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ABSTRACT

Rate of penetration (ROP) is one of the most critical parameters affecting virtually all drilling characteristics including technical, operational, economical, safety and other aspects of it. ROP evaluation may provide important information which can be applied to improve drilling efficiency and decrease the cost of drilling per meter.

The choice of ROP for every single case is dependent on variety of factors such as diameter of the well, target depth, present geological formations, pressure, water depth, hole cleaning, types of drilling tools that will be used. Additionally, there are different requirements depending on what country or state the well is located in. All these factors must be considered while choosing the proper ROP for drilling of every oil well interval.

In this master thesis several subsea wells of Norwegian Continental Shelf and several wells of Sakhalin Offshore location in Russia have been reviewed. Last technological and scientific trends and tendencies have been analyzed. A literature study of related topics has been done. Possible solutions have been suggested for every analyzed case based on well design, depth, cost of work and technologies and geological environments. Analyses have been carried out primarily by means of mechanical, hydraulic, stress, loads and safety calculations in different software applications including Landmark software applications, Weatherford software applications as well as calculations in Matlab software with applying different calculation methods.

Based on the results of calculations, implemented models and analyses of the related materials possible well designs and methods of increasing and optimizing the ROP were found for every considered case.

Keywords: Rate of Penetration, Hole Cleaning Efficiency, Pressure Window, Drilling Safety, Drilling Optimization, Well Design, Loads, Drilling Tools, RSS, Mud motors, TBS.

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LIST OF ABBREVIATIONS

ROP – Rate of Penetration

DLS – Dog-leg severity

TF – Tool-face

TBS – Targeted bit speed

RSS – Rotary steerable system

AGS – Adjustable gauge stabilizer

ROOH - Run out of the hole

RIH – Run in the hole

ERD – extended reach drilling

IADC - International Association of Drilling Contractors

RPM – Revolutions per Minute

TSP - Thermally stable PDC

MSE - Mechanical Specific Energy

BUR – build-up rate

PDM – positive displacement motor

MW – Mud Weight RKB – Rotary Kelly Bushing

MSL – Mean Sea Level

MD – Measured Depth

TD – True Vertical Depth

LWD – Logging While Drilling

MWD – Measurement While Drilling

WOB – Weight on Bit

WBM – water based mud

PDC - polycrystalline diamond compact bit

TCI - Tungsten Carbide Inserts bit

DST – Drill Stem Test

NCS - Norwegian Continental Shelf

PV – Plastic Viscosity

1. INTRODUCTION

In this master thesis we analyzed how the rate of penetration can be affected by different factors of the drilling process and how it can be optimized to obtain as high ROP as possible without losing of drilling efficiency, quality and providing the highest safety standards. In several chapters of this thesis we discussed how ROP is related to the type of the directional drilling method and to the type of tools used during drilling, how the drill bit choice affects ROP, how hydraulic and mud parameters may influence ROP and finally how ROP may be related to well path of the well. In the last chapter, ROP model has been developed with consideration of all the information from previous chapters.

In the second chapter of the thesis detailed analysis of the three directional control technologies currently available in the market is provided. Steerable mud motors, targeted bit speed systems and rotary steerable systems. The main objective of this chapter is to show what the difference between these three technologies, what advantages and disadvantages they have and how these technologies can affect ROP. For every technology there is separate subchapter with several sections where technological and operational aspects of technologies are described. Second chapter includes two case field studies where real drilling data from several wells provided and analyzed.

In the first field case we compare TBS technology with conventional mud motor steering technology. For this case 13 similar wells from the same oilfield have been chosen, 8 drilled with TBS method and 5 drilled with conventional method.

In the second case we compare RSS technology with conventional mud motor steering technology. For this case 18 similar wells from one oilfield have been chosen, 13 drilled with RSS method and 5 drilled with conventional method. Drilling parameters from these wells analyzed in the same way like in the previous case.

In the third chapter we analyzed factors of BHA construction and its characteristics that may affect ROP. Special attention provided to drill bit characteristics and MWD system properties. In the section related to drill bits researched effect of bit design and its wear on ROP. Field data provided which shows how important to choose proper bit design for every particular case.

The fourth chapter analyzes effects of the well path design on ROP. In this chapter several types of well paths considered and description for optimization of typical drilling intervals is provided. Also, in this chapter effect of build rate or DLS is researched. For this research drilling data from six wells has been used. Again, all wells were from the similar environment.

In the fifth chapter we considered properties of drilling fluids which can influence the ROP. In this chapter next properties are analyzed with relation to ROP: density, viscosity, mud filtration, solids content and lubrication properties of the mud. In every subchapter provided detailed information about ROP and mud properties relation.

The goal of the sixth chapter is to summarize the data obtained from previous chapters and provide a ROP model with reasonable accuracy comparing to real drilling data. For ROP simulation in this chapter three wells have been chosen. Multiple regression analysis of drilling parameters from these wells has been applied. Drilling variables have been obtained and drilling model has been developed.

2. MUD MOTORS, RSS, TBS

2.1. Mud motors

2.1.1. Introduction into mud motors

Well drilling and directional drilling in particular is the vital part of the modern oil and gas industry. Over 50% of all money spent on oilfield development is the money used for well drilling and well completion operations. Directional drilling used to wide range of purposes including offshore drilling from platforms, facilitation of oil reserves under environmentally sensitive areas such as national parks, increasing filtration area in a pay zone by drilling horizontal wells thus enhancing production rates from these wells and also allows multilateral completions and geo-steering.

First directional oil wells were drilled in 1933 in the California [1]. Soon after that, directional drilling started in the Gulf of Mexico offshore waters. Such wells were mainly drilled by using technologies and tools like whip-stocks or jetting to provide deviation of the well trajectory in the preplanned direction from the beginning. After that some level of control for well paths was achieved by using bottom hole assemblies (BHAs) with several stabilizers designed in the way to provide passive control for well trajectory without possibility to change the direction during the drilling process itself.

In 1962 the first system based on using a mud motors with positive displacement and bent subs was introduced which provided the first opportunity and practical capability to start developing an offshore field from an offshore platform. The system for directional drilling with mud motor was introduced in the California and soon begins to spread on the oil rigs of Gulf of Mexico. Eventually, it evolved into the modern steerable motor systems that are widely used all around the world today [2].

Most of the early directional wells have been drilled by a simple “S” shaped or “J” shaped (also called “build-and-hold”) trajectories. By utilizing such kind of trajectories well may be kicked off with the mud motor with bent sub, after that BHA could be changed on the rotary type and drilling process can be continued in a rotary mode. The main goal for such well paths was not the precise drilling to the chosen target but the displacement of the final bottom hole coordinates from the initial coordinates of the top of the drilled well to some preplanned target area. In case of necessity of further corrections in trajectory’s inclination angle and azimuth it was necessary to make additional trip-out of the rotary BHA and then run-in the hole a BHA with bent sub mud motor to carry out sliding with this motor and change direction of drilling to desired one. Usually, BHA with mud motors were run in for some short distance and then it was run out of the hole and replaced with rotary BHA again. So, maintaining the precise control for trajectory was a quite hard expensive and not very practical process [3].

Bent sub mud motors were used for directional drilling only in correction runs until the end of 1980’s. In 1985 the steerable motors technology was introduced. This technology dramatically increased the effectiveness of directional drilling by providing the opportunity to control the well path while drilling without additional runs. In the same time, other technologies increasing the efficiency of well path trajectory control were introduced which greatly improved capabilities of directional drilling. Applying BHAs with MWD systems and steerable motors provided to the industry the possibility to drill more complex and more prolonged well path trajectories.

Horizontal wells were found to be an efficient way of enhancing production from certain types of reservoirs. 3-D seismic technology began to give resource managers the ability to define much smaller and more complicated reservoir traps. LWD capability provided the ability to evaluate the formations as the well was being drilled. This ultimately led to geo-steering that allowed the wellbore to be guided based on real-time measured formation parameters rather than simply relying on a predetermined geometrical trajectory.

Today, most of the directional wells drilled with using of a steerable mud motors. This type of bottom hole assembly uses a fluid power and bent sub to apply some hydraulic pressure to the drilling bit, so that it becomes possible to drill in the wanted direction with necessary dog-leg severity. The directional control or steering is provided by sliding operations. In the process of sliding the drill string is oriented in some particular direction called tool-face direction. During sliding only drilling bit is rotating by the hydraulic power of mud motor while the rest of the drilling string stays without rotation. Innovations in mud motor's construction, materials and technologies of its application continue to be one of the important questions in the drilling industry for more than 50 years now. Steerable motors have become one of the most effective and reliable tools by which effective directional drilling process can be provided. Another important trait of mud motor application is its low price comparing to other directional drilling tools such as RSS. In total, drilling motor today is an effective, reliable well tested and relatively cheap tool for directional drilling control.

ROP of drilling with motors is both a strong and a weak trait for the mud motor – depending on some particular circumstances. Directional control by carrying out sliding operations can be a quite slow process - ROP can be twice lower than in rotational mode. Though the total rate of penetration for one BHA run usually still is substantial enough because most of the time we don't have to slide and apply slide mode only to correct well path while drilling. After correction with sliding is completed, it is possible to continue drilling a straight section in rotational mode with higher ROPs. In rotational mode mud motor provides additional ROP because in this mode hydraulic power from motor and rotary power are combined thus providing higher horsepower values at the drilling bit on the bottom. This advantage of mud motors means that in other competing technologies such as RSS the similar principle of hydraulic energy use must be applied in some way. Otherwise, ROP of drilling long sections with trajectory's parameters stabilization will be higher with steerable mud motors due to small amount of direction corrections or absence corrections at all [3].

2.1.2. Mud motors construction

Drilling mud motors consist of five major elements:

1. Dump Sub Assembly
2. Power Section
3. Drive Assembly
4. Adjustable Assembly
5. Bearing Section (Mud Lubricated or Sealed)

The gear reduced type of mud motor may also contain a gear reducer assembly located inside the bearings section. Some motors have mud lubricated bearings sections.

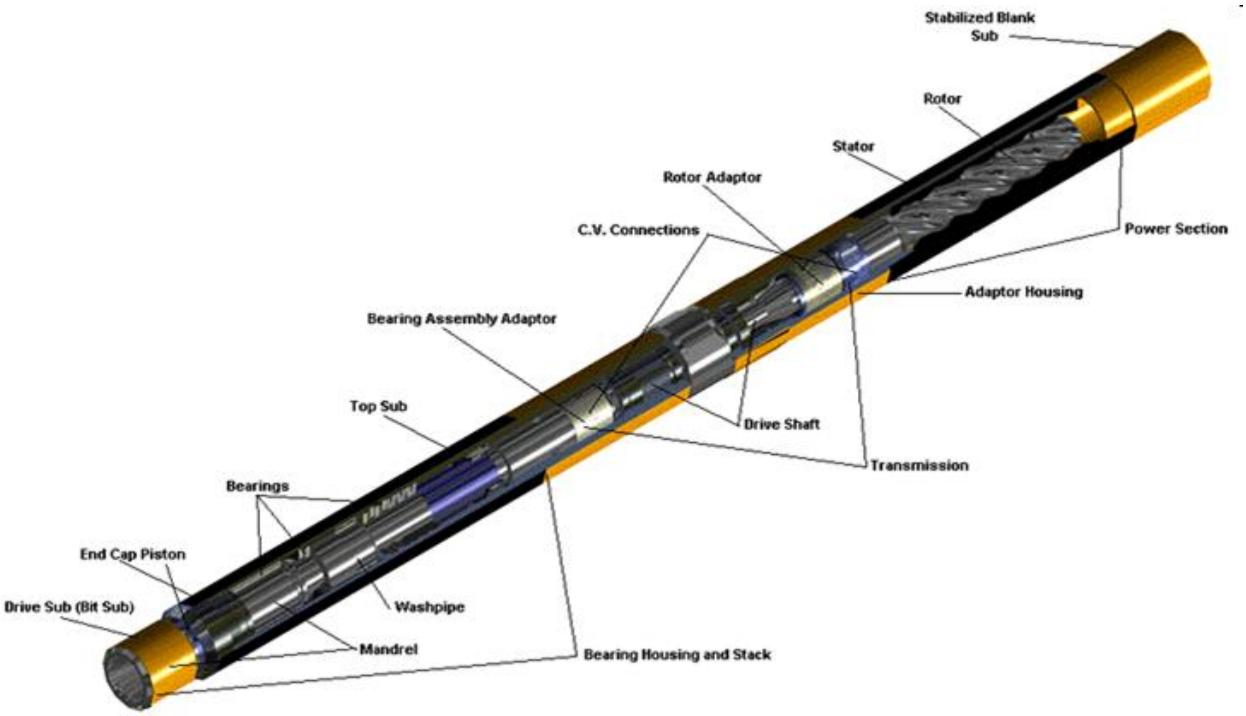


Figure 2.1. Mud motor construction dump sub assembly

Dump sub assembly is used to prevent problems with pressure and wet trips. The assembly is activated by hydraulic power. The main element of the assembly is the valve at the top side of the mud motor. During RIH operations it allows to fill the drill string with mud as well as drain the string during ROOH operations. When the drilling pumps work, dump sub valve automatically closes and drilling mud flows through the mud motor [5].

- Power Section

The power section of mud motors is an adaptation of one of the types of hydraulic pumps with positive displacement. Basically, power section can convert hydraulic power of the drilling mud flow into mechanical horsepower of the drill bit.

There two main components of the power section it is the rotor and the stator. The stator is a metal tube (typically steel tube) that contains inside it some elastomer bonded to it walls. The elastomer has lobes of helical pattern on its body. The rotor is a helical steel rod with lobes that fits the pattern of the elastomer. When the stator and rotor are assembled together it become possible for drilling fluid flowing through the mud motor to provide some pressure drop across the lobes and cause the rotor stem to turn around inside stator. That's the basic pattern of the mud motor work.

Output characteristics of the power section are dictated by the length and pattern of the lobes. The fundamental feature of the design for any stator and rotor that rotor always has one less lobe comparing to the motor. Illustrations in Figure 2.2 show different lobe cross-section from 3:4 to 9:10 lobe-ratio. Generally, when lobe-ratio is lower, the motor rotation speed is higher but the torque on the drill bit is lower [5].

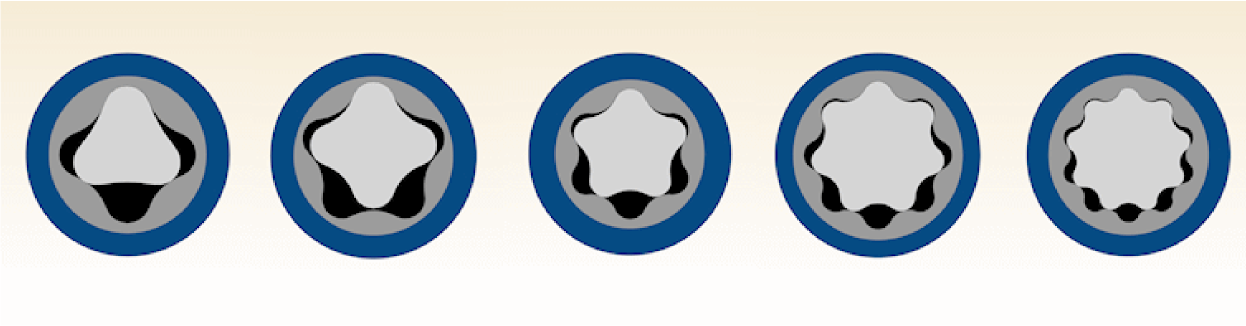


Figure 2.2. Stator and rotor cross-sections

Another characteristic of power section is its length. Power sections can be described by amount of stages. One stage is a one helical rotation of the stator. A power section with three stages contains one more full helical rotation comparing to a two stage. The pressure differential on the power section becomes greater with more stages included which provide higher values of torque.

These characteristics are used to vary the characteristics of mud motors. It is possible to change power section on one motor to change its characteristics.

- Drive Assembly

Drive assembly is utilized to compensate eccentric rotation of rotor inside stator and convert it to concentric rotation. The drive assembly main elements are the drive shaft and drive joints connected to the shaft’s ends. These joints are modeled to withstand the torque high magnitudes of the power section [5].

- Adjustable Assembly

The adjustable assembly allows setting the mud motor dog leg build rate from 0 to 3 degrees. This design provides the opportunity to vary build rate of the motor for every particular drilling case depending on the well path. Wear pads are located below and above the adjustable assembly bend to minimize adjustable components wear [5].

- Bearing Section (Mud Lubricated or Sealed)

The bearing section includes bearings (thrust type and radial type) and bushings. They are used for transmission of loads to the drill string from the drill bit. The bearing section may contain oil filled, sealed, mud lubricated or pressure compensated assemblies. Bearing in the sealed assemblies are not interacts with drilling mud and as mud flow is not used for lubrication, all of it can be directed straight to the drill bit thus maximizing its hydraulic efficiency, providing better bottom-hole cleaning and as a result longer drill bit life and increased ROP. If bearing are mud lubricated then 4-10% of the mud is used to lubricate the bearings. The mud then exits directly above the drill bit to the annulus [5].

2.1.3. Mud motor technologies

Impossibility of providing trajectory corrections with steerable motor while rotating is a main drawback of this technology. Another drawback it is the inability of a mud motor to drill straight sections without carrying out corrections by sliding time to time. When the tangent sections drilled with higher ROP begins to deviate from its course, it becomes necessary to apply sliding corrections decreasing the ROP and consequently increasing the cost of drilling. These issues have been considered and as a result different types of motors that can provide high level of stabilization in tangent section have been developed. Thus the need for sliding operations in tangent sections was decreased. Eventually, adjustable gauge stabilizers (AGS) have been introduced. AGS became valuable in a variety of situations by allowing correction of well path while rotating a whole drilling string with drilling motor. Although, the AGS has one serious drawback – it may provide corrections only in two dimensions, up or down thus it is impossible to control azimuth direction by means of AGS without sliding. However, it is still possible to avoid considerable amounts of sliding by applying AGS, in some cases sliding can be avoided at all. Another benefit of the AGS is a high reliability of operations with this tool and relatively low cost of AGS. Additional reliability is achieved considering the fact that AGS and mud motor are separate BHA units. Thus, if AGS fails it is still will be possible to steer the wellbore according to the planned trajectory by sliding with mud motor if it will be necessary [35].

2.1.4. Mud motor control techniques

Using a bent sub mud motor to drill tangent sections is comparable in some way to using the older rotary BHAs which were often used for directional drilling in the past. Upper stabilizers (usually 1 or 2) placed above the mud motor in the assembly will increase drop rate and stabilizers placed below the motor close the drill bit will increase build rate [6]. But if we will look closer at the rotation principle of a bent sub motor assembly, we will see a much more complex applications of oscillating lateral drill bit forces. These forces vary as the drill string with mud motor bent sub is rotated. These forces have the net effect of stabilization, building or dropping trajectories just the same way like their rotary assembly counterparts. Though, differently from their assembly-predecessors, the forces applied to the drill bit are changing seriously within one rotation of a drilling string and discontinuous in general.

AGS used to be the one of the common methods to control inclination while using a rotating assembly with a mud motor. AGS typically installed above the mud motor, work by the principle of applying continuous force on the drill bit in the given direction, but only up or down. This principle is very similar to principles how some of the rotary assemblies work on dropping or building intervals. One of the advantages of AGS is that the AGS stabilizer diameter may be changed while BHA is down on the bottom, thus there is no need in additional ROOH operation. Every time when bent sub is in use near the drill bit, forces are applied to the drill bit in lateral directions while rotation happens. So, rotating the motor with bent housing is not similar to a rotary assembly movements – the process may be described as periodical.

The motor bent sub points down, and the stabilizer is used above such motor. We can sum and resolve full string rotation of these forces in some final direction which may be called the net drop.

When the AGS is in retracted position, the collar placed above the mud motor typically may lie on the bottom-hole and the collars weight has to be lifted if the motor bent sub with a bit pointed upward. In such configuration the drilling bit usually builds angle in periods when lateral loads applied to the bit. If the motor bent sub position points down, it adds some distortion to the drill string. The final direction of rotation of the drilling string is upward. Lateral loads may vary functionally depending on orientation of the motor bent sub or tool-face. If collars near the bottom-hole, the drilling bit tends to be leveraged in the upward direction. To sum that up, we may say that the drilling bit below a motor bent sub undergoes different periodic variations in forces (lateral forces) and the net effect of these variations (drop or build) may be controlled by means of changing the stabilizer's placed above the motor bent sub.

The necessity to steer a mud motor along the given well trajectory may be duplicated by varying other drilling parameters within a single bent sub rotation, if this variable (a) was powerful enough to influence a change in the motor drilling direction and (b) could be accurately triggered to occur at any bent housing angular position as the string is rotating. Using of an AGS is one of the methods to accomplish it [7]. By application of periodic lateral loads to the drill bit, the drilling collars work against the pull of gravity, resulting in an upward force.

2.1.5. Mud motor problems

Although, in many cases it could be favorable to carry out directionally oriented drilling with hydraulic steerable mud motor, there are some cases and situations where mud motor cannot be applied in an efficient way. In some particular applications, carrying out a well path correction with a steerable motor may become a slow and expensive process. For example, if the trajectory is complicated and corrections must be carried out by sliding of relatively long intervals through abrasive or hard rock, this may subsequently lead to considerably lower ROP on extended time periods. Eventually this even can lead to a complete impossibility to continue directional steering. In such situation, mud motors may be abandoned in a favor of other rotary systems which can deliver trajectory deviation without stopping rotation of the drill string. Though, it worth to mention that such rotary steerable systems are often much more expensive and usually not so reliable like mud motors, they often may become the only possible mean of cost-effective directional drilling process.

2.1.6. Steerable mud motors operational and technological aspects

Many constructive and technological improvements have been suggested and provided for the directional mud motors since its first introduction. There are several important milestones of this evolution Figure 2.3.

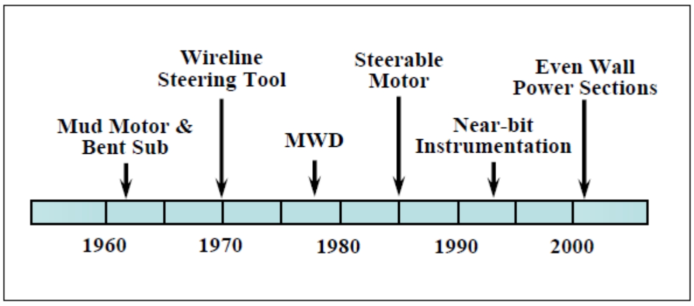


Figure 2.3. Technology to improve the performance of positive displacement directional motors has steadily improved.

<u>Steerable mud motor’s advantages</u>: mud motors are used with MWD systems to control the well path in real time. It’s cheap and widely available in different sizes and characteristics. Also, these tools are easy to operate and maintain, there are relatively few amount of moving parts and level of reliability is quite high [9].

<u>Fundamental limitations for motors</u>: steerable mud motors are better suited for building simple well trajectories. Motors have limitations affecting their ability to maintain the proper level of directional control in some particular environment.

Drilling with mud motors is divided by intervals of sliding. On these intervals trajectory is guided in preplanned direction while during periods of rotation there is no active trajectory control. Problems related to this are grouped in Table 2.1. The ROP is usually reduced during sliding by 40-60% and at some depth it may become impossible to continue effective sliding.

Bulk part of inefficiencies and limitations are related to the fact that the well is needed to be drilled without rotation of the drilling string or with technical limitations of the mud motors including rotation limits for particular dogleg values. Upgrades of the mud motor construction and parameters cannot solve many of the problems since these problems are based on the fundamental steerable mud motor characteristics.

Common sliding problems	**Common Rotating problems**
Inability to slide	Vibrations (motor failures, MWD failures)
Maintaining orientation	Accelerated bit wear
Poor hole cleaning	Poor hole quality logs
Limited bit selection	Poor performance in air
Low effective ROP	
High tortuosity	
Build rate formation sensitive	
ECD fluctuations	
Differential sticking	
Buckling and lock up	

Table 2.1. Deficiencies of steerable motor directional drilling systems

Steerable motors improvements:

- New power sections with higher performance that can deliver more hydraulic power to the drill bit.
- Drill bits with a special design to improve steerable mud motor performance. Such bits allow higher WOB while drilling with motors. Goal for other drill bit improvements is to provide better stabilization while drilling with steerable motors especially in sliding mode [11].
- Mechanical systems have been introduced to reduce friction especially while sliding. These systems provide energy to the string to reduce the frictional contact of the borehole wall and the drill string.
- Sensors for monitoring formation properties and inclination closer to the bit. This opens opportunity to geo-steering and provides drilling data that helps the drilling engineer optimize the performance of their tools [12].

Steerable mud motors in conjunction with MWD systems still capable to successfully drill most of the borehole types typical for modern oil and gas industry. These motors are also capable to drill some of the 3D-designed wells. However, it worth to remember that just because these motors can drill a well according to the planned well path does not automatically mean that using such motors is always the most efficient and cost effective method to drill it.

2.2. TBS technology

2.2.1. Introduction for TBS technology

Targeted bit speed technology has been derived from a conventional directional drilling with mud motor bent housing in a conjunction with some MWD tools. This technology has the similar advantages to RSS (rotary-steerable system) drilling, and allows full directional control in all three dimensions, without the need of quitting rotating for sliding operations. Steering of the drilling string is carried out by modulating the flow of the fluid inside the drilling string. This flow modulation creates small oscillations in the mud motor flow rate. This technology allows high-frequency variations in parameters of drilling to control drill bit speed which meantime allows steering the well in any target direction. In some cases the planned DLS cannot be achieved by means of TBS drilling technology, so in such situation it is possible to use the motor in a conventional way – it still can be oriented in the target direction and sliding can be carried out using standard steerable mud motor techniques for directional drilling [14].

The primary goal of the targeted bit speed (TBS) method of drilling is the repeatability of a drilling speed modulated in some particular direction of drilling. The rate of penetration (ROP) of the bit must be controlled with precision so each segment of arc of string rotation is divided with the same variations of speed throughout drilling string rotations. To carry out consistent and precise ROP target boundaries, the lowest and highest drill bit speeds are targeted at the same tool-face values, with every revolution of the drilling string and motor bent sub. Drill bit speed modulation repeatability will equate a ROP modulation with high level of precision which in its turn should maximize the efficiency of this method. If the targets start to vary and become inconsistent and not clear, then the outcome well bore trajectory direction will be changed after of each rotation and the tendency of direction build will become unpredictable and wandering between different tool-face values.

High quality of the well path is a vital property to consider optimizing performance of any tool in the drilling string and BHA. Well path shape and borehole size seriously effect drill bit loads especially when stabilizers enter in the sections with unstable parameters of borehole trajectory. Such factors impact negatively on the steerability of the BHA in what could otherwise be a properly controlled drilling environment. It is especially important when chosen drill bit does not suit well to chosen mud motor. In such situations fluctuations in drill bit load may occur.

Bits with gauges of longer length have shown considerably better building rates, better well path and borehole quality and better directional drilling control than drill bits with short gauges in multiple cases. Testing shows that, by means of proper drill bit stabilization, mud motor assembly which employed by the targeted bit speed (TBS) method could definitely provide a high quality trajectory of borehole without ledges and other negative factors [8].

In this chapter we will research the real field results from the several wells, where TBS technology has been used to drill wells with S-shaped well paths. S-shaped trajectories are some of the most challenging for drilling with continuous drill string rotation and bottom hole assembly with a steerable mud motor because it is necessary to drill the curve section, provide a firm hold of the angle in the tangent section and then drop the borehole angle by using the same drilling tools. Such concept of one single BHA for drilling whole well was not possible before the TBS technology has been introduced. This chapter is focused on the possible improvements that can be achieved in the directional control and in the resultant ROP by using the TBS method.

2.2.2. TBS technology basics

Targeted bit speed (TBS) is one of the periodic steering methods. TBS method employs an oscillating flow rate applied to the mud motor with bent sub to provide a well path control while drilling with rotation. Timing flow rate changes to some specific predefined bent-housing tool-face, so it becomes possible to drill well paths of any complexity. Flow variations is a cause for small differences in the axial drilling rate and when combined with a motor bent sub, the drilling bit drills actively further toward the target direction. These flow differences are applied continuously to the same position of the angle of the mud motor bent housing. Drilling string rotated such way that any 3-dimensional well path may be chosen by the drilling engineer. In some ways, this method is quite similar to the method of sliding by intervals of the drill string, but the highlight is that we do not have to stop rotation of the drilling string to provide the well path control during drilling. Instead, drilling string rotates continuously with the same speed while the drilling bit speed alone changes depending on the angular position in the hole [15].

The periodical flow is accomplished by application of simple fluctuations of pressure within the drilling string which is generated by a telemetry device (MWD system). Pressure pulses typically are timed to a mud motor housing position. Such pressure changes manage oscillations of the fluid volumes entering the drilling mud motor so the rotation bit speed can be varied as a tool face's function. It allows the mud motor to drill through a disproportional volume of rock at the specific tool-face segment in the hole thus causing the well path to follow in the higher bit speed direction.

The mud motor bent typically equal to 1.15-1.5 degrees at the adjustable mud motor bent sub and the borehole trajectory is curved down to the right (Figure 2.4). It is the typical borehole and mud motor position if the mud motor slides in a downward well path. In such situation the drilling bit turns round while the motor bend holds it toward particular side of the borehole or tool-face. As well as, when we use TBS, the angular position at which the drill bit speed should be maximal if the string is continuously rotated. The mud motor can be rotated 180 degrees from the planned well trajectory (Figure 2.5). In such position, mud motor speed will be minimized while the TBS method is applied. As we repeat the sequence, it is become possible to maintain inclination angle drop of the trajectory [15].

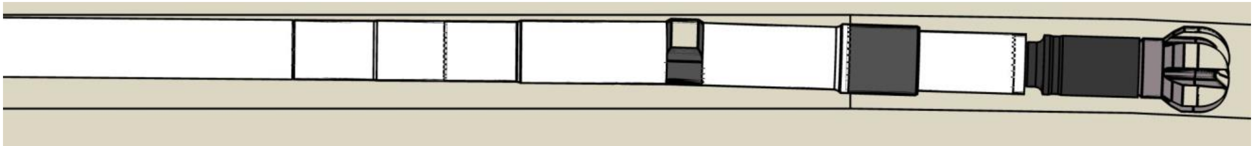


Figure 2.4. Rotated motor pointed in the direction of borehole curvature

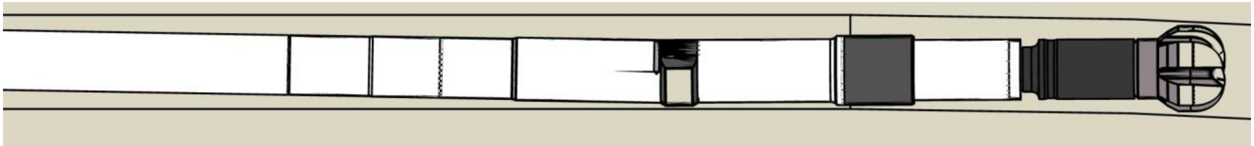


Figure 2.5. Rotating motor pointed against the direction of borehole curvature

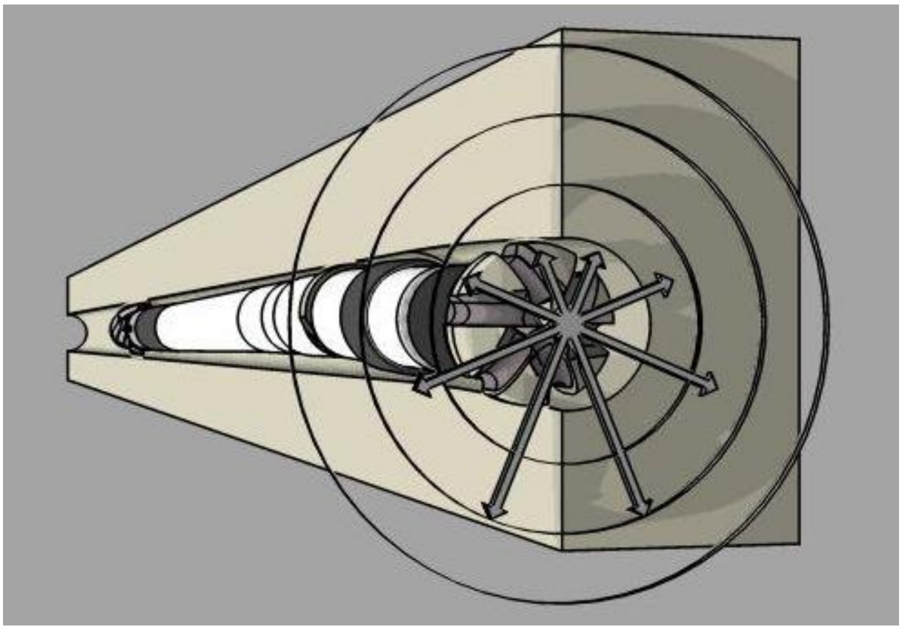


Figure 2.6. Bent sub and motor shown dropping inclination using upper stabilizer

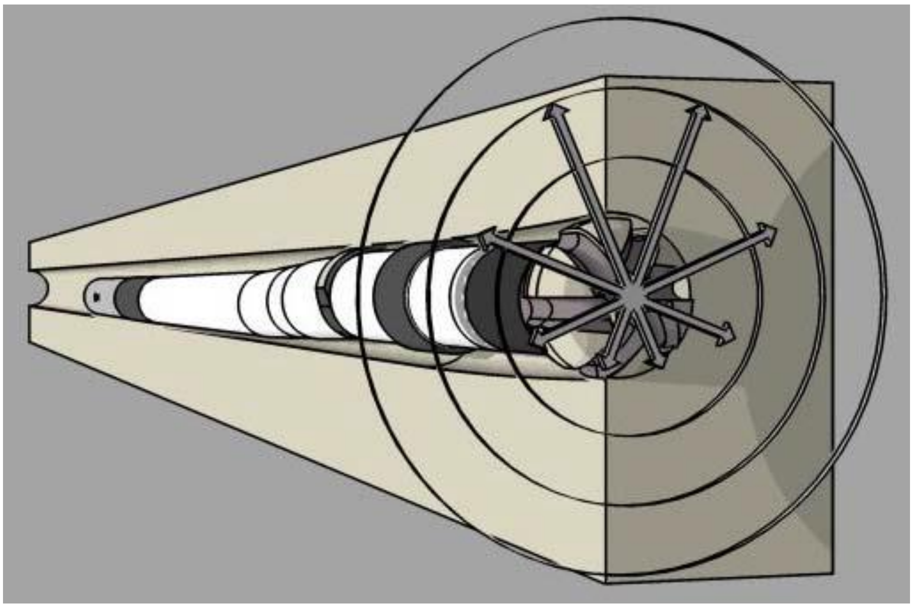


Figure 2.7. Bent sub and motor shown building inclination without using upper stabilizer

Considering the different applications of the rotary BHA principles in the way they are typically applied to motors with bent housing, we may say that method of periodical variations of some particular drilling parameters as a tool-face function is not totally a new technique; although, TBS applies such pattern to provide control on trajectory in 3-dimensions instead of two dimensions. Thus, this technology has all the benefits of proven products like RSS technology while the cost of drilling is lower.

TBS method was invented and tested in the USA. It was quickly accepted as a low BUR assist tool. Original tests confirmed that small drill bit sizes show higher build-up rates (BURs), when larger drill bit sizes show lower BURs in the same environment. For example, a 4.75 inch TBS tool with a 6 inch drill bit can provide build-up rate around 2.5 - 3.0 degrees per 100ft. Larger

TBS tool sizes, like 8.5 inch tool with 12.25 inch drill bit for instance, can achieve BUR equal to 0.5 - 1.0 degree in the same environment [16].

Applications of TBS method [14]:

1. Control of TVD (Vertical control)

2. Drilling horizontal sections

3. Hold of the angle in tangential sections

4. Drilling wells with S-type trajectories

TBS method is especially effective for tangential and horizontal intervals, where it is necessary to hold the current angle only correcting it time to time. Low build up rates are very helpful in such situations and can provide very high precision of drilling [16]. Long tangential sections as well as horizontal tangential sections are difficult to drill with a hold since the drill string is fighting geological and other natural tendencies which can lead to a natural angle build, drop or turn in any direction, and sometimes geology can severely affect the drilling tendency. Wells with a S-type trajectory are one of the most complicated cases for applying TBS method, since the same BHA has to be used to drill all of the wellbore sections – vertical section, build section, tangent section, drop the angle section and finally a vertical section again. In the process of drilling all of these sections proper directional drilling control for azimuth and inclination should be provided while continuously rotating. Though, in some situations it is possible to provide some amount of sliding. But if the amount of sliding will be too high then it may be assumed that applying TBS technology on the particular well was failed.

2.2.3. TBS method advantages

1. TBS system effect easy to prove. Thus this technology became commercially successful relatively fast. The technology provides combination of accurate directional control with using MWD systems and the PDM hydraulic horsepower which guarantee high level of reliability, measurement capabilities and drilling effective capacity. TBS method and related technologies used in conjunction with this method are well understood by specialists in the oil industry. TBS drilling concept is easy to grasp by both office and rig-site personnel even if they have minimal experience. Minimal theoretical explanation and technical experience are required [14].

2. TBS method allows the full 3-dimensional directional control with continuous rotation of the drilling string [16].

3. Since the fact that TBS method uses a conventional mud motor with a bent sub in its typical BHA, it can be used for steering while drilling by carrying out drilling in sliding mode to control azimuth and inclination of the. Actually, it could be the biggest advantage of targeted bit speed method [14]. The directional driller can stop TBS drilling in any point of time and start to steer the drill string in a conventional way by orienting mud motor in the hole and drilling by slides. Sliding operations during TBS drilling are usually carried out when planned DLS cannot be achieved only by means of TBS technology.

4. The ROP is considerably increased due to the lack of slides and continuous drill string rotation in combination with additional hydraulic horsepower from the mud motor. This significantly increases the hydraulic power at the bit even comparing to RSS drilling [14].

5. There are two possible ways to control direction of the drilling for TBS method from the surface. The first one is sending hydraulic pulses by changing pump flow rate during short periods of time. The second one is sending some RPM sequence by changing rotation rate of the drill string [14].

6. Design of the TBS system allows transmission of formation evaluation in the same time with the process of directional control [14].

7. Large experience of using and repairing mud motors and MLWD systems in general guarantees good understanding how to maintain the TBS system providing high reliability of this system on the same level like it is for conventional sliding drilling. The tools are easy to transport and repair due to existed infrastructure and well defined methods of tool maintenance. Most of the TBS system elements may be transported by air, thus it is possible to use such equipment in remote operations and in offshore drilling [16].

8. Lost in hole situation's cost almost the same as it is for conventional mud motor drilling method. It is a big advantage comparing to the cost of loss for one RSS unit [14].

2.2.4. Comparing TBS method with conventional mud motor directional drilling method (case study 1)

2.2.4.1. Wells chosen for research

Chosen wells have been drilled on the same oilfield in the same area. Analysis of the drilling parameters on these wells can provide a great opportunity to gather the data about TBS method performance in a similar environment establishing metrics and research well-to-well improvements in performance. In this chapter of the thesis we will describe in details the drilling process of the wells using TBS technology and compare the data with several baseline wells drilled by conventional mud motor BHAs applying sliding modes. These baseline wells were selected with the purpose to represent a typical for considered oilfield well design and run performance in general.

All the wells were drilled using water-based mud with almost identical properties. The targets for the wells were placed in the same reservoir formations made up of dolomites, limestone and anhydrites. Before the TBS technology has been introduced, such wells were drilled by means of steerable mud motors and PDC drill bits. Sliding mode operations often was close to 30% of the total time of drilling. Typically, the rate of penetration in the sliding mode decreases on 50% and more from the ROP in rotating mode. Thus some reduction in time for sliding could result in a significant busting of the overall ROP making drilling process cheaper and faster.

2.2.4.2.Wells drilled with conventional technology with sliding intervals (without TBS)

Five wells chosen for comparison have S- or L-shaped well paths. Average measured target depth (target MD) is 3200 meters. Most of these well drilled in four or five bit runs. During the run 1 it is necessary to kick off and start to build angle. Average angle needed to be achieved is 21 degree. This angle will be then held during the tangent section drilling. During the runs number 2 and 3 tangent section is drilled. At the end of the tangent section it's necessary to drop the angle back to o degree. Drop angle is carried out during bit run number four. Additional runs are possible due to drill bit wear or other emergency situations like mud losses. Average rotor vs. slide ratio for selected wells is 84.3% / 15.7% on a metrage basis with an average ROP of 6.96 meters per hour (Figure 2.11, Figure 2.12).

2.2.4.3. Wells drilled with TBS method

For this case 8 wells have been selected. All of the wells drilled on the same oilfield with 5 wells drilled with using conventional mud motor sliding method. Wells consisted of a build angle section, tangent section, and drop angle section. Typically most of these wells drilled for three or four runs. During the 1st run drill string drills out of shoe of previous casing and then builds angle to 10-15 degrees after what drill string pulled out to change a drill bit. During 2nd run angle is built up to 20-25 degrees and then held with this inclination value during tangent section. After ROP gets significantly lower drill string will be pulled out for another bit change. During 3rd run there is usually a continuation of tangent section with angle hold. At some point drop angle section starts so the 20-25 degrees angle is dropped to vertical or close to vertical with values of inclination from 0 to 3 degrees. Drilling is continued to target depth. There are additional runs are possible most of all due to the drill bit wear or other emergency situations. Average interval length of continuous drill string rotation is 98.0%. On the figure 2.11 values of slide percentage are provided for every considered well.

