Master thesis

FULL DESIGN OF A DRILLING MUD PUMP AND FLOW PROGRAM

Srđan Balać

TECHNICAL UNIVERSITY OF CRETE DEPARTMENT OF MINERAL RESOURCES ENGINEERING

The undersigned hereby certify that they have read and recommended to the Faculty of Mineral Resources Engineering for acceptance a thesis entitled “Full Design of a Drilling Mud Pump and Flow Program ‘’ by Srđan Balać in requirements for the degree of Master of Science.

Examination committee:

Supervisor	Prof. Dr Nikos Pasadakis
Scientific advisor	Assist. Prof. Gaganis Vassilis
Professor	Dr Dimitris Marinakis

Date of presenting: __________________07.02.2019________________

Acknowledgement

This work could not have been completed without the assistance and supervising of Prof. Nikos Pasadakis.

He has been a real source of motivation during this work by giving new challenges and developing me engineering way of thinking.

His is always there when you need help with his valuable comments, guidelines, and interesting discussions during this study.

I would also like to thank all the professors at the MSc Petroleum Engineering program for their effort and unrelenting attitude to teach and inspire students, but most of all preparing them for future success in their engineering life in the petroleum industry. It was such a great honor to study under Professor Pasadakis, Professor Varotsis, Dr. Marinakis, Dr. Kourounis, Dr. Maravelis, and of course Dr. Gaganis.

Also, a big thank you to the secretary of the program, Mrs. Maria Michalogianaki; whose guidance and leadership has helped in my successful completion of the program.

A special thank you for EKO Serbia A.D. Member of the Hellenic Petroleum Group that provided me with the scholarship and give me opportunity to study at Technical University of Crete as a student of Master petroleum engineering. I was honored to be your scholar and thank you for your generosity.

Finally, I would like to show my appreciation to my family, friends and classmates for their care and support, esspecily to my mom Olgica Balać, dad Milan Balać, brothers Danilo and Tomislav Balać.

Abstract

Drilling projects must be planned carefully as they need to be a balance of both efficiency of drilling and the project expenditure; that is, the goal is to drill the well reaching target depth with highest performance at the lowest cost.

When it comes to reducing the cost of a project, mud hydraulics are one of the most important factors. By minimizing pressure loss, due to friction in drilling string and annulus, maximum efficiency of the drilling bit and the maximum usage of pump pressure is achieved.

Knowing the rheology of the mud and the flow regime we can calculate pressure loss in the system. Rheology studies the flow, or rather deformation of matter, described in terms of shear rate and shear stress. Shear rate is defined as the flow velocity gradient in the direction perpendicular to the flow direction. Hence, the higher the shear rate, the higher the friction between the flowing particles. On the other hand, Fluids are described as Newtonian or non-Newtonian depending on their response to shear stress.

Flow regime that appear in drilling are laminar flow, turbulent flow, and transitional flow. Pressure loss in the system can be expressed by calculating fluid velocity and Reynolds number for flow regimes. Circulating fluid must overcome friction between the fluid layers and the drill pipe, hole walls or casing walls, as well as the friction between solid particles and fluid. The major pressure loss occurs on the drilling bit nozzles. Therefore, pressure on the pump must be high enough to compensate for it; and it is equal to sum of all these forces.

When it comes to the required hole cleaning and high rate of penetration, mud pumps are the most important equipment for providing the bit hydraulics. Drilling hydraulics can always be optimized by altering the pump liner, flow rate, and size of the nozzles; in accordance to the depth of drilling.

In making an effective design, it is essential to have an understanding of hydraulics problems, as well as all their possible causes; in order to prepare adequate solutions to overcome delays, reduce operation costs, and reach the target.

This thesis studies hydraulics as a means of assisting the design of full flow programs, that will in return give us the necessary mud pump specification for optimal drilling. Through modeling this problem, the goal is to avoid potential drilling problems in order to ensure further efficient drilling; especially in complex and inclined wells, where the hydraulic are usually more complex because of well path and geometry.

Table of Contents

List of figures

List of tables

Chapter 1 Basic of drilling

1.1. Introduction

Drilling exploration and exploitation wells require huge capital investments; it can take up to more than 40% of whole project for exploration and developing the field (Bourgoyne, 1986). Therefore, it must be planed carefully and there needs to be a balance between the efficiency of drilling and the costs. That is, the goal is to drill the well reaching target depth with optimal performance at minimal cost. In this chapter, we will take a brief look at the basics of drilling and the necessary equipment. Although, this project is aimed at design and optimization of mud pumps, its implications go far beyond that. Hence, we will further highlight its significance in other drilling projects.

1.2. Drilling

1.2.1. Borehole planning

Simply reaching the target depth does not imply a successful outcome. Well designs should fulfil these general requirements: safety, minimum costs, and functionality. Different variables influence well designs and a program that defines these variables is termed as Borehole Planning.

Health, safety and the environment are imperative, and must be considered at all times. Due to the nature of the work, human error must be avoided as much as possible, as it may lead to serious injury, or even loss of human life. Furthermore, the safety of the well itself must be evaluated in order to avoid eruptions, mud loss in formation, and other problems that threaten the safety of workers and their environment. Furthermore, another factor that should be taken into consideration is the costs of the project. Risk and cost management is a key part of project development, and it must be done with care.

1.2.2. Well types

Wells can be classified either according to their purpose of use, or according to the type of fluid that they produce or inject. Based on their purpose there are:

1. Wildcat wells – based on seismic data in an area where very little is known about the geology, and no drilling projects were conducted before. Very high cost and high-risk drilling, as it is likely to lead to a dry well.
2. Exploration wells – drilled solely for the purpose of gathering information in a new area.
3. Appraisal wells – used to assess characteristics (e.g. flow rate) of a proven hydrocarbon reservoir.
4. Production wells – drilled primarily for producing oil or gas once the producing structure and characteristics are established.

On the other hand, most wells produce a mixture of oil, gas and water. Depending on their production they can be classified in 5 groups:

1. Oil producers
2. Gas producers
3. Aquifer producers
4. Water injectors
5. Gas injectors

1.2.3. Drilling rigs

Drilling rigs are primary used for drilling the well. However, they can also be used for installing the casing and cementing, as well as doing well testing while drilling.

Depending on the location of where the drilling operations are conducted, drilling rings can be classified into, two big groups; land or marine (Figure 1.1). When it comes to the drilling technology and the design of the borehole, there are no significant differences between land and water installations. However, the cost of equipment for offshore drilling rigs is much higher; and is progressively increasing with the water depth.

