mixing machine. The mixture is then left for cure in a mold under predetermined temperature and pressure for up to 24 hours. After it has been cured, the compressive strength can be determined either by crushing the specimen or by evaluating it in a UCA (Ultrasonic cement analyzer, Fig. 3) mold [25].

Figure 3: UCA, Halliburton cement testing lab [26]

The UCA is used as a non-destructive method to find compressive strength of a specimen basing on measured delay time of an ultrasonic wave traveling through the molded cement sample. The compressive strength can be described as a *function of time it takes the acoustic signal to travel through the sample*. A set of equations is then used to convert velocity to uniaxial compressive strength [22]. Results of UCA test are usually presented as in the graph below.

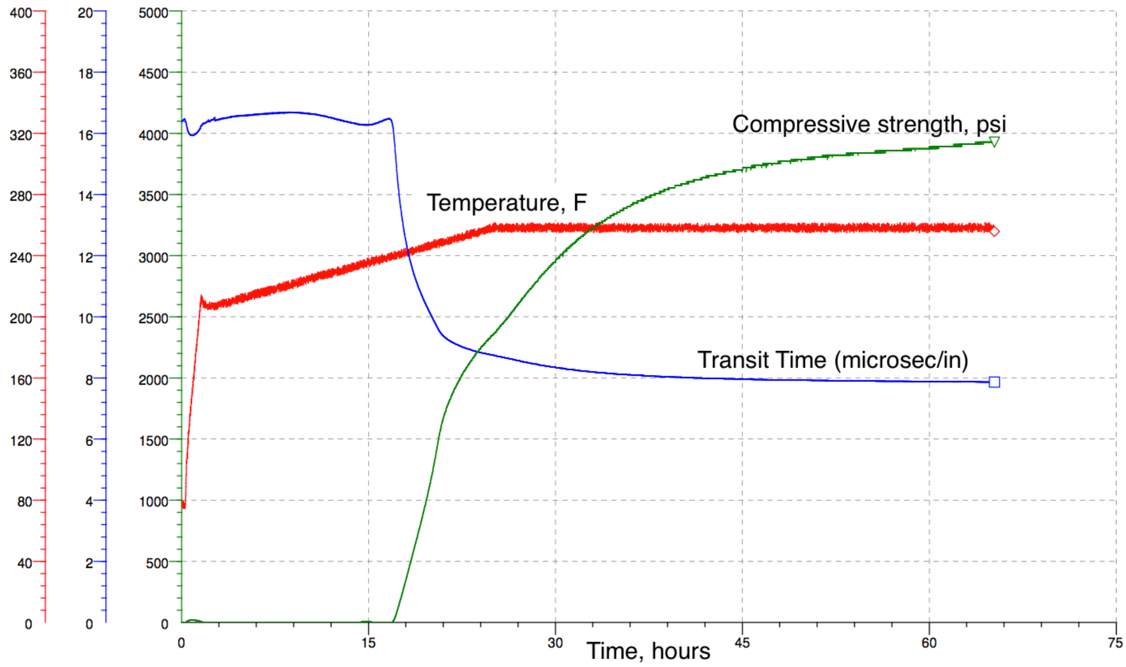

Figure 4: Example of an UCA chart for cement slurry used for casing cementing for a well on Ekofisk field [19]

As mentioned before, this test determines the concrete strength under conditions similar to the downhole ones. Experience showed that 3000 psi is the optimum curing pressure, and the increase in strength above this pressure was small. This number might vary depending on slurry composition and equipment. In some cases the actual wellbore pressure should be used to achieve a good strength development [26].

2.3 Shoe track

"The distance between the float collar and float shoe (usually 1-3 joints) is called the *shoe track*" [33]. This space is filled with tail slurry after the top cementing plug has been placed in the collar. Cement in the shoe track is often mixed with some mud wiped from the inside of the casing. It is not desirable for contaminated slurry to be displaced into the annulus, since the contamination potentially reduces compressive strength of cement. So the purpose of shoe track is to ensure that contaminated cement stays inside the casing [47]. Some companies use another definition for shoe track. They refer to it as to all components found at the bottom of casing related to casing cementing (collar, cement and float shoe). In this thesis we also hold to this definition. All the mechanical components are referred to as *float equipment*.

2.3.1 Casing float equipment

At the bottom a guide shoe or a float shoe protects casing. The shoe is placed one or two joints below the *float collar*. Guide and float shoes can have different designs, but commonly they are tapered and bullet-nosed. The outer parts of this device are usually made of steel and have the same size as casing. The inside part is made of more easily drillable material, like concrete or thermoplastic. If it is not the last section of the well, the inside parts will have to be drilled out, and hence they are made of less hard materials. There is a difference between guide shoe and float shoe: guide shoe does not have check valve. Check valve is used to prevent backward flow, or U-tubing, of cement slurry from the annulus to the casing. Another function of check valve is to increase casing buoyancy by not allowing mud to enter casing from inside [37, p. 362].

Service companies that provide float equipment have their own models for all parts typically used for cementing. Halliburton, for example, offers two types of guide shoes, these are *standard guide shoes* and *down-jet guide shoes*. Features of both types are presented in the table below [30]:

Table 2: Halliburton guide shoe types [30]

Standard Guide Shoes	Down-Jet Guide Shoes
Directs casing away from ledges	Has additional side ports to allow for fluid discharge both through bottom and sides
Has large diameter hole in the bottom to allow high cementing rates	Additional ports create turbulence for better cement placement
PDC drillable	PDC drillable

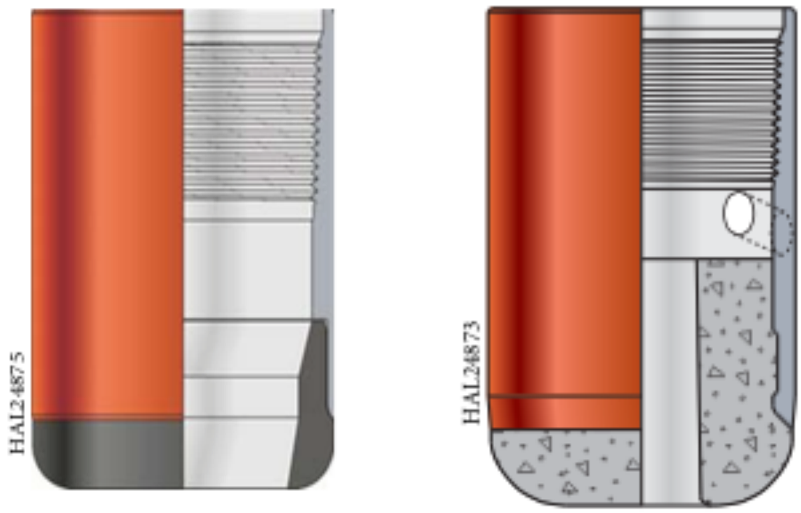

Figure 5: Halliburton's guide shoes: Standard type and Down-Jet guide type [30]

Shapes of guide shoes can differ. Examples of the designs are *Texas pattern* with a beveled nose and the *Saw-tooth pattern* (Fig.6) with saw-teeth looking edges. These noses are made of steel.

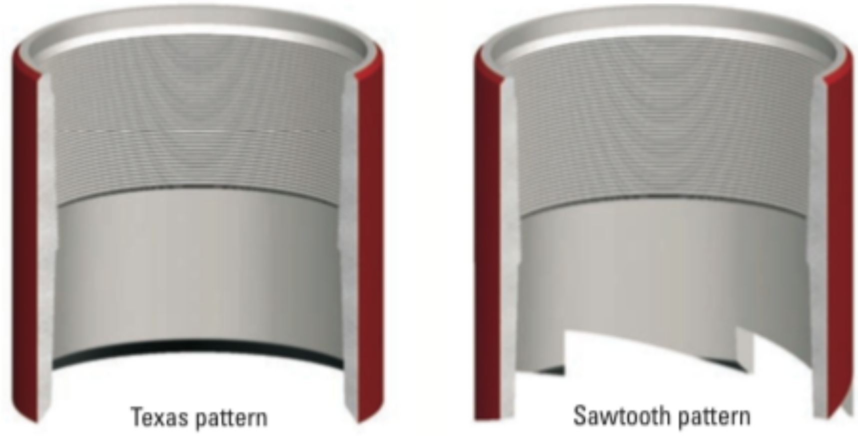

Figure 6: Weatherford's Texas pattern and Saw-tooth pattern guide shoes [51]

There is a variety of materials nose can be made of. The most common type is cement shoe, which is usually made of high-strength concrete with a compressive strength up to 7 MPa. The rounded nose is a form of protection from different obstacles met on the way. Another option is aluminum nose shoes. They are more difficult to drill through, but they come in different shapes and designs. Yet another option is composite nose shoes. They are often preferred because they resist high loads, abrasion, high temperatures and erosion.

Nowadays many operators prefer to use a float shoe because it provides additional non-return valve. There is a great variety of float shoes. To drill out the majority of them one has to use PDC drill bit as specified in the product sheets. An example of float shoe is shown in the figure below.

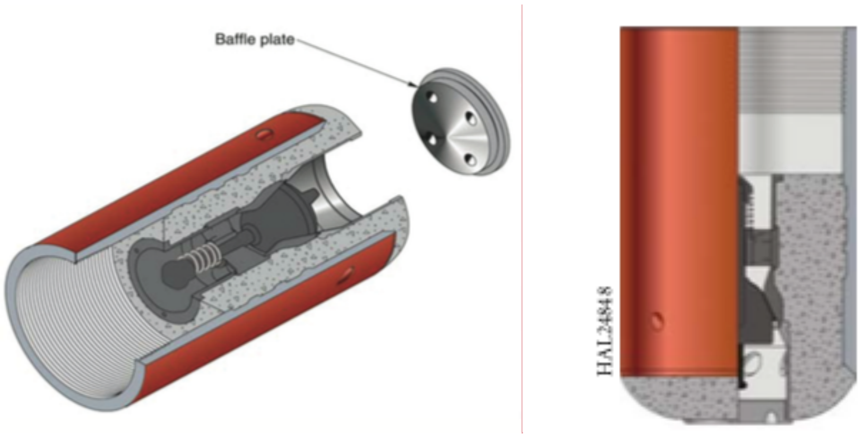

Figure 7: Halliburton's Super Seal II HPUJ (high-port jet-up) float shoe [27]

A *float collar* is placed one or two joints above the shoe to create space for shoe track cement and provide seat for wiper plugs. Usually when the casing is lowered it is filled with mud to prevent casing collapse and control the buoyancy [37, p. 365].

Wells are constantly getting longer and casings heavier. This leads to increased stress on derrick. Float equipment can help to control and reduce derrick stress by not filling the casing from surface while wellbore fluids are not allowed to enter the casing from the bottom. Once the casing is in place, it can be carefully filled, and mud can be circulated. A big concern in this operation is casing collapse. Operators and service companies provide a thorough study of casing drag prior the operation start and choose proper float equipment accordingly. Example of typical float collars is illustrated below.

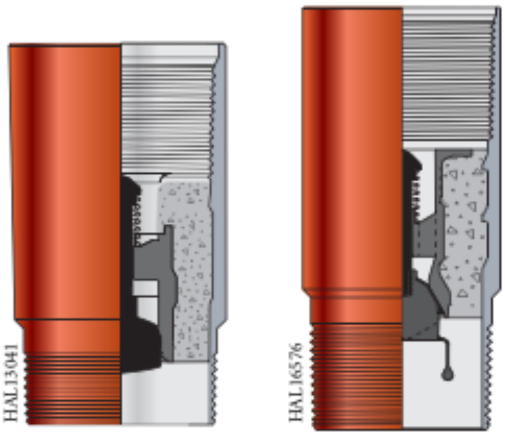

Figure 8: Halliburton's Trophy Seal float collar and Super Seal II float collar [27]

Alternative type of float collar is used for some of the wells analyzed in chapters 5 and 6. *Autofill float* equipment is used sometimes instead of the conventional one to save time while tripping casing in the hole and reduce pressure surges. Like the conventional ones, autofill collar contains check valves, but here they are adjusted to be in open position to allow reverse filling. This way casing is being filled constantly. To begin working as a conventional one-way valve, automatic fill-up equipment has to be converted. It is usually done when the casing is in place, however, it also might happen accidentally while running casing in. Abrupt stops for example can induce conversion mechanism. Maximum flow rate should also be limited to reduce sudden stresses. The valves are generally made to limit the casing overflow, but since annular space becomes smaller, this might be problematic. It often requires reduction of running speed.

Figure 9: Davis-Lynch double-flapper type autofill float equipment: running position and closed flapper valve [37, p.371]

After cementing has been performed, the *float valve* must prevent U-tubing. If that function fails, surface pressure should be applied until the cement sets. This practice is not preferred, because the casing expands under surface pressure, and when the pressure is released, the casing shrinks, which might lead to micro annulus between casing and cement.

Commonly three types of valves are used in float equipment: *ball, flapper* and *poppet* valves. There are many design variations. The latest inventions are double-flapper valve used for large bores. Various materials are used for valves depending on requirements for drillability, temperature resistance and bit compatibility. The most typical materials are resins, composites and aluminum. Different resins might be optional; the most standard one is phenolic resin[3]. Other types are nitrile rubbers[4], which are used for valve seals and coatings for temperatures up to 150^0 C. Some types of nitrile rubbers can withstand temperatures as high as 165^0 C and long-term contact with chemicals and oils. If the temperature downhole is higher – viton rubber[5] is used. Large springs are usually made of a phosphorous bronze, beryllium, or aluminum alloy. Small parts are made of steel, and they are typically too small to create a problem while drilling. All components are tested for drillability prior to use. Plastic parts are usually made of resins with high temperature and oils resistance and are drillable for any bit. Even though aluminum is easily drilled, some problems may occur while drilling through it, because it tends to tangle and smear over some PDC bits, so the bit choice in this case is important [37, p.368-369].

Typical design for *ball valves* (Fig. 10) is a ball-and-cage design. It consists of a ball, which is typically made of phenolic resin and may be covered with rubber, and a cage, which can be made of hard plastic or aluminum. These valves are effective in vertical wells; however, in highly deviated wells they may not block tiny flow of liquid or gas. Clearance between cage and ball is quite small, so use of solids should be limited to avoid jamming the valve. Resistance to temperature and wear depends on materials used, as described above. In general, ball valves are becoming less popular to use as a primary valve for cement placement [37, p.368].

Flapper valves (Fig. 10) represent a system of a spring-loaded flapper attached to a plate with an integral seat. Common materials for flapper and plate are aluminum or composite. Benefit of this system is that it is nearly unaffected by well inclination. The flapper opening is dependent on the flow rate and the spring strength. Flapper valve is probably the most common type of valves on the NCS (Norwegian Continental Shelf) due to its reliability. Backpressure and wear

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[3] Phenolic resin – hard, heat- treated plastic produced as a result of reaction of a carbon-based alcohol and aldehyde. Formaldehyde is used commonly, but other chemicals can be used too [55]

[4] Nitrile rubber – oil-resistant synthetic rubber fabricated from a copolymer of acrylonitrile and butadiene [23]

[5] Viton rubber – is a brand of fluoroelastomer. It is claimed to provide resistance to chemicals and extreme temperatures [16]

resistance to a big extent depends on the valve body, and usually has a good safety margin for the downhole conditions [37, p.368-369].

Figure 10: Weatherford's ball-type valve and flapper-type valve [51]

Poppet valves represent a spring-loaded plunger, placed in a cage. The system is similar to ball valves. The cage is made of phenolic resin or aluminum, while plunger is either fully made of nitrile-rubber or coated with it. Cage is made of the same materials as for ball valves: either phenolic resin or aluminum. Similarly to ball valve, the poppet valve has limited flow passage, so the solids in the mud should be avoided. The seating is practically not affected by hole deviation. This type of valves usually has higher-pressure resistance than flapper or ball valves. Wear and temperature resistance greatly depends on the materials used, and should be tested prior to operations execution. The general rule is to use softer alloys for the spring materials, chosen with temperature consideration. Poppet-type valve is illustrated in the figure below.

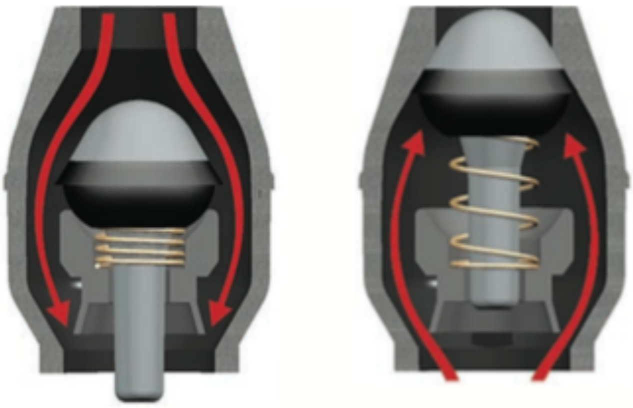

Figure 11: Weatherford's poppet-type valve [37, p.369]

Cementing plugs, or *wiper plugs* are mechanical barriers to separate cement slurry from other fluids, used prior and post cementing. They also wipe the casing from inside and help to recognize when cement slurry has reached the target position. Some years ago, there was a big variety of materials used for plugs, including wood and leather. Nowadays nitrile and polyurethane are used along with plastic for plugs production. One of the main requirements of many operators is non-rotation of plugs, because once plugs start spinning, it becomes more difficult for bit to get a good grip and achieve good penetration rate [37, p.378].

W.C. Perkins and E.P. Halliburton were first to use cementing plugs in the beginning of the 20th century. Nowadays, cementing plugs are even more significant due to increased requirements to job quality. Functions of cement plugs are:

- Fluid separation inside the string
- Wiping of the inside surface of the string to prevent the formation of film from fluids displaced earlier
- Hydraulic seal with collar

Cementing plugs can be made of different materials. Usually, the following ones are used to build insert - the structural component of cementing plugs:

- Cast or wrought aluminum – used in low to moderate cost environments, in general very common. Their pressure-holding capability depends on the elastomeric material used to provide the hydraulic seal on landing seat
- Hard elastomer or rubber – such materials have moderate strength at temperatures up to 80^{o}C and low strength above 90^{o}C
- Phenolic plastic – these lower-cost materials are used to manufacture low to moderate service environment cementing plugs. Engineered phenolic plastic materials are used for the production of moderate to extreme service environments production plugs. Pressure-holding capability mostly depends on the outer elastomeric material, used to form the hydraulic seal.

Materials have to be evaluated for chemical capability with the fluids used.

Another important component of the cementing plug is wiper (fins). Materials listed below are the most common for wiper manufacturing [47]:

- Natural rubber – offers very good water resistance and pressure-holding capabilities for both low and high temperature applications
- Urethane – it is less expensive material, has good to excellent water resistance at low temperatures. However, when the temperature is above 90^{o}C mechanical properties become weaker leading to low pressure-holding capability
- Synthetic rubber – this material has been successfully used for many years at all temperatures with all types of mud system. This material has great wear-resistance and offers excellent pressure-holding capabilities.

Two plugs are typically used during cementing: a top and a bottom ones. They look similar from outside, but have different internal design and functions. Bottom plug is launched before cement and has an internal bypass for slurry. It also has thin membrane, which is broken under high hydrostatic pressure and allows the slurry to flow through it. It happens when the bottom plug has landed into collar and further passage is impossible. This plug also provides a seat for the top plug. More plugs can be used to separate spacers or washers. Third plug also provides a possibility to measure strokes required to bump the plug before pumping cement. This makes it possible to pressure test the casing before cement slurry has set without being concerned about improper cement-casing bond [37, p.378].

There is a big variety of wiper plugs in the service market nowadays. One example is presented below.

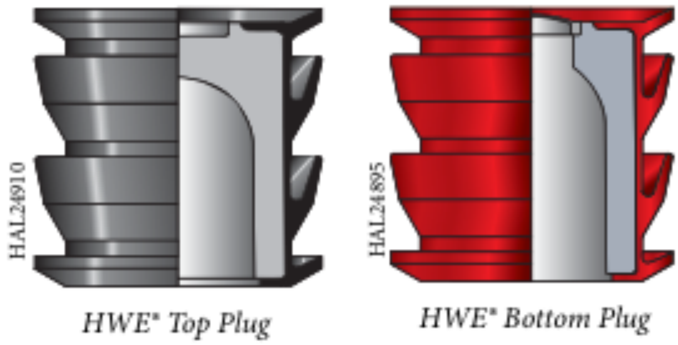

Figure 12: Halliburton's high wiping efficiency cementing plugs [29]

The plugs above are made from rubber and phenolic plastic. These materials are claimed to have high drillability and smaller cuttings [29]. The bottom plug 750-psi rupture disk provides larger opening, and therefore is more compatible with loss circulation material (LCM), which often tends to clog the fluid passage way. Important to notice, that unlike the majority of equipment we have seen so far, these plugs can be drilled with both PDC bits and roller cone bits. Some alternative models are presented in Appendix C.

2.3.2 Liner float equipment

Shoe track assembly is the lowermost part of the liner. Similarly to casing, primary function of liner shoe track assembly is to prevent contaminated cement from entering open hole section when cement job has been completed. Important components of the shoe track assembly are various valves (backpressure valves, float valves etc.), which are used to prevent U-tubing of cement slurry after running tool has been raised above the liner top [37, p. 415].

Typical assembly consists of three main parts:

1. *Float collar*. It is a valve system positioned at top of the shoe track, one or two joints above the shoe. The main functions of a float collar are serving as basis for wiper plugs (if landing collar is not used) and preventing slurry from moving up the casing string after it has been pumped into the annular space. After cement job has been performed, the space between shoe and float collar should ideally be filled with clear cement.
2. *Landing collar*. This part is usually run one or two joints above the float collar. In liner cementing jobs, landing collars offer an additional backup to the float valves. They prevent cement U-tubing when the running tool is pulled out of the liner top. In casing cementing, this part of the shoe track can be omitted.
3. *Liner shoe*. It is placed at the bottom of the string and is called float shoe or guide shoe. It is used to direct the liner down the well through open hole section. It also has side and bottom ports to ensure steady circulation even if the string is on its lower side. Usually the float shoe has one or two drillable backpressure valves.

Displacement plugs in liner serve the same purpose as cementing plugs in casing. Cement has to be separated from the other fluids to avoid contamination, which may provide a path for hydrocarbons and compromise well integrity. Standard cementing plugs are dropped directly from the surface as they go through the casing of constant diameter. Liners are run on drillstring, which has smaller diameter than liner itself, so the plug cannot just be dropped from the surface because of the size. Two displacement plugs are used in this case: a drillpipe dart and a liner wiper plug. The dart is placed in the cementing equipment on the surface and is kept in place by a pin inside the dropping device. The wiper plug is positioned downhole and is either attached to the bottom of the liner setting tool or to the top of the liner hanger equipment. It has a passage for fluid flow. After cement has been pumped through the string, the drillpipe dart is launched by shearing a pin, which holds it in place. The dart serves as a mechanical separation between cement and displacement fluid. It goes through the inside of the string until it reaches the liner wiper plug. Then they both move to the landing collar and push cement into the annulus. Increased pump pressure indicates that plugs have displaced the cement. The whole sequence is illustrated below:

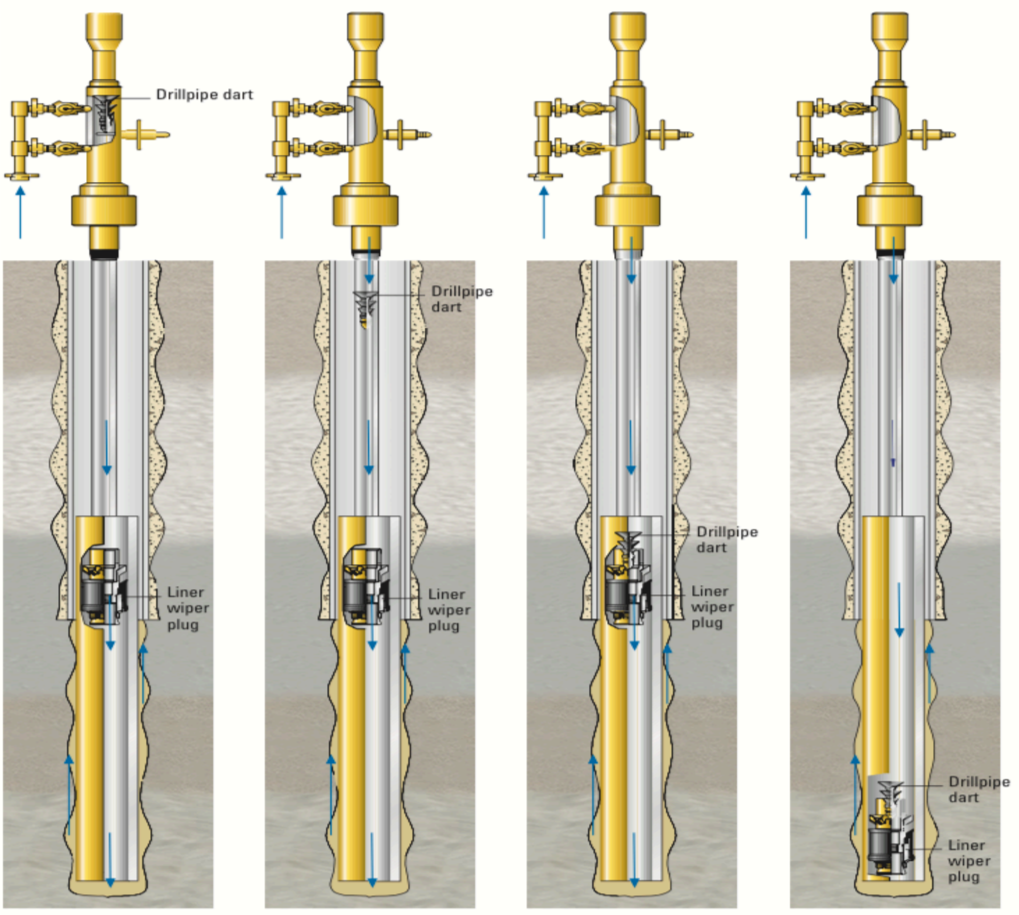

Figure 13: Displacement sequence using wiper plug and dart, Baker Oil Tools [37, p.417]

This way of cementing does not prevent intermingling of cement and spacer at the head. Thus some operators prefer another method, where cement is separated at both ends by the drillpipe darts, so the number of plugs doubles. A special landing collar is required for this operation to let the slurry pass by after the first drillpipe dart has landed on it. This system of plugs is also preferred when the formation is weak and cannot withstand hydrostatic pressure of total cement volume at once.

Cementing valve is placed in the liner to allow first portion of cement to be placed and set. Then the valve is opened, and second portion is placed on top of the first one. The first portion has already been set, and it does not exert hydrostatic pressure, as does the liquid slurry. Thus the total hydrostatic pressure is reduced.

2.3.3 Special offshore techniques

Cementing operations offshore differ from those on land. Plug system is the one that varies depending on the surroundings. Plug system offshore is similar to the one used for liners. It usually includes a top and a bottom plugs. The bottom one is normally activated with a ball, which moves through the drillpipe by gravity. Nowadays darts are often preferred to balls to initiate the activation [37, p. 484].

Conventional plug release system consists of a special subsea assembly in the casing (Fig.14). Cementing head, which is connected to the drillpipe, carries out control of cementing plug release. A launching ball and a dart are placed in the cementing head, while plugs are located subsea. General cementing procedure is as follows: ball is released from the head and it lands into the bottom plug before slurry is pumped. Pressure is increased, and connector pins that were holding the plug, are ripped, so it is now free to move down the casing until it meets the collar. More pressure is applied to squeeze the ball out through its orifice seat, and cement movement continues. A ball catcher in the bottomhole plug then captures and keeps the ball. After cement has been displaced, the top-plug launching dart is released. It moves down until it meets the top cementing plug, where it settles. Increased pressure leads to sheared pins, and the plug is released from the launching mandrel. It moves along the string and bumps on the float. Increased pressure indicates end of operation.

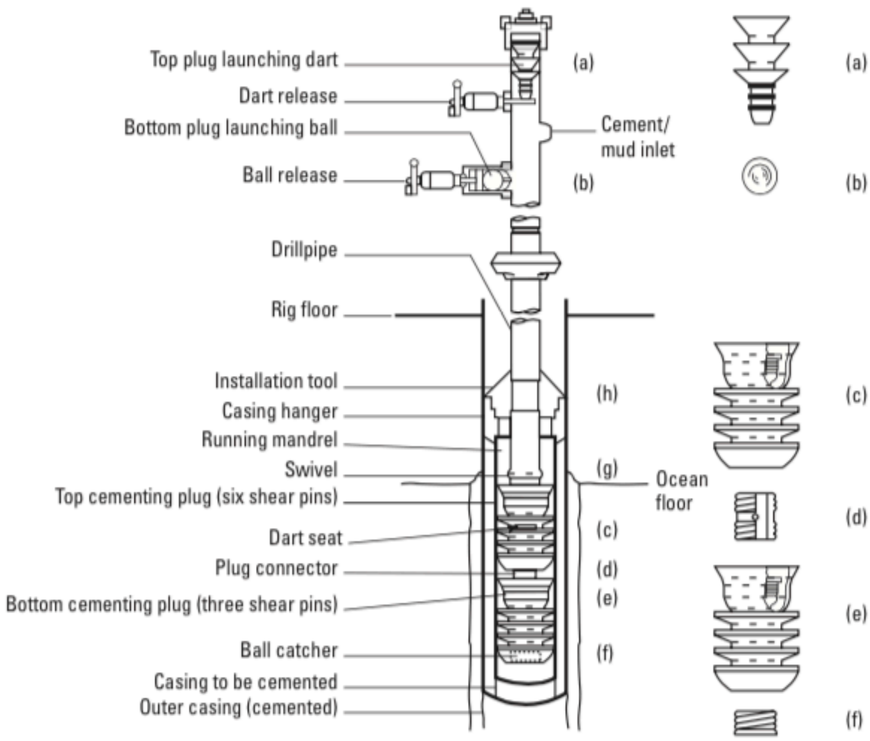

Figure 14: Single stage subsea cementing system [37, p.485]

2.4 Drill bits

Bit types are divided into two main categories, which are roller cone bits and fixed cutter bits. Fixed cutter bits can be subdivided into several types, which are diamond-impregnated bits, thermally stable PDC bits and natural diamond bits. The most common of them is polycrystalline diamond compact, or PDC bits. The primary difference between roller cone and PDC bits is that PDC works as one piece, there are no separately moving parts; therefore it is often considered to be more robust. Roller cone consists of body and bearings that are rotating independently of each other.

2.4.1 Design and characteristics of roller cone bit

This type of bits is typically used for hard or very soft formations at low rotational speed, usually for top holes drilling (Fig.15). The roller cone bits typically consist of three *conical rollers*. Each of them is mounted on *bearings*. When bit is in rotation, the rollers revolve around their center, breaking target surface with teeth, placed on them. Teeth can be made from different materials, typically steel and more rare tungsten carbide. The ones made from steel are called *milled-tooth bits*, where the cones and teeth represent one unit. The tungsten carbide bits have inserts, pressed into the cones. There are several rows of the inserts, and each row operates differently and has its own function. The inner ones have lower velocity of rotation, and hence, have different tooth action than the outer rows. Higher tungsten grades are normally used for their design to provide better wear-resistance [49].

Figure 15: Milled tooth bit and tungsten carbide bit [6, p. 31 and 29]

2.4.1.1 General design areas

The design goals of roller cone bits are low costs, long downhole life without need for tripping out, steady and vibrational free drilling, and precise cut gauge. Multiple parameters affect bit performance. One of the most important is drilling environment: hole length, nature and formation homogeneity. Other important parameters are drilling fluid, rotational speed and weight on bit. Design process is usually focused on the following aspects: materials, geometry and type of cutting structure, mechanical operating and hydraulic requirements. Steel is the most typical bit material. It should have proper yield strength, heat and temperature resistance, and hardenability. The cutting structure is crucial for efficient penetration and cut gage. It has to be designed to avoid direct contact of formation and bit body. Hydraulic arrangement is important for cuttings removal and efficient penetration [49, p. 4-5].

2.4.1.2 Roller cone components

Bearings are tools that allow circular motion of a cone around a pin. Roller cones use typically two types of bearings: *roller bearings* and *journal bearings*. Each type consists of a number of separate components, including primary and secondary bearings, seal system, cone retention balls and a lubrication system. Bearing structure is critical for successful drilling, because bearings must tolerate high loads, while drilling the most abrasive formation. Increased size allows bearings to withstand larger weights and drill in harder formations; however, their size is limited by available space.

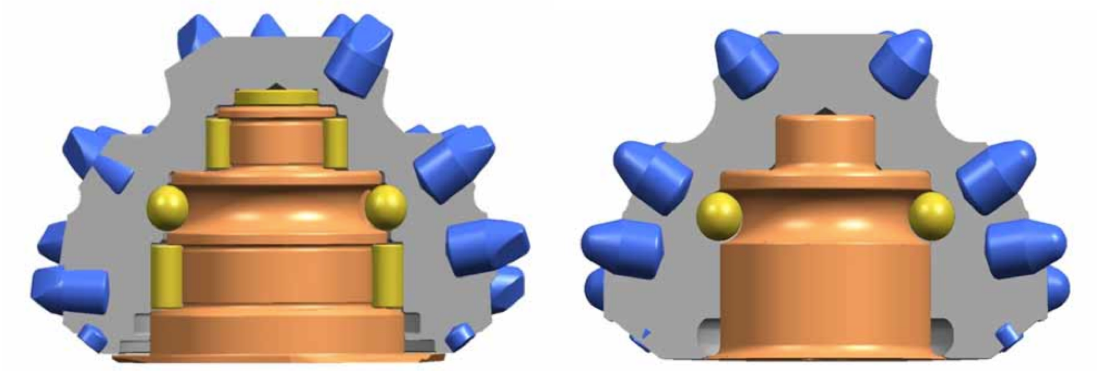

Figure 16: Roller bearing and journal bearing [2]

Seals provide protection for bearing system from cuttings and drilling mud. There are two main types of seal systems: *static* and *dynamic*. The first one involves sealing of non-moving parts, while the second one takes care of parts that are in relative motion to each other. As a rule seal system is present on all journal bearings, roller bearings might have no seal [10, p. 14]. Bearings with no sealing system are filled with grease and exposed to mud during drilling. Drilling mud lubricates and cools bearings, but at the same time its particles might be very abrasive. Therefore, nowadays sealing system is present on majority of the bits [10, p. 15].

Lubrication system carries important functions, including lubrication and cooling of bearings. A small lubricants reservoir is placed on each leg, so the three-cone bit has three reservoirs filled with lubricant. The lubricant is released when mud and cuttings pressure acts on the seal system and prevents seal failure due to high differential pressure in the well.

The roller cone bit arrangement is shown in the figure below.

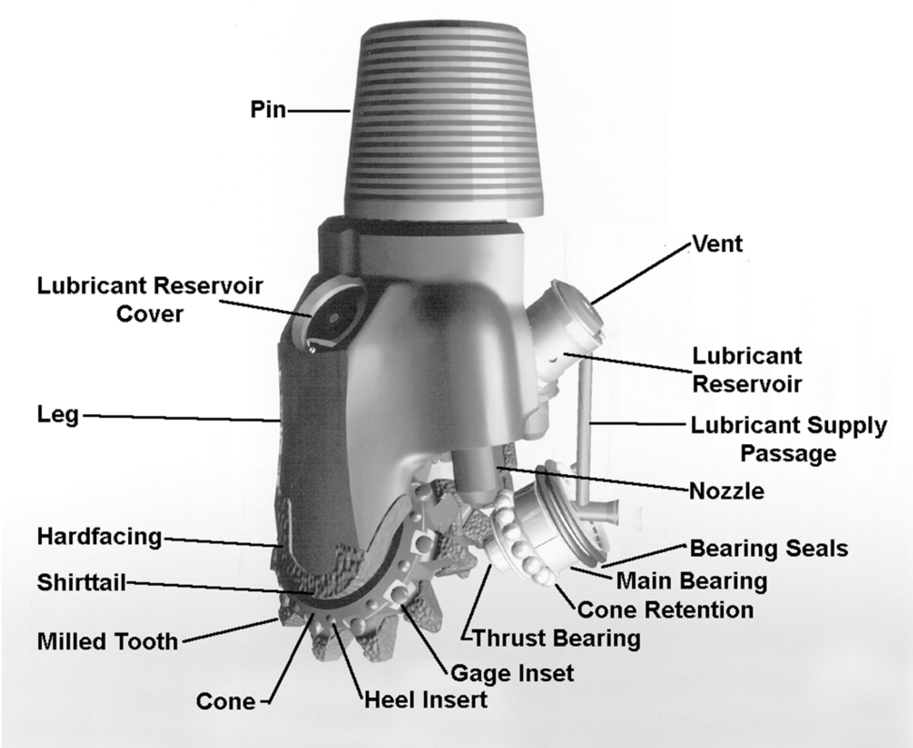

Figure 17: General roller cone bit design [49, p.5]

Hydraulic energy is one of three existing on the rig energy inputs, which helps to optimize the drilling performance. Other two types are weight on bit and rotational speed. Hydraulic energy distribution depends on *nozzles*, *flow tubes* and *center nozzle ports*.

Nozzles represent passage for drilling fluid, which is supplied under high pressure to remove and transport generated cuttings from the wellbore. Nozzles are typically divided into *standard*, *extended* and *diverging* types. Extended nozzles minimize flow dispersion, increasing flow velocity and hydraulic energy. Higher velocity prevents cuttings regrinding and aids their removal, which improves penetration rate. Diverging nozzles on the contrary disseminate the flow. This system also includes a center nozzle of larger area, which results in flow of low velocity. The benefit of this system is possibility to control hydraulic flow distribution for maximized efficiency.

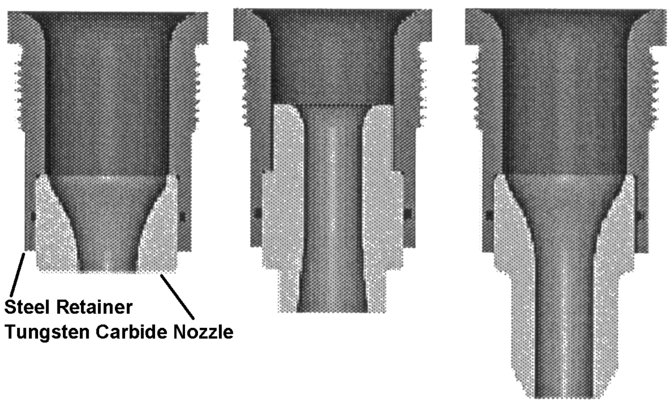

Figure 18: 3 types of nozzles: standard, divergent and extended [49, p.29]

Flow tubes are used sometimes together with standard nozzles to improve hydraulic efficiency by reducing space between mud outlet and the drilling target. This action reduces additional bit wear from cuttings regrinding. Flow tubes are illustrated in the figure below.

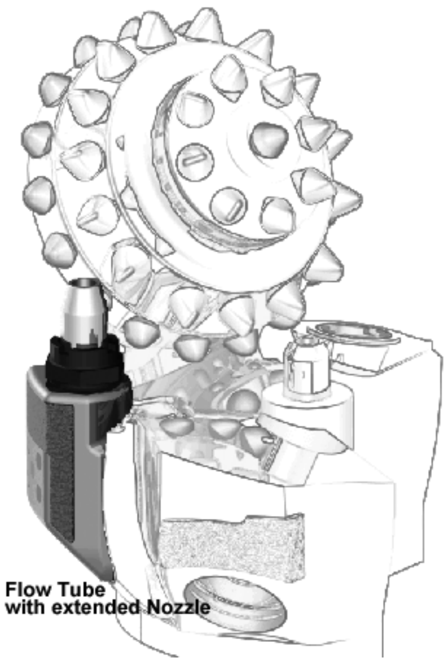

Figure 19: Flow tube [49, p.30]

2.4.1.3 Specific design parameters

Roller cone bits use two kind of drilling action: *crushing* and *skidding*. The first one happens when weight is applied to the formation through bit's teeth. The second one is a result of slight inclination of cone rotation axis to axis of bit rotation. It also happens because bit teeth leave the crushed zone by moving along the surface, this way applying a lateral force.

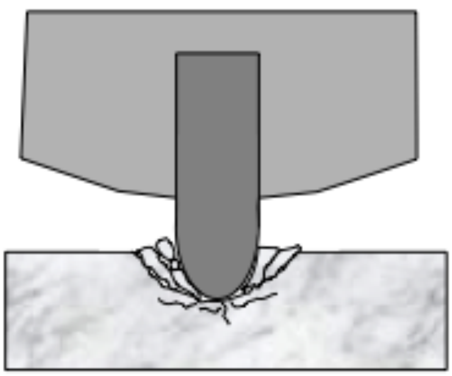

Figure 20: Crushing action of roller cone [48, p. 33]

Bit diameter is a parameter responsible for the hole diameter, therefore all components must fit within the claimed bit diameter. At the same time, size of individual components may vary to some extent.

Journal angle is a fundamental parameter in bit design, which represents an angle between line perpendicular to the bit axis and axis of the bit's leg journal[6]. All cones on a bit always have the same journal angle. Typically, bits with low journal angle are used for drilling through softer formations to increase penetration rate; bits with large journal angle are used in harder formations to minimize damage of the bit.