2.2.5. Observations for TBS method

Although all of the wells have a similar construction and design and drilled on the same oilfield, there are considerable differences in ROPs and drilling times of these wells. Possibly, one of the explanations for such a difference is that the rig crews as well as directional drillers and MWD engineers became more familiar with technology from well to well thus improving efficiency of their decisions and actions and by this decreasing the amount of slide and increasing the ROP.

On a basis of separate drilling intervals, some improvements are recognized from well to well. For example on some wells with higher values of inclination angles total ROP is higher and slide percentage is lower than on other wells where inclination is lower. Percent of drill string rotation increased from 84.3% in the wells drilled with conventional method to 98.06% for well drilled with TBS method. Drilling rates of each of the TBS well show significant improvements (9.59 m/hr) comparing to the wells drilled with conventional technology (6.96 m/hr).

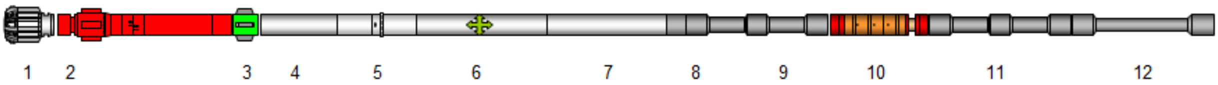
2.2.6. Conclusions/recommendations for TBS method

Targeted-bit-speed method allows effective continuous 3-dimensional directional drilling control for S-type and J-type trajectories of the wells.

Considering the fact that the selected wells with TBS as well as with conventional method were drilled with essentially almost the same types of equipment, same drilling parameters and mud properties, allowing us to provide consistent and clear analysis of efficiency of every method and evaluate advantages and disadvantages for it.

To utilize the full potential of targeted bit speed technology, it is crucial to improve mud cleaning system and provide a proper control for mud parameters.

ROP increased in all of the wells with TBS method applied. Percentage of sliding vs. percentage of rotating significantly decreased on footage and time basis. Average ROP for TBS wells significantly higher. Percent sliding decreased on 14.0%. Average rate of penetration has been increased by 27.5%. Also, several wells were drilled with TBS method with 0% of sliding which means that efficiency of TBS method on these wells is the same as for RSS technology.



BHA Description

#	Element Name	Length	Ø outer mm	ø inner, mm	ø max, mm	upper thread	lower thread	weight, kg	company
1	PDC Bit MDZi616 (Mi813)	0,32	220,70		220,7		H3-117	38,72	Schlumberger
2	Mud motor 6 3/4-7/8 CTK-215.9 1.5deg.	8,92	172,00		215,9	M3-117	M3-133	1386,52	NOV
3	Stab ЦЛ-212.7	0,97	172,00	52,0	212,7	H3-133	M3-133	176,54	NOV
4	NMDC - 172 Pony	4,40	172,00	80,0	172,0	H3-133	M3-133	639,85	WFT
5	IDS+PDS	1,10	172,00	76,2	172,0	H3-133	M3-133	159,96	WFT
6	MWD 6 3/4 HEL	9,46	172,00	83,0	172,0	H3-133	M3-133	1361,48	WFT
7	NMDC -172	9,43	172,00	83,0	172,0	H3-133	M3-133	1357,17	WFT
8	Safety sub	0,46	172,00	90,0	172,0	H3-133	M3-133	68,89	WFT
9	HWDP -127	108,00	127,00	76,0	168,3	M3-133	M3-133	8603,28	Дойтар
10	Hydaulic jar 6 1/2	9,53	165,00	64,0	165,0	H3-133	M3-133	976,44	NOV
11	HWDP - 127	108,00	127,00	76,0	168,3	M3-133	M3-133	8603,28	Дойтар
12	DP -127*9.19 (S-135)	2190,00	127,00	108,6	168,3	H3-133	M3-133		Дойтар
	BHA Length	260,59							
	Total length	2450,59					Total weight	23372,13	

Figure 2.8. Typical BHA for TBS drilling

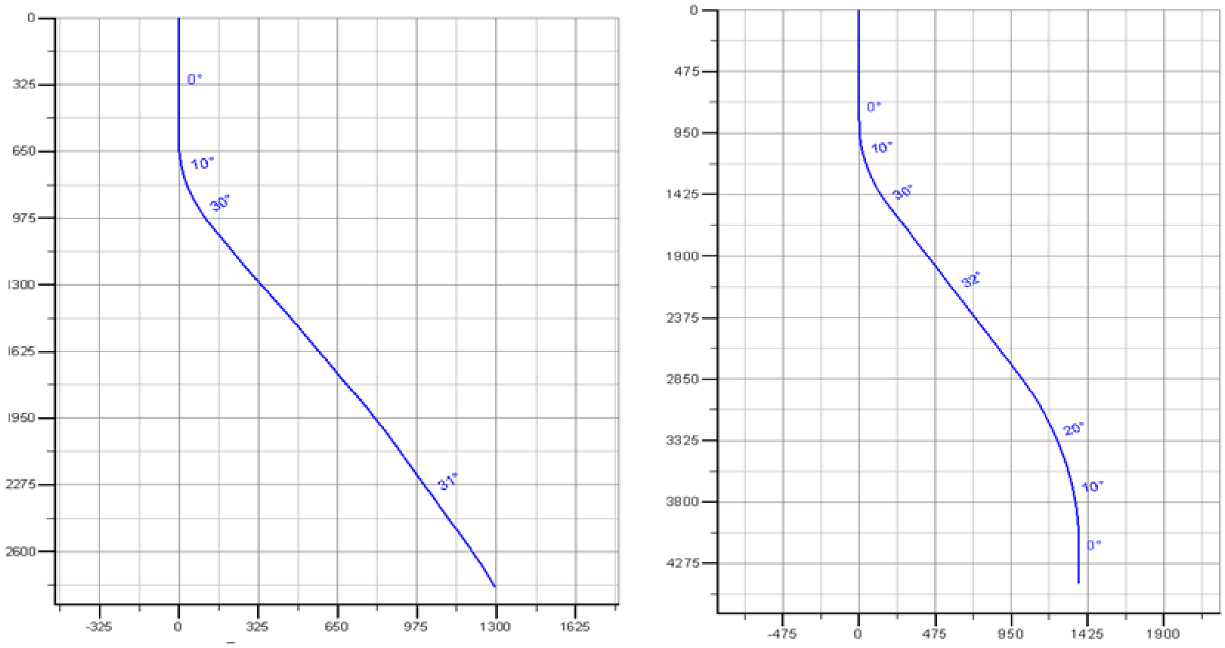
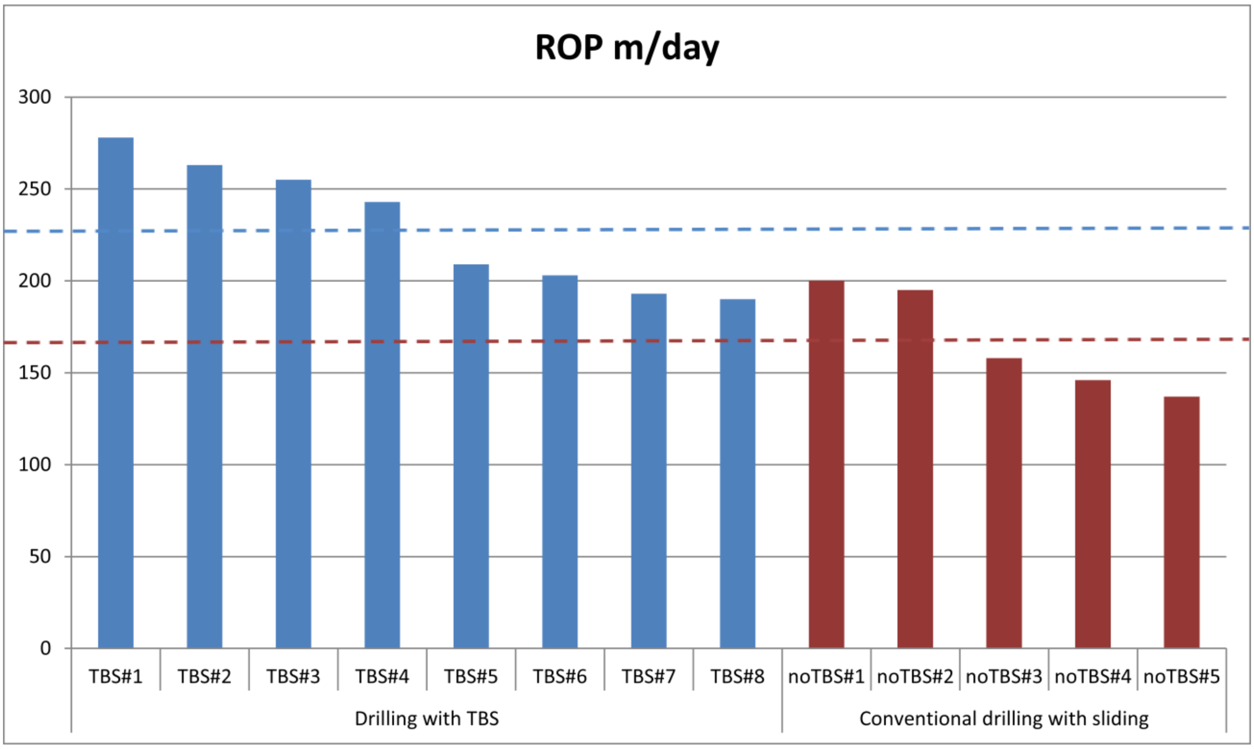


Figure 2.9. Well paths for some of the selected wells



average ROP with TBS - 229.3 m/day

avergae ROP without TBS - 167.2 m/day

Figure 2.10. Comparison of ROP (m/day) for wells drilled with and without TBS method

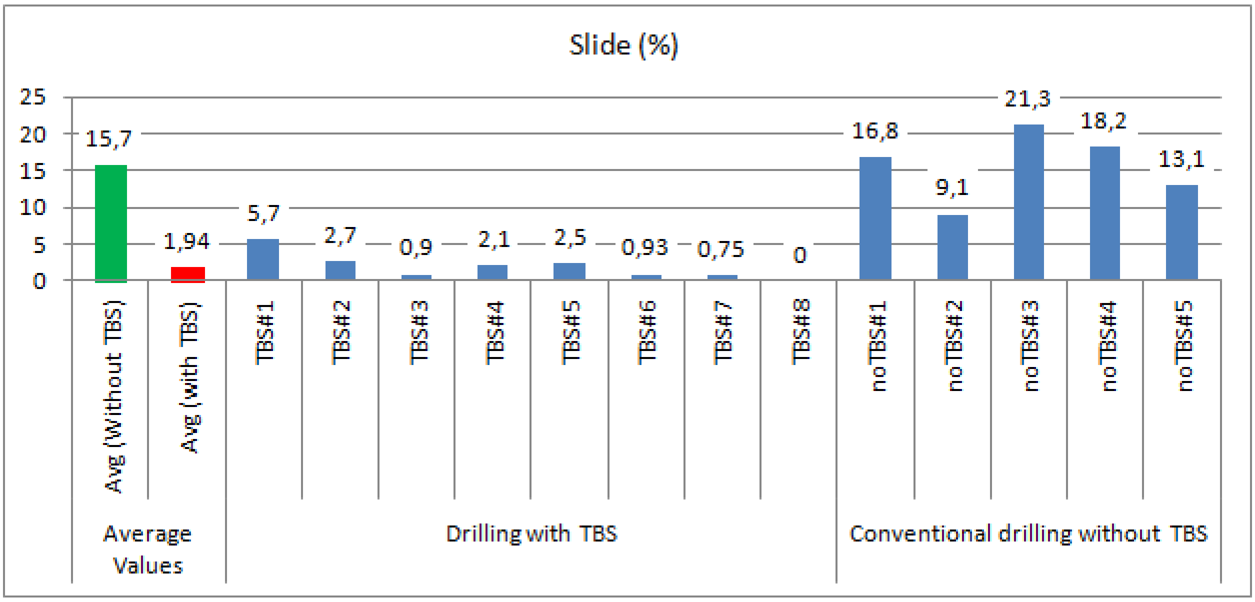


Figure 2.11. Percentage of sliding for the wells drilled with and without TBS method

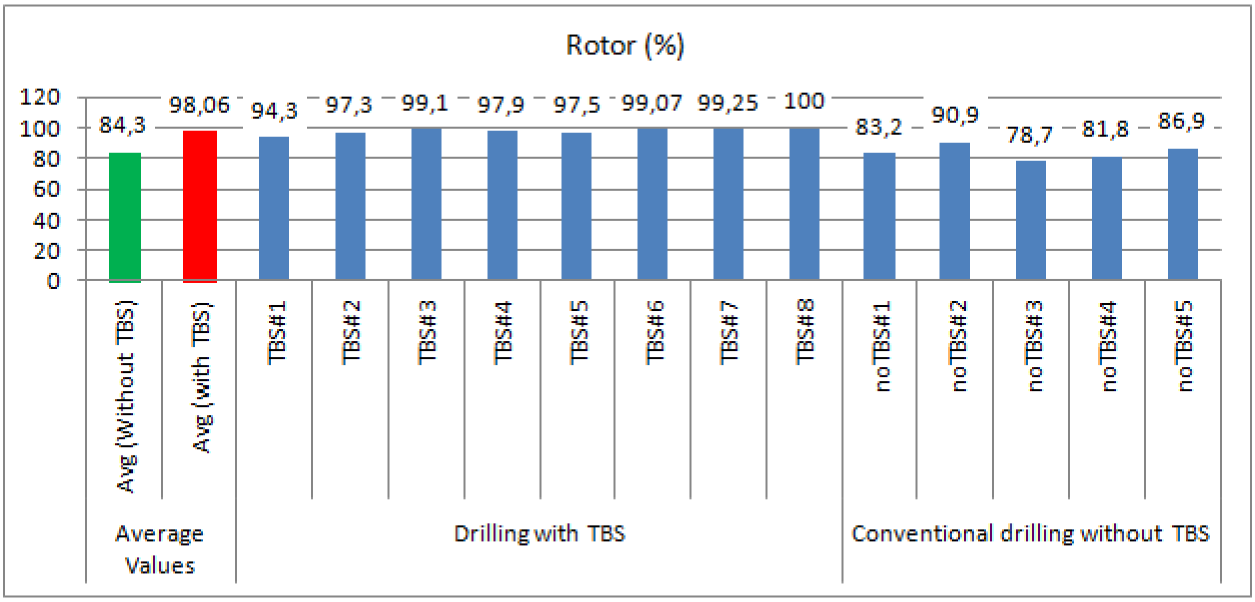


Figure 2.12. Percentage of rotating for the wells drilled with and without TBS method

2.3. Rotary steerable systems

2.3.1. Rotary steerable systems basics

Rotary steerable systems (RSS) can overcome some of the mud motor limits.

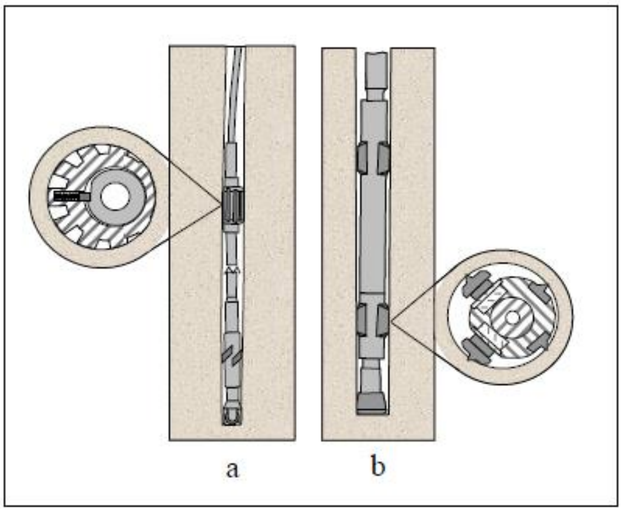


Figure 2.13. Early rotary steerable tool concepts

RSS are the directional tool that allows maintaining inclination and azimuth of the well path in the targeted direction while continuously rotating the drilling string. There are different concepts of rotary steerable systems today.

First mention about mechanical RSS can be found somewhere in 1960-s literature sources. The fundamental concept of these systems has lots of similarities to the modern rotary steerables. figure 2.13a shows a system concept created in 1955 [17]. This concept uses an eccentric non-rotating sleeve which allows directing the drill bit in a target direction.

Another system is shown on the figure 2.13b. This type of system was patented in the year 1959 [18]. This system used guide shoes activated by hydraulic power with stub near the drill bit to provide control for the trajectory in a manner that is quite similar to some of the modern types of RSS. The guiding shoe was powered by pressure of the mud flow and could be retracted or activated without ROOH operations. The main goal of creating such tools back there was to eliminate the necessity of additional ROOH and RIH operations for setting whipstock on the bottom.

There are much more examples of tools that were patented with the purpose of more effective directional drilling before steerable mud motors started to dominate the oil market. Tools provided directional control by pointing the drill bit or by pushing the drill bit in the target direction. Modern RSS tools are very similar to these first concepts. Though, none of these old steerable systems were successful commercially.

The early RSS tools were mechanical because such things common for the modern world like hydraulic MWD systems, downhole electronics, computers and control systems did not exist at the time of introducing RSS concepts. Work on RSS was abandoned as mud motor directional systems got widely accepted and commercially successful. The wide spread of mud motors as a directional control tool over the RSS concepts was related to the fact that mud motors can be oriented from much easier and more consistently than the RSS sleeves [3].

The lack of any success of the first RSS did not prevent the further research attempts in this direction. After almost 40 years of directional control by steerable motors, new wave of interest grew to the rotary steerable system concept due to the increasing complexity of well trajectories.

One of the reasons why RSS technology was resurrected after several decades of mud motors monopoly is growing necessity in drilling ERD wells. The capability of mud motors was not enough to meet the requirements of efficient and cost effective drilling of ERD wells. The horizontal limit for wells drilled by BHAs with mud motors was equal to 16,000 ft (almost 5000m). On the lower depths quality of trajectory control is significantly worse and direction control itself becomes much more complicated. RSS tools allow to increase lateral reach of the wells almost twice up to 28,000 ft. Direction control was also improved. Nowadays the maximum reach MD for rotary steerable systems is more than 35,000 ft [19].

Another area where RSS became highly appreciated is offshore drilling with its complex ERD horizontal wells with complicated geometries of well paths. Steerable mud motors are not suitable for some of such wells and most probably use of motors will not be economically effective even if it would be technically possible.

Figure 2.14 shows an example of the trajectory of the well that can be drilled with RSS system. According to the drilling program it was required to carry out 255 degree azimuth turn and hold the inclination angle value above 88 degrees. In addition it was necessary to provide strict anti-collision control due to the lots of neighboring drilled wells.

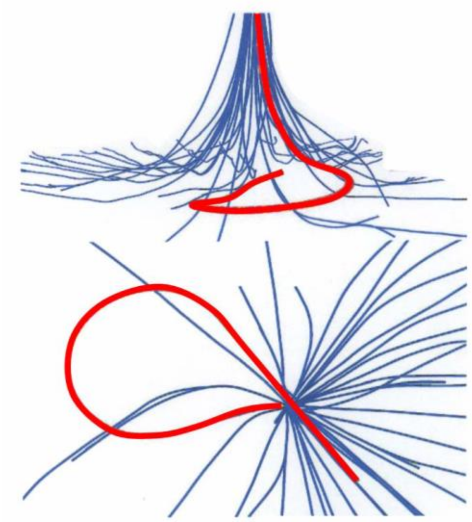


Figure 2.14. Well path drilled with RSS that could not be drilled with steerable motor

Extended reach wells trajectories are continuing to become more and more widespread because of the capabilities of rotary steerable systems. Drilling with RSS provides serious advantages making drilling of challenging ERD wells possible. These advantages will be reviewed in the next section related to RSS technological and operational aspects.

2.3.2. Rotary steerable system technological and operational aspects

In this thesis technological aspects of the rotary steerable systems will be reviewed on the example of Weatherford “Revolution” Rotary Steerable System.

Modern rotary steerable system designs were introduced to the industry in the early 1990’s. Two basic RSS concepts currently exist. The first one is “push-the-bit” and the second one is “point-the-bit” concept. Pushing the bit method refers to exerting lateral side force applied on the drill bit during drilling process. Pointing the bit is more complicated from the technological point of view and involves bending the BHA so that the drill bit is pointed in the planned direction. Point-the-bit is generally considered as being superior to push-the-bit concept, resulting in smoother well bore trajectories with increased dogleg capabilities [20].

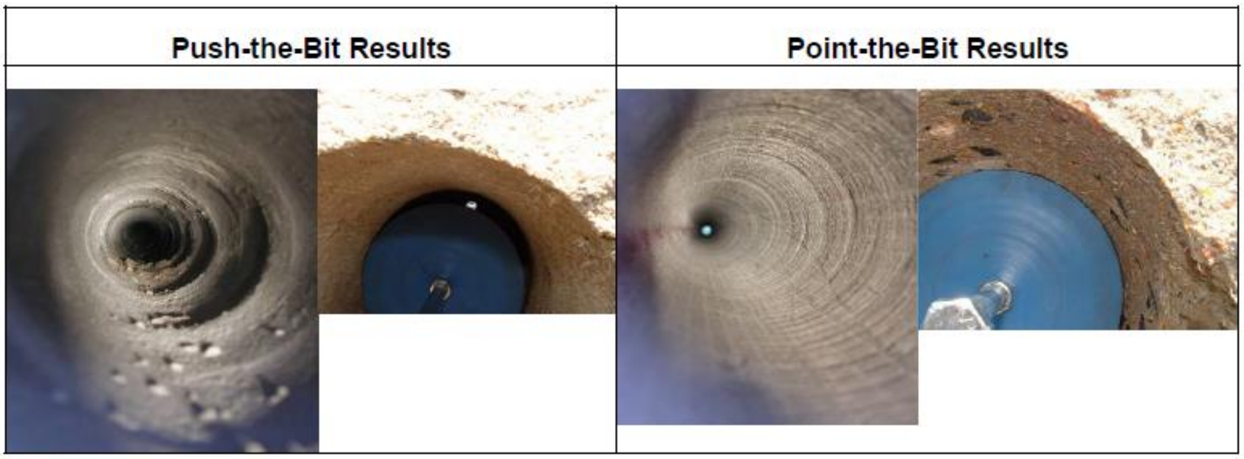


Figure 2.15. Comparison of push the bit and point the bit technologies

RSS development was driven by the technological opportunities and economic advantages which could be acquired due to steering the wellbore trajectory while continuously rotating the drill string. Operator’s demand was driven by the growing difficulty of well profiles, some of which were not possible to drill using only conventional steering systems available at this time. There are advantages provide by applying RSS in the directional drilling process [20]:

- Save time spent on aligning of tool face while steering with motor; the RSS tool controls it automatically.

- Over 50% increase of total ROP while rotary drilling instead of sliding with a mud motor.

- Improved hole cleaning which results in a higher consistency of ECD values comparing to steering process with a mud motor.

- Drag is significantly reduced comparing to motor sliding. The result is a more consistent WOB and reduced stress on down-hole equipment.

- Less possibility of the drill string stuck if it's rotating most of the drilling time.

- Deviation rate is more consistent because there are no changes in drilling modes between sliding and rotation for producing the required DLS.

- PDC drill bits with more aggressive designs can be applied and optimized for ROP performance, rather than a balance between ROP performance and ability to control tool face while using a mud motor.

- Well profiles are smoother, without transition ledges resulting from changes between sliding and rotating modes.

- Improved quality of MLWD data due to continuous rotation process. Slide intervals would have to be reamed to obtain the same level of results.

- Reduced possibility of wet trips. These wet trips can result in slower tripping in and out speeds and are associated with motor draining.

2.3.3. Operational overview

The Weatherford Revolution system is the 4.75 inch RSS applying the point-the-bit technology in its construction which improves wellbore quality and drill bit life. This RSS uses a near drill bit stabilizer for orientation of the drill bit axis with the desired borehole trajectory direction. Testing and experience show that point-the-bit technology drills smoother and cleaner wells by cutting formations with the face of the drill bit. The Weatherford RSS's simple and compact design makes it cost-effective, reliable and easy to scale-up for various tool sizes [20].

Figure 2.16. The 4 3/4–inch rotary steerable system

A non-rotating RSS sleeve is used with special paddles to restrict it from simultaneous rotation with the whole drill string. RSS drive shaft is constructed to send torque through the down-hole tool to the drill bit. Rotation between the central RSS shaft and the non-rotating sleeve drives a hydraulic pump. The pump generates the force necessary to offset the drive shaft within the RSS sleeve in the required direction. When changes in trajectory direction are necessary, hydraulic pistons are energized and thus activated to provide deflection of the shaft from the sleeve of stabilizer centerline. Shaft deflection forces the drill bit to point in the opposite direction [20].

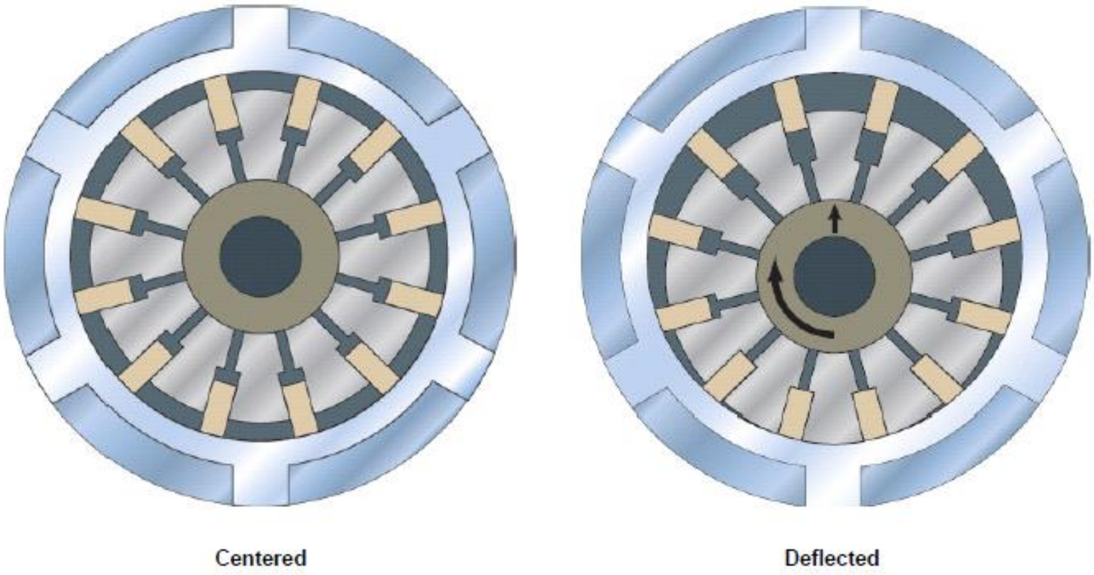


Figure 2.17. Shaft deflection during steering process

The RSS's inner navigation control system directs the internal hydraulic system via a solenoid operated electrically. The solenoid provides energy to some particular pistons, controlling by these means tool-face and trajectory deflection.

Figure 2.18. Deflection of RSS during testing

If the outer sleeve needs to begin to roll, the RSS electronics make the hydraulic system to maintain the required deflection and tool-face settings. Sensors installed on the central shaft can measure actual deflection, actual drill string tool-face, and relative rpm between the shaft and sleeve. Power for the control system is provided by internal lithium batteries. The electronics insert houses a near-bit inclination sensor, and also has a provision for near-bit gamma ray and azimuth measurements. Uplink telemetry can be accomplished with mud pulse via an internal connection with MLWD system [20].

Deviation rates and tool-face values are set from the surface using changes of rpm. Parameters can be changed in 4-9 minutes. The Weatherford RSS can operate in 4 modes [20]:

1) Drilling mode in which energized pistons maintain preplanned deflection rate and direction of drilling.

2) Pump-back mode energizes all pistons making the outer sleeve rigid. It is holding the shaft concentric with the stabilizer sleeve. This mode recommended for back-reaming and tripping operations.

3) Stiff mode (similar to previous mode) the pistons are energized up to 100% duty cycle–unlike pump-back mode actuating pistons when some correction is necessary.

4) Neutral mode in which all pistons are not energized and the outer sleeve is free to move relative to the RSS shaft. Any time when drill-string rotation stops, the RSS tool automatically goes into neutral mode. It is not recommended to use neutral mode for reaming.

2.3.4. RSS BHA configuration

The standard RSS BHA configuration may consist of the next elements [20]:

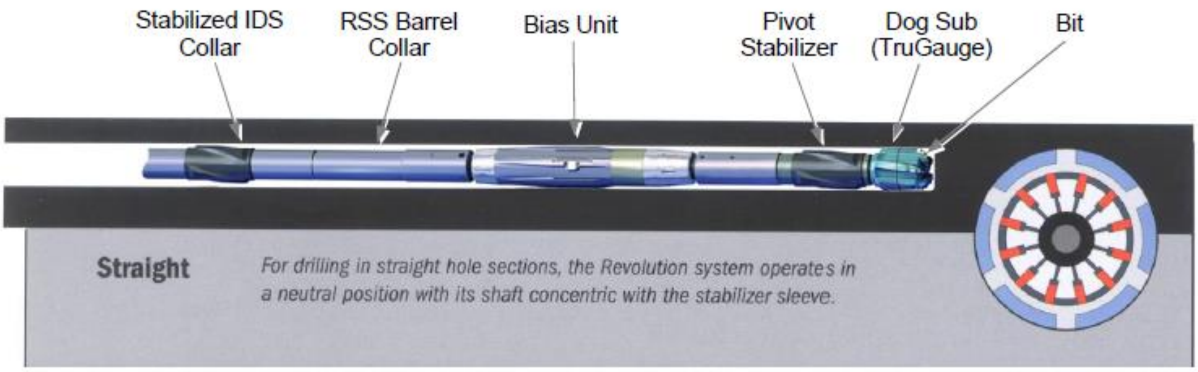


Figure 2.19. BHA with RSS (drilling straight)

The RSS outer sleeve, dog sub and stabilizer are all have true gauge or close to it. Testing and experience show that this is the optimal BHA configuration for maximum directional drilling performance with the RSS tool. The RSS is capable to provide DLS up to 12 degrees per 100 ft or even more in some cases. At 90 degrees inclination values tests have shown that with zero deflection parameter the RSS tool tends to hold inclination angle or provide a slight build. This is rock formation dependent and thus it may vary to some degree from one well to another.

To build inclination angle at 6 degrees per 100 ft with this RSS tool with little or no turn, a 0 degree tool-face and 50% deflection should be selected. The resulting surveys should be checked and then settings should be adjusted accordingly to obtain the required DLS and counteract any azimuth turn. Better to be aware that rock formation changes can have a considerable impact on RSS tool response. The BHA achieves the build by deflecting the outer sleeve upwards and internal RSS shaft downwards, which in its turn pushes the drill collar above the pivot stab downwards. The pivot stab points the dog-sub and drill bit upwards to build inclination angle. This is illustrated on the figure below:

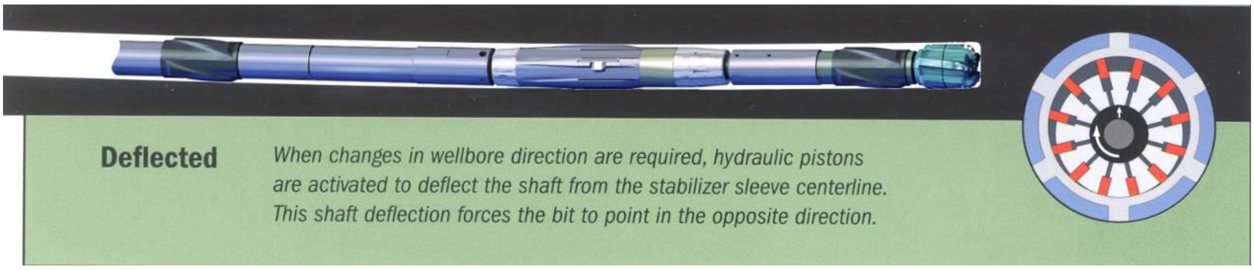


Figure 2.20. BHA with RSS (drilling with deflection)

To drill in any other direction it is necessary to change the tool-face. To generate different DLS, it is necessary to change the deflection. The RSS tool may take some time to react on applied changes in settings, but typically only a couple of minutes.

2.3.4.1. Tool configuration considerations

The RSS is typically run with the MLWD system. This allows the directional driller to see operational data from the RSS such as actual tool-face, actual deflection, down-hole rpm and confirmation of changes in settings. RSS can be run stand-alone as well (without MLWD). Although, run without the MLWD, the directional driller would not see any real-time data related to the RSS performance, or what's even more important, the data about receiving settings changes by tool. The only way to check the performance of the RSS will be to analyze the MLWD surveys. This will significantly reduce the possibility to detect problems in time and thus will decrease the ability to stay on the projected well path [20].

The point-the-bit RSSs are usually run in a couple with PDC bits. Unlike for push-the-bit RSS, gauge length and side cutting ability are less critical, so drill bit optimization and selection is more similar to the principles applied to conventional rotary BHAs [20]. It worth to remember that there is no necessity to include features into the drill bit design to allow the chosen BHA to maintain tool-face easily which is normally required for mud motors. Thus, more aggressive cutting element's angles can be applied with the point-the-bit RSS to maximize drilling rate. More detailed information about drill bit selection for RSS can be found in chapter 3.2 related to drilling bits.

2.3.4.2. Drilling parameter considerations

Drilling fluid flow and pump pressure are typically selected according to the requirements for the MLWD tools. WOB usually is not an issue which can affect on the choice of the RSS. However, RPM is an important factor because all signals and commands for setting changes are transmitted by changing the RPM values. Thus it is important to know in advance the RPM range that can be provided by the drilling rig equipment including:

- The maximum and minimum RPM that the drilling rig can provide for consistent rotation off-bottom.

- Possible or planned drilling RPM range while on the bottom.

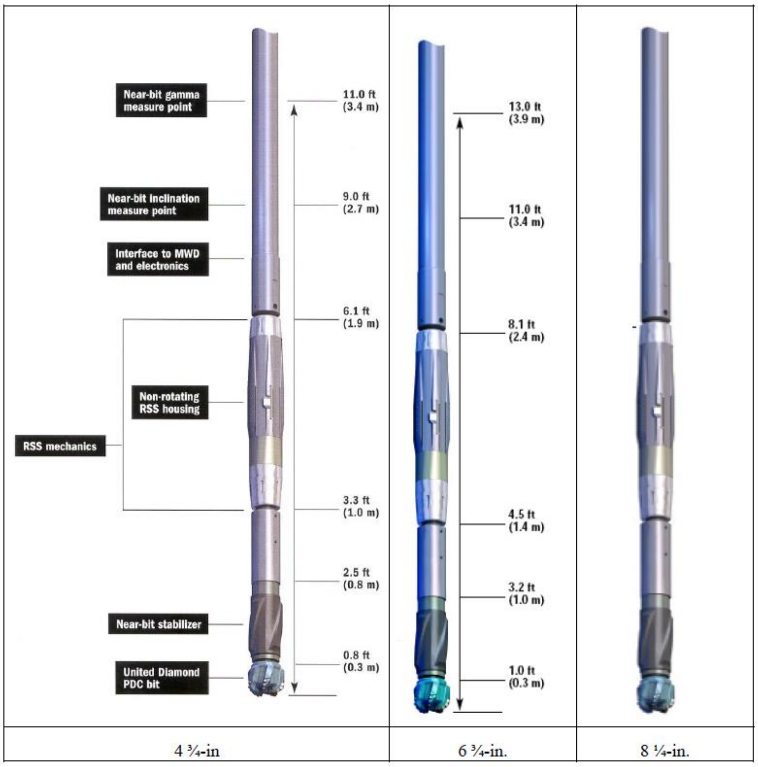


Figure 2.21. RSS size configurations

2.3.4.3.Drilling practices

The RSS BHA should be treated as a rotary assembly during drilling process. It is important to optimize drilling parameters to avoid vibration, downhole shocks, and stick-slips.

The point-the-bit RSS is capable to operate at up to 250-290 rpm, but due to stick-slip problem down-hole rpm may become higher than this, as well as the drill bit can even stop for a period of time that may turn off the tool. In case of significant stick-slip, directional performance suffers and maintaining constant tool-face and deflection rate will be more difficult [20].

If stick-slips are seen during drilling on the bottom, the drill bit should be raised off the bottom on 5-15m and after that the rpm should be increased. It may become necessary to change the rotary table or top drive to other model providing higher RPM and then return to drilling process slowly increasing WOB, to see did the increased rpm improved the stick-slip parameter. If the increase of RPM doesn't have any effect, then it is necessary to reduce the WOB. Combination of different RPM / WOB variations should be tried to reduce the stick-slips. The ROP decrease will be seen, but it should be remembered that it always better to have good directional control with moderate ROP than high ROP with reduced directional control. Reduced directional control may lead to situations when the drilling interval or even the whole well may be needed to be re-drilled.

If the stick-slip cannot be reduced by all methods stated above then engineers should consider the possibility of running a different type of drill bit. Also, lubricants may be added in the drilling mud to reduce stick-slip generated by the drill bit.

If the stick-slip problem is seen on and off the bottom of the well, then the most probable reason for that is a combination of the BHA interaction and drill-string interaction with the wellbore trajectory. Some lubricants should be added to the drilling mud system in this case to decrease the stick-slips. Hole cleaning quality also need to be checked as a poor hole cleaning may be another reason for stick-slip occurrence. BHA and drill string for subsequent bit runs should be improved or altered according to the drilling environments to reduce the possibility of any components causing stick-slip and torque & drag.

2.3.4.4. Mud and lost circulation materials

The RSS tools typically are very tolerant to adding lost circulation materials (LCM) in the mud because there are no restrictions inside RSS small enough to become blocked by LCM. Most often, the limiting factor for using LCM of some particular size is MWD tools. MWD pulser, normally has the smallest LCM size restrictions in the BHA, typically safe size of LCM particles for adding it in the mud flow without applying pipe filters or activating valves is 3-5 mm.

The RSS should be resistant to many different mud types. Before running the tools with some new type of mud a rubber compatibility check must be carried out to ensure that the drilling mud does not significantly affect the diaphragms and rubber seals.

2.3.4.5. Tight hole / stuck pipe

Using RSS reduces the possibility of stuck pipe compared to directional drilling with conventional mud motors since the drill string is rotating most of the time, including when steering is necessary and stops only when we need to make pipe connection or when setting the RSS tool (about 15 seconds). The constant rotation benefits borehole cleaning. Before changing the RSS settings directional driller must ensure that torque and drag are not an issue to avoid possible stuck.

If the pipe is stuck, the rotary steerable system’s design allows withstanding maximum over-pull values according to its specifications. Jarring on the RSS is highly not recommended unless if it is really essential.

2.3.5. RSS and steerable motors

Commercial RSS tools were available for about 20 years [3]. Initially it was considered that the only application for these tools is the most difficult wells. However, soon it was clear that RSS can provide wide range technical advantages over mud motors [21]. Thus RSS have experienced continuous growth up until now. RSS technology now accounts for more than 20% of the directional drilling footage.

The rotary steerable systems are still more expensive comparing to steerable mu motors. Costs of manufacturing, development, maintenance as well as operational costs for RSS are still on a high side. Rotary steerable systems are much more complex than mud motors and that partially means that they less reliable. Figure 2.22 shows a comparison of rotary steerable systems reliability with other technologies used in directional drilling [22].

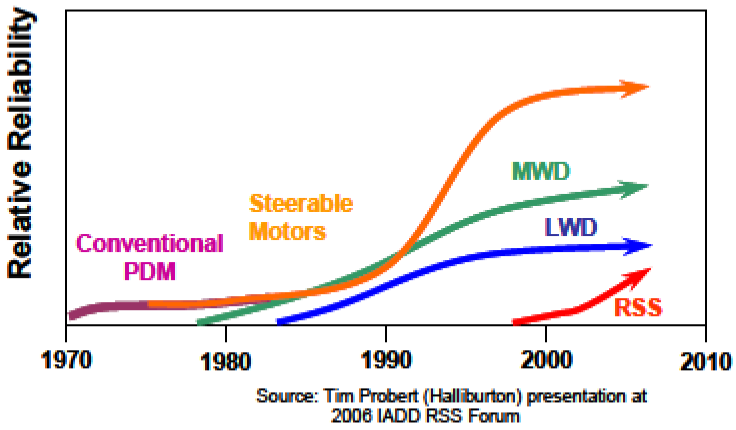


Figure 2.22. RSS reliability will follow a well established industry trend.

Directional wells can have construction and well path of different complexity from simple wells with J-type trajectory up to extremely complex constructions with several sidetracks, extended horizontal reach section and complex well paths with parameters changed in all three dimensions. Wells with more challenges usually drilled in a high spread investment environment. Such wells make up the main fraction of the projects where rotary steerable systems are used. About 90% of all deepwater wells, more than 50% of offshore wells, and only 3% of wells on surface are using RSS technology according to reports [22]. So, the continued growth of RSS will require making this technology more affordable for the less expensive drilling environments.

2.3.6. RSS and steerable motors comparison (case study 2)

In this section gathered the results of data analysis from 13 directional wells drilled with RSS and 5 wells drilled with mud motors. All of the wells drilled in the same area on the same oilfield and have a similar construction and well paths.

Figure 2.23 shows one of the typical BHAs used for a RSS drilling on the chosen oilfield.