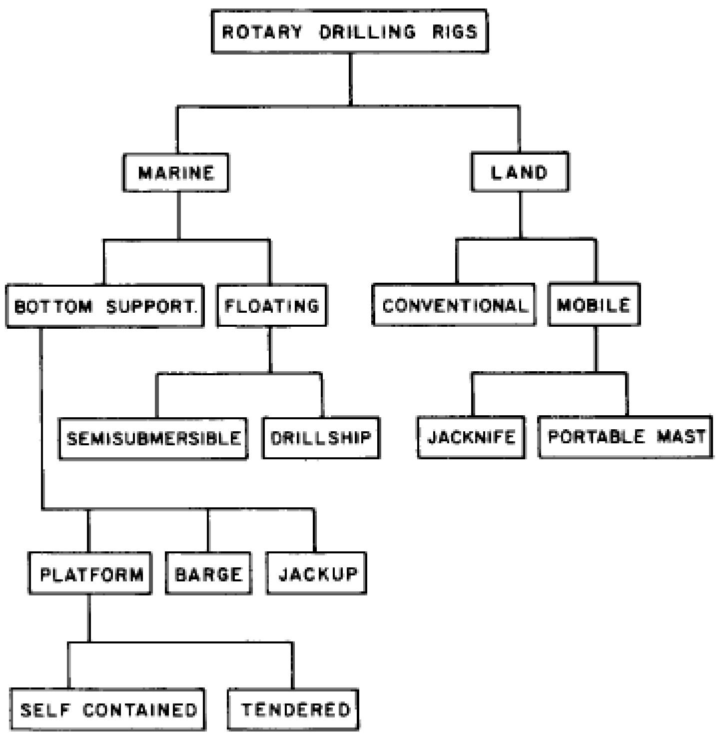


Figure 1.1. Classification of Rotary Drilling Rigs.

Onshore, that is, land rigs can be further divided into two subgroups:

1. Conventional Rigs - use a standard derrick, that used to be built on location before drilling the well, and is dismantled before moving to the new location. However sometimes, if necessary, the installation stays on the location in case of workover jobs (e.g. installing the production pump)

2. Mobile Rigs - due to the high cost of installation for conventional rigs, mobile rigs are used as a cheaper and easier transporting alternative.
    a. The Jackknife derrick (Figure 1.2) is assembled on the ground using hoisting equipment to be raised as a unit.
    b. The Portable Mast (Figure 1.3) is commonly mounted on the wheel trucks or trailers; it has a hoisting system, engines, and derrick acting as a single unit. The portable unit must be lifted vertically before stretching to its full height, after which it stretches to the full height by an hydraulic system (Mitchell, Miska ,2001).

Figure 1.2. Jackknife

Figure 1.3. Portable mast

On the other hand, offshore, or the marine rigs are divided in two big subgroups

1. Bottom Supported Rigs - for shallow water and there are three main types
    a. Barge (Figure 1.5) - is used for waters between 8ft and 20ft of depth, the rig floats to the drill site where the lower hull is sunk to the sea bottom.
    b. Platforms (Figure 1.) - use a jacket structure in order to provide support for the surface production equipment, the living quarters, as well as the drilling rig. They are meant for waters up to 1500ft of depth and can be used for drilling multiple direction wells. Furthermore, they can be both a self-contained or a tendered platform.
    c. Jackups (Figure 1.6) - most commonly used bottom supported rigs, similar to platforms except that their support legs are not permanently attached to the seafloor. That is, the support legs can be jacked down to drill as well as jacked up for transport. Jackups can be used for water
2. Floating Rigs - for deep water drilling, where attaching to the bottom is implausible. Hence, they are floating vessels stabilized by an anchor or by a dynamic positioning system. Because they are not restricted by the length of the rig's legs, there is no limitations when in it comes to the water depth besides the cost of operation; which increases proportionally, the deeper it gets.
3. The Semisubmersible Rigs (Figure 1.7) are quite like the bottom supported barge rigs, except that they can drill at a much higher depth of up to 6000ft. They are usually anchored over the hole; however, a dynamic motion system can also be used in order to stabilize the rig. They offer high stability; hence, they are used in restless wavy waters,
4. Drilling ships (Figure 1,8) - they are less costly than the semi-submersible rigs, if not using a dynamic motion system. They can operate at depths of up to 13000ft, but they cannot sustain strong waves.

Figure 1.4. Drilling Barge

Figure 1.5. Drilling Platform

Figure 1.6. Jackup rig

Figure 1.7. The semisubmersible rig

Figure 1.8. Drilling ship

1.2.4. Rotary Drilling System

The rotary drilling system (Figure 1.9) is the most widespread drilling system; it utilizes a drill bit, which combines the downwards gravitational force and rotation of the system to create cracking and breaking rock into smaller pieces. The rotation of the drill bit comes from a drill string that is rotated on the surface either by a rotary table or a top driving drilling system. The downward force comes from the weight of the pipes, which can be achieved through adding drilling collars and heavy wall drilling pipes to the drilling string.

Drilling fluid circulates through the drilling string and bit nozzles, lifting up drilled material; the drilled material is lifted up through the annulus up to the surface where it is separated from the mud, so it may be reused later. Rotary drilling is the most widespread drilling system, while the application of drilling motors is mainly reserved for directional and horizontal drilling.

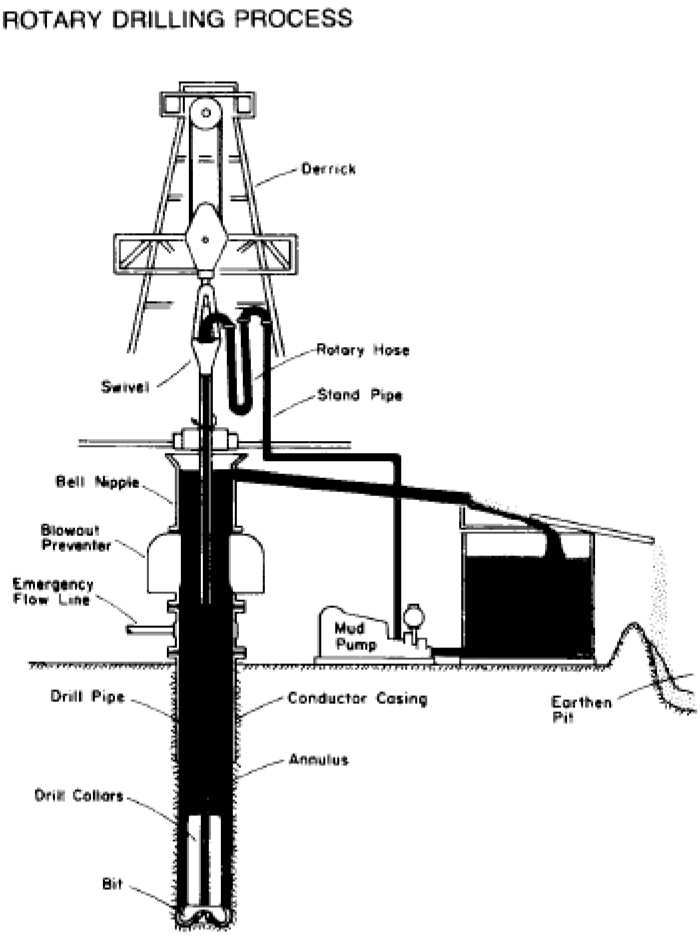


Figure 1.9. The Rotary Drilling Processes.