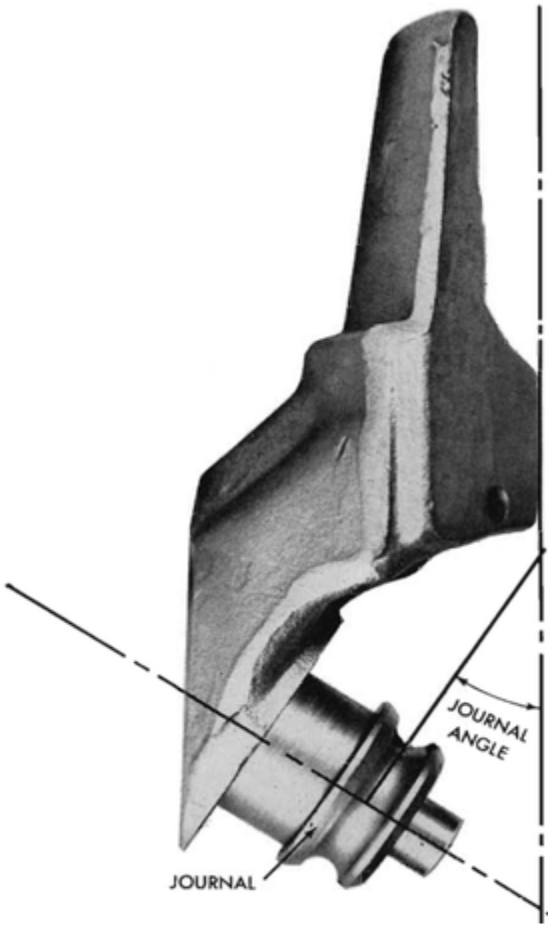

Figure 21: Journal angle [9, p.291]

To increase the skidding-gouging action for better penetration, the cone centerlines can be offset from the centerline of the bit, so all three of them don't intersect at a common point. This is called *cone-offset* and is defined as "horizontal distance between the axis of a bit and the vertical plane through the axis of its journal" [35, p.194]. Zero offset means that cones axis intersect in the center of the bit. Side effect of offset is inserts/teeth wear. Offset is typically used just for soft or medium formation, because in hard formation it leads to severe damage of bit's cutting structure.

[6] Journal - metal shaft that rotates in a bearing.

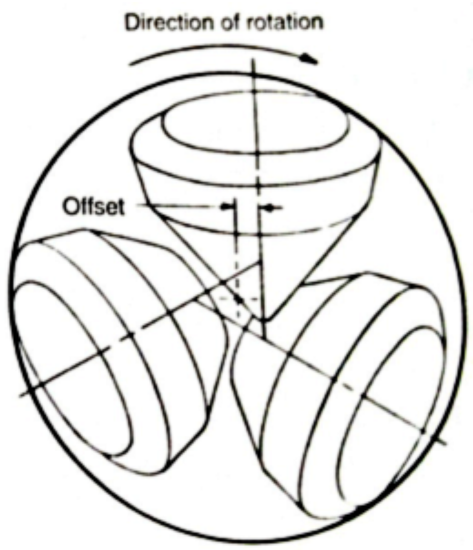

Figure 22: Cone offset [38, p.43]

Tooth and inserts are designed according to structural requirements or formation requirements. Soft formations with low compressive strength require long, sharp and widely spread teeth. For drilling such formation, maximum tooth depth should be used. Space between teeth is required for efficient fluid flow and cuttings removal. Hard, high compressive strength formations require short, heavy and closely placed teeth. This allows even distribution of loads to minimize loading on individual teeth. Soft to medium hard formations often require a tailored drill bit. Inserts/teeth design to a large extent depends on formation drillability, which is a capricious parameter due to formation heterogeneity. Drillability will be discussed more precisely in section 3.3.

Figure 23: Cutting structure for soft and hard formation [49, p.25]

2.4.1.4 Materials design

Material properties are fundamental when it comes to bit performance. Bit must be able to withstand wear, erosion, temperature and loading. The bit robustness depends on alloy type, way the material is being processed and type of heat treatment. Choice of material and a way of processing it for a particular component depends on special needs of the component. Rotating parts, for instance, are more affected by fatigue, while inserts get destroyed due to wear.

Legs and cones are usually made from forged metals. Forging makes metal more durable by increasing metal density and metallic grain structure.

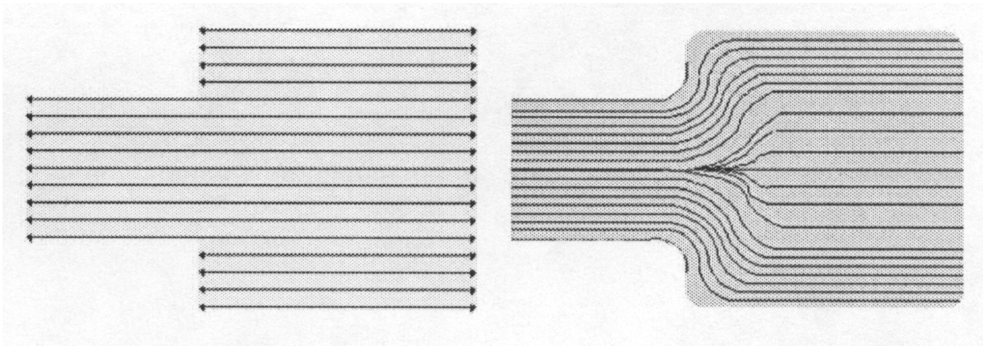

Figure 24: Wrought metal structure (left) and more robust forged metal structure (right) [49, p.20]

2.4.2 Design and characteristics of PDC bit

The PDC bit represents one-piece drilling tool with fixed cutters. The cutters are made of 3 parts: tungsten carbide cutter body, thin bonding layer and a layer of synthetic diamond (compact). Cutters manufacturing requires high pressure and high temperature [39, p.29]. Compacts on the tip of cutters are made of artificial diamond to be able to drill the hardest formations. Diamond is the hardest material known, however, use of natural diamonds is often not economically favorable, therefore a synthetic diamond material, *diamond grit*, is used instead. Property wise this material is alike natural diamond, but it is less stable in higher temperatures, than the natural one. The cutters are pressed into slots on the bit body, arranged in predetermined way, required for drilling particular formation. If the mechanical shock becomes too large, the polycrystalline diamond compacts might disconnect from the cutter body. Currently new technologies are being developed to introduce an additional shock-absorbing layer between compact and tungsten part of the cutter [10, p. 26].

PDC bits used for soft formations have fewer cutters and large junk slots to have space for removing large amount of cuttings. Opposite applies for PDC bits used for drilling hard formation. To provide a required hole gauge, PDC bits are equipped with cutters on the outer side of the bit. It might reduce need for reaming the hole, which saves rig time.

PDC bits drill through rock by *shearing* the formation (Fig. 25). Force that makes this action possible is a result of vertical force from drill collar and horizontal rotational force. The volume of rock removed depends on the rock strength. Application of shear force requires less energy to break the rock, than when applying compressive force. Hence lower WOB can be used when drilling with PDC bits.

PDC bits are sensitive to properties of the drilling target, and their performance to a big extent depends on proper hole cleaning. PDC bits have excellent performance in suitable formations; however, they might be destroyed fast if chosen incorrectly. In addition they are expensive, so the proper selection and prudent treatment of the bit are vital for desired drilling performance.

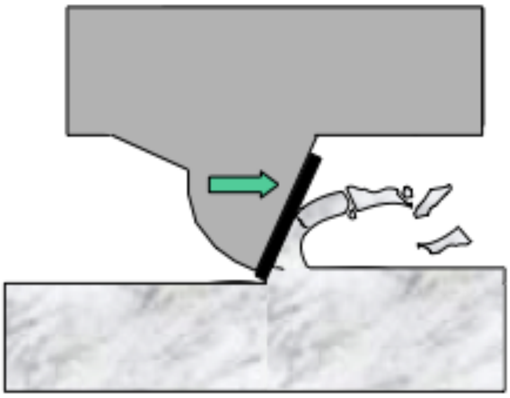

Figure 25: Shearing action of PDC bit [48, p.33]

2.4.2.1 Body material

PDC bits can have either *matrix body* or *steel body,* which both have their own application and advantages. Matrix is a composite material, manufactured from copper and tungsten carbide grains, bonded with metallic binder. This material is preferred due to its greater toughness and higher load and abrasion resistance. It obviously has more complex and to some extent unpredictable structure than steel. Steel is a relatively soft, elastic material, which might get destroyed rather quickly due to abrasion and erosion. The design of steel PDC bits differs from the design of matrix ones. Since steel is a ductile material, it can withstand greater impact loads, what allows building steel body bits in larger sizes. Matrix PDC bits are usually preferred when drilling through abrasive formations. Nevertheless, steel PDC bits have stronger bodies. Steel bits can also be repaired if they get worn or destroyed. In general, steel bits don't have lower penetration rate than matrix bits. Advantage of the latter ones is that they can stay longer in the hole, what reduces number of bit trips [39, p.33].

2.4.2.2 Blades and cutters

Number of blades depends on the formation softness: fewer blades are required for drilling through soft formations. The same goes for number of cutters. Large cutters are usually preferred in soft formations, because they provide higher volume of formation removed per one bit revolution. If the formation is hard and challenging, smaller cutters are preferred to prevent bit damage [10, p. 26].

Figure 26: PDC bit with 5 blades and PDC bit with 6 blades [6, p.12 and 17]

Blade layout can differ from bit to bit. They discriminate between *straight blade* and *spiral blade*. The spiral blades have a concave shape. Blades can be also divided into *symmetrical* and *asymmetrical*. Symmetrical blades are perpendicular to each other. Asymmetrical blades have different angle between each other, see figure below.

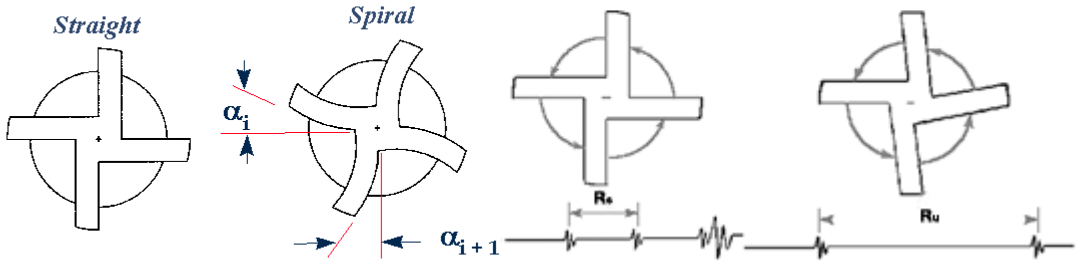

Figure 27: Illustration of straight and spiral blade design and symmetrical and asymmetrical blade design [49, p. 58]

Density of cutters, or in other words, how tightly cutters are placed to each other depends on shape, length and size of cutters. In general more cutters are placed towards the outer radii, because more work has to be done to shear the formation at this point. Higher density of cutters results in ROP decrease, but will prolong the bit life because it reduces load per cutter.

An important characteristics of PDC cutters is their *orientation*, or *rake* (attack) *angle. Back rake angle* is an angle between a cutter's surface plane and a plane perpendicular to the target of drilling (Fig.28). This angle represents aggressiveness of the cutter. When angle is increased, aggressiveness decreases, so does the ROP, because the depth of cut becomes smaller. This, however, prolongs the cutters life, and is a preferred method while drilling through hard formations. Bake rake normally varies between 0 and 25 degrees depending on formation hardness.

The *side rake* angle is the radial orientation of the cutter with reference to the bit body, or inclination of the cutter from left to right. With no side rake all cutters are in line with a direction of rotation at any point. Added side rake prevents cuttings from jamming underneath the bit, reducing risk for bit balling [39, p.38].

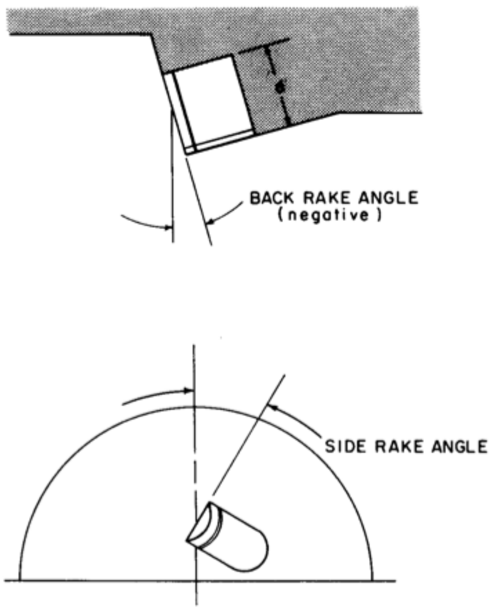

Figure 28: Bake rake and side rake angle representation [11, p.195]

Another parameter to describe the cutting design is *cutter exposure*. "Cutter exposure is the distance between bit face and cutting tip" [49, p. 60]. *Full cutter exposure* means that the whole cutter surface is exposed to the formation while shearing it. This design improves drilling performance, though in hard formations often less than full exposure is favored to reduce bit damage.

Cutter clearance is a cavity on the bit face just by the cutter surface, which provides space for newly created cuttings that have not been yet removed.

2.4.2.3 Bit profile

Bit profile is a term that covers shape of a bit body. It has a direct influence on bit's stability, steerability and durability, also on penetration rate, cleaning efficiency and thermal bit damage severity. Bit profile consists of six zones: apex, cone, nose, shoulder, outside diameter radius and gage (Fig.29). *Apex* represents a juncture between bit's profile and its vertical centerline. *Cones* are described by angle. Deep cone angles (90 degrees or less) offer higher stability, compromising though steerability and hole cleaning. Shallow cones allow better steerability and are more aggressive than deep cone bits. They are less stable, but this disadvantage can be compensated by improved cutting structure and gage design. The radius of curvature of a bit blade and the distance from bit centerline to the most salient point on the curvature represent a *bit nose.* Larger nose radius increases bit durability, and shorter distance provides higher bit aggressiveness. Large surface area on the nose provides place for more cutters, what allows for even distribution of loading related to drilling hard formations. *Shoulder* or *taper* is the transition between nose and outside diameter radius. *ODR (outside diameter radius)* represents a transition between shoulder and gage. *Gage* is the outermost part of the bit profile. Gage also has cutters to ensure proper hole diameter. There are different gage types and gage length available for drilling optimization.

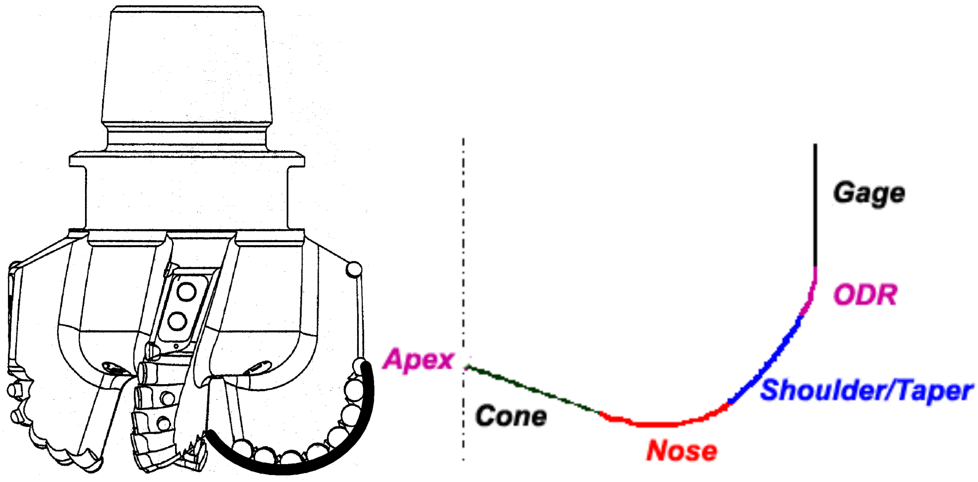

Figure 29: PDC bit profile [49, p.64]

Four classes for PDC bit profiles are defined. These are *flat profiles, short parabolic profiles, medium parabolic profiles and long parabolic profiles*. Parabolic profiles are more aggressive than flat profiles and deliver high penetration rate at the cost of higher cutters wear. Flat profile is preferred when drilling hard formation, because it allows distribution of loading equally on all cutters and increase in penetration rate. The most common profiles used are short or medium parabolic profiles in conjunction with large shoulder and radius. This design offers greater flexibility for efficient drilling using either rotary drilling or downhole motor. Different combinations of bit profile characteristics have their applications, which depend mostly on hardness and abrasiveness of the drilled rock [49, p. 67-68].

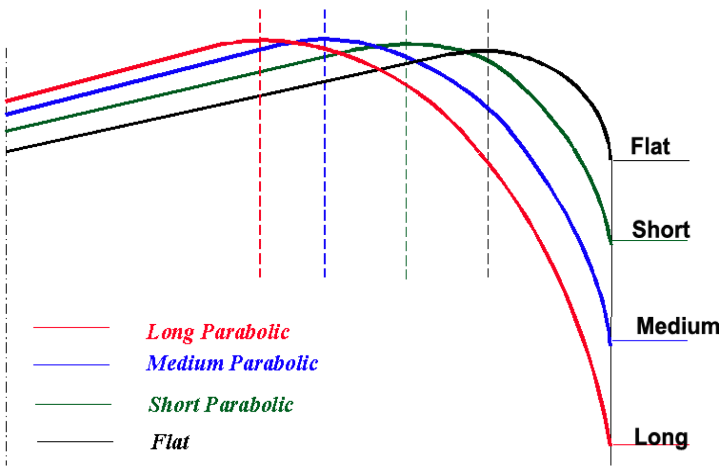

Figure 30: PDC bit profile types [49]

2.5 Factors affecting rate of penetration

It was found out that the most important parameters affecting penetration rate are: *bit type, formation characteristics, drilling fluid used, operational parameters, bit tooth wear* and *hydraulics*. The best way to study effect of a single parameter is to vary it while holding other parameters constant. This practice is limited by costs; therefore historical information about drilled wells represents important material for analysis like this.

2.5.1 Bit type

Bit selection has very important influence on penetration rate. Roller cone at first has higher penetration rate in soft formations when long teeth and large cone offset angle are used. In hard formations shorter teeth are preferred since the teeth wear is a big issue. The optimal situation is when the tooth life is consistent with bearing life at required operational conditions. The drag bit performance depends on the number of blades and cutters. We can estimate number of blades required basing on cutters width and their number [11]. With increasing length of the face cutters, the depth of cut will be smaller.

When it comes to shoe track drilling, we have seen that PDC bit was preferred for drilling out 13 3/8" casing equipment. Roller cone was used in some cases for a dedicated shoe track drillout run. For drilling out 7 ¾" liner equipment roller cone bit was preferred for most cases.

2.5.2 Drilling target characteristics

The most important variables here are elastic limit and ultimate strength of the formation. Formation permeability also has a major influence on the ROP. If the rock is permeable, the drilling fluid filtrate might move into the rock before the bit crushes it. The pressure then is being equalized, which makes rock behaving in elastic way while being penetrated with the bit. Undoubtedly, the rock composition also has an important influence on penetration rate. Hard and abrasive minerals can damage the bit fast, and drilling through gummy clays can result in bit bailing [11].

2.5.3 Drilling fluid properties

Drilling fluid properties is a general name that compiles density, rheology, composition and filtration characteristics. With higher mud weight and viscosity ROP tends to decrease. Coarser particles in mud also have negative influence on penetration rate. Viscosity controls pressure loss through the drillstring and hydraulic energy that affects bit cleaning. Even when the bit is clean, high viscosity may still decrease penetration rate. Density, solids contain and filtration characteristics are the parameters responsible for differential pressure between wellbore and crushed rock. Chemical composition of the drilling fluid may affect formation behavior that may result in both higher and lower penetration rate. Increase in drilling fluid density results in increase in bottom hole pressure, and if the pore pressure is constant, we get higher differential pressure in the well. This effect is called *overbalance* [11]. It was found out that small overbalance has significant negative effect on penetration rate. Increasing overbalance does not have much additional negative influence on ROP. Bourgoyne *et al.* [11] have documented that the relation between overbalance and drilling rate follows almost straight line on semilog plot. Straight-line relation is valid for moderate values of overbalance. The relation they have come up with is as follows:

$$\log\left(\frac{R}{R_o}\right) = -m\,(p_{bh} - p_f) \quad (1)$$

where R is the penetration rate,
R_0 – penetration rate at zero overbalance,
P_{bh} – downhole pressure,
P_f – formation fluid pressure,
m – slope of the straight line

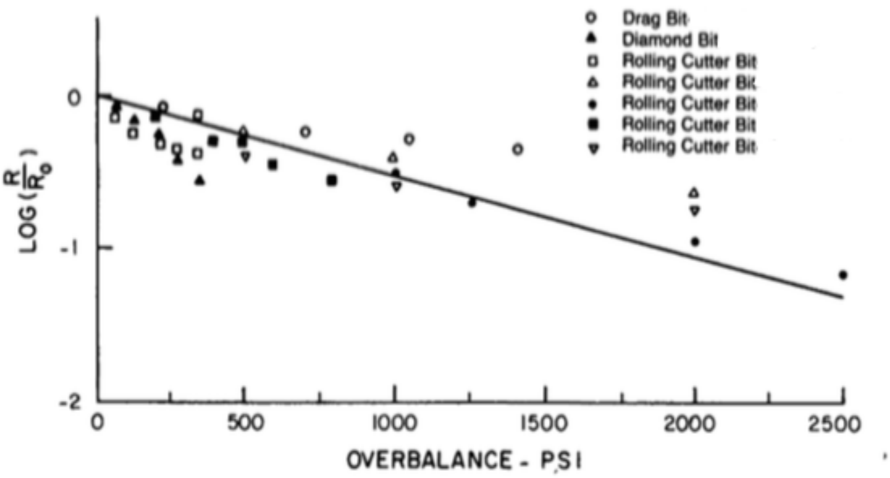

Figure 31: Exponential relation between penetration rate and overbalance [11, p.225]

2.5.4 Operational parameters

Operational parameters are the ones that can be changed directly while drilling. Numerous authors throughout many decades have studied their effect on penetration rate. Typically to check how a parameter influences drilling speed, other parameters have to be held constant. It is difficult to isolate the variables completely, especially when analysis of drilling fluid is performed. In the field, especially offshore, it also might be not reasonable due to high costs. Therefore, most of the tests are conducted in the laboratories or onshore.

2.5.4.1 Weight on bit

The first parameter we are going to look at is *weight on bit*. It is a quantitative term that describes weight or force conveyed to the drill bit through drillstring [54]. "It presses the teeth against the formation that it breaks, and each tooth makes a small crater" [48, p.33]. When the drilling assembly is suspended from the derrick, without touching the bottom, its weight is recorded. Then the string is lowered to the bottom of the hole. Some weight is supported by the formation, and the hookload is decreased. The difference in the weight between these two positions is called weight on bit. In deviated wells, applied weight on bit is not fully transferred to the well bottom due to friction between drillstring and wellbore. Some authors differentiate between WOB – the applied force from surface, and WOT – weight on target, the netto force that reaches the well bottom

[46]. It is equal WOB minus the upward force acting from the cutting bed or other obstacles. It was found out that penetration rate as function of weight on bit follows pattern shown in the figure below. One has to cross the threshold weight to start penetrating the rock. Penetration rate then increases rapidly with increasing WOB until a point, where the relation becomes almost linear. Higher values of bit weight will lead to drop in penetration rate growth. If weight on bit is increased even more, the penetration rate will start decreasing. This behavior is typically called *bit floundering* [11, p.226].

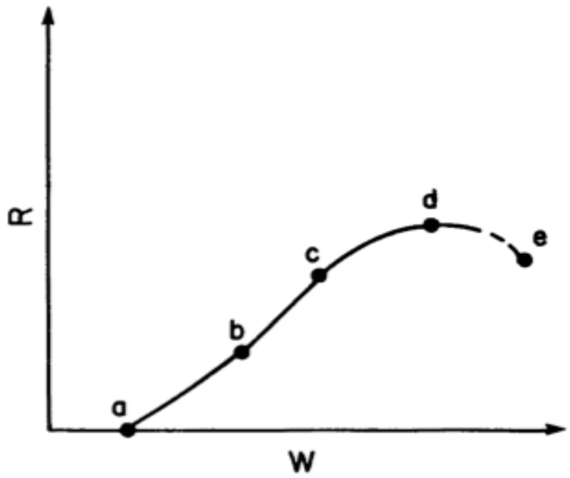

Figure 32: Penetration rate as a function of bit weight [11, p.226]

2.5.4.2 Rotary speed

Rotational speed is measured in RPM or revolutions per minute. It is simply the frequency of rotation of the drillpipe around its axis while drilling. Tests were performed to find dependence of penetration rate on rotary speed. Penetration rate typically increases linearly with rotary speed for low and moderate values of rotary speed. After crossing some point, the increase in rotary speed might start affecting cuttings transport, which results in poor hole cleaning and reduction in penetration rate. Typical behavior is shown in the figure below.

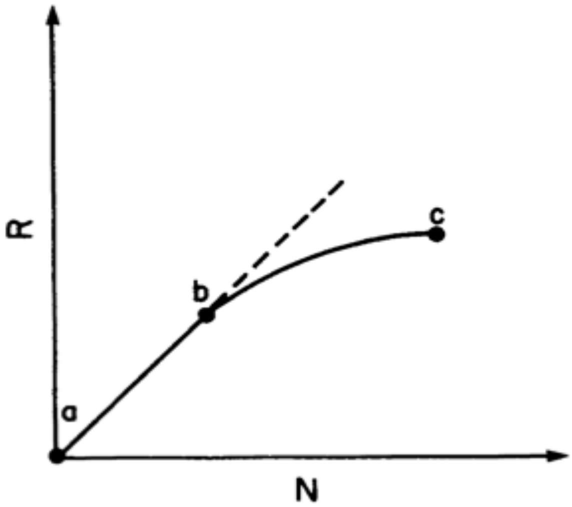

Figure 33: Penetration rate as a function of RPM [11, p.226]

RPM effect on ROP also depends on the formation hardness: it will enhance ROP in soft formations and reduce it in hard formations [44].

2.5.4.3 Hydraulic energy

Hydraulic energy on the rig is carried by the drilling fluid, which is supplied by the rig pumps. It is commonly also called *hydraulic horsepower* and is equal to

$$H = pq/1.714 \qquad (2)$$

where p is pump pressure (system pressure loss), psi
q – flow rate, gpm
1.714 – conversion factor.

This energy is required to reduce friction energy loss of the whole system, including surface lines and annulus. However, usually when we talk about hydraulic horsepower in oil well, we mean bit hydraulic horsepower. It can be expressed the same way as in equation above. The difference is that in this case instead of total pressure loss, we use pressure loss at the bit [14].

Bourgoyne *et al*. [11] found out that bit hydraulics and in particular hydraulic horsepower improves penetration rate, see figure below.

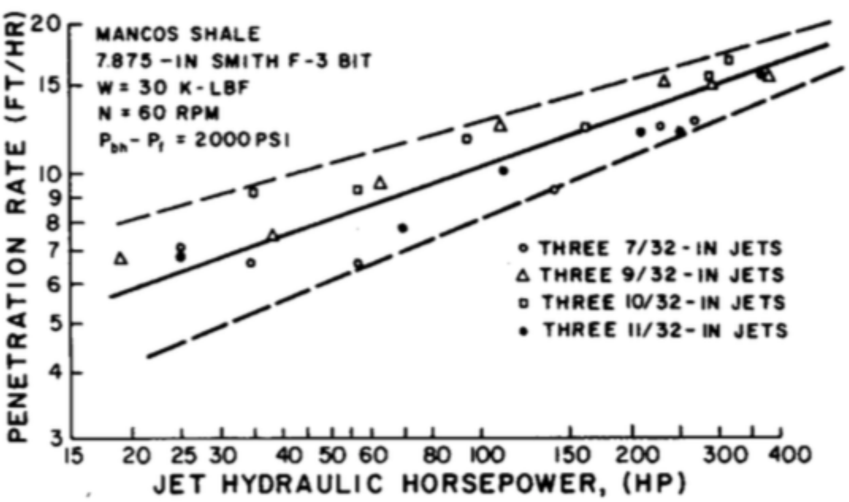

Figure 34: ROP as function of jet hydraulic horsepower [11, p. 231]

The adjacent parameters are *fluid velocity* through the bit nozzles, which can be expressed as

$$v = \frac{0.32086q}{TFA} \qquad (3)$$

where TFA is the flow area of the bit nozzles, in^2
0.32086 – conversion factor

and *jet impact force*, which we will refer to in chapter 6. Equation for it is derived from Newtons second law. Assuming that fluid momentum is fully transferred to the bottom hole, jet impact force can be calculated as:

$$JIF = 0.000518MWqv \qquad (4)$$

where MW is the mud density, ppg
0.000518 – conversion factor.

According to Bourgoyne *et al.* [11] jet impact force, like horsepower, has positive influence on ROP, see figure below.

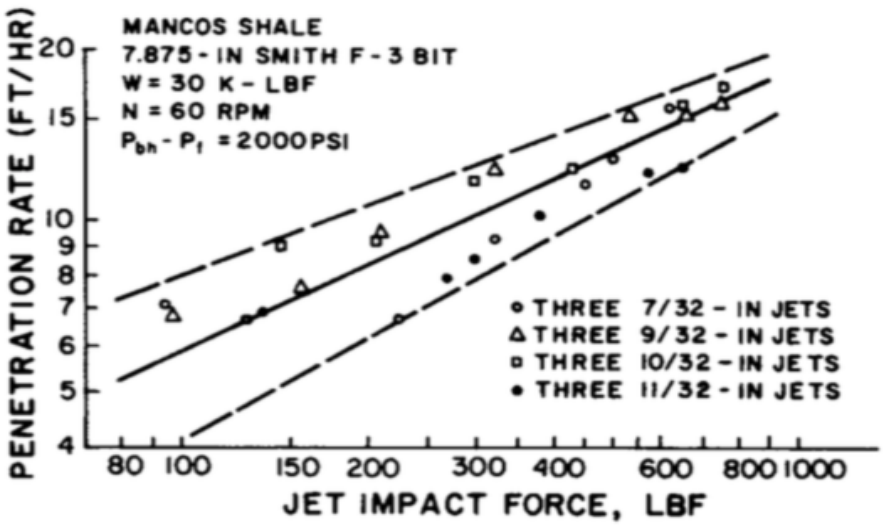

Figure 35: ROP as function of jet impact force [11, p.231]

3. Drilling optimization models

Bit type is usually chosen based on sonic logs data from offset wells. Hydraulics is also planned using data from nearby wells. ROP models are used to calculate the formation drillability basing on the drilling parameters or combination of drilling parameters, bit design and cutters wear. By trying out different combinations of abovementioned factors, the best ROP is estimated. The inclusion of bit wear can also be helpful to understand when it is time to change the bit for more economic drilling. If the formation can be considered to be homogeneous, we can optimize ROP by varying WOB and RPM. As mentioned before, ROP increases linearly with increasing WOB up to some point, after which the increase in WOB might cause ROP reduction. Increase in RPM will affect ROP in a similar way: ROP will increase until we get hole cleaning problems [44].

We considered several ROP models that potentially could be used for cement drillout analysis. Our choice was mainly based on model accuracy and data availability. In this chapter we describe models that were used in this thesis. Other models that were considered for this analysis are described in Appendix E.

3.1 Bourgoyne and Young model

An ROP model was suggested by Bourgoyne and Young in 1973. In this model effect of several independent drilling variables was considered. The following parameters are included in this model: pore pressure, bit weight, sediments compaction, jet impact force, RPM, bit hydraulics and bit cutters wear [5]. This model represents a product of eight factors:

$$ROP = f_1 * f_2 * f_3 * f_4 * f_5 * f_6 * f_7 * f_8 \qquad (5)$$

Factors f_1 to f_8 represent the normalized effects of operational parameters and formation characteristics on ROP. Expressions for f_1 to f_8 include constants from a_1 to a_8. These constants can be calculated from offset wells and then applied to model ROP for current well. Factors from f_1 to f_8 are presented below (equations 6.1-6.8):

f_1 – the rock drillability, $f_1 = e^{2.303a_1}$
f_2 – effect of the depth, $f_2 = e^{2.303a_2(10,000-D)}$, where D is TVD in ft
f_3 - effect of pore pressure, $f_3 = e^{2.303a_3D^{0.69}(g_p-9)}$, where gp – the pore pressure in ppg
f_4 – the effect of overbalance on ROP, $f_4 = e^{2.303a_4D(g_p-P_c)}$, where Pc is equivalent circulating mud weight in ppg
f_5 – WOB's effect on ROP, $f_5 = [\frac{\left(\frac{w}{d_B}\right)-\left(\frac{w}{d_B}\right)_t}{4-\left(\frac{w}{d}\right)_t}]^{a_5}$, where w is WOB, dB is bit diameter, and $(W/d)_t$ is threshold bit weight

f_6 – the effect of rotary speed on the ROP, $f_6 = (\frac{N}{60})^{a_6}$, where N is revolutions per minute

f_7 – the effect of bit wear on the ROP, $f_7 = e^{-a_7 h}$, where h is amount of bit wear for a bit, $h = \frac{(Depth_{Current} - Depth_{in})}{(Depth_{Out} - Depth_{in})} * \frac{DG}{8}$, where DG is dull grade, estimated after the bit has been pulled out of the hole to the surface

f_8 – the effect of bit hydraulics on the ROP, $f_8 = (\frac{F_j}{1000})^{a_8}$, where F_j is jet impact force in lbf

Explanation to the factors is as follows:

f_1 describes formation strength and drill bit type contribution to rate of penetration. It also comprises factors that are not included in other functions of this model, like mud composition. This factor is expressed in the same units as penetration rate and is commonly called *drillability.* It varies with the strength of the formation. According to Bourgoyne *et al.* [11], drillability of the formation is equal to the penetration rate observed when drilling formation at zero overbalance with WOB of 4 klbf/in and RPM of 60 at the depth of 10000 ft.

f_2 and f_3 represent the effect of compaction. f_2 function models the rock strength increase due to normal compaction, and f_3 describes the effect of under-compaction, which happens in abnormally pressurized formations. Multiplication of these two functions is equal 1 for TVD equal 10000 ft and 9 ppg pore pressure.

f_4 characterizes the effect of overbalance on ROP. If no overbalance is present this function gives value of 1.

f_5 accounts for the effect of bit weight on ROP, including term of threshold WOB – weight, which is necessary to reach for bit to start the penetration. This function has value of 1 when the threshold weight is equal 4 klbf/in of bit diameter.

f_6 models the effect of rotary speed on ROP and equals 1 for a rotary speed of 60 RPM.

f_7 represents the effect of tooth wear on ROP. It takes value of 1 for no tooth wear. Tungsten carbide bits have negligible tooth wear.

f_8 defines the effect of bit hydraulics on ROP, which is neither positive nor negative for jet impact force equal to 1000 lbf [11, p.234].

3.2 Mechanical specific energy

Calculation of the *mechanical specific energy* (MSE) is one of the main approaches for drilling process optimization. The MSE is defined as work required for breaking a given volume of rock. This term includes several drilling parameters and is used to assess and optimize the drilling efficiency by altering the abovementioned parameters while drilling. It can also be looked upon as input energy to the output ROP [44]. First to propose a way of MSE calculation was Teale in 1965. The MSE equation looks like this:

$$MSE = \frac{WOB}{A_b} + \frac{120\,\pi\,RPM\,\tau}{A_b\,ROP} \tag{7}$$

where A_b is bit surface area in inch^2
τ torque in lbf*ft
MSE is measured in psi

Later on a bit specific coefficient of sliding friction, μ, was introduced by Pessier and Fear [40] to avoid using torque value in case its measurement is unavailable. They found out that torque could be expressed as follows:

$$\tau = \mu \frac{D_b WOB}{36} \tag{8}$$

where D_b is bit diameter

Combining together these two equations we get

$$MSE = \frac{WOB}{A_b} + \frac{13.33\ \mu RPM\ WOB}{D_b\ ROP} \tag{9}$$

μ is usually assumed to be 0.25 for roller cone bits and 0.5 for PDC bits [4].

Finally, to evaluate the drilling efficiency following correlation was used [37]:

$$EFF_D = \frac{MSE_{min}}{MSE_{actual}} \times 100 = \frac{UCS}{MSE} \times 100 \tag{10}$$

Dupriest and Koederitz [15] estimated that the drilling efficiency is 35% for all bits. Using this approximation, MSE is determined as:

$$MSE = 0.35\left(\frac{WOB}{A_b} + \frac{120\ \pi\ RPM\ \tau}{A_b\ ROP}\right) \tag{11}$$

There is no perfect correlation between MSE and UCS (unconfined compressive strength): the latter one is usually lower than MSE, even when MSE value is reduced by 65% as in the equation above [4]. Some authors mean that CCS (confined compressive strength) has better correlation with MSE. In the second part of the thesis we will be calculating drilling efficiency while cement drilling.

3.3 Drillability

Drillability is a measure of drilling capacity of a drilling target, which is expressed as a combination of drilling parameters. It can be used for evaluation of target homogeneity and ultimate drilling efficiency.

The MWD tools have advanced significantly with time, however, they are still placed 10-15 meters above the bit. Using the instantly available parameters, we see changes in the formation before we can see them on the MWD logs. The drillability curve would fluctuate if change in any of the 4 parameters included in the equation occurs. Drillability, how it is defined by B. Aadnøy [1] is:

$$d = \frac{ROP*Dbit}{WOB*RPM} \tag{12}$$

where D_{bit} is bit diameter.

4. Introduction to the field and data acquisition

4.1 Ekofisk and Eldfisk fields

The Ekofisk Field is an oil field in block 2/4 in the Greater Ekofisk Area on the NCS, which contains 40% of hydrocarbons in the Central Graben area. This was the first big hydrocarbon discovery offshore Norway made by Phillips oil company. The production started in early 1970s' and is planned to continue until 2050 [15]. The Ekofisk reservoir consists of naturally fractured chalk and can be divided into two major layers: Ekofisk Formation (average thickness – 188 m) and Tor Formation (average thickness – 120 m). It also contains a narrow impermeable zone of low porosity, thickness of which varies from 15 to 36 m.

The Eldfisk Field is oil and gas containing field, located around 320 km from Stavanger in block 2/7 in the Greater Ekofisk Area on NCS. It has been in production since late 1970', and is planned to be developed until 2050. The reservoir, similarly to main Ekofisk field, consists of naturally fractured chalk. It is the second largest producer in the Greater Ekofisk and one of the largest in entire Norway [15].

Figure 36: Ekofisk complex (left) and Eldfisk complex (right) [15]

4.2 Field data sources

There are several methods of real-time data recording in the oil field. These include for example MWD/LWD data, which uses so-called *mud pulse telemetry* (MPT). A pulser unit is placed downhole, and its function is to alter the drilling fluid pressure inside the drill-string. Surface pressure transducers measure it as analogue voltage signal. This signal is then sent to the surface computers, which digitize it. The digitized signal is displayed as waves on the computers, where MWD engineers and well-site geologist interpret them. Downhole turbine, which uses the energy of mud flowing through it, is a source of electrical and mechanical power. The tools are also equipped with lithium batteries, which can be used together with the turbine or as a back up source of energy [21].

Another way to obtain data is surface logging (mud logging). There are sensors placed around the drilling rig, which measure operational parameters while drilling. Some of the measured parameters are listed below [34]:

- Block position is registered by a sensor, which counts the rotation of drawworks drum when the position of traveling block is changing
- Penetration rate is downward movement divided on drilling time
- Hook load is measured by a weight sensor on the top drive. It is usually documented as weight of the drill string minus buoyancy
- WOB is measured by the same sensor (see section 2.5.4.1)
- Torque represents the resistance of a string to rotation. An ammeter measures current in the electrical cables, connected to top drive. If the rotation movement, provided by top drive, is hampered, the registered value is increased
- RPM is the drillripe rotation around its axis per minute, which is provided by the top drive. In cases when rotation of the whole pipe might affect angle building, just the bit is in rotation. RPM is then function of fluid volume pumped through the turbine of the mud motor
- Flow in/out is measured by sensors in the flow lines, and is simply equal volume divided by time.

Analysis of plugs and float equipment drillouts in this thesis is based on data, gathered from daily reports and 24 hours plots. Daily reports were mostly used to find the reported depth for cement, collars and shoe, as well as drilling parameters used while drilling through these components. Description sheets for float equipment were used to learn about design of float equipment and wiper plugs. Surface logging data recorded by Sperry SDL was used to analyze cement drillout. Cement reports, bit reports and bit specification sheets were used as additional source of information.

4.3 INSITE software

Sperry Halliburton provides mudlogging service to oil companies. The main software that they use is called INSITE and it represents main database of well information in depth and time formats. It conveys real-time information from wells that are being drilled to a remote computer in the office offshore or on land. It is also used to retrieve the historical data from wells that have been drilled. INSITE allows performing various operations on databases, for example acquire or import, display, process and export data.

Well information is typically stored under name, run number, record type (specifies where the data comes from) and description (denotes how the data was collected).