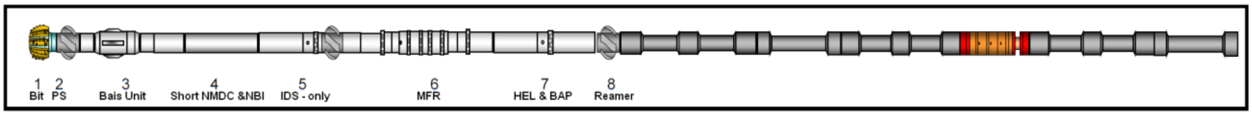


Figure 2.23. Typical RSS BHA

Figure 2.24 shows typical well path for the selected group of wells.

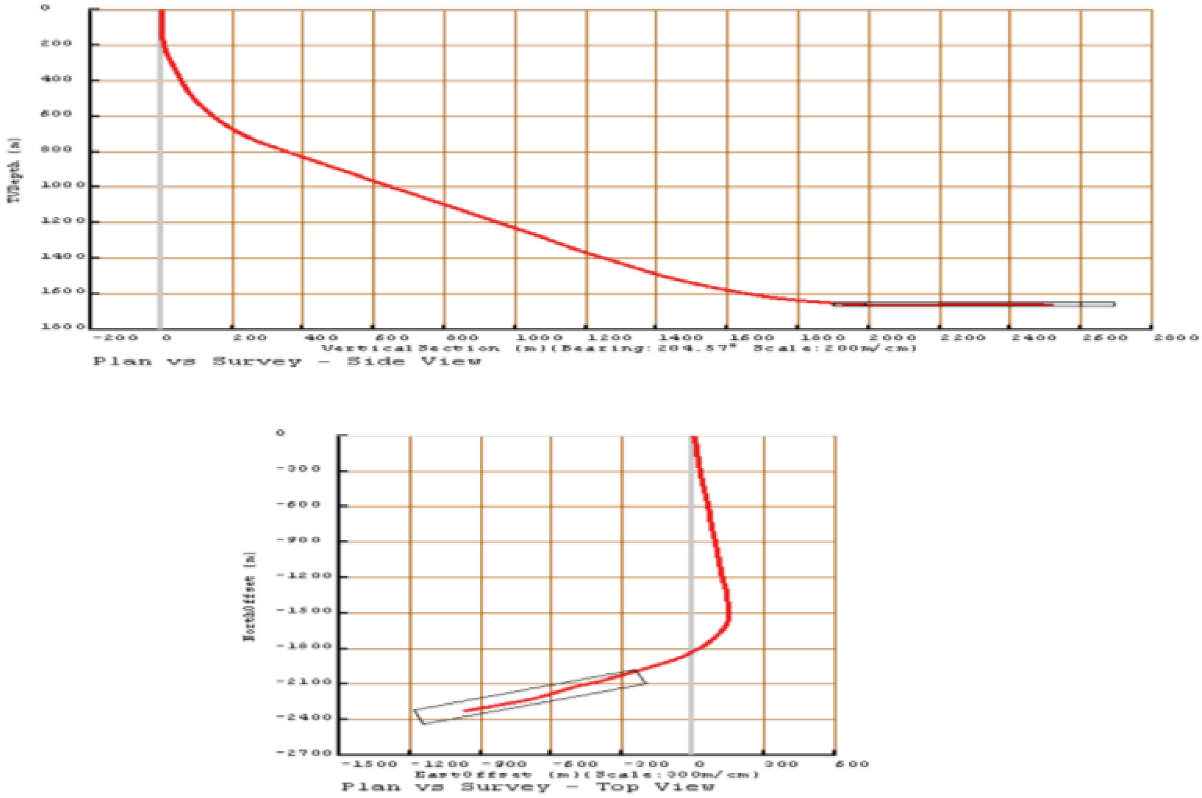


Figure 2.24. One of the well trajectories drilled with RSS

On the figure 2.25 shown geo-steering image of the horizontal section of one of the wells drilled with RSS.

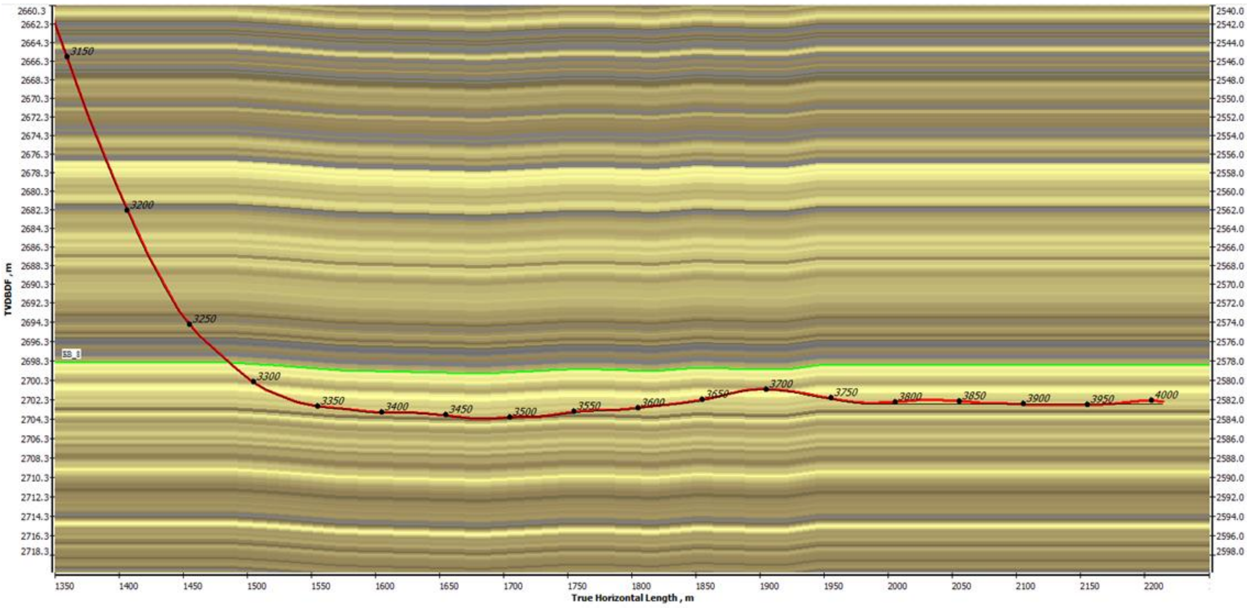


Figure 2.25. Horizontal section of one of the wells drilled with RSS

On the figure 2.26 shown the graph with average ROPs for all of the chosen wells drilled both with RSS and mud motors. These values include only ROP data for section drilled with 6 inch drill bit since on the selected oilfield RSS is used only for this section.

As it can be clearly seen from the graph, average ROP for the wells drilled with RSS is significantly higher comparing to the ROP for the wells drilled with mud motor. The main reason for such a difference is that while drilling with RSS we maintain rotation of the drill string 100% of drilling time. Wells drilled with motor loose in their final ROP because directional control on this wells provided by carrying out sliding operations.

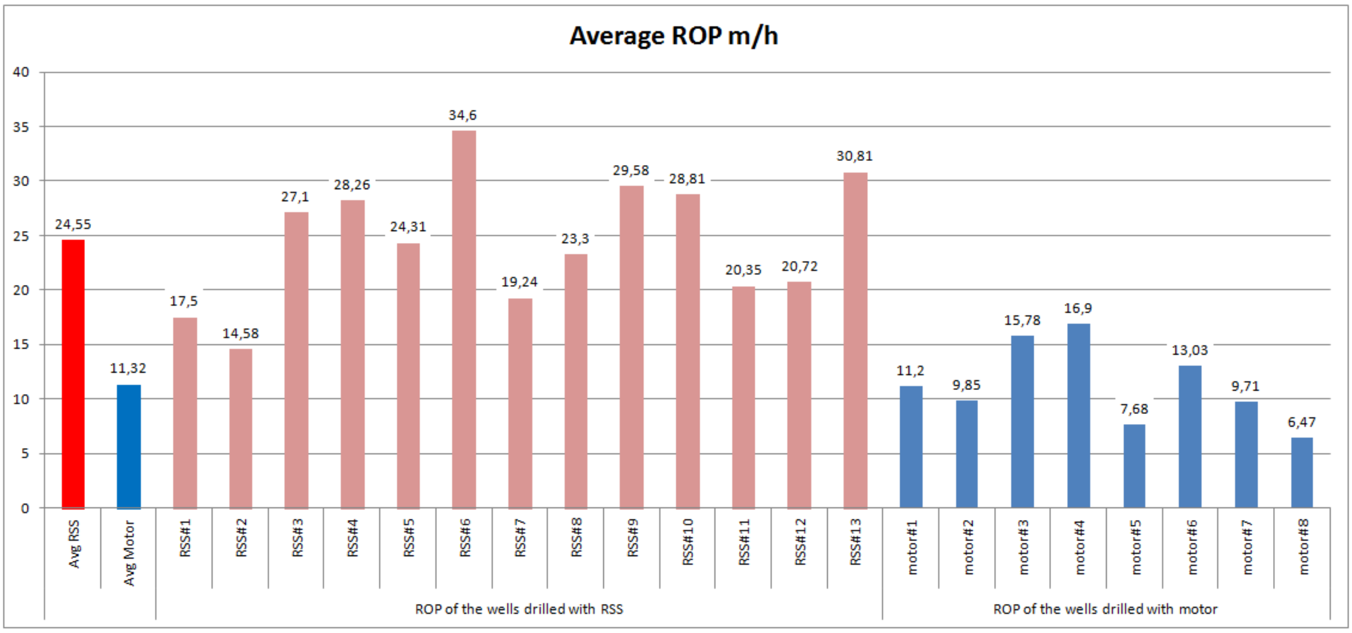


Figure 2.26. Comparison of average ROP for 4 ¾ section of wells drilled with RSS and with motor on the same oilfield

Tables below contain information about main drilling parameters on these wells. Information included in tables is related only to the section drilled with 6 inch drill bits.

Parameter	RSS#1	RSS#2	RSS#3	RSS#4	RSS#5	RSS#6
Bit size, inch	6	6	6	6	6	6
MD, m	3706,9	3263	3234	2675	2893	2636
TVD, m	1661,12	1673,12	1654,74	1658,41	1665,57	1681,71
Bit runs	3	1	2	1	1	2
Mud type	Flo-Pro NT	Flo-Pro NT	Flo-Pro NT	Flo-Pro NT	Flo-Pro NT	Flo-Pro NT
Mud weight	1,1	1,1	1,09	1,09	1,1	1,1
Bit type	NOV RSF613	NOV RSF613	Smith MDi613	NOV RSF613M	NOV RSF613M	NOV RSF613M
Nozzles 1/32'	3x13	3x13	6x9	3x12	3x12	3x12

Table 2.2 Drilling parameters for RSS wells

Parameter	RSS#7	RSS#8	RSS#9	RSS#10	RSS#11	RSS#12	RSS#13
Bit size, inch	6	6	6	6	6	6	6
MD, m	2815,5	3152	2895	2536	3183	2957,8	3056,1
TVD, m	1603,53	1605,51	1608,16	1608,17	1633,56	1628,81	1654,91
Bit runs	1	1	1	1	1	2	1
Mud type	Flo-Pro NT	Flo-Pro NT	Flo-Pro NT	Flo-Pro NT	Flo-Pro NT	Flo-Pro NT	Flo-Pro NT
Mud weight	1,1	1,05	1,09	1,1	1,1	1,1	1,09
Bit type	NOV RSF613M	Smith MDi613	NOV RSF613M	Varel V613	Baker Q406F	NOV SKH613M	NOV SKH613M
Nozzles 1/32'	3x12	3x10; 3x11	2x13; 1x12	3x12	6x9;	3x12	3x12

Table 2.3. Drilling parameters for RSS wells

Parameter	Motor#1	Motor#2	Motor#3	Motor#4	Motor#5
Bit size, inch	6	6	6	6	6
MD, m	2386,4	2653,9	2426,1	2921,2	2182,1
TVD, m	1613,42	1608,3	1602,9	1611,37	1628,6
Bit runs	3	2	3	2	2
Mud type	Flo-Pro NT	Flo-Pro NT	Flo-Pro NT	Flo-Pro NT	Flo-Pro NT
Mud weight	1,11	1,12	1,09	1,13	1,08
Bit type	Reed SKH616D	Reed SKH616D	Smith MDI613LWPX	Smith MDSI 716LW	Smith MDI613LWPX
Nozzles 1/32'	3x12; 3x14	6x13;	2x13; 4x16	3x12; 3x13	6x12;

Table 2.4. Drilling parameters for motor wells

2.3.7. Summary for rotary steerable systems

RSS technology provides to the oil industry the capacity to drill complex ERD wells and provides the opportunity to improve the efficiency of drilling of directional wells. Rotary steerable systems provide technological advantages that are definitely superior to other directional drilling control technologies nowadays. The RSS has almost completely replaced steerable mud motors in one of the most expensive drilling environments – deepwater operations. Although, rotary steerable systems are still not very popular in land drilling operations due to high costs and somewhat lower reliability comparing to mud motors which can adequately drill not very complex trajectories. However, there are some successful attempts to introduce RSS to land drilling market.

3. BHA OPTIMIZATION

3.1. BHA optimization introduction

Research of BHAs design and characteristics which can influence vibrations, torque and drag and other parameters as well as improvements in design of PDC bits has increased efficiency of drilling and reduced some of the problems. Most BHAs and drill bit – motor combinations are still chosen and optimized from the experience of previous jobs and errors occurred during these jobs. The main reason is that the interaction between drill bit and rock and the dynamics of the drill bit exerted on the BHA are most of all stochastic processes, and most analytical methods use simplified or idealized assumptions for this type of interaction. Currently there are some approaches exist which can predict different drill bit – motor combinations' performance and provide more or less precise estimations of the rate of penetration before such combinations were run in the hole. The main reason why numerical approaches cannot provide absolutely successful and precise results is that though the properties of BHA are known and vibrations can be estimated, still the impact forces on components with variable formation properties conditions and in an imperfect bore hole cannot be calculated precisely. Additionally, the forces influencing the BHA and drill string through the drilling bit are semi-chaotic, complex and multi-modal.

Technologies related to drilling dynamics continue their advancing on a considerable amount of work fronts. High frequency real-time data acquisition systems have provided possibility for the diagnosis and research of system behaviors which were previously unrecognized, for example torsion high-frequency oscillations driven by some fundamental BHA characteristics [24, 25]. Several important researches have been accomplished with the use of MDS (multiple dynamic sensors) placed near to the key drilling elements such as PDM, RSS or MLWD systems [26, 27]. Additionally, dynamic sensor systems or 'along string' approaches have succeed in providing more data about system behaviors [28]. The development of new options for telemetry has been achieved with use of 'wired drilling pipe'. Later, it has been successfully applied on some field projects [30].

Modeling of drilling dynamics has been focused on a range of different well construction design issues, for example reduction of BHA and drilling pipe twist-offs [31], optimization of hole enlargement operations while drilling [32, 33], effective milling operations for sidetracking [36], early detection of changes in lithology [37, 38], and resolution of hard-formations drilling challenges. With the possibility of acquisition of more precise data from sensors, advances in computational methods have been made to interpret the drilling data in real-time. Drilling dynamics analysis also focuses on new areas like conditions monitoring and preventive maintenance. These methods provide the possibility of furthering the useful drilling tool life and minimize possibility of failures and decrease amount of NPT [39, 40].

Downhole tools development may change the dynamic conditions for BHA with special sub designs that can damp some vibration modes or induce non-damaging vibration modes instead. In some operations dynamical data acquisition method of monitoring can be used as an integrity assurance tool for providing real-time information about physical load and its variations [41].

Significant advance has been made in the area of BHA modeling, and new approaches have been demonstrated [42]. Although, there is much more work to be done in order to achieve higher level of precision of dynamic sensors, metrics, measurements, and reporting.

3.2. Drill bits

3.2.1. Rotary drilling bits introduction

The process of drilling a borehole in the ground requires using drilling bits. The bit is the most basic drilling tool used in the drilling industry. The selection of the best drill bit and conditions for its operations is one of the most common problems that could be faced. Large variety of bits is manufactured for every kind of possible drilling environment. It is very important to consider fundamentals of the drill bit design while planning the drilling process.

Rotary drilling bits usually are classified by their design as either drag bits or rolling cutter bits. Drag bits consist of the blades with fixed cutters that are integral with the bit body and rotate as unit with drilling string. This type of bits start its history in the same time when the first drilling begun. Rolling cutter drilling bits have several cones with cutting elements. These elements rotate about cone's axis as the drilling bit is rotated on the bottom of the hole.

3.2.2. Polycrystalline diamond (PDC) drill bits

PDC drill bits use a thin layer of artificial diamonds on rock crushing elements of the bit. PDC bits are effective in medium plastic rock formations such as shale and salt. PDC bits typically can provide significantly higher ROP and have better endurance comparing to cone bits. First PDC drill bits had a tendency to ball their cutters during drilling resulting in overheating and wear of diamond layer faster than it was planned. Such problem was especially common for water-based muds used in those times. Improvements in drilling mud compositions and in drill bit's design helped to mitigate the problem [4].

PDC drill bit's body is typically made out of steel and can have a matrix construction for some designs. It is possible to renew drill bits after they got some wear in the drilling process. Although, the body of the drill bit should be in an appropriate condition to be renewed – if the drill bit is damaged or worn too much then it may be impossible to renew it.

PDC drill bits have a variety of cutting structures and elements. Cutters of larger sizes usually provide better efficiency in soft formations and work aggressively, removing large formation cuttings at higher ROP. Although, aggressive bit designs are typically not suitable or at least not recommended for directional drilling due to the problems with steering. Heavier drill bits with higher amount of smaller cutters more suitable for harder formations and generally better for steering. Any PDC drill bit should have gauge protection; sometimes protection can be made in the form of natural diamond layer similarly to the layer on crushing and cutting elements.

PDC drill bits commonly are not suitable for drilling in very hard and abrasive rock formations.

If it is important to identify a pressure transition zone, then it would be better to use a tricone drill bit instead of the PDC bit [4]. PDCs do not provide a good enough d-exponent trend.

Also, PDC drill bits are not recommended for use in hard chert and other nodule type formations. Though, some PDC bits can be used in such formations after thoughtful optimization of all drilling parameters [4]. Large enough flow-by area around the cutter elements should be provided, flow rate should be maximal and RPM should be as minimal as possible. WOB is needed to be continuously controlled and kept at moderate values. This way, hard nodules can be washed away fast enough before any significant damage to bit cutters and its body will be done.

3.2.3. Defining recommended bits

Defining process of the best drill bit for every particular interval of the borehole can be quite complicated sometimes. To simplify the defining process we can choose not the only one bit in the first place but 2 or 3 bits which are fitted for the current drilling interval and only after consideration of other factors more carefully we can choose the one bit which is definitely better than others [4]. Also we have to consider drilling parameters from previous bit run on the same well and parameters of bit runs in the same interval from neighboring wells. All these parameters should be carefully analyzed with the main objective to improve the efficiency of drilling in the current run.

It is necessary to examine the best bit runs for particular well. Check the drill bit grading as well as the bit run details. Any differences and distinctions between the best two bit runs can point the proper way in what we can alternate in our next bit run. For example, if the best drill bit was for softer formations than the second best bit, then we may consider that the drill bit for even softer formations can provide better results. It is not unusual when drilling engineers initially choose drill bits that are designed for harder formations than the formations being actually drilled and therefore this often ends up in the decrease of drilling performance.

If the best bit from previous runs was pulled out of the hole with significant wear, then it is important to analyze the character of the wear. For example, if there were a large number of broken bit teeth, then what was the reason for that? Maybe it was bad run practices in general, some particular geological formation conditions or high level of drill string vibrations. If the cause or several causes of the bit wear were identified then drilling specialists should provide solutions how to avoid the same problems in the next run typically by changing something in drilling process, changing of BHA configuration, or including a shock sub in the BHA.

If the best drill bit from previous runs was pulled out with undergauge, then it will most probably cost additional time on the next drill bit run due to the additional reaming operations. Viability of using premium bit gauge protection should be considered as the result will be a better drilling performance and less amount of reaming during the next bit run. Though the main question in this situation is cost as sometimes it is cheaper to carry out additional reaming than use more expensive drill bit [4]

Bit hydraulic parameters must be checked as well. Special attention should be provided to the nozzles size of the bit. This parameter can be easily altered between runs and it may have a significant impact on the ROP and mud cleaning characteristics.

In any standard situation economics will be the final fundament for decision. The main question is: which drill bit will be the most cost-efficient? PDC drill bits of larger sizes tend to be less economic on low-cost drilling rigs, but it changes when the hole size decreases (there is less extra PDC bit cost and a higher possibility of losing cones for tricone bits), the borehole deepens (tripping time becomes more important), and the drilling rig day pay rate increases. Modern wells are typically drilled slimmer than it was in the past and as PDC drill bits improve in their performance and cost, options for their potential application and use should be re-examined carefully.

By proper analysis of all aspects of every drill bit run and by grading and considering all of the possible restrictions imposed by the BHA design, the engineer should be able to identify what drill bit characteristics and features can be altered to provide better drilling performance comparing to previous runs [4].

3.2.4. Particular bit features and how they relate to bit selection.

At the well planning stage drilling engineers and bit specialists choose bits according to bits' particular features depending mainly on the known downhole conditions data. Later when practical drilling operations are discussed, dull bit features can be used to identify and clarify such downhole conditions that may lead to a modified drill bit selection.

3.2.4.1. Using IADC codes to identify a general class of suitable bit.

- IADC tricone drill bit classification.

Each drill bit manufacturing company has their own code system to name their drill bits. Because of that an identification of some particular drill bit to use it for different rock formations can be difficult sometimes. The IADC recognized such problem and created a special code system with three digits for easier identification of principal drill bit features and characteristics. The IADC code is a useful for comparison of drill bits from different manufacturers since this code is typically given as well as the drill bit name.

The first digit in the code is formation hardness series and can be from 1 to 8. Low numbers relate to softer formations; 1 to 3 are for mill tooth drill bits and 4 to 8 are for TCI drill bits [4].

The second digit of the code is type and its classification of rock hardness. The code can be from 1 to 4 for drill bits that increase hardness within the formation hardness series.

The third code digit is feature classification and can be 1 to 9 as follows [4]:

1 - Standard, non-sealed bearings

2 - Air-lubricated, for air-drilling

3 - Standard, non-sealed bearings with insert gauge protection

4 - Bearings with sealed rollers

5 - Bearings with sealed rollers with insert gauge protection

6 - Bearings with sealed journal

7 - Sealed journal bearing with insert gauge protection

8 - Directional

9 - Special application

For example, a drill bit type IADC 5-4-7 could be a Reed HP54, Baker Hughes ATJ33 or Smith F37. Each of these drill bits has comparable application as journal bearing insert drill bits for medium formations of high compressive strength. Note that the drill bit manufacturer company, not the IADC gives a drill bits their IADC classifications [4].

The system also defines 16 codes which can be placed after the IADC drill bit classification to show some particular features.

IADC special feature code and description:

A - Air-drilling application

L - Lug-pads

B - Special bearings seal

M - Motor application drill bits

C - Center nozzle jet

S - Standard model

D – For deviation control

T – Two coned drill bit

E – Extended length jet

W - Enhanced structure of cutting

G - Additional gauge and protection

X - Predominantly tooth inserts

H – For horizontal steering

Y - Conical tooth inserts

J - Jet deflection drill bit

Z - Other shapes of inserts

As with roller cone bits, IADC have defined a classification system for describing fixed cutter type bits. There are four digits that classify the type of body material, cutter density, size/type, and body profile. Following is a summary of how the system works.

First digit: body material

M is for matrix and S is for steel.

Second digit: cutter density

Ranges from 1 to 4 for PDC bits and 6 to 8 for surface set (e.g., diamond) bits. The PDC bit number relates to the cutter count; there is a higher number for a heavier set. The surface set number relates to diamond size [4].

0 - Reserved for future use

1 - Less than 31 x 0.5 in diameter PDC cutters

2 - 30 to 40 x 0.5 in diameter PDC cutters

3 - 40 to 50 x 0.5 in diameter PDC cutters

4 - 50 or more x 0.5 in diameter PDC cutters

5 - Reserved for future use

6 - Larger than 3 stones/carat

7 - Between 7 and 3 stones/carat

8 - Smaller than 7 stones/carat

9 - Reserved for future use

Third digit: size (PDC) or type (diamond) of PDC surface set

1 - >24 mm diameter natural diamonds

2 - 14-24 mm diameter thermally set polycrystalline (TSP)

3 - 8-14 mm diameter mixed (e.g., natural and TSP)

4 - <8 mm diameter impregnated diamond

Fourth digit: body profile

1 - Flat face surface set or "fishtail" type PDC

2 - Almost flat profile

3 - Medium length profile (e.g., round or short parabolic)

4 - Long profile (e.g., long flanked turbine bit)

3.2.4.2. Mud motors, steerable systems, and turbines.

When planning to run a downhole motor, the following additional considerations apply [4, 10]:

1. If the string is rotated while drilling with a motor, will the maximum bit RPM be exceeded?

2. Will the mud flow through the steerable motor clean the borehole at the planned flow rates?

3. Are there any particular limitations on the drill bit pressure drop imposed by the mud motor?

4. Is the proposed drill bit suitable for using with the chosen type of mud motor?

5. Can LCM be safely pumped through the mud motor and, if not, should a circulating sub be installed above?

6. What sizes of liners are needed in the pump for the necessary flow rates and pressures?

7. Are there any issues with the drilling mud properties (e.g., sand content, chemical compatibility with seals, etc.)?

8. Check with the mud motor supplier – what is the plan for operations before and after the mud motor run? For instance, if running in for straight borehole turbo-drilling with a PDC drill bit, the previous BHA should be stiff enough to avoid reaming in with the turbine. Any junk in the borehole would require an additional junk run first. Wiper trip with a rotary BHA should be carried out in some cases to ream the hole to the bottom and reduce the possibility of mechanical casing stuck by reducing DLS and ledges.

3.2.5. Special bits for RSS and TBS methods

The increased use of RSS in drilling industry in recent years leads to further consideration of the PDC bits design in order to improve efficiency of drilling and capitalize on the potential of RSS to improve drilling performance that these system may offer. In order to be effective when applying with RSS the drill bit must have three qualities [44]:

1) Stability

2) Steerability

3) Durability

An existing 8.5 inch diameter, PDC drill bit designs were modified and successfully used in the initial runs with the rotary steerable tools, particularly in terms of steerability. However, further drill bit runs show several weak points affecting the stability and the durability of this design in the same time. Thus new modifications have been made to the bit body and its cutting structure. Through field monitoring and continued development, additional changes to the bit cutting structure and body design have been made to provide a bit design that will fulfill all requirements stated above [44]. Developed features of the new bit design can be transferred to produce a range of bits to match specific geological applications and sizes.

The developments of the RSS bits are illustrated in case study in the chapter 3.2.6 that displays how different bit designs provide different results on the same oilfield.

3.2.5.1. Design specification

Three design qualities are essential to a successful combination of PDC bit and 'Push the bit' rotary steerable tool. For future use, this will be referred to as SFRS (Side Force Rotary Steerable) [44].

1) Stability – The drill bit design must not make serious vibration on the bottom of the well during drilling, which could cause premature failures to the drill bit or other tools in BHA [45].

High values of lateral vibrations (drill bit whirls) will lead to damage and fatigue failures of the weakest parts of the drilling string. In the case of a SFRS system [59], the mechanical units that are used to provide the directional steering control can be damaged. The electronic elements of the tool in the control unit are also can be very vulnerable to drill bit whirls.

Torsion vibrations (slip - stick) are the major cause of drill string and drill bit failures. The application of SFRS systems is connected to higher risks of stick and slip incidents comparing to a steerable mud motors due to the lower rotation speeds and the stiffness of the BHA [46, 47].

2) Steerability – The SFRS tool is commonly used in horizontal wells or in wells with high values of inclination and thus the drilling bit should be with short gauge and possess the ability to move laterally [59], thus capable of accurate and immediate response to the directional changes initiated by the tool. This will result in improved dog leg potential.

3) Durability – From the experience of applications the drill bit it is expected to successfully drill through hard stringers interbedded formations.

The main goal is to reach the target depth without additional bit runs and thus the drill bit should have proper diamond volume to complete the interval without failing in the hard rocks or stringers. The drill bit has to endure drilling both soft and hard formations at similar drilling parameters and be able to prevent or at least decrease the damage caused by drilling in hard rock layers [44].

Bit design features that can fulfill all of the above issues need to be transferable. So, qualities induced by parameters such as number of blades and cutter sizes are less important, while the design specification depicted by cutter placement and profile methodology are more relevant.

3.2.5.2. Recommended bit types for RSS

There is no specific type of drill bit cutting structure that has to be run with the RSS, which operates in "point-the-bit" mode. It requires relatively small side-cutting action to provide necessary borehole curvature. Consequently, drill bit selection can be carried out in exactly the same way as that for conventional rotary assemblies. That means that both PDC and tricone drill bits, optimized for ROP rather than for steerability in the first place. However, whichever drill bit type is chosen for drilling it is important to be sure that the cutting structures are laterally stable. RSS is by design relatively flexible compared to other most common elements of a BHA, so the possible failure to restrain the side-to-side oscillations can result in the borehole taking on a shape along the continuum between a spiral, a ripple and an hour-glass [20].

Figure 2.27. Different drill-sting stress conditions

In such borehole conditions the borehole diameter at some point of time, experienced by the pivot RSS stabilizer and bias stabilizer, can be significantly higher than the nominal drill bit diameter for the dogleg capability of the RSS to become considerably reduced. For spiral borehole such result may seem opposite, since the drift diameter of the borehole may at the same time be small enough to require stabilized, close-to-gauge elements higher up the assembly to be reamed through the section which was spiraled. It is the borehole diameter values experienced at the contact lengths of the bias stabilizer and the pivot RSS stabilizer, which helps to determine what DLS response the selected RSS bias unit deflection will produce [20].

For PDC drill bits it is typically harder to achieve lateral stability. In general, the drill bit cutting structure offered will be either shallow cone, short taper, medium cone or short taper, “Flat” (API Type 9), as shown below [20].

Figure 2.28. Drilling bits with different gauge length

The configuration of the passive and active gauge sections above the rock cutting structures may vary significantly. In the case of RSS "point-the-bit" type the requirements are for a gauge length that decreases lateral oscillation values enough to prevent the amplitude from increasing continuously as drilling proceeds, while at the same time allowing borehole curvature to continue developing process.

Diagram A from figure 3.3 below shows what might happen if drill bit 1 (from figure 3.2) will be used without a special gauge-control stabilizer. The increasing borehole diameter would reduce DLS response and cause the bias RSS unit stabilizer to start slipping, reducing achievable borehole curvature even further.

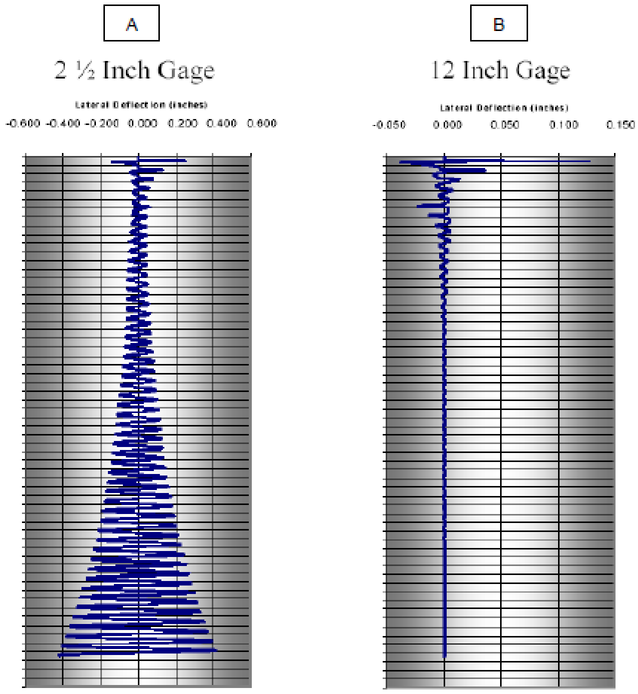


Figure 2.29. Effects of using bits from figure 3.2 with RSS

Diagram B from figure 3.3 shows the possible response of drill bit 4 (from figure 3.2). The cutting structures of the bit are tightly constrained, which helps to drill a close to gauge borehole. However, the lateral damping is too significant, so dogleg response would be too low and most probably not enough for efficient directional control [20].

Drill bit 3 is a compromise between lateral damping level and gauge length. Proper choice of gauge section size will provide the possibility to run the bit successfully without a special gauge-control stabilizer. Lateral oscillation may occur in some degree, but it should be dampened to prevent a continuous increase in borehole diameter for any significant drilling interval.

As drill bit technologies move forward and drill bit stability improves the need for gauge-control stabilization will diminish as well as recommended minimum lengths of passive under-gauge and passive gauge on the drill bit will become different. Currently there are drill bits which can fulfill these requirements in relatively favorable drilling conditions for conventional BHAs. However, for challenging drilling environments (e.g. in the presence of BHA whirl, stick-slip, lateral vibrations, etc.) drill bits should be selected with an excessive carefulness and caution [20].

It worth to mention that several drill bit's manufacturers produce so-called "rotary steerable bits". Typically these bits are designed for push-the-bit RSSs and may have cutting elements along the leading edge of the gauge section blades [20] (The example is RSX 162A4HDW from figure 3.4). This bit feature is absolutely not compatible with RSS types based on "point-the-bit" technology.

However, it is important to know that drill bits with quite similar names can have very different gauge section type. For example the drill bit RSX 162A8DGW, shown on the figure 3.4. Design of this bit has only gauge section cutting elements on a reduced body diameter, at the up-hole end of the bit blades [20].

Figure 2.30. Two types of RSS bits, one of incompatible with point-the-bit systems

- General selection criteria for RSS bits [20]:

1. Approximately 2 inch (1.5 inch to 2.5 inch) passive gauge length at full gauge

2. 3-4 inch gauge length at 0.05 inch under-gauge

3. Less than 1 inch active gauge length

4. Total gauge length should be approximately 6 inch

5. Should be short taper, shallow cone "flat" or short taper, medium cone.

- Effects of improper gauge length:

If gauge length is too short, the drill bit may wander in the hole, reducing the effective dog leg produced in the process of drilling. If gauge length is too long, the drill bit is unable to provide proper deflection in the borehole, reducing the effective DLS produced.

- All drill bits must be approved for use in BHA by technical or engineering support before running to the hole

- Drill bit selection is very important for proper tool operations – the bit size/type/model must be determined before drilling during the planning phase or better during contract negotiation phase

- Change of the drill bit type at the drilling rig without approval from the drilling coordinators from all sides involved in the process is prohibited

- Field personnel do not select drill bits at the drilling site

3.2.6. Review of different drilling bit designs and their efficiency (case study 3)

The purpose of this case study is to show the significance in choosing the drill bit with design which better fits to some particular drilling environment. Some bit designs may be more efficient in one environment when the other designs will be more efficient in another environment.

For this case study 19 wells were chosen. All wells were drilled on the same oilfield, so drilling environments are almost identical. Well paths of the wells and well construction also similar. For this research only 8.5 inch bit data has been considered.

There is no better way to choose the proper drilling bit than statistical data from previously drilled wells. By analyzing data from previous wells it is possible to choose a bit type with better fit to drilling environment.

Data from wells related to this research gathered in the Table 3.1.

Well#	From, (m)	To, (m)	Interval, (m)	Avg ROP, (m/hr)	Bit service	Bit model
#1	587,9	1652,6	2301,00	20,70	NOV	RSF616M- C4E
#2	591,2	1658,5	2046,50	23,50	Smith	MDSi716
#3	582,9	660,4	79,00	17,17	NOV	SKH616S
#3	660,4	1648,9	2103,70	19,50	Smith	MDSi716LWMBIX
#4	589,7	1650,0	1515,00	25,45	NOV	SKH616D-C4D
#5	593,3	1649,7	1459,00	31,93	Smith	MDSi716
#6	618,7	1669,6	1188,00	17,86	Halliburton	FX75DMR
#7	627,9	1667,0	1646,50	25,11	Halliburton	FX75DMR
#8	621,7	1664,1	1959,00	18,96	Baker Hughes	DP507X
#9	502,9	1595,2	1739,50	24,79	NOV	SKH616D-C4B
#10	497,1	1011,0	833,00	21,69	Smith	MSi716WMBPX
#10	1011,0	1610,3	1743,50	22,83	Smith	MSi716WMBPX
#11	502,2	1504,9	1565,30	24,60	Halliburton	FXD65D
#11	1504,9	1596,7	423,70	14,87	Halliburton	FXD65D
#12	499,1	1110,5	836,60	20,96	Baker Hughes	DP507X
#12	1110,5	1598,9	1013,50	17,60	Baker Hughes	DP507X
#13	508,5	1596,0	1447,00	24,19	Halliburton	FX75DMR
#14	511,5	1309,7	1236,30	24,80	Baker Hughes	DP507X
#14	1309,7	1623,8	845,50	18,70	Baker Hughes	Q506FX
#15	503,3	780,4	375,00	48,26	Baker Hughes	DP507X
#15	780,4	1634,3	1933,00	23,40	Baker Hughes	DP507X
#16	505,5	1621,4	1846,80	27,81	NOV	SKH616D-C4D
#17	610,9	1632,5	1405,00	22,57	Varel	V716P2DG1XU
#18	636,7	923,4	374,00	18,54	Halliburton	FX75DMR
#18	923,4	1512,0	1326,00	19,74	Halliburton	FXD65D
#18	1512,0	1681,2	870,90	14,66	Halliburton	FX75DMR
#19	618,0	1616,5	1177,00	29,11	NOV	SKH616D-C4D
#19	1616,5	1734,4	35,00	3,15	Baker Hughes	MX-35CG

Table 3.1. Comparison of different 8.5 inch bits' ROPs for the wells from one oilfield with similar drilling environment

Figure 3.5 shows the depths where chosen bits were used and average ROP for these intervals. From this graph can be seen that all of the drilled intervals are almost the same by length. So, all the bits can withstand almost the same length of drilling without wear. Although, it can be seen that NOV bits show slightly better ROP than other bits for this particular oilfield. Generally we can say that engineers on the considered oilfield already found the best drill bits from any manufacturer company, but also it can be seen that NOV bits provide slightly better total performance on this particular oilfield.

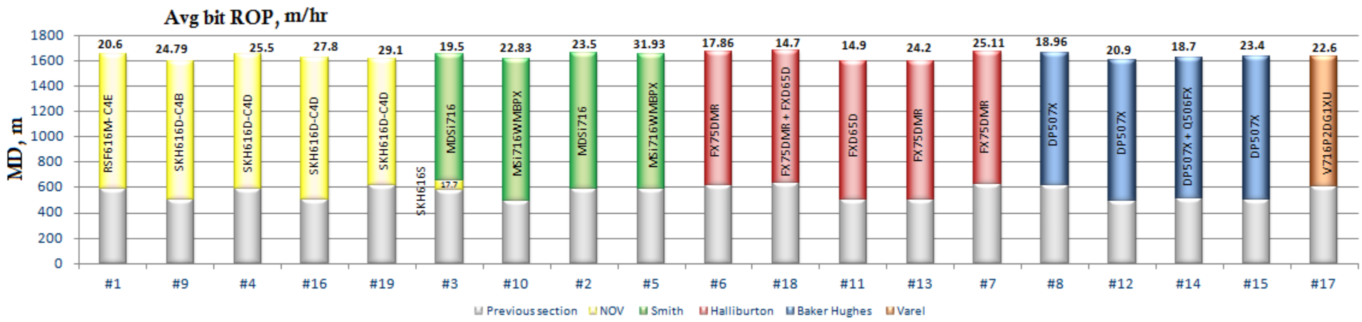


Figure 2.31. Comparison of different 8.5 inch bits' ROPs for the wells from one oilfield with similar drilling environment

3.3. MWD systems

Telemetry tools or MWD tools basically amount to accessing and transmitting data to and from remote locations.

In MWD real-time applications there are 2 telemetry methods [48]:

• Mud Pulse:

  - Positive
  - Negative

• Electromagnetic

3.3.1. Mud pulse telemetry

Both positive and negative mud pulse telemetry systems utilize an incompressible transmission path to carry pressure waves to surface (within drill pipe mud column).

Sensor data can be encoded in a variety of ways, but all methods require the detection of pressure pulses at the surface in order to decode the data.

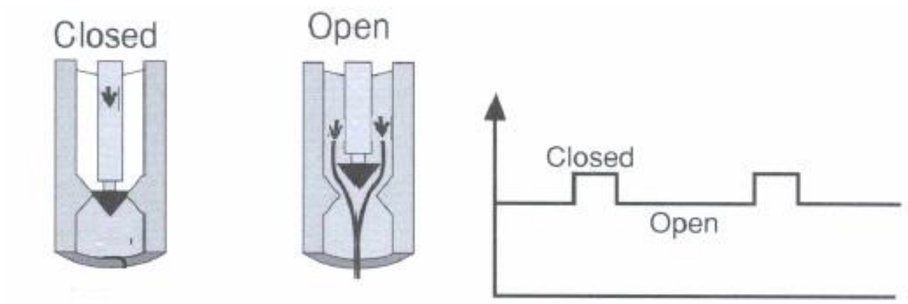


Figure 2.32. Positive mud pulse telemetry

MWD systems with positive pulse data transmitting principle use hydraulic valves to momentarily restrict the flow of drilling mud through an orifice at the tool in the MWD pulser [48].