- ### 1.2.4.1. Basic elements of rotary system

Although drill rigs differ significantly when it comes to their external appearance, as well as developed methods, all of them share the same basic elements.

1. Power system

Most drilling rigs are required to operate in a remote location where a power supply is not available. Therefore, they must have a way to generate the necessary electrical power required to operate the system. he total power requirements for most rigs are from 1000 to 3000 HP; and the major users are mud pumps and drawworks. Older rigs used mechanical transmission systems, but modern drilling rigs use electric transmission. Generally, this is accomplished through a power system with a diesel engine as its prime mover, as well as some means of transmitting the power to the end-use equipment; such as drawworks, rotary table, and mud pumps.

2. Hoist system

The hoisting system is a large pulley system used for lowering and raising equipment into and out of the well. Primarily, it is used for the drill string and casing, and these operations are known as making a connection and making a trip, respectively.

The main parts of a hoist system are:

i. the derrick and substructure

ii. block and tackle

iii. drawworks

iv. miscellaneous hoisting equipment such as hooks, elevators, and weight indicator.

3. Circulating system

The circulating system is necessary for removing the drilled cuttings from the face of the bit; achieved by circulating fluid down through the drill string and up the annulus, this way the drilled cuttings are carried to the surface.

4. Rotary system

The rotary system is used to rotate the drill string, and hence the drill bit on the bottom of the borehole.

The main parts of a rotary system are:

i. The Swivel - positioned at the top of the drill string, it has three functions: to support the weight of the drill string, to permit the string to rotate, and to allow mud to be pumped while the string is rotating.

ii. The Kelly - the first section of pipe, right below the swivel. Usually 40' long with an outer hexagonal cross-section. This hexagonal, and sometimes square, shape is necessary in order to transmit the rotation from the rotary table to the drill string. More modern rigs use the top drive system in place of the kelly; where rotation is attained through electrical or hydraulic motors.

5. Well-control system

The well control system regulates the flow of formation fluids from the wellbore; it enables the driller to:

i. Detect a kick;
ii. Close the well at the surface;
iii. Circulate the well under pressure in order to remove the formation fluids and increase the mud density;
iv. Move the drill string up and down with the well closed;
v. Divert the flow away from rig personnel and equipment;

A kick refers to the displacement of drilling fluid from the well, as a result of fluid formation pressure being higher than the drilling fluid pressure. Failure to detect a kick, or other malfunctions in the well-control system, may result in an uncontrolled flow of formation fluids into the wellbore. This unwanted fluid production is called a blowout. In case of such an event a Blowup preventer (BOP) is used. The BOP is a safety equipment, consisting of preventers, accumulators for activation of the BOP, and the chock manifold.

6. Well-monitoring system

Constant monitoring of some parameters is essential in order to improve safety, as well as the efficiency of the process. Some of the major parameters that are monitored and recorded are: well depth, load on the bit, pump pressure, pump rate, rotary speed, and torque.

1.3. Mud circulation system

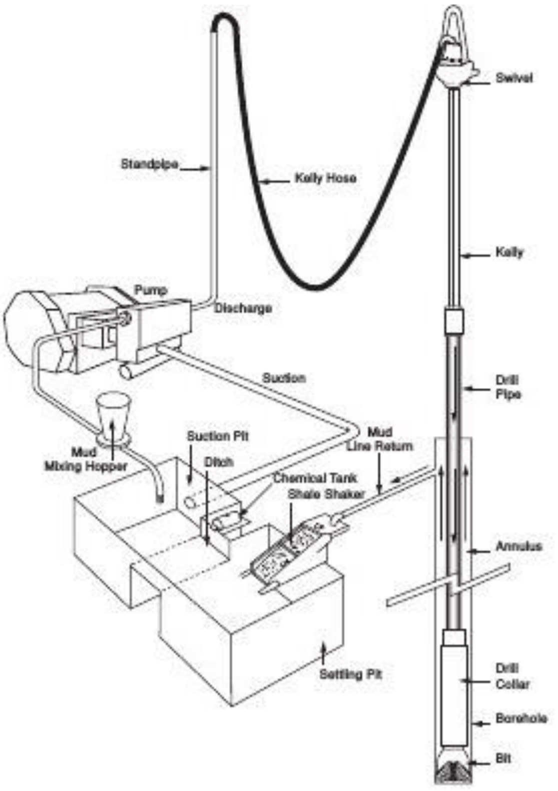


Figure 1.10. Circulating system

The circulating system (Figure 1.10.) is one of six major aspects of the rotary drilling process. It is a network of components in continuous motion, providing hydraulic power to drilling mud during the drilling process. To generate desirable hydraulic power, mud pumps and primer movers are used.

First, pumped drilling mud travels along the drilling string to the drill bit. there it is released in the annulus through nozzles of the bit, later returning to the surface carrying produced rock cuttings. Finally, on the surface drilling mud is removed out of the annulus using contaminant removal equipment, and returned to mud pit for treatment and reusing. The recovered cuttings can be used by geologists to identify which formation is being drilled so far.

1.3.1. Mud pit

At the surface of the rig, mud pits (Figure 1.11.) are required for storing and preparing drilling mud; to be used in the circulation process. Mud pits are a series of large interconnected steel tanks fitted with motor-driven agitators; keeping solids in suspension. Some pits are used for circulation and others are used for mixing and storing drilling mud. Fresh water and base oil, which are used for making drilling fluids, are pumped from storage tanks.