There are two types of data in a dataset within INSITE database: measured data and calculated data, which are indexed against time or depth. Data comes from many sources, both surface sensors and downhole tools.

5. Analysis of shoe track drillout

In this chapter we will analyze drillout of main shoe track components one by one due to big variations in materials' properties used for different components. Wiper plugs are drilled along with inside of landing collar or float collar, thus these parts will be looked upon as one piece. Firstly, we will study mechanical components in 13 3/8" shoe tracks in wells "H", then we will analyze float equipment in 7 ¾" liner in "K" wells. After we will have studied the float equipment drillouts, we will proceed with analysis of cement drilling.

5.1 Wiper plugs, float collars and casing shoe drillout

In this section we analyze mechanical components drillout with respect to the drilling time. Mechanical components are relatively short, and their configuration is fairly complicated. Consequently median value for ROP will not be representative, and it is favorable to use drilling time as a measure of drillout efficiency instead. The drillout time therefore will be studied as function of operational parameters and equipment configuration.

5.1.1 13 3/8" casing equipment

For the plugs drillout analysis we have chosen 13 3/8" casing shoe tracks in 8 wells drilled as a part of a water injection project in Ekofisk area. Being drilled using similar equipment, these shoe tracks represent a good material for comparative analysis. There is usually some cement on top of the wiper plug, so the drill bit could get a better grip on the plug. Cement in these shoe tracks has identical (or very similar) quality. Firstly we will look at the operational parameters used, trying to find out whether any of them was decisive for the drillout time. After that we will compare PDC bits performance from three suppliers.

Float equipment used for cementing of 13 3/8" casing consisted of 2 sub components, which are sub-surface released cementing plugs with float collar and a float shoe. Weatherford was supplier for all components. "The Sub-Surface Release Cementing plug system is comprised of four parts: double dart plug container, swivel equalizer, non-rotating sub-surface plugs with drillpipe wiper darts and a non-rotating float collar'' [51]. The plugs' fins are made from polyurethane, inner part - of duromer, the poppet valve is plastic and internal parts of the float collar are made from concrete and phenolic. The whole configuration is claimed to be non-rotating and PDC drillable because it does not contain any metallic components (as mentioned in section 2.3.1 produced swarf tends to jam bit blades). Collar specifications are presented in the figure below.

Figure 37: Wiper plug and float collar system used in analyzed wells [51]

Median time for plugs and collar drillout was 5.4 hours. Minimum time was 30 minutes. We will now try to find out why drilling through plugs and collar in other wells took much longer time.

Table 3: Drillout data for float collar used in analyzed wells[7]

Well	Time to drill float collar (hrs)	WOB, klbs	Torque, klbs*ft	Flow rate, gpm	RPM
1H	11	30	6,5	700	50
2H	2,3	20	6,0	900	100
3H	0,5	3,0	7,7	962	50
4H	5,2	20	7,0	870	60
5H	2,5	10	6,4	795	90
6H	5,5	15	8,0	770	47
7H	7,9	20	12	790	60
8H	6,1	17	8,0	900	56

Table 4: Comments to wiper plugs and float collar drillout

Well	Comments
1H	Claimed rubber stuck on bit/BHA.
2H	Drilling float collar took longer than expected, tried up to 40 klbs WOB.
3H	
4H	
5H	
6H	
7H	Very slow progress drilling wiper plugs and float collar.
8H	Started with 3 klbs WOB, gradually increasing. Slow progress of wiper plugs and float collar.

Even though no problems with spinning plugs were documented to occur during these drillouts, 50% of them were reported to have slow progress. The reason for

[7] Median values for operational parameters were used throughout the analysis

it could be complicated configuration of the plug system, which, as mentioned earlier, consisted of two plugs and two darts.

Wiper plugs, drilled with PDC bit and recovered on the surface are shown in the figure below:

Figure 38: Rubber and plastic parts of wiper plugs, recovered on the surface[8]

We have found out that relation between float collar drillout time and WOB can be described by power function, where drillout time is increasing for higher WOB (see chart below).

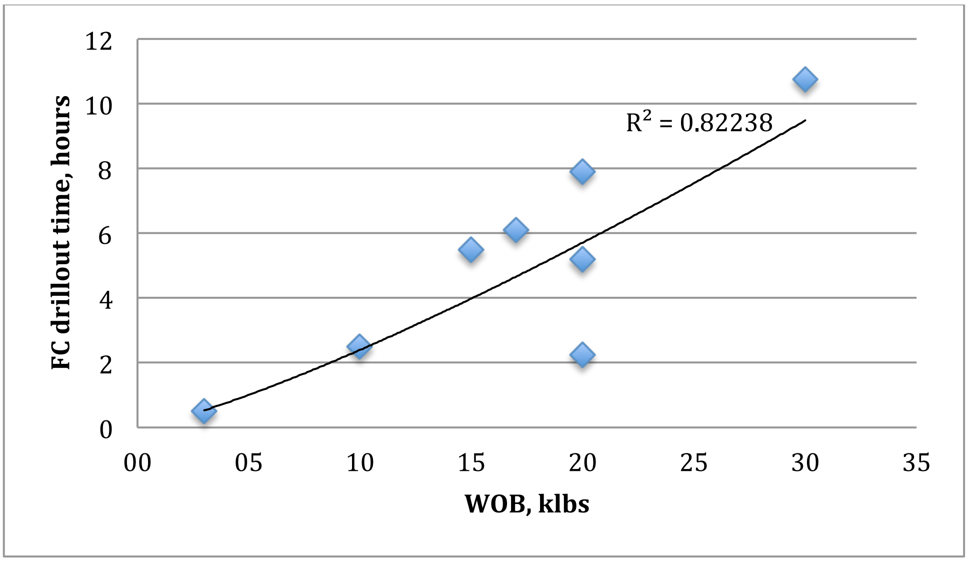

Figure 39: FC drillout time as function of WOB

As we have mentioned earlier, identical plug system and float collar design and similar bit specifications let us assess the drillout efficiency as function of operational parameters. We see that effect of WOB on drillout time is different from formation drilling, where ROP is improved with higher WOB. We conjecture that it happens due to complex design of darts and wiper plugs system. Even non-rotating configuration can start spinning when high WOB is applied. Halliburton's recommendation is to keep 0.5-1 klbs/in of bit WOB while drilling shoe track with

[8] Picture is taken on-well site by thesis author

PDC bit, which corresponds well with our observations. Drillout time did not show clear dependence on RPM or flow rate. Our recommendation for plug system and adjacent collar drillout would be to *start with very low WOB, keep it just about 4-10 klbs during drilling, use high flow rate and medium-low RPM.* Best practice among experienced drilling engineers is to tag the plug and note its depth, go down applying no RPM and low WOB to start with to prevent plugs from spinning.

For these wells, a composite nose shoe was chosen. The shoe also contained another PDC drillable poppet valve. These components are illustrated below:

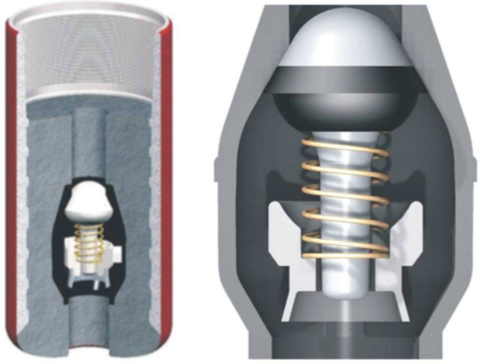

Figure 40: Composite float shoe and poppet valve used in analyzed wells [51]

The median time for shoe drillout was 0.8 hours. Table with drilling parameters used during shoe drillout is presented below:

Table 5: Drilling parameters used for shoe drillout

Well	Time to drill shoe (hrs)	WOB, klbs	RPM	TRQ, ft*klbs
1H	1,00	9,60	80	8,3
2H	0,33	10,7	100	7,8
3H	1,90	11,0	100	7,8
4H	1,80	14,0	66	6,0
5H	0,75	10,4	90	6,4
6H	0,80	4,80	74	8,3
7H	0,33	13,0	60	10
8H	0,25	12,0	60	8,8

We do not see correlation between parameters and the drillout time when we plot these data. We conclude that *relation between shoe drillout time and operational parameters could not be determined.*

We will now look at the total drillout time for float equipment drilled with different PDC bits:

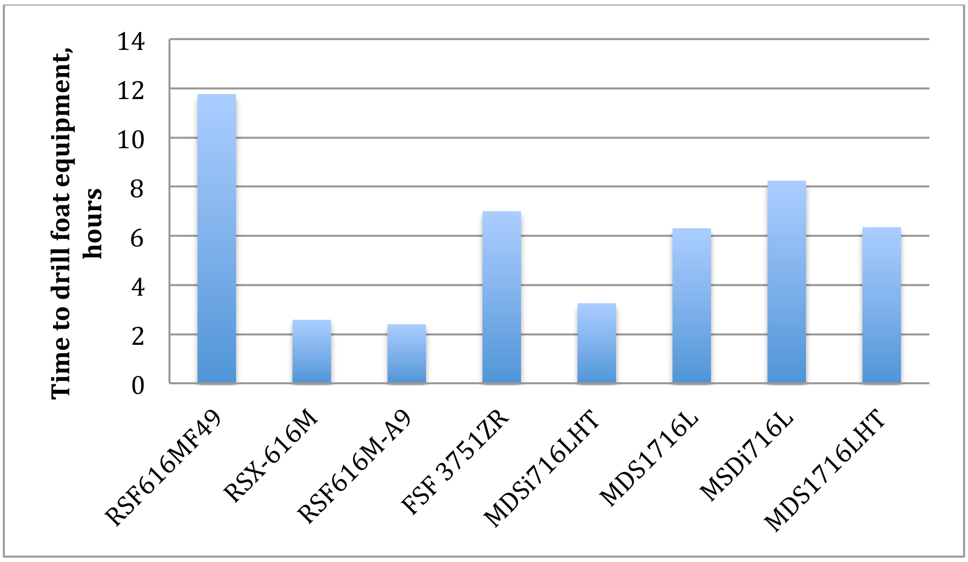

Figure 41: Time to drill float equipment with different PDC bits for wells 1H-8H (from left to right)

Table 6: Drill bits specifications

Well	Blade number	IADC code	TFA, in^2	JSA, in^2	Cutters number	Cutters row design
1H	6	M422	1,608	31,76	69	7 double
2H	6	M422	1,491	31,76	69	7 double
3H	6	M422	1,666	31,76	69	7 double
4H	7	M322	1,374	30,84	80	7 single
5H	7	M423	1,635	28,00	76	3 double, 4 single
6H	7	M423	1,635	27,96	76	3 double, 4 single
7H	7	M423	1,659	27,96	76	3 double, 4 single
8H	7	M423	1,664	28,00	76	3 double, 4 single

According to the drilling program, bits used for 1H, 2H and 3H are very similar in design; the distinction is the TFA of the bits. The difference in drillout time between 1H and 2H/3H, as mentioned in remarks, is due to stuck rubber, which possibly happed due to high WOB used while drilling through plugs.

Conclusion:

- The drillout of wiper plug system, which consisted of two plugs, two darts and a poppet valve, showed clear relation with WOB: the drillout time increases with higher WOB. No correlation with other parameters was observed. We recommend applying 4-10 klbs WOB (depending on a bit size), very low RPM to start with and high flow rate.
- The float shoe included a poppet valve. The shoe drillout results are not observed to be dependent on variations in drilling parameters. We, however, recommend using WOB just above the one used for plugs drillout to avoid creation of large debris, which might result in plugged blades.
- Bit used for wells 2H and 3H showed the best performance during this drillout. We suppose that higher number of blades and cutters will not improve the drillout, however, larger junk slot area and double row of cutters may have positive impact on float equipment drillout. TFA has not shown any influence on the drillout time.

5.1.2 7 ¾" liner equipment

Here we have also chosen eight wells drilled from one platform in Ekofisk area, analysis in this case is performed for 7 ¾" liner shoe track instead of 13 3/8" shoe track. The shoe track in seven wells was drilled with HC MX-20DX tri-cone bit, for eighth well (K6) HC MX-18DX tri-cone bit was used. These two models have just minor difference: HC MX-20DX is used for slightly more abrasive applications, see IADC classification in Appendix D and bit specification sheets in Appendix F. Identical bit design represents a good reference point for our analysis, as we can compare the drillout results focusing on operational parameters and mechanical components design. As described in section 2.3.2, shoe track in liners is often added an additional collar – landing collar. It has the same functions as float collar in other casings.

Wiper plug system and landing collar from two suppliers were used for these wells. For wells equipped with Halliburton tools, Versaflex Liner Hanger Plug Assembly was used. This system incorporates one wiper plug, run on a setting tool (no need for equalizing swivel, which is typically used on other systems), releasing dart and specially designed landing collar, see figure below.

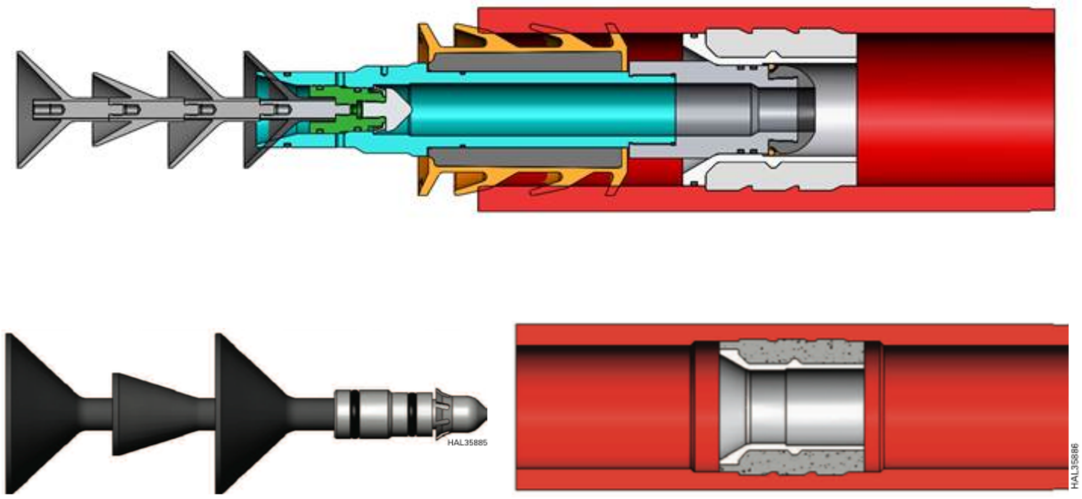

Figure 42: Top: Versaflex liner hanger plug assembly, bottom left: dart, bottom right: landing collar [28]

Parts that have to be drilled out are dart, plug fins, internal part of the plug and internal part of the landing collar. The wiper plug is made from wrought aluminum, rubber, phenolic and brass (shear pins). The dart is made from wrought aluminum and rubber. The drillable parts of landing collar are made from wrought aluminum, concrete and rubber [18].

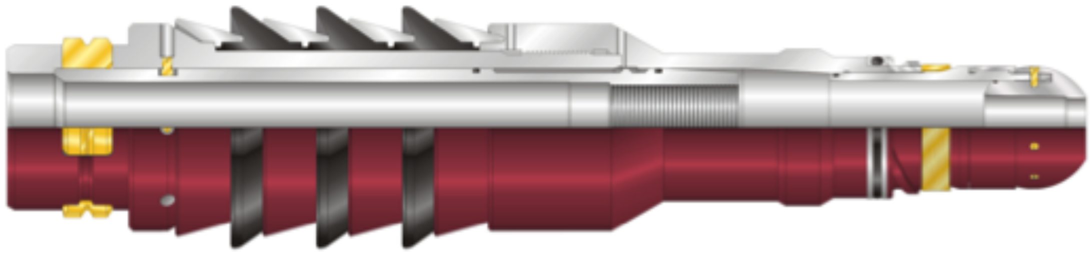

Figure 43: Weatherford's Mk55 Single Wiper Plug [52]

Weatherford SWP (single wiper plug) system with integral ball seat was used in other wells (Fig.43). This system consists of a wiper plug, a drillpipe dart and a landing collar, and is described as non-rotating and PDC drillable. Parts that have to be drilled out are made from elastomeric materials and aluminum. The internal part of the landing collar is made from aluminum [20]. Design of these two wiper plug systems is similar: in both cases there is a single plug, one dart and one landing collar. The drillout data for landing collar-plug system is presented in the tables below:

Table 7: Drillout data for landing collar system in 7 ¾" liner

Well	Time to drill LC	WOB, klbs	Flow rate, gpm	RPM	Supplier
K1	1,8	6,0	200	30	WTF
K2	5,3	16,5	220	60	HB
K3	5,5	15,0	250	55	WTF
K4	5,3	15,0	200	60	HB
K5	4,8	8,5	155	50	HB
K6	5,3	10,0	230	85	HB
K7	6,0	15,0	230	95	WTF
K8	16,8	14,5	185	55	HB

Table 8: Comments to landing collar system drillout

Well	Comments
K1	
K2	Up tp 20 klbs WOB was tried.
K3	Various parameters and up to 18 klbs WOB was tried.
K4	Up to 23 klbs and 40 RPM were found to be the most effective.
K5	
K6	
K7	Debris had to be cleared from around the BHA by vigorously reciprocating the pipe.
K8	Tried all combinations of parameters (10-19 klbs in WOB, 30-80 RPM) to improve penetration and minimize shock on Autotrack[9].

Median time for landing collar system drilout was 5.3 hours. The Halliburton's one had 5.3 hours as a median drillout time, while Weatherford's one took on

[9] Autotrack - Baker Hughes steering tool, used as a part of bottom hole assembly

average a bit longer – 5.5 hours. Time to drill out wiper plug system in this case varies less than for 13 3/8" casing.

In this case relations between drillout time and operational parameters can be easily seen; for better overview they are presented in the charts below:

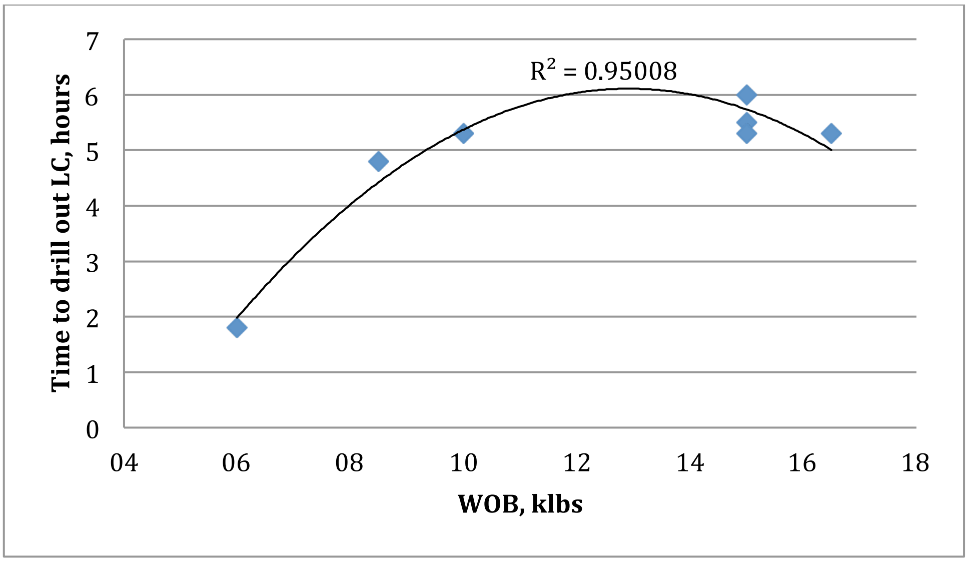

Figure 44: LC system drillout time as function of WOB

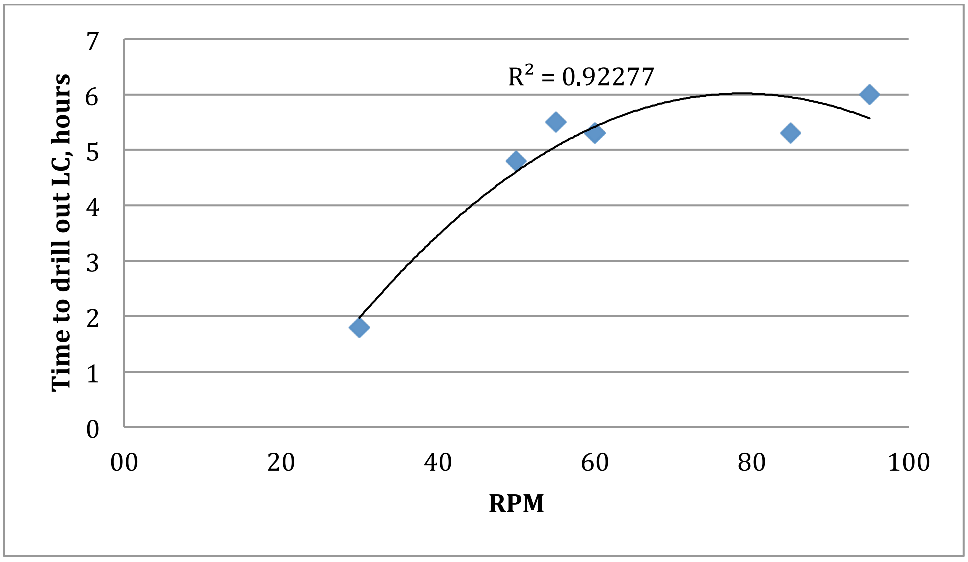

Figure 45: LC system drillout time as function of RPM

From the charts above we see that both WOB and RPM have significant influence on drillout time. Both relations follow polynomial 2nd order function. The trend here is opposite to the one, described in chapter 2: ROP (length upon time) in this case drops with increasing WOB and RPM. Our explanation to this behavior is that when low WOB is used, bit is capable of getting good grip on plugs and collar. Low RPM prevents plugs from spinning and aids junk removal. As a result we get fast and effective drilling. Increase in these parameters leads to longer drillout due to spinning components (even non-rotating plugs might start spinning), jammed bit parts, stuck rubber etc. However, when we significantly increase WOB and RPM, the bit starts pushing hard on the target, which ultimately crushes it resulting in slight improvement in the drillout. We can conclude that *for the successful plugs and landing collar drillout with tri-cone bit, combination of low WOB and low RPM should be used.*

To prevent backflow from the well, Weatherford's Mid Bore Autofill float collar with double aluminum flapper valve was used in all wells (Model M45AO). Unfortunately, due to lack of permission for image reproduction, we cannot place it here. In Fig.46 a similar model is presented. Even though the collar is documented to be PDC drillable, roller cone bit was chosen to drill through it. The reason for it could be incompatibility of PDC and aluminum.

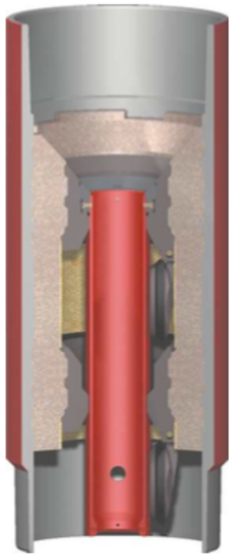

Figure 46: Autofill collar with double valve (Model L45WP) [51]

The drillout data is presented below:

Table 9: Drillout data for autofill float collar

Well	Time to drill FC, hrs	WOB, klbs	Flow rate, gpm	RPM
K1	2,5	5,0	200	30
K2	0,5	14,0	240	60
K3	0,5	16,0	290	60
K4	0,8	15,0	250	60
K5	1,8	10,0	200	60
K6	2,1	13,0	238	65
K7	0,8	13,5	222	50
K8	1,8	10,0	224	51

No issues were documented while drilling this equipment. Median time to drill through these component was 0.8 hours. Autofill collar drillout time turned out to be dependent on WOB, RPM and flow rate, see the charts below:

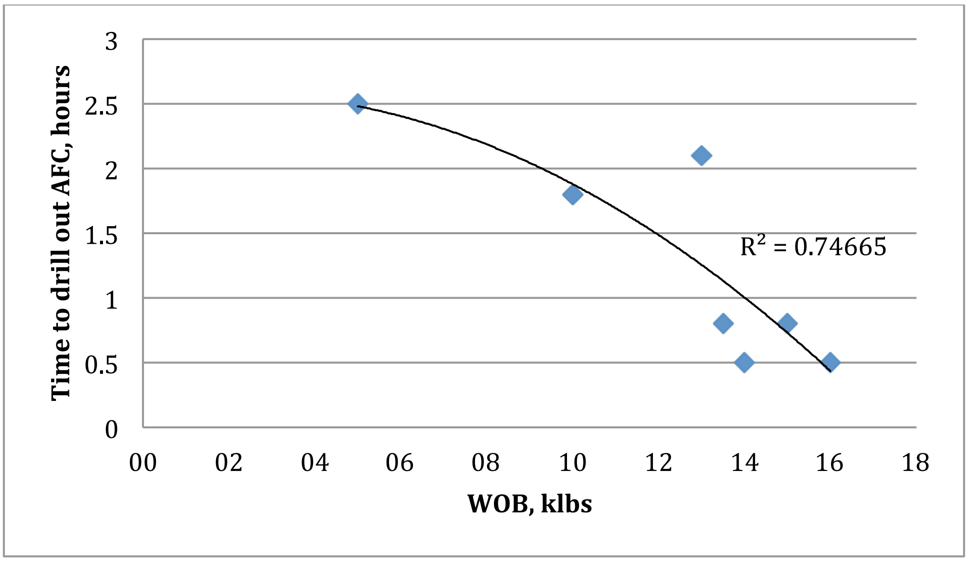

Figure 47: Time to drill out AFC as function of WOB

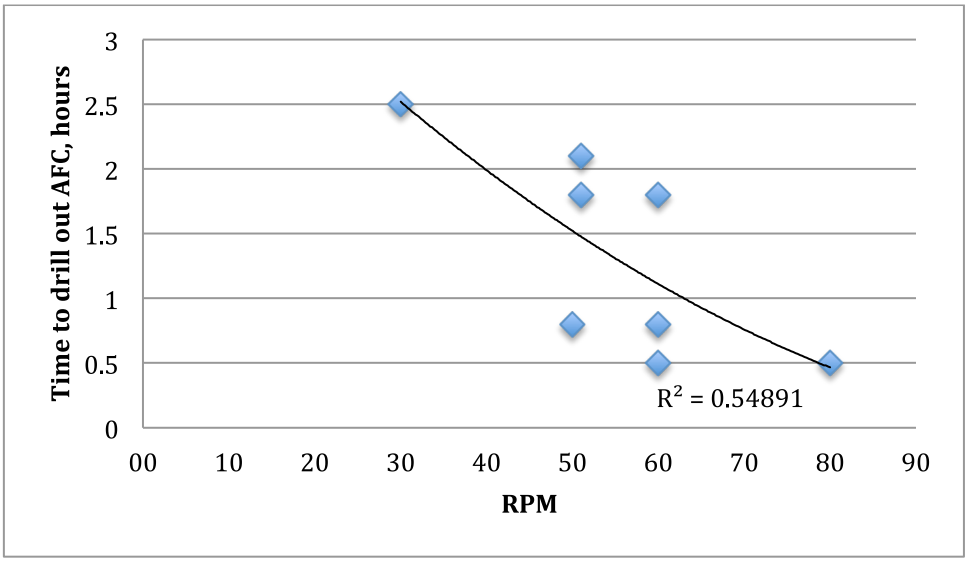

Figure 48: Time to drill AFC as function of RPM

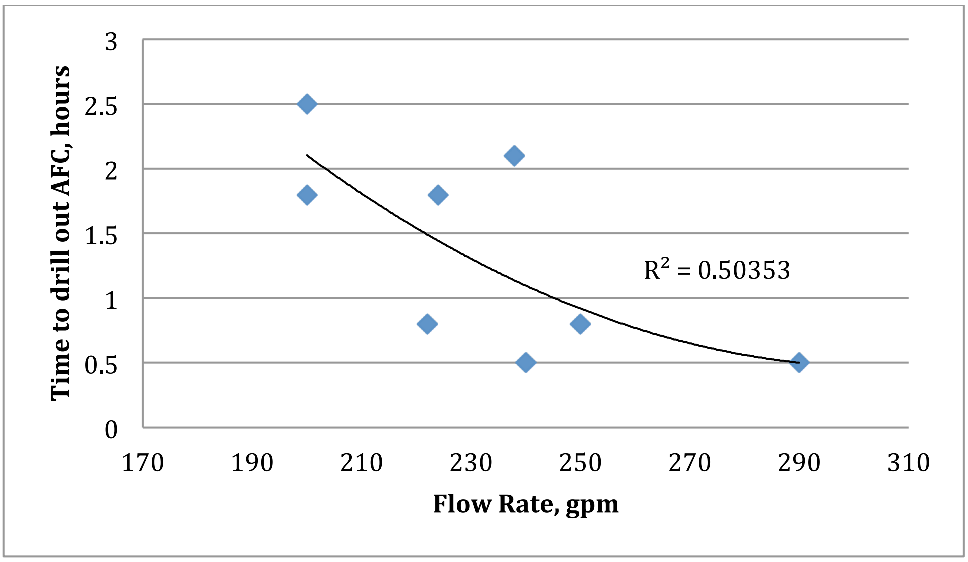

Figure 49: Time to drill AFC as function of flow rate

All relations follow polynomial 2nd order function. As expected, WOB has the strongest influence on the drillout time. The relations here, however, differ from those we found for drilling through float collar system with PDC bits and landing collar system with roller cone bits, where both systems consisted of collar itself and wiper plugs. *WOB, RPM and flow rate in this case have positive influence on float collar drillout.* Our explanation to this is that a collar without wiper plugs represents a simple system. Materials it is made from are aluminum, concrete and cement, which are rather easily drillable with tri-cone bit. Therefore the drillout pattern of this configuration follows the general pattern for formation drilling, described in section 2.5.

We would like to point out that landing collar and plug system drillout took nearly 7 times longer than float collar drillout, see chart in Fig.50 for time distribution overview. We can conjecture that *wiper plugs is the reason for long drillout time of landing collar system.*

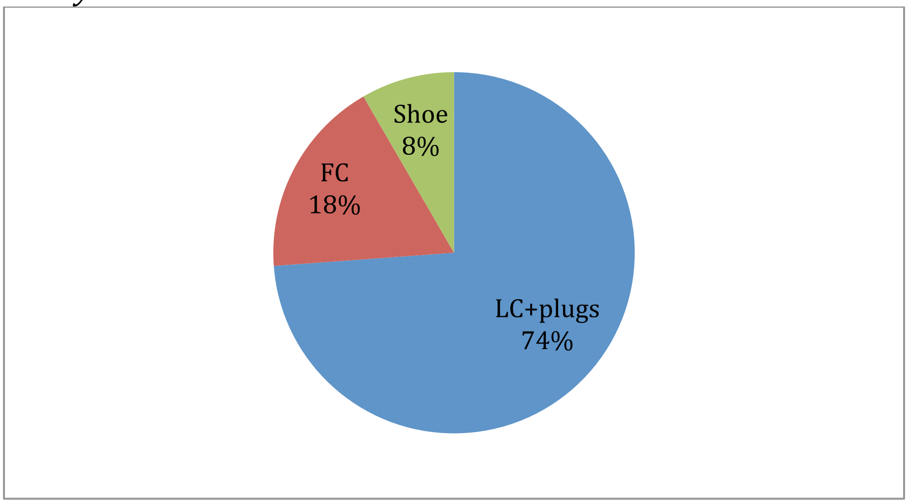

Figure 50: Time in percent to drill through shoe track components

Liner shoes used for these wells were of two types: 7 ¾" liners in wells K1 and K7 were equipped with conventional Weatherford's composite guide shoe and liners in other wells were ending with Weatherford's reamer aluminum shoe without float valves (Fig.51):

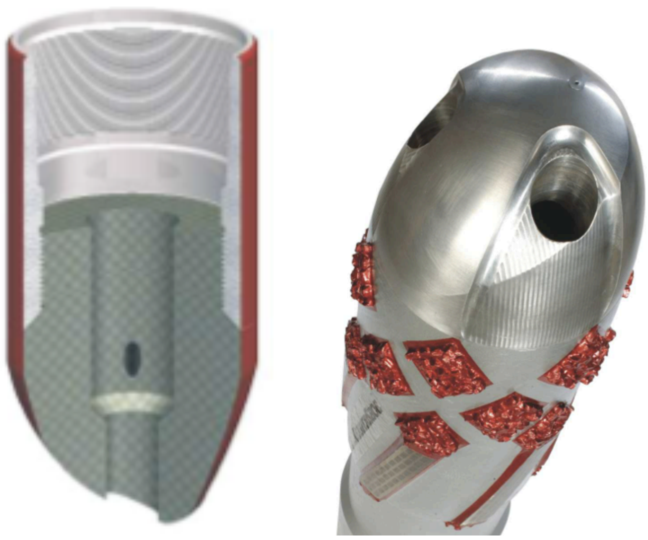

Figure 51: Composite guide shoe (left) and reamer shoe (right) [51]

First of all we will list some features typical for reamer shoe:

- Tungsten carbide cutting structure on the gauge (diamond shaped elements)
- Backreaming feature
- Drillable aluminum eccentric nose
- Internal parts are made from materials, which are drillable with either PDC or tri-cone bit

The reamer shoe can be used while running with liner through challenging formations to avoid stuck liner.

The drillout data for liner shoe is presented below:

Table 10: Operational parameters used during shoe drillout

Well	Time to drill shoe, hrs	WOB, klbs	RPM	Flow rate, gpm
K1	0,2	2,0	50	230
K2	1,3	12,0	80	275
K3	1,3	12,5	60	250
K4	0,2	8,0	120	205
K5	2,3	9,0	60	164
K6	0,4	5,0	100	260
K7	0,3	9,0	50	270
K8	2,6	15,0	70	235

The median drillout time for all shoes was 0.6 hours. For reamer shoes the median time was 1.4 hours, and for guide shoes – 0.3 hours (Fig.52). Reamer shoe took on average 4 times longer to drill through than guide shoe due to its design and materials used (aluminum vs. composite). However, we see that there is one exception: reamer shoe in well K4 took just 0.2 hours to be drilled through.

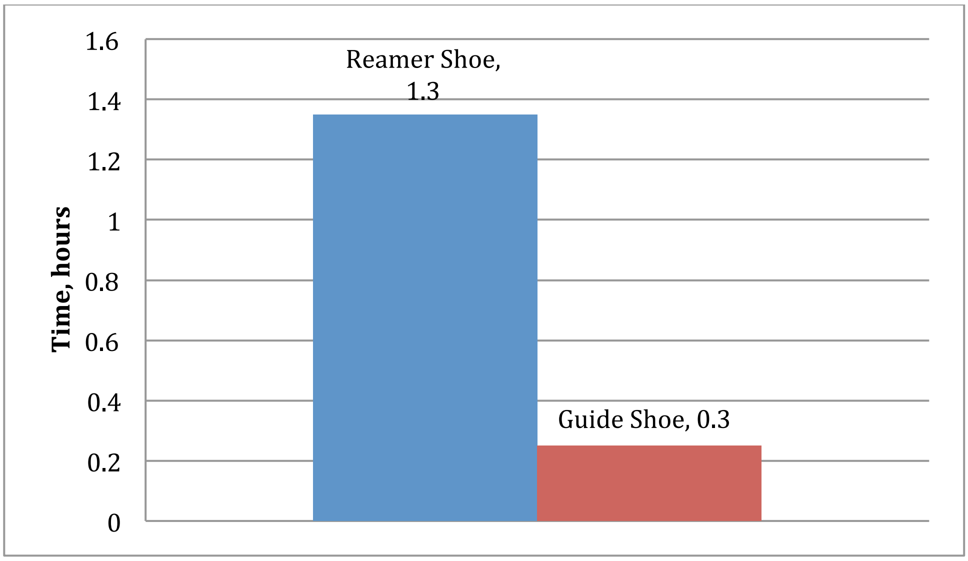

Figure 52: Reamer shoe and guide shoe drillout time

Analysis of drillout showed that drillout time is to some extent dependent on WOB and RPM. These relations also can be described by 2nd order polynomial function:

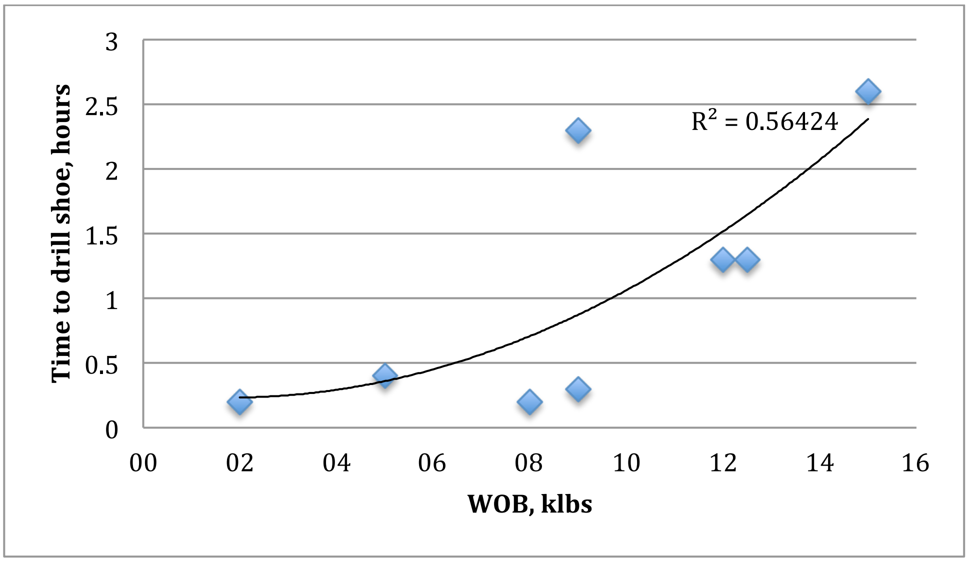

Figure 53: Shoe drillout time as function of WOB

We see that the drillout time increases with higher WOB. Relatively low R square means that drillout time depends on variation in WOB on 56% (see detailed explanation for R square in the next section). Despite different function, this relation is similar to the one found for landing collar system drillout: higher WOB leads to longer drillout. The reason for such behavior, as we see it, is design and materials of the reamer shoe. Having simple configuration, composite guide shoe can be easily drilled with both low and moderate high WOB (2-10 klbs).

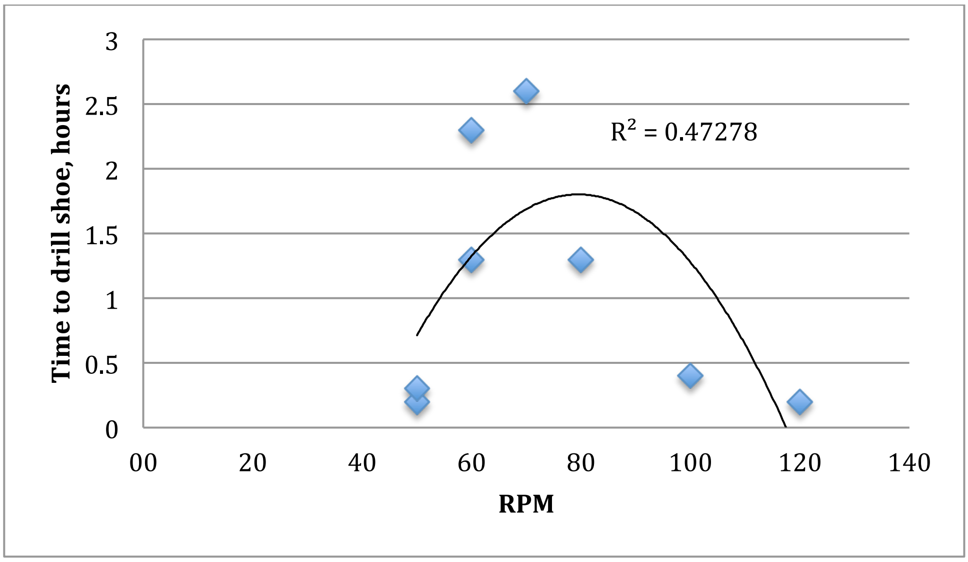

Figure 54: Shoe drillout time as function of RPM

We see that time to drill through the shoe is low when we either apply low or very high RPM. The latter, however, might shorten the bit life due to high wear. *Our recommendation when using tri-cone bit for drilling reamer shoe would be high RPM and low WOB; for drilling guide shoe – low-medium high WOB and low RPM.*

Conclusions:

- There was no significant difference in drillout time between two wiper plug systems, which both consisted of single plug, dart and landing collar. The drillout time was rather consistent for all wells comparing to plug system drillout in "H" wells; we then may conjecture that roller cone drillout is more predictable than PDC one (see previous section).
- We recommend using low WOB (6-8 klbs) and low RPM (30-50) for drilling out wiper plug system with roller cone bit.
- Autofill float collar, which included two aluminum flapper valves, was drilled successfully with high WOB (14-17 klbs), medium RPM (60) and high flow rate (240 gpm and above).
- Our recommendation on how to drill reamer shoe is to use high RPM (over 100) and low WOB (5-7 klbs); low-medium high WOB (7-10 klbs) and low RPM (50) should be used for guide shoe drillout.
- Roller cone bit is a good choice when significant amount of aluminum has to be drilled out.