This generates an excessive pressure in the form of a positive hydraulic pulse or wave which travels to surface in the drill pipe and detected by a sensor on the standpipe.

Advantages [48]:

- Mechanical operations for this type of MWD tool are easy to understand and carry out.
- High reliability when proper maintenance is provided.
- Conventional method with good research and technical base – successfully used for drilling all around the world for more than 30 years.

Disadvantages [48]:

- No air can be in the drilling mud column.
- Relatively slow data transmission rate.
- Advanced signal processing techniques are needed to be applied to decrease noise and distortion effects within the telemetry bands.
- To switch between modes it is necessary to complete a series of pump cycles.
- Use of filter screens is obligatory
- Signal acquisition precision is affected by the formation resistivity and as a result by depth.
- Signal identification is affected by the attenuation level and the noise level.
- Work of the system based on Ohm's law: $V = IR$
- Resistivity directly relate to accuracy of the signal transmission.

3.3.2. Electromagnetic telemetry

Electromagnetic tools inject electric current into the rock formations around the borehole. Data is transmitted by means of current modulation and decoded to final data at the surface. An electromagnetic wave is created, which propagates into the rock formation while being channeled along the drill string. Propagation of EM waves along the drill string is enhanced by the guiding effect of the electrically conductive drill string and casing.

Advantages [48]:

- No restriction on drilling fluid characteristics (water, air, foam, mud)
- Drilling mud can be compressible or incompressible (allows for use in Underbalanced Drilling operations).
- Reduced connection and survey time. Tool is always working; cycling pumps to turn tool on and off is not necessary.
- Full two-way communication between the surface and the MWD tool.
- No moving parts.

Disadvantages [48]:

- Signal attenuation caused by formation resistivity, as a result of geographic locations and depths.
- Relatively slow survey transmission rate

- Higher vibration are possible for underbalanced drilling

3.3.3. Data acquisition methods

There are two methods in which MWD data can be acquired:

- Recorded in memory
- Real-time

3.3.3.1. Memory data measurement process

MWD memory data is obtained by sampling the downhole tool sensors, storing each point of data in the downhole memory, and retrieving these data when the drilling string is tripped out of the borehole. Each data point is associated with some point of time beginning from the time of battery connection. Depth tracking is carried out on the surface during the process of drilling. Synchronization of the probe connection time and depth tracking at the beginning of the drill bit run is very important. During post-run processing operations, the component of time from the depth and data files are matched to make sensor data vs. depth, which can be plotted [48].

Advantages [48]:

- High level of data resolution. Data resolution quality is significantly better than real-time.
- Usually replaces real-time data as soon as it was extracted from the MWD-tool memory.
- Independent of problems with transmission
- No data missed because of surface sensor problems or poor detection.
- Fast rates of sampling comparing to real time methods
- More data survey points per depth interval.
- Data can be stored at a significantly higher rate than transmitted to the surface.
- The same data quality while logging the borehole faster than real-time methods.

Disadvantages [48]:

- No real-time data feedback
- Recorded drilling data is less useful for drilling operations.
- Using recorded data for geosteering and directional drilling is very expensive and impractical.

3.3.3.2. Real-time data measurement process

MWD real-time data is received by sampling the MWD down-hole sensors, encoding the obtained drilling data into a binary format, and transmitting this data through some medium to the operator on the surface. The transmitted signal is typically decoded into the final data at the surface and then processed and associated with drilling depths to provide real-time logging data.

Advantages [48]:

- Data available in almost real-time, so it can be effectively used during directional drilling as well as during geo-steering operations.

- Geo-steering is more effective

Disadvantages [48]:

- Data resolution typically less than for recorded data.
- Sampling interval changes as a function of rate of penetration.
- Any detection/transmission problems will lead to missed data.

3.3.4. Directional survey taking operations and drilling rate (case study 4)

Directional drilling and trajectory control is impossible without taking directional surveys. Directional survey taking can be carried out by means of MWD system. Typically, surveys need to be taken at least every 10 meters for build, drop or horizontal sections and at least every 30 meters for vertical or tangent sections. Drilling program usually contains the information about intervals between surveys for every particular well.

Survey taking operations indirectly affect the drilling rate because typically we need to interrupt the drilling process to take every survey. Before take a survey it is common to ream the interval drilled after a previous survey point. After reaming this interval, driller needs to put the bit in the position above the bottom (usually 1-3 meters above the bottom, but this value may vary depending on the situation). When drill bit is above the bottom drill string stays still – there no rotation. After that we need to stop the pumps for about 1 minute then start them again and wait for a survey data. Only after all this operations we can continue drilling. Typically, it takes from 5 to 15 minute to take a single survey. So obviously, when we take more surveys the drilling rate becomes lower. Though, typically survey time is subtracted from drilling time and thus does not influence the ROP. Still, it is possible to increase average drilling rate by optimizing survey taking operations decreasing their amount where it is possible to decrease, for example on tangent and vertical sections. Also, it may be useful to decrease survey taking time in general by introducing new technologies or updating conventional technology of survey taking. Daily drilling rate can be significantly increased if it will become possible to take a survey without interrupting the drilling process. According to field data, it is common to spend on survey taking operations about 1 hour for every 10-12 hours of drilling.

One of the possible technologies that can help to decrease survey taking time is geo-steering technology. Currently this technology is effectively used for drilling horizontal intervals and especially ERD wells. By means of geo-steering it is possible to stay in the productive zone of reservoir and provide fast real-time corrections in case if there are any signs of drilling out of productive zone. Although, currently it is not possible to carry out a directional survey without an interruption of the drilling process. So even using geo-steering technology it is still necessary to interrupt drilling for survey taking operations especially after corrections in the trajectory.

If we consider the case where average daily drilling time (when the bit is on the bottom and ROP is higher than 0) is 16 hours then typically we will have about 2 hours of hole cleaning operations, 1.5 hours of connection making, 3 hours reaming operations and about 1.5 hours of survey taking. If average ROP is 20 m/hr than obviously we lose at least 1 hour of drilling or 20m every day on survey taking stops.

Typical time balance for one of the common drilling days is shown in the table from the appendix 7. It can be seen that surveys were taken every 30 m and only in the end of the pipe joints. Taking surveys in the end of the pipe joints is a rational decision because of the reaming operations which are obligatory before every connection operation. By taking survey after reaming before connection operations we don’t need to ream for survey itself, for example if we want to take a survey in the middle of the pipe joint we need to ream for at least 10 minutes first and only then we can take a survey.

It can be seen that for 1 day 314.94m have been drilled, pure drilling time (when ROP is higher than 0) is 8.37 hours, surveying time is 55 minutes. It can be seen that surveying takes a significant part of the day time and it can take even more time because in this example surveys are taken only in the end of pipe joints while it is a very common practice to take surveys every 10m.

4. WELL PATH OPTIMIZATION STUDY

4.1. Planning a directional well

Before beginning of drilling operations, all components of the drilling process should be reviewed, properly optimized as much as possible and all necessary and related information should be included into the program for drilling a well. Land locations are surveyed to determine the best areas that will provide suitable access for equipment transportation, drilling rig setting, production facilities with cost consideration. Also, in addition to the main drilling program there are other types of programs that should be prepared as well, including casing program, mud program, directional drilling program, bit program and other types of documents depending on the type of the well.

Drilling fluid program is developed for providing such mud parameters that will guarantee efficient wellbore cleaning, minimal damage to formation and proper development of filter cake. Cement program is required to provide high quality casing support and hydraulic isolation under given bottom hole pressure and temperature.

Casing program should provide data that will help to maintain construction integrity, provide adequate well control, prevent contamination of water, plan for different depths fracture gradients and maintain hydraulic isolation for production formations and pay zones.

Since, it is always important to have the highest ROP as possible, adequate amount of time needs to be spent on bit program preparation to drill the well in the most effective manner. Offset wells drilled previously in the particular area need to be reviewed, to identify potential problems that may occur during drilling process. Proper bottom hole assembly and string design need to be prepared which will meet all safety parameters.

The service company providing directional drilling services will review all the same components of drilling process and will apply this data to calculate a well profile and identify equipment limitations for every particular job. For example mud properties need to be fully compatible with the MWD equipment and steerable motors. Hole cleaning capabilities for directional wells need to be reviewed as well. The selected steerable mud motor must provide optimal performance for chosen hydraulics otherwise it is better to find other type of motor more suitable for particular situation.

BHA and drilling string designs need to be suggested by the service company. Designs must allow the highest rate of penetration for various conditions of drilling. In some particular cases the well path that was planned initially cannot be drilled with the drilling string and equipment available on the drilling rig. In such case changes of well trajectory are recommended because it is simpler to change a well path than to wait for necessary equipment.

Drilling bit types suitable for vertical wells most probably will not be suitable for directional wells. Some PDC drill bits may provide the optimal ROP for the oilfield but may not provide the directional steering control as needed. Additionally, special mud motors will be required to provide a sufficient value of horsepower to the bit. If there is a sidetracking operations planned then special diamond drill bits for sidetracking may be required.

Oilfield formation knowledge is very important for directional drilling for minimization of possibility of potential problems and improving a drilling time. Let’s consider a well plan with a small target size and with very low kick-off point in formations with a history of unstable or unpredictable build rates. In such situation several events can happen:

• Planned DLS is provided and target will be reached as planned

• Aggressive orientation control operations will be required like drilling only with slide thus the ROP may be half of normal

• Additional bit runs may be required to change the mud motor bent settings according to the drilling situation at some point of time

• Dog-legs may be unstable which may cause significant problems during casing running operations

• Target can be missed and well must be sidetracked or plugged

If necessary, a directional drilling service company will review the pad plan and will provide recommendations to reduce costs of drilling for this well pad. When one service company is involved in one project from the beginning and thus knows all the information about all production requirements, possible multi-laterals, future reentries and sidetracks well path can be designed more optimally.

4.2. Profiles of directional wells

There are several types of trajectories used; 1) Slant well type, 2) J-type, 3) S-type, 4) ERD wells and 5) Horizontal wells. It is possible to combine these profiles if necessary. For example most of the ERD wells are typically horizontal [51].

4.2.1. Slant type wells

Special drilling rigs need to be used for drilling and completion of these types of wells. The well drilling is started from beginning with an angle inclination value higher than 0^{o} (up to 45 degrees). Such kind of profiles is often used for shallow wells when it necessary to hit the target with a horizontal displacement greater than 50% of the well TVD. It is also may be used on well pads to drain some area of oilfield with several wells from a central site. One of common patterns for such situation is the star-shaped pattern. By using it is possible to drill up to 27 wells from one drilling site. Reduced lease costs and spending on production facilities may be very substantial [51].

4.2.2. J-type profile

This is probably the most popular profile for directional wells. It consists of a build section to some preplanned angle and hold section where the angle is held until the target will be reached. Often, when the target is close enough and there is no possible risk of missing this target the directional control tools may be run out and detached [51]. After that, the hole maybe finished with rotary BHA without further directional control. Inclination for J-type wells is typically 15-25^{o}.

4.2.3. S-type profile

The S-type well path has a build section, hold section and drop section where the inclination angle is dropped down to values close or equal to 0 degrees. S-profile can be used the following reasons [51]:

• Reach several targets without changes of horizontal displacement

• Provide a necessary horizontal displacement and in the same time allow drilling through troublesome or severely faulted formations in a almost vertical mode

• Avoid faults and other geological problems

• Minimize the inclination in the fracking zone.

4.2.4. Extended reach wells

A significantly modified and complex J-type wells that usually have an inclination angle values between sixty and eighty degrees with a horizontal reach that is values of the TVD between 4 and 6 times. One typical location where such wells are in common is off-shore oilfields where drilling occurs from a drilling platform.

4.2.5. Horizontal with multiple or single legs

A well path of horizontal well consists of a build section to 90^{o} (typically from 88 to 92 degrees) with a horizontal section which have to be held through one reservoir formation without exiting it. Additional lateral legs can be drilled from the first wellbore into different zones or into different regions [51].

4.3. Information required for planning

In order to provide the most effective plan for a directional well that will be cost effective and safe, lot of information is needed. By reviewing and analyzing this information and drilling requirements for every particular case the best drilling plan can be selected which will meet all of the drilling politics and procedures and produce a wellbore with high enough production parameters. The well planning process involves variety of disciplines which must be successfully combined and used in the final well path proposal. Well planning process does not require input of all information from each division for absolutely all wells, but the more complex the drilling environments and well path is the more important a good contact and synergy within the departments and with the service company providing directional drilling services.

4.3.1. Geology

Geological information provided by company operator to directional drilling company is the first step to understand limitations of the particular area where drilling is planned. All geological data gathered is important to the process of drilling operations and communication at this stage is the make or break point of the wellbore [51].

• Lithology of the well (shales, limestones, sand, coals, medium hard rock formations, sloughing tendencies, salt, marker zones)

• Water/oil and gas/oil boundaries locations

• Geological control quality

• Target formation type and its properties (channel sands, a seismic irregularity, pinnacle reefs, infill drill or exploration)

• Target geological structures (faults, dip, shales)

• Regulation issues (Gas/oil boundaries, anti-collision, final MD and TVD)

• Well type (exploration, injection, oil/gas production)

• Possibility of sidetracks in future

4.3.2. Completion and production

Completion and production issues sometimes can be missed during well planning phase. That can result in expensive errors in the future if the needs were not properly considered during well planning phase. Planning responsibilities related to completion and production:

• Location for new facilities and possibility of moving existing facilities after finished active drilling on the pad

• Completion type (fracking, pump rods etc.)

• Maximum inclination angle and DLS limits based on production and drilling requirements

• Positioning of well with relation to the future production plan

• Pressure gradients and temperatures

4.3.3. Drilling

Drilling company usually controls all main operations and provides connection between all parties related to the drilling process. Typically, estimation of costs and economics also rest in the hands of drilling company. As a result, the representatives of directional drilling company (well planner and directional drillers) spend most of the time consulting with specialists of drilling company. Although, other parties also have as much as important data and information, the drilling specialists and representatives control the drilling process directly and most of the time they make final decisions on any kind of issues that may occur during drilling process [3, 51].

• Selection of the drilling location for centre of the well slot

• Casing construction and depths of casing shoes

• Section sizes

• Drilling mud parameters

• Choice of rig type, drilling equipment and their capabilities

• Confirmation of the final well path and types of survey methods and equipment

• Drilling data from previous wells and identification of possible drilling problems typical for the area of drilling.

4.4. Planning process

As soon as all the information and data have been received from the different departments in operator and drilling contractor companies, a directional drilling program that meets all the requirements should be prepared. Well planning engineer must take into consideration all possible issues that may contribute or affect the success of the drilling process or may have an impact on the time factors. It is especially important for drilling pads with multiple wells and may save significant expenses if utilized properly.

It is quite easy to plan a well path from point ‘A’ to ‘B’ but it needs lots of operational expertise and knowledge to provide a profile that will meet all requirements for given hole size and geology and will be drilled without unnecessary runs to change elements in BHA. There are some of the main rules for preparation of well paths [51]:

• Average DLS kept at 2-3^{o}/30m for oil wells with pumps. Actually, most of the wells are planned with this build rate except for the horizontal wells where build rates should be higher to reach the final target. Generally, most of the operator companies use to keep the DLS less than 8-9^{o}/30m, thus the well trajectory plan have to be no more than 7^{o}/30m to allow some operational variations.

• The hold interval for J-type profile types should be 50m or longer to allow possible adjustments in case of troubles in achieving planned DLS.

• The rate of angle drop for S-type wells is preferable at 1.5^{o}/30m but may be changed up to 2.5^{o}. For higher drop rates differential sticking or key-seating may occur in softer formations.

• KOP should be as low as possible because will lower directional costs and decrease possibility of early casing wear especially for producing wells. KOP must be placed in only competent formation's layers.

• KOP should be in formations allowing the planned DLS to be achieved.

• On ERD wells the KOP should be low to provide a larger vertical interval which is vital for applying enough WOB.

• Different build rates are possible for the mud motors in every specific borehole size. These rates are most standard for mud motors.

311 mm borehole - up to 10^{o}/30 m

222 mm borehole – up to 14^{o}/30 m

159 mm borehole – up to 25^{o}/30 m

121 mm borehole – up to 35^{o}/30 m

• Keep distance between sidetracks at least 20m apart.

• If possible do not place the KOP for sidetracks until 20m distance from casing point or further.

• Assume DLS of 12-15^{o}/30m may occur while kicking off from whipstock.

• Anti-collision procedures need to be applied for all neighboring wells.

• Design a trajectory in the way that will provide minimal percentage of borehole drilled by the motor sliding in the oriented mode. The rate of penetration while sliding typically twice lower than for rotary mode.

4.5. Selection of DLS for well path

Before choosing the DLS for build and drop sections it is vital to consider several factors. First of all it is necessary to decide about the preferred build rate (short radius, medium or long). Long radius are the most time consuming and more costly than other radius types. Medium radius wells are more common though it requires higher DLSs which lead to a lower TVD tolerance in case of formation tops come up at depths different from planned. Short radius wells require the most clear and accurate geological data and special drilling equipment will be needed as well so the directional drilling costs will be higher. Additionally, the bending stress produced by short radius DLS require special type of tubing - high strength tubing [3]. Usually a short radius is used for sidetracking, re-entry operations and when the geology changes unpredictably and to fast with increase of distance to the surface. When indentifying proper build rates the possibility of errors in final build rate on the finished well should be considered [51]. Figure 4.1 shows the change of TVD for the build rate changes ±10%.

Long Radius - 6^o/30m or less

Medium Radius – between 6^o/30m and 40^o/30m

Short Radius - more than 40^o/30m, typically up to 100^o/30m

These classifications may be applied to borehole size vs. DLS.

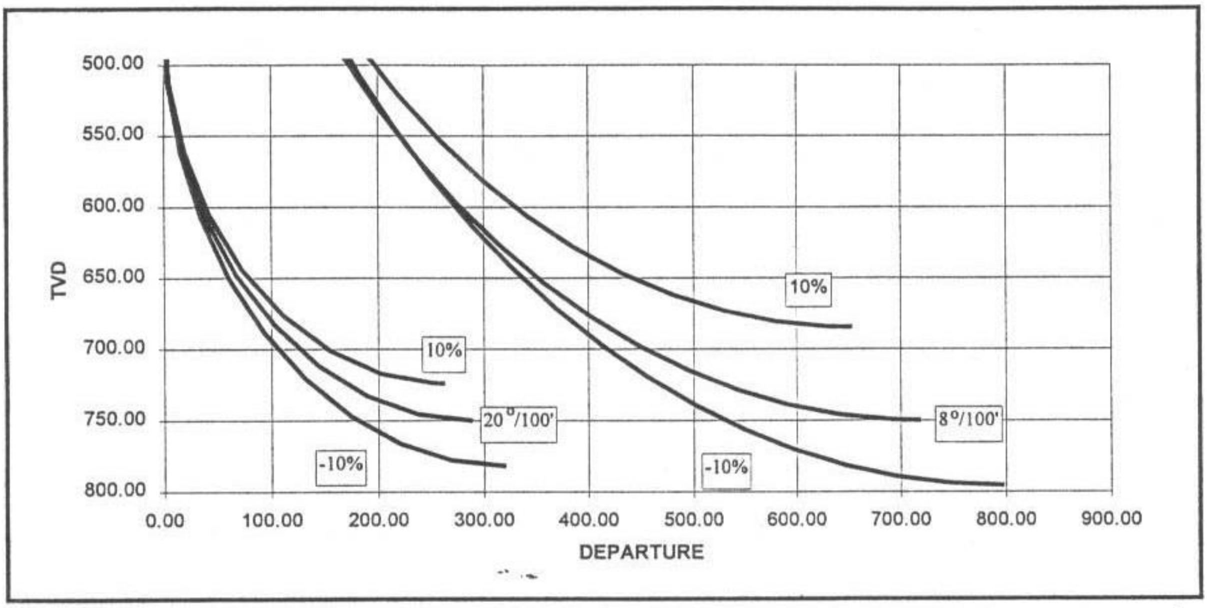


Figure 2.33. TVD variance with an error in achieved build rate

Final choice of the build rate of angle is usually based on available kick off points or other preferences. Higher values of build rates are more typical for boreholes with small diameters while low build rates are common for bore holes with larger diameters. The DLS limit for 4 ½" drilling pipes is 18^o per 30m in the same time the DLS limit for 3 ½" drilling pipe is 23^o/30m. Fatigue can become a serious problem for too high DLSs. Additionally, the directional control tools like as mud motors cannot build angle as fast in a larger diameter boreholes as in a smaller diameter. An 8.5 inch borehole is limited to 15-18^o/30m DLS depending on the type of motor configuration being used. A 6 inch borehole is limited to 22-25^o/30m DLS though there are short radius drilling tools which can be used for high DLS trajectories [51].

The company-operator has to decide what build rate is better to use. Commonly, higher build rates provide faster angle change and thus drilling in steering mode takes less time. On the other side, higher build rate required more sliding operations and it is known that ROP in the sliding mode twice lower than in the rotary mode. More precisely, the build rate can be determined by depths of casing shoes and by possible borehole. After selection of kick off point, the build rate can be calculated.

When requirements for target placement are tight, it may become necessary to adjust or correct well path during drilling process to hit the final target. The build rate for most of mud motor assemblies is more or less predictable. If there are previously drilled wells in some particular area, then it will be easier to predict possible build rates for every interval. In drilling areas where little or no previous experience exists, it is not unusual to plan the well path with a soft landing or a tangent section. This tangent section is a short interval included in the build curve interval planned to be drilled with constant inclination. For instance, the trajectory can have a build interval with 13^o/30m DLS up to 46^o, then a 40m interval will be drilled at 46^o before continuing to drill with 13^o/30m build rate.

Such tangent section makes it possible to have some difference between planned and actual DLSs during drilling. If the actual build rate is less than planned then the well will reach 90^o with higher TVD. If build rate is higher than planned one, then the well will reach angle of 90^o with smaller TVD – above planned level. Including of short tangent interval provide compensation for such differences. If the real build rate is considerably greater than anticipated in the first place, the tangent section can be made longer. On the other side, for build rate lesser than planned, it is possible to shorten the tangent section or eliminate it at all. These special tangent sections are not necessary to include in plan for wells with big enough targets [51].

Otherwise it is possible to include in plan a “soft land” section. For “soft land” section we have to reduce drilling build rate when we are close to target - usually last 3-10m by TVD. “Soft land” section will make it possible to provide slight changes in trajectory design and in depths of casing landing. Additional bit run may be required to change mud motor bent sub settings though usually it is not obligatory since build rate can be decreased by decreasing amount of slide operations. Additional trip will be expensive and thus it is better to be avoided if possible.

4.6. BHA performance considerations

Active deviation operations are better to be finished in the upper sections of the hole. Kick-off point should be below surface casing shoe or below intermediate casing shoe. Finish the build is better before the next casing string running. After active deviation phase of the drilling process is finished it becomes possible to use rotary assemblies for the next sections. This kind of approach maximizes rate of penetration and minimizes total drilled footage.

Deviating BHAs can work predictably only when hole is in-gauge diameter. If there are any borehole enlargement issues in the kick-off part and if drilling fluid’s design or modification of other drilling parameters cannot solve these problems, then the kick-off direction and quality control may be complicated, depending on the ROP and rate of borehole enlargement. It would be better to case these problematic zones before beginning of the directional control. For example, if the kickoff point chosen too shallow and there are unconsolidated sand formations at that depth range, there may be some problems related not only to the direction control but to hole cleaning and tripping as well. Also there can be increase of possibility of sidetracking in the well while reaming. Directional control is more effective while parameters of BHA and other drilling parameters are optimal [3].

It should be avoided to set the casing immediately above or in the kick-off interval. Setting casing near kick-off point interval may lead to casing shoe key seating, which can lead to significant problems with running of casing up to high possibility of stuck in the hole.

Rotary drilling assemblies have a tendency of turning right in considerable amount of cases. Such problem may be compensated by finishing the build interval on the left side from the planned azimuth. Using high WOB with tangent section BHA to maximize ROP typically may give a slight angle build tendency. Setting the inclination angle 2-3° below the planned value to would compensate for this, but it is better to analyze previous cases of drilling in the same interval on the particular oilfield before doing that, because in case if build tendency will not occur then it is possible to lose control on the trajectory and drop the angle to low. With proper offset data from other wells it is possible to consider finishing the build section with trajectory pointing a drill bit above the lower edge of the target. This should provide higher ROP and allow applying higher WOB and capacities for the maximum tolerance and a slow build.

When finishing the build interval 1-2 degree higher than planned trajectory and later drop the angle, ROP will be compromised due to the lower WOB necessary for pendulum assemblies. However, if building will be needed then short length build assembly will need additional WOB to work so rate of penetration will not be decreased in such situation.

If corrections are needed to be done during the drilling process, it is better to carry out them sooner than later. [3]

4.7. Kicking off the well

Kicking off is basically the separation from vertical of the wellbore with inclination angle growth. When drilling is carried out from pad or platform with several wells then it is obligatory to provide anti-collision control including proper well planning. From the first view it looks like highly impossible that one well will collide in another though according to field experience such situations happen time to time even when all anti-collision control is carried out. Sometimes only one error in planning or directional drilling may lead to well collision [3].

If the kick-off point is placed relatively deeper, then close neighboring wells can be “nudged” in some appropriate direction. This will provide additional separation in the necessary direction. So-called nudge may be achieved by using a whipstock, jetting or with a mud motor.

It is possible to turn conductor while driving it and once driving starts it is still impossible to stop it. In the worst case scenario, the conductor can become unusable because of the high dogleg to miss all of the nearest wells [3].

4.8. Kickoff and build

When the KOP is reached, the trajectory has to be steered in the planned direction with inclination angle build. If the well path is a simple J-type profile then the kick-off interval will be ended when the wellbore trajectory is generally pointing in the target direction with some inclination angle usually more than 4-5 degrees [3].

Rotary assemblies for tangent drilling often have a tendency to slowly turn to the right in the process of drilling. It can be compensated by completing the build section interval to the left side from the planned azimuth. Also, we can decrease this tendency by increasing ROP when it is possible. For high enough ROPs described tendency may be even reversed [4].

Another interesting fact for rotary BHAs is that by applying high WOB to maximize rate of penetration it is possible to acquire some build tendency. In such case, it is better to leave 1-2^{o} below the planned inclination at the end of the kicking-off [3]. More WOB will provide the stronger building tendency. If the BHA is locked up, full drill bit characteristics can be used for maximal ROP while the build tendency will be small.

Another important thing for planning the end of the build interval 1-2^o lower is that if we build angle higher from plan too much and thus later we have to drop it, then we will compromise rate of penetration with the low WOB needed for drop-off assembly's effective work. However, if we need to build angle, a short-build BHA can be used which needs less WOB to work so the ROP will not be decreased too much. Pendulum BHA's for dropping the angle may lose horizontal control and thus can be less predictable by azimuth direction. Pendulum assemblies are also have tendency to drill a spiral borehole while inclination angle value decreases considerably to the vertical and this can be very important to stability of the well, sticking tendency, borehole drags and wear of casing.

If data from neighboring wells indicates that particular formations have some predictable tendencies in well deviation then the well plan can initially incorporate such tendencies and modify some parameters of trajectory for example kickoff point. If a long interval of slow angle build is expected in the tangent section (in correction purposes for example) then it will be useful to apply some data from offset wells to improve the well path. [3]

4.9. Drilling the tangent section

The tangent sections are designed to be drilled without changes in azimuth and inclination angles. However, the wellbore is never completely straight even if drilled with the most precise methods. Trajectory is always influenced by the drill bit, drilling parameters, BHA parameters, and geological formations characteristics.

With a rotary BHA rotating clockwise, the side forces are generated at the drill bit and turn it slightly to the right. Tendency is higher with lower ROP, also if the drill bit gets dull.

Typically the tangent interval needs to be drilled as quickly as possible, DLS should be minimal and wellbore should not be overgauged or spiral so different logs and later casing tubing can be run into the bore hole without problems [3].

4.10. Dropping hole angle

Sometimes it becomes necessary to drop the inclination angle. Most common reason for that is drilling drop interval for S-type trajectory. For angle drop process, either mud motor assembly or pendulum assembly is required.

Most often, a simple rotary BHA is preferred. Common problem with a mud motor assembly is that when the mud motor tool-face is pointed to the low side of the borehole, the motor tends to flip over as soon as reactive torque is applied as the drill bit contacts the borehole bottom. Holding the mud motor bent in the lower side position may be complicated if the well is deep and angle is close to 80-90 degrees. A steerable BHA is preferred to a mud motor-bent sub BHA combination because the steerable BHA has a smaller bend near the drill bit.

Parameters of drilling are very important with a pendulum rotary assembly. Until an angle dropping trend will be established, only low WOBs should be applied. As soon as the dropping trend is identifiable, it becomes possible to increase WOB. Increase of WOB will improve rate of penetration, also it can increase the angle-drop rate a bit more because it forces the collars in the drill string to buckle due to the bend in the BHA between the drill bit and the second stabilizer.

It is obligatory to carry out reaming operations before each connection especially in soft hardness and medium hardness rock formations.

Applying maximal values of hydraulic force can help to crush rock formations at the drilling bit face helping to drop angle even a bit more. [3]

4.11. Anti-collision study

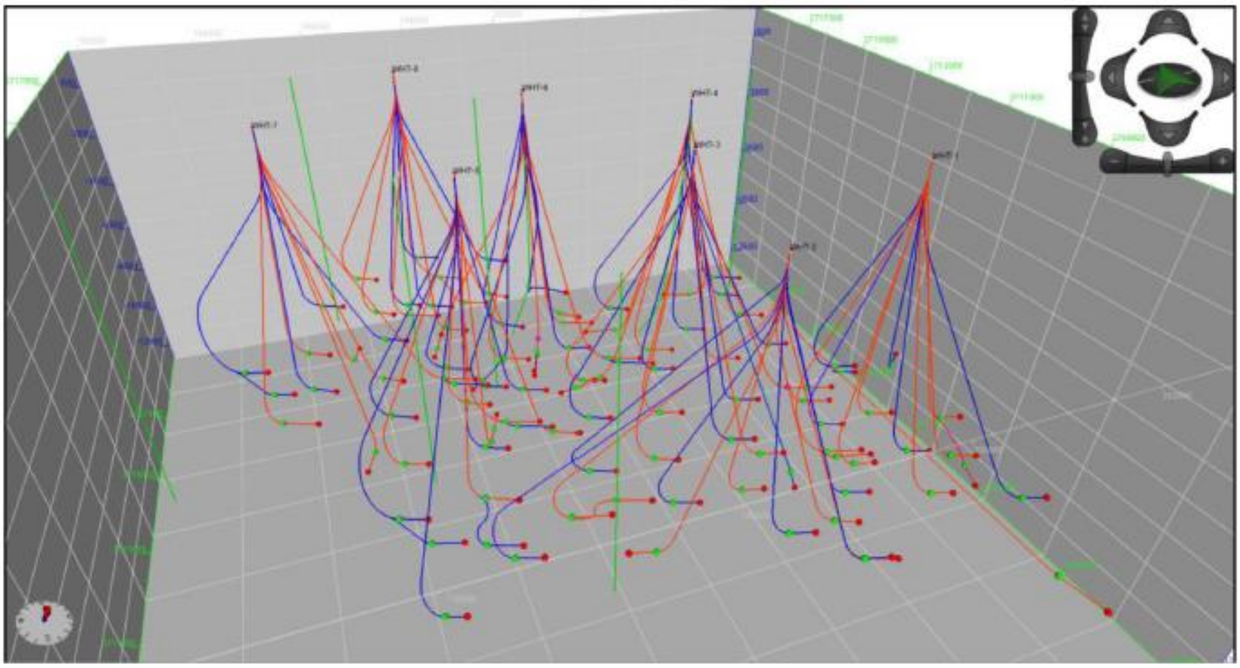


Figure 2.34. Software view of drilling survey database for one of the oilfields

Anti-collision analysis is a vital part of the well planning process for such cases. Shortly after pad drilling started (from historical point of view) the danger of well collision became much more important thus anti-collision methods and programs were present. By gathering the survey data imported from neighboring wells, drilling engineers provided anti-collision control and gave some solutions in situations where collision is technically possible. Anti-collision standards are applied for identifying possible problems. Alert indexes were introduced to identify problems in wells more effectively. It is typical indicators for an anti-collision analysis like center to center distance and separation factor which help to assess fail major risk and pass major risk [49].

According to the anti-collision policies introduced in the drilling databases, the same type criteria were applied on the projects ensuring consistency and minimizing the possibility of collision. For example, if the drilling depth was less than 3000 ft MD, then the minimum separation distance between the uncertainty ellipses of the two wells is about 1% of the total drilling depth.

This typical anti-collision analysis, applied for each well where problem exists, assumes that in case of the collision risk a manual correction of the well paths is necessary with purpose to make separation factor on the problematic depths higher than minimal values (according to standards). Figures 4.3 and 4.4 show the example of anti-collision analysis results obtained in "Landmark WellPlan" software program.

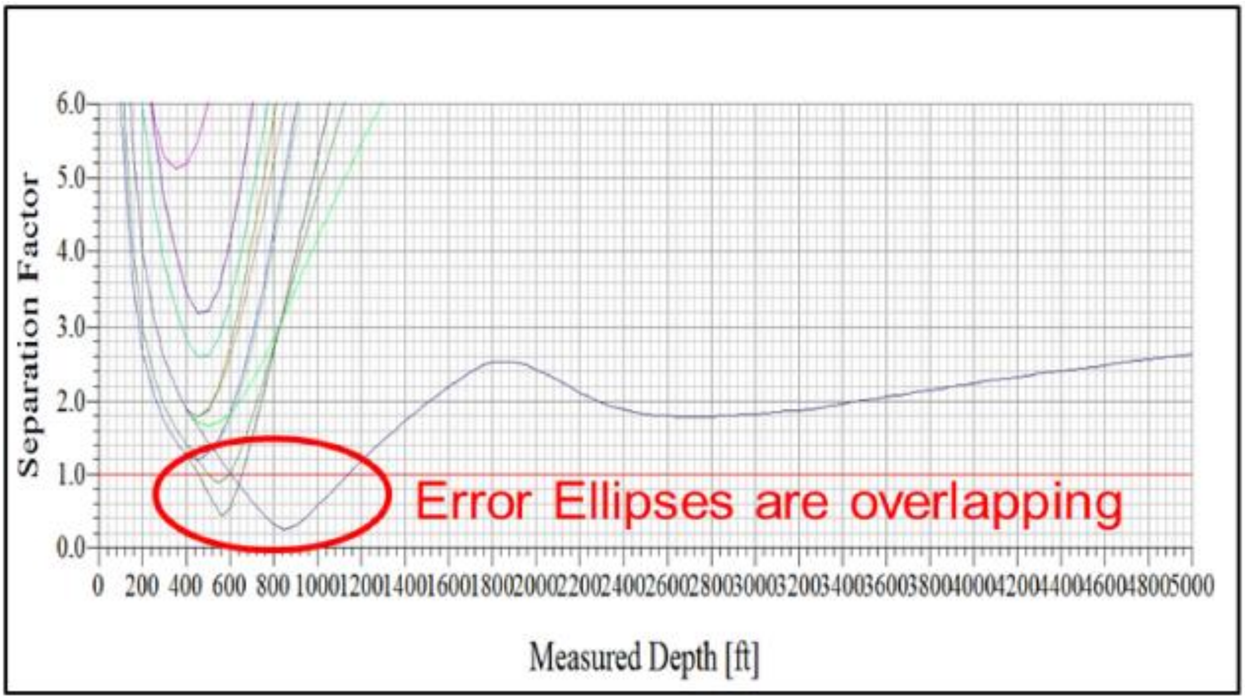


Figure 2.35. Well with anti-collision issues before corrections.

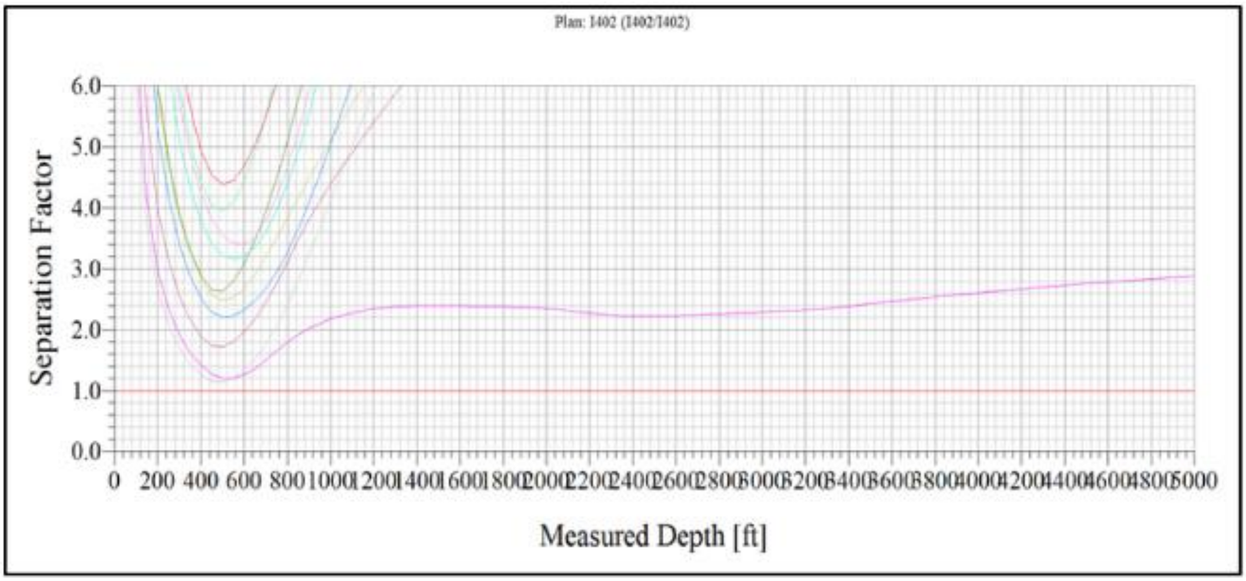


Figure 2.36. Well with anti-collision issues after corrections.

4.11.1. Possible reasons for collisions

• Human factor

• Poor quality of procedures and practices

• Inadequate improper well planning

• Lack of cooperation between directional drilling service company, drilling company and operator company

• Inadequate survey measurements in database

• Errors in measurements

• Missed measurements for one or several wells on the oilfield

4.11.2. Anti-collision techniques used in the planning stage

- Database should contain only final confirmed measurement surveys

- Common coordinate reference for all survey measurements on the field - true north or magnetic north coordinate system

- Cylinders should be used for identifying trunk bends during planning

- Risk assessment based on separation factors analysis

- Realistic risk assessment criteria

- Design BHA according to the situation

4.11.3. The techniques used in the drilling stage

- Field circuit - cylinders application and pad preplanning

- Directional drilling program taking into consideration the possible risks if any

- Use of special software programs for precise anti-collision analysis and control

- Field engineers always should check the directional drilling plan before start of drilling

- Daily anti-collision control

- Any deviations from the initial plan should be reported and analyzed

- Measurements should be uploaded into databases on daily basis or even more often there are collision risks.

• Methods of measurement calculation:

- Balanced Tangential

- Radius of Curvature

- Average Angle

- Minimum Curvature

There is some uncertainty of measurements can be due to the variety of factors like errors in azimuth angle measurements, errors in relation to the north, depth errors, errors because of the magnetization of the tubes and environment, errors due to the gyroscope drift [50].

4.12. Decreasing DLS

When the trajectory control is carried out by means of BHA with steerable mud motor and MWD system it is necessary to drill sliding intervals to steer the borehole in the necessary direction. The process of sliding described in more details in the previous chapters. It is important that the ROP during sliding usually 40-50% lower than during rotating. Thus it is obvious that when we drill with sliding longer intervals the total ROP gets lower and lower. The main reason why we have to carry out longer sliding drilling intervals is high dog-leg severity on these intervals. Higher dogleg severity typically means that it is necessary to drill longer sliding intervals and shorter rotation intervals. In some cases it may become impossible to drill with rotation at all. Considering this we may assume that it is possible to increase the ROP by decreasing DLS of the well path and thus decreasing amount of possible sliding.

Decreasing DLS is one of the well optimization objectives. Drilling or well planning engineer always have to provide the well path with DLS as low as possible. High value of DLS not only leads to increasing amount of sliding but also may be the reason for sticks and slips of tools in the hole, for increasing friction factors in the well and for stuck of equipment in the hole. Although, we should keep in mind that the main goal for DLS optimization is choosing the most appropriate value of it not just to decrease it to minimum. In some cases higher DLS can be more desirable.

Control for DLS is an ongoing process. It starts when well planning engineer prepares the well path and then continues during the whole drilling process until the end of drilling. It is prohibited to drill with DLS which differs from the planned DLS for particular interval.

If we consider two wells which will be drilled in the absolutely similar environment with application of the similar methods and techniques then it will be possible to introduce coefficient or index which will show the relativity between DLS and ROP. To provide such coefficient we have to consider several wells which were already drilled on the same oilfield.

Let's consider three wells with similar parameters and in similar environments drilled on the same oilfield. To provide the index we need the next parameters for every well: average planned DLS, averaged real DLS (after drilling was finished), average ROPs on different intervals, percentage of sliding and rotating.

4.13. DLS influence on the total ROP analysis (case study 5)

As it was mentioned before, total ROP can be severely affected by the amount of sliding operations carried out on the well during drilling. And it is clear that when directional drilling performed with a steerable mud motor the amount of slides will be higher when the DLS is higher. One of the goals of this paper is to find relation between DLS and ROP and provide a coefficient that can describe it. This can be done by considering drilling parameters of several directional wells drilled in the past. First of all next parameters need to be taken into consideration: average DLS, motor dog-leg, length of the intervals drilled in the sliding mode and in the rotating mode, ROP on each of these intervals.