Figure 1.11. Mud pits

1.3.2. Mud Pumps

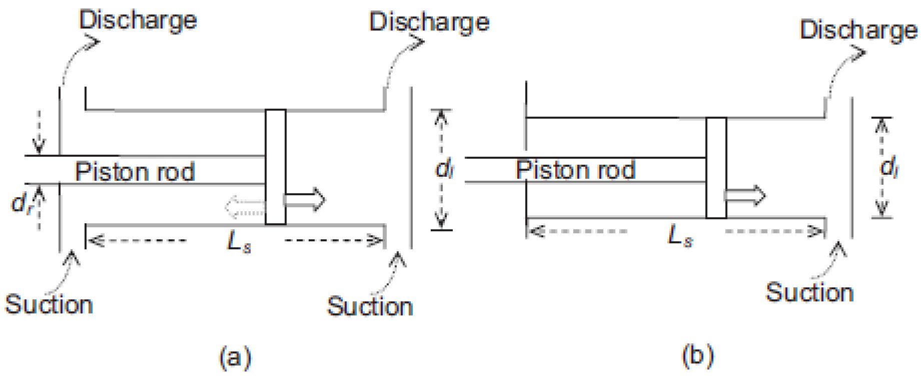
Mud pumps (Figure1.12) are the heart of the circulating system; they deliver pressure differential allowing the drilling fluid to flow. Usually there are at least two mud pumps on drilling rigs, to ensure the rig does not stop working, in case of main pump failure and needs a replacement

There are two types of mud pumps used in the industry, the duplex (two-cylinder) and the triplex (three-cylinder) pump; both using reciprocating positive-displacement pistons (Figure 1.13). By changing the diameters of pump liners and pistons, reciprocating positive-displacement pumps have the ability to push high solids content mud and operate over wide range of pressures and flow rates.

The duplex pump is generally double acting because of the double acting piston stroke. Meaning the piston is pumped forward displacing fluid and then pumped backwards returning to its previous position. Duplex pump can provide higher flow rate than triplex.

Aside from its lighter and more compact size, the main advantage of the triplex pump is that the piston is single action, and therefore cheaper to operate. The triplex pump design makes up most of the mud pumps used on drilling rigs today. Triplex pump provides high pressure.

Figure 1.12. Mud pumps



Picture 1.13. a) duplex double-acting pump b) triplex single-acting pump

The discharge flow rate depends on: stroke length of each piston, rod size, liner size, volumetric efficiency, and pumping speed. Pumping speed can be regulated with prime movers, such as diesel engines or DC motors. Volumetric efficiency varies with the fluid properties. The rod size changes with the size of liner.

The discharge flow for duplex pump depending on geometrical analysis can be calculated with following equation (Guo et al., 2007).

$$q_T=0.0068e_v(2d_1^2-d_2^2)lN \tag{3.1}$$

where:

q_T – flow rate of duplex pump [gpm]

e_v – volumetric efficiency, dimensionless

d_1 - piston diameter [in]

d_2 - rod diameter [in]

l – stroke length [in]

N – pumping speed [spm]

The pumped volume per stroke is:

$$q_s = \frac{evd^2l}{5{,}912} \tag{3.2}$$

where:

q_s - pumped volume per stroke [bbl]

Input for horsepower needed from prime movers can be calculated with following equation.

$$HP = \frac{p(2d1^2 - d2^2)lN}{252{,}101em} \tag{3.3}$$

Where:

HP – pump horsepower [hp]

Em – pump mechanical efficiency, dimensionless

The discharge flow for triplex pump depending on geometrical analysis can be calculated with following equation.

$$q_T = 0.01e_vd^2lN \tag{3.4}$$

where:

q_T – flow rate of triplex pump [gpm]

e_v – volumetric efficiency, dimensionless

d - piston diameter [in]

l – stroke length [in]

N – pumping speed [spm]

The pumped volume per stroke is

$$q_s = \frac{evd^2l}{4{,}118} \tag{3.5}$$

where:

q_s - pumped volume per stroke [bbl]

Input for horsepower needed from prime movers can be calculated with following equation.

$$HP = \frac{pd^2lN}{168{,}067em} \tag{3.6}$$

Where:

HP – pump horsepower [hp]

Em – pump mechanical efficiency, dimensionless

1.3.3. Mud-mixing equipment

Mud is mixed in the mud pit by adding in base–makeup water (for water base mud); bentonite, polymers, or some other special additives. The quality of makeup water is one of the most important factors in mixing a good mud. To get the most from bentonite fluid, water should be warm and soft, otherwise there is a risk of inhibiting the performance of the bentonite and any polymers added to the mix. When needed, trichter (Figure 1.14.) is used to slowly dose additives in mud.

Figure 1.14. Trichter for adding additives in drilling mud.

1.3.4. Contaminant removal equipment

Once the drilling fluid reaches the surface and completes one cycle; passing through the drill string, down to the drill bit and back up to the surface, it will contain solids, some gas (if drilling is performed through the reservoir), and other contaminants. These non-drilling fluid products or contaminants must be removed in order to keep the required properties for drilling mud.

The drilling fluid passes over a series of vibrating screens (Figure 1.15.) of different mesh sizes. Tanks can also allow residue settling before the mud passes to the mud pits. Fine solids are removed by other components such as de-sanders and de-silters; a combination of them is called a mud cleaner or centrifuge.

Figure 1.15. Vibrating screens

Figure 1.16. Desander and Desilter

Removing all types of solids that are not desirable in drilling fluid we improve drilling performance, and consequently reduces drilling costs. Fluids properly treated will:

i. Increase drilling rates, by enhancing cuttings removal
ii. Provide better bit hydraulics, due to lower fluid viscosity
iii. Avoid premature wear on surface equipment such as lines and the mud pumps
iv. Reduce formation damage

1.4. Drilling cost and significance of optimization

In order for a drilling project to be effective, there needs to be a design for the process of drilling that is as safe and as cheap as possible.

The estimation of drilling costs represents the last stage in design of the borehole project, because it depends on the technical aspects of the designed borehole, and in many cases, it plays a key factor in the evaluation for approval of the project.