5.2 Cement drillout

The largest part of our work is dedicated to analysis of cement drillout in the shoe track. Here we study just the shoe tracks from wells "H" due to wet shoe tracks[10] often observed in wells "K". Our goal is not limited to analysis of current drillouts; we also intent to describe the general effect of operational parameters on penetration rate in cement. For this purpose we try to identify models that can be used to predict the effect of drilling parameters on ROP. Background for these models was given in chapter 3, general methodology was described in section 1.4, step by step procedure and final results will be described in the following sections.

5.2.1 Effect of WOB and RPM

Drilling efficiency depends on a few factors, which include operational parameters, drilling target characteristics and equipment used. Cement in analyzed shoe tracks had identical composition and properties. The tail slurry density was 15.9 ppg and its compressive strength was 2000 psi in all shoe tracks. The bits used to drill out cement were PDC bits with very similar characteristics (Table 6). ROP, however, was varying from well to well; we assume that the main reason for this is the drilling parameters used. Median values for operational parameters for these wells are presented in Table 11.

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[10] Wet shoe track – "occurrence of unset, contaminated or no cement in the casing section between float collar and shoe after a primary cement job" [33]

Table 11: Operational parameters for cement drillout

Well	Torque, ft-klbs	WOB, klbs	RPM	Jet impact force, lbf	Flow rate, gpm	ROP, ft/hr
1H	8,4	14	60	1123	866	76,0
2H	9,0	7,0	100	576	900	229
3H	8,0	11	50	1050	800	95,7
4H	7,0	10	60	1316	870	27,0
5H	7,0	3,0	90	784	795	88,4
6H	10	11	75	978	815	164
7H	9,5	9,0	60	1217	916	148
8H	9,0	13	60	960	814	155

In this section we will check whether the theory, described in section 2.5.4, is applicable for cement drilling. We made plots of ROP as function of WOB and RPM to see how these parameters affect ROP in cement. The results are presented below:

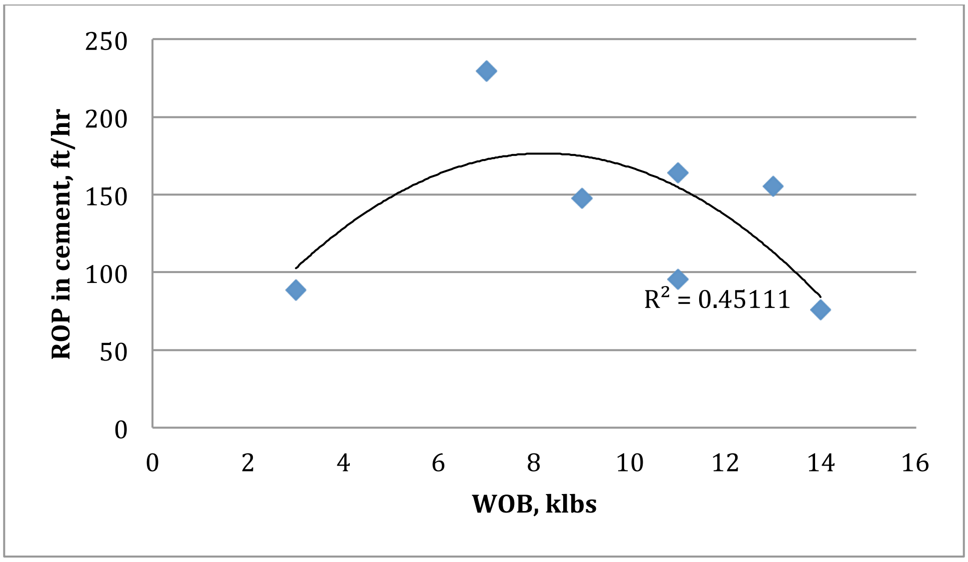

Figure 55: ROP as function of WOB

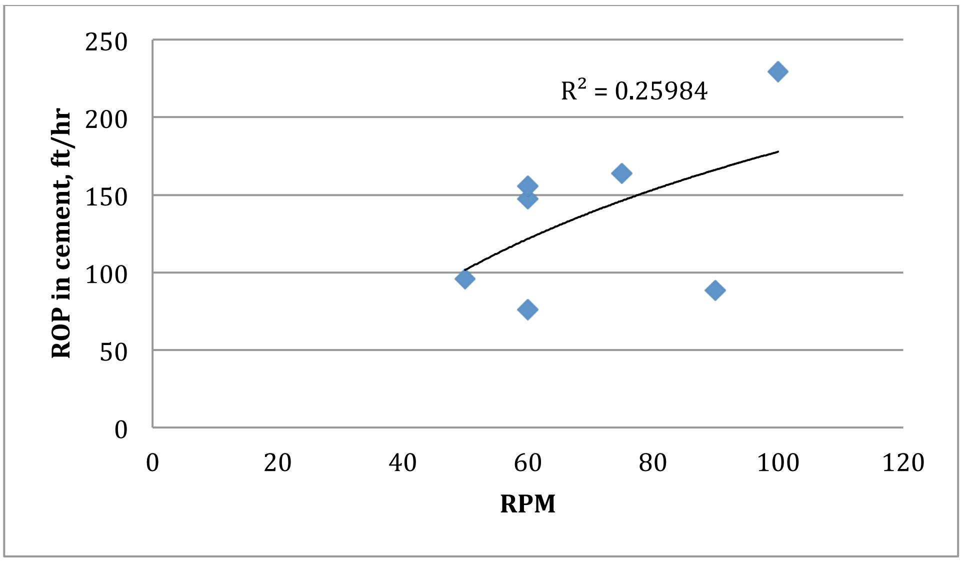

Figure 56: ROP as function of RPM

Even though the relations cannot be deemed to be precise due to variation in other operational parameters, we can see a general trend: penetration rate improves with increasing WOB up to a point, crossing which, it goes down. Compare figure above to plot in Fig.32. Penetration rate in general improves with increasing RPM. Compare this to Fig.33. We see that cement drilling has similar pattern to formation drilling. Low R square indicates that there are other factors affecting penetration rate in cement. To find out how combination of parameters influences ROP in cement, we conducted regression analysis, which is described in the next section.

5.2.2 Regression analysis

Regression analysis offers a way to justify to which extent a combination of drilling parameters affects the penetration rate in cement. For this purpose we have chosen Data Analysis package in Microsoft Excel.

We have modeled ROP as a linear function of several operational parameters, namely WOB, RPM, torque and jet impact force. Our input was observed median ROP for each well, and set of above-mentioned variables. In the output we get a new value for ROP, equation for which is a general linear equation, $y=b+ax$, where y is ROP, a is a slope, b is an intercept and x is one or more variables. Before presenting the results, we would like to explain the general structure of Excel regression analysis and important factors used to assess significance of results.

Part 1: Regression statistics [50]

This section indicates how well calculated values fit the original ones. We will briefly explain some of the factors included in this part:

1. *Multiple R* – correlation coefficient. It shows how strong the linear relation is. 1 indicates perfect correlation.
2. *R square* – coefficient of determination, familiar to most of us parameter from Excel plots and charts. It shows how much of the variation in y parameter is caused by linear relation with one or several x parameters.
3. *Adjusted R square* – adjusted for the number of variables in the model. In our case we will use this factor to assess the correlation, since we will always have more than one variable.

Part 2: ANOVA (Analysis of variables)

Here we are interested in *Significance F* factor, which shows how reliable the results are. If this value is less, than 0.05, the results are reliable.

Part 3: Interpret regression coefficients

This section provides specific information about input components. Some of the factors are listed below:

1. Coefficient for each input parameter and intercept

2. *P value* – this parameter should be below 0.05 to consider results to be statistically significant.

After having explained main principles, we can present obtained results. We have chosen to analyze two sets of parameters: WOB, RPM and torque; and WOB, RPM, torque and jet impact force.

First set of parameters

Table 12: Regression statistics for Set 1

Regression Statistics	
Multiple R	0,92
R Square	0,84
Adjusted R Square	0,72

Multiple R of 0.92 represents strong linear relation between analyzed parameters. Adjusted R square of 0.72 indicates that ROP depends on chosen variables on 72%.

Table 13: Significance F for Set 1

Significance F
0.0460

Low value for Significance F means that the results are reliable, and ROP therefore can be expressed as a linear function of WOB, RPM and torque.

Further we compare predicted and observed ROP and plot them in one graph:

Table 14: Observed and modeled results for ROP, data Set 1

Well	Predicted ROP	Observed ROP
1H	97,80	76,00
2H	200,7	229,0
3H	67,13	95,70
4H	40,91	27,00
5H	100,5	88,40
6H	197,8	164,0
7H	153,0	147,5
8H	125,7	155,4

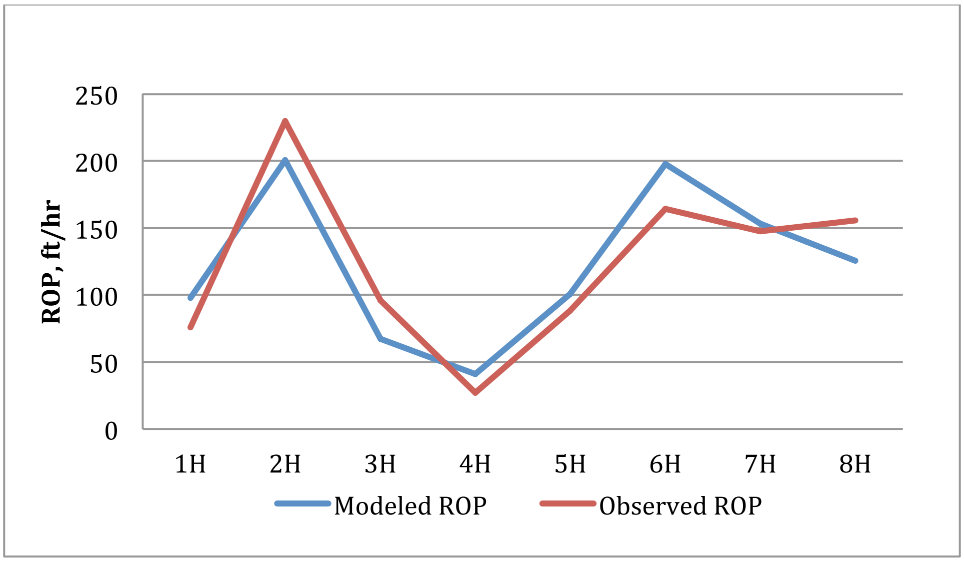

Figure 57: Observed ROP and modeled ROP, based on WOB, RPM and torque

Second set of parameters

Jet impact force is included in this set of variables. This parameter is explained in details in section 2.5.4.3 and chosen here as one, that combines majority of variables, related to well hydraulics: flow rate, TFA and mud weight. We assume that it should have significant influence on ROP.

Table 15: Regression statistics for set 2

Regression Statistics	
Multiple R	0,92
R Square	0,84
Adjusted R Square	0,62

Multiple R of 0.92 represents strong linear relation between analyzed parameters. Adjusted R square of 0.62 indicates that ROP depends on these variables on 62%.

Table 16: Significance F for Set 2

Significance F
0,1460

Table 17: Observed and modeled results for ROP, data set 2

Well	Predicted ROP	Observed ROP
1H	97,80	76,00
2H	200,9	229,0
3H	67,06	95,70
4H	41,22	27,00
5H	100,2	88,40
6H	197,7	164,0
7H	153,2	147,5
8H	125,5	155,4

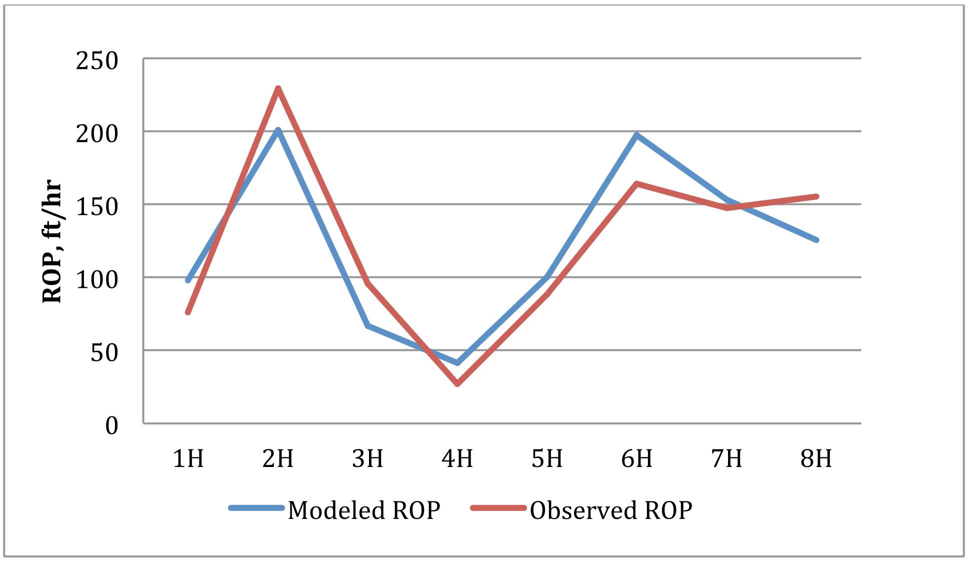

Figure 58: Observed ROP and modeled ROP, based on WOB, RPM, torque and jet impact force

We see that modeled ROP fits the observed one less than in the first case. At the same time, reliability of this model is lower comparing to the first one (Significance F is higher) – this could have affected the final results.

Having found linear relations, we carried out sensitivity analysis of the model for four operational parameters. We varied them in the range of +/- 10% to check what influence such variation would have on ROP. The tables with variables and results are presented below.

Table 18: Modeled ROP when changing WOB by +/- 10%

Increase WOB with 10%	Decrease WOB with 10%	ROP 1	ROP 2	ROP obs
15,4	13	95,76	99,40	76,00
7,70	6,3	199,7	201,6	229,0
12,1	9,9	65,42	68,28	95,70
11,0	9,0	39,65	42,25	27,00
3,30	2,7	99,65	100,4	88,40
12,1	9,9	196,0	198,9	164,0
9,90	8,1	151,7	154,1	147,5
14,3	12	123,6	127,0	155,4

In the figure below we plotted observed ROP and two modeled ROPs for higher and lower WOB. As we see, according to this model, WOB has slightly positive effect of ROP.

Figure 59: Effect of WOB variations on ROP

Next parameter we performed sensitivity analysis for is RPM. Table with drilling data and ROP plot are presented below. The effect here is more significant comparing to previous case: RPM noticeably improves penetration rate.

Table 19: Modeled ROP when changing RPM +/- 10%

Increase RPM with 10%	Decrease RPM with 10%	ROP 1	ROP 2	ROP obs
66	54	107,7	87,48	76,00
110	90	217,5	183,8	229,0
55	45	75,27	58,43	95,70
66	54	51,06	30,85	27,00
99	81	115,2	84,89	88,40
82,5	67,5	210,1	184,8	164,0
66	54	163,0	142,8	147,5
66	54	135,4	115,2	155,4

Figure 60: Effect of RPM variations on ROP

Further we looked at how variations in torque affect penetration rate in cement and noticed that it has significant positive influence on ROP.

Table 20: Modeled ROP when changing torque +/- 10%

Increase torque with 10%	Decrease torque with 10%	ROP 1	ROP 2	ROP obs
9,2	7,6	134,8	60,37	76,00
9,9	8,1	240,5	160,8	229,0
8,8	7,2	102,3	31,41	95,70
7,7	6,3	71,96	9,946	27,00
7,7	6,3	131,0	69,03	88,40
11	9,0	241,8	153,2	164,0
10	8,6	195,0	110,8	147,5
9,9	8,1	165,2	85,43	155,4

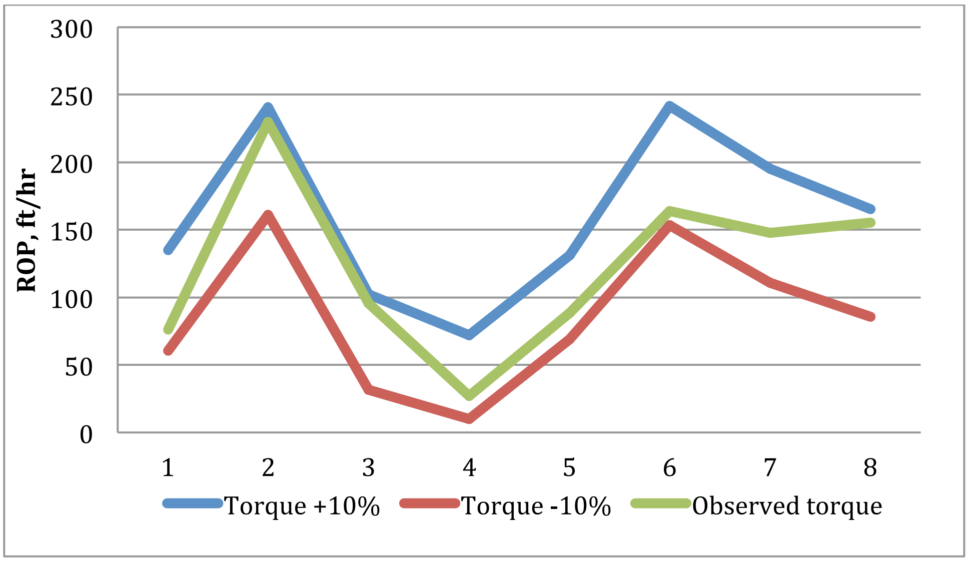

Figure 61: Effect of torque variations on ROP

The last parameter to be analyzed was jet impact force. Data and plots are presented in table and figure below.

Table 21: Modeled ROP when changing jet impact force +/- 10%

Increase JIF with 10%	Decrease JIF with 10%	ROP 1	ROP 2	ROP obs
1235	1011	97,69	97,47	76,00
1287	1053	200,8	200,5	229,0
1155	945,0	66,95	66,74	95,70
1448	1184	41,09	40,82	27,00
862,4	705,6	100,1	99,96	88,40
1076	880,2	197,6	197,4	164,0
1339	1095	153,0	152,7	147,5
1056	864,0	125,4	125,2	155,4

Figure 62: Effect of jet impact force variations on ROP

We cannot distinct between modeled curves – JIF has negligible effect on ROP according to this model.

Conclusions:

- We have seen positive effect of RPM and torque on penetration rate
- WOB did not show significant positive influence on ROP
- We expected to see increase in ROP with increasing JIF, however, this model did not show this relation
- The reason for disagreement between theory and practice might be uncertainties in logging data, which led to low reliability of the model.

5.2.3 MSE analysis

In previous sections we found out that ROP variation to big extent is caused by variation in drilling parameters. One of the expressions that combine drilling parameters is MSE, described in section 3.2. MSE is a function of WOB, ROP, RPM, torque and bit area. We created MSE logs for wells 1H-8H to see how it varies with depth (see Appendix H). We also attempted to find out what is the drilling efficiency in cement (we recall that it is 35% in formation), and whether this factor can be averaged for any shoe track, drilled with either PDC or RC bit. Given known drilling efficiency factor and UCS, we suppose we could predict penetration rate in cement (recall that *MSE=UCS/drilling efficiency*). To check this, we will introduce four more wells, two of which were drilled with PDC bits, and other two - with roller cone bits. We will perform sensitivity analysis for some of the drilling parameters and explain how they influence ROP.

5.2.3.1 Analysis of shoe track in "H" wells

The UCS of cement used in analyzed shoe tracks was 2000 psi. Below we present a table of averaged ROP, MSE and drilling efficiency for each well.

Table 22: Median ROP, MSE and drilling efficiency for 13 3/8 shoe tracks in wells 1H-8H

Well	ROP, ft/hr	MSE, psi	Drilling efficiency
1H	76,0	27252	0,07
2H	229	16402	0,12
3H	95,7	15616	0,13
4H	27,0	53590	0,04
5H	88,4	22420	0,09
6H	164	16435	0,13
7H	147	12456	0,16
8H	155	12318	0,17

We see that in general wells with low ROP have very low drilling efficiency (4-7%); wells with high ROP have higher drilling efficiency (16-17%). We would like to point out that, drilling efficiency is not a direct function of ROP - it also depends on UCS, torque, bit diameter, WOB and RPM (see (7)). We notice that drillout with the highest ROP (229 ft/hr) had drilling efficiency of 12%, while the highest drilling efficiency was calculated for the drillout with median ROP of 155 ft/hr. While drilling, our goal is not just to *maximize* ROP, but *optimize* it, to have sufficient hole cleaning and to limit equipment wear. Therefore we should aim towards *minimum MSE* and *maximum drilling efficiency.*

5.2.3.2 ROP modeling using MSE

As mentioned in previous sections, these wells are very similar in design and equipment used. Now we would like to check, whether calculated above factors could be used for any cemented interval. We introduce four wells from Ekofisk and Eldfisk fields, drilled from different rigs using different equipment. In the table below we summarize some relevant information:

Table 23: ROP, USC and bit data for wells used for MSE sensitivity analysis

Well	Bit used	Cement UCS, psi	Median ROP, ft/hr
A	RC, 12.25”, EQHC1RC	2000	142
B	PDC, 12.25”, MMD65DH	3480	50,0
C	RC, 12.25”, MX-3	1900	67,0
D	PDC, 12.25” SKRE716D	2143	195

We modeled ROP for these wells using MSE concept and drilling efficiency factors calculated above. The modeling showed that drilling efficiency in cement (called “alpha” in the plots) varies between 7 and 10% for both roller cone and PDC bits. The results are presented in four charts below:

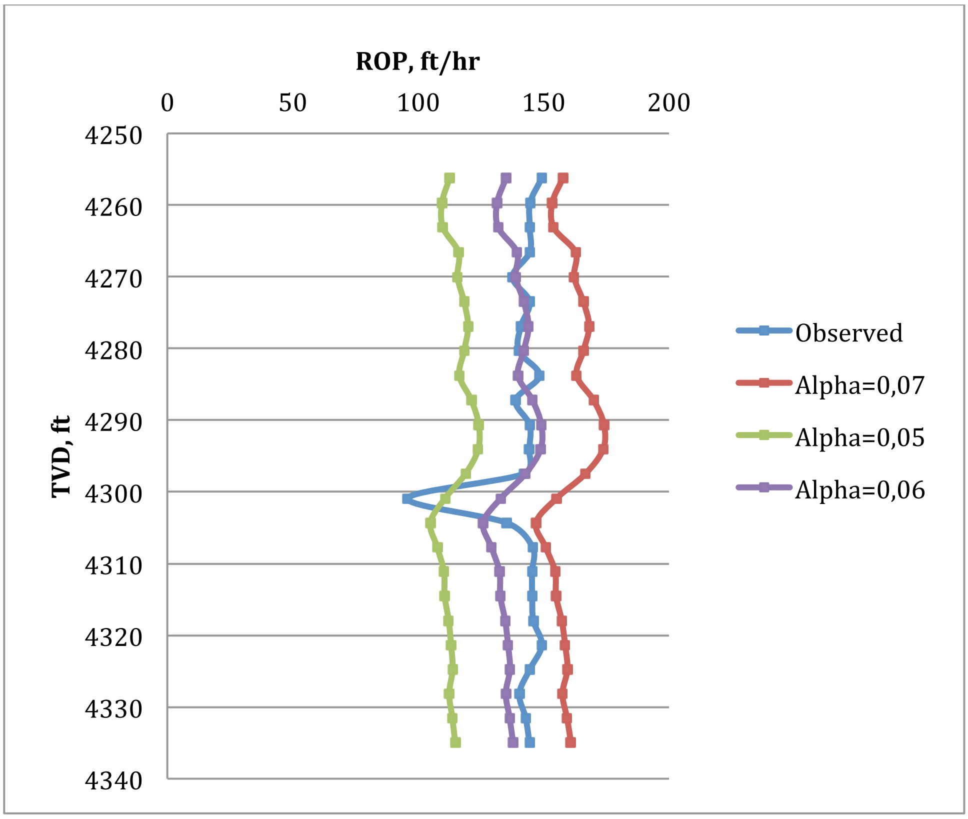

Figure 63: Modeled ROP for well A

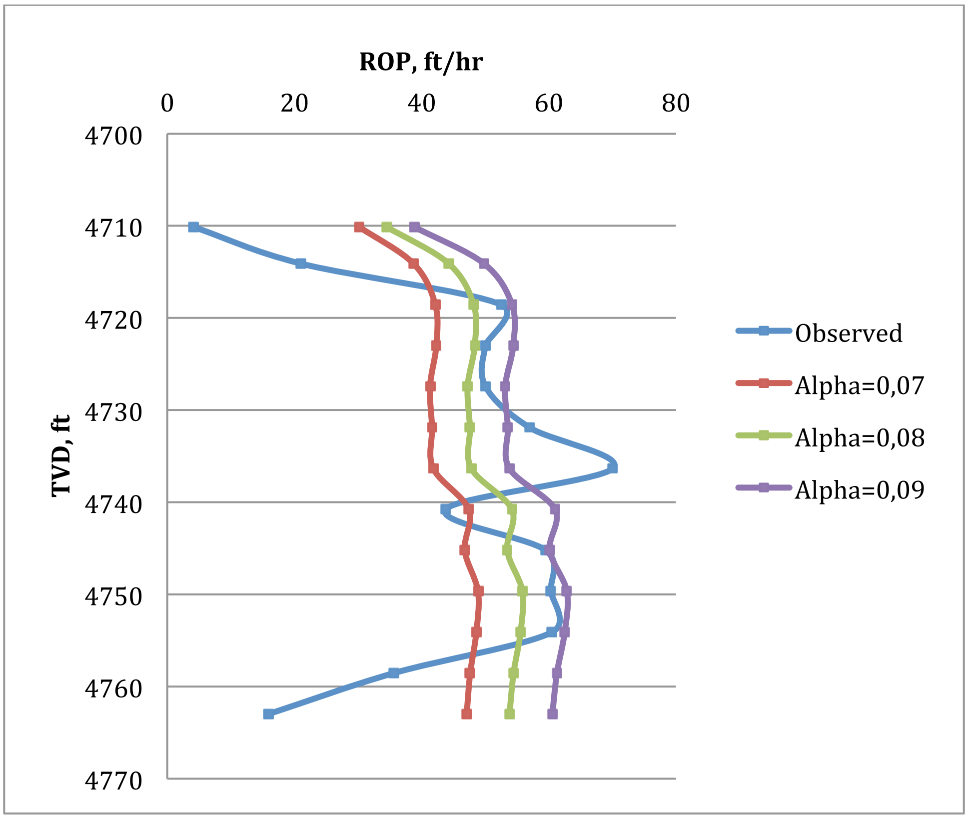

Figure 64: Modeled ROP for well B

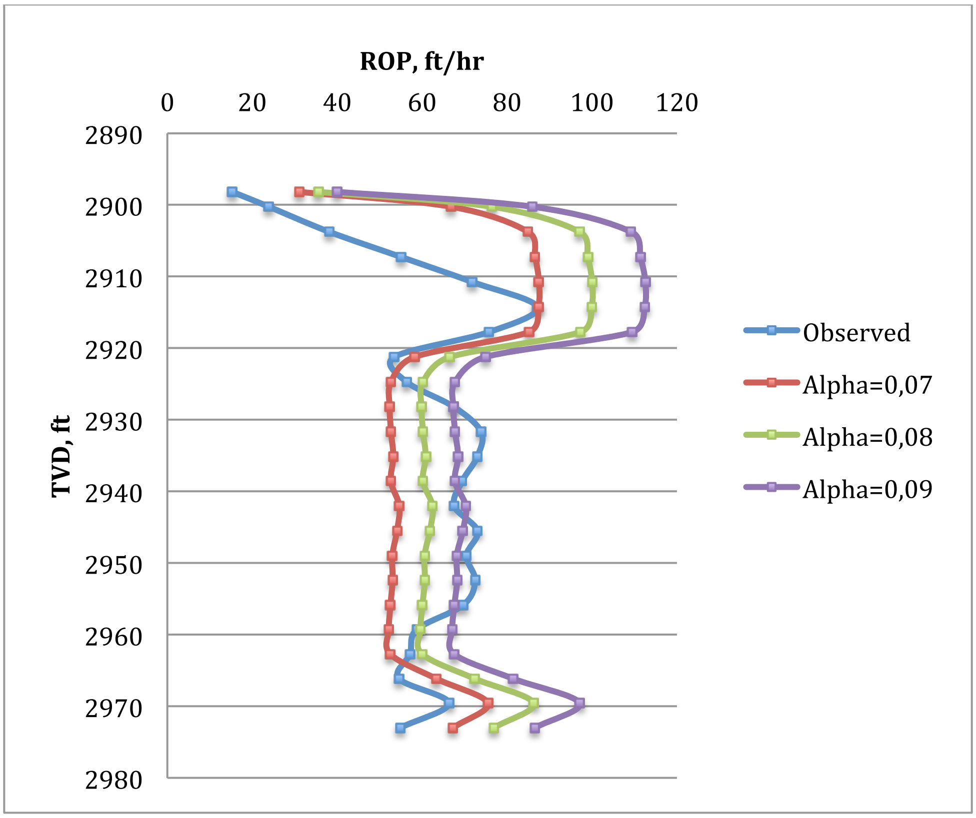

Figure 65: Modeled ROP for well C

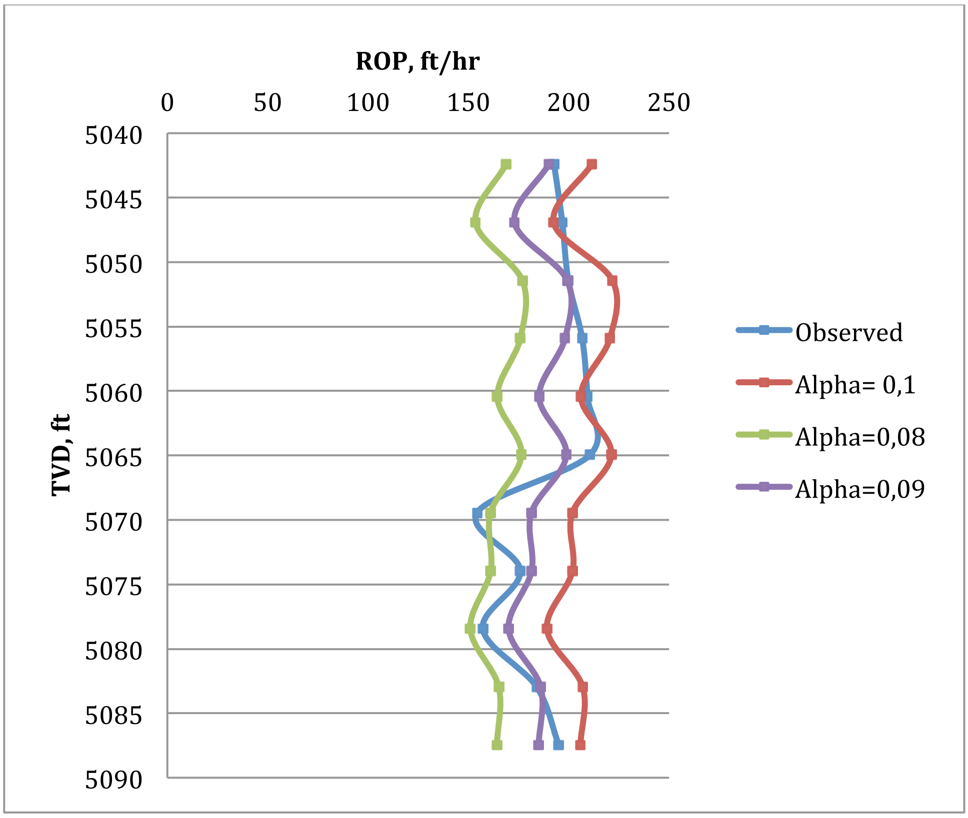

Figure 66: Modeled ROP for well D

Obtained results indicate that common value for drilling efficiency in cement can be approximated to 9% by averaging "alpha" factors from several cases.

5.2.3.3 Sensitivity analysis

We have chosen to conduct sensitivity analysis on well A to see how ROP varies with operational parameters. Two combinations we studied were RPM and torque variation while WOB was held constant, and WOB and torque variation, while RPM was held constant. For this analysis we prepared a code in Matlab, which can be found in Appendix I. Deriving ROP from MSE equation, we get following relation:

$$ROP = \frac{120\pi \, RPM \, \tau}{A_b MSE - WOB} \tag{12}$$

where *MSE=UCS/drilling efficiency*.

For the first combination we let torque vary from 5000 to 10000 lbs*ft and RPM – from 30 to 60, while WOB was held constant at 12000 lbs. We used all possible combinations for RPM and torque and found ROP for each of them. The results for the first combination are presented below in 2-D and 3-D plots:

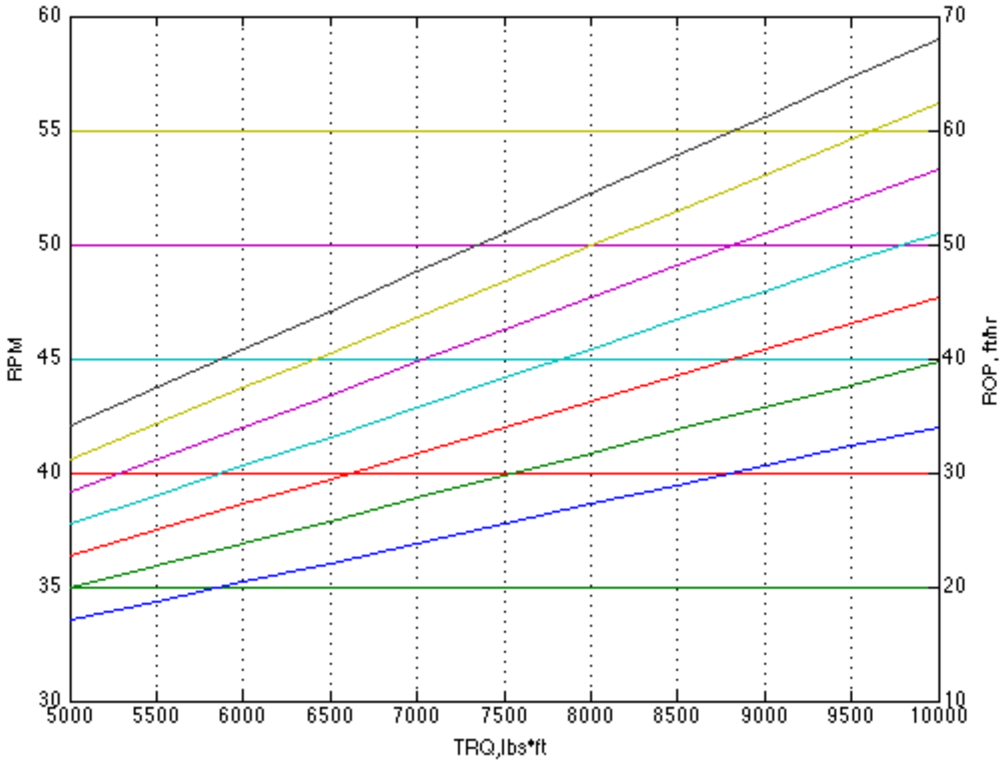

Figure 67: ROP as function of RPM and torque, 2D

As follows from (12), ROP increases linearly with increasing torque and RPM. The 3D illustration is a plane, see figure below:

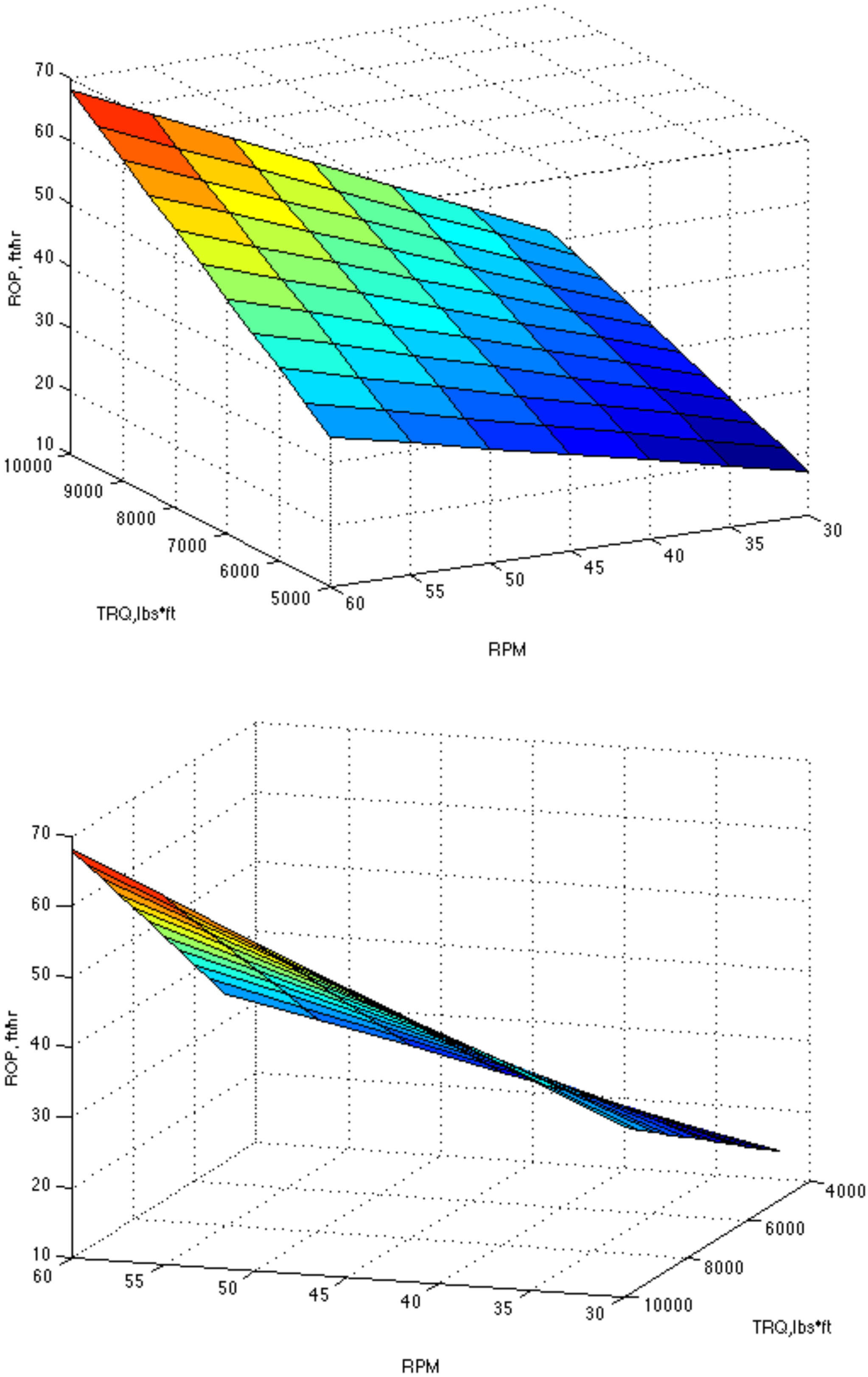

Figure 68: ROP as function of RPM and torque, 3D

Next combination consists of varying WOB and torque and constant RPM. WOB was chosen to range between 6000 and 12000 lbs, while torque varied between

5000 and 10000 ft*lbs. RPM was held constant at 80 revolutions per minute. The results are illustrated in 2D and 3D plots.