For this purpose 6 wells drilled on the same oilfield has been considered.

To find our DLS coefficient we need to create an equation based on the real drilling data from these wells.

According to the calculations carried out with parameters of 6 wells the average total ROP can be found from the next equation:

$$ROP_{total} = ROP_{rot} \cdot (1 - n \cdot DLS) + ROP_{rot} \cdot vn \cdot DLS; \qquad (4.1)$$

Where "n" is an average percentage (from length) of sliding from the whole drilling interval necessary to maintain build/drop of 1 degree/10m. For the chosen wells n=0.25. "v" is an average drilling rate drop while drilling without rotation. "v" is commonly equal to 0.5-0.6 for any case in general. For chosen well average v=0.56.

Equation 4.1 can be used to estimate possible ROP_{total} based on the data from the previously drilled wells. Typically, if we have drilled several wells on one oilfield we can forecast ROP in rotation mode for the future wells. We also can forecast possible decrease in ROP while sliding - "v", though this value usually is more unpredictable. For equation 4.1 we assume that ROP_{rot} is our forecasted or modeled ROP for rotation mode. Based on the data from previous wells we may apply coefficient "v" to this ROP_{rot} to receive average possible $ROP_{sliding}$ so basically in this equation we consider that:

$$ROP_{sliding} = ROP_{rot} \cdot v; \tag{4.2}$$

Equation 4.1 can be simplified like that:

$$ROP_{total} = ROP_{rot} \cdot (1 - n \cdot DLS) + ROP_{sliding} \cdot n \cdot DLS; \tag{4.3}$$

This equation can be used to forecast possible ROP_{total} for the well with some particular trajectory drilled with mud motor. Based on this equation it can be said that higher DLS will lead to decrease of ROP_{total} for some particular drilling interval due to the increase of the distance drilled with sliding.

It should be taken into consideration that on all of the chosen wells except one the motor bent angle value was equal to 1.83 degree. If the motor bent value is higher it is possible to provide higher DLS on the same sliding interval. But usually it is impossible to setup motor bent higher than 1.83 degree since it is prohibited to rotate the drilling string at all while motor bent values are high due to the possibility of motor damaging. So, if the motor bent will be 2.12 degrees for example, than according to the safety standards we will need to drill 100% of interval in sliding mode which is very slow. Thus high motor bent values typically can be applied only for sidetracking operations or for other special cases when we really need a high build rates on the short interval.

For the chosen case we can use the next equation:

$$ROP_{total} = ROP_{rot} \cdot (1 - 0.25 \cdot DLS) + ROP_{rot} \cdot 0.56 \cdot 0.25 \cdot DLS \tag{4.4}$$

Coefficients "n" and "v" are found based on the field data which can be found in tables 4.1 and 4.2.

Results of application this equation on the chosen wells can be seen on figure 4.5

It also worth to notice that ROP_{total} can be found in the field environment for already drilled interval by using simple equation:

$$ROP_{total} = (L_{rot} + L_{sliding})/(T_{rot} + T_{sliding}); \tag{4.5}$$

Where L_{rot} is a length of interval drilled with rotation, $L_{sliding}$ is a length of interval drilled with sliding, T_{rot} is a time of drilling with rotation and $T_{sliding}$ is a time of drilling with sliding.

Equation 4.5 is a quite typical equation used in morning reports and drilling slide sheets for ROP_{total} calculation.

Since all of the ROP models do not take into consideration influence of directional drilling control operations it may be considered that the ROP value resulted from such models including Bourgoyne and Young model is the ROP for rotating mode. Thus if we want to provide more precise model of ROP for the directional well we can apply equation 4.1 or its alterations to find the total ROP which will be lower than ROP calculated from the ROP model.

If we want to increase total ROP then it could be useful to consider using such directional control methods like TBS or RSS. These methods analyzed in more details in the chapters 2 and 3.

Well#	Motor bent angle, (deg)	Avgd DLS (deg/10m)	MD from, (m)	MD to, (m)	Interval, (m)	Avg ROP for slide, (m/hr)	Avg ROP for rotor, (m/hr)	Avg Total ROP, (m/hr)
1	1,74	2,05	1820	2115	284,7	6,6	8,9	7,6
2	2,12	1,76	1848	2287	439	2	7,5	4,1
3	1,83	1,01	1729	2015	286	5,1	9,4	7,7
4	1,83	1,47	1677	2003	326	12,9	21,3	16,6
5	1,74	2,29	1660	1969	309	2,4	5,1	3,3
6	1,83	2,71	1710	2050	340	6,4	8,4	6,8

Table 2.5. Drilling parameters for chosen wells

Well#	% rotary (m)	% slide (m)	% rotary (hr)	% slide (hr)	Rotating (m)	Slide (m)	Rotating (hr)	Slide (hr)
1	52,1	47,9	44,7	55,3	148,2	136,5	16,67	20,6
2	69,2	30,8	38	62	304,2	135,3	40,65	66,33
3	74,6	25,4	61,4	38,6	213	72,4	37,07	14,32
4	56,7	43,3	44,3	55,7	184,8	141,2	8,68	10,93
5	51,1	48,9	33,2	66,8	158	151	31,25	62,88
6	27	73	22	78	90,8	245,4	10,82	38,35

Table 2.6. Drilling parameters for chosen wells (continued)

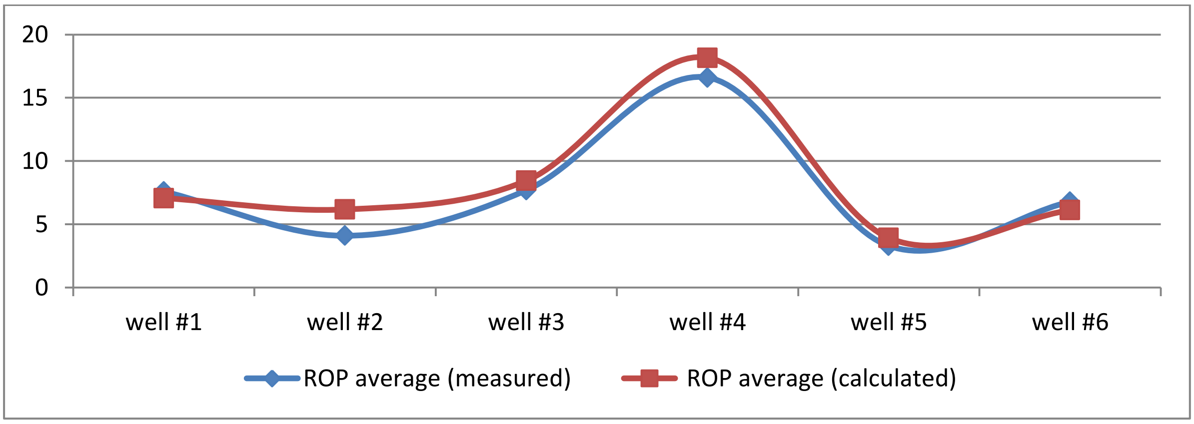


Figure 2.37. Comparison of real ROP and calculated ROP for chosen wells

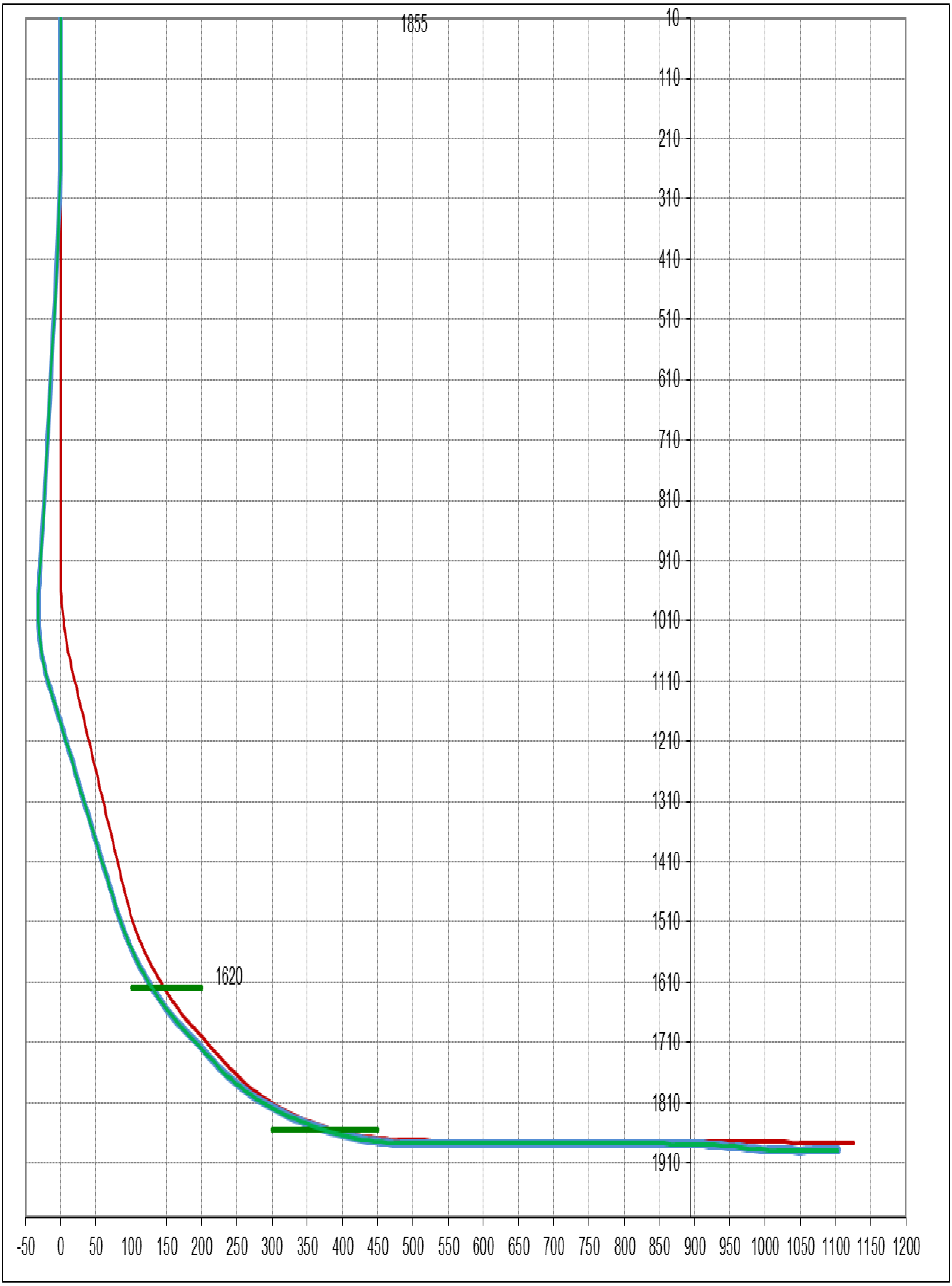


Figure 2.38. Vertical projection of well#4

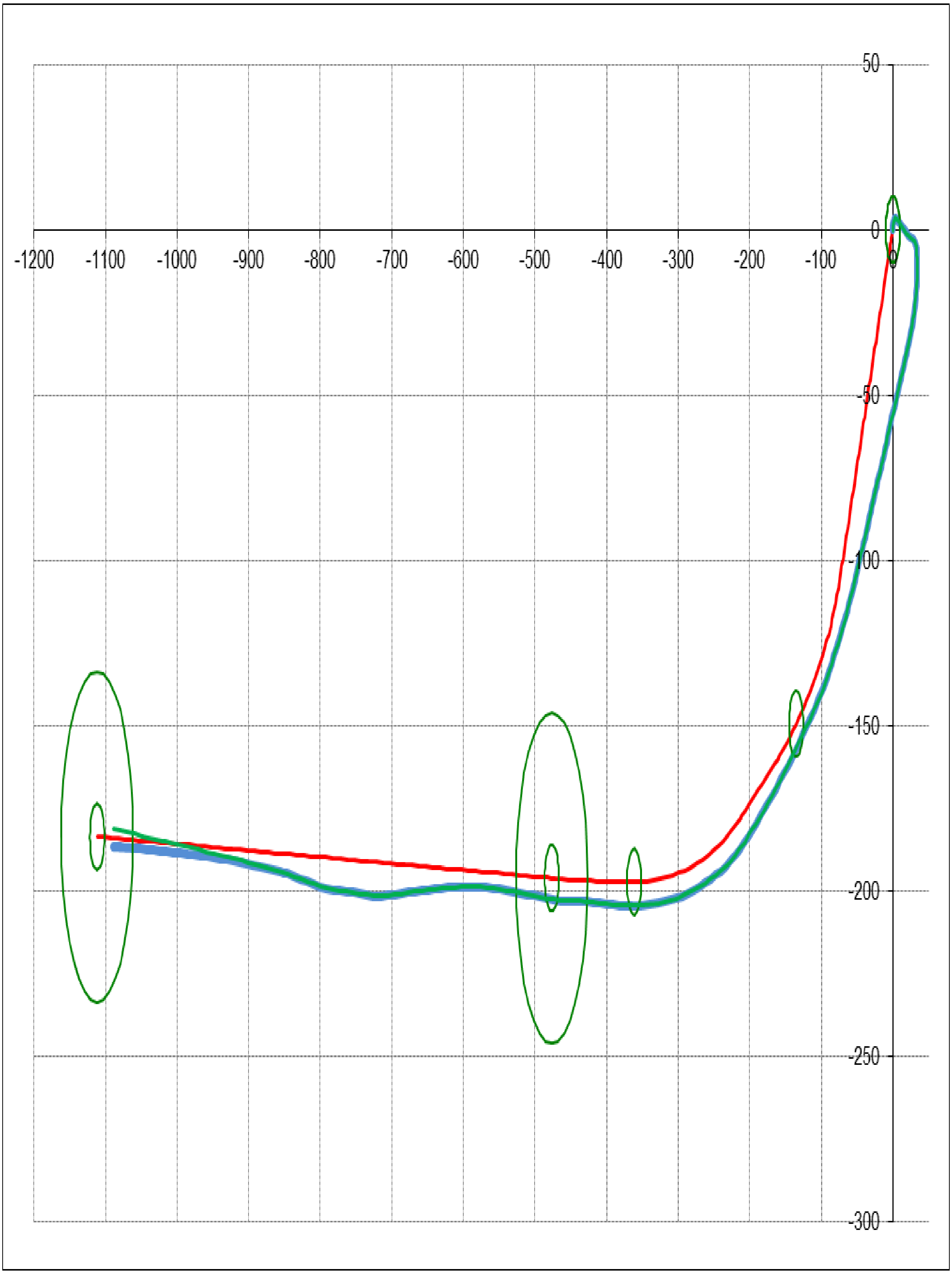


Figure 2.39. Horizontal projection of well#4

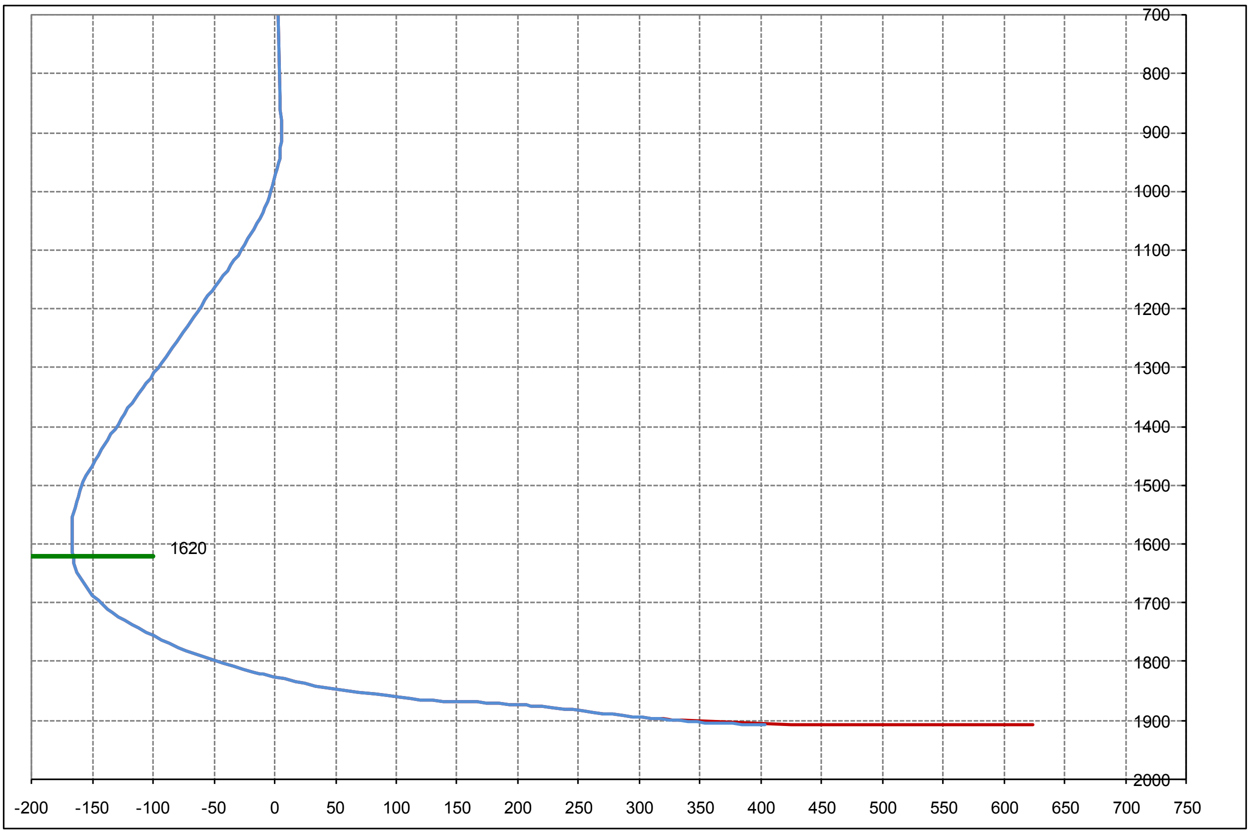


Figure 2.40. Vertical projection of well#5

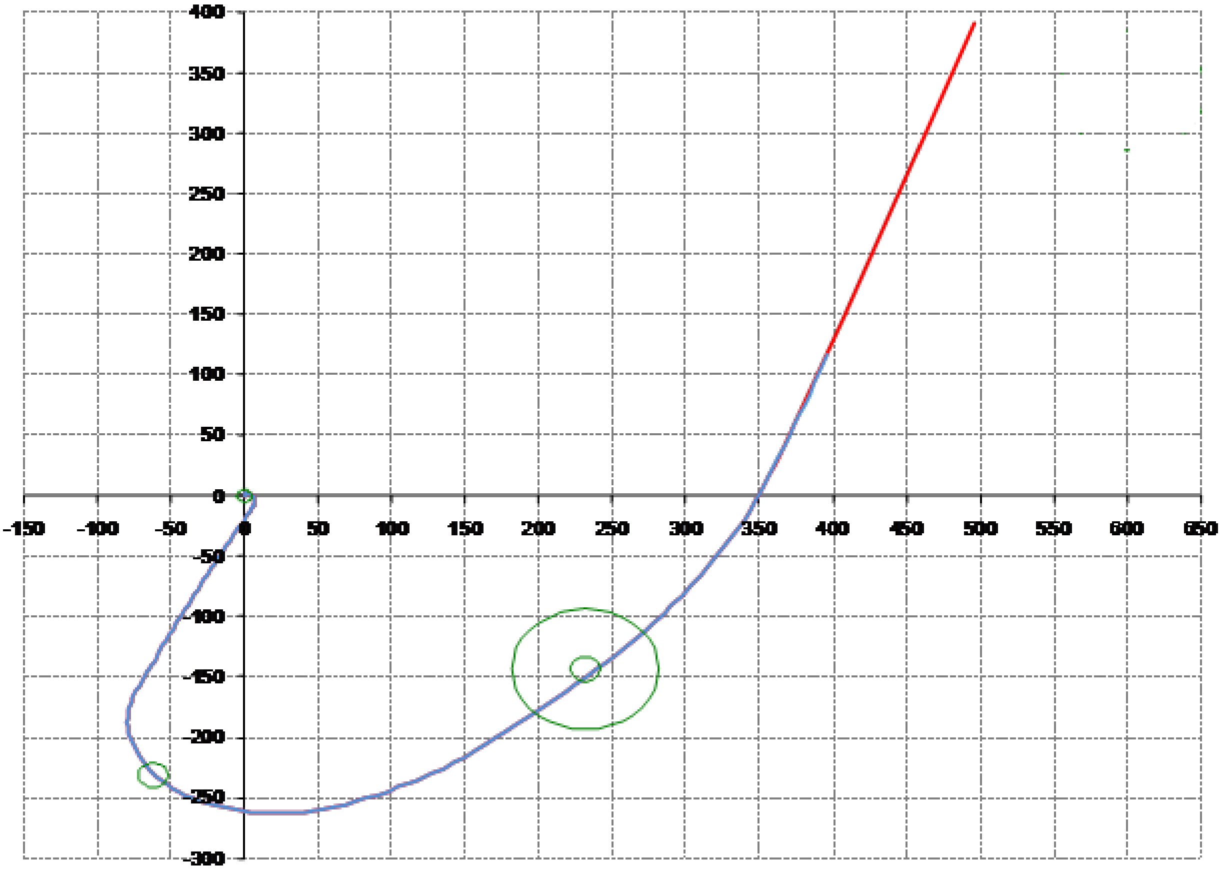


Figure 2.41. Horizontal projection of well#5

5. DRILLING FLUIDS, HYDRAULICS AND THEIR INFLUENCE ON ROP

The ROP is influenced by variety of different factors such as geological formation properties, drill bit characteristics, mechanical factors, hydraulic factors, mud properties. Most of these factors are related to each other.

In this chapter we consider and analyze how mud properties and hydraulics of the mud flow influence the ROP.

Plots and graphs provided in this chapter are based on the field data.

5.1. How hydraulics and drilling fluids affect ROP

Talking about mud properties first of all we think about: 1. Density; 2.Viscosity; 3.Water filtration; 4. Solid phase content; 5. Lubricating properties.

Relation between ROP and drilling mud characteristics is shown on the figure 5.1.

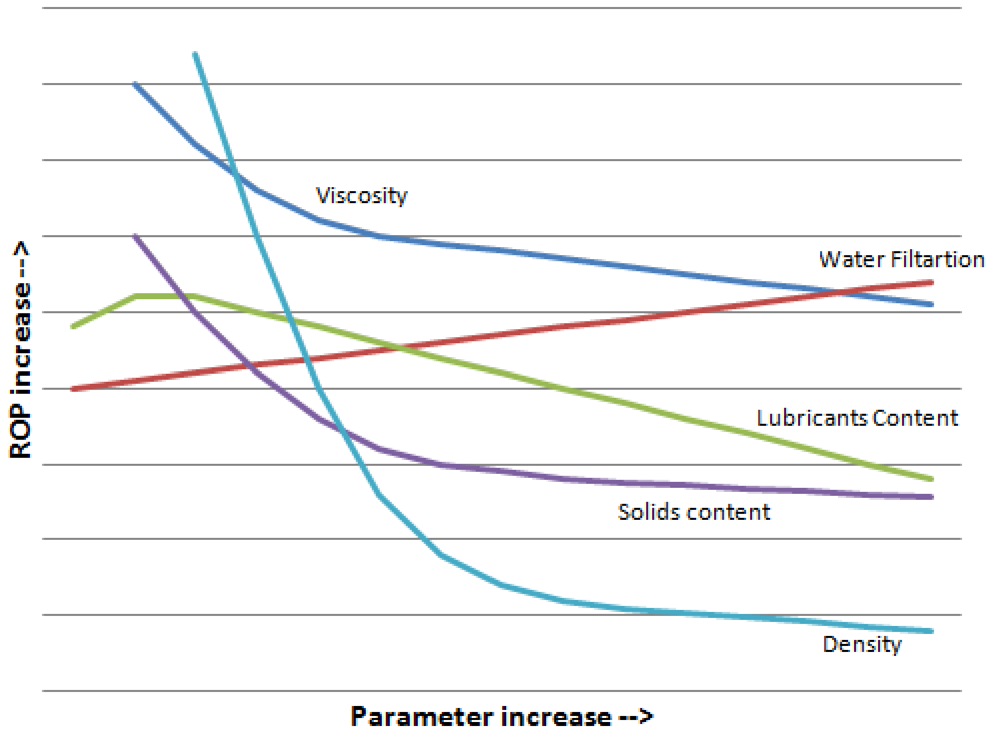


Figure 2.42. Relation between ROP and mud characteristics

All of these properties are influenced by the variety of other factors. The only property which can be identified and described in a simple way is density. While viscosity basically includes measurements of plastic viscosity and yield stress measurements related to each other. Filtration rate typically is evaluated in static environment or less often in dynamic environment (while drilling). It's considered that filtration rate has a linear relation to ROP and also related to the surface tension of the rock. Solid content value considers only the volume of all solid particles in the mud but does not consider the size of particles, though exactly the size of particles influences the ROP in a higher scale. Lubrication of the mud depends on the hydrocarbon content percentage in the mud.

There are different ROP models which attempt to describe the ROP relation to different parameters. One of these models can be described by the next equation.

$$R = \frac{KN^{\lambda}(W-W_O)(R_O-\alpha\Delta P)}{R_O DS^2(1+CH)}\left(\frac{Q\rho}{d\mu}\right)^{a} \quad (5.1)$$

Where: R – ROP; K – drilling constant; W – WOB; W_o – maximal WOB; N – RPM; D – bit diameter; S – formation strength; λ – exponential value (approximately 0.5); C – constant; H – bit teeth wear; Q – flow rate; ρ – mud density; d – nozzles diameter; μ – viscosity of drilling mud flowing through bit nozzles; a – constant (approximately 0.271); α – constant; ΔP – differential pressure; Ro – ROP while ΔP =0.

Special attention should be pointed to the formation strength value which is squared and thus even small changes of this parameter will lead to significant ROP change.

5.1.1. Density of the drilling mud

Mud density has a greater influence on the ROP than any other property of the drilling fluid. Basically, penetration rate is mainly affected by the difference between the hydrostatic pressure of the drilling fluid and pore pressure of the formation fluids. Relation between the ROP and pressure differential was carefully researched both in the laboratory and in the field environments. It is possible to say that the rate of penetration increases with decreasing of differential pressure and continues to increase in the underbalanced conditions as the pore pressure becomes higher than the mud column pressure [52].

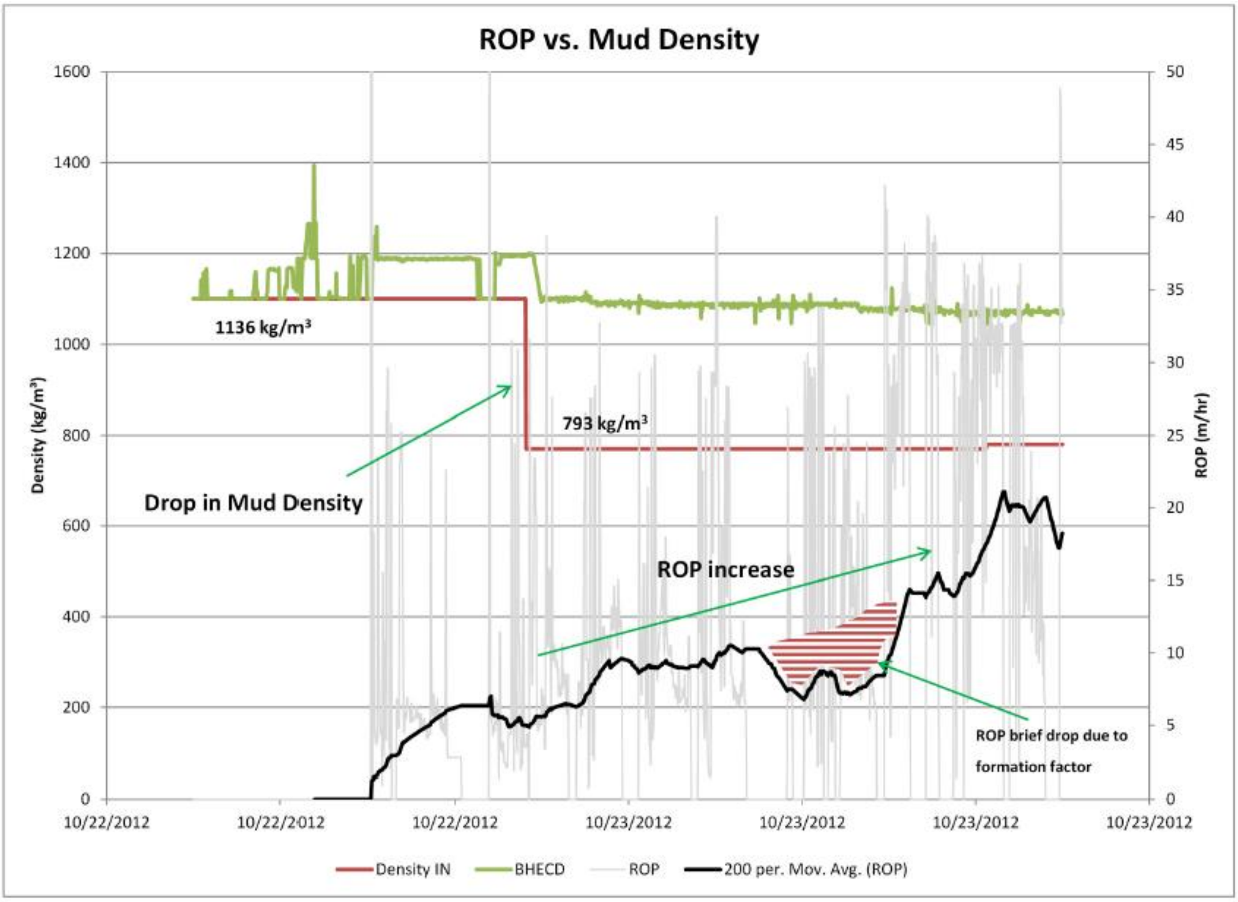


Figure 2.43. ROP to MW relationship

Laboratory data describing relation between penetration rate and pressure repression values is shown in Figure 5.2. The ROP slowly decreased by about 65-80% in the sandstones and limestones in the research while the mud column pressure P_m excess over the reservoir pressure P_f has grown from 0 to about 1200 psi.

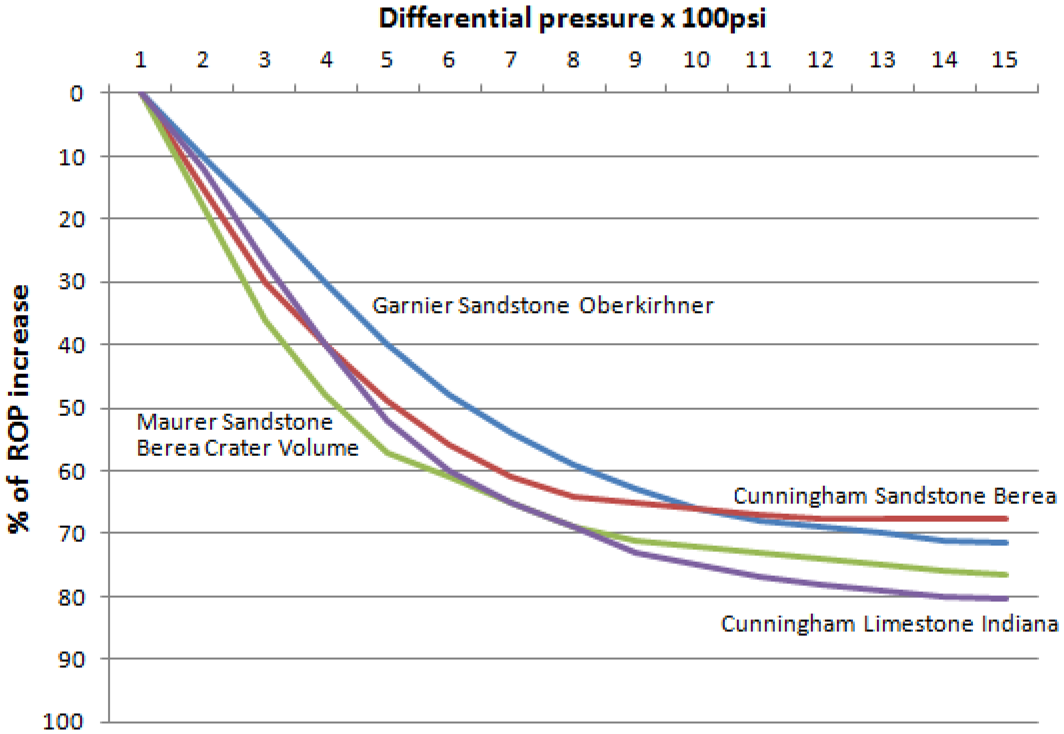


Figure 2.44. Laboratory data. % ROP decrease related increase of pressure differential

The results of the research with the goal to determine the relation between the pressure drop and the rate of penetration in the clays are shown in Fig 5.3 and 5.4. Intervals of clays were selected for the purpose of electrical logging diagrams research. Drilling data has been saved only for clay intervals, the resistivity data of which was used to calculate the pore pressure of the formation. Researched clay intervals had a thickness which was sufficient to accurately determine the pressure and the drilling rate.

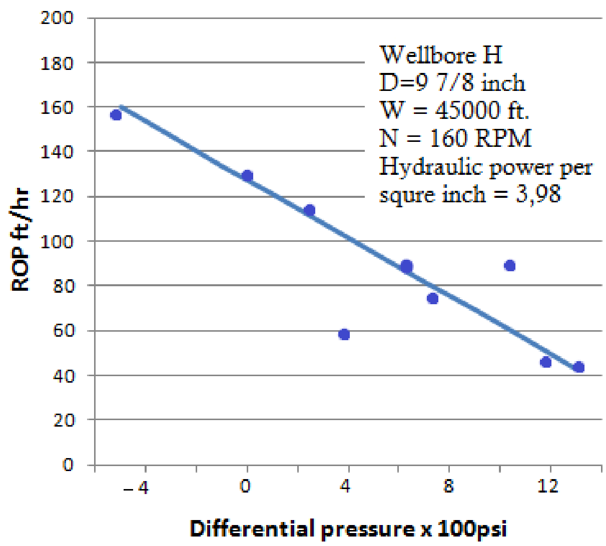


Figure 2.45. Relation between pressure differential and ROP

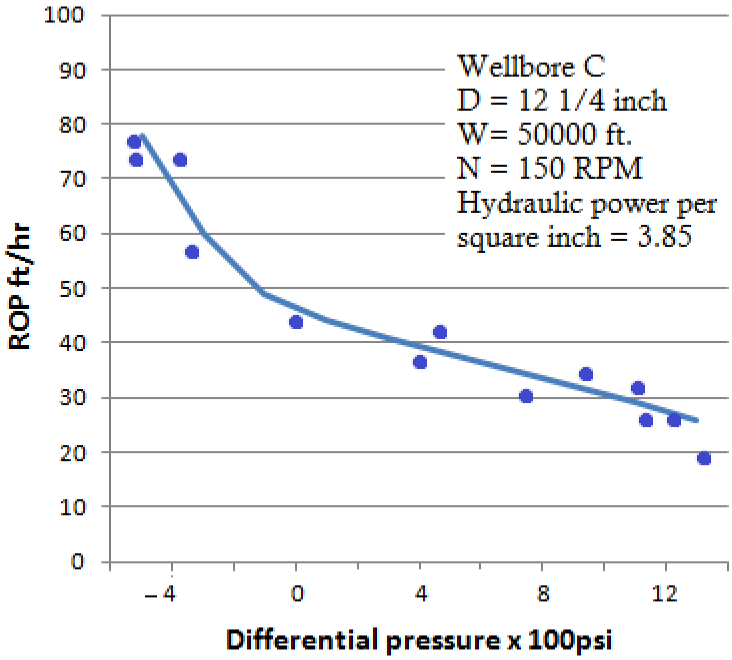


Figure 2.46. Relation between pressure differential and ROP

Data analysis of figures 5.3 and 5.4 shows that the ROP in the clay is greatly affected by the pressure differential changes. The ROP for the well shown on Figure 3 decreased by approximately 70%, whereas the difference between the reservoir pressure and the pressure of the drilling mud column increased from 0 to 1000 psi. It was determined that when the reservoir pressure became higher than drilling fluid column pressure, penetration rate continued to increase. Sometimes this increase even accelerated, as shown in Figure 5.4.

5.1.2. Viscosity of the drilling mud

The viscosity of the drilling fluid is connected with solids content parameter, particle size distribution of the solid phase, the attraction or repulsion between the particles and the viscosity of the base fluid. Mud filtration characteristics also depend on the particle size distribution. Bit teeth formation penetration is more often described by parameters of filtration and solids content than by viscosity values. However, there is some correlation between the rate of penetration and viscosity of the mud, which are described below.

The role of viscosity in the process of cuttings formation by the drill bit typically is a better mud cleaning due to the ability to hold newly formed cuttings particles in the flow and bring it to the surface faster avoiding an excessive waste of energy on particles grinding to the smaller size. Turbulent flow is more effectively clean the borehole comparing to the laminar flow. Additionally, mud flowing from the bit nozzles actively participates in the process of breaking soft formations. It is logical to assume that the efficiency of formation breaking is directly and linearly related to the mud flow rate. The maximum ROP for the same horsepower on the bit will be provided while using the drilling mud with the lowest density.

Optimum values of mud viscosity mud shown in Figure 5.5. The lowest possible viscosity is desired for flowing through bit nozzles, and a higher viscosity is required to suspend barite as a drilling fluid flowing through mud pits.

Concerning the shear rate, c^{-1}:

The drilling fluid flow rate flowing through the drill string or annulus is minimal in the areas close to the wall, and the maximum between it [52]:

$$\frac{Flow\ rate\ 1 - Flow\ rate\ 2}{Radius\ 1 - radius\ 2} = Shear\ rate; \qquad (5.2)$$

$$\frac{dv, ft/sec}{dr, ft} = \frac{dv}{dr}, \frac{1}{c} = \frac{dv}{dr}, c^{-1}; \qquad (5.3)$$

Reduction of viscosity vs. shear rate is called shear thinning and may occur due to the influence of viscosity on the rate of penetration. Some adjustments could be made in a particular mud system to improve the shear thinning. It is assumed that the mud system with low viscosity near the bit nozzles will exhibit a higher penetration rate than clay-water suspension or dispersed drilling mud.

5.1.3. Viscosity and mud cleaning

Cleaning wells can affect the rate of penetration when high concentration of cuttings in the annulus can cause buildup of these cuttings on drill collars, and even on the bit. Positive vertical force affects cutting's particles due to the flow rate, viscosity and density of the mud slurry, as well as the negative vertical force of the gravitational nature. The most important parameters for well cleaning are the flow rate in the annulus and hydraulic properties of the drilling fluid. The density of the drilling mud, cuttings particle size, the size of the annulus and RPM also may affect cleaning process of the well, but to a lesser degree.

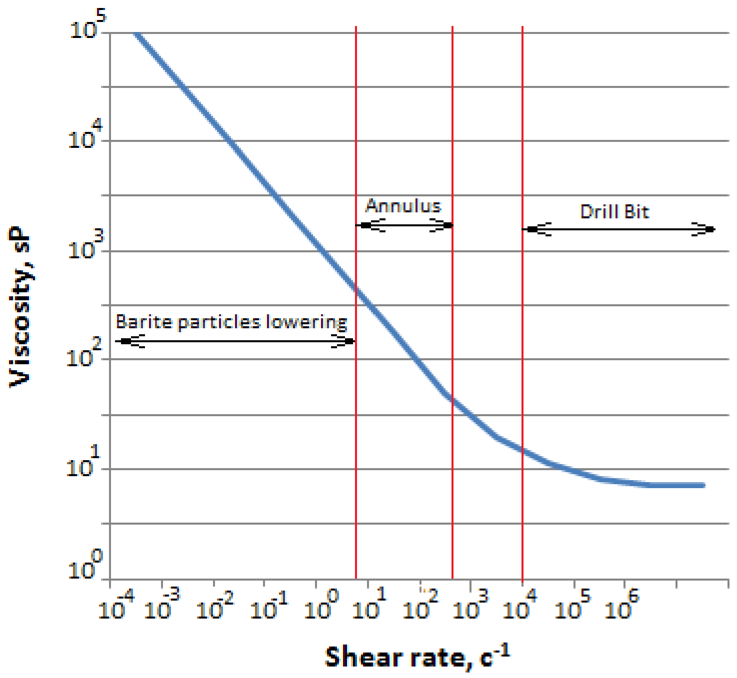


Figure 2.47. Shear rate and viscosity

The rate at which the cuttings particle falls down through the drilling fluid in the annulus is called the slip speed. To make the cuttings particle reach the surface, the slip rate must be less than the velocity in the annulus. The concentration of the slurry in the annulus fluid is dependent on the slip rate and the rate of penetration.