Primarily, the cost of drilling depends on the location and depth of the well. Expenses of drilling increase exponentially with depth and is calculated using the following equation:

$$C=a*e^{bd} \quad (4.1)$$

Where:

C – costs of drilling [$]

a,b – constants that depends on well location

d – depth of the well [ft]

For a more detailed analysis of the cost of drilling, these factors must be taken into account:

i. Equipment costs (location surface preparation, rig rental, facilities, tubulars, mud program, cementing, casing program, formation evaluation...),
ii. Daily operative costs (rental crew, transportation, crew housing, drilling fluid treatment, completion jobs, rig supervision etc...)
iii. Drilling time (drilling and completion, trip, casing placement, formation evaluation)

iv. Trouble time (losing circulation, stuck pipe, formation fracturing, fishing, mud pollution…)

A Simple equation that is used to calculate costs of drilling. based on drill bit efficiency:

$$C_f=\frac{C_b+C_r*(t_b+t_t+t_c)}{\Delta D} \quad (4.2)$$

Where:

C_f – drilled cost per unit depth

C_b – bit cost per item

C_r – fixed operating cost per unit time

t_b – total rotating time during bit run

t_t – trip time

t_c – total non-rotating time during bit run

The majority of time spent on drilling, is spent on drilling operations and tripping. Hence, estimation for drilling operation time can be calculate based on data for penetration rate and depth. Penetration rate exponentially decrees with depth.

$$\frac{dD}{dt} = K * exp(-2.3032 * a_2 * D) \quad (4.3)$$

Where:

K – penetration rate at surface

a - decrease rate of the penetration rate with depth.

Penetration rate can be used for predicting drilling time by separating variables and integration by t_d:

$$\frac{dD}{dt} = K * exp(-2.3032 * a_2 * D)$$

$$dD = K * exp(-2.3032 * a_2 * D)\ dt$$

$$exp(2.3032 * a_2 * D)\ dD = K\ dt$$

$$\int_0^D exp(2.3032 * a_2 * D)\ dD\ e = K \int_0^{t_d} K\ dt$$

$$t_d = \frac{1}{2.3032 a_2 D}(exp\ exp\ (2.3032 a_2 D)\ - 1) \qquad (4.4)$$

Estimation of tripping time can be calculated with following equation:

$$t_t = 2 * \frac{t_s}{l_s} D \qquad (4.5)$$

Where:

t_t - tripping time

t_s – time to handle one stand of pipelines

l_s – length of one stand of pipelines

The value of tripping increases linearly with depth, while drilled footage with bit decrease with depth. Hence, the value of tripping increase with depth. If bit life and penetration rate are known; by integrating equation 4.3 the depth at which the tripping will be required can be calculated

$$D = \frac{1}{2.3032 a_2} ln(2.3032 * a_2 * K * t_d + exp(2.3032 a_2 D_i) \qquad (4.6)$$

From the equations above, it is clear that time has a major role in influencing the cost of drilling. Therefore, it is a good reason to optimize circulating system and mud pumps.

Mud can take from 5% up to 15% of drilling costs but may cause 100% of drilling problems. If mud velocity is too low, drilled solids will stay and can cause tools to be stuck or reduce the efficacy of the drill bit by decreasing the rate of penetration. In turn, all these malfunctions lead to an increase in cost, due to the time spent on addressing the issues. The highest power usage comes from the circulating system and hydraulics. Hence, the pump pressure needs to be optimized to satisfy minimum pump pressure and pump flow rate. Furthermore, the bit hydraulics need to be optimized to have maximum jet impact force, hydraulic horse power on drill bit, and maximum bit velocity. Other key factors in the evaluation are also bit nozzle size and flow rate.

1.5. Objective of thesis

The objective of the thesis is to deal with the pressure loss in the flow path which is dependent on the type of fluid and regime of flow and to ensure that fluid will be delivered on the surface at any point of drilling. The biggest pressure loss is at drilling bit, but we want to spend as much power we can on the drill bit to have higher efficiency in drilling. Evaluation of drilling hydraulic will provide a full return of mud to the top hole of drilling system. Intermediate objectives include to evaluate possible system components, and solutions to obtain a functional system. This includes selection of:

- Rheological model,
- Pressure loss calculations,
- Satisfying all requirements,
- System optimization,
- And on the end providing final pump pressures that needs to be satisfied.

First of all, there will be talk about the drilling fluids and their properties, afterwards it will be talk about Newtonian and Nonnewtonian fluids which is very important for further hydraulic calculations and to obtain the pressure loss in drilling system. Some requirements for fluid flow and pressure need to be satisfied so we will have functional system, but after we can optimize those parameters to have better efficiency of the system.

For the system parameters above, needs to be considered and a new system to be developed. It will be done on model using real data for this project. Code for calculations of full flow path is developed for all cases and it is given results of optimizing the system and choosing the best solution and select the right mud pump properties.

Chapter 2 Hydraulics calculation

2.1. Introduction

Drilling fluids or muds are one of the vital components of all drilling processes. Thus, we can call it the “blood’’ of any drilling system. Drilling fluids can have base of water, oil or gas, depending on the characteristic of mud needed for the drilling process. Mud hydraulics are the one of most important factors for reducing the cost of project. With optimization, maximum efficiency of drilling bit and the maximum usage of pump pressure are achieved. Optimization is accomplished by minimizing pressure loss due to friction in drilling string and annulus.

2.2. Drilling Fluids

The cost of mud by itself is lower when compared to the cost of the rig cost. Choosing the appropriate mud for drilling can have an effect on total well cost. The things that need to be considered while selecting the most suitable type of mud are: the type, the function and the properties of mud.

2.2.1. Type of muds

- Water-based Muds (WBM)

Water-based muds are the most commonly used mud type for drilling purposes. They are relatively inexpensive and are available on most rigs.

They can either be pure water, or a combination of fresh or salt water mixed with various solids. Some water-based muds also contain emulsified oils or other additives to increase their cooling and lubricating capacity.

An inhibited water-based mud can be used to minimize chemical reaction between the drilling mud and formation in the borehole. Hydration reduces the structural stability of the wellbore and slows down the speed at which clays in the formation hydrate. For these reasons inhibitors are used in drilling muds. Four common inhibited muds are gypsum muds, lime muds, seawater muds, and saturated saltwater muds.

Dispersed*:* In dispersed mud, chemicals are used that cause clay to disperse within the fluid. Dispersed muds tend to have better viscosity control, higher solids tolerance, and better filtration control than non-dispersed muds. A common example of dispersed mud is lignosulfonate mud which is frequently used in drilling young, highly active clay.

Non-dispersed*:* These muds are usually formulated with a minimum amount of bentonite and lack chemical dispersants. A polymer that extends the effects of small amounts of bentonite and selectively flocculates undesirable drilled solids is used in this mud type. While using non-dispersed mud system, careful monitoring of solids control equipment, alkalinity, and bentonite concentrations is required for the system to function effectively.

Brines: In drilling operations that do not require high densities or high viscosites, clear water and some brines can be used. Brines are used extensively in completion and workover operations where very low solids and a clean environment are critical. Brines can be composed of as many as three salt compounds.