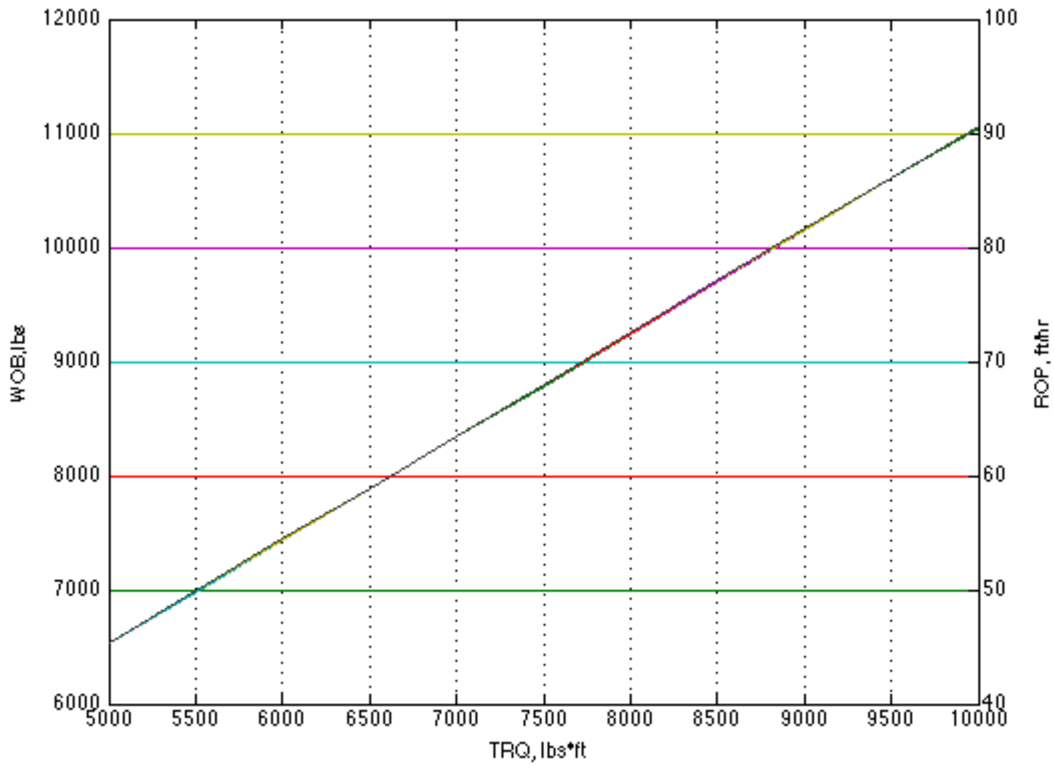

Figure 69: ROP as function of WOB and torque, 2D

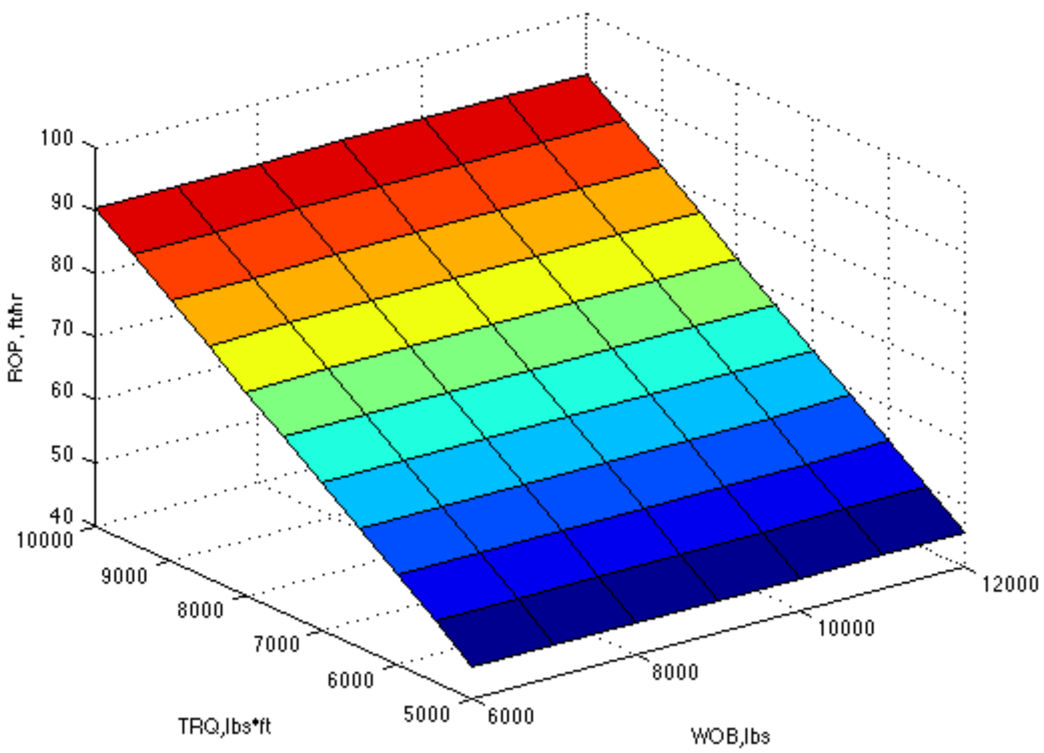

Figure 70: ROP as function of WOB and torque, 3D

As we can see, MSE model does not account for WOB influence on ROP. In Fig.69 we notice that all lines for WOB fall into one, regardless of what value WOB takes. We go back to the (12), and see that, calculated ROP is hardly affected by WOB indeed, because denominator varies just slightly when WOB is altered. Product of MSE and bit area is incomparably greater than WOB; therefore WOB does not show any influence on ROP.

Conclusions:

- There is a narrow range of drilling efficiency values, so this factor can be averaged to be 9%
- MSE concept can be used neither for ROP modeling, nor for sensitivity analysis, because it neglects WOB contribution.

5.2.4 Drillability analysis

In this section we calculate drillability for cement in wells 1H-8H and make drillability logs. The drillability logs are presented along with MSE logs for easier comparison. They can be found in Appendix H. Our assumption is that drillability, as a function of drilling target hardness, should not vary significantly within one shoe track or between shoe tracks, where cement has identical characteristics. We have computed the drillability to see whether or not it had common value for the analyzed wells. Higher drillability values were expected to correspond with higher ROP. Table of averaged drillability values and ROP is presented below:

Table 24: Median drillability for "H" wells[11]

Well	Median ROP	Median drillability
1H	76,00	0,76
2H	229,0	2,20
3H	95,70	3,08
4H	27,00	0,36
5H	88,40	3,21
6H	164,0	2,74
7H	147,5	3,49
8H	155,4	2,47

We see that drillability varies quite significantly from well to well, and we cannot distinguish one common value for cement in analyzed shoe tracks, despite identical cement specifications. When we compare drillability logs to MSE logs we see that the latter one, as a rule, is more consistent. The reason for it is more parameters involved, which combined together, create a better picture of the drillout.

MSE and drillability functions are inversely proportional, and therefore have opposite trends. An example of depth log for well 6H is presented below.

[11] In our study we perform only comparative analysis and can therefore specify units ourselves: ROP is in ft/hr, bit diameter is in inch and WOB – in klbs.

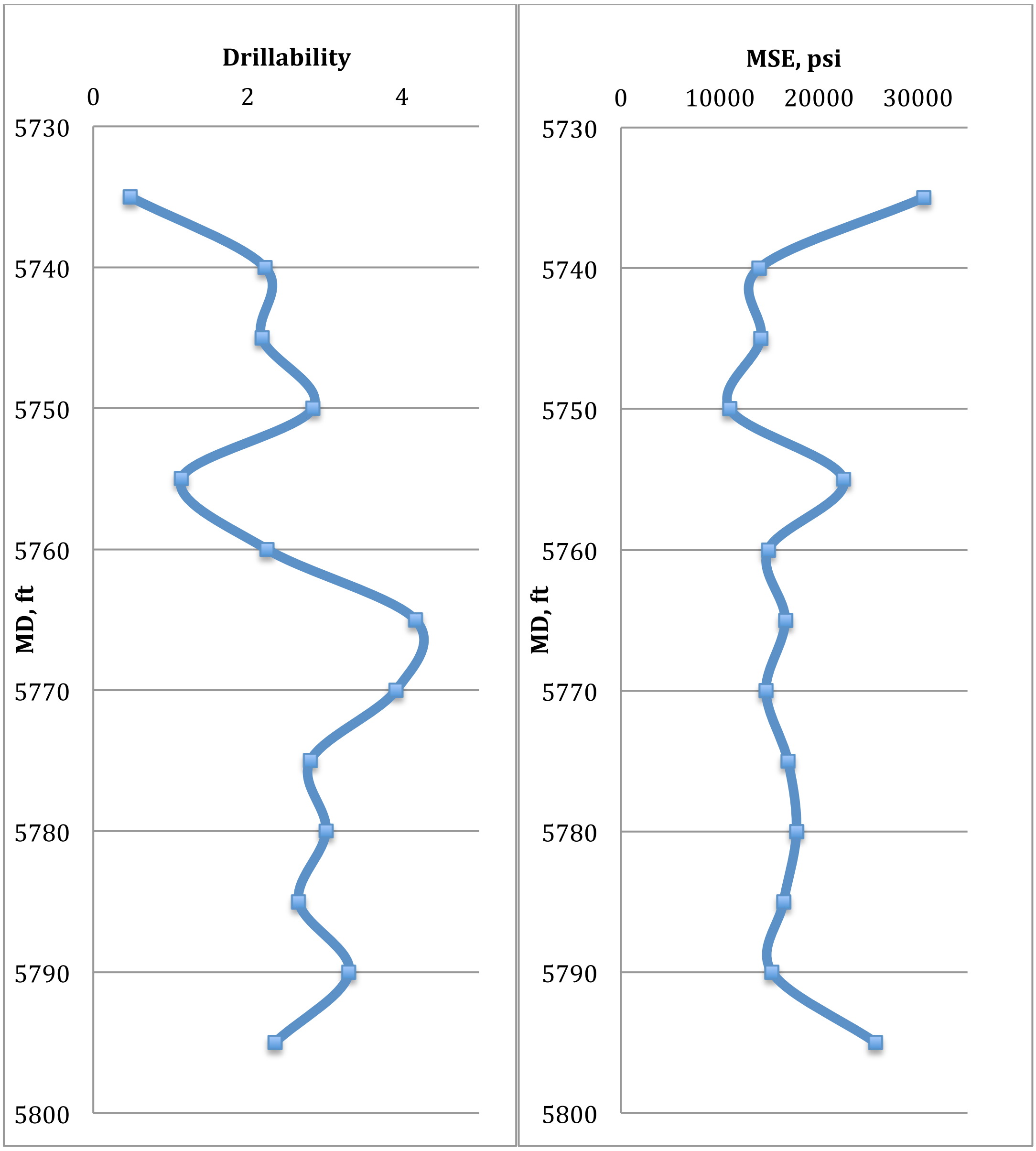

Figure 71: Drillability and MSE depth logs for well 6H

Conclusion:
This method is a good way to assess formation drillability, because here we expect to see more variations within drilling interval, and drilling break always indicates change in formation properties. However, this method cannot be used for ROP modeling, because a common value for cement drillability could not be identified.

5.2.5 Bourgoyne and Young modeling

To calculate penetration rate using Bourgoyne and Young ROP model (BYM), we need to identify *a*-coefficients described in section 3.1. Bourgoyne and Young [12] used multiple regression to determine these coefficients. This method may give zero or negative values, which cannot be used as they provide meaningless results. Bahari *et al.* proposed to use genetic algorithm to determine these coefficients. This method allows setting boundaries for the coefficients, what gives better control of output. Bahari *et al.* [5] reported improvement in penetration rate prediction comparing to multiple regression method.

We propose another simple method for *a*-coefficients determination. It is based on historical drilling data and can be used for ROP prediction while drilling or sensitivity analysis of operational parameters after the well has been drilled. In the following we will use this method to model ROP and to find out which operational parameters affect penetration rate the most according to BYM. To determine the coefficients we have prepared a computer code in Matlab, which can be found in Appendix J. In the flow-chart below we present the general algorithm.

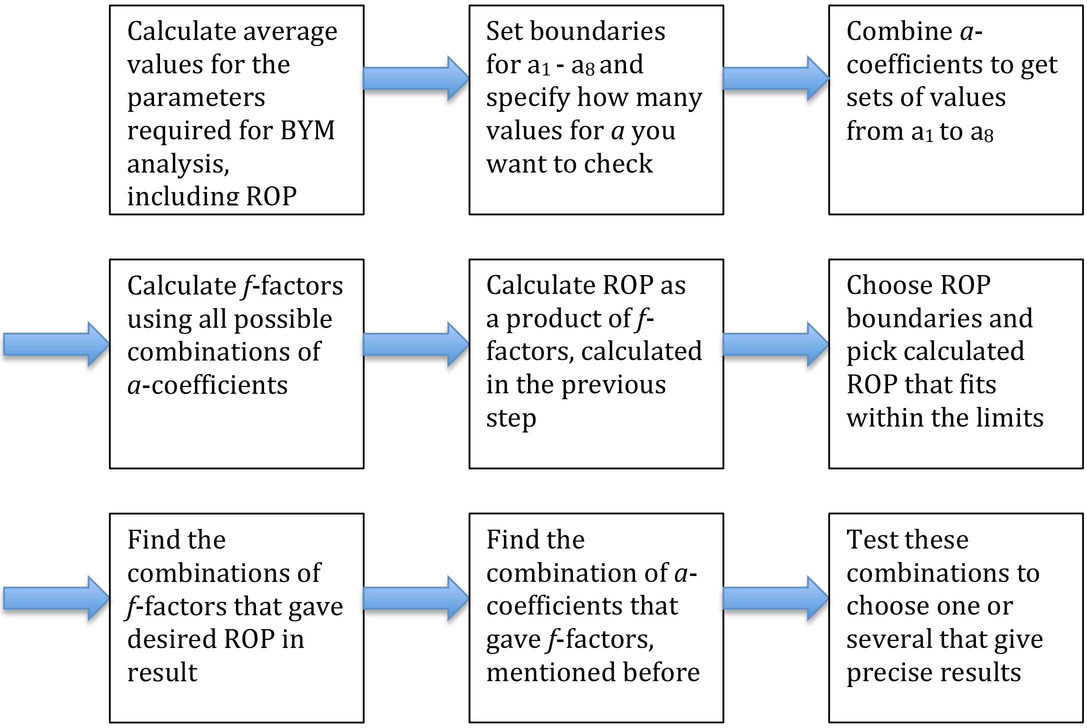

Figure 72: Algorithm of steps implemented in the new model

Explanation for the algorithm steps:

1. Mentioned values can be taken from drilling logs for historical wells or can be obtained real-time while drilling.
2. Boundaries can be taken from Bourgoyne *et al.* [11] or Bahari *et al.* [5]. One can for example take 10 values between boundaries for each *a.*
3. If you have chosen 10 values for each *a,* you will get 10^8 possible combinations of *a*-coefficients.
4. Calculate *f*-factors using equations from section 3.1.
5. Product of 8 *f*-factors gives value for ROP.
6. Chosen boundary for ROP should be narrow and not more than +/- 1 ft/hr to get manageable number for *a*-coefficients combinations.
7. Find combination for *f*-factors that gave the most precise results.
8. Check which values for *a* were used to calculate *f*-factors from previous step.
9. 5-20 (by our experience) combinations would fit the observed data. You now can test the coefficients for all depths to find the best matching set. This

step can be either automated and integrated into the code or performed manually using for example Excel spreadsheet.

This algorithm was implemented for two randomly chosen wells: a well from "H" group and a well from "K" group. For coefficient calculation we used median values of operational parameters and TVD. Five values for each *a*-coefficient were taken from within specified boundaries (see Table 25). Our assumptions here were negligible tooth wear (f_7 is equal to 1) and zero threshold weight. The first one was made because shoe track is placed in the beginning of the section, and the bit has not been worn yet. The second assumption will be discussed later.

Table 25: Boundaries for coefficients *a* taken from [5]

a-coefficients	Boundaries
a1	0,5-1,9
a2	0,000001-0,0005
a3	0,000001-0,0009
a4	0,000001-0,0001
a5	0,5-2
a6	0,4-1
a7	-
a8	0,3-0,6

Tables with field data and calculated values for *a*-coefficients and *f*-factors can be found in Appendix K. In this section we present graphical illustration for field and modeled ROP along with results of sensitivity analysis.

Well 6H:

Having completed steps 1-9, we computed ROP along the whole length of cement in the shoe track using the same set of *a*-coefficients. Observed ROP vs. modeled ROP is presented in the table and figure below.

Table 26: Calculated and observed ROP for well 6H

TVD, ft	Modeled ROP, ft/hr	Field ROP, ft/hr
4800,55	162,01	150,37
4803,64	167,49	144,33
4806,74	171,47	203,05
4809,84	185,81	85,90
4812,93	127,49	186,55
4816,03	142,30	164,41
4819,13	153,69	194,41
4822,23	144,76	164,15
4825,33	158,95	157,65
4828,43	150,07	169,47
4831,53	150,07	189,96
4834,63	117,61	91,17

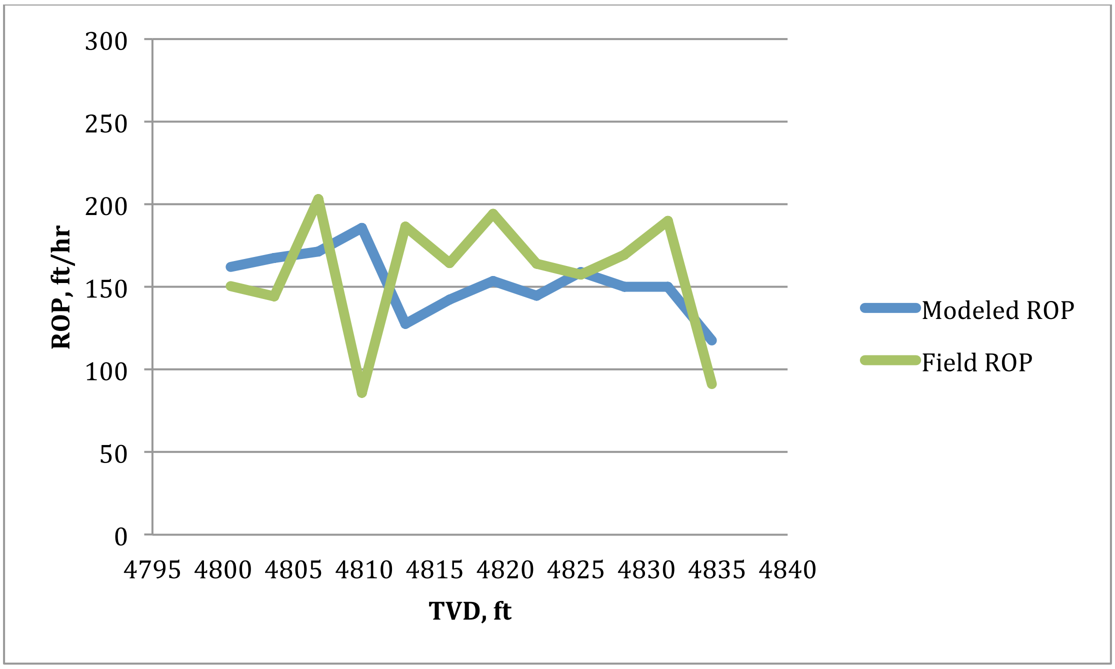

Figure 73: Modeled and field ROP for well 6H

Moderate fit is observed in the figure above. Mismatch can be explained by either error in measurements or presence of other factors, which were not taken into account by BYM. From Appendix table 2 in Appendix K we see that for some depths lower WOB corresponded higher ROP while other parameters were kept constant. However, from the theory and experiments we know that increased WOB should result in improved ROP. Ideally penetration rate should have more or less stable values along the whole cement length as cement is relatively homogeneous and no factors from outside affect drilling (cased hole). Thus such sudden jumps in ROP can be explained by uncertainties in drilling ROP calculation, as relative block movement divided by time (see section 4.2).

Further we studied ROP dependence on following combinations of operational parameters:

1. WOB and RPM
2. RPM and threshold WOB, and
3. ECD and jet impact force.

Recommended by ODC WOB value for 12.25" PDC bit is around 24 klbs (see Table 1). RPM should vary between 40 and 60. The observed median values were 9 klbs and 85 RPM respectively. Other values used for BYM sensitivity analysis are median drillout parameters, which can be found in Appendix table 2. In the figure below we illustrate how ROP varies with these two parameters according to BYM model.

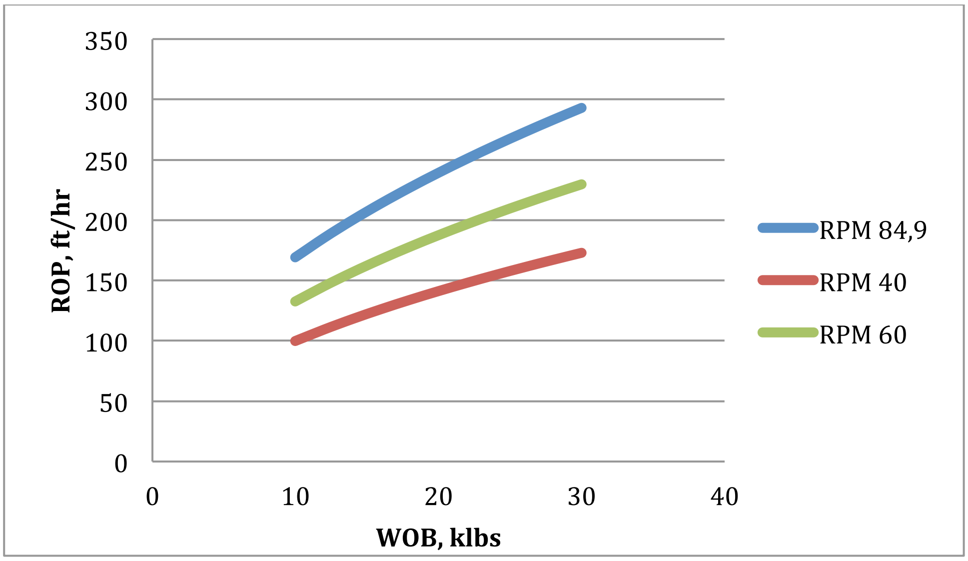

Figure 74: ROP as function of WOB and RPM for well 6H

As expected, reduction in WOB and RPM significantly decreases ROP. We have calculated that when RPM is decreased to 60, ROP drops by 21.6%, while RPM reduction from 85 to 40 will lead to 41% drop in ROP. Modeled ROP and variation in ROP in terms of percent are presented in Appendix table 5.

As mentioned earlier, threshold WOB was assumed to be 0 klbs, because no particular value could be deducted from the drilling data. We, however, have checked how potential presence of threshold WOB along with variations in RPM would affect penetration rate. The results are presented below:

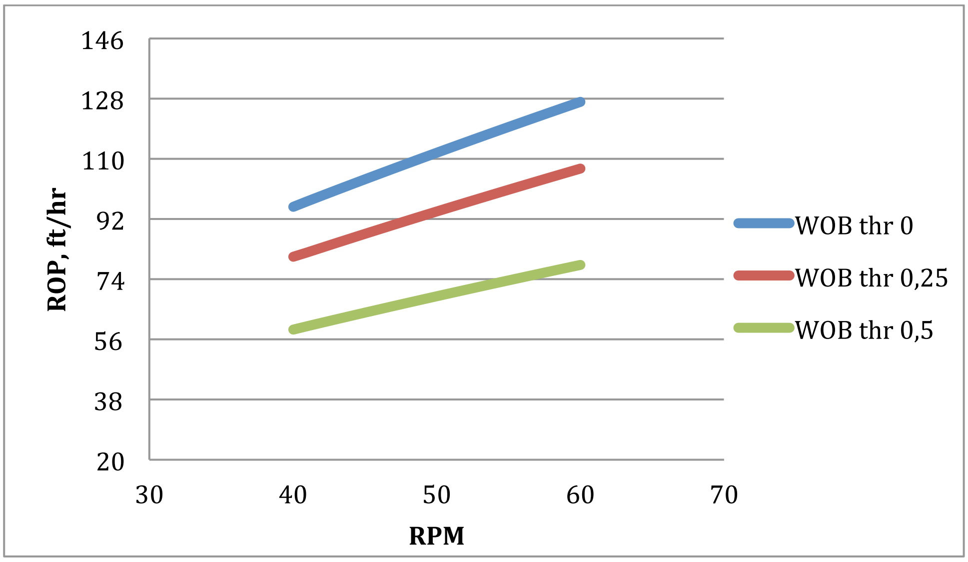

Figure 75: ROP as function of RPM and WOB threshold for well 6H

We see that WOB threshold has significant influence on ROP. We have found out that increase in threshold WOB to 0.25 klbs for 12.25" bit leads to 15.7% ROP reduction, while increase in WOB threshold from 0 to 0.5 gives 38.4% ROP reduction. See Appendix table 6.

Finally, we checked how ROP varies with overpressure and well hydraulics according to BYM. The field values were 15.3 ppg for ECD and 978 lbf for jet impact force. ROP variation with these parameters is presented below:

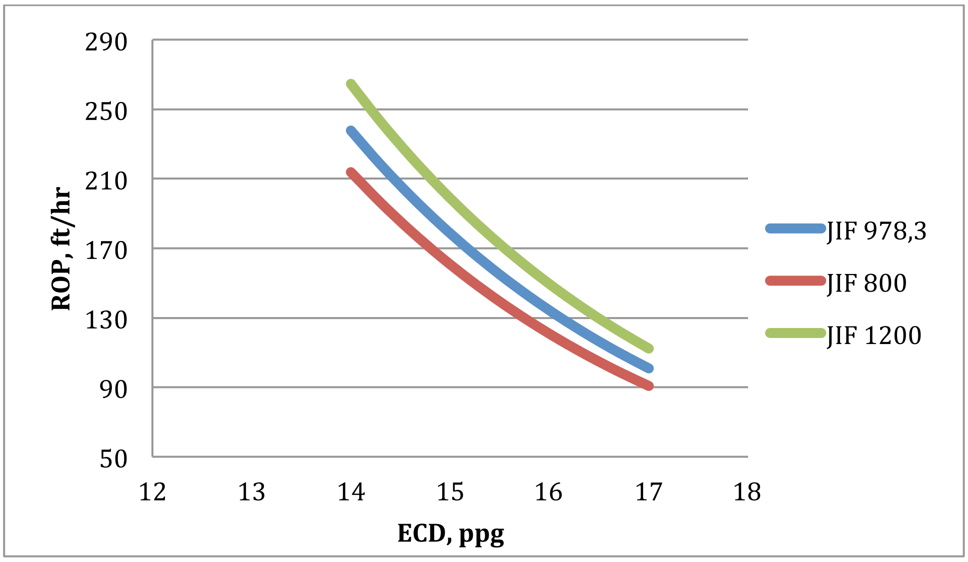

Figure 76: ROP as function of ECD and JIF threshold for well 6H

As expected, JIF improves ROP, and ECD reduces it. JIF increase to 1200 lbf results in 10% ROP increase, while reduction from 978 lbf to 800 lbf gave -11% in ROP. See Appendix table 7.

Well A:

Similar analysis was performed for well A, introduced in section 5.2.3.2. First we found a set of *a*-coefficients that gave the most precise results for ROP. Observed ROP vs. modeled ROP is presented in the table and figure below.

Table 27: Calculated and observed ROP for well A

TVD, ft	Field ROP, ft/hr	Modeled ROP, ft/hr
4256,21	149,29	144,11
4259,67	144,60	145,96
4263,12	144,47	147,37
4266,57	144,49	149,31
4270,02	137,58	157,08
4273,46	144,42	157,07
4276,90	140,92	159,94
4283,77	148,40	159,29
4290,63	144,42	155,89
4297,48	142,15	154,86
4304,31	135,28	154,86
4314,54	145,45	138,21
4321,35	149,30	151,40
4328,15	140,32	149,77
4334,93	144,35	156,88

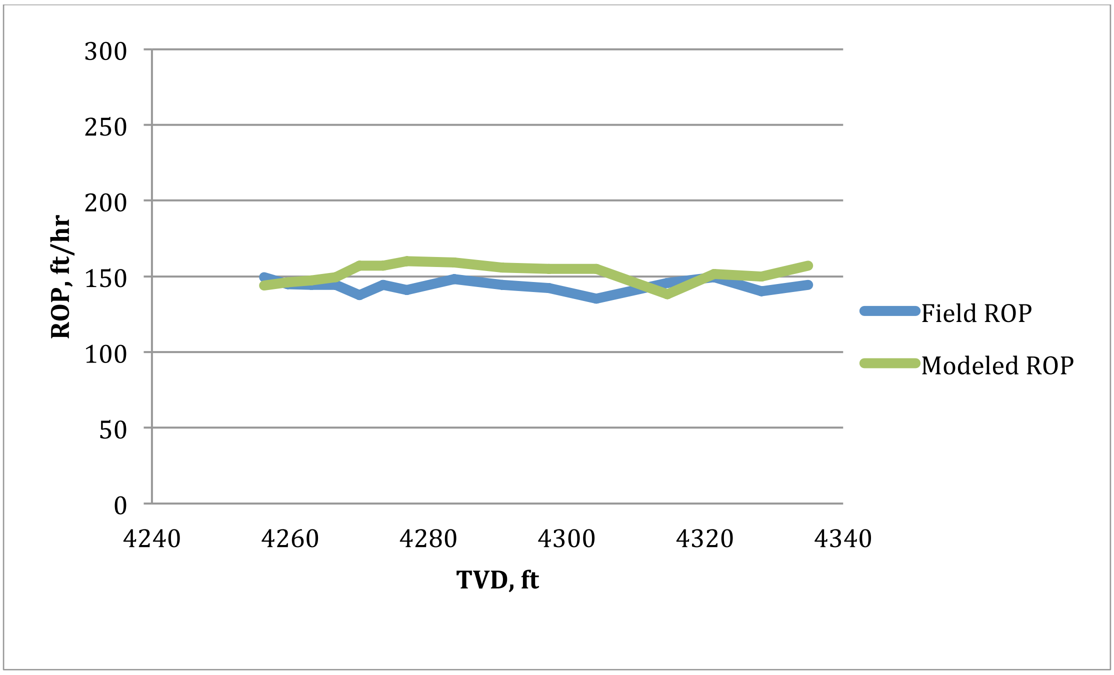

Figure 77: Modeled and field ROP for well A

Cement column in this shoe track was almost three times longer comparing to the one in well 6H, what helped to stabilize the drilling parameters while drilling. Therefore, the match between modeled and observed values is better in this case.

Having modeled ROP, we performed sensitivity analysis for other operational parameters. This shoe track was drilled with a roller cone bit. The recommended drillout parameters were 40-60 RPM and 6-10 klbs in WOB. The real values were 12.2 klbs for WOB and 178 for RPM. In the figure below we illustrate how ROP was varying with these two parameters according to BYM model. Values used for analysis can be found in Appendix table 8.

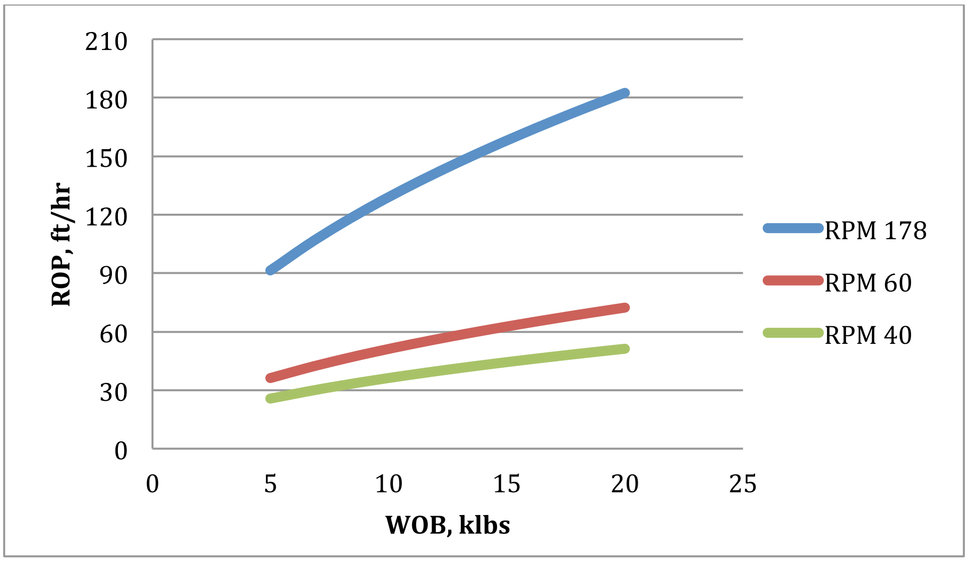

Figure 78: ROP as function of WOB and RPM for well A

The relation follows the same pattern that we observed for well 6H. In this case, due to large difference in RPM, we can see that ROP increases faster with WOB for high RPM than for low RPM. We calculated that RPM reduction to 60 revolutions leads to 60% ROP drop, while RPM reduction from 178 to 40 will lead to almost 72% drop in ROP. Modeled ROP and variation in ROP in percent are presented in Appendix table 11.

Influence of threshold WOB and RPM variations on ROP is illustrated in the figure below:

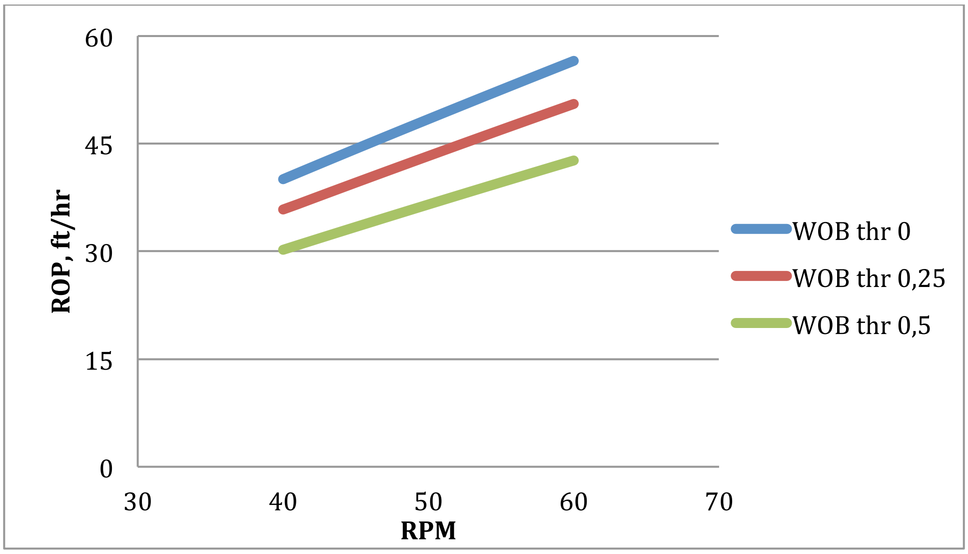

Figure 79: ROP as function of RPM and WOB threshold for well A

Threshold WOB and RPM proved to have the same affect on ROP in this case as for well 6H. For this set of operational parameters, increase in threshold WOB to 0.25 klbs leads to 10.6% ROP reduction, while increase in WOB threshold from 0 to 0.5 gives 25.6% ROP reduction. See Appendix table 12 in Appendix K.

Finally, we plot ROP as function of varying overpressure and well hydraulics. The field values were 12.6 ppg for ECD and 1342 lbf for jet impact force. ROP variation with these parameters is presented in the figure below:

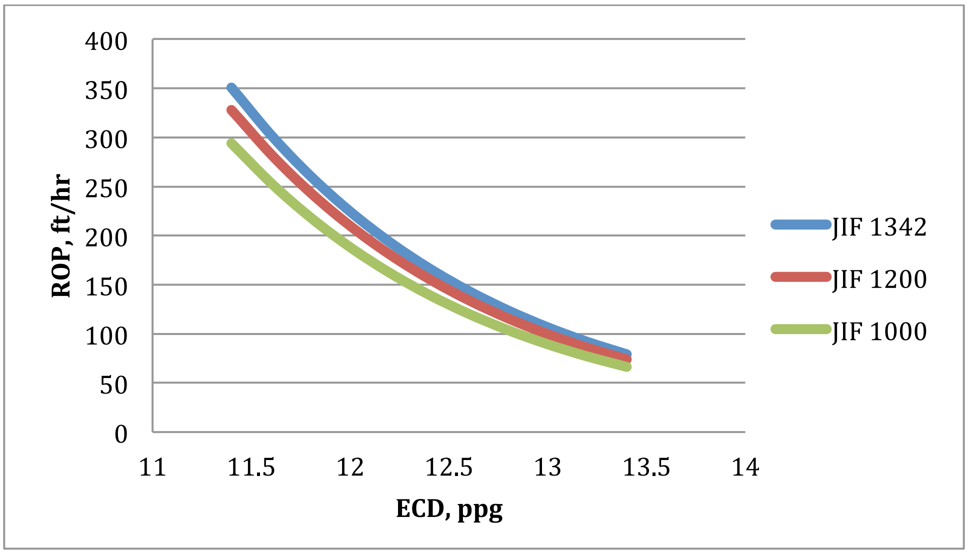

Figure 80: ROP as function of ECD and JIF threshold for well A

We see that JIF improves ROP, while ECD has the opposite effect. This relation has similar pattern as the one observed for well 6H. Here we also have calculated relative ROP change with JIF variations, which is -6.5% when we go from 1342 lbf to 1200 lbf, and -16.2% when we decrease JIF from its original value to 1000 lbf. Results are presented in Appendix table 13.

Conclusions:

- New model gives good ROP approximation for long cement columns (>50ft)
- New model can be used for analysis of historical data
- 25% RPM reduction gives 20% ROP drop
- When we double threshold WOB, drop in ROP more than doubles
- 25% JIF reduction leads to approximately 15% ROP drop.

5.3 Drill bits performance evaluation

As specified earlier, cement in "H" wells shoe tracks was drilled with PDC bits, which had similar design. Drill bit is typically chosen considering properties of formation in the next section (unless it is a dedicated shoe track ran), so it is unlikely that shoe track drilling will be the first priority when selecting drill bit. It is, however, important to bear in mind that shoe track drillout may not just take long time, but also lead to equipment failure if wrong drillout strategy is chosen. Therefore, we have also included bit analysis in this study. Table with drill bits specifications used on "H" wells is presented below:

Table 28: ROP and bits specifications

Well	ROP in cement	Blade number	IADC code	TFA, in^2	JSA	Cutters number	Cutters row design
1H	76,0	6	M422	1,608	31,76	69	double
2H	229	6	M422	1,491	31,76	69	double
3H	95,7	6	M422	1,666	31,76	69	double
4H	27,0	7	M322	1,374	30,84	80	single
5H	88,4	7	M423	1,635	28,00	76	3 double, 4 single
6H	164	7	M423	1,635	27,96	76	3 double, 4 single
7H	148	7	M423	1,659	27,96	76	3 double, 4 single
8H	155	7	M423	1,664	28,00	76	3 double, 4 single

ROP in cement was included into this table to get better overview of bit design influence on penetration rate. From the table we see that in general *higher cutters density results in slower drilling*. This agrees with theory from section 2.4.2.2. We also see that *double cutters row provides higher ROP than single row of cutters*.

At the same time, we see that for the same bit design (1H, 2H, 3H and 5H, 6H, 7H, 8H), ROP differs significantly. We don't see clear correlation between bit design features and ROP; therefore we conclude that *minor changes in bit design do not have determining effect on ROP.*

6. Cutting transport analysis

Rate of penetration is highly dependent on proper well hydraulics. An important aspect of well hydraulics is *hole cleaning*. During drilling, we want cuttings to be transported as they are created to avoid setting limits on penetration rate. To successfully transport cuttings, high flow rate and special mud composition along with string rotation should be used. Simulations are conducted prior drilling to identify what parameters should be used to provide sufficient hole cleaning. In this chapter we present results of cuttings transport simulation carried out in WELLPLAN software for one randomly chosen "H" well.

6.1 Background

Cutting bed usually occurs in highly deviated or horizontal wells. It was observed, that inclination of 45^0-60^0 is the most challenging for cuttings transport because cuttings tend to accumulate at the bit due to gravity [32]. High flow rate and mud viscosity offer better conditions for cuttings removal at the cost of lower penetration rate. Problems that typically occur due to insufficient cutting transport are pack off, lost circulation, poor cement job, low ROP etc.

To explain the relation for particle's settling velocity, we define two parameters: *drag force* and *buoyant weight*. Drag force represents fluid's upward force that acts against the particle. Stoke [42] has found a relation for the drag force around a spherical particle:

$$F_d = 3\pi\mu d_c V_s \tag{13}$$

where V_s is particle's settling velocity in m/s,
d_c – cutting diameter in m,
μ – fluid's viscosity in Pa-s.

When we equate this relation to the buoyant weight of the particle, which can be expressed this way:

$$W = \frac{\pi}{6}\left(\rho_c - \rho_f\right) g d_c^3 \tag{14}$$

we get equation for particle's settling velocity:

$$\mathrm{Vs} = \frac{\mathrm{g} \times \mathrm{d}_c^2 \times (\rho_c - \rho_f)}{18 \times \mu} \tag{15}$$

where g is gravitational constant,
ρ_c – cuttings' density in kg/m^3,
ρ_f – density of fluid in kg/m^3.

To find fluid velocity, we simply use the relation between flow rate and cross sectional area:

$$\mathrm{Vf} = q/\mathrm{A} \tag{16}$$

Cuttings transport velocity then equals to fluid velocity minus cuttings settling velocity:

$$Vt = Vf - Vs \tag{17}$$

Stoke's law is an easy way to estimate settling velocity of particles, however, it has limitations: it can be used just for small spherical particles (smaller than 0.1 mm) and pure laminar flow [32].

In the following study we check whether used well hydraulic parameters could have caused cutting transport problems in well 8H, and give recommendations about operational parameters to be used for cement drilling.

Theory for hole cleaning calculations in WELLPLAN is given in Appendix L [56].