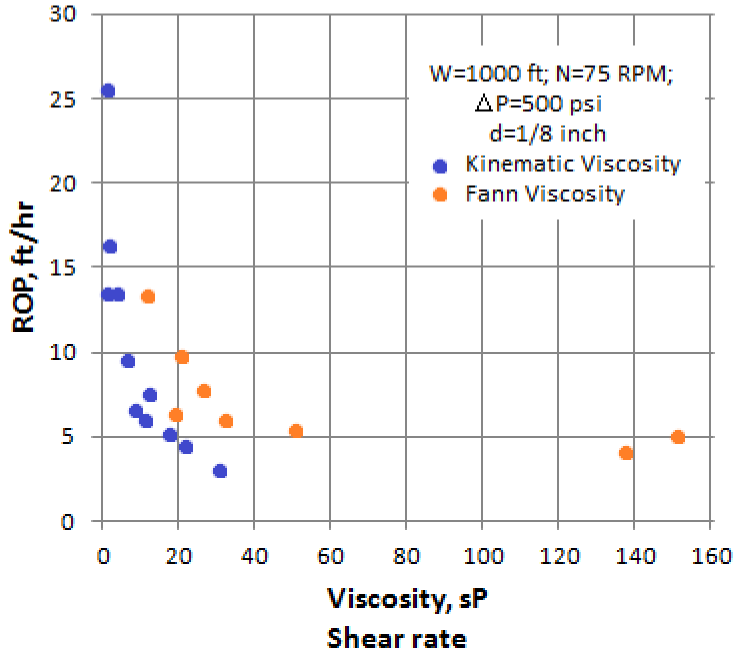


Figure 2.48. ROP and shear rate relation

The most important component of viscosity influencing slip velocity of slurry in the drilling fluid in laminar flow is a maximum shear stress.

Many wells are drilled with the water washing, which has a zero yield stress. Slurry particles of various shapes and dimensions, contained in the water upstream stuck in each other and thus hinder precipitation of discrete particles. It has been shown that the water stream velocity in the annulus equal to 120 ft/min provides sufficient borehole cleaning in a turbulent flow [52]. It is noticed that the increase in shear stress limit often increases the cleaning ability to for a particular drilling mud. This increase may be caused by a change in the flow regime from turbulent to laminar. It is believed that this change may improve the slurry transfer to the surface because the slurry tends to be disposed in a portion of laminar flow with higher velocity due to the drill pipe rotation.

Well with diameter above nominal can become a serious source of error in the calculations of the well cleaning. For example, the injection rate, which provides a 120 ft/min velocity in the annulus for a borehole of 10 inch diameter with a 5 inch drill pipe inside will provide velocity in only 60 ft/min if the borehole diameter will be increased to 13 1/4 inch.

5.1.4. Mud filtration

In the areas where drilling is carried out with water based muds noted that the penetration rate is significantly reduced when water gets contaminated. Mud flocculants have been introduced mainly in order to clean the dirty water. It was concluded that the decline in the rate of penetration is caused largely by filtration properties. After clay inflows in the water mud during drilling process ROP is getting reduced. In the course of further research the mechanism was described by which the filtration decreased ROP. Decrease of the rate of penetration was related to the pressure which should be enough to allow the particles to keep the cuttings suspended (CHDP).

While the slurry particles go up after the bit drills deeper, in the place where particles were, some sort of vacant space or cracks occur which should be filled with a sufficient amount of fluid. The fluid for filling cracks may come from the following sources [52]:

1. The drilling fluid flows into the crack where particles were. It can be expected that this source will meet considerable resistance, as the initial crack width is zero.

2. The flow through the pores of the slurry particles. Ease of filling the cracks by this source will depend on the rock permeability, the pressure difference between the mud column and the pore pressure and bridging properties of the drilling fluid.

3. The flow of liquid through the pores of the rock. Most likely this will be the source of liquid for filling the cracks when drilling is the permeable enough formations with effective cork forming (the sealing) mud.

From the previous text it is evident that the degree to which the ROP affects the mud filtration depends on:

(A) rock permeability and

(B) the difference between the mud pressure and pore pressure.

If the slurry is impenetrable then repression will occur (pressure of the mud fluid will be higher than the pore pressure) with a complete vacuuming. When slurry is relatively permeable - a partial vacuum may occur. Under circumstances of any degree of pressure depression initial crack around the particle slurry to be filled immediately in permeable rock, and less rapidly in a relatively impermeable rock. It is expected that the rate of penetration will vary depending on the speed with which liquid filling cracks.

5.1.4.1. Influence of filtration rate on the rate of penetration.

Measurements for a determination of the rate at which the filtrate from the drilling fluid can flow into the reservoir, produced in the following ways:

1. Static tests:

(A) Analysis of filtration properties at low temperature by API,

(B) Analysis of filtration properties at high temperature by API.

2. Dynamic test:

(A) Using a special laboratory filtration device

(B) Using the special “laboratory” drilling rigs for research drilling characteristics with laboratory precision.

In both types of static tests the rate of filtration is measured through the filter paper. Variety of devices for measuring dynamic filtration in the laboratory has been created. Filter paper and permeable rocks are used for filtering. Such type of test is not conducted on a regular basis. Special drilling rigs for laboratory researches are used to measure filtration in the drilled formations [52].

It is expected that research of the filtration properties, should be carried out in the conditions reproducing downhole conditions as closely as possible. Such researches will be the most reliable source of information about the correlation between the filtration rate and penetration rate. When filtration rate is measured on a special laboratory drilling rig the borehole conditions are simulated more accurately than by any other method described above. Filtration in such conditions is carried out through a rock in the environment close to the real drilling process under conditions of temperature and pressure existing at a certain depth. It is also contemplated that a test at a low temperature by API (filtration rating within 30 minutes) is providing the least useful measurements since the filtering is performed through the paper at room temperature, when the mud does not work in the way similar to the real drilling environment.

5.1.4.2. The relationship between the API filtration and rate of penetration

The correlation between filtration and rate of penetration is inaccurate, as shown in Figure 5.7. These data were obtained in the beginning of the 1950s.

The ratio between the filtration rate and the rate of penetration in clays was determined at the end of the 1950s. The results are shown in Figure 5.8. The cores of clay used during the course of this test drilling were obtained from wells in the Gulf of Mexico at depths of 7900 to 8400 feet (Vicksburg, Miocene and Wilcox) [52]. Note that the rate of penetration in these argillaceous rock decreased by about 20 percent as filtering API mud decreased from about 15 to less than 5. The reasons for changes of the rate of penetration in almost impermeable rocks simultaneously with the change of filtration rate are not determined by API. The assumption, that the significant water inflow into the crack around the newly seceded particles at high filtration rate might occur, is difficult to confirm or deny.

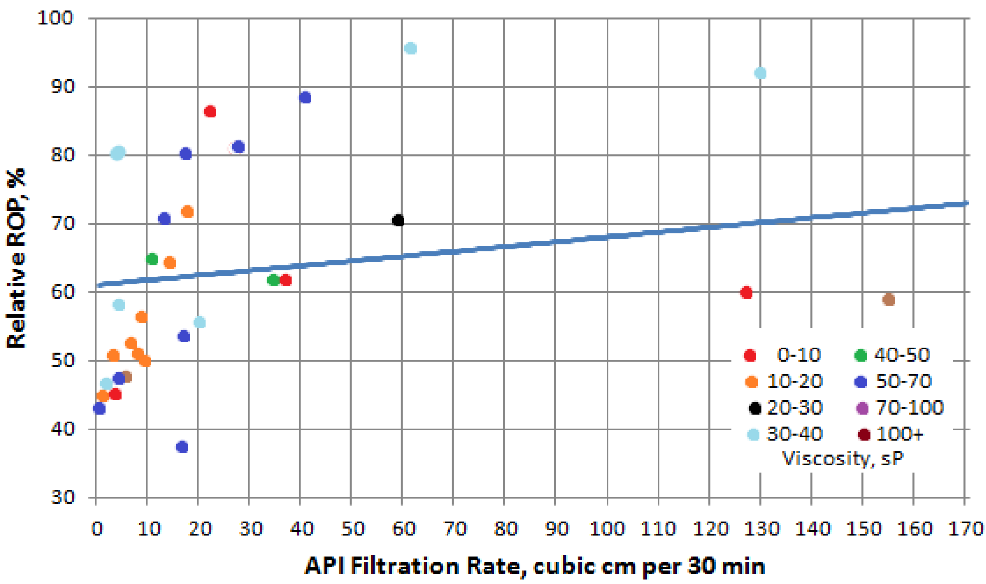


Figure 2.49. Laboratory data shows relation between filtration and ROP

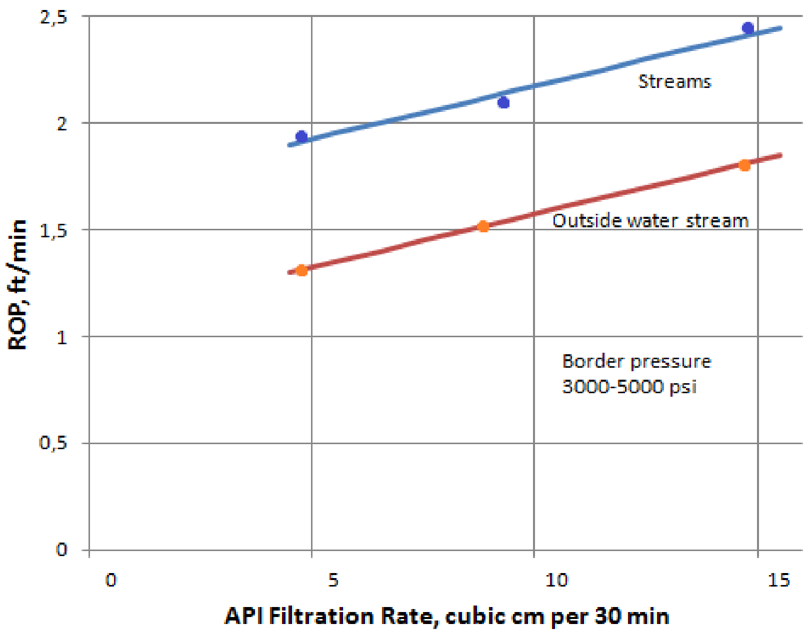


Figure 2.50. Laboratory data shows relation between filtration and ROP

The rate of penetration in the limestone and sandstone, correlated with filtration by API, is shown in Figure 5.9. The rate of penetration was determined in the laboratory during the repression 1000 psi. Symbol Ka represents the permeability of rocks. For each of the tested rocks penetration rate was decreased by over than 30 percent when the API filtration was reduced from 50 ml to 10 ml.

From the examples above it can be concluded that the rate of penetration can be significantly improved by increasing filtration by API. Although, it's necessary to pay attention to the spread of the data points in Figure 5.7 as evidence that behavior of correlation between ROP and filtration rate by API is not clear as values of ROP vary widely. Nevertheless, it can be stated that by increasing the filtration rate the penetration rate definitely will not fall and in some conditions may become higher.

5.1.4.3. The characteristics of the filtrate and the ROP

Drilling fluid filtrates used today are typically water or a liquid hydrocarbons. Water based mud filtrates may be fresh, or they may contain different concentrations of various substances in it. Hydrocarbon filtrates are typically oil or crude oil. However, heavy oil may be used as well as crude oil and their quality can vary widely. In general, the water based mud filtrates can be characterized based on their viscosity.

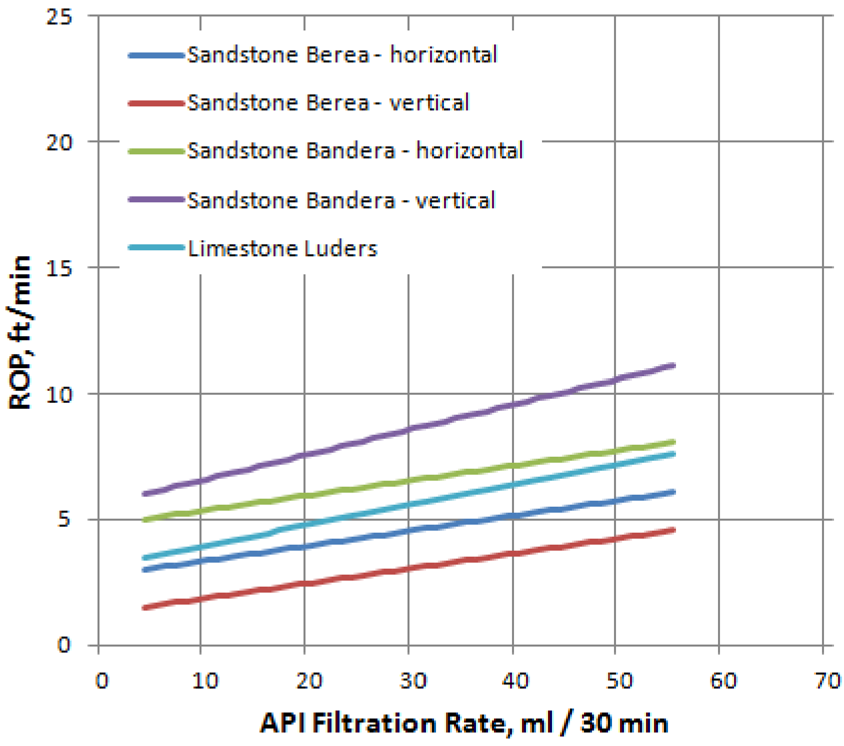


Figure 2.51. ROP and filtration API relation, bottom pressure 1000psi

The ratio between the rate of penetration and viscosity of the hydrocarbon used for the preparation of oil-based drilling mud is shown in Figure 5.10 and 5.11. If hydrocarbon has lower value of viscosity then the penetration rate is higher.

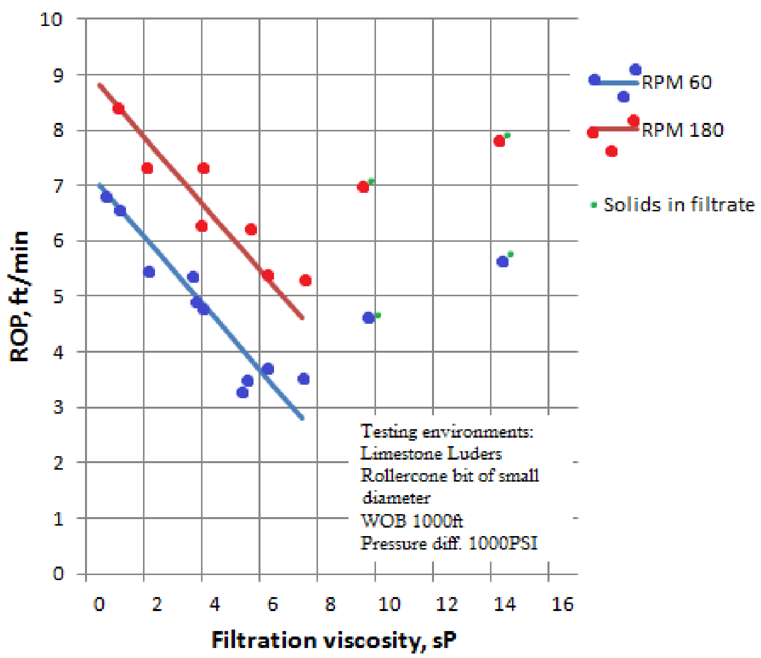


Figure 2.52. ROP and viscosity relation for roller cone bit

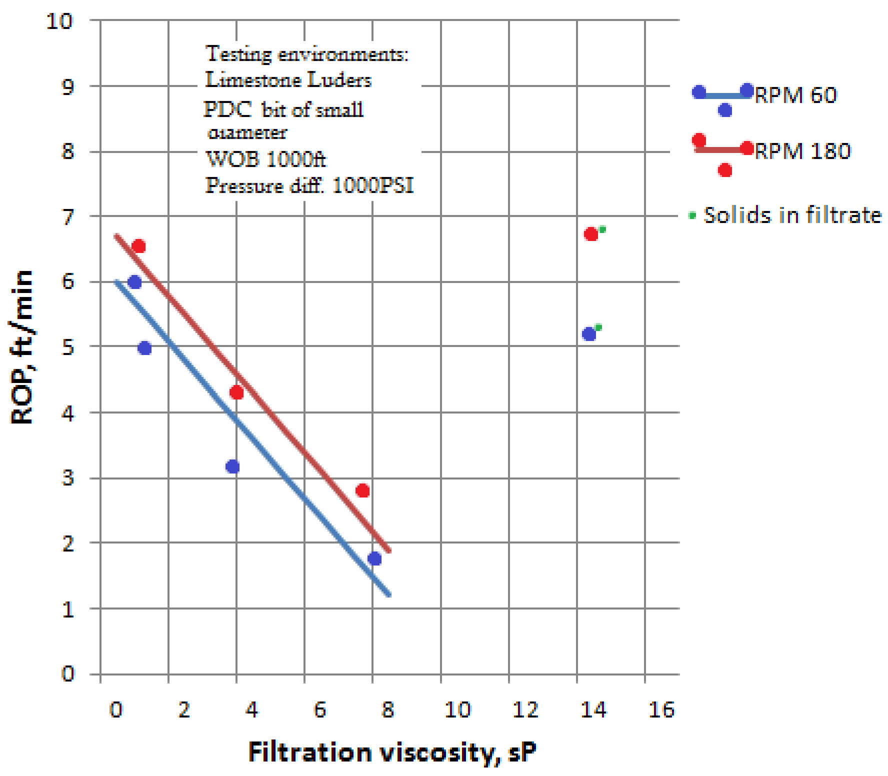


Figure 2.53. ROP and viscosity relation for PDC bit

5.1.5. Solids content

5.1.5.1. Solids content and mud density

From the measured properties of the drilling fluid, which relate to the rate of penetration, density is the most important (or basically pressure drop) as well as solids content. There is a significant relationship between solids content and other properties of the drilling fluid which affect the rate of penetration. The solids content in the drilling fluid affects the density, viscosity and filtration. Viscosity and filtration also affects the particle size distribution of the solid phase of drilling mud.

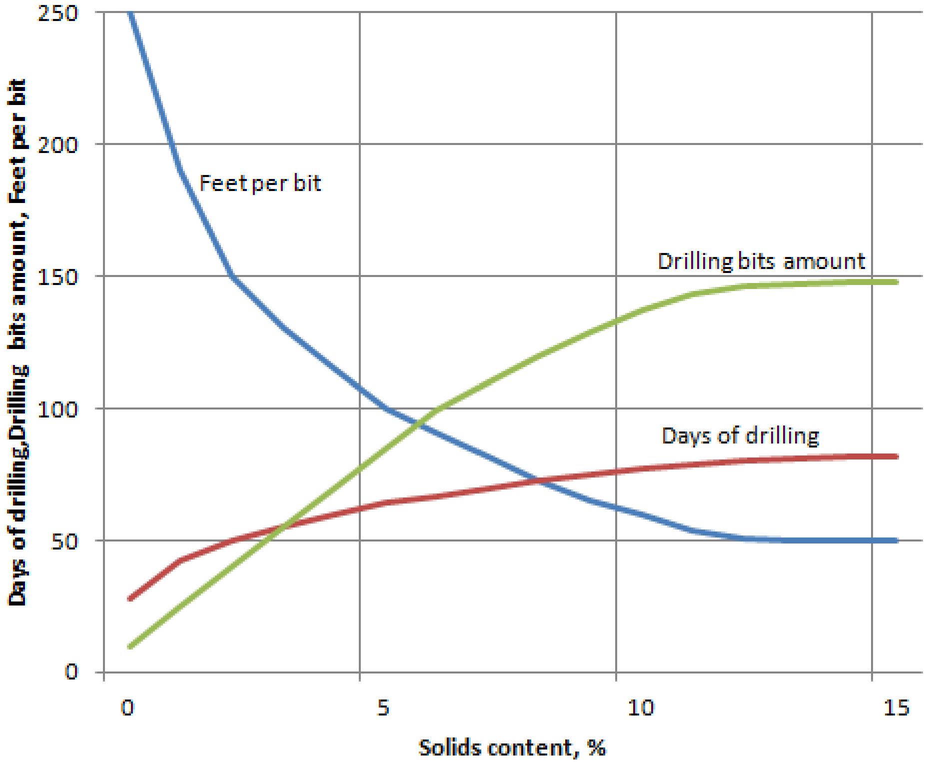


Figure 2.54. Solids content and drilling operations

Importance of solids content in the drilling operation generally reflected in Figure 5.12. This graph shows a statistically averaged data, and it provides information about the impact of solids in the drilling mud characteristics. It is necessary to pay careful attention to many advantages obtained by small incremental decreases of the solids content.

The relationship between solids content and penetration rate is well known and assessed in many years, not only for the light drilling fluids, as might be considered from Figure 5.12, but even for drilling fluids weighted with barite in which the solid phase is a necessary part of the mud system. This point is illustrated in Figure 5.13, which shows a correlation between the average drilling time and the relative density of the solid phase of drilling mud. At the density value equal to 2.4 all solids should be mud cuttings. At the density value equal to 4.35 all solids should be barite. When the density of the solid was 3.0 and mud density was 11.5 lb/gal, the well 9000 feet deep was drilled approximately for 250 hours of rotation of the drill bit at the bottom. When using the drilling fluid of the same density with the solid phase density of 2.4 to 2.7 for the same drilling depths it requires from 400 to 500 hours of rotation of the drill bit at the bottom [52].

Over the last 20 years a lot of effort has been expended to improve solids control in drilling mud. Tools and methods for solids control are still continuously improved.

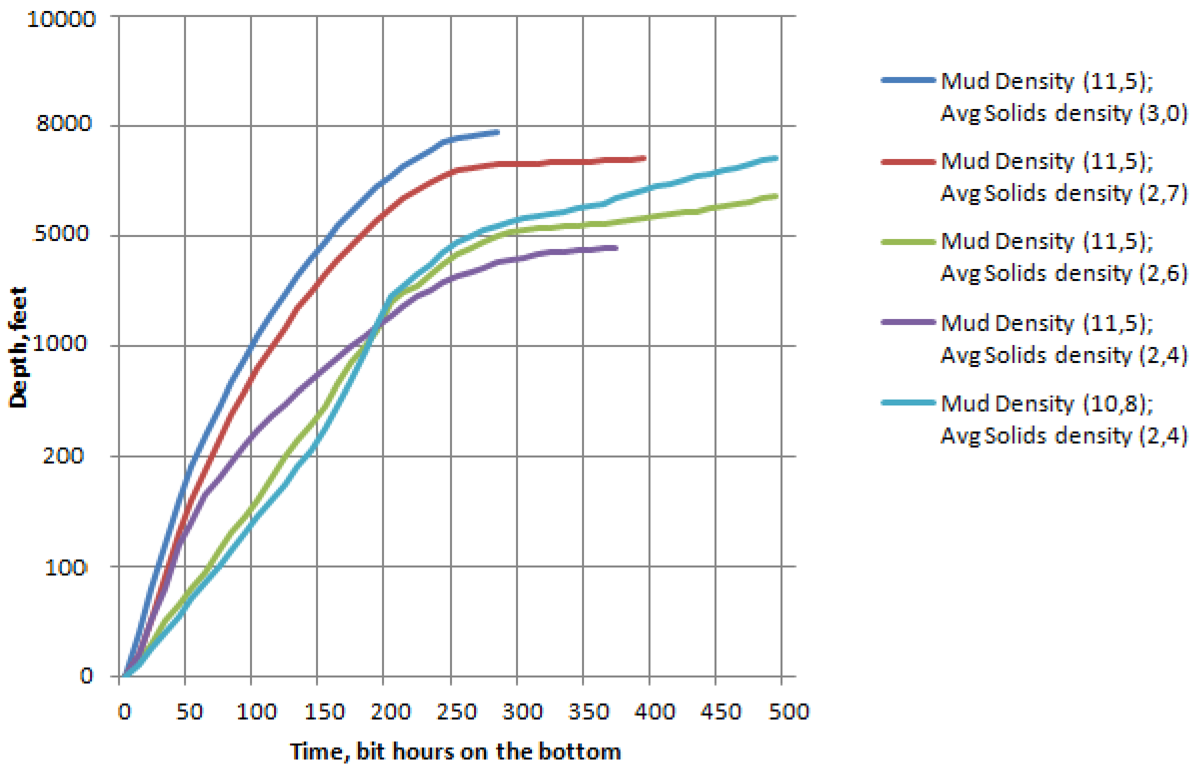


Figure 2.55. Drilling time related to depth with different mud density and solids content

5.1.6. Lubrication

Correlation between the rate of penetration and drilling fluid lubrication observed for many years. However, only recently it became possible to quantify the lubrication value, and usually it is used only in cases of abnormal torque and tightening. However, the increase of the ROP by changing lubrication value is significant enough to cause a reduction of drilling costs. Therefore, this aspect should be considered even in spite of the fact that lubrication cannot be thoroughly documented as parameter of ROP.

5.1.6.1. Water-based drilling fluids with hydrocarbon addition

Ratio between the content of hydrocarbon and ROP in limestone is shown on figure 5.14. These tests were conducted during the drilling of uniform limestone formation by alternately injecting portions of the test mud and water to bit and maintaining all other recognized parameters in constant. Drilling fluids used during these tests have been mixed with bentonite clay suitable for preparing a drilling fluid and barite with the necessary chemical treatment. Tests have shown that although hydrocarbon-emulsion muds caused reduction in the rate of penetration compared to water-based drilling fluids, there was an optimal concentration of hydrocarbon in mud when the reduction of the rate of penetration is minimal. Differences between the emulsion prepared mechanically and emulsions prepared with alkali emulsifier were found to be insignificant.

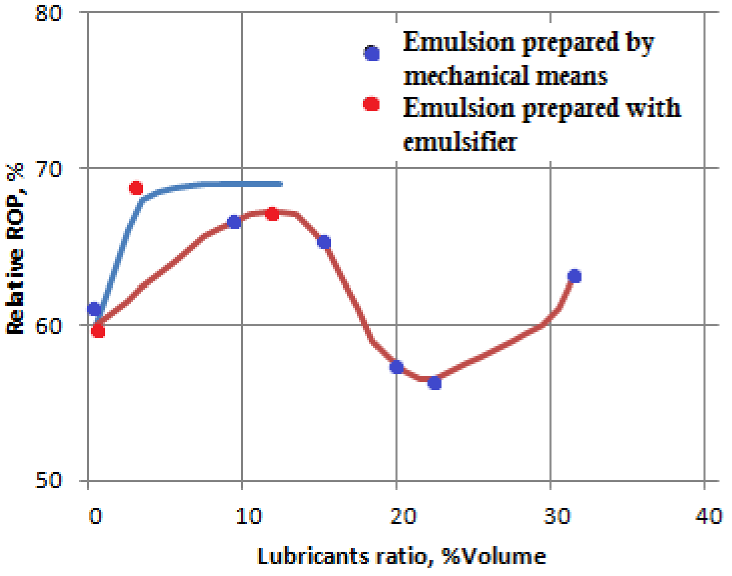


Figure 2.56. Field data showing relation between ROP and Lubrication ratio

The influence of the hydrocarbon content in clay on ROP is shown on figure 5.15. These tests were conducted in the laboratory using cores of clay taken from the drilling wells. During the tests common lime muds were used.

Considerable increase in the rate of penetration which is observed after the addition of hydrocarbons is related to reduction of the slurry balling on the drill bit. By increasing the concentration of hydrocarbons balling is decreased. The rate of penetration in the Miocene clay has a maximum value at 15% hydrocarbon content value, but slurry balling continued to decrease even after further addition of a hydrocarbons. From figure 5.15 can be assumed that the addition of the same volume of hydrocarbons leads to the different extent of ROP increase to different clays.

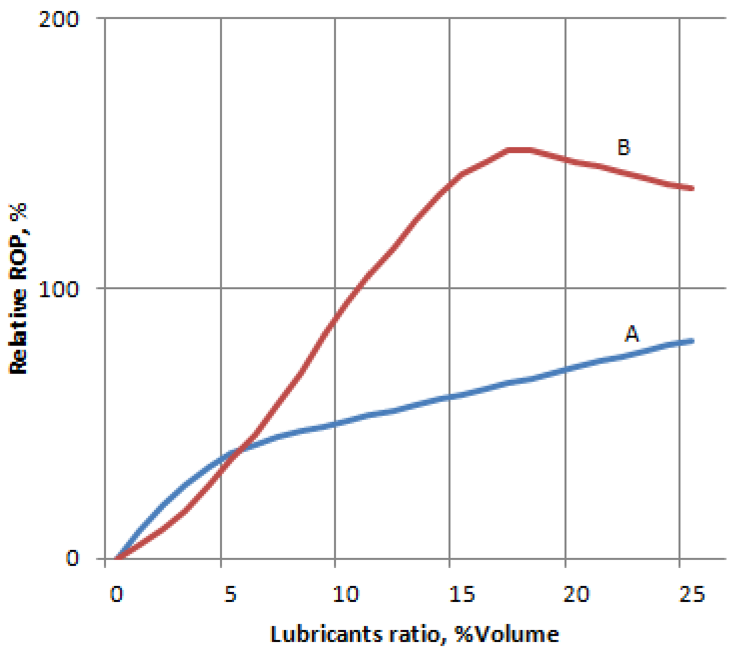


Figure 2.57. ROP increase depending on lubrication ratio

It is expected that the influence of hydrocarbons becomes less significant at lower solids content and in less dispersed clays.

5.1.6.2. Reasons why ROP increases when adding hydrocarbons in water-based mud

Adding emulsified hydrocarbon affects following key mud characteristics:

1. The lubrication ability,
2. The ability to clog the filter cake on the walls of the borehole,
3. Hydrocarbon wettability of steel,
4. Cuttings coating.

All of these properties, except for the hydrocarbon wettability become more or less quantitatively measured. Clogging ability of the filter cake is measured during the course of filtration properties identification.

While discussing the question of why the addition of hydrocarbons in the water-based drilling fluid causes an increase in the rate of penetration, the main factor for this is almost always considered as a reduction of "slurry sticking to the bit". There are two aspects of the phenomenon of slurry sticking to the bit or balling, which typically affect the rate of penetration.

The first is the incomplete removal of cuttings from beneath the bit, which depends on the WOB. Its impact on the rate of penetration is shown in figure 5.16. Lack of bottom cleaning often leads to a reduction of drilling efficiency due to grinding or re-cutting debris on the bottom of the well. The initial stage of balling or slurry sticking is difficult to detect, and perhaps drilling is largely performed by partially balled drilling bits.

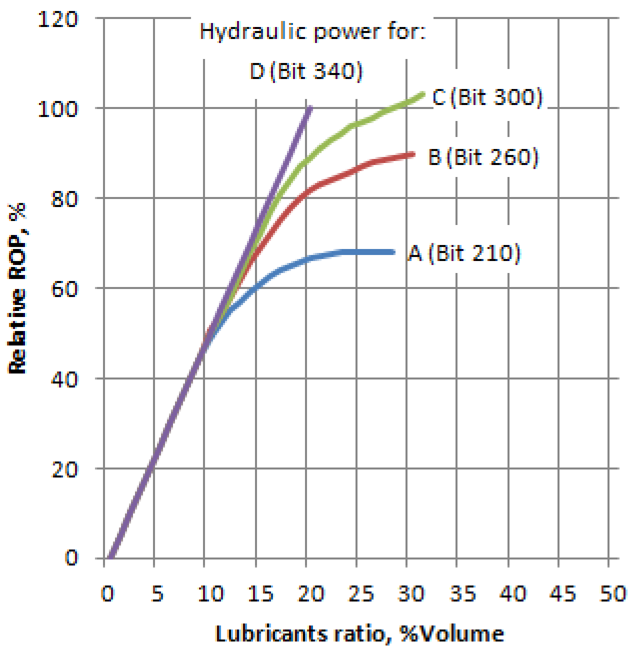


Figure 2.58. ROP and lack of hydraulic power relation

The second is a balling of slurry on bit, drill collars and drill pipes. The degree of sticking is dependent on the moisture content of the slurry, the type and concentration of clay in the slurry, and the slurry concentration in the drilling fluid. Strong adhesion is often observed in the drilling gumbo-clays. Layer adhering on the collar may be thick and strong enough to stop the circulation up the annulus.

Below are some explanations of ROP increase due to adding of hydrocarbon to the drilling fluid [52]:

1. Wetting of steel by hydrocarbon prevents sticking of wet clay to a steel surface;

2. Slurry particles coating by hydrocarbon prevents the particles tendency to agglomerate (adhere) to each other, thereby reducing the tendency to increase the size of the slurry balls in the mud;

3. Any improvement of cleaning of bottom hole area during drilling is likely the result of better pumpability due to the slurry particle size increase in the drilling fluid. Change of other properties due to the introduction of the hydrocarbon drilling fluid is not likely the reason of ROP increase.

5.1.6.3. ROP using oil-based drilling mud

Differences in the rate of penetration between the oil-based mud and water-based mud can be seen in Figure 5.17, where it is shown that drilling limestone and sandstone with diesel fuel mud is somewhat slower than when using water instead. Below is an explanation how ROP for oil-based drilling fluid can be correlated with the measured properties of the drilling fluid.

The ratio between the density and the rate of penetration should include appropriate factors for solids content and for the ability to stabilize the borehole mud. At this mud density solids content in the hydrocarbon based fluid is higher than in the water-based drilling mud, but the average particle size of the solid phase in the oil-based drilling mud should be greater. The importance of the mud's ability to stabilize the wellbore is illustrated in Figure 5.4, where the high-rate drilling on depression is only possible due to sufficient stabilization of the borehole by the hydrocarbon-based drilling mud with controlled salinity.

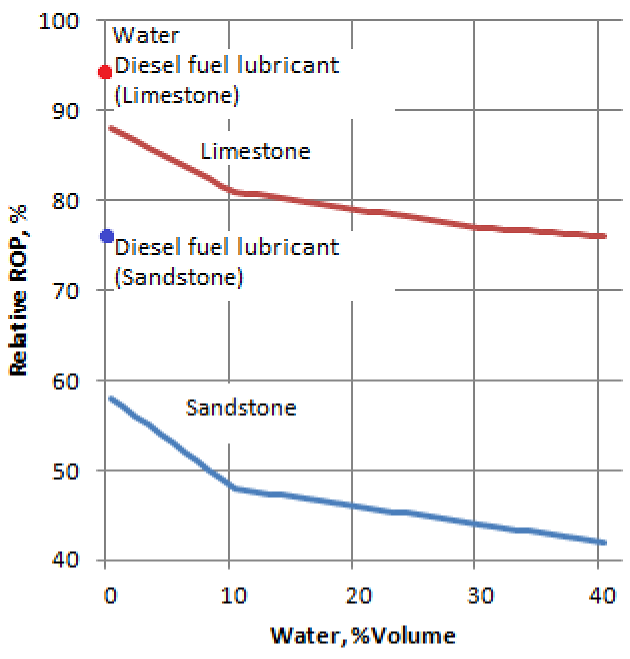


Figure 2.59. Diesel based drilling mud

Based on the data above it is evident that the oil-based mud, prepared by using diesel fuel, should provide a higher penetration rate than the drilling fluid prepared using a heavy oil or asphalt dissolved in a hydrocarbon.

The slurry dissolves less in the oil-based drilling fluid than in the water-based mud. Therefore, the use of fine shakers to remove slurry is optimal when using oil-based drilling mud.

Excellent lubrication ability and wettability by hydrocarbon typical for oil-based muds, allow to expect that it will be possible to avoid any balling on the bit, which can be the result of sticking wet clay to drilling tools. This should provide an advantage in drilling, particularly when drilling clay formations.

The very low rate of penetration for hydrocarbon-based drilling mud was considered inevitable since the beginning of use of such type of fluids in 1930-s years and until the start of 1960-s [52]. Statistical analysis of the rate of penetration was made using a hydrocarbon-based drilling fluid compared to the penetration rate of drilling with water-based drilling fluid.

Following conclusions have been made:

1. Drilling clays is faster with oil-based mud than with water based mud of the same density and with the same rheological properties.

2. In wells where it is necessary to drill clays and sands, the total rate of penetration is usually higher for use of oil-based drilling mud than for water-based drilling mud with similar density and rheological properties.

3. Currently, there are insufficient data to support any conclusion that there is a clear relation between ROP in carbonates formations while using oil-based drilling mud. Existing data suggest that the use of oil-based drilling fluid reduces ROP in carbonates.

Experience showed adequate validity of these conclusions.

Special hydrocarbon-based drilling muds have been developed to provide sufficient suspending of barite in the density range from 10 to 18 lb/gal at temperatures up to 400° F. Attention was also paid to maintenance of a good water emulsification and wetting of slurry by hydrocarbons. All materials that have no value in achieving these two goals, deliberately excluded from the composition of oil-based drilling fluids. As a result, drilling fluids have a reduced concentration of colloidal solids, lower viscosity and increased filtration rate.

Recently, field tests with the use of oil-based fluids specially formulated for optimal penetration rate, have begun.

6. ROP MODELS DEVELOPMENT

6.1. ROP models

In the effort to increase the drilling rate, researchers try to provide different models to analyze the drill bit type influence, mud motor selection effect, different fluid components, and weight on bit. These some of the most important parameters that may affect drill bit hydraulics. Different methods and models have been provided in time to optimize drill bit hydraulics and as a final result increase drilling rate. Researchers proposed to use some prediction algorithms and correlations. In such approaches real time drilling data was analyzed and monitored. Results were used for validation of ROP prediction models.

Currently, there are several drilling ROP models which can be used in the oil industry [53]. The most common models are the Bourgoyne and Young model, Galle and Woods model and Maurer's model.

Maurer's ROP optimization model equation was used for roller-cone drill bits in the form of a function of several parameters: bit size, weight on bit, rock strength and revolutions per minute. This method cannot be used for the cases considered in this master thesis, because all of the considered wells were drilled with PDC drill bits thus we are mainly focused on optimization of ROP for this kind of drill bits. Generally speaking, most of the modern wells are drilled with PDC bits with only a temporary use of roller cone drill bits. Although it is still worthy to mention existence of Maurer's optimization model since it was used in the past years.

Another method is **Galle and Woods model** which is based on the selection of RPM and WOB better suited for every particular case. Galle and Woods provided three core relationships [55].

1. Drilling rate directly related to the weight on bit, tooth dullness, formation drillability and rotary speed.
2. Rate of tooth dullness relates to the rotary speed, formation abrasiveness, WOB, and to tooth dullness in the inverse way.
3. Wear rate of bearings directly relates to RPM and WOB and in the inverse way to the drilling mud parameters.

Galle and Woods model was quite popular to use since it was introduced in 1960-s. This model has been modified several times.

There are next general equations in modified version of the model:

A. The equation of drilling rate:

$$\frac{dF}{dt} = \frac{C_f \overline{W}^k r}{a^p}; \tag{6.1}$$

B. The equation of rate of dulling:

$$\frac{dD}{dt} = \frac{i}{A_f a \overline{m}}; \tag{6.2}$$

C. The equation of bearing life:

$$B = \frac{SL}{N} \tag{6.3}$$

Function of bearing life in time is

$$B_x = \frac{TN}{SL} \tag{6.4}$$

Equation (4) may be applied when WOB and RPM are the constants in time. If WOB and RPM vary in time then equation 4 should be written as:

$$\frac{dB_x}{dt} = \frac{N}{SL} \tag{6.5}$$

From this we may assume that the bearing life depends on the WOB and RPM at any time on the particular interval.

Gale and Woods model can be optimized or modified to any particular case thus it is possible to add some new variables, indexes and coefficients to these equations. Such equations may be used to develop and solve non linear optimization problems for any sets of data. By that it becomes possible to optimize the parameters of drilling that considered in the model.

Bourgoyne and Youngs' is the third method which is the most common, modern and detailed ROP optimization modeling method nowadays. This method is based on statistical synthesis analysis of the parameters from the past drilling cases. Bourgoyne and Youngs' model is one of the most completed mathematical models used for drilling rate optimization. Detailed analysis of drilling data is vitally important to modify the indexes and coefficients which are used in the proposed modes with available drilling data. The equation (6.6) gives the linear rate of penetration equation. It is a function of uncontrollable and controllable parameters of drilling [54].

$$\frac{dF}{dt} = e^{\left(a_1 + \sum_{j2}^{11} a_j x_j\right)}; \tag{6.6}$$

This equation may be rewritten in another way to make it more understandable:

$$ROP = e^{\left(a_1 + \sum_{j2}^{11} a_i x_i\right)}; \tag{6.7}$$

Where x_i are drilling parameters and a_i are constants.

The uncontrollable and controllable parameters of drilling which can affect the drilling rate, may vary depends on the well path, tools, drilling fluids etc. We will discuss in this paper next parameters that can affect the ROP [54]:

1. The type of drill bit. It has a tremendous effect on a drilling rate and on the efficiency of drilling in general. While considering the bit type we have to evaluate such important bit parameters like durability, gauge length, geometry and aggressiveness. Basic design of the drill bit also must be considered since modifications of its design may influence the hydraulic and mechanical parameters of the whole drill string.

2. Formation properties. Geological formation have lots of different properties and some of the most important properties for drilling are rock strength, elasticity limit, rock's permeability, abrasiveness and the mineral composition in general.

3. Hydraulic properties, such as plastic viscosity, density, sand and solids content, salts content, pH, water filtration, yield and other parameters. Additionally different

additives should be considered especially if they directly change the properties of the mud.

4. Operation parameters such as WOB and RPM. Generally, increasing these two parameters will lead to increase of ROP but usually it's not relates linearly and thus the better values need to be calculated or found by the experimental way.
5. The type of directional control method. It can be steerable motor drilling with applying slides, TBS drilling or RSS drilling.
6. DLS and length of the build and drop sections of the well path. Typically, when we have higher values of DLS and longer build or drop sections, the ROP will be lower. Especially it can be easily seen on the wells where directional control provided by steerable motor sliding method.