- Oil-based Muds (OBM)

Oil-based muds are the most expensive mud type. In oil-based muds, diesel or highly processed paraffin-based minerals oils are commonly used because they are less harmful to the environment. However, they are less environment-friendly than nonpetroleum oils.

Most oil-based muds contain additives that increase viscosity, and emulsified water. Some of the water is added intentionally, while some is accumulated from the formations. Less than five percent of the oil mud is comprised by water. When the water concentration is more than five percent, it is called an invert emulsion.

Oil-based muds are generally used in cases that demand high lubricity, maintenance of hole stability in hydratable formations, or drilling of hydrogen sulfide-bearing zones.

❖ Advantages of Oil-based mud in comparison with Water-based mud

Positive aspects of oil-based muds include:

- Oil-based muds possess higher inhibitive properties when compared to water-based muds. This characteristic inhibits clays from swelling and breaking into pieces.
- PDC performance can be improved through inhibition of reactive formations by oil-based muds. Through inhibition, reactive shales are kept from swelling and becoming sticky, thus improving bit cleaning.
- Bit performance is better with oil-based mud than with water-based muds. However, water-based mud is more commonly used.
- The lubricity of oil-based muds assists cleaning by keeping the bit, cutter surfaces and drilled particles coated with oil.
- Higher solids contents can be tolerated, because they act less abrasively on the bit head and cutters.
- Diamond material is oil wettable, but not water wettable. This means that not only does the diamond material benefit from oil's higher heat transferring capability, but also from being microscopically wetted on its surface.
- Oil-based muds hold good rheological properties: flow characteristics.
- These muds are effective against most types of corrosion.
- Permits mud densities as low as 7.5 lbs per gallon.

.

❖ The disadvantages of oil-based muds include:

- Higher initial cost is demanded.

- More stringent pollution control procedures are required.
- Effectiveness of reservoir analysis (logging and core analysis) is reduced. This refers to diesel, oil-based systems.
- More difficult and expensive treatments are required in cases of lost circulation.

- Aerated Muds

Aerated drilling fluids are comprised of air, natural gas, foam, or aerated muds. Their reduced hydrostatic pressure allows the drilled rock fragments to explode into the wellbore, thus, allowing high penetration rates. Lost circulation problems are minimized with aerated muds.

Air is more commonly used than natural gas because it is free. Natural gas is used where a hydrocarbon gas zone is expected, since explosions can occurs when air, formation gas and the heat from drilling are combined.

In certain circumstances, soap is added to aerated muds to increase the thickness of the fluid. These "foam muds" can improve cleaning because cuttings are lifted by the mud.

A disadvantage of aerated drilling fluids is the cost of the large compressors required to pump the air or gas. In addition, aerated fluids cannot be used in fluid making formations. Wellbore stability and pressure control are more difficult with these systems as well as establishing necessary lubricity levels.

2.2.2. Functions of mud

Drilling fluids(muds) serve many purposes or functions. The major functions are:

- Cleaning the bit and bottom hole

Bottom hole and bit must be cleaned so that new formations are drilled effectively, and the re-cutting of old cuts is avoided.

- Annular cleaning

Annular cleaning refers to the "lifting" of formation pieces up the annulus to the surface. In this process, the fluid is required to overcome gravity and carry the cuttings upward. The average speed of fluid moving up the annulus is called annular velocity, while the velocity of the cuttings trying to fall downward through the moving fluid is called slip velocity. Annular velocity must be greater than the downward falling rate or slip velocity.

- Cooling and lubricating the bit

All bits need to be properly cooled and lubricated for best performance. Diamond cutter elements especially require good cooling. Lubrication increases penetration rate and reduces wear.

- Pressure balancing

Subsurface pressures are controlled by drilling fluids. As a formation is drilled, wellbore pressure should be higher than formation pressure to prevent formation fluid from flowing into the hole, and to prevent collapses. The exceeding wellbore pressure is called "overbalance."

The typical situation of well pressure controlling should be approximately 50-300 psi to prevent kicks and blowouts, where formation fluids enter the wellbore and push the cuttings to the surface.

- Fluid-Loss Control

Filter cake with low permeability is formed by mud on the walls of hole which seals pores in formation and minimizes mud loss.

2.2.3. Properties and Characteristics

The properties and characteristics of drilling fluids are interrelated, however, they can be individually identified and measured. Each property is controlled for best overall drilling results.

- Density

Density refers to the weight of the drilling fluid, and is usually referred to as mud weight. It is expressed in pounds per gallon (ppg). For example, clear water weighs 8.33 ppg and typical drilling mud’s weighs between the range of 9 to 16 ppg or higher in some cases. Mud weight is a key factor in controlling subsurface pressures.

- Solid Content

Solid content refers to the volume percentage of solid matter in a volume of drilling fluid. This refers to the specific gravity (sg) of the solids. High gravity solids (Barite 4.2 sg and Hematite 5.0 sg) are added to raise the density and hydrostatic pressure of the fluids. Sometimes low gravity solids (Bentonite 2.6 sg) are added to increase viscosity and reduce fluid loss. However, these solids generally accumulate in the drilling fluid from the breakdown of formation cuttings. The solids content measured is the result of both low and high gravity solids.

Another measure of solids in drilling fluids is the sand content. Due to sand’s notable abrasiveness, its amount should be kept to a minimum, usually less than 0.25%.

- Viscosity

The viscosity of drilling fluids can be changed using chemical additives, that are polymers. Viscosity needs to be high enough to carry cuttings to the surface and maintain proper flow in the annulus, but low enough to prevent excessive annular pressure and to permit the release of the drilled cuttings at the surface. The circulating fluid naturally picks up additional solids, thus, effectively increasing the fluid’s viscosity.

2.3. Mud hydraulics

2.3.1. Rheological models

Rheology is the study of the flow or deformation of matter; these phenomena are described in terms of shear rate and shear stress. Shear rate is defined as the flow velocity gradient in the direction perpendicular to the flow direction. The higher the shear rate, higher is the friction between the flowing particles. Shear stress is the friction between particles and is measured by the shear force per unit area of shearing layer. [3] For rheological models, the properties can be measured with a viscometer. The most commonly used viscometer type is Fann 35 VG. Using this instrument, the shear rate and stress for six different speeds are measured. Plotting the measured data, we can identify the rheological model which can later be used to calculate the parameters for each model.