6.2 Simulation results

Input simulation values for well 8H are as follows:

- Field ROP, flow rate and RPM are respectively 155 ft/hr, 800 gpm and 60
- Assume cutting diameter to be 0.125 inch
- Cutting density is a typical density of hardened cement – 2.4 sg
- Well inclination at the shoe track is approximately 55^0
- Drilling mud density is 14.5 ppg

Firstly we will see how variation in RPM would affect minimum flow rate required for sufficient cuttings removal. ODC procedures (Table 2) recommend using RPM in a range of 40-60. We have found the minimum flow rate for this RPM range and well inclination $0\text{-}90^0$, see the figure below:

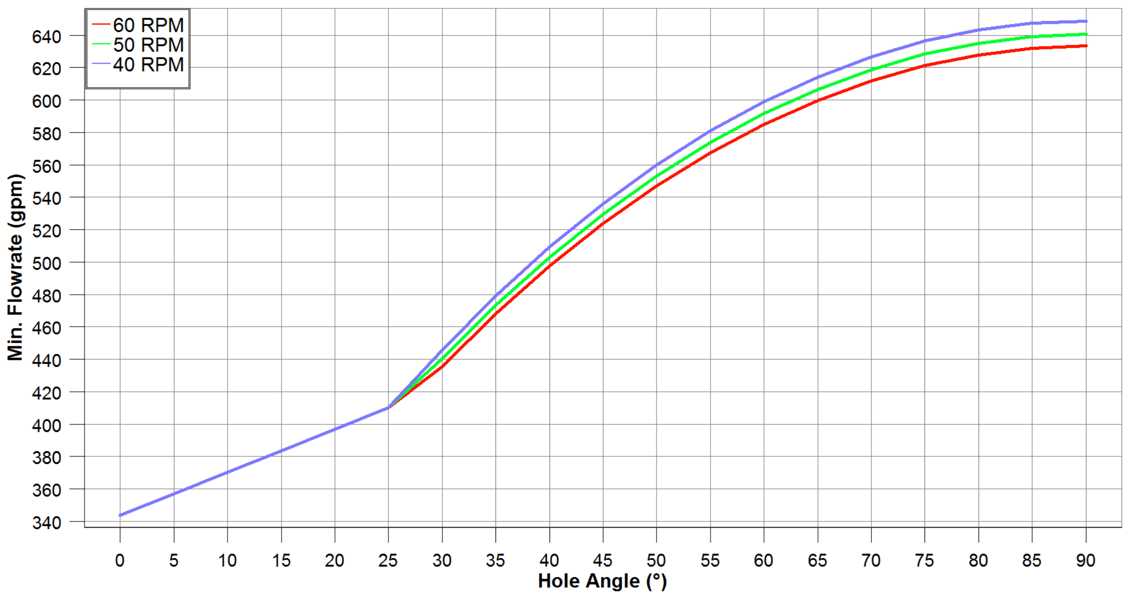

Figure 81: Minimum flow rate required for RPM 40-60 and hole angle $0\text{-}90^0$

As we see, minimum flow rate has to be increased to provide significant cuttings transport. In the table below we specify how much the flow rate has to be increased when we go down from 60 RPM to 50 RPM and 40 RPM for well inclination $0\text{-}90^0$.

Table 29: Minimum flow rate vs. RPM: percent indicates how much the flow rate has to be increased

Hole Angle(°)	60 RPM (gpm)	From 60 to 50 RPM (%)	From 60 to 40 RPM (%)
0	343,59	0,00	0,00
5	356,86	0,00	0,00
10	370,12	0,00	0,00
15	383,39	0,00	0,00
20	396,65	0,00	0,00
25	409,91	0,00	0,00
30	435,52	1,08	2,25
35	468,24	1,09	2,28
40	497,54	1,10	2,30
45	523,72	1,11	2,32
50	546,94	1,11	2,33
55	567,31	1,12	2,35
60	584,87	1,13	2,36
65	599,68	1,13	2,37
70	611,78	1,13	2,37
75	621,18	1,14	2,38
80	627,88	1,14	2,38
85	631,91	1,14	2,38
90	633,25	1,14	2,38

Next variable we will perform simulations for is cutting size. Author of this thesis observed that majority of cement cuttings have size in the range of 0.1-0.5 inch in diameter. Flow rate required to transport cuttings is presented below:

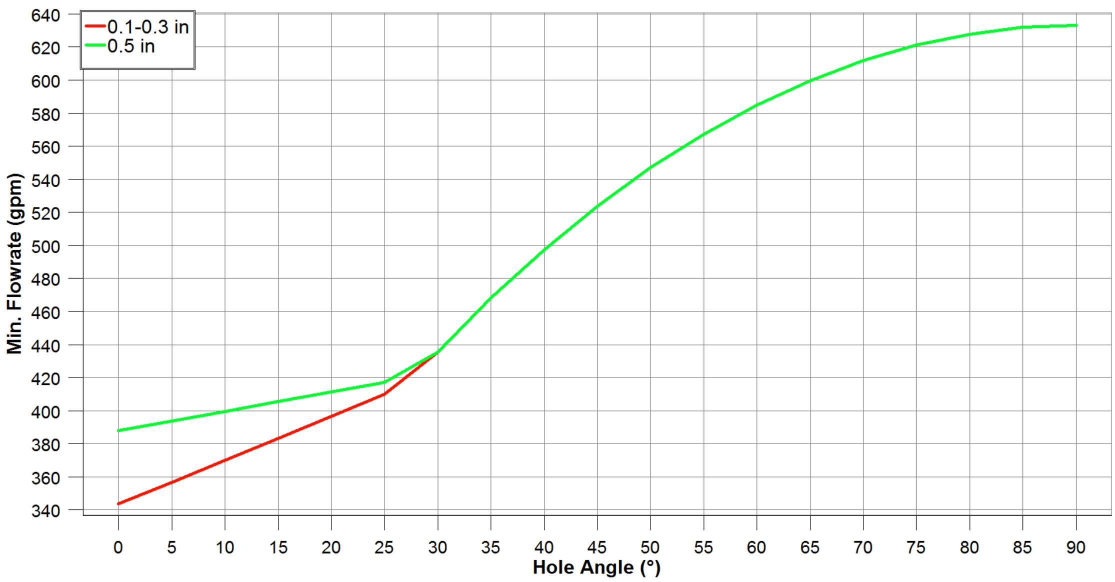

Figure 82: Minimum flow rate required for cuttings sizes 0.1-0.5 inch and hole angle 0-90^0

Minimum flow rate, required for cuttings transport has to be significantly increased for the inclination 0-30^0 when we assume worst-case scenario – largest cuttings. Relative increase in the required flow rate to transport larger cuttings is presented in Table 30.

Table 30: Minimum flow rate vs. cuttings size: percent indicates how much the flow rate has to be increased

Hole Angle(°)	0.1-0.3 in (gpm)	From 0.3 in to 0.5 in (%)
0	343,59	11,43
5	356,86	9,38
10	370,12	7,40
15	383,39	5,46
20	396,65	3,59
25	409,91	1,77
30	435,52	0,00
35	468,24	0,00
40	497,54	0,00
45	523,72	0,00
50	546,94	0,00
55	567,31	0,00
60	584,87	0,00
65	599,68	0,00
70	611,78	0,00
75	621,18	0,00
80	627,88	0,00
85	631,91	0,00
90	633,25	0,00

Next variable we will study is mud weight. Weight of mud is typically selected basing on requirements for the next section. In our study we will vary it from 10.6 ppg to 14.5 ppg. These mud systems were chosen as the ones available in the fluid library for "H" wells. We would like to point out that composition and rheology of the mud is also very important along with its weight. Rheological parameters used for drilling this shoe track were taken from daily reports.

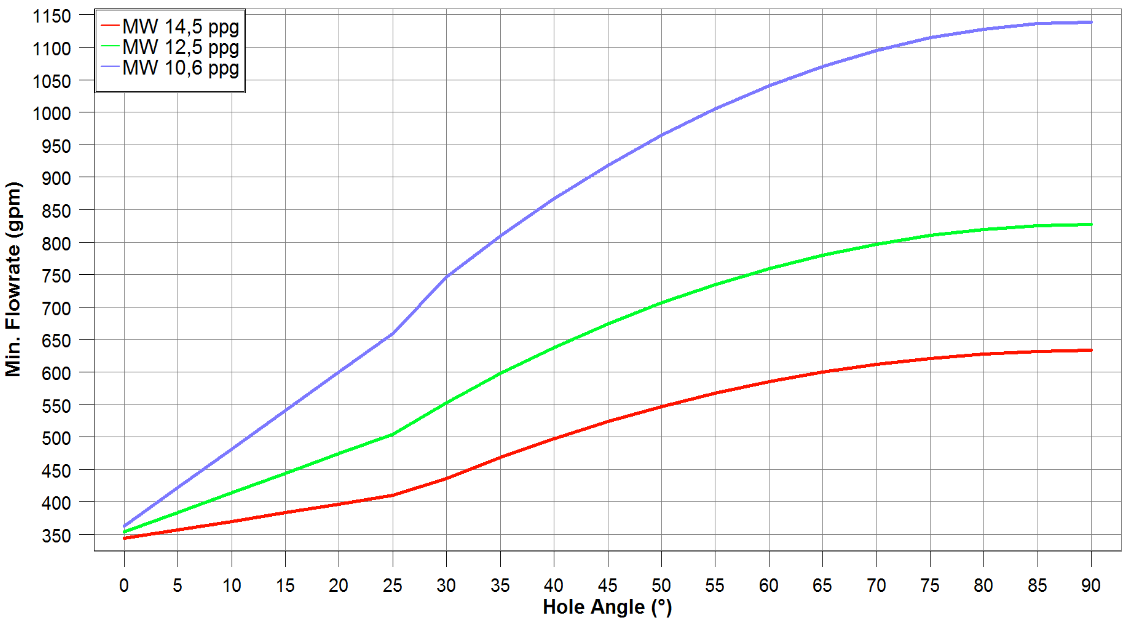

Figure 83: Minimum flow rate required for mud weight 10.6-14.5 ppg and hole angle 0-90^0

As we see from the graph, mud weight has significant impact on hole cleaning. Below we present the rheology of fluids chosen for this simulation and table of relative increase in required flow rate when mud weight is decreased.

Table 31: Rheology for 3 types of fluids used in simulations

10,6 ppg	Versatec	12,5 ppg	Versatec	14,5 ppg	Versatec
Speed (rpm)	Dial (°)	Speed (rpm)	Dial (°)	Speed (rpm)	Dial (°)
600	61	600	100	600	160
300	39	300	62	300	95
200	30	200	50	200	73
100	22	100	35	100	48
6	10	6	14	6	17
3	9	3	13	3	15

Table 32: Minimum flow rate vs. mud weight, percent indicates how much the flow rate has to be increased

Hole Angle(°)	MW 14,5 ppg (gpm)	From 14,5 to 12,5 ppg (%)	From 14,5 to 10,6 ppg (%)
0	343,59	2,85	5,28
5	356,86	7,02	15,46
10	370,12	10,58	23,14
15	383,39	13,66	29,12
20	396,65	16,35	33,92
25	409,91	18,71	37,86
30	435,52	21,24	41,60
35	468,24	21,66	42,14
40	497,54	22,02	42,60
45	523,72	22,31	42,99
50	546,94	22,56	43,31
55	567,31	22,78	43,58
60	584,87	22,96	43,81
65	599,68	23,11	44,00
70	611,78	23,23	44,15
75	621,18	23,32	44,26
80	627,88	23,38	44,34
85	631,91	23,42	44,39
90	633,25	23,43	44,40

Last parameter we will perform simulation for is cutting density. From (15) we see that the particles settling velocity increases with density. In this simulation we will find out how strong is the influence of cutting density on hole cleaning.

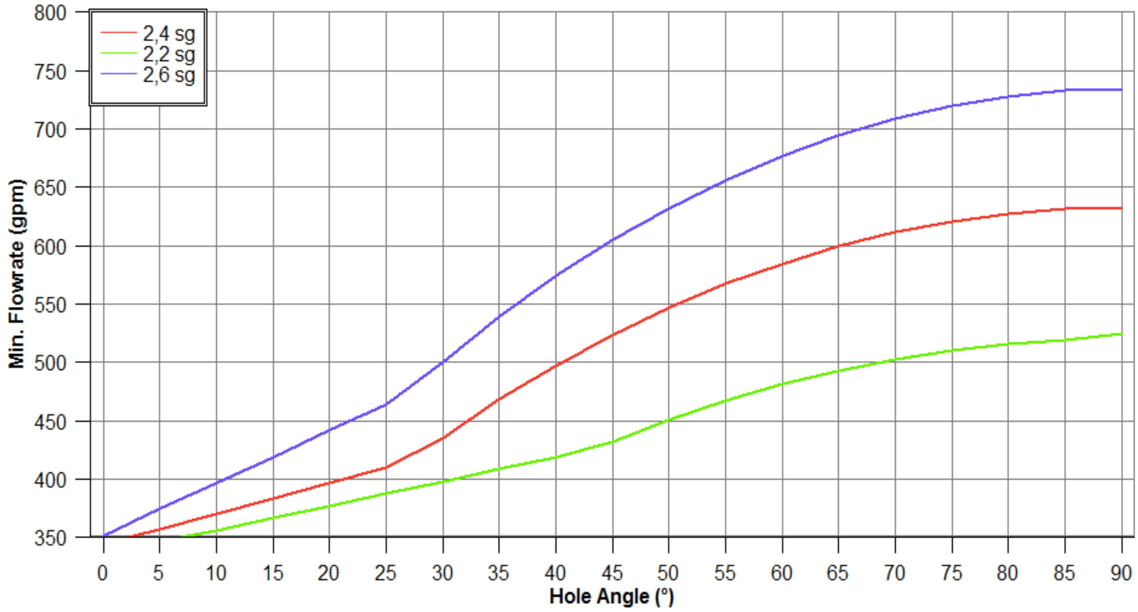

Figure 84: Minimum flow rate required for cuttings density of 2.2-2.6 sg and hole angle 0-90^0

We see that cuttings density has significant negative influence on cuttings transport. Flow rate has to be noticeably increased to transport heavier cuttings through the whole length of annulus to the surface.

In the table below we specify how flow rate should be changed (increased or decreased) with varying cuttings density.

Table 33: Minimum flow rate vs. cuttings density, percent indicates how much the flow rate has to be changed: - means reduction, + means increase

Hole Angle(°)	2,4 sg (gpm)	From 2,4 sg to 2,2 sg (%)	From 2,4 sg to 2,6 sg (%)
0	343,59	-2,51	2,39
5	356,86	-3,23	4,69
10	370,12	-3,90	6,73
15	383,39	-4,54	8,55
20	396,65	-5,14	10,18
25	409,91	-5,70	11,66
30	435,52	-9,34	13,05
35	468,24	-14,53	13,19
40	497,54	-18,64	13,32
45	523,72	-21,06	13,42
50	546,94	-21,22	13,50
55	567,31	-21,35	13,56
60	584,87	-21,46	13,63
65	599,68	-21,55	13,68
70	611,78	-21,62	13,72
75	621,18	-21,68	13,75
80	627,88	-21,72	13,77
85	631,91	-21,74	13,78
90	633,25	-20,71	13,79

Conclusions:

- RPM increase leads to lower minimum required flow rate
- Increase in cutting size leads to higher minimum required flow rate
- Mud weight increase leads to lower minimum required flow rate
- Cuttings density increase requires higher minimum flow rate

In the table below we summarize the effect of variation in aforementioned parameters on minimum required flow rate for this particular shoe track in well 8H, where the inclination was approximately 55^0 along the whole shoe track length. Middle, high and low values for different parameters are taken from tables above. For example, middle for RPM is 50, high is 60 and low is 40.

Table 34: Minimum flow rate (gpm) required for cutting transport for well 8H as function of variation in operational parameters

	Middle value	High value	Low value
RPM (50-60-40)	573,67	567,31	580,62
Cuttings diameter (0.3-0.5-0.1 in)	567,31	567,31	567,31
Mud weight (12.5-14.5-10.6 ppg)	696,5	567,31	814,5
Cement density (2.4-2.6-2.2 sg)	567,31	656,34	467,5

Summary and recommendations

	Roller cone	PDC	Comments
Wiper plug and collar	Tag plugs with no rotation and notice the depth. Use low WOB, 6-8 klbs, and low RPM, 30-50, while drilling. No clear relation was seen between drillout time and flow rate. Minor modifications in plug design did not affect drillout time.	Tag plugs with very low WOB, no rotation. Notice plugs depth. Start drilling with low WOB, keep WOB within 0.3-0.9 klbs/in during drilling. Use high flow rate, ca 70 gpm/in. RPM can be carefully increased while drilling if good progress is seen.	Drillout time for wiper plugs system was consistent when drilled with roller cone and erratic when drilled with PDC. Roller cone should be preferred if aluminum components are present. Our recommendations to big extent match the ODC best practices.
Collar without plugs	Use high WOB, RPM and flow rate for drilling collars without plugs. WOB 13-16 klbs, RPM 60-80, flow rate from 40 gpm/in.	N/A	We have determined that WOB value should be higher than the one recommended by ODC while drilling with roller cone bit.
Cement	N/A	Best results were obtained when 0.5-1 klbs/in WOB, 60 RPM and 70 gpm/in flow rate were applied. Small variations in bit design did not affect drillout efficiency.	Recommendations from ODC are 2 klbs/in, 40-60 RPM and 40 gpm/in during cement drilling with PDC bit. Recommended flow rate might be not enough for efficient cutting transport. Simulations have to be carried out prior to flow rate selection. If inclination is significant, flow rate has to be increased accordingly.
Shoe	Low WOB, 6 klbs, and high RPM, 100, should be used for drilling reamer shoe. Low-medium WOB, 7-10 klbs, and low RPM, 50, should be used for drilling guide shoe.	No clear correlation was found.	Drillout time depends rather on shoe type and materials than on the operational parameters used. In general our recommendations match ODC procedures. Special types of shoe might require different drillout approach.

Conclusions

In this thesis we have carried out an extensive analysis of shoe track drillouts for two groups of shoe tracks: 13 3/8” casing shoe track drilled with PDC bit and 7 ¾” liner shoe track drilled with roller cone bit. Our main goal was to find out how operational parameters influence drillout time, and what is the optimal way of drilling through the shoe track. Along with these tasks, we looked into mechanical components configuration and drill bit design to determine what effect these factors have on the drillout. Finally, we carried out cuttings transport simulation to see how some operational parameters influence minimal required flow rate. We will now briefly go through main points of analysis.

Wiper plug system
In the first case the plug system consisted of double wiper plug and double dart and was drilled with PDC bit. Single dart-plug configuration and roller cone bit were used in the second case. Despite twofold number of sub-components in the first case, average time for these two drillouts was the same (5.4 hours). We can conclude that PDC bit should be favored unless significant amount of aluminum is present in the wiper plug system, which may jam PDC bit blades. WOB and RPM increase had in general negative effect on wiper plug systems drillout.

Collar without wiper plugs
Float collar without wiper plugs was a part of the shoe track in the second group. Operational parameters in this case had similar effect as during the formation drilling: increase led to drillout improvement. Double aluminum flapper valves were successfully drilled with roller cone bit.

Shoe
Shoe drillout was mainly contingent upon the shoe design. In our study we had shoes of three types: float shoe with a poppet valve, a reamer shoe and a guide shoe. Consequently, drilling time varied: guide shoe was the fastest to go through (0.3 hours), shoe with a poppet valve took a bit longer to be drilled out (0.8 hours), and reamer shoe took on average longest time to be drilled through (1.4 hours). Drillout time did not show significant correlation with operational parameters.

Cement
Multiple regression analysis and three drilling optimization models were used to study cement drillout:

1. MRA showed that JIF has negligible effect on ROP, WOB and RPM have small positive effect on ROP and torque has significant positive effect on ROP.
2. MSE concept was used to calculate drilling efficiency in cement; average drilling efficiency was found to be 9%. MSE concept, however, was not found to be suitable for sensitivity analysis since it neglects WOB impact on ROP.
3. Drillability in cement was calculated. We supposed that this value should be alike in all shoe tracks due to apparent cement homogeneity, and by reversing the equation (7), we would be able to predict ROP in cement.

This hypothesis, however, was not proved to be correct. The reason for it could be too few parameters considered by this model.

4. To estimate a-coefficients used in BYM, a computer code was created and implemented in Matlab. It allows forecasting ROP while drilling or carrying out sensitivity analysis on historical data. This model showed that RPM and mud weight have significant positive effect on ROP; WOB has moderate positive effect on ROP; JIF and threshold WOB have small respectively positive and negative effect on ROP.
5. Finally, cuttings transport analysis was conducted for one randomly chosen well. Effect of four parameters (RPM, cuttings diameter, mud weight and cuttings density) on minimal required flow rate was studied. The results showed that decrease in mud weight and increase in cement density will require significantly higher flow rate for proper cuttings transport. Cutting size affects minimal flow rate to minor extent, and the latter one will have to be slightly increased for low inclination. Small variations in RPM will not significantly affect minimal flow rate required.

In the end, we would like to emphasize importance of properly chosen strategy and equipment while drilling out shoe tracks. As we have seen, the drillout can take up to a whole day if drilling problems occur. The most common problems are jammed bit and rotating plugs. These problems can be almost fully prevented by using recommended drilling parameters and non-rotating float equipment.

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Appendices

Appendix A: Procedure for shoe track drillout (developed by ODC, Halliburton, citation)

PDC Drillout Procedures	Tri-cone Drillout Procedures	Tri-cone with motor Drillout Procedures
Plugs/Landing Collar: – Auto Driller OFF – Note free rotating torque before drilling wiper plugs – Ensure hydraulic pump-off on hookload is accounted for before drilling plugs – Tag gently with low flow/no rpm – DO NOT SPUD the bit – Low WOB, 0.5-1 klbs per inch of bit – High Flow Rate – Low RPM: 20 - 80 – Pick up every 15 - 30 min to clear debris – Too much weight may make even non-rotating plugs spin – Brass balls are not recommended to be drilled out with PDC *Float Collar/ Cement/ Shoe:* – Auto Driller OFF – Optimize parameters for drilling cement while drilling float equipment, take extra care in transition zones – 40-60 rpm – 2 klbs per inch of bit – 40 gpm per inch of bit – Don't excess WOB when the plugs\float collar is drilled. The center of the bit might be unsupported if there is no cement below the plugs\LC\FC Excessive weight on the gauge cutters can damage the PDC	– Take free moving up/down weight – Take free rotating torque – 40 gpm per inch of bit – 40-60 rpm – 6-10 klbs WOB – Need to see 1 to 3 kftlbs torque over free rotation to see bit working – If not working, parameters must be changed – more WOB and flow rate – Sometimes need to stop pumps, set 10-20klbs WOB, rotate for 1 minute and then start pumps. This operation helps to break the aluminum and rubber.	– Take free moving up/down weight – Take free rotating torque – 200 - 220 gpm (consider the motor bit revs/gal) – Wash down to tag and commence drilling with 30-60 rpm – 4-8 klbs WOB, should start gently and in controlled manner – Need to see 1 to 3 kftlbs torque over free rotation reading to see if bit working – If not working, parameters must be changed – more WOB, – Allow WOB to drill off before applying more, adjust flow rate and maintain to clear debris. – If plug spins, reduce flow rate, pick up off bottom, shut off pumps and sit the bit gently on the plug till it takes weight. Pick up re-establish parameters and return to drilling. *When using a mud motor:* – Consider differential pressure in addition to torque – Adjust flow-rate with regards to rpm – No motor load/standpipe pressure rise/fluctuations indicate the bit is not drilling through the

Aluminum casing shoe may drill slowly. It is possible to 'trepan' the shoe – especially with a flat profile PDC – cutting out behind the nose leaving an uncut disc of aluminum to be punched to bottom.		rubber.

Procedures for drilling EZcase bit (drilled with roller cone bit):

Tri-cone drillout Procedure	Drilling out float equipment with downhole motor
– Use 0.9 ton (2 klbs) per inch of bit diameter and 40-60 rpm with a steel tooth bit. An insert bit may need slightly more weight – Flow rate should be 35-50 gpm per inch of bit diameter – If there is no significant increase in torque when weight is applied to the bit, additional WOB can be applied up to the maximum allowed. If this does not lead to progress, stop rotation and set weight on the bit without rotation. Set down weight, pick up and rotate 30 degrees then set down weight and repeat. The idea here is to break up the pattern that has been established and is hindering progress.	– RPM is up to 20 - 40 – Do not reduce the flow rate to restrict the motor rotary speed – Keep weight on bit as low as is necessary to ensure that no motor stalling occurs – Do not spud (lift off bottom and then drop back down so that the bit strikes the hole bottom) the assembly in an attempt to break up or remove the plug, float or shoe – Once the float and EZcase bit have been drilled and the hole circulated clean, make a check run with the string rotary off, in order to confirm that the shoe track is full gauge.

Appendix B: Foamed cement

Cement slurry can be turned into foam when gas is injected into it. Usually this gas is either air or nitrogen. Foamed cement consists of base cement with density of 1.8-1.9 kg/m^3, a gas (nitrogen or air) with density of 0 kg/m^3 and a foaming surfactant. The foam density is regulated by the amount of gas. Cement foams are characterized by their *quality*, or percent of gas in slurry. This number seldom goes above 70, however, technically speaking this is the lowest limit for cement to be considered foam [37]. Cement structure varies with its quality. Concentrated foams consist mainly of gas cells surrounded by thin liquid films. Dilute foams represent thick layers of cement with spherical bubbles inside. Due to large amount of gas foamed cement is compressible. So its density changes when circulating in the well due to hydrostatic pressure difference. When moving from surface to bottom, foam quality decreases and density increases. When coming up in the annulus, gas in foam expands and quality increases while density decreases. The density change can be estimated using compressibility laws and solubility of the gas used.

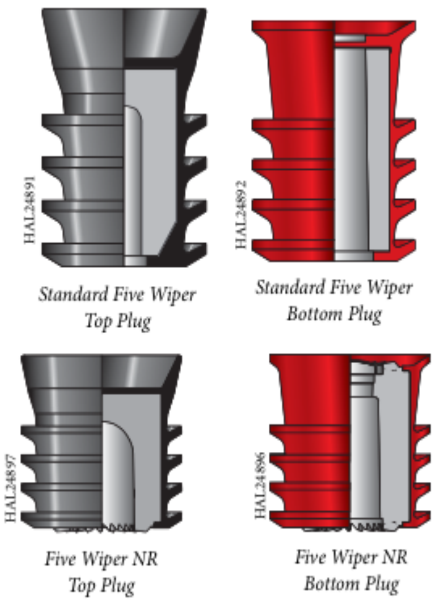
Foamed cement is a complicated 3-phase system, which is hard to describe due to changing properties under different conditions. In addition to changes in gas phase, the base (mixture of liquid and solid phase) undergoes chemical reactions too. The most typical way to prepare the slurry is to mix all components, except surfactants, which are added when slurry is being pumped into the well.

Stability of this cement depends on a few parameters, like its quality, chemical and physical composition, conditions etc. Stable foams have rounded, disconnected pores, while unstable ones look like sponge, have lower compressive strength and higher permeability. Set-properties of cement depend on the base slurry chosen. Standard density slurries will provide higher compressive strength, however, more gas will be required to get the desired foam density. This will result in higher permeability. Lower density base cement will require less gas; hence permeability and compressive strength will be lower.

Foamed cement must be tested for its stability to make sure that gas bubbles will not join together and form big voids of space. One of the possible tests is to cut a column of cement in equal pieces and weight them: the weight has to be the same to conclude that the system is stable. Another property foamed cement has to be tested for is its compressive strength and permeability. Physical properties of foamed cements are similar to lightweight cements, because the base slurry is diluted just slightly.

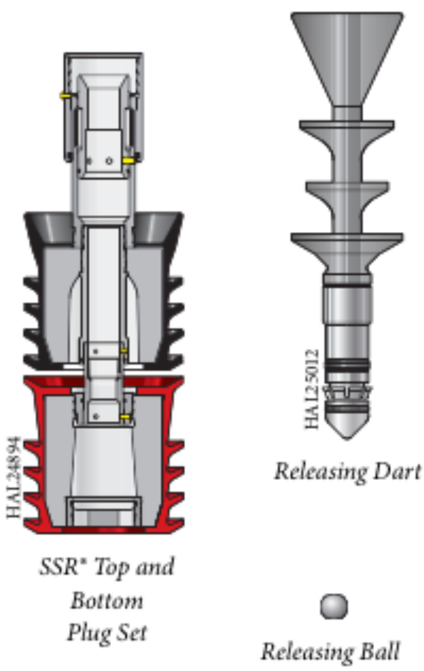
Foamed cement is expected to have good bonding with casing or formation. This may be the result of pressure preservation by the compressed gas in the cement. When cement sets and loses the hydrostatic pressure, the pressure within the bubbles keeps the tight contact with casing or formation [37].

Appendix C: Alternative wiper plug systems



Appendix figure 1: Halliburton's standard five wiper plugs and non-rotating five wiper plugs [29]

A model of wiper plugs supplied by Halliburton is a five-wiper plug and its variations, see the figure. *Standard five-wiper plugs* have 350-psi reputable disk and their body inserts are made of plastic. These types of wiper plugs are not recommended for drillout with PDC bit. NR in plug name stands for "non rotating", and that is the main reason of changing simple design of cementing plugs. *Non-rotating five wiper cementing plugs* have locking teeth to prevent equipment from spinning. Inserts for these plugs are made of high-strength plastic and, according to the product sheet, are easy to drill with either PDC or roller cone bits. [29]



Appendix figure 2: Halliburton's SSR cementing plug system: top and bottom wiper plugs, releasing dart and ball [29]

Subsurface release (SSR) cementing plug system, which is presented in the figure below, is popular to use on floaters, where wellhead is placed on the sea bottom. The SSR system launching mechanism is as follows: two plugs, bottom and top ones, are run into the well. At a particular depth, a ball is dropped, which allows release of bottom plug. Then the bottom plug is displaced to float collar, and bypass mechanism for cement flow is activated. After the cement slurry has been placed, a releasing dart is dropped and latched into the top plug, so the plug is displaced to the bottom [29].

Appendix D: IADC bits' classification

Roller Cone

Each bit has a bit model and a serial number, which describes main characteristics of a particular bit type. In addition, some companies differentiate bits further, specifying details of a particular tool. Halliburton HDBS, for example, uses Material number as an individual name for a specific bit. An oil company might have hard time choosing bit supplier due to difficulty in comparison. The IADC has therefore come up with an integrated bit classification system for naming the bits.

The IADC roller cone bit classification established in 1992 is an internationally accepted standard for the description of roller cone bits. The coding is based on design and application for the drill bit [36]. Four characters describe the bit: the first three are always digits; the last one is always a letter. The first digit represents a bit series, the second one – bit type, and the last digit describes bit bearings and gauge arrangement. The fourth sign refers to bit feature. Lets look at them in more details.

The first character describes general formation characteristics and specifies whether the bit is milled-tooth or insert-type. Eight series are used to categorize bits. Series from 1 to 3 are used for milled–tooth bits, series from 4 to 8 – for insert-type bits. Higher number bits are used for more abrasive applications and vice versa. However, the definitions for "hard" and "soft" are not specified in the classification and are therefore subjective.

The second character shows the bit type (milled-tooth or insert-tooth) and formation hardness within each series, described by first digit. It ranges from 1 to 4.

The third character represents bearing design and gauge protection. They discriminate between 7 categories:

1. Non-sealed roller bearing (also known as open bearing bits)
2. Air-cooled roller bearing (designed for air, foam, or mist drilling applications)
3. Non-sealed roller bearing, gauge protected[12]
4. Sealed roller bearing
5. Sealed roller bearing, gauge protected
6. Sealed friction bearing
7. Sealed friction bearing, gauge protected.

The fourth sign represents features available. This category is optional, and you find bit description sheets without this character in the name.

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[12] Term "gauge protected" indicates that a bit has a feature that protects or improves bit gauge. For example, it could indicate special inserts positioned on the side of the cone (heel row) or diamond-enhanced inserts on the gauge row.

Similar to roller cones, PDC bits also have their own classification created by IADC and registered in 1992 [13]. The system consists of four characters that describe body material, cutters density, cutters size or type (for diamond impregnated bits) and bit profile.

The first digit represents material the bit body is constructed of: M stands for matrix body, and S stands for steel body. These are the most typical materials. The PDC bit body can also be made of natural diamond matrix body (D) or it can be a TSP (thermally stable PDC), where cobalt is used (T). Other materials are rarely used for PDC manufacturing, and referred to as O in IADC nomenclature.

The second sign represents how tight together the cutters are placed. The density of cutters is related to their amount. Normally for PDC bit digits from 1 to 4 are used, where 1 (less or equal 30 cutters) denotes a light cutter density, and 4 (more or equal 50 cutters) denotes a heavy density.

The third character represents size of cutter. Here 1 means the largest cutter - more that 24 mm in diameter, 4 is cutter of small diameter - less than 8 mm.

The fourth sign describes the appearance of the bit. It basically means length of the cutting face, which can be *flat, short, medium* and *long*. These profiles are respectively referred to as 1, 2, 3 and 4 in IADC system.

Appendix E: ROP models

1.Bingham ROP model

In 1965 Bingham proposed an ROP model based on limited laboratory data. This model neglects the depth of drilling, and is therefore considered to have limited reliability [8]. The correlation is as follows:

$$ROP = K(\frac{WOB}{Db})^{a5}N^{e},$$

where Db is a bit diameter,
K - rock strength constant,
a5 - WOB exponent,
N - RPM

2. Warren model

Warren (1981) introduced a penetration rate model for soft formation, for cases where hole cleaning does not affect ROP. The model integrates drilling parameters, bit design and formation strength. The "perfect-cleaning" model looks the following way:

$$ROP = (\frac{aS^2Db^3}{N^bWOB^2} + \frac{c}{NDb})^{-1},$$

First term defines the maximum rate used for breaking the rock. Second term also considers spreading of the applied WOB among larger number of teeth [10].

Later on an analysis was conducted to determine how to include factors affecting hole cleaning into the equation above. Model presented below includes in addition modified impact force and mud properties. Third term included in this model is the bit size and nozzles standoff distance as a function of varying diameter. Relation that describes the experimental data is presented below:

$$ROP = (\frac{aS^2Db^3}{N\,WOB^2} + \frac{b}{NDb} + \frac{cDb\rho\mu}{F_{jm}})^{-1},$$

Bataee *et al.* [8] applied these three models to estimate ROP while drilling through Aghajari and Gachsaran formations of Iranian fields using both roller cone and PDC bits. Table below briefly presents the obtained results by classifying data fitting as poor, moderate or good.

Appendix table 1: Data fitting for 3 ROP models

Model	**Section**	17 ½"	12 ¼"	8 ½"	PDC
Bingham		Poor	Good	Moderate	Poor
BYM		Good	Good	Good	Poor
Warren		Poor	Good	Poor	Poor

According to some authors, all models presented above are more suitable for roller cone bit. This could affect the modeled PDC penetration rate [8].

3. Hareland model (modified Warren model)

In 1994 Warren's model was modified by Hareland. He included chip hold down[13] and bit wear effects on ROP. The extended model looks the following way:

$$ROP = W_f \left[f_c(P_e) \left(\frac{aS^2Db^3}{N\,WOB^2} + \frac{b}{NDb} \right) + \frac{cDb\rho\mu}{F_{jm}} \right]^{-1},$$

where $f_c(P_e)$ - chip hold down function,
W_f - wear function,
S – confined rock compressive strength (psi),
D_b – drill bit diameter (in),
F_{jm} – modified impact force (lbs),
ρ – mud weight (ppg),
μ – mud viscosity (cp),
a,b,c – bit design constants

[13] "Chip hold down" represents the resultant force on the cuttings after they have been produced by the bit and the combined effect this force has on ROP

Appendix F: Bits' specification sheets

1. Bit used to drill through 13 3/8" shoe tracks in wells 1H, 2H and 3H

Product Report

12 ¼" RSR616M

Design Features of this bit

100% Raptor® cutters - Thermostable PDC cutters featuring an unique layer of thermostable PDC that is 200% more heat tolerant and 400% more abrasion resistant than premium PDC. The thermostable layer dramatically improves abrasion resistance by maintaining a sharp, slow-wearing tough cutting edge. When a wearflat finally develops. the thermostable layer wears more slowly than the multimodal polycrystalline diamond behind it , forming two sharp lips that maintain ROP. This allows the bit to drill significantly further and faster than premium PDC cutter bits.

Rotary Steerable - This design is one of the extensive ReedHycalog range of products for rotary steerable (RS) applications. It has been engineered specifically in terms of profile, cutting structure, and gauge geometry to enhance drilling performance when in used in combination with RS tools.

SystemMatched™ Gauge Design – The use of a specifically engineered extended spiral gauge offers circumferential gauge contact for efficient deflection along with better borehole quality and improved lateral stability.

DiamondBack™ cutters - Double the PDC coverage by providing a second row of cutters on each blade. The durability of the bit or tool is dramatically enhanced, giving more footage and a higher average ROP. Additionally, lateral stability is improved since the number of blades is effectively doubled. Available as an option in Hybrid PDC bits and tools, DiamondBack cutters replace the diamond impregnated studs in critical areas of the bit or tool.

Design Specifications

Make up Length (ft):	1.96
Shank Bore (ins):	2.835
Shank Diam (ins):	8.000
Connection std:	Y
Connection Size(ins):	6.625
Connection Type:	Api Reg Box
Make up Torque (ft-lbs):	47500
IADC Code92:	M422
Diameter:(ins)	12 ¼"
Body Material:	Matrix
JSA(in²):	31.76
Face Volume:(in³)	156.90
Normalised Face vol:	63.10%
Blade Qty:	6
Gauge Length:(ins)	18.375
Gauge Geometry:	200% Spiral
Profile:	Short Taper - Shallow Cone

Recommended Operating Parameters

Min Operating WOB (klbs):	5
Max Operating WOB (klbs):	49
Pressure Drop(psi):	700-1200
HSI:	2-6

In some applications this bit is run successfully beyond these parameters. Contact your ReedHycalog Representative for recommended operating parameters in your application. ReedHycalog reserves the right to revise these specifications, based on advances and improvements in technology.

This report is valid for 30 days from 03-Nov-2008

Cutting Structure

Type	Qty	Location	Diameter	Shape
Primary	43	FACE	16 mm	CYLINDER
Primary	6	GAGE	13 mm	PREFLATTED
Primary	2	GAGE	16 mm	CYLINDER
Secondary	16	FACE	16 mm	CYLINDER
Secondary	2	GAGE	16 mm	CYLINDER

Nozzles & Ports

Qty	Type	Size
6	BBK	VARIABLE

NOV ReedHycalog

ref: 10026107-1108

2. Bit used to drill through 13 3/8” shoe tracks in well 4H

HALLIBURTON | Drill Bits & Services

12-1/4" (311mm) FMF3751ZR

PRODUCT SPECIFICATIONS

Cutter Type			Z3
IADC Code			M322
Body Type			MATRIX
Total Cutter Count			70
Cutter Distribution		13mm	16mm
	Face	6	47
	Gauge	7	10
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)			30.84
Normalized Face Volume			44.3%
API Connection			6-5/8 REG. BOX
Recommended Make-Up Torque*			58,885 Ft*lbs.
Nominal Dimensions**			
Make-Up Face to Nose			19.9 in - 505 mm
Gauge Length			2 in - 51 mm
Sleeve Length			12 in - 305 mm
Shank Diameter			8.75 in - 222 mm
Break Out Plate (Mat.#/Legacy#)			181978/44757
Approximate Shipping Weight			880Lbs. - 399Kg.

SPECIAL FEATURES

FullDrift Design, Tapered to 1/16" Under Gage, P100, R1 Backup

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 #422785

*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.

3. Bit used to drill through 13 3/8" shoe tracks in wells 5H and 8H

12-1/4" MDSi716LHTBPXC

IADC M423, 64527D

ONYX

Smith Bits is uniquely positioned to provide drill bits that will consistently deliver superior performance in directional applications with point-the-bit rotary steerable systems.

IDEAS (Integrated Dynamic Engineering Analysis System), the industry's most advanced engineering design system, offers the unparalleled ability to accurately model not just the interaction of the bit and formation, but also the complete BHA and each of its individual components.

Equipped with the new generation high performance ONYX cutters, delivering exceptional durability, with improved wear resistance and thermal stability.

SPECIFICATIONS

Total Cutters	76
Cutter Size	16mm (5/8")
Face Cutters	(57) 16mm
Gauge Cutters	(7) 16mm
Back-Up Cutters	(12) 16mm
Blade Count	7
Nozzles	10 Standard Series 60N
Bit Connection	6-5/8" API Reg.
Junk Slot Area (sq in)	28.014
Gauge	Length: 3" Protection: Options Available
Length	Make-Up: 11.065" Overall: 16.003"
Fishing Neck	Diameter: 8" Length: 3.271"

OPERATING PARAMETERS

Rotary Speed	Rotary Steerable BHA and Downhole Motors
Weight-on-Bit	6,000 **To** 40,000 (lbs) 2,727 **To** 18,180 (daN) 3 **To** 18 (Tonnes)
Flow Rate (GPM)	500 to 1200
Hydraulic Horsepower (HSI)	1 to 6

The operating parameters listed here are general parameters, please contact your local SMith Bits representative for precise recommendations for your individual well.

FEATURES

Bit design and performance have been certified through the validation process prescribed by IDEAS simulation technology.