While some of these parameters like WOB and RPM directly affect the ROP other parameters like DLS and type of the directional control method affect the ROP due to the particular operations that need to be carried out while drilling the well. While it is important to choose a right drill bit it's equally important to provide an optimal well path and directional control method. Poorly planned trajectory or wrong choice of control method may lead to a significant loss of ROP or even to a temporary stop of drilling even if other parameters are well fitted to the particular drilling case.

Coefficients:

1. a_1 coefficient is for the formation strength. In case if all the wells are drilled from the same well pad this coefficient could be ignored or considered the same for all wells participating in the calculations.
2. x_2 and x_3 may be used to model the influence of depth pore pressure on ROP. For instance if the average TVD depth of the well on the considered oilfield is 13000ft than x_2 may be considered equal to 13000-D where D is current depth. X_3 considers increase of pore pressure with depth. $x_3=D^{0.69}(p_p-10.5)$. Where p_p is pressure on some particular depth and 10.5 ppg is an average pressure at the 13000ft depth.
3. x_4 is a coefficient which represents the differential pressure effect: $x_4=D(p_p-p_c)$. This equation describes exponential decrease of drilling rate with the bottom pressure overbalance. x_4 equal to 1 when there is no overbalance.

$$f_4 = e^{a_4 x_4} = e^{a_4 D(g_p - g_c)} \tag{6.8}$$

ROP is lower when, $BHP = [HP(MW \times TVD \times 0.00981) + AFP] > PP$ (6.9)

Optimal higher ROP when $BHP \leq PP$ (6.10)

4. x_5 is an index related to WOB and diameter of the bit. Depends on the type of the bit x_5 can be different and thus should be chosen for every type of the bit. Coefficient for PDC bits looks like that:

$$x_5 = ln\left(\frac{\left[\frac{W}{d}\right]_m}{\left[\frac{W}{d}\right]_c}\right) = ln\left(\frac{C_r\left[\frac{W}{d}\right]_a - 0.942\Delta P_b \frac{d-1}{d}}{\left[\frac{W}{d}\right]_c}\right) = ln\left(\frac{C_r W_a - 0.942\Delta P_b(d-1)}{d\left[\frac{W}{d}\right]_c}\right) \tag{6.11}$$

$$\Delta P_b = \frac{q^2\rho}{12031A_n^2} \tag{6.12}$$

Where C_r coefficient is for the weight splited between the drill bit and under-reamer. In case if we do not use under-reamer the coefficient will be equal to 1. W – WOB, d – bit diameter, A – bit area, ΔP – pressure differential. WOB is typically composed of the measured weight without hydraulic force which act in the inverse way decreasing the total WOB on the bottom. Average WOB on the considered wells is 9-11 tones or 20000-21000 pounds or 370 lbs/in.

5. x_6 is a coefficient related to the RPM. It can be defined as x_6=ln(N/40). Where 40 is an average rotary speed on the chosen wells. And N is an RPM on the particular interval.
6. x_7 represents drill bit worn. There are different models to predict drill bit worn. This paper will use one simplified bit worn model.
7. x_8 is a coefficient which represents hydraulic effects. The main value here is hydraulic power per area (hpsi). Also it worth to consider force of jets impact and density of the fluid as well. These parameters can be calculated in the Landmark Wellplan software.

$$f_8 = e^{a_8 x_8} = e^{a_8 \frac{\rho q}{350\mu d_n}} \tag{6.13}$$

8. x_9 is a ECD pressure coefficient.

   The coefficient shows the effect of changing ECD value of the drilling mud column. This coefficient was obtained by experimental way during the work with drilling parameters of the wells chosen for this case. It shows that ROP has a reverse relation to ECD of the mud column. ECD of the mud column grows when mud density grows. More detailed information about mud density and differential pressure effects on the ROP can be found in the chapter 5.1.1.

$$f_9 = a_9 x_9; \tag{6.14}$$

$$x_9 = ecd^k; \tag{6.15}$$

Where m is the coefficient that should be identified for every particular oilfield or some group of wells by analyzing related field data.

For the wells, chosen for this chapter, k=-6;

9. $x_{10,\ 11}$ are DLS coefficients. These coefficients show how the DLS value, the length of build or drop section and torque values impact the total ROP value. Higher torque summed with higher DLS provides lower ROP due to increased complication of steering operations especially with motor. Higher torque value makes it harder to control tool-face position. Two coefficients work in pair better, it looks like it is possible to make one coefficient out of x_{10} and $x_{11,}$ but separately they provide higher accuracy for the model.

$$f_{10} = a_{10} x_{10}; \tag{6.16}$$

$$f_{11} = a_{11} x_{11}; \tag{6.17}$$

$$x_{10} = \frac{H^{0.01}}{T^2} / DLS^b; \tag{6.18}$$

$$x_{11} = \rho * DLS^z / T^2; \tag{6.19}$$

Where T is torque values, ρ is mud density, H is a measured depth of the well, b and z are DLS coefficients, identified for every particular oilfield or group of wells by analysis of related field data. For the wells chosen for this chapter b=10.5, z=0.01.

All the considered functions help to indentify relations between ROP and other drilling process variables. The a_{1-11} constants need to be identified by means of analysis of real field data from chosen wells.

$$ROP = Exp\left(a_1 + a_2 \cdot (TVD - D) + a_3 \cdot D^{0.69}(p_p - 10.5) + a_4 D(p_p - p_c) + a_5 \cdot \ln\left[\frac{W_a - 1.6 \cdot 10^{-4} q^2 \rho}{9800}\right] + a_6 \cdot ln\left[\frac{N}{RPM_{plan}}\right] + a_7 \cdot (-ht) + a_8 ln\left(\frac{q^3 \rho}{8.9 \cdot 10^9}\right) + a_9(ecd^k) + a_{10}\left(\frac{H^{0.01}}{T^2} / DLS^b\right) + a_{11}(\rho * DLS^z / T^2)\right) \quad (6.20)$$

6.2. ROP model simulation

For ROP simulation drilling parameters from 3 wells have been taken. Main drilling parameters can be seen in table 6.1. Example of whole data table for well#1 can be seen in table in appendix 6.

Well#	1	2	3
MD interval, ft	5448,08 - 6439,3	6481,96 - 8572,83	6986,22 - 8956,69
Average DLS, degree/10m	2.25	0.2	1.16
Average ROP, fph	16.89	80.94	28.6
RPM	20	45	30

Table 2.7 Main drilling parameters for wells used for ROP modeling

All the coefficients from x_1 to x_{11} have been obtained using equations related to these parameters. Multiple regression analysis (MRA) has been performed in Matlab. The coefficients a_1 to a_{11} were obtained.

The results of model simulation can be compared with real ROP parameters by applying accuracy index G. Higher value of index G means higher accuracy of ROP model calculations. Maximum value of G is 1 which means that modeled ROP values completely equal to real ROP values, though acquiring G=1 is highly unlikely due to the variety of factors influencing ROP.

$$G = \sqrt{1 - \frac{\sum[ROP_{real} - ROP_{modelled}]^2}{\sum[ROP_{real} - ROP_{average}]^2}} \quad (6.21)$$

ROP simulation model should be applied for every bit run interval separately since changes in BHA configuration, bit parameters and flow regime seriously influence accuracy of the model. Thus, applying the model without consideration of changes between bit runs will lead to significant decrease of efficiency of this model.

There were attempts to improve accuracy of the model by introducing additional parameters and coefficients in the model. The DLS coefficients have been included in the new version of the model which improves the accuracy of it.

Next figures show the results of simulation for three chosen wells. For every well there are two plots: one for initial model without DLS coefficient consideration and one with DLS coefficient included.

From the results can be seen that including DLS values may considerably increase model accuracy.

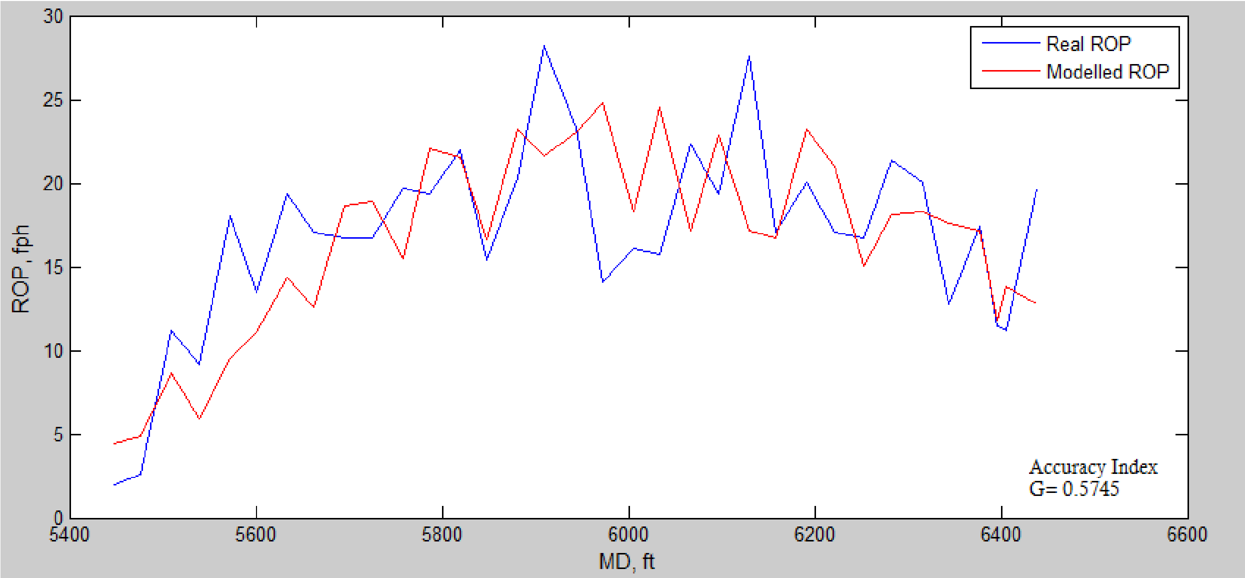


Figure 2.60. Graph for the initial ROP model. Well #1

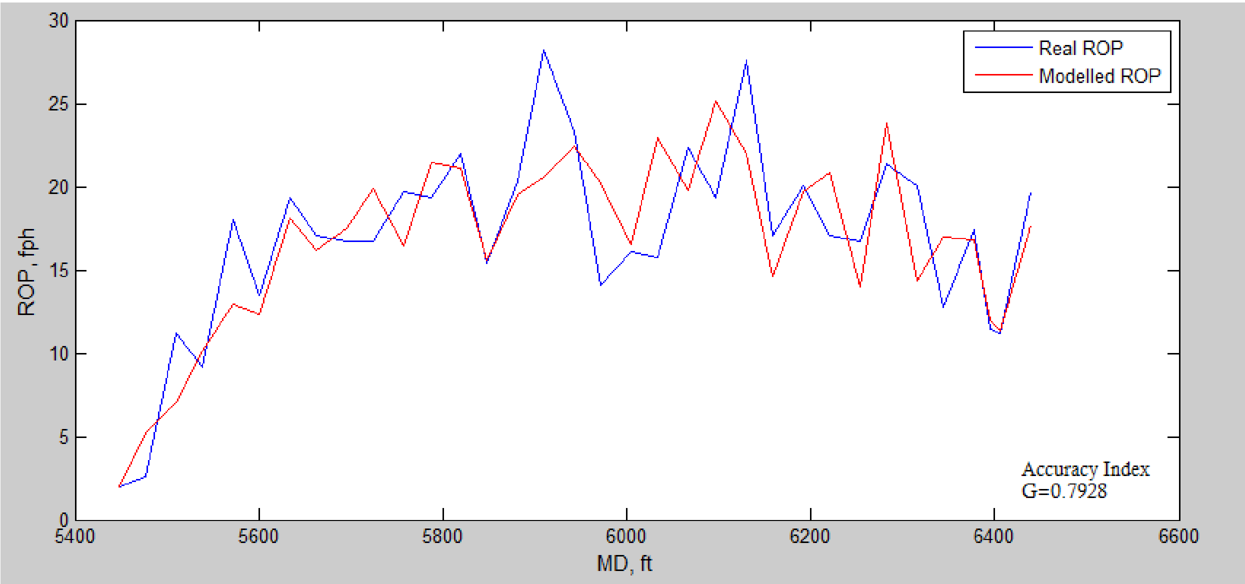


Figure 2.61. Graph for the updated ROP model. Well #1

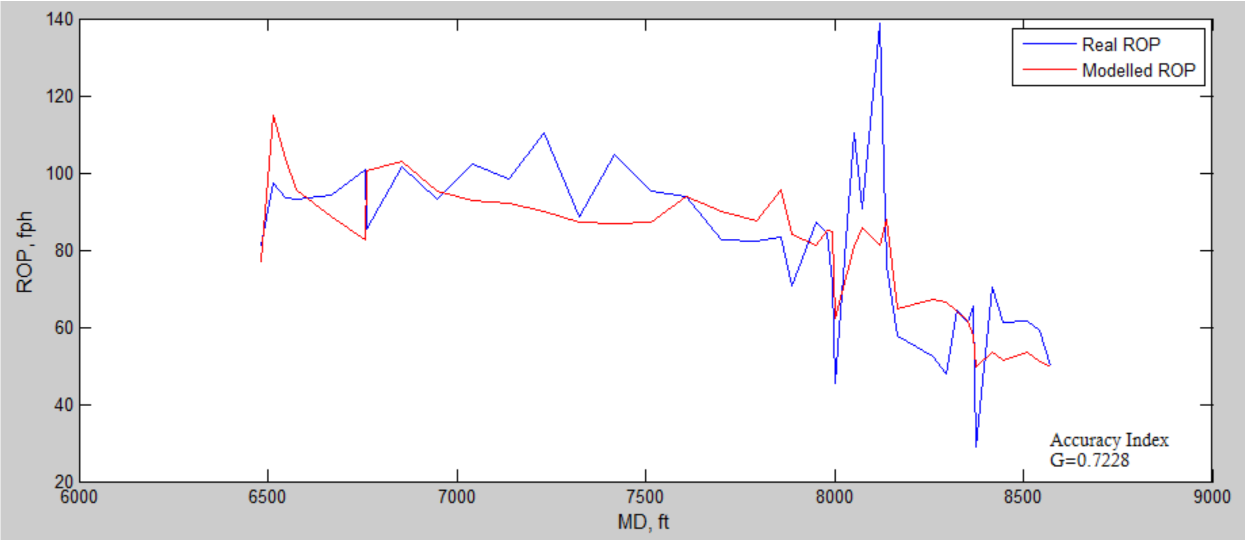


Figure 2.62. Graph for the initial ROP model. Well #2

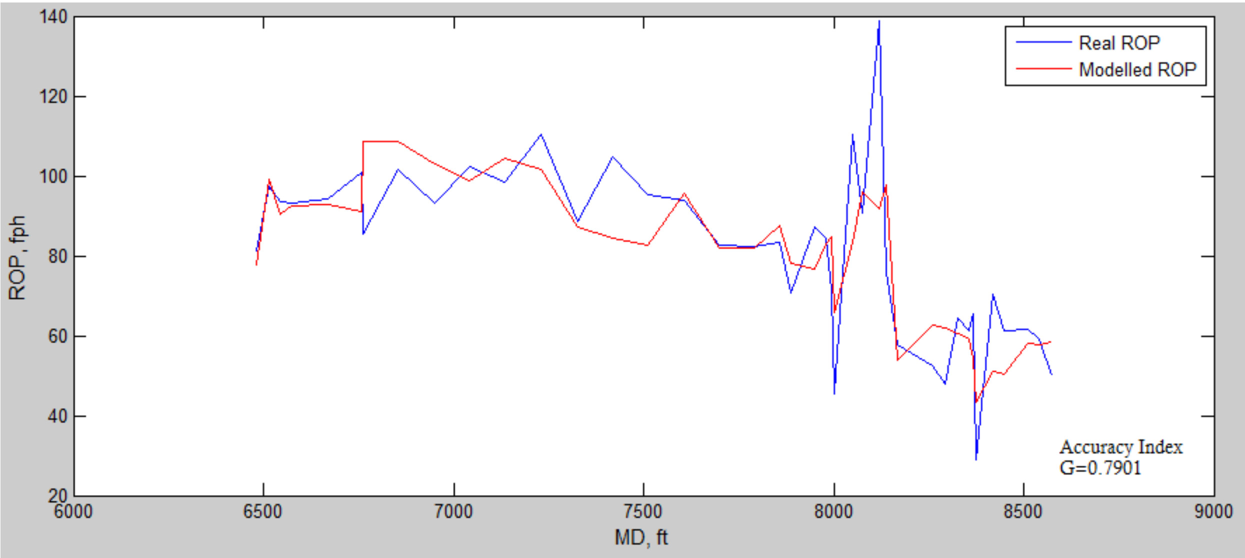


Figure 2.63. Graph for the updated ROP model. Well #2

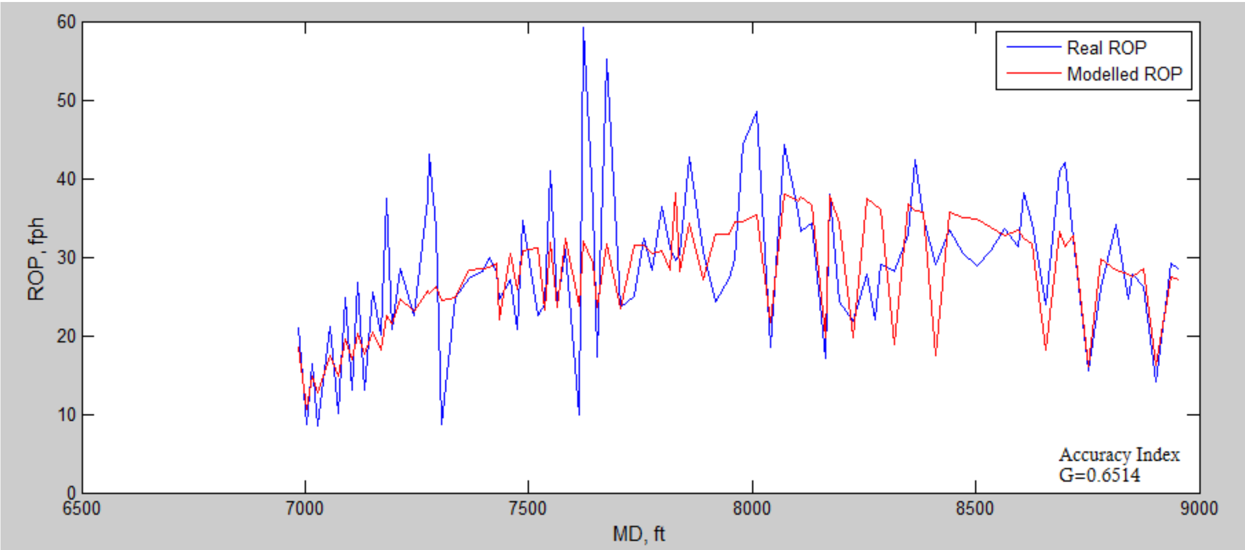


Figure 2.64. Graph for the initial ROP model. Well #3

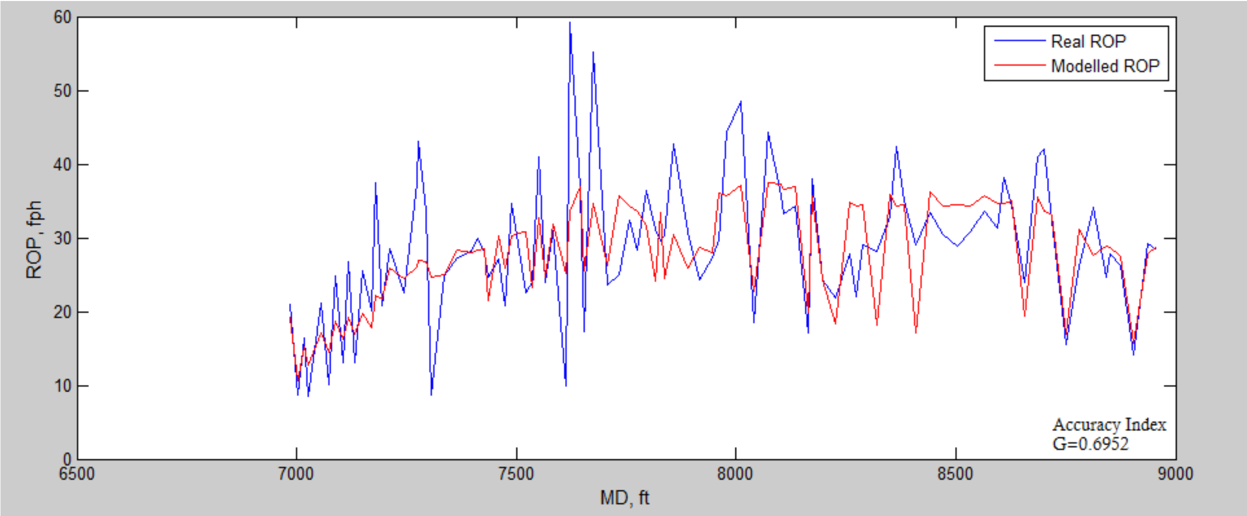


Figure 2.65. Graph for the updated ROP model. Well #3

6.3.Optimizing MSE

6.3.1. Mechanical specific energy

The concept of MSE was defined by Simon and Teal [57] to quantify the relation between the amounts of energy to destroy some volume of formation rock. MSE has been used for evaluation of the drilling efficiency of drill bits, drilling performance analysis, and most recently, as a tool to maximize the rate of penetration in real time and obtain more objective assessment of drilling parameters efficiency [56].

ROP is often constrained by different factors which not in the driller's control and in ways which cannot be properly documented. Dupriest [58] classifies several factors that may determine penetration rate into two categories:

1. Factors that the reason for inefficiencies.

2. Factors limiting energy input.

There are three causes of founder, which are bottom hole balling, bit balling, and drill string vibrations. Different variety of factors may limit input of energy, such as quality and efficiency of hole cleaning, steerable mud motor pressure difference rating, hole integrity, rotational speed limits, etc.

The MSE is not a model for estimation of complexity or cost, but an effective tool for ROP optimization. MSE is the work that is can be performed to destroy some particular volume of rock. Teale derived the next MSE equation [56]:

$$MSE = \frac{WOB}{A_B} + \frac{120 \times \pi \times RPM \times TQ}{A_B \times ROP} \tag{6.22}$$

Where A_B – drill bit area (sq. inch), WOB – weight on bit (lbs), ROP – rate of penetration (fph), RPM – rotations per minute (rpm), TQ – torque (f-p).

There is another way to estimate drilling efficiency – calculation of Drilling Specific Energy (DSE). This equation is quite similar to MSE equation.

$$DSE = \frac{WOB}{A_B} + \frac{120 \times \pi \times RPM \times TQ}{A_B \times ROP} - \frac{2\hat{}10^6 \times \lambda \times HP_B}{ROP \times A_B} \tag{6.23}$$

Where λ – drill bit hydraulic index (equal to 0.086), HP_B – hydraulic power on drill bit.

DSE can be correlated with CCS – confined compressive strength to find drill bit efficiency for its drilling interval.

Estimated CCS and DSE values for well #2 are shown on the Figure 6.7:

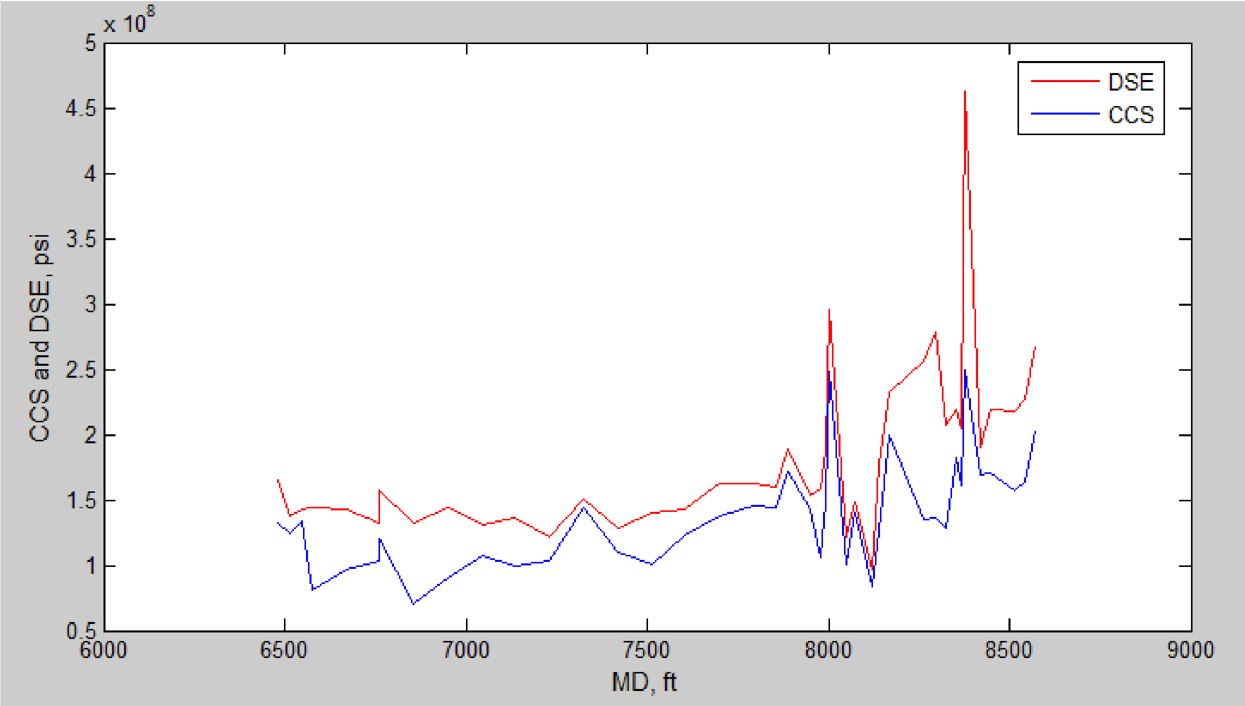


Figure 2.66. CCS and DSE for Well #2

Relation between CCS and DSE shows the efficiency of drill bit use for particular interval. If DSE and CCs are equal then efficiency is 100%, but typically CCS is lower than DSE so efficiency can be calculated by simple equation:

$$Efficiency = \frac{CCS}{DSE}; \qquad (6.24)$$

For well #2 for interval 6481-8572ft bit efficiency is 0.7631 or approximately 76%. Matlab code for DSE and bit efficiency calculation can be found in appendix 12.

Operations specialists have used to analyze the bit performance of successfully drilled wells to identify the factors which lead to such results and in an attempt to repeat these results in future. The relation developed to use bottom hole assembly, the drill bit and directional control systems for similar wells [58]. Rate of penetration management focuses on the limitations, rather than the identification of better drill bit system. Rate of penetration is advanced by identification of limiters and re-engineering it, rather than seeking systems with better performance from experience.

Using MSE and DSE analysis in the field environment allows drillers to change parameters of drilling and observe are there any changes in MSE values or not. Drilling parameters are maintained at the MSE minimum point. When drilling optimization finished, engineering redesign is necessary to adjust bit nozzles and mud flow rates for the highest hydraulic horsepower. MSE surveillance is used for process of drilling optimization identifying the best drilling parameters and providing the data to justify costs for design updates [56, 57].

6.3.2. Conclusions for DSE and MSE

Many factors are influencing ROP. Several methods exist to assess and qualify drilling costs and drilling complexity. These methods provide balance of variables involved in the drilling operations with the uncertainty in relative factors selection in construction of a descriptive model. Several primary models for estimation of drilling costs and complexity were reviewed, including the basis of the model’s structure. The MRI and JAS analyses are commonly employed in several locations, but not too much attention has been given to the basis of the reliability or procedures of the assessment. Recent progress in using of the MSE analysis to was highlighted.

Drill bit performance can be highly dependent on the drilling characteristics and manner in which this drilling bit is used. Analysis of MSE in real time helps the driller to select proper RPM, weight on bit, and hydraulic parameters that provide the most efficient drill bit performance. When drilling bit performance is affected by factors that beyond the DD and driller's control, the MSE curve can provide documentation for the drilling engineer required to correct or redesign the drilling system for particular interval, and to justify this new design according to cost and technological needs. The combination of drill bit parameters data and vibrations data can be very useful in identification causes of it.

The information MSE and vibrations data monitoring provide do not improve performance of drilling in direct way. Though it helps to find better solutions how to make drilling process more effective. An understanding of the reasons for drill bit problems and mitigation of these problems in time is essential.

7. DISCUSSION AND CONCLUSION

There were several goals and objectives for this thesis. The main goal was to find how ROP can be affected by different factors and parameters of the drilling process and what can be done to optimize ROP. Every chapter is related to some particular element or technology in the drilling process that can have some effect on ROP. So every chapter has its own objective to show how some particular technology or drilling property affect ROP. Mostly, all objectives of the thesis have been achieved. Every chapter contains detailed information about its topic including analysis of real field data.

The main objective of the second chapter was to show what the difference between steerable mud motors, targeted bit speed systems and rotary steerable systems technologies, what advantages and disadvantages they have and how these technologies can affect ROP. From provided materials and from analysis of these materials it can be seen that TBS technology provides increase of ROP with almost the same cost and reliability as for the conventional technology. Percent of sliding for TBS well decreased on 14.0% and average ROP increased on 27.5%. RSS technology provides even more significant bust of ROP. Average ROP on the wells drilled with RSS on 54% higher than on the wells drilled with mud motors on the same oilfield and in the same drilling environment. Although, every technology has its advantages and disadvantages described in the chapter, so it is still necessary to choose most properly fitted technology for every particular drilling case.

The objective of the third chapter was to analyze how BHA construction and its characteristics may affect ROP. From this chapter we can conclude that drill bit characteristics and design can significantly affect the ROP, but drill bit design should be chosen separately for every particular well based on its construction and drilling environment. From provided field data it can be seen that drill bits from different manufacturers with more or less similar design show different results on the same oilfield, so even if the bit of one manufacturer shows good results on one oilfield it doesn’t mean that the same bit will be the best choice for another oilfield. Additionally, this chapter shows that not every kind of bit can be used with RSS and TBS. Thus if RSS or TBS method is applied then it is necessary to choose a bit with consideration of compatibility for these technologies. For MWD systems, example of morning report from one of the wells for whole single drilling day has been provided. This data shows how improper choice of MWD system type or improper program for survey taking may lead to decrease of drilling rate even if other parameters of tools in BHA are chosen properly.

The objective of the fourth chapter was to analyze effects of well path design on ROP. Provided data shows, that when the drilling environments and trajectories of the wells are similar but DLS of one well trajectory is higher than DLS of the other well trajectory, total ROP for the whole well tends to decrease. Especially it is related to wells drilled wholly or partly with steerable mud motor directional control methods. Another factor that also can affect the quality of well path, its DLS and as a result its total ROP is improper application of anti-collision measures. Without doubt it is vitally important to prevent even the smallest possibility of collisions between two wells; though planning with consideration of anti-collision must be carried out properly without unnecessary increase of DLS and MD of the well. Generally, it can be recommended to provide lower values of DLS where it is possible, because it will not only lead to ROP increase but also will make casing running easier. Although it is not recommended to decrease DLS too much because may lead to increase of MD parameter of the well and thus will increase cost of the well.

The objective of the fifth chapter was to show how properties of drilling fluids influence the ROP. Information in the chapter clearly shows how every parameter of the drilling mud affecting the ROP and how one parameter can affect another. Thus, all mud parameters have to be properly chosen and continuously monitored and corrected during drilling accordingly to drilling environment.

In the sixth chapter we developed model which can provide reasonable accuracy for chosen wells equal to approximately 75-80%. This accuracy level provide the possibility of forecasting possible ROP for other wells, though for higher precision of the model it is necessary to carry out additional analysis based on data from larger amount of wells. It the thesis provided two codes for the model, one was developed initially and the final one includes additional DLS coefficients which provide additional model accuracy for all 3 wells. Thus, from the analysis results for this chapter it can be recommended to include DLS coefficients in other ROP models if possible.

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APPENDIXES

Appendix 1. Specification of RSS bit MM64R used one several wells considered in thesis

HALLIBURTON | Drill Bits & Services

6-1/8" (156mm) MM64R

PRODUCT SPECIFICATIONS

Cutter Type		SelectCutter
IADC Code		M333
Body Type		MATRIX
Total Cutter Count		26
Cutter Distribution		13mm
	Face	20
	Gauge	6
Number of Large Nozzles		3
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)		7.35
Normalized Face Volume		39.21%
API Connection		3-1/2 REG. PIN
Recommended Make-Up Torque*		5,173 – 7,665 Ft*lbs.
Nominal Dimensions**		
Make-Up Face to Nose		12.39 in - 315 mm
Gauge Length		5 in - 127 mm
Sleeve Length		0 in - 0 mm
Shank Diameter		4.5 in - 114 mm
Break Out Plate (Mat.#/Legacy#)		181953/44030
Approximate Shipping Weight		90Lbs. - 41Kg.

SPECIAL FEATURES

Secondary Cutting Element - "R" Feature

Material #862079

*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 2. Specification of RSS bit MDi516 used one several wells considered in thesis

Directional

6 1/8 in MDi516 PDC

SMITH BITS
A Schlumberger Company

(155.575 mm) ID:64758A0201 ER:25508

FEATURES

- Bit design and performance have been certified through the validation process prescribed by IDEAS simulation technology.
- The PX feature places thermally stable diamond inserts (TSP) on the gauge to maximize gauge retention and extend bit life.

Smith Bits Directional bits consistently deliver superior performance in directional applications with both push-the-bit and point-the-bit rotary steerable systems.

Specifications

Total Cutters	20
Cutter Size	16mm (5/8 in)
Face Cutters	(11) 16mm
Gauge Cutters	(5) 16mm
Cone Cutters	(4) 16mm
Blade Count	5
Nozzles	5 Standard Series 40N
Bit Connection	3 1/2 Reg
Junk Slot Area (sq in)	7.857
Gauge	Length: 6" Protection: Options Available
Length	Make-Up: 11 3/4 in Overall: 15 7/16 in
Fishing Neck	Diameter: 4 1/2 in Length: 2 7/8 in

Operating Parameters

Bit Speed	Rotary Steerable BHA
Weight-on-Bit	2,500 To 19,000 (lbf) 1,136 To 8,636 (daN) 1 To 9 (Tonnes)
Flow Rate (GPM)	150 To 300
Hydraulic Horsepower (HSI)	1 To 6

Operating parameters are typical ranges. Please contact your Smith Bits representative for recommendations for your individual well.

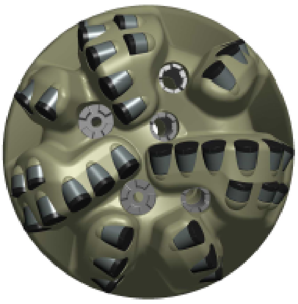
Appendix 3. Specification of RSS bit MSi713 used one several wells considered in thesis

SHARC

6 1/8 in MSi713 PDC

SMITH BITS
A Schlumberger Company

(155.575 mm) ID:65368A0001



The Smith High Abrasion Resistance Configuration (SHARC) bits are designed with the durability to withstand the demands of highly abrasive formations without sacrificing ROP.

Specifications

Total Cutters	40
Cutter Size	13mm (1/2 in)
Face Cutters	(19) 13mm
Gauge Cutters	(8) 13mm
Cone Cutters	(6) 13mm
Back-Up Cutters	(7) 13mm
Blade Count	7
Nozzles	2 Standard Series 50N, 3 Standard Series 40N
Bit Connection	3 1/2 Reg
Junk Slot Area, in2	5.004
Gauge	Length: 6" Protection: Options Available
Length	Make-Up: 11.521 Overall: 15.208
Fishing Neck	Diameter: 4.5 Length: 2.902

Operating Parameters

Bit Speed	Suitable for Rotary & PDM
Weight-on-Bit	2,500 To 22,000 (lbf) 1,136 To 9,999 (daN) 1 To 10 (Tonnes)
Flow Rate galUs/min	150 To 300
Hydraulic Horsepower, HSI	1 To 6

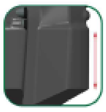
Operating parameters are typical ranges. Please contact your Smith Bits representative for recommendations for your individual well.

FEATURES

- Bit design and performance have been certified through the validation process prescribed by IDEAS simulation technology.
- The PX feature places thermally stable diamond inserts (TSP) on the gauge to maximize gauge retention and extend bit life.

- Bit design is available with advanced ONYX cutter technology. This includes the next generation ONYX II cutters that have superior abrasive wear and exceptional resistance to thermal degradation, enhancing cutter durability for increased footage drilled and faster ROP.

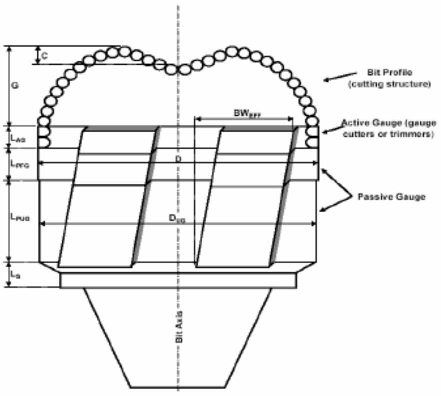
- Extended gauge pad length



www.slb.com/sharc

Appendix 4. Bit dimension guidelines for IADC PDC bits

Bit dimension guidelines for IADC PDC Bit Type 8 (Short Taper, Medium Cone) and Type 9 (Short Taper, Shallow Cone) on Revolution RSS



For use without TruGauge stabilizer

D (Nominal Bit Diameter & Diameter of Passive Full Gauge)	6.00	6.50	8.50	8.75	9.875	12.25		
D_{UG} (Diameter of Passive Under Gauge)	5.97	6.47	8.47	8.72	9.845	12.22		
Circumferential Blade Coverage = BW_{EFF} x No. of blades = > [0.5 x π x D]	>9.43	>10.21	>13.36	>13.75	>15.52	>19.25		
G (Outer Structure Height)								
L_{AG} (Length of Active Gauge)	Not > 1.00	Not > 1.00	Not > 1.00	Not > 1.00	Not > 1.00	Not > 1.00		
L_{PFG} (Length of Passive Full Gauge)	1.50 to 2.00	1.50 to 2.00	1.50 to 2.00	1.50 to 2.50	1.50 to 2.50	1.50 to 2.50		
L_{PUG} (Length of Passive Under Gauge)	3.00 to 3.50	3.00 to 3.50	3.00 to 3.50	3.00 to 3.50	3.00 to 3.50	3.50 to 4.50		
Total Make-Up Length [G + L_{AG} + L_{PFG} + L_{PUG} + L_S] = Not > 1.5 x Nominal Bit Diameter	Not > 9.00	Not > 9.75	Not > 12.75	Not > 13.13	Not > 14.81	Not > 18.38		
L_S (Length of Shank/Fishing Neck)								
Total Gauge Length [L_{AG} + L_{PFG} + L_{PUG}]	Not > 6.00	Not >6.00	Not >6.00	Not > 6.00	Not > 6.00	Not > 7.50		
C (Inner Cone Depth)								
BW_{EFF} (Effective Blade Width)								
NOTE: All dimensions in inches.								