- Newtonian fluids

Fluids are referred to as Newtonian or non-Newtonian, depending on their responses to shear stress. Newtonian fluids' shear stress is directly proportional to the shear rate:

$$\tau = \gamma\mu \tag{2.1}$$

Where:

τ – shear stress [lb/100ft^2]

γ – shear rate [s^{-1}]

μ – viscosity [cP]

Newtonian fluids are water or light oil, but drilling fluids are usually non -Newtonian. In Figure 2.1., a linear increase in stress with increasing shear rates is observed, where the slope is given by the viscosity of the fluid. This means that the viscosity of Newtonian fluids remains a constant regardless of how fast they are forced to flow through a pipe or annulus.

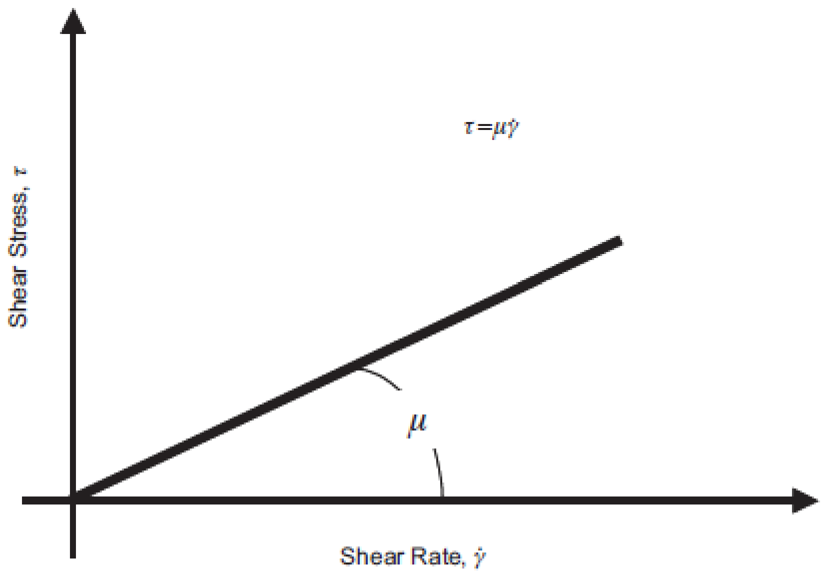


Figure 2.1. Shear stress vs shear rate for Newtonian fluid.

Viscosity can be calculated using the measured data from Fann 35 Vg using following equations:

$$\mu = \frac{300}{N}\theta_N \tag{2.2}$$

Where:

N – rotary speed of Fann VG meter [rpm] usually 300rpm

θ_N – dial reading of Fann VG meter at rotary speed N

- Bingham plastic model

The most commonly used fluid model to determine the rheology of non-Newtonian fluid is the Bingham plastic model. The equation of the model is expressed as:

$$\tau = \tau_y + \mu_p \gamma \tag{2.3}$$

Where:

τ_y– yield point [lb/100ft^2]

μ_p – plastic viscosity [cP]

Bingham plastic model (Figure 2.2.) makes the assumption that the shear rate is straight line function of the shear stress. however, this model flow is not described in low shear-rate regions. Bingham plastic fluid doesn't flow until minimum shear stress, also known as yield point, is applied.

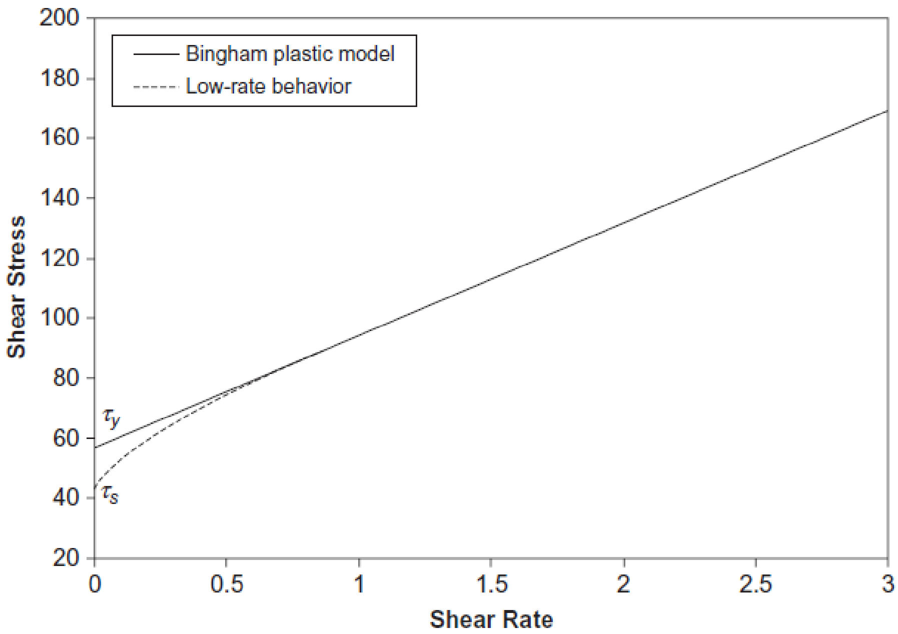


Figure 2.2. Shear stress vs shear rate for Bingham plastic fluid.

The plastic viscosity can be calculated using data received from Fann VG meter using following equation:

$$\mu_p = \frac{300}{N_2 - N_1}(\theta_{N_2} - \theta_{N1}) \quad (2.4)$$

Where:

θ_{N1} – dial reading of Fann VG meter at rotary speed N_1

θ_{N2} – dial reading of Fann VG meter at rotary speed N_2

If the rotary speeds, N_1 and N_2, are chosen to be 300 and 600 respectively, equation 2.4. has the following expression:

$$\mu_p = \theta_{600} - \theta_{300} \quad (2.5)$$

If the rotary speed if Fann VG meter is 300 rpm, the Bingham yield point can be calculated with following equation:

$$\tau_y = \theta_{N1} - \mu_p \frac{N_1}{300} = \theta_{N1} - \mu_p \quad (2.6)$$

- Power Law model

The behaviors of non-Newtonian fluids are determined by the Power Law model by measuring the flow behavior of the fluids.

Fluids behave as pseudo plastic fluids when the flow behavior is less than 1 ($n<1$), as Newtonian fluids when flow behavior is equal to 1 ($n=1$), and as dilatant fluids when flow behavior is higher than 1 ($n>1$).