L: Managed depth of cut

S: SHARC back-up cutters

B: Backreaming cutters

TPX: Turbine sleeve with premium gauge protection

SMITH
IDEAS CERTIFIED DIRECTIONAL

SMITH BITS

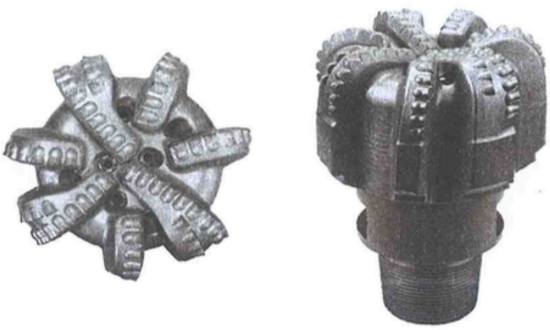
PEOPLE TECHNOLOGY RESULTS

4. Bit used to drill through 13 3/8" shoe tracks in wells 6H and 7H

12-1/4" MDSi716LBPX

IADC M423

ONYX™



Smith Bits is uniquely positioned to provide drill bits that will consistently deliver superior performance in directional applications. IDEAS (Integrated Dynamic Engineering Analysis System), the industry's most advanced engineering design system, offers the unparalleled ability to accurately model not just the interaction of the bit and formation, but also the complete BHA and each of its individual components.

SPECIFICATIONS

Total Cutters	76
Cutter Size	16mm (5/8")
Face Cutters	(50) 16mm
Gauge Cutters	(7) 16mm
Back Reamer Cutters	(7) 13mm
Back-Up Cutters	(12) 13mm
Blade Count	7
Nozzles	7 Standard Series 60N
Bit Connection	6-5/8" API Reg.
Junk Slot Area (sq in)	27.965
Gauge	Length: 3" Protection: Options Available
Length	Make-Up: 12.712" Overall: 17.65"
Fishing Neck	Diameter: 8" Length: 3.918"

OPERATING PARAMETERS

Rotary Speed	50 - 300
Weight-on-Bit	6,000 **To** 45,000 (lbs) 2,727 **To** 20,452 (daN) 3 **To 20** (Tonnes)
Flow Rate (GPM)	500 to 1200
Hydraulic Horsepower (HSI)	1 to 6

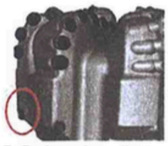
The operating parameters listed here are general parameters, please contact your local Smith Bits representative for precise recommendations for your individual well.

FEATURES

Bit design and performance have been certified through the validation process prescribed by IDEAS simulation technology.

L: Managed depth of cut

S: SHARC back-up cutters



B: Backreaming cutters

PX: Premium gauge protection

SMITH IDEAS CERTIFIED DIRECTIONAL

SMITH BITS PEOPLE TECHNOLOGY RESULTS SMITH

5. Bits used to drill through 7 ¾" shoe tracks

6 1/2'' MX-20DX

(165.1 mm)

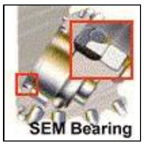
- **Single Energizer Seal & Bearing System (SEM)** UltraMax utilizes a patented single energizer metal sealing system (SEM) with a more robust design to provide consistency and reliability in high speed drilling and other demanding applications.

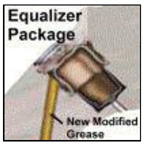
- **Grease & Lubrication System (Equalizer)** New grease formulation better lubricates the seal faces. Improved compensation system increases reliability.

- **Anti-Mud Packing System (Excluder)** A secondary static seal eliminates the detrimental effects of mud packing, creating a seal between the mud and the seal package. Also working against the effects of mud packing are the Mud Wiper and the Cone Backface Groove, which work in tandem to wipe away packed-in mud.

- **Clean Sweep Hydraulics** Nozzles are positioned closer to the cones with their fluid streams directed toward areas where bit balling occurs. Clean SweepÆs high velocity core strikes heel and adjacent heel teeth and sweeps the critical bit offset space on the backside of the cutter.

- **Motor Hardfacing (M)** Protects the bearing and seal to enhance performance and bit durability.





PRODUCT SPECIFICATIONS:

IADC:	517
Bearing / Seal Package:	Journal / Metal
Cutting Structure:	
Inner Row	Chisel
Heel Row	Wedge Chisel
Gauge Trimmers	N/A
Gauge Row	DSE
OD Hardfacing:	Motor
Nozzle Type:	FF
Center Jet Display:	N/A
Makeup Torque:	7.0 - 9.0 klbf-ft (9.5 - 12.2 kNm)
Connection:	3-1/2 API REG
Approx. Shipping Weight:	47 lb (21.4 kg)
Reference Part Number:	L6420DA1

OPERATING RECOMMENDATIONS*:

Weight On Bit:	15 - 35 klb (6 - 15 tn or kdaN)
Rotation Speed:	For High Speed Rotary/Motor Applications

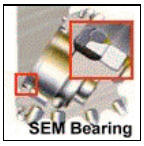
Hughes Christensen

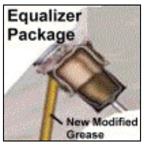
* The ranges of bit weight and RPM shown are representative of typical operating parameters, but will not necessarily yield optimum bit life or lowest drilling cost. It is not recommended that the upper limits of both weight and RPM be run simultaneously. Contact your local Hughes Christensen representative for recommendations in your area.

6 1/2’’ MX-18

(165.1 mm)

- **Single Energizer Seal & Bearing System (SEM)** UltraMax utilizes a patented single energizer metal sealing system (SEM) with a more robust design to provide consistency and reliability in high speed drilling and other demanding applications.
- **Grease & Lubrication System (Equalizer)** New grease formulation better lubricates the seal faces. Improved compensation system increases reliability.
- **Anti-Mud Packing System (Excluder)** A secondary static seal eliminates the detrimental effects of mud packing, creating a seal between the mud and the seal package. Also working against the effects of mud packing are the Mud Wiper and the Cone Backface Groove, which work in tandem to wipe away packed-in mud.
- **Clean Sweep Hydraulics** Nozzles are positioned closer to the cones with their fluid streams directed toward areas where bit balling occurs. The Clean Sweep high velocity core strikes heel and adjacent heel teeth and sweeps the critical bit offset space on the backside of the cutter.
- **Motor Hardfacing (M)** Protects the bearing and seal to enhance performance and bit durability.





PRODUCT SPECIFICATIONS:

IADC:	447
Bearing / Seal Package:	Journal / Metal
Cutting Structure:	
Inner Row	Modified Dbl Angle Chisel
Heel Row	Wedge Chisel
Gauge Trimmers	N/A
Gauge Row	Gage
OD Hardfacing:	Motor
Nozzle Type:	Standard
Center Jet Display:	N/A
Makeup Torque:	7.0 - 9.0 klbf-ft (9.5 - 12.2 kNm)
Connection:	3-1/2 API
Approx. Shipping Weight:	48 lb (21.8 kg)
Reference Part Number:	L6418A1

OPERATING RECOMMENDATIONS*:

Weight On Bit:	15 - 35 klb (6 - 15 tn or kdaN)
Rotation Speed:	For High Speed Rotary/Motor Applications

Hughes Christensen

* The ranges of bit weight and RPM shown are representative of typical operating parameters, but will not necessarily yield optimum bit life or lowest drilling cost. It is not recommended that the upper limits of both weight and RPM be run simultaneously. Contact your local Hughes Christensen representative for recommendations in your area.

6. Bit used to drill through 13 3/8” shoe track in well D

Product Report

Serial Number: 225319

12 ¼" SKRE716D

Design Features of this bit

RazorEdge™ cutters - Feature a more aggressive chamfer angle to enhance ROP and improve drilling efficiency. Early life cutter chipping is avoided by the unique geometry and material properties of Raptor® Thermostable PDC cutters, which reduce stress and mechanically support the cutting edge. RazorEdge™ cutters have proven very efficient in applications where torque or weight is limited, including coil tubing and ERD intervals. They have also been shown to reduce Mechanical Specific Energy and stick-slip in hard formations.

Seeker™ Directional Drill Bits - Seeker™ Directional Drill Bits – This design is one of the extensive range of products offered for steerable motors or RSS tools in a range of directional applications. The Seeker product line matches the bit to the specific well profile, drive type and lithology by using a comprehensive range of products in the industry coupled with proprietary bit selection software providing a SystemMatched™ solution for each drilling challenge.

SmoothTorque™ Torque Control Components - SmoothTorque™ Torque Control Components (TCC) - Insert configurations that provide a predictable torque response to applied weight on bit and reduction in torque variance. Torque Control Components deliver a reduced risk of torsional vibration and improved toolface / directional control. Insert configuration set behind the PDC cutters that act as instantaneous torque reducers, damping out torque spikes that may be encountered while drilling.

SmoothSteer® - SmoothSteer® - The SmoothSteer® gauge delivers maximum gauge contact, lowers resistance to steer and reduces torque, leading to improved ROP and extended bit and tool life. This arrangement improves borehole quality while rotating and smoother steering in sliding mode when on a steerable motor.

DiamondBack™ cutters - Are strategically positioned in the critical wear areas of the bit to provide a second row of cutters to some or all blades. This gives up to twice the PDC cutter density, enhancing the durability of the bit or tool, giving more footage and a higher average ROP (since the bit stays sharper for longer). Additionally, lateral stability is improved since the effective number of blades is dramatically increased. Available as an option in Hybrid PDC bits and tools, DiamondBack cutters replace the diamond impregnated studs in critical areas of the bit or tool.

Hybrid PDC Bit - Diamond impregnated studs, set behind the PDC cutters, provide depth of cut limitation. Typically used on the shoulder of the bit, the Hybrids improve lateral stability without compromising rate of penetration.

TSP Gauge Protection - Thermally Stable Product (TSP) tiles and welded hardmetal gauge protection give both a highly durable and ultra-smooth gauge.

Spiral Gauge - Stability is improved by increasing the circumferential contact of the bit gauge. Improved stability enhances steerability and ROP. This feature is less effective than the SteeringWheel® or Ring gauge design however.

DuraShell™ - DuraShell™ Premium Erosion Protection - Dramatically extends bit body life, giving a better-looking dull and significantly reducing the risk of lost cutters. Developed by

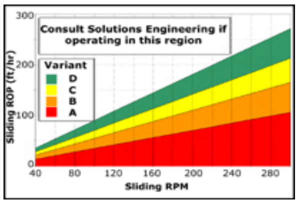
Design Specifications

Make up Length (ft):	.84
Shank Bore (ins):	2.835
Shank Diam (ins):	8.000
Connection std:	Y
Connection Size(ins):	6.625
Connection Type:	Api Reg Pin
Make up Torque (ft-lbs):	47500
IADC Code92:	M422
Diameter:(ins)	12 ¼"
Body Material:	Matrix-DuraShell
JSA(in²):	29.80
Face Volume:(in³)	107.25
Normalised Face vol:	61.00%
Blade Qty:	7
Gauge Length:(ins)	2.500
Gauge Geometry:	Spiral-Trailing
Gauge Protection:	TSP Tiled
Profile:	Short Taper - Shallow Cone

Recommended Operating Parameters

Max Operating WOB (klbs):	49
TFA Range (ins²):	3.093-4.209
Max Flow (gpm):	1700
Pressure Drop(psi):	2
HSI:	7

SmoothTorque



In some applications this bit is run successfully beyond these parameters. Contact your NOV Downhole Representative for recommended operating parameters in your application. NOV Downhole reserves the right to revise these specifications, based on advances and improvements in technology.

This report is valid for 30 days from 03-Oct-2011

ReedHycalog® Bits

ref: 10040072-1011

7. Bit used to drill through 13 3/8" shoe track in well A

HALLIBURTON | Drill Bits & Services

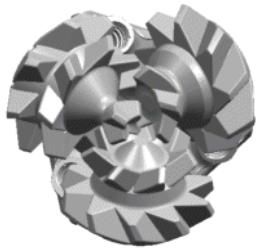
12-1/4" (311mm) EQHC1RC

PRODUCT SPECIFICATIONS

IADC Code	117W
Total Tooth Count	50
Gage Row Tooth Count	27
Journal Angle	33°
Offset (1/16")	6
Jet Nozzle Types	
Standard	83244
Extended	302447
Center Jet	(If Center Jetted) 501813
T.J. Connection	6-5/8" (API Reg.)
Recommended Make-Up Torque*	28000/32000 Ft*lbs.
Bit Weight (Boxed)	250 Lbs. (113 Kg.)
Bit Breaker (Mat.#/Legacy#)	515353/506463

PRODUCT FEATURES

- New patented Diamond™ Claw® tooth bit design.
- Energy Balanced® cutting structure for increased rate of penetration and increased bit life.
- Premium bearing and seal configuration suitable for both rotary and motor applications.
- Innovative mechanical pressure compensating system provides reliable pressure equalization and relief for maximum bearing and seal life.
- Raised tungsten carbide inserts and proprietary hardfacing provides maximum arm protection in abrasive and directional applications while minimizing drill string torque.
- QuadPack® Plus Series incorporates its successful "longevity" features and patented engineered hydraulics system for optimal cleaning efficiency.
- Center jet feature to prevent bit balling problems
- Raised shale burn insert helps to break-up shale packing so that cuttings can be easily flushed away from sealing area.



Material #490101

RECOMMENDED OPERATING PARAMETERS

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

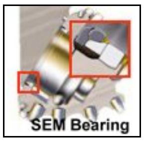
Rotary Speed: 50 - 300
WOB: 3 - 37

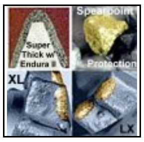
*Calculations based on recommendations from API and tool-joint manufacturers.

8. *Bit used to drill through 13 3/8” shoe track in well C*

12 ¼” MX-3
(311.2 mm)

- **Single Energizer Seal & Bearing System (SEM)**
 UltraMax utilizes a patented single energizer metal sealing system (SEM) with a more robust design to provide consistency and reliability in high speed drilling and other demanding applications.
- **XLX Steel Tooth Package**
 Endura II Hardfacing, Super Thick Tooth Crest Hardfacing, LX & XL Hardfacing Features, Bi-Metallic Super Gauge, Enhanced Spearpoint Protection
- **Grease & Lubrication System (Equalizer)**
 New grease formulation better lubricates the seal faces. Improved compensation system increases reliability.
- **Anti-Mud Packing System (Excluder)**
 A secondary static seal eliminates the detrimental effects of mud packing, creating a seal between the mud and the seal package. Also working against the effects of mud packing are the Mud Wiper and the Cone Backface Groove, which work in tandem to wipe away packed-in mud.
- **Clean Sweep Hydraulics**
 Nozzles are positioned closer to the cones with their fluid streams directed toward areas where bit balling occurs. The Clean Sweep high velocity core strikes heel and adjacent heel teeth and sweeps the critical bit offset space on the backside of the cutter.
- **Boss Stabilization**
 With six-point contact with the borehole wall, Boss bits are cushioned against vibrating forces, protecting the cutting structure from damaging blows.
- **Motor Hardfacing (M)**
 Protects the bearing and seal to enhance performance and bit durability.





PRODUCT SPECIFICATIONS:

IADC:	137
Bearing / Seal Package:	Journal / Metal
Cutting Structure:	
Inner Row:	Super Thick
Heel Row:	Bi-Metallic II
Gauge Row:	Super Gauge
Gauge Trimmers:	Chisel
Tooth Hardfacing:	Endura II
OD Hardfacing:	Motor
Nozzle Type:	Standard
Center Jet Display:	FK or VK
Makeup Torque:	28.0 - 32.0 klbf-ft (38.0 - 43.4 kNm)
Connection:	6-5/8 API
Approx. Shipping Weight:	235 lb (106.6 kg)
Reference Part Number:	M223B1

OPERATING RECOMMENDATIONS: *

Weight On Bit:	22.5 - 55 klb (10 - 24 tn or kdaN)
Rotation Speed:	For High Speed Rotary/Motor Applications

Hughes Christensen

* The ranges of bit weight and RPM shown are representative of typical operating parameters, but will not necessarily yield optimum bit life or lowest drilling cost. It is not recommended that the upper limits of both weight and RPM be run simultaneously. Contact your local Hughes representative for recommendations in your area.

9. Bit used to drill through 13 3/8" shoe track in well B

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.

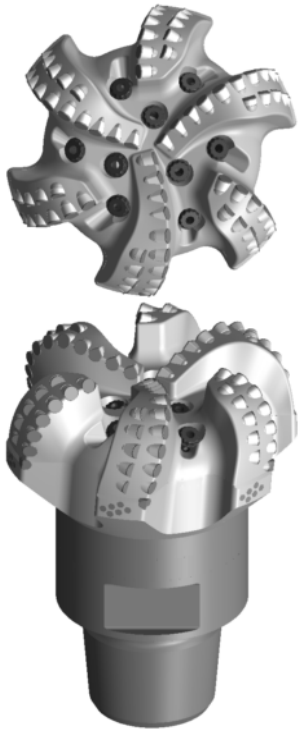
SPECIAL FEATURES

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



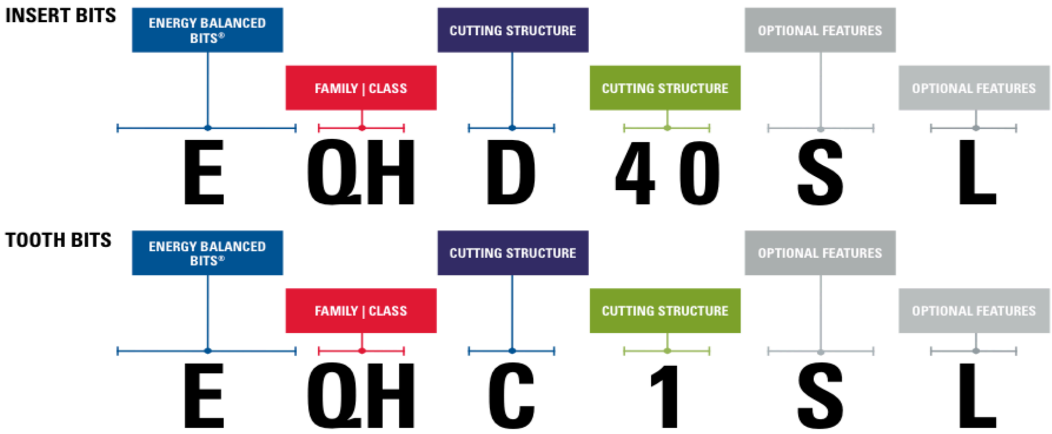
Material #866233

*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 G: Bits' nomenclature

1. HDBS bits' nomenclatures



ENERGY BALANCED® BITS

E = Energy Balanced® Bits

FAMILY | CLASS

QH = QuadPack® Plus Engineered Hydraulics Bits (4 1/2 through 13-1/2 in.)

CUTTING STRUCTURE (PREFIX)

C = After Class Alpha for Claw Tooth on Steel Tooth Model
D = For Gauge/Face Diamond Insert on Insert Model

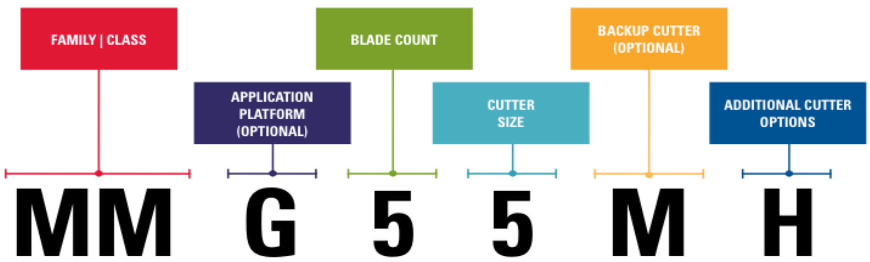
CUTTING STRUCTURE

For Tooth Bits Single Numeric Variant From 1 to 7
For Insert Bits Dual Numeric Variant From 00 to 99

OPTIONAL FEATURES

For more information, please contact your local Halliburton Drill Bits representative.

A = Air Application
C = Center Jet
D = Diamond Surf Row (33%)
D2 = Diamond Surf Row (50%)
D3 = Diamond Surf Row (100%)
G = Non-Standard Gauge Row
L = Lug Pads
LD = Diamond Insert Lug Pads
P = Protective Carbide Coating
R = Raised Enhanced Shirttail / Arm Protection
S = Enhanced Shirttail Protection
SD = Shirttail Diamond – Enhanced Protection
RD = Shirttail Diamond – Raised Protection



FAMILY | CLASS

MegaForce™ 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

2. Smith bits' nomenclature

Product Line	Prefix Description
A	ARCS & ARCS advanced
C	Carbonate
D	Natural diamond bit
Di	IDEAS certified directional design
G	Reamers with API connections (box down, pin up)
H	Kinetic hybrid bit
HOX	Heavy oil series
K	Kinetic impregnated bit
L	LIVE
M	Matrix body
PR	Pilot reamer
QD	Quad-D dual diameter
R	ONYX 360 rolling cutter
S	Steel body
S	SHARC
ST	Side track
SHO	Staged hole opener
T	Turbine
V	VertiDrill
Z	Stinger—conical diamond element

Nomenclature identifies blade count/cutter size.
Example: M616 = 6 Blades /16 mm cutters

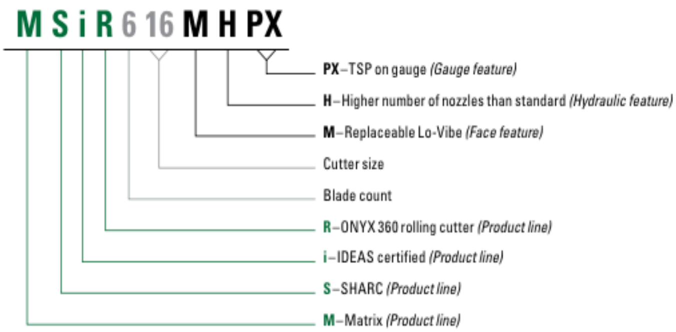
Face Features	Description
K	Impregnated cutter backing
L	Low exposure
M	Replaceable Lo-Vibe
V	Lo-Vibe

Hydraulic Features	Description
H	Higher number of nozzles than standard
N	Lower number of nozzles than standard
Q	Fixed ports
U	50 series nozzles
W	40 series nozzles
Y	30 series nozzles

Gauge Features	Description
A	Active gauge
B	Back reaming cutters
D	Dog sleeve
E	Extended gauge pad length
PX	TSP on gauge
PXX	Full diamond on turbine sleeve
S	Short gauge pad length
T	Turbine sleeve

Connection Features	Description
C	Non API standard connection
I	IF connection

Nomenclature example



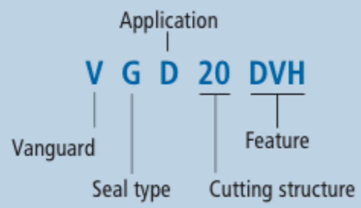
3. Hughes Christensen bits' nomenclature

Bearing and Performance Packages

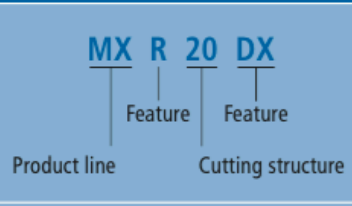
	Vanguard			MX	GX	STX	GTX	Triton
	VXG	VM	VG					
Journal bearing		•	•	•	•	•		•
Ball and roller bearing	•	•	•	•			•	•
Metal seal		•		•				
Elastomer seal			•		•	•	•	•
GT performance package				•	•	•	•	
High-temperature package	•	•						
Directional package	•	•	•					
Unsealed	•							•

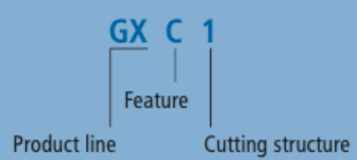
Tricone Roller Cone Bit Nomenclature

Advanced tricone drill bits

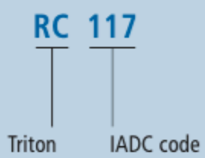


Classic tricone drill bits





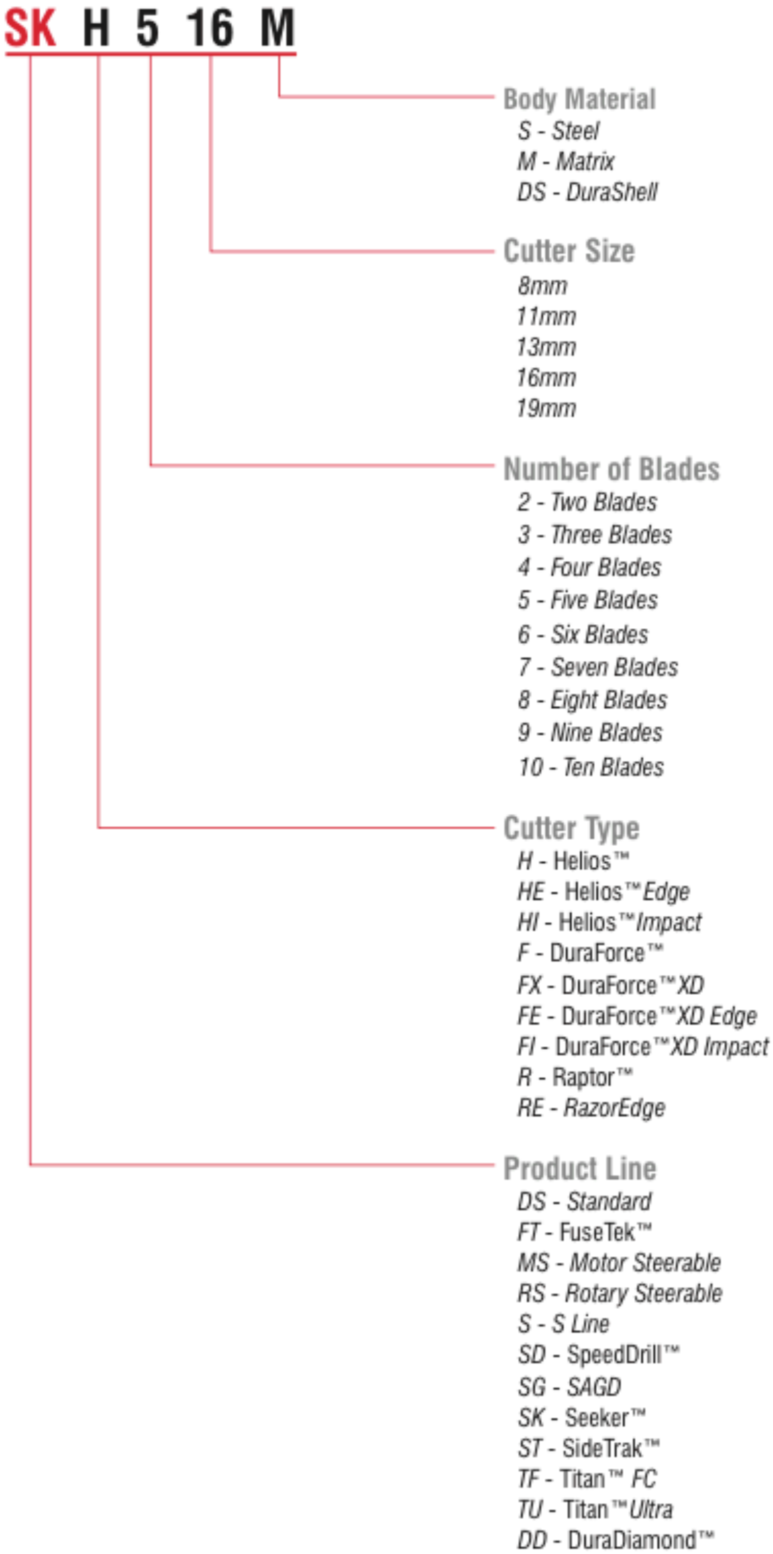
Standard tricone drill bits



Product Features and Enhancements

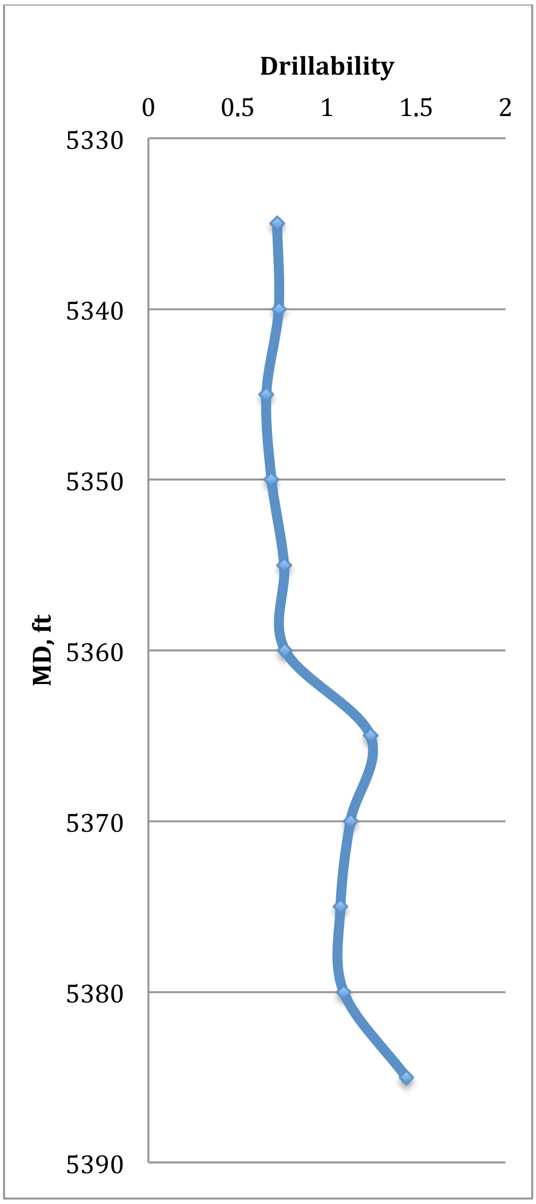
Code	Description	Example
A	Air journal bearing, air nozzles	VG-40**A**
C (prefix)	Center jet	GX-**C**18
C (suffix)	Conical-shape insert	GX-18**C**
C3	Three-directed center jets	MX-**C3**1
DDX	DSE diamond gauge (33%) / diamond trimmers (50%)	MX-09**DDX**
DDT	DSE diamond gauge (33%) / diamond trimmers (100%)	MX-09**DDT**
DH	Diamond heel compacts (100%)	STX-50**DH**
DH1	Diamond heel compacts (50%)	STX-50**DH1**
DP	Diamond-enhanced stabilization pad	GX-**DP**66
DS	Diamond-enhanced shirttail compacts	GX-**DS**20
DT	Diamond gauge trimmers (100%)	MX-09**DT**
DT1	Diamond gauge trimmers (50%)	MX-1**DT1**
DX	DSE diamond gauge compacts (33%)	MX-09**DX**
DX0	DSE diamond gauge compacts (20%)	MX-09**DX0**
DX1	DSE diamond gauge compacts (50%)	MX-09**DX1**
DX2	DSE diamond gauge compacts (100%)	MX-09**DX2**
DX3	DSE diamond gauge compacts / 1st row (33%), 2nd row (100%)	MX-09**DX3**
DVH	Diamond Vanguard bit heel	VGD-20**DVH**
DVHX0	Diamond Vanguard bit heel +20% gauge	VGD-20**DVHX0**
DVHX	Diamond Vanguard bit heel +33% gauge	VGD-20**DVHX**
DVHX1	Diamond Vanguard bit heel +50% gauge	VGD-20**DVHX1**
DVHX2	Diamond Vanguard bit heel +100% gauge	VGD-20**DVHX2**
G	Enhanced gauge wear resistant	MX-20**G**
H	Enhanced gauge breakage resistant	GTX-11**H**
M (prefix)	Motor hardfacing	GTX-**M**1
M (suffix)	M technology	GX-20**M**
P (prefix)	Leg stabilization wear pad	GX-**P**35
R	Spray-coat cones	MX-**R**09
S	Shirttail compacts	MX-**S**20
T	High-flow nozzles (two)	MX-**T**03
T1	High-flow nozzle (one)	MX-**T1**03
T3	High-flow nozzles (three)	MX-**T3**03

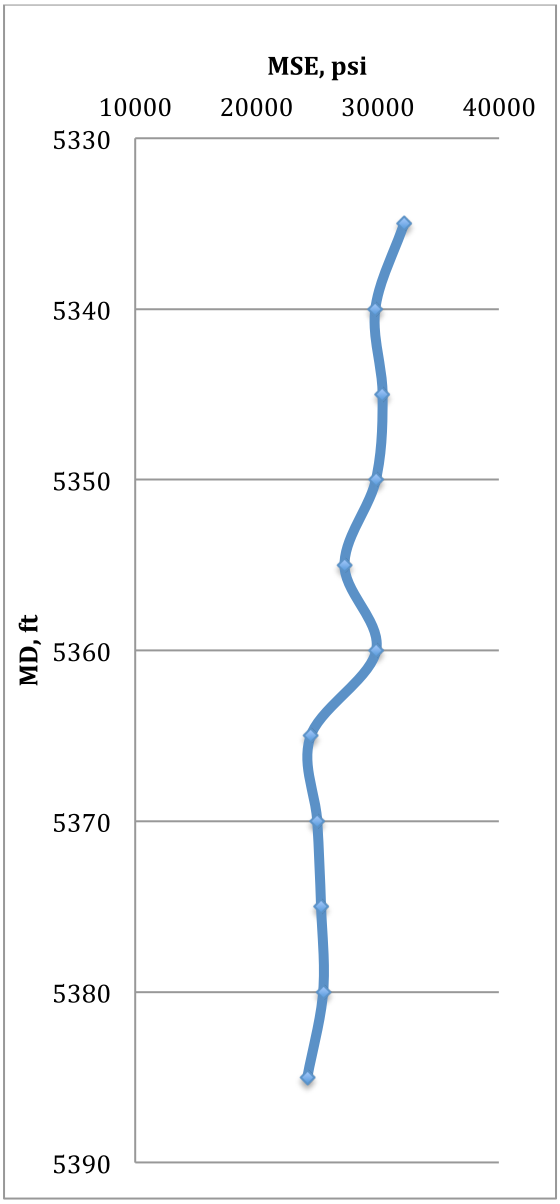
4. Reed bits' nomenclature



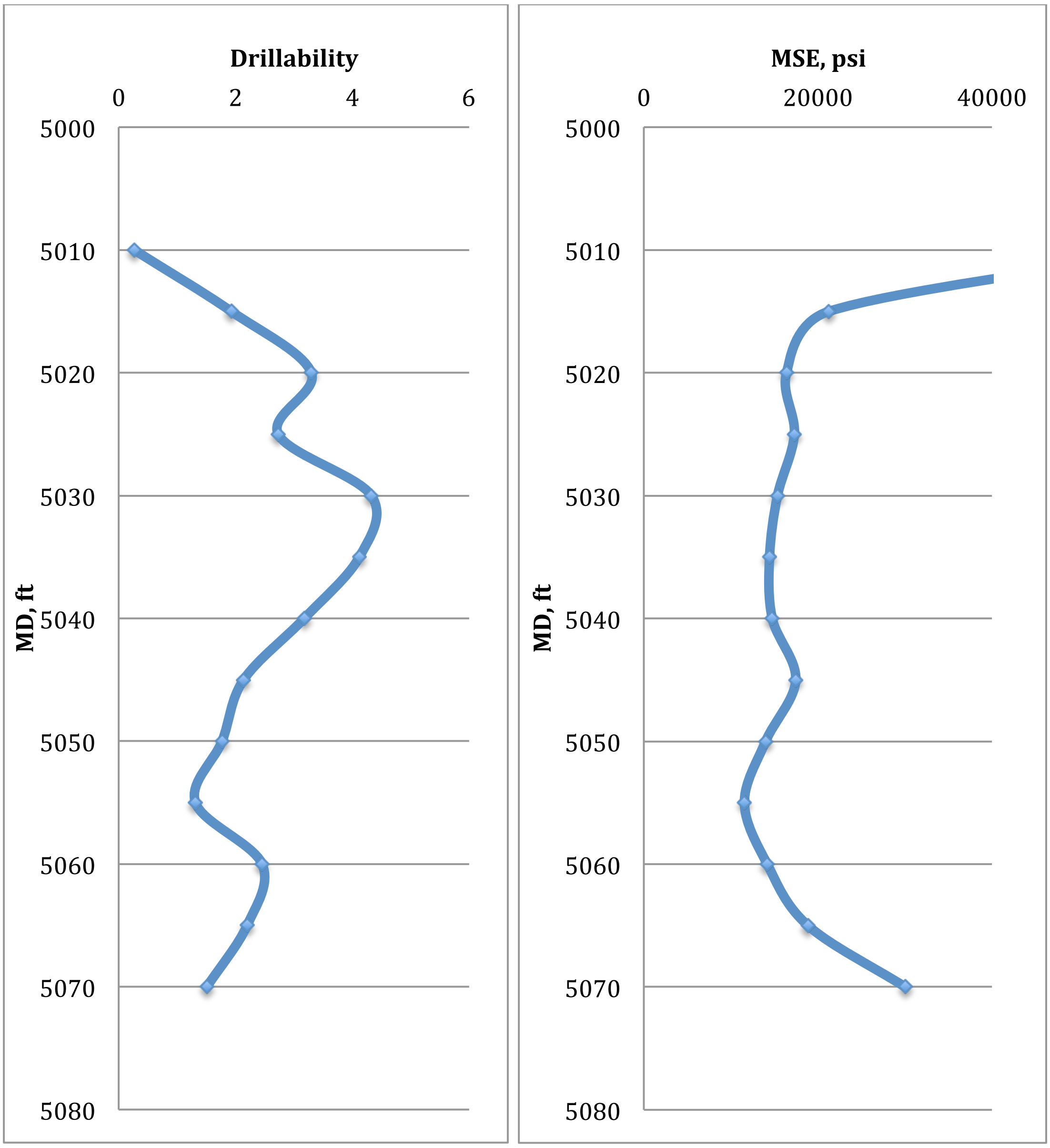
Appendix H: MSE and drillability logs for "H" wells

1H:



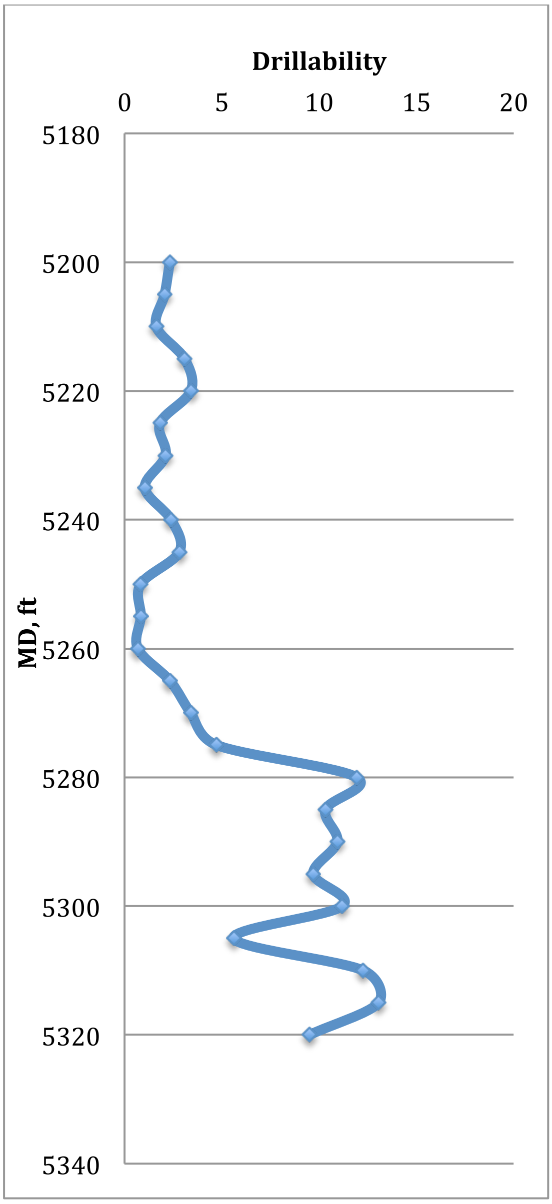


2H:

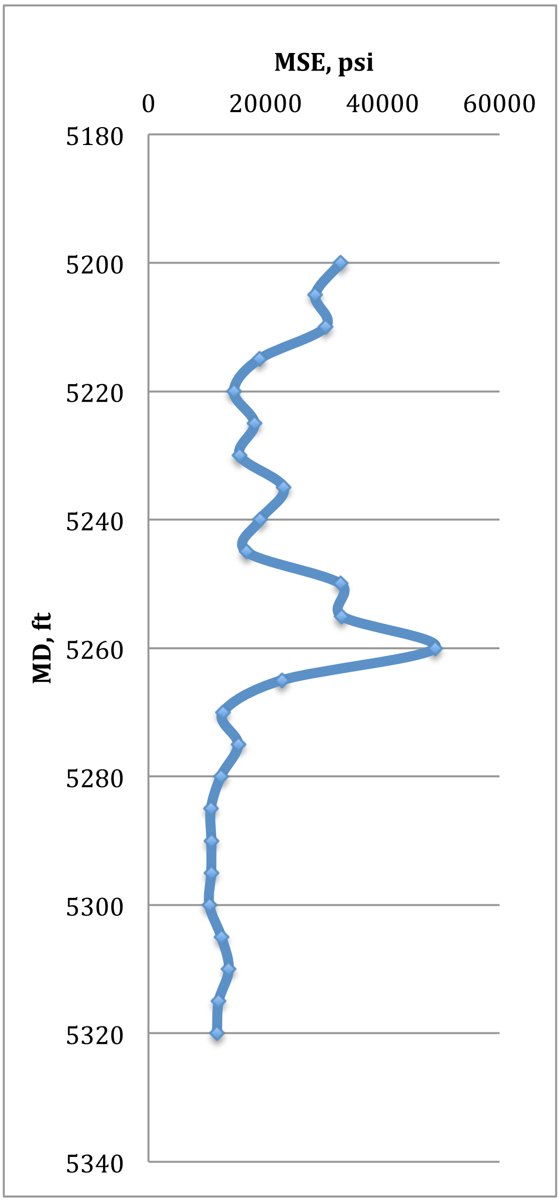


Drillability
0
2
4
6
MD, ft
5000
5010
5020
5030
5040
5050
5060
5070
5080
MSE, psi
0
20000
40000
MD, ft
5000
5010
5020
5030
5040
5050
5060
5070
5080