Appendix 5. Directional surveys for DLS analysis case

Well#1			Well#2			Well#3		
MD, m	INC, deg	Az, deg	MD, m	INC, deg	Az, deg	MD, m	INC, deg	Az, deg
0,00	0,00	11,00	0,00	0,00	0,00	0,00	0,00	0,00
10,00	0,27	191,00	10,00	0,00	0,00	396,60	2,08	261,50
20,00	0,17	281,00	20,00	0,00	0,00	406,50	2,17	261,68
30,00	0,38	11,00	30,00	0,00	0,00	415,30	2,35	265,43
40,00	0,40	101,00	40,00	0,00	0,00	425,30	3,18	268,08
50,00	0,31	191,00	50,00	0,00	0,00	434,10	4,10	271,46
60,00	0,53	281,00	60,00	0,00	0,00	444,00	4,79	273,55
70,00	0,29	11,00	70,00	0,00	0,00	452,80	5,61	276,26
80,00	0,30	101,00	80,00	0,00	0,00	463,00	6,49	275,29
90,00	0,27	191,00	90,00	0,00	0,00	471,80	7,34	276,86
100,00	0,28	281,00	100,00	0,00	0,00	481,80	8,28	276,64
110,00	0,36	11,00	110,00	0,00	0,00	490,60	9,21	277,16
120,00	0,45	101,00	120,00	0,00	0,00	500,50	10,31	276,63
130,00	0,35	191,00	130,00	0,00	0,00	509,20	11,39	277,16
140,00	0,47	281,00	140,00	0,00	0,00	519,20	12,74	276,61
150,00	0,38	11,00	150,00	0,00	0,00	528,00	13,63	275,27
160,00	0,43	101,00	160,00	0,00	0,00	538,20	14,97	275,54
170,00	0,61	191,00	170,00	0,00	0,00	547,00	15,97	276,00
180,00	0,57	281,00	180,00	0,00	0,00	566,70	18,39	273,63
190,00	0,67	11,00	190,00	0,00	0,00	575,80	19,46	272,41
200,00	0,66	101,00	200,00	0,00	0,00	584,60	20,46	271,75
210,00	0,71	191,00	210,00	0,00	0,00	594,50	21,41	271,78
220,00	0,74	281,00	220,00	0,00	0,00	603,30	22,10	271,12
230,00	0,69	11,00	230,00	0,00	0,00	613,30	23,01	271,25
240,00	0,67	101,00	240,00	0,00	0,00	622,00	23,89	271,42
250,00	0,70	191,00	250,00	0,00	0,00	632,00	24,58	271,48
260,00	0,62	281,00	260,00	0,00	0,00	640,80	25,84	271,82
270,00	0,61	11,00	270,00	0,00	0,00	651,00	27,04	272,12
280,00	0,57	101,00	280,00	0,00	0,00	659,70	27,99	273,13
290,00	0,54	191,00	290,00	0,00	0,00	669,70	28,92	273,80
300,00	0,43	281,00	327,40	0,95	3,00	678,40	29,80	273,40
310,00	0,42	11,00	365,20	0,97	354,98	688,40	30,71	274,15
320,00	0,35	101,00	402,85	1,22	340,49	697,20	31,75	274,20
330,00	0,28	191,00	440,51	1,26	339,30	707,20	32,46	275,43
340,00	0,19	281,00	478,23	1,45	346,61	715,90	33,46	275,81
350,00	0,10	11,00	515,92	1,68	356,01	725,90	33,96	276,19
360,00	0,17	101,00	553,67	1,90	359,31	734,70	34,11	276,38
370,00	0,19	191,00	591,41	1,94	5,57	744,60	34,64	277,09
380,00	0,33	281,00	629,14	2,28	5,24	753,40	34,96	276,78
390,00	0,33	11,00	666,82	2,94	7,92	763,30	35,63	276,95
400,00	0,61	101,00	704,50	3,36	10,78	772,00	35,94	277,20
410,00	0,61	191,00	742,20	3,59	12,49	782,00	35,77	276,17
420,00	0,74	281,00	779,90	4,02	14,41	790,80	35,91	275,26
430,00	0,80	11,00	817,60	4,06	12,16	800,90	36,13	275,26
440,00	0,84	101,00	829,00	3,85	13,87	809,60	35,99	274,22
450,00	0,73	191,00	835,40	3,73	21,25	828,40	36,53	273,32
460,00	0,64	281,00	845,80	3,39	27,37	838,30	37,10	273,41
480,20	1,05	347,99	854,30	2,77	35,70	847,10	36,52	272,96
536,40	1,30	347,39	864,70	2,59	49,72	857,10	36,25	272,89
592,80	1,22	356,16	873,10	2,57	59,85	865,90	36,29	273,07
648,90	1,47	357,97	884,02	2,57	68,75	875,80	36,44	273,32
705,20	1,54	353,76	891,90	2,69	84,20	884,70	36,60	273,51
761,38	1,83	357,45	902,40	3,04	101,89	894,70	35,83	272,93
817,80	2,41	354,67	910,80	3,57	110,29	903,50	35,43	273,19
855,23	2,85	356,88	921,20	3,94	114,85	913,40	35,61	272,86
873,80	3,01	358,96	929,60	4,45	119,20	922,20	35,98	273,05
892,50	2,88	355,13	940,10	5,31	120,76	932,20	35,38	272,56
911,20	3,09	355,28	948,50	6,69	124,05	941,00	35,15	272,80
930,00	3,05	357,08	958,90	8,10	131,60	951,00	35,43	272,75
948,80	3,14	354,37	967,30	8,60	135,90	959,80	35,71	273,20
978,10	3,27	355,53	977,75	9,10	137,90	969,80	36,26	273,27
986,30	3,23	358,70	986,16	9,39	138,24	978,50	36,69	273,21
996,70	2,82	12,67	996,58	9,47	137,24	988,50	36,69	272,89
1005,00	2,33	30,64	1005,02	9,79	136,48	997,20	36,41	272,47
1015,20	2,27	55,00	1015,43	10,90	135,90	1007,20	35,72	271,85
1023,60	2,50	69,50	1023,85	11,66	136,31	1016,00	35,90	271,22
1033,99	3,04	82,00	1034,30	12,14	136,41	1034,90	34,35	270,34
1042,30	3,28	92,04	1042,70	12,54	137,17	1044,90	34,56	270,81
1052,80	3,98	97,78	1053,10	13,23	136,59	1053,70	34,53	270,87
1061,10	4,69	101,58	1061,60	13,65	136,05	1063,60	34,72	270,94

1070,50	5,82	105,96	1072,00	14,24	135,40	1072,40	34,93	271,15
1079,90	6,65	110,17	1080,40	14,78	136,02	1082,30	34,93	271,68
1089,30	7,24	115,85	1090,80	15,64	136,56	1091,10	34,96	272,32
1098,70	7,81	119,90	1099,30	16,42	137,46	1109,90	35,44	272,81
1108,10	8,34	122,66	1109,68	17,11	138,13	1119,80	35,94	273,10
1117,47	8,83	127,65	1118,12	17,80	138,23	1128,60	35,83	273,01
1126,80	9,34	132,60	1128,52	18,24	138,18	1133,65	35,53	273,14
1136,20	10,26	135,41	1137,00	18,60	137,00	1138,60	35,23	273,26
1145,60	11,20	136,47	1146,35	19,03	138,17	1147,30	34,00	273,77
1155,10	12,51	136,53	1155,80	19,56	138,36	1157,30	32,56	271,36
1164,50	13,60	138,17	1166,20	20,37	138,48	1166,10	31,96	271,85
1192,70	16,18	139,26	1174,70	20,92	138,05	1176,10	31,48	272,30
1202,10	16,86	139,38	1185,10	21,73	137,34	1184,90	31,02	272,64
1211,60	17,89	139,98	1193,50	22,52	137,00	1194,90	30,29	273,10
1221,00	18,74	142,05	1204,00	23,06	136,53	1203,60	29,91	273,43
1230,40	19,47	144,25	1222,81	24,24	136,50	1213,40	28,49	274,20
1239,80	20,62	145,66	1231,20	24,50	135,80	1222,30	27,26	275,50
1249,10	21,42	146,48	1241,70	25,00	136,30	1232,30	26,58	276,20
1258,49	22,32	147,18	1250,10	25,27	136,79	1241,00	25,91	276,90
1267,85	23,20	147,73	1260,60	25,20	137,00	1251,00	24,87	279,00
1277,25	23,84	148,36	1269,00	25,40	137,00	1259,70	24,05	280,90
1286,67	24,67	149,33	1279,40	25,83	136,52	1269,60	23,22	282,96
1296,00	25,71	150,30	1287,80	26,13	136,70	1278,40	22,37	284,90
1305,37	26,32	151,10	1298,30	26,20	137,85	1290,00	21,12	288,00
1314,80	26,98	151,69	1306,70	26,30	138,72	1297,30	20,62	290,00
1324,23	27,83	151,51	1317,10	26,62	139,02	1307,20	20,49	293,60
1333,63	28,34	152,17	1325,56	26,63	138,44	1316,00	20,44	297,00
1342,90	28,43	152,84	1336,00	26,49	138,06	1325,90	20,40	297,30
1352,30	28,82	152,84	1344,43	26,75	137,60	1334,60	20,16	300,00
1361,80	29,14	152,82	1354,90	26,70	137,30	1342,60	19,82	299,80
1371,20	29,33	152,25	1363,30	26,71	137,72	1351,30	18,96	302,40
1380,60	29,09	151,81	1373,70	26,74	138,02	1363,30	18,20	307,10
1390,00	28,20	151,59	1382,10	27,05	138,60	1372,00	17,90	309,70
1399,40	28,13	151,64	1392,60	27,33	138,70	1382,00	17,05	311,44
1408,80	28,38	151,83	1401,00	27,35	138,50	1390,80	16,61	312,33
1418,20	28,32	151,39	1411,50	27,38	138,40	1400,70	16,10	315,53
1427,50	28,47	151,36	1419,90	27,45	138,30	1409,40	15,40	316,05
1434,00	28,16	151,34	1430,30	27,50	138,70	1419,40	15,16	321,65
1446,30	28,14	151,85	1438,80	27,33	138,70	1428,10	14,60	323,70
1455,70	28,33	151,68	1449,20	27,33	138,81	1438,10	14,90	327,60
1465,11	28,59	152,03	1457,60	27,28	138,62	1446,80	15,37	329,41
1474,50	28,93	151,48	1468,00	27,42	138,82	1456,80	15,67	334,88
1483,90	28,85	151,45	1476,50	27,88	138,45	1465,50	15,76	336,72
1493,10	28,58	151,44	1486,90	28,67	138,48	1475,50	15,96	341,09
1502,50	28,22	151,94	1495,30	29,85	138,41	1484,20	16,47	343,88
1511,90	28,08	152,31	1505,80	30,87	137,50	1494,20	15,96	346,83
1521,20	27,75	152,61	1514,20	30,80	136,40	1503,00	16,32	349,20
1530,60	27,75	152,97	1524,60	30,30	135,10	1513,00	15,89	352,06
1540,00	27,69	153,26	1533,10	30,21	133,90	1521,80	15,59	354,83
1549,40	26,95	153,23	1543,50	30,38	132,74	1531,70	16,21	358,75
1558,80	26,77	153,72	1551,93	30,53	132,05	1540,50	16,26	2,74
1568,17	27,08	153,92	1562,30	31,10	130,60	1550,50	16,89	6,13
1577,50	27,53	154,55	1570,80	31,60	128,80	1559,40	17,44	8,68
1586,92	27,69	155,75	1580,10	32,15	127,82	1569,40	17,86	11,12
1596,40	27,86	157,76	1589,50	32,89	126,04	1578,20	17,74	13,79
1605,70	28,15	159,28	1599,00	33,65	124,54	1596,90	18,83	19,28
1615,00	28,33	160,87	1608,40	34,14	123,68	1615,50	19,44	26,91
1624,40	28,57	162,53	1617,90	34,50	122,26	1633,00	21,33	33,45
1633,80	29,05	163,46	1627,30	34,75	121,00	1642,30	22,00	35,70
1643,20	29,21	165,13	1636,70	35,50	119,45	1651,10	22,80	37,70
1652,60	29,85	166,18	1646,10	36,09	118,50	1669,80	24,79	39,80
1662,00	30,37	167,97	1655,50	36,40	117,30	1688,50	26,80	42,60
1671,40	30,60	169,57	1664,90	36,56	116,22	1698,40	27,75	44,44
1680,80	30,75	170,79	1674,30	37,27	115,47	1707,20	28,50	45,60
1690,30	31,10	171,70	1683,70	37,77	114,84	1732,10	30,54	47,60
1699,70	31,56	172,88	1693,10	38,58	114,35	1744,10	31,72	49,90
1709,00	32,07	173,69	1702,50	39,26	113,72	1754,80	32,60	52,13
1718,40	32,59	175,35	1711,90	40,20	112,90	1762,40	33,37	53,35
1727,81	33,07	176,91	1721,30	41,27	111,72	1771,30	33,92	54,31
1737,20	33,30	178,75	1730,70	42,45	110,90	1781,20	34,36	54,76
1746,60	33,00	181,66	1740,10	42,37	110,33	1790,40	35,26	56,43
1756,10	33,27	183,92	1749,50	42,40	109,70	1800,40	35,27	57,36
1765,50	33,40	184,61	1758,90	43,02	108,73	1809,20	36,19	58,23
1774,90	33,59	185,35	1768,30	44,20	108,10	1819,20	36,30	58,58

1784,30	34,49	186,39	1777,70	44,76	107,30	1827,90	36,72	59,15
1793,70	35,38	187,13	1784,50	45,21	106,75	1837,78	37,48	59,36
1803,12	35,60	188,12	1790,00	45,24	106,52	1837,80	37,48	59,36
1828,12	37,51	189,42	1800,00	45,29	106,10	1846,60	37,56	59,29
1838,14	39,52	191,58	1802,50	45,30	106,00	1865,30	38,27	58,74
1847,58	41,76	193,00	1810,00	45,05	105,08	1875,20	38,44	58,61
1856,88	43,60	194,81	1815,67	44,86	104,39	1884,00	38,57	58,72
1866,27	45,23	197,49	1815,69	44,86	104,39	1894,00	38,39	58,67
1875,66	46,99	198,81	1820,00	44,72	103,86	1902,70	38,06	58,46
1885,06	48,39	200,52	1830,00	44,39	102,63	1912,70	37,78	58,86
1894,49	50,22	202,24	1840,00	44,09	101,38	1921,50	38,10	59,13
1903,92	52,00	203,11	1843,00	44,00	101,00	1931,40	39,20	59,38
1913,32	53,59	203,80	1848,00	44,00	101,00	1940,20	41,62	59,87
1922,71	55,84	204,37	1855,30	44,40	99,98	1949,50	43,51	60,38
1932,14	57,51	204,94	1863,70	45,61	97,94	1958,82	44,89	60,44
1941,58	59,45	204,54	1871,10	46,39	96,39	1968,80	46,25	60,87
1951,01	61,95	205,18	1882,50	48,45	93,43	1977,55	48,46	62,18
1960,42	63,51	206,28	1892,90	50,15	91,96	1987,53	50,58	62,99
1969,82	65,28	207,57	1901,30	52,06	89,47	1995,00	52,29	63,71
1979,22	66,53	208,93	1910,70	53,64	88,63	2004,98	54,58	64,58
1988,63	66,88	210,49	1920,10	55,18	87,35	2013,74	55,97	64,93
1998,03	67,21	212,00	1929,50	56,97	84,23	2023,69	56,14	64,95
2007,46	68,04	213,93	1938,90	58,82	82,98	2031,66	56,44	64,83
2016,87	68,56	215,78	1949,30	60,18	81,66	2045,70	57,48	65,00
2026,29	69,45	217,25	1957,70	61,23	80,06	2055,90	58,10	64,59
2035,68	70,50	218,31	1968,10	62,48	77,56	2065,10	60,43	63,96
2045,09	71,82	219,22	1976,50	63,94	75,58	2075,00	62,59	63,55
2054,49	73,40	219,90	1986,90	65,51	73,75	2084,64	64,66	63,32
2063,91	75,02	220,67	1995,30	66,86	72,68	2093,41	66,80	63,55
2073,32	76,82	221,17	2004,70	68,49	70,69	2094,10	66,97	63,57
2082,71	78,55	221,44	2014,10	69,54	69,22	2103,10	69,28	64,32
2092,08	80,60	221,05	2024,50	70,47	67,45	2113,20	71,17	65,45
2097,08	81,50	220,72	2032,90	71,52	65,90	2118,87	72,59	65,97
2107,46	82,89	220,21	2043,30	72,57	64,30	2122,30	73,45	66,28
2120,50	82,40	221,01	2051,70	73,52	62,28	2123,49	73,68	66,47
2129,40	80,23	223,01	2062,10	74,89	60,68	2132,50	75,43	67,88
2139,30	77,78	224,69	2070,50	75,46	60,12	2141,60	77,71	68,13
2148,20	77,84	225,06	2079,90	75,82	59,11	2151,60	80,29	69,01
2158,10	79,90	224,30	2089,20	76,17	56,62	2160,80	81,90	70,22
2167,00	81,90	223,71	2098,60	76,39	54,33	2170,90	84,32	69,88
2176,94	83,58	223,22	2108,00	77,39	52,47	2180,10	86,79	69,74
2186,34	86,05	222,84	2114,51	77,73	51,08	2189,80	89,01	69,37
2195,74	86,98	222,54	2117,40	77,89	50,46	2198,90	89,32	69,34
2205,07	86,73	222,68	2119,09	77,90	50,16	2208,80	89,63	69,41
2214,37	86,80	223,09	2126,80	77,97	48,80	2218,00	90,31	69,49
2223,78	88,58	223,55	2136,20	78,83	47,40	2228,00	90,35	69,92
2233,20	88,46	224,23	2145,70	79,04	45,33	2237,10	90,68	70,41
2242,60	87,97	224,24	2155,10	80,04	44,46	2247,20	90,74	70,09
2252,00	87,60	223,76	2164,50	80,89	44,09	2256,30	90,37	69,60
2260,90	89,26	222,75	2173,90	81,16	44,11	2266,50	89,57	69,03
2270,80	90,00	222,09	2183,30	81,81	44,63	2275,50	89,38	69,17
2279,70	89,45	222,47	2192,70	82,29	45,12	2285,50	89,26	69,42
2289,57	87,17	222,65	2202,00	82,20	45,22	2294,70	89,69	68,88
2298,48	85,25	223,36	2211,60	82,43	45,24	2304,80	90,12	69,35
2308,40	84,20	224,24	2221,00	84,19	45,21	2313,80	90,31	69,13
2317,29	84,08	224,28	2230,30	86,78	45,93	2323,70	90,25	69,03
2327,18	83,00	224,42	2239,70	87,21	46,26	2332,90	90,37	69,43
2336,08	82,10	224,88	2249,10	87,13	46,12	2342,90	90,43	69,17
2349,00	81,78	224,69	2253,09	87,18	46,09	2361,80	90,62	69,06
2354,90	81,54	224,68	2253,90	87,19	46,09	2370,80	90,49	69,10
2364,80	82,65	224,35	2254,14	87,19	46,09	2380,80	90,49	68,87
2373,70	84,26	223,84	2258,50	87,25	46,06	2389,70	90,37	68,68
2383,10	86,92	224,31	2267,90	87,00	45,92	2399,70	89,94	68,37
2391,36	87,91	224,32	2282,70	85,44	45,50	2408,80	89,51	67,40
2401,30	87,84	224,28	2291,10	86,00	45,52	2418,80	89,75	66,57
2410,30	87,54	224,07	2301,40	85,81	45,02	2427,80	90,55	66,84
2420,20	87,41	223,67	2309,80	86,73	45,21	2437,90	91,23	66,74
2429,10	89,01	223,01	2320,10	87,91	46,97	2446,90	91,79	66,91
2438,90	89,32	222,51	2328,50	89,94	48,42	2456,90	93,08	66,69
2447,90	89,08	222,60	2337,90	89,82	50,99	2466,00	93,95	66,99
2457,80	89,08	222,10	2347,30	89,88	53,20	2476,10	93,76	67,13
2466,70	89,20	221,94	2356,70	88,46	53,27	2485,20	93,57	67,28
2476,62	90,00	222,18	2366,10	87,23	53,21	2495,20	93,27	66,76
2486,02	89,90	222,17	2375,50	88,40	54,50	2504,20	93,02	66,43

2495,42	89,21	222,55	2384,90	89,88	56,72	2514,20	93,08	66,86
2504,30	89,14	222,90	2394,20	91,48	57,66	2523,40	92,22	67,76
2514,22	88,95	223,13	2403,60	90,49	57,99	2533,30	90,99	68,01
2523,10	87,84	223,93	2413,00	89,32	57,55	2537,40	90,86	68,07
2533,00	87,53	223,60	2422,30	88,15	57,04			
2542,00	87,48	223,06	2431,70	86,86	56,55			
2551,70	89,01	222,33	2441,10	86,73	56,76			
2560,60	89,08	222,85	2450,50	87,47	57,06			
2570,50	89,01	223,57	2459,90	88,58	56,87			
2579,40	89,02	223,84	2469,20	89,26	56,88			
2589,30	88,83	223,72	2478,60	89,82	57,16			
2598,20	88,65	223,33	2488,00	90,00	57,78			
2607,60	88,58	223,13	2497,40	90,31	57,44			
2617,00	88,73	223,16	2506,80	90,98	56,68			
2626,30	90,62	223,26	2516,10	91,05	56,63			
2635,80	90,49	223,38	2525,40	91,11	55,87			
2645,70	90,18	222,57	2534,80	91,48	55,62			
2655,60	88,03	223,14	2544,20	92,03	55,81			
2664,50	88,09	222,98	2553,50	91,66	55,97			
2673,36	88,09	223,14	2562,90	91,11	56,37			
2683,30	87,97	223,25	2572,20	90,49	57,30			
2692,20	88,15	223,63	2581,60	90,31	56,52			
2702,10	88,52	223,53	2591,00	89,75	56,21			
2708,50	88,40	223,20	2600,40	88,64	56,62			
2730,00	88,40	223,20	2609,80	87,91	56,46			
			2619,10	85,68	56,91			
			2628,50	85,26	55,58			
			2637,90	85,07	54,59			
			2647,30	85,62	53,48			
			2656,70	86,43	53,54			
			2666,10	89,08	53,73			
			2675,50	90,99	54,97			
			2679,90	90,68	54,60			
			2700,00	90,68	54,60			

Appendix 6. Drilling parameters for well#1 used in simulation

MD, feet	ROP, ft/hr	WOB, lbs	RPM	TQA, fp	Flow rate, gp	Mwa, ppg	Sppa, psig	ecda, ppg	ppe, ppg	bpl, psig	hpsi	tvd, feet	dcwoba	dctqa	adldens	ht	DLS
5448,08	1,968	130,254	20	10325	523	10,02	1476	10,9385	9,46	35	0,601	5298,755	1102,31	11062,5	10,521	0,01	1
5476,944	2,624	130,254	20	9587,5	523	10,02	1476	10,9385	9,46	35,2	0,611	5324,697	1102,31	11062,5	10,521	0,02	1,922971
5509,744	11,184	260,462	20	10325	523	10,02	1476	10,9385	9,46	35	0,615	5353,774	8818,48	11062,5	10,521	0,03	2,43
5538,936	9,152	150,356	20	10325	523	10,1035	1617	11,1055	9,48	35,5	0,602	5379,298	13227,72	11062,5	10,521	0,04	2,5
5572,064	18,04	260,462	20	10325	523	10,1035	1617	11,1055	9,48	36,1	0,607	5407,813	13227,72	11062,5	10,521	0,05	2,77
5600,928	13,448	257,2057	20	10325	523	10,1035	1911	11,1055	9,51	36,7	0,63	5432,245	15432,34	11062,5	10,521	0,06	2,856536
5633,728	19,352	367,4367	20	10325	523	10,2705	1911	11,523	9,55	38,2	0,621	5459,596	22046,2	11062,5	10,521	0,07	2,305135
5662,92	17,056	260,462	20	8850	523	10,2705	1911	11,523	9,55	38,6	0,632	5483,753	13227,72	11062,5	10,521	0,08	2,666991
5695,72	16,728	367,4367	20	10325	523	10,2705	1911	11,523	9,55	39,3	0,654	5510,838	22046,2	11062,5	10,521	0,09	2,518267
5724,584	16,728	404,1803	20	10325	523	10,2705	2058	11,523	9,58	39,9	0,635	5534,436	24250,82	11062,5	10,521	0,1	2,64
5757,712	19,68	260,462	20	10325	523	10,2705	2058	11,523	9,61	40	0,638	5560,915	13227,72	11062,5	10,521	0,11	2,66
5786,904	19,352	440,924	20	10325	523	10,2705	2058	11,523	9,65	40,2	0,634	5583,624	26455,44	11062,5	10,521	0,12	2,26
5819,704	21,976	404,1803	20	11062,5	523	10,2705	2058	11,523	9,68	40,8	0,629	5608,602	24250,82	11062,5	10,521	0,13	1,69
5848,568	15,416	260,462	20	10325	523	10,354	1984,5	11,6065	9,78	41,5	0,627	5630,252	13227,72	11062,5	10,521	0,14	1,893065
5881,368	20,336	404,1803	20	10325	523	10,354	1984,5	11,6065	9,78	42	0,629	5654,523	24250,82	11062,5	10,521	0,15	2,391294
5910,232	28,208	367,4367	20	8850	523	10,354	2058	11,6065	9,78	42,8	0,628	5675,532	22046,2	11062,5	10,521	0,16	2,975912
5943,36	23,288	404,1803	20	10325	523	10,4375	2058	11,6065	9,78	42,9	0,622	5699,028	24250,82	11062,5	10,521	0,17	2,839829
5972,224	14,104	440,924	20	10325	523	10,4375	2058	11,69	9,81	43,2	0,627	5718,936	26455,44	11062,5	10,521	0,18	2,6758
6005,024	16,072	260,462	20	10325	523	10,4375	2058	11,69	9,83	43,6	0,631	5741,19	13227,72	11062,5	10,521	0,19	1,89361
6033,888	15,744	440,924	20	10325	523	10,4375	2058	11,69	9,83	43,3	0,625	5760,568	26455,44	11062,5	10,521	0,2	2,663473
6067,016	22,304	260,462	20	10325	523	10,354	2131,5	11,69	9,83	43,8	0,619	5782,571	13227,72	11062,5	10,521	0,21	2,075684
6096,208	19,352	404,1803	20	10325	523	10,354	2131,5	11,69	9,85	43,9	0,623	5801,647	24250,82	11062,5	10,521	0,22	2,627313
6129,336	27,552	260,462	20	11062,5	523	10,354	2131,5	11,69	9,86	44,4	0,622	5822,736	13227,72	11062,5	10,521	0,23	2,228428
6158,2	17,056	260,462	20	10325	523	10,354	2058	11,857	9,87	44,9	0,625	5840,667	13227,72	11062,5	10,521	0,24	2,311748
6191,328	20,008	440,924	20	10325	523	10,4375	2058	11,857	9,87	45,1	0,625	5860,802	26455,44	11062,5	10,521	0,25	2,258224
6220,52	17,056	404,1803	20	10325	523	10,354	2058	11,857	9,87	45,8	0,625	5878,172	24250,82	11062,5	10,521	0,26	2,160916
6253,32	16,728	260,462	20	10325	523	10,354	2058	11,9405	9,87	46,2	0,621	5897,127	13227,72	11062,5	10,521	0,27	2,378728
6282,512	21,32	367,4367	20	10325	539	10,354	2058	11,857	9,89	47,8	0,623	5913,247	22046,2	11062,5	10,521	0,28	2,24828
6315,312	20,008	404,1803	20	10325	539	10,2705	2131,5	12,024	9,89	47,8	0,623	5930,44	24250,82	11062,5	10,521	0,29	2,218924
6344,504	12,792	440,924	20	10325	539	10,2705	2131,5	12,024	9,89	48,5	0,619	5944,932	26455,44	11062,5	10,521	0,3	2,047325
6377,304	17,384	440,924	20	8112,5	539	10,2705	2131,5	12,024	9,95	49,1	0,624	5960,327	26455,44	11062,5	10,521	0,31	1,301323
6395,344	11,48	260,462	20	10325	539	10,354	2058	12,024	10,3	49,9	0,624	5968,472	13227,72	11062,5	10,521	0,32	1,301323
6406,168	11,152	404,1803	20	8850	539	10,354	2058	12,1075	10,5	50,6	0,624	5973,262	24250,82	11062,5	10,521	0,33	2,589583
6439,296	19,68	404,1803	20	10325	539	10,354	2058	12,024	10,5	51,9	0,624	5987,548	24250,82	11062,5	10,521	0,34	1,460268

Appendix 7. Typical drilling time balance for one day of active drilling operations

Time Balance							
Run	**Date**	**Start time**	**End Time**	**Time Interval**	**Start Depth**	**End Depth**	**Operation**
2	24/11/2011	0:00	0:17	0:17	2118,06 m	2118,06 m	RIG-NPT-Pump Repair
2	24/11/2011	0:17	0:32	0:15	2118,06 m	2118,06 m	RIG-OPS-Reaming/Hole Opening
2	24/11/2011	0:32	0:36	0:04	2118,06 m	2118,06 m	RIG-NPT-Pump Repair
2	24/11/2011	0:36	0:49	0:13	2118,06 m	2118,06 m	RIG-OPS-Reaming/Hole Opening
2	24/11/2011	0:49	1:06	0:17	2118,06 m	2118,06 m	RIG-NPT-Pump Repair
2	24/11/2011	1:06	1:13	0:07	2118,06 m	2118,06 m	RIG-OPS- Reaming/Hole Opening
2	24/11/2011	1:13	1:25	0:12	2118,06 m	2118,06 m	RIG-OPS-Connection-(Kelly PU/LD)
2	24/11/2011	1:25	1:29	0:04	2118,06 m	2118,06 m	**D&M-OPS-Surveying**
2	24/11/2011	1:29	1:41	0:12	2118,06 m	2130,11 m	D&M-OPS-Drilling
2	24/11/2011	1:41	1:45	0:04	2130,11 m	2130,11 m	RIG-OPS-Other
2	24/11/2011	1:45	1:55	0:10	2130,11 m	2136,00 m	D&M-OPS-Drilling
2	24/11/2011	1:55	2:01	0:06	2136,00 m	2139,12 m	D&M-OPS-Drilling
2	24/11/2011	2:01	2:08	0:07	2139,12 m	2139,12 m	RIG-OPS-Other
2	24/11/2011	2:08	2:23	0:15	2139,12 m	2145,92 m	D&M-OPS-Drilling
2	24/11/2011	2:23	2:55	0:32	2145,92 m	2145,92 m	RIG-OPS-Reaming/Hole Opening
2	24/11/2011	2:55	3:08	0:13	2145,92 m	2145,92 m	RIG-OPS-Connection-(Kelly PU/LD)
2	24/11/2011	3:08	3:12	0:04	2145,92 m	2145,92 m	**D&M-OPS- Surveying**
2	24/11/2011	3:12	3:19	0:07	2145,92 m	2155,03 m	D&M-OPS-Drilling
2	24/11/2011	3:19	3:26	0:07	2155,03 m	2155,03 m	RIG-OPS-Other
2	24/11/2011	3:26	3:36	0:10	2155,03 m	2160,09 m	D&M-OPS-Drilling
2	24/11/2011	3:36	3:49	0:13	2160,09 m	2175,22 m	D&M-OPS-Drilling
2	24/11/2011	3:49	4:06	0:17	2175,22 m	2175,22 m	RIG-OPS-Reaming/Hole Opening
2	24/11/2011	4:06	4:44	0:38	2175,22 m	2175,22 m	RIG-NPT-Pump Repair
2	24/11/2011	4:44	5:11	0:27	2175,22 m	2175,22 m	RIG-OPS-Reaming/Hole Opening
2	24/11/2011	5:11	5:22	0:11	2175,22 m	2175,22 m	RIG-OPS-Connection-(Kelly PU/LD)
2	24/11/2011	5:22	5:26	0:04	2175,22 m	2175,22 m	**D&M-OPS- Surveying**
2	24/11/2011	5:26	5:45	0:19	2175,22 m	2198,02 m	D&M-OPS-Drilling
2	24/11/2011	5:45	5:49	0:04	2198,02 m	2198,02 m	RIG-OPS-Other
2	24/11/2011	5:49	6:06	0:17	2198,02 m	2204,25 m	D&M-OPS-Drilling
2	24/11/2011	6:06	6:31	0:25	2204,25 m	2204,25 m	RIG-OPS-Reaming/Hole Opening
2	24/11/2011	6:31	6:42	0:11	2204,25 m	2204,25 m	RIG-OPS-Connection-(Kelly PU/LD)
2	24/11/2011	6:42	6:47	0:05	2204,25 m	2204,25 m	**D&M-OPS- Surveying**
2	24/11/2011	6:47	6:55	0:08	2204,25 m	2213,07 m	D&M-OPS-Drilling
2	24/11/2011	6:55	6:59	0:04	2213,07 m	2213,07 m	RIG-OPS-Other
2	24/11/2011	6:59	7:05	0:06	2213,07 m	2215,56 m	D&M-OPS-Drilling
2	24/11/2011	7:05	7:13	0:08	2215,56 m	2215,56 m	RIG-OPS-Other
2	24/11/2011	7:13	7:18	0:05	2215,56 m	2216,50 m	D&M-OPS-Drilling
2	24/11/2011	7:18	7:27	0:09	2216,50 m	2225,03 m	D&M-OPS-Drilling
2	24/11/2011	7:27	7:32	0:05	2225,03 m	2225,03 m	RIG-OPS-Other
2	24/11/2011	10:13	10:24	0:11	2261,71 m	2261,71 m	RIG-OPS-Connection-(Kelly PU/LD)
2	24/11/2011	10:24	10:48	0:24	2261,71 m	2261,71 m	RIG-NPT-Other
2	24/11/2011	10:48	11:02	0:14	2261,71 m	2270,00 m	D&M-OPS-Drilling
2	24/11/2011	11:02	11:13	0:11	2270,00 m	2270,00 m	RIG-OPS-Other
2	24/11/2011	11:13	11:58	0:45	2270,00 m	2290,54 m	D&M-OPS-Drilling
2	24/11/2011	11:58	12:24	0:26	2290,54 m	2290,54 m	RIG-OPS-Reaming/Hole Opening
2	24/11/2011	12:24	12:41	0:17	2290,54 m	2290,54 m	RIG-OPS-Connection-(Kelly PU/LD)

2	24/11/2011	12:41	12:46	0:05	2290,54 m	2290,54 m	**D&M-OPS-Surveying**
2	24/11/2011	12:46	13:00	0:14	2290,54 m	2300,05 m	D&M-OPS-Drilling
2	24/11/2011	13:00	13:05	0:05	2300,05 m	2300,05 m	RIG-OPS-Other
2	24/11/2011	13:05	13:24	0:19	2300,05 m	2306,99 m	D&M-OPS-Drilling
2	24/11/2011	13:24	13:31	0:07	2306,99 m	2313,03 m	D&M-OPS-Drilling
2	24/11/2011	13:31	13:38	0:07	2313,03 m	2313,03 m	RIG-OPS-Other
2	24/11/2011	13:38	13:54	0:16	2313,03 m	2319,42 m	D&M-OPS-Drilling
2	24/11/2011	13:54	14:21	0:27	2319,42 m	2319,42 m	RIG-OPS-Reaming/Hole Opening
2	24/11/2011	14:21	14:41	0:20	2319,42 m	2319,42 m	RIG-OPS-Connection-(Kelly PU/LD)
2	24/11/2011	14:41	14:49	0:08	2319,42 m	2319,42 m	**D&M-OPS- Surveying**
2	24/11/2011	14:49	15:00	0:11	2319,42 m	2326,05 m	D&M-OPS-Drilling
2	24/11/2011	15:00	15:24	0:24	2326,05 m	2339,75 m	D&M-OPS-Drilling
2	24/11/2011	15:24	15:37	0:13	2339,75 m	2339,75 m	D&M-OPS-Other
2	24/11/2011	15:37	16:09	0:32	2339,75 m	2348,28 m	D&M-OPS-Drilling
2	24/11/2011	16:09	16:34	0:25	2348,28 m	2348,28 m	RIG-OPS-Reaming/Hole Opening
2	24/11/2011	16:34	16:45	0:11	2348,28 m	2348,28 m	RIG-OPS-Connection-(Kelly PU/LD)
2	24/11/2011	16:45	16:57	0:12	2348,28 m	2348,28 m	**D&M-OPS- Surveying**
2	24/11/2011	16:57	17:02	0:05	2348,28 m	2354,00 m	D&M-OPS-Drilling
2	24/11/2011	17:02	17:10	0:08	2354,00 m	2354,00 m	RIG-OPS-Other
2	24/11/2011	17:10	18:04	0:54	2354,00 m	2375,31 m	D&M-OPS-Drilling
2	24/11/2011	18:04	18:07	0:03	2375,31 m	2377,20 m	D&M-OPS-Drilling
2	24/11/2011	18:07	18:31	0:24	2377,20 m	2377,20 m	RIG-OPS-Reaming/Hole Opening
2	24/11/2011	18:31	18:41	0:10	2377,20 m	2377,20 m	RIG-OPS-Connection-(Kelly PU/LD)
2	24/11/2011	18:41	18:44	0:03	2377,20 m	2377,20 m	**D&M-OPS- Surveying**
2	24/11/2011	18:44	18:52	0:08	2377,20 m	2386,97 m	D&M-OPS-Drilling
2	24/11/2011	18:52	18:57	0:05	2386,97 m	2386,97 m	RIG-OPS-Other
2	24/11/2011	18:57	19:29	0:32	2386,97 m	2406,16 m	D&M-OPS-Drilling
2	24/11/2011	19:29	20:00	0:31	2406,16 m	2406,16 m	RIG-OPS-Reaming/Hole Opening
2	24/11/2011	20:00	20:12	0:12	2406,16 m	2406,16 m	RIG-OPS-Connection-(Kelly PU/LD)
2	24/11/2011	20:12	20:16	0:04	2406,16 m	2406,16 m	**D&M-OPS- Surveying**
2	24/11/2011	20:16	20:23	0:07	2406,16 m	2414,12 m	D&M-OPS-Drilling
2	24/11/2011	20:23	20:30	0:07	2414,12 m	2414,12 m	RIG-OPS-Other
2	24/11/2011	20:30	20:54	0:24	2414,12 m	2423,78 m	D&M-OPS-Drilling
2	24/11/2011	20:54	21:02	0:08	2423,78 m	2433,00 m	D&M-OPS-Drilling
2	24/11/2011	21:02	21:29	0:27	2433,00 m	2433,00 m	RIG-OPS-Reaming/Hole Opening
2	24/11/2011	21:29	21:33	0:04	2433,00 m	2433,00 m	**D&M-OPS- Surveying**

Appendix 8. Regress_1_initial.m

```
%Load data%

load data.mat

wobma=xlsread ('data.xls','Sheet1','C2:C35');
ht=xlsread ('data.xls','Sheet1','S2:S35');
d=8.7;

%Model predictors%
x2=6439-tvd;%normalized TVD = 6439ft%
x3=tvd.^0.69.*(ppe-10.5); %normilized ppe=10.5 ppg
x4=tvd.*(ppe-ecda); %overbalance
x5=(log(wobma/(d*1000))); %normilized WOB = 800 lbs/in
x6= log(rpma/20);%normlized RPM = 20
x7=-ht;
x8=log(hpsi/0.62);%normilized hpsi = 0.62


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

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

a = x\y;

%index of correlation%
ropm=[];
for i=1:size(x,1)
    ropm=[ropm;exp(sum(a'*x(i,:)'))];
end

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

Appendix 9. Regress_1.m

```
%Load data%
load data.mat

wobma=xlsread ('data.xls','Sheet1','C2:C35');
ht=xlsread ('data.xls','Sheet1','S2:S35');
d=8.7;

%Model predictors%
x2=6439-tvd;%normalized TVD = 6439ft%
x3=tvd.^0.99.*(ppe-10.5); %normilized ppe=10.5 ppg
x4=tvd.*(ppe-ecda); %overbalance
x5=(log(wobma/(d*1000))); %normilized WOB = 800 lbs/in
x6= log(rpma/20);%normlized RPM = 20
x7=-2*ht.*ecda.^2;
x8=log(hpsi/0.62);%normilized hpsi = 0.62
x9=ecda.^-6;
x10=(dls.^0.5./tqa.^2.*depth.^0.01./dls.^4)./dls.^7;
x11=dls.^0.01./tqa.^2.*mwa;

%check the minimum range of predictors%
range=[max(x2)-min(x2); max(x3)-min(x3); max(x4)-min(x4);
max(x5)-min(x5);
    max(x6)-min(x6); max(x7)-min(x7); max(x8)-min(x8); max(x9)-
min(x9); max(x10)-min(x10); max(x11)-min(x11)];
%%

%regression analysis%
y=log(ropa);
x=[ones(size(y)) x2 x3 x4 x5 x6 x7 x8 x9 x10 x11]; %predictors

a = x\y;

%index of correlation%
ropm=[];
for i=1:size(x,1)
    ropm=[ropm;exp(sum(a'*x(i,:)'))];
end

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

Appendix 10. Params.m

```
%name parameters%
depth=xlsread ('data.xls','Sheet1','A2:A35');%MD, ft
ropa=xlsread ('data.xls','Sheet1','B2:B35');%ROP avg, ft/hr
woba=xlsread ('data.xls','Sheet1','C2:C35');%WOB avg, lbs
rpma=xlsread ('data.xls','Sheet1','D2:D35');%RPM avg, rpm
tqa=xlsread ('data.xls','Sheet1','E2:E35');%TQ avg, f-p
flowa=xlsread ('data.xls','Sheet1','F2:F35');%Flow-in pump avg,
gpm
mwa=xlsread ('data.xls','Sheet1','G2:G35');%MW in, ppg
sppa=xlsread ('data.xls','Sheet1','H2:H35');%SPP average, psig
ecda=xlsread ('data.xls','Sheet1','I2:I35');%ECD avg, ppg
ppe=xlsread ('data.xls','Sheet1','J2:J35');%Pore pressure, ppg
bpl=xlsread ('data.xls','Sheet1','K2:K35');%Bit pressure loss,
psig
hpsi=xlsread ('data.xls','Sheet1','L2:L35');%Hydraulic power,
hpsi
hob=xlsread ('data.xls','Sheet1','M2:M35');%Hours on bottom, hr
rob=xlsread ('data.xls','Sheet1','N2:N35');%rotations on
bottiom, krev
tvd=xlsread ('data.xls','Sheet1','O2:O35');%TVD, ft
dcwoba=xlsread ('data.xls','Sheet1','P2:P35');%WOB avg, lbs
dctqa=xlsread ('data.xls','Sheet1','Q2:Q35');%TQ avf, f-p
adldens=xlsread ('data.xls','Sheet1','R2:R35');%Composite
density, g/cc
dls=xlsread ('data.xls','Sheet1','T2:T35');%DLS

ropm=xlsread ('data.xls','Sheet1','T2:T35');%ROP modelled, ft/hr
save data
```

Appendix 11. Smooth.m

```
[num,T,vT]=xlsread('data.xls','Sheet1');
 x1 = num(:, 1);
 y1 = num(:, 2);
%  y2 = num(:, 20);
figure
plot(x1(1:34),y1(1:34),'b',x1(1:34),ropm,'r');%plot original ROP

xlabel('MD, ft', 'FontSize', 11);
ylabel('ROP, fph','FontSize',11);
```

Appendix 12. CCS and DSE.m

```
%variables%
%run ('params')
ab=pi*8.7^2/4; %bit area

%DSE%
dse1=dcwoba./ab;
dse2=(110*pi*ab).*(rpma.*dctqa./ropa);
dse3=1980000*0.00876*hpsi./ropa;
dse=dse1+dse2-dse3;

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

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