3H:

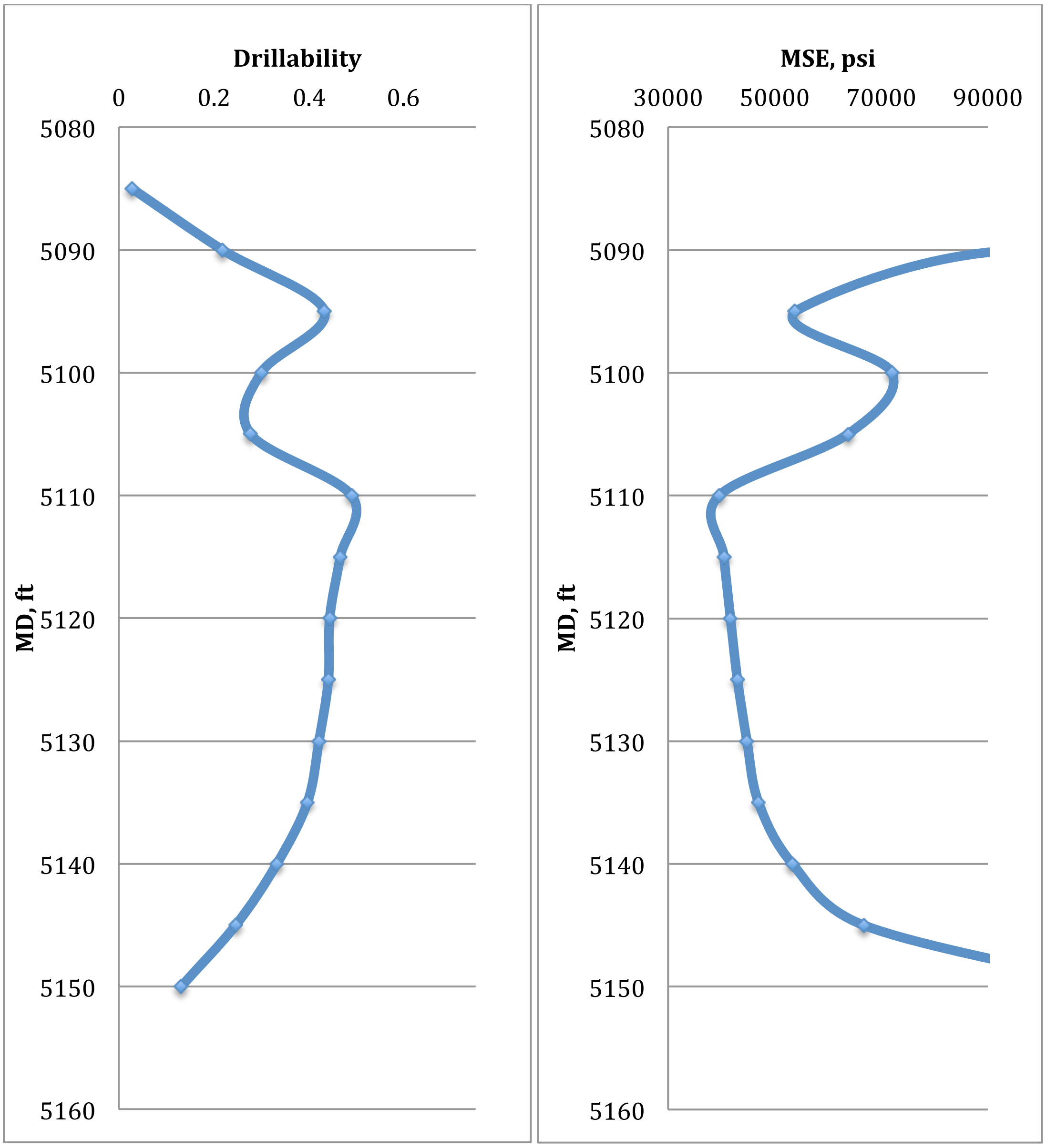


Drillability
0
5
10
15
20
5180
5200
5220
5240
5260
5280
5300
5320
5340
MD, ft



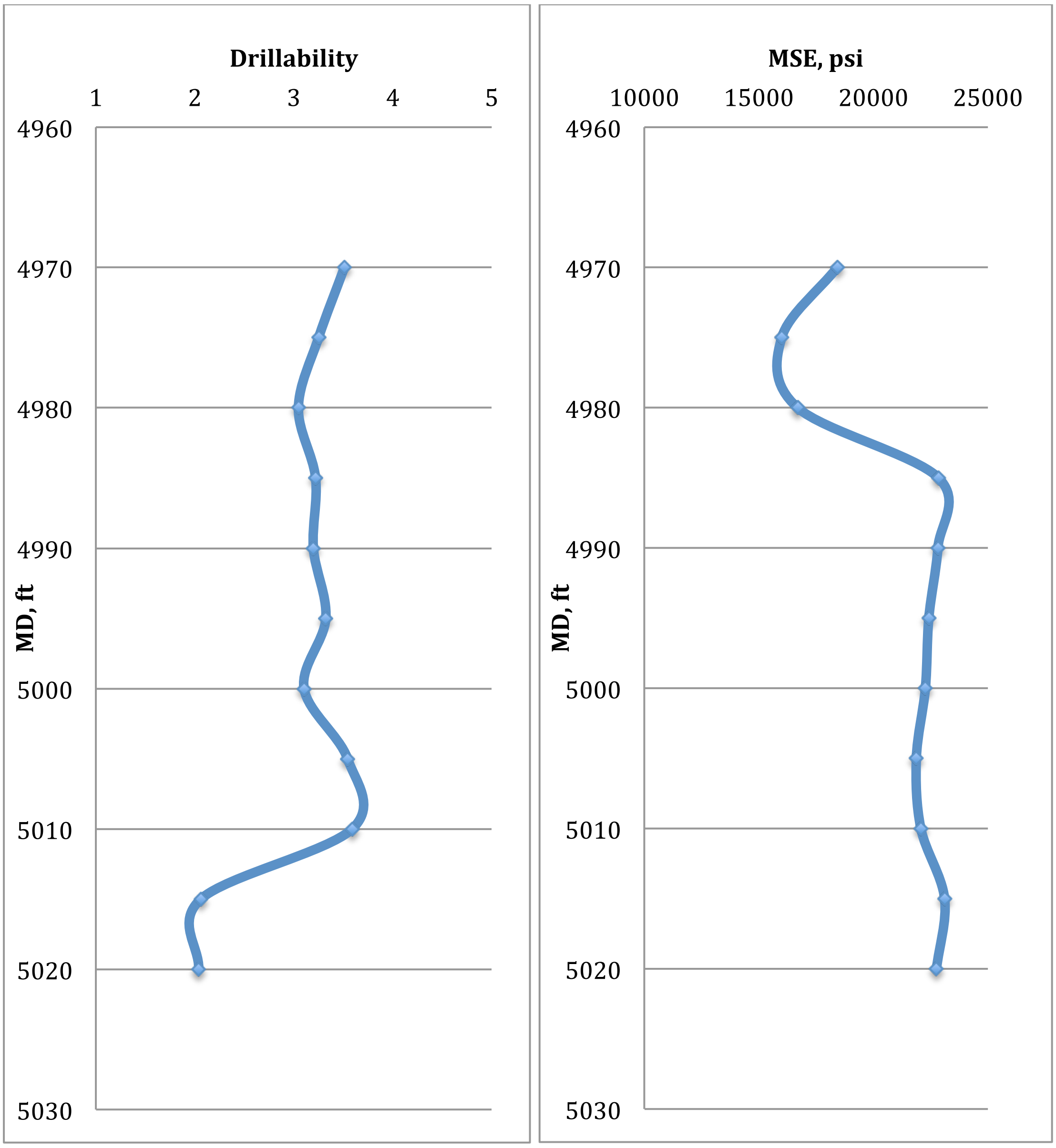
MSE, psi
0
20000
40000
60000
5180
5200
5220
5240
5260
5280
5300
5320
5340
MD, ft

4H:

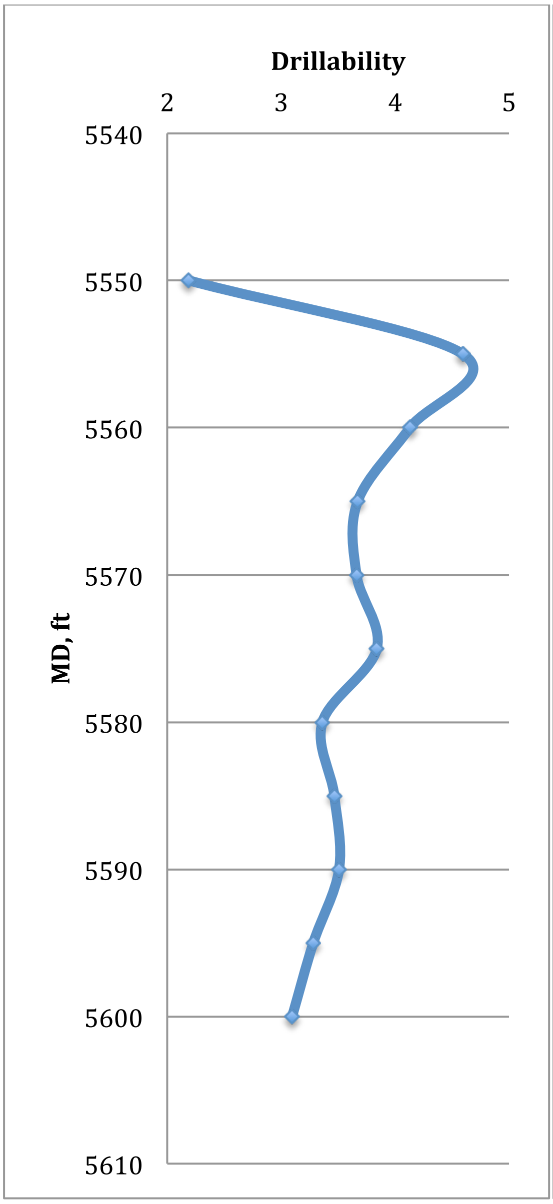


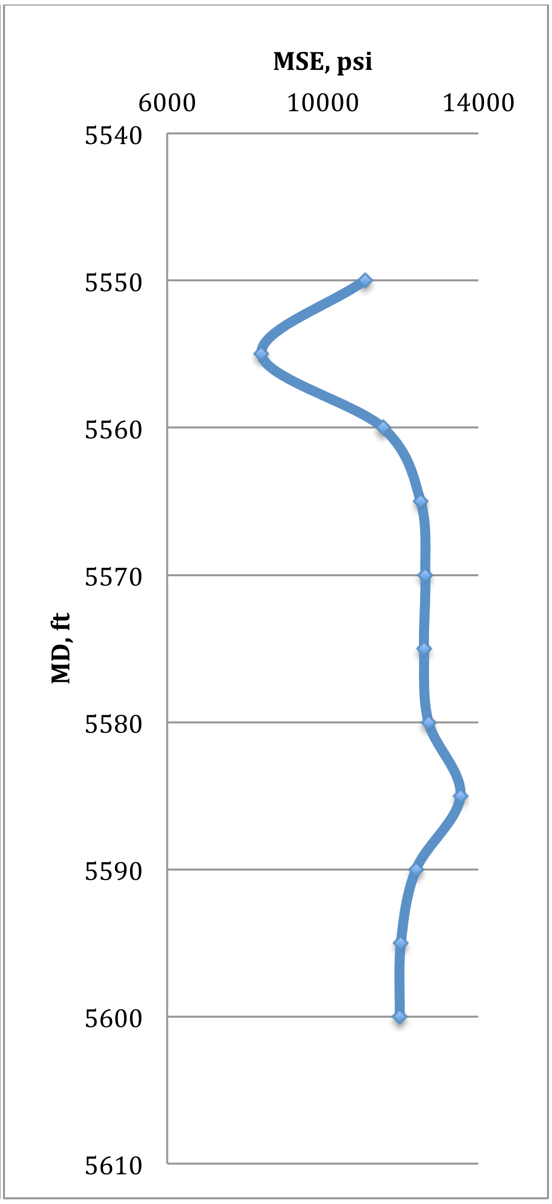
Drillability
0
0.2
0.4
0.6
MD, ft
5080
5090
5100
5110
5120
5130
5140
5150
5160
MSE, psi
30000
50000
70000
90000
MD, ft
5080
5090
5100
5110
5120
5130
5140
5150
5160

5 H:

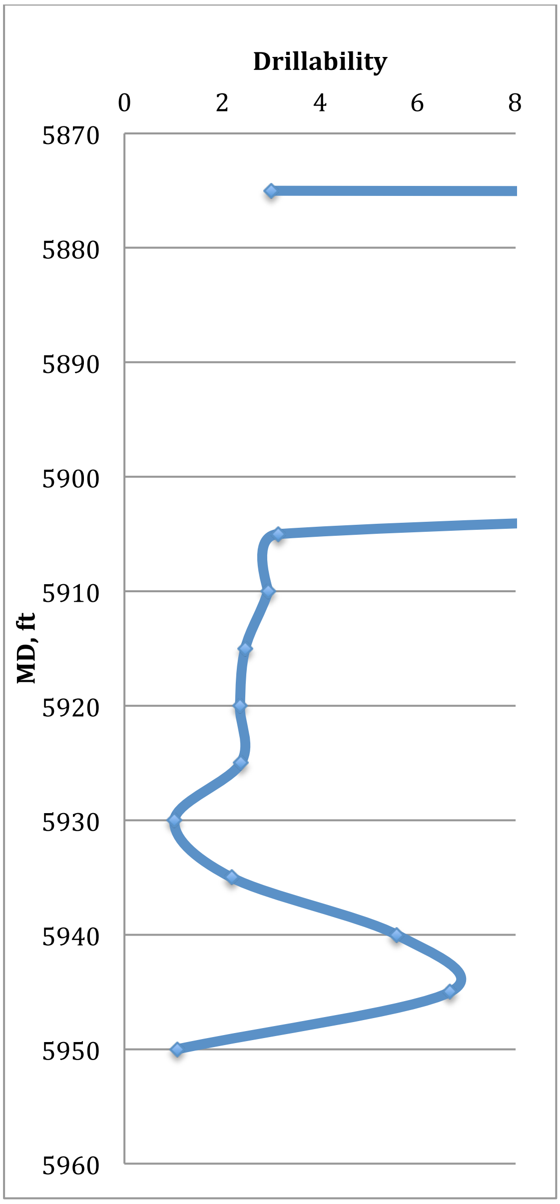

Drillability
1
2
3
4
5
4960
4970
4980
4990
5000
5010
5020
5030
MD, ft
MSE, psi
10000
15000
20000
25000
4960
4970
4980
4990
5000
5010
5020
5030
MD, ft

7 H:

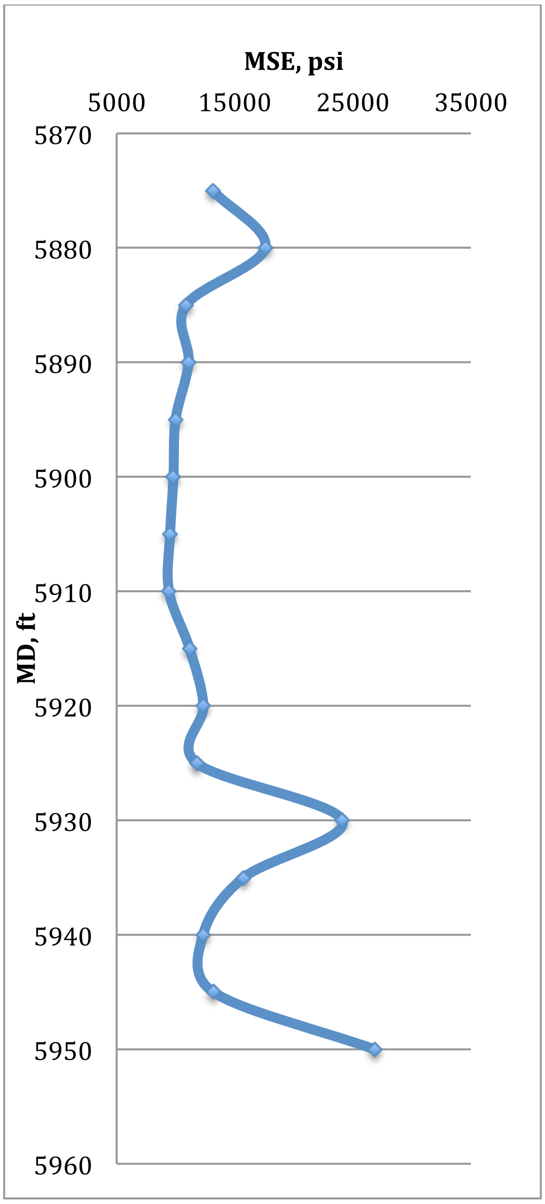

Drillability
2
3
4
5
5540
5550
5560
5570
5580
5590
5600
5610
MD, ft


MSE, psi
6000
10000
14000
5540
5550
5560
5570
5580
5590
5600
5610
MD, ft

8 H:



Drillability
0
2
4
6
8
MD, ft
5870
5880
5890
5900
5910
5920
5930
5940
5950
5960



MSE, psi
5000
15000
25000
35000
MD, ft
5870
5880
5890
5900
5910
5920
5930
5940
5950
5960

Appendix I: Matlab code for sensitivity analysis using MSE model (Well A)

```
Depth=4560:5:4670;
ROP=[149.29 144.60 144.47 144.49 137.58 144.42 140.92 140.10 148.40
138.87 144.42 144.15 142.15 95.84 135.28 145.62 145.37 145.45 145.90
149.30 144.50 140.32 142.86];
WOB=[11.01 11.40 11.74 12.21 13.62 13.87 14.36 14.56 14.63 14.63
14.36 14.51 14.46 14.24 11.95 11.58 11.90 12.20 12.50 14.95 17.07
14.96 17.06]*1000;
RPM=[178.12 178.29 178.22 178.32 178.39 178.38 178.26 178.35 178.27
178.37 178.31 178.39 178.35 178.22 178.17 178.17 178.12 178.05 178.17
178.12 178.12 178.05 178.09];
TRQ=[6842.70 6651.04 6676.32 7050.25 7019.89 7178.36 7281.21 7178.94
7065.40 7353.17 7535.47 7517.58 7213.28 6721.91 6372.24 6541.00
6704.95 6723.64 6816.79 6871.60 6905.94 6827.75 6901.05];
Ab=12.25^2*pi/4; %drill bit's area
UCS=1737; %psi
format shortg
MSE=WOB./Ab+(120*pi*RPM.*TRQ)./(Ab.*ROP);
Coeff=MSE/UCS;
Coeff_av=mean(Coeff); %take the average value for coefficient

%%
WOB=6000:1000:12000; %from procedures
TRQ=5000:500:10000;
[WOB,TRQ]=meshgrid(WOB,TRQ)
RPM_max=80*ones(size(WOB)); %PRM is constant
ROP=(120*pi*RPM_max.*TRQ)./(UCS*Coeff_av*Ab-WOB);
[ax,p1,p2]=plotyy(TRQ,WOB,TRQ,ROP)
xlabel('TRQ, lbs*ft')
ylabel(ax(1),'WOB,lbs')
ylabel(ax(2),'ROP, ft/hr')
grid on
%%
surface(WOB,TRQ,ROP)
xlabel('WOB,lbs')
ylabel('TRQ,lbs*ft')
zlabel('ROP, ft/hr')
view(3)
grid on
%%
TRQ=5000:500:10000;
RPM=30:5:60;
[RPM,TRQ]=meshgrid(RPM,TRQ);
WOB_max=12000*ones(size(RPM)); %WOB is constant
ROP=(120*pi*RPM.*TRQ)./(UCS*Coeff_av*Ab-WOB_max);
[ax,p1,p2]=plotyy(TRQ,RPM,TRQ,ROP)
xlabel('TRQ,lbs*ft')
ylabel(ax(1),'RPM')
ylabel(ax(2),'ROP, ft/hr')
grid on
%%
figure
surface(RPM,TRQ,ROP)
xlabel('RPM')
ylabel('TRQ,lbs*ft')
zlabel('ROP, ft/hr')
view(3)
grid on
```

Appendix J: Matlab code for a-coefficients calculation for BYM

```
i=1;
for a1=linspace(0.0,0.5,5);
    f1(i)=exp(2.303*a1);
    i=i+1;
end
f1;

i=1;
D=[Paste TVD];
for a2=linspace(0.000001,0.0005,5);
    f2(i)=exp(2.303*a2*(10000-D));
    i=i+1;
end
f2;

gp=8.58; %ppg, pore pressure
i=1;
for a3=linspace(0.000001,0.0009,5);
    f3(i)=exp(2.303*a3*D^0.69*(gp-9));
    i=i+1;
end
f3;

roc=[Paste mud weight]; %ppg, mud weight
r0cem=gp;
i=1;
for a4=linspace(0.000001,0.0001,5)
    f4(i)=exp(2.303*a4*D*(gp-roc));
    i=i+1;
end
f4;

WOB=[Paste WOB]; %1000 lbf
db=[Paste bit diameter]; %inch
W_db=[Paste threshold bit weight]; %1000 lbf
i=1;
for a5=linspace(0.5,2,5);
    f5(i)=(((WOB/db)-W_db)/(4-W_db))^a5;
    i=i+1;
end
f5;

RPM=[Paste RPM]; %RPM cannot be equal 60
f6=(RPM/60)^a6;
i=1;
for a6=linspace(0.4,1,5);
   f6(i)=(RPM/60)^a6;
   i=i+1;
end
f6;

f7=1;

Fj=[Paste JIF]; %lbf
i=1;
for a8=linspace(0.3,0.6,5);
    f8(i)=(Fj/1000)^a8;
    i=i+1;
```

```
end
f8;

ROP = zeros(length(f1), length(f2), length(f3), length(f4),
length(f5), length(f6), length(f7), length(f8));

for f1i = 1:length(f1)
    for f2i = 1:length(f2)
        for f3i = 1:length(f3)
            for f4i=1:length(f4)
                for f5i = 1:length(f5)
                    for f6i = 1:length(f6)
                      for f7i = 1:length(f7)
                         for f8i = 1:length(f8)
                            ROP(f1i,f2i,f3i,f4i,f5i,f6i,f7i,f8i) =
f1(f1i)*f2(f2i)*f3(f3i)*f4(f4i)*f5(f5i)*f6(f6i)*f7(f7i)*f8(f8i);
                         end
                      end
                  end
                end
            end
        end
    end
end

x=find(ROP>[Paste min ROP] & ROP<[Paste max ROP]);
good_fs = zeros(length(x),8);
good_as = zeros(length(x),8);
for xi = 1:length(x)
    [r1,r2,r3,r4,r5,r6,r7,r8] = ind2sub(size(ROP),x(xi));
     syms a1 a2 a3 a4 a5 a7 a6 a8
     good_a1 = solve(exp(2.303*a1)==f1(r1),a1);
     good_a2 = solve(exp(2.303*a2*(10000-D))==f2(r2),a2);
     good_a3 = solve(exp(2.303*a3*D^0.69*(gp-9))==f3(r3),a3);
     good_a4 = solve(exp(2.303*a4*D*(gp-roc))==f4(r4),a4);%a4;
     good_a5 = solve((((WOB/db)-W_db)/(4-W_db))^a5==f5(r5),a5);
     good_a6 = solve((RPM/60)^a6==f6(r6),a6);
     good_a7 = solve(exp(-a7*h)==f7(r7),a7);
     good_a8 = solve((Fj/1000)^a8==f8(r8),a8);

good_as(xi,1:end)=[good_a1,good_a2,good_a3,good_a4,good_a5,good_a6,go
od_a7,good_a8]; %find set of coefficients a

good_fs(xi,1:end)=[f1(r1),f2(r2),f3(r3),f4(r4),f5(r5),f6(r6),f7,f8(r8
)]; %find f-factors
end
```

Appendix K: Operational parameters, a-coefficients and f-factors for BYM analysis

Well 6H:

Appendix table 2: Operational parameters for well 6H

	TVD, ft	ROP, ft/hr	WOB, klbs	RPM	JIF, lbf	ECD, ppg
	4797,45	49,65	20,97	59,73	638,59	15,13
	4800,55	150,37	11,83	69,99	978,84	15,34
	4803,64	144,33	11,56	70,01	978,72	15,34
	4806,74	203,05	12,48	70,00	978,69	15,34
	4809,84	85,90	13,18	70,00	978,69	15,34
	4812,93	186,55	11,95	84,98	978,36	15,34
	4816,03	164,41	5,68	84,97	978,33	15,34
	4819,13	194,41	7,14	85,00	978,30	15,34
	4822,23	164,15	8,41	84,99	978,33	15,34
	4825,33	157,65	7,53	85,03	978,33	15,34
	4828,43	169,47	9,17	84,99	978,35	15,34
	4831,53	189,96	8,26	84,96	978,36	15,34
	4834,63	91,17	6,61	71,85	937,36	15,30
Median values:	4816,03	164,15	9,17	84,96	978,35	15,34

Appendix table 3: *a*-coefficients calculated for well 6H

a1	a2	a3	a4	a5	a6	a7	a8
0,85	0,0005	0,0009	2,58E-05	0,5	0,7	0	0,525

Appendix table 4: *f*-factors for well 6H

Depth	f1	f2	f3	f4	f5	f6	f7	f8
4800,55	7,08	398,29	0,74	0,15	0,49	1,11	1	0,99
4803,64	7,08	396,87	0,74	0,15	0,49	1,11	1	0,99
4806,74	7,08	395,46	0,74	0,15	0,50	1,11	1	0,99
4809,84	7,08	394,05	0,74	0,15	0,52	1,11	1	0,99
4812,93	7,08	392,64	0,74	0,15	0,49	1,28	1	0,99
4816,03	7,08	391,25	0,74	0,15	0,34	1,28	1	0,99
4819,13	7,08	389,85	0,74	0,14	0,38	1,28	1	0,99
4822,23	7,08	388,46	0,74	0,14	0,41	1,28	1	0,99
4825,33	7,08	387,08	0,74	0,14	0,39	1,28	1	0,99
4825,33	7,08	387,08	0,74	0,14	0,39	1,28	1	0,99
4828,43	7,08	385,70	0,74	0,14	0,43	1,28	1	0,99
4831,53	7,08	384,33	0,74	0,14	0,41	1,28	1	0,99
4834,63	7,08	382,96	0,74	0,15	0,37	1,13	1	0,97

Appendix table 5: ROP variation with WOB and RPM

WOB, klbs	ROP (RPM 84,9), ft/hr	ROP (RPM 40), ft/hr	ROP (RPM 60), ft/hr	84,9 to 40 RPM, ROP reduction, %	84,9 to 60 RPM, ROP reduction, %
10	169,21	99,86	132,63	40,98	21,61
12	185,36	109,39	145,29	40,98	21,61
14	200,21	118,16	156,93	40,98	21,61
16	214,03	126,31	167,77	40,98	21,61
18	227,01	133,98	177,95	40,98	21,61
20	239,29	141,22	187,57	40,98	21,61
22	250,97	148,12	196,73	40,98	21,61
24	262,13	154,7	205,47	40,98	21,61
26	272,84	161,02	213,86	40,98	21,61
28	283,13	167,1	221,94	40,98	21,61
30	293,07	172,96	229,73	40,98	21,61

Appendix table 6: ROP variation with RPM and threshold WOB

RPM	ROP (W thr 0), ft/hr	ROP (W thr 0.25), ft/hr	ROP (W thr 0.5), ft/hr	0 to 0.25 W thr, ROP reduction, %	0 to 0.5 W thr, ROP reduction, %
40	95,63	80,61	58,92	15,71	38,39
42	98,95	83,41	60,97	15,71	38,39
44	102,23	86,17	62,99	15,71	38,39
46	105,46	88,89	64,98	15,71	38,39
48	108,65	91,58	66,94	15,71	38,39
50	111,8	94,24	68,88	15,71	38,39
52	114,91	96,86	70,8	15,71	38,39
54	117,99	99,45	72,7	15,71	38,39
56	121,03	102,02	74,57	15,71	38,39
58	124,04	104,55	76,42	15,71	38,39
60	127,02	107,06	78,26	15,71	38,39

Appendix table 7: ROP variation with ECD and jet impact force

ECD, ppg	ROP (JIF 978), ft/hr	ROP (JIF 800), ft/hr	ROP (JIF 1200), ft/hr	978 to 800 JIF, ROP reduction, %	978 to 1200 JIF, ROP increase, %
14	237,58	213,76	264,47	10,03	11,32
14,3	218,07	196,21	242,75	10,03	11,32
14,6	200,17	180,10	222,82	10,03	11,32
14,9	183,73	165,31	204,52	10,03	11,32
15,2	168,64	151,73	187,73	10,03	11,32
15,5	154,80	139,27	172,31	10,03	11,32
15,8	142,09	127,84	158,16	10,03	11,32
16,1	130,42	117,34	145,18	10,03	11,32
16,4	119,71	107,71	133,26	10,03	11,32
16,7	109,88	98,86	122,31	10,03	11,32
17	100,86	90,74	112,27	10,03	11,32

Well A:

Appendix table 8: Operational parameters for well A

	TVD, ft	ROP, ft/hr	WOB, klbs	RPM	ECD, ppg	JIF, lbf
	4256,21	149,29	11,01	178,12	12,61	1341,97
	4259,67	144,60	11,40	178,29	12,61	1341,78
	4263,12	144,47	11,74	178,22	12,61	1343,52
	4266,57	144,49	12,21	178,32	12,61	1340,02
	4270,02	137,58	13,62	178,39	12,61	1342,74
	4273,46	144,42	13,87	178,38	12,61	1342,28
	4276,90	140,92	14,36	178,26	12,61	1344,86
	4280,34	140,10	14,56	178,35	12,61	1342,21
	4283,77	148,40	14,63	178,27	12,61	1344,09
	4287,20	138,87	14,63	178,37	12,61	1341,01
	4290,63	144,42	14,36	178,31	12,61	1340,60
	4294,05	144,15	14,51	178,39	12,61	1342,21
	4297,48	142,15	14,46	178,35	12,61	1341,72
	4300,90	95,84	14,24	178,22	12,61	1344,45
	4304,31	135,28	11,95	178,17	12,61	1344,99
	4307,73	145,62	11,58	178,17	12,61	1348,30
	4311,14	145,37	11,90	178,12	12,61	1339,55
	4314,54	145,45	12,20	178,05	12,61	1341,15
	4317,95	145,90	12,50	178,17	12,61	1342,73
	4321,35	149,30	14,95	178,12	12,61	1341,01
	4324,75	144,50	17,07	178,12	12,61	1340,55
	4328,15	140,32	14,96	178,05	12,61	1340,90
	4331,54	142,86	17,06	178,09	12,61	1343,43
	4334,93	144,35	16,77	178,14	12,61	1340,07
Median values:	4295,77	144,42	14,30	178,22	12,61	1342,09

Appendix table 9: *a*-coefficients calculated for well A

a1	a2	a3	a4	a5	a6	a7	a8
1,2	0,00037525	0,0004505	7,53E-05	0,5	0,85	0	0,6

Appendix table 10: f-factors for well A

Depth	f1	f2	f3	f4	f5	f6	f7	f8
4256,21	15,86	143,13	0,87	0,05	0,47	2,52	1	1,19
4259,67	15,86	142,71	0,87	0,05	0,48	2,52	1	1,19
4263,12	15,86	142,28	0,87	0,05	0,49	2,52	1	1,19
4266,57	15,86	141,86	0,87	0,05	0,50	2,52	1	1,19
4270,02	15,86	141,44	0,87	0,05	0,53	2,52	1	1,19
4273,46	15,86	141,44	0,87	0,05	0,53	2,52	1	1,19
4276,90	15,86	140,60	0,87	0,05	0,54	2,53	1	1,19
4283,77	15,86	139,77	0,87	0,05	0,55	2,52	1	1,19
4290,63	15,86	138,94	0,87	0,05	0,54	2,52	1	1,19
4297,48	15,86	138,12	0,87	0,05	0,54	2,52	1	1,19
4304,31	15,86	138,12	0,87	0,05	0,54	2,52	1	1,19
4314,54	15,86	136,10	0,87	0,05	0,50	2,52	1	1,19
4321,35	15,86	135,30	0,87	0,05	0,55	2,52	1	1,19
4328,15	15,86	134,51	0,87	0,05	0,55	2,52	1	1,19
4334,93	15,86	133,72	0,87	0,05	0,59	2,52	1	1,19

Appendix table 11: ROP variation with WOB and RPM

WOB, klbs	ROP (RPM 178), ft/hr	ROP (RPM 40), ft/hr	ROP (RPM 60), ft/hr	178 to 40 RPM, ROP reduction, %	178 to 60 RPM, ROP reduction, %
5	91,27	25,63	36,18	71,92	60,36
6,5	104,06	29,22	41,25	71,92	60,36
8	115,44	32,42	45,76	71,92	60,36
9,5	125,80	35,33	49,87	71,92	60,36
11	135,37	38,02	53,66	71,92	60,36
12,5	144,30	40,52	57,20	71,92	60,36
14	152,72	42,89	60,53	71,92	60,36
15,5	160,69	45,13	63,70	71,92	60,36
17	168,29	47,26	66,71	71,92	60,36
18,5	175,55	49,30	69,59	71,92	60,36
20	182,53	51,26	72,35	71,92	60,36

Appendix table 12: ROP variation with RPM and threshold WOB

RPM	ROP (W thr 0), ft/hr	ROP (W thr 0.25), ft/hr	ROP (W thr 0.5), ft/hr	0 to 0.25 W thr, ROP reduction, %	0 to 0.5 W thr, ROP reduction, %
40	40,04	35,79	30,21	10,61	24,55
42	41,74	37,31	31,49	10,61	24,55
44	43,42	38,81	32,76	10,61	24,55
46	45,09	40,31	34,03	10,61	24,55
48	46,76	41,79	35,28	10,61	24,55
50	48,41	43,27	36,52	10,61	24,55
52	50,05	44,74	37,76	10,61	24,55
54	51,68	46,19	38,99	10,61	24,55
56	53,30	47,65	40,22	10,61	24,55
58	54,92	49,09	41,44	10,61	24,55
60	56,52	50,52	42,65	10,61	24,55

Appendix table 13: ROP variation with ECD and jet impact force

ECD, ppg	ROP (JIF 1342), ft/hr	ROP (JIF 1200), ft/hr	ROP (JIF 1000), ft/hr	1342 to 1200 JIF, ROP reduction, %	978 to 1000 JIF, ROP reduction, %
11,4	351,00	328,20	294,20	6,49	16,18
11,6	302,44	282,80	253,50	6,49	16,18
11,8	260,60	243,68	218,43	6,49	16,18
12	224,55	209,97	188,21	6,49	16,18
12,2	193,49	180,92	162,18	6,49	16,18
12,4	166,72	155,89	139,74	6,49	16,18
12,6	143,66	134,33	120,41	6,49	16,18
12,8	123,78	115,75	103,75	6,49	16,18
13	106,66	99,73	89,40	6,49	16,18
13,2	91,90	85,94	77,03	6,49	16,18
13,4	79,19	74,05	66,38	6,49	16,18

Appendix L: Hole cleaning calculation in WELLPLAN

Calculate n, K, τ_y, and Reynold's Number

$$n = \frac{(3.32)(\log 10)(YP + 2PV)}{(YP + PV)}$$

$$K = \frac{(PV + YP)}{511}$$

$$\tau_y = (5.11K)^n$$

$$R_A = \frac{\rho V_a^{(2-n)}(D_H - D_P)^n}{(2/3)G_{f2}K}$$

Concentration Based on ROP in Flow Channel

$$C_o = \frac{\left(V_r D_B^2/1471\right)}{\left(V_r D_B^2/1471\right) + Q_m}$$

Fluid Velocity Based on Open Flow Channel

$$V_a = \frac{24.5Q_m}{D_H^2 - D_P^2}$$

Coefficient of Drag around Sphere

If $R_e < 225$ then,

$$C_D = \frac{22}{\sqrt{R_a}}$$

else,

$$C_D = 1.5$$

Mud carrying capacity

$$C_M = \frac{4g\left(\frac{D_c}{12}\right)(\rho_c - \rho)}{3\rho C_D}$$

Slip Velocity

If $V_A < 53.0$, then $V_{SV} = (0.00516)V_A + 3.0006$

If $V_A \geq 53.0$, then $V_{SV} = (0.02554)(V_A - 53.0) + 3.28$

Settling Velocity in the Plug in a Mud with a Yield Stress

$$U_p = \left[\frac{4}{3}\frac{gD_c^{1+bn}(\rho_c - \rho}{aK_b\rho_c^{1-b}}\right]^{\frac{1}{2-b(2-n)}}$$

Where:

$$a = 42.9 - 23.9n$$

$$b = 1 - 0.33n$$

Angle of Inclination Correction Factor

$$C_a = (\sin(1.33\alpha))^{1.33}\left(\frac{5}{D_H}\right)^{0.65}$$

Cuttings Size Correction Factor

$$C_s = 1.286 - 1.04\,D_c$$

Mud Weight Correction Factor

If $(\rho < 7.7)$,then

$$C_m = 1.0$$

else

$$C_m = 1.0 - 0.0333\,(\rho - 7.7)$$

Critical Wall Shear Stress

$$\tau wc = [ag \sin(\propto)(\rho_c - \rho) D_c^{1+b} \rho^{b/2}]\frac{2n}{2n - 2b + bn}$$

Where:

a = 1.732

b = -0.744

Critical Pressure Gradient

$$Pgc = \frac{2\tau wc}{r_h[1-(\frac{r_o}{r_h})^2]}$$

Total Cross Sectional Area of the Annulus without Cuttings Bed

$$A_A = \frac{\pi}{4}\frac{\left(D_H{}^2 - D_P{}^2\right)}{144}$$

Dimensionless Flow Rate

$$\prod g_b = \prod[8 \times \frac{\overline{2(1+2n)}^{\,n}}{(a)\frac{1}{b}}]^{\frac{1}{2-(2-n)b}} \times (1 - (\frac{r_p}{r_h})^2)(1 - (\frac{r_p}{r_h})^{\frac{b}{2-(2-n)b}}]$$

Where:

a = 16

b = 1

Critical Flow Rate (CFR)

$$Q_{crit} = rh^2\left[\frac{\rho g b^{\frac{1}{b}} r_h^{\left(\frac{1}{b+n}\right)}}{K\rho^{\left(\frac{1}{b-1}\right)}}\right]^{\frac{b}{2-b(2-n)}} \prod_{gb}$$

Correction Factor for Cuttings Concentration

$$C_{BED} = 0.97 - \left(0.00231\,\mu_a\right)$$

Cuttings Concentration for a Stationary Bed by Volume

$$C_{bmc} = C_{BED}\left(1.0 - \frac{Q_m}{Q_{crit}}\right)(1.0 - \phi_B)(100)$$

Where:

D_B = Bit diameter

D_H = Annulus diameter

D_P = Pipe diameter

D_{TJ} = Tool joint diameter

D_C = Cuttings diameter

τ_y = Mud yield stress

G_{fa} = Power law geometry factor

R_A = Reynolds number

R_e = Particle Reynolds number

ρ = Fluid density

ρ_c = Cuttings density

V_a = Average fluid velocity for annulus

V_R = Rate of penetration, ROP

V_{CTV} = Cuttings travel velocity

V_{so} = Original slip velocity

V_{SV} = Slip velocity

V_{CTFV} = Critical transport fluid velocity

V_{TC} = Total cuttings velocity

K = Consistency factor

n = Flow behavior index

a, b, c = Coefficients

YP = Yield point

PV = Plastic viscosity

Q_C = Volumetric cuttings flow rate

Q_m = Volumetric mud flow rate

Q_{crit} = Critical flow rate for bed to develop

C_o = Cuttings feed concentration

C_D = Drag coefficient

C_m = Mud carrying capacity

C_A = Angle of inclination correction factor

C_S = Cuttings size correction factor

C_{mud} = Mud weight correction factor

C_{BED} = Correction factor for cuttings concentration

C_{bnc} = Cuttings concentration for a stationary bed by volume

U_{sp} = Settling velocity

U_s = Average settling velocity in axial direction

U_{mix} = Average mixture velocity in the area open to flow

α = Wellbore angle

ϕ_B = Bed porosity

μ_a = Apparent viscosity

λ_p = Plug diameter ratio

g = Gravitational coefficient

r_0 = Radius of which shear stress is zero

r_p = Radius of drill pipe

r_h = Radius of wellbore or casing

P_{gr} = Critical frictional pressure gradient

τ_{wc} = Critical wall shear stress