Power Law is expressed with equation:

$$\tau = K\gamma^n \quad (2.7)$$

Where:

K – consistency index [cP]

n – flow behavior index, dimensionless

Figure 2.3. is a graphical representation of the model

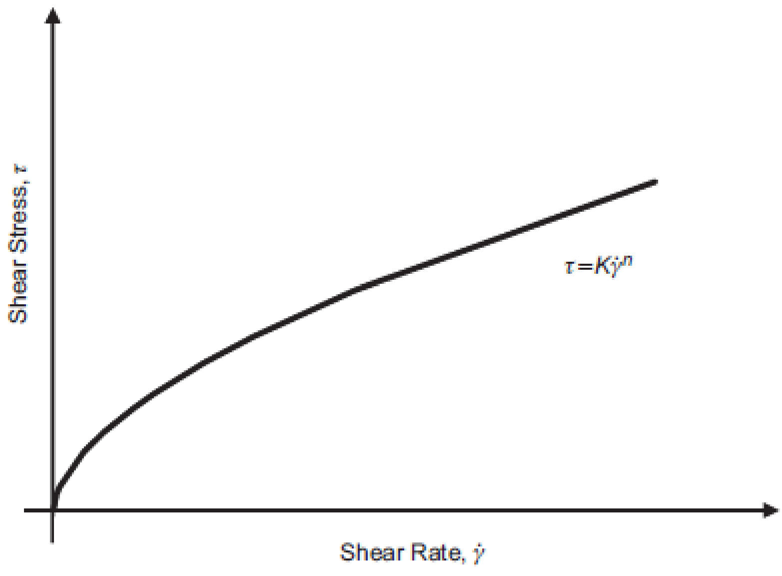


Figure 2.3. Shear stress vs shear rate for pseudoplastic Power Law fluid.

The flow behavior index of Power Law model can be calculated using data got from Fann VG meter using following equation:

$$n = \frac{log(\frac{\theta_{N_2}}{\theta_{N_1}})}{log(\frac{N_2}{N_1})} \tag{2.8}$$

If the rotary speed of Fann VG meter is N_1= 300 rpm and N_2=600 rpm than Power Law flow behavior index can be calculated with following equation

$$n = 3.322 * log(\frac{\theta_{N_2}}{\theta_{N_1}}) \tag{2.9}$$

The consistency index of Pawer Law model can be calculated using data got from Fann VG meter using following equation:

$$K = \frac{510\theta_N}{(1.703N)^n} \tag{2.10}$$

If speed is taken as N_1= 300rpm:

$$K = \frac{510\theta_{300}}{(511)^n} \tag{2.11}$$

- Herschel-Bulkley Fluids model

The Herschel Bulkley is an improved version of the Power Law fluid model to match the actual behavior of drilling fluid at a low shear rate. It is done by assuming an initial shear stress value. Herschel Bulkley (Figure 2.4.) can be described as per the equation below:

$$\tau = \tau_y + K\gamma^n \tag{2.12}$$

This model determines fluids as yield-pseudoplastic fluid ($n < 1$), a dilatant fluid ($n > 1$), a pseudoplastic fluid ($t_y = 0$, $n < 1$), a plastic fluid ($n = 1$), or a Newtonian fluid ($t_y = 0$, $n = 1$). These rules are specific to laminar flow.[1]

Like in the Bingham plastic model, a fluid will not flow until the applied shear stress τ exceeds a minimum value of yield stress τ_{yy}. The fluid behaves like a solid until the applied force is high enough to exceed the yield stress.[1]

The rotary speeds of Fann VG meter for yield stress are taken at N_1=3 rpm and N_2=6 rpm, and the speed for behavior index and consistency index are N_1= 300 rpm and N_2=600 rpm respectively. Shear stress is calculated with following equation:

$$\tau_y = 2\theta_3 - \theta_6 \tag{2.13}$$

The flow behavior index

$$n = 3.322 * log(\frac{\theta_{N_2} - \tau_y}{\theta_{N_1} - \tau_y}) \tag{2.14}$$

The consistency index

$$K = \frac{510(\theta_{300} - \tau_y)}{(511)^n} \tag{2.15}$$

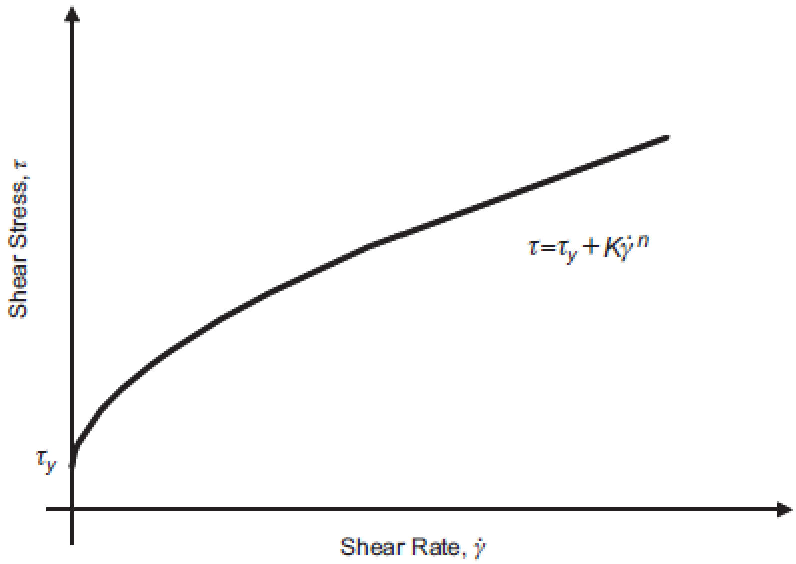


Figure 2.4. Shear stress vs shear rate for pseudoplastic Herschel-Bulkley fluids.

2.4. Hydraulics calculation for different models

Hydraulics models define the relationships between pressure drop and flow rate for various rheology models and given geometry of flow and flow regime. Flow regime that are observed while drilling are laminar flow, turbulent flow and transitional flow.

In laminar flow, the fluid flows in parallel layers with different velocities, the highest velocity is in the center of pipe and the lowest are closer to the walls of the pipe or annulus. Laminar flow is desirable in annulus to prevent erosion and move the cuttings to the surface.

In turbulent flow, the fluid moves chaotically and have higher velocity than in laminar flow. This flow is useful below the drilling bit in the annulus to help removing of cuttings, and cleaning the bottom hole.

Transitional flow has the characteristic of both laminar and turbulent flows. This regime has not been found in normal drilling conditions.

The flow regime is defined is by calculating a fluid's Reynolds number.

2.4.1. Reynolds number Newtonian fluids

For Newtonian fluids, laminar flow occurs when Reynolds number is less than 2100, turbulent flow when Reynolds number is higher than 4000, and transitional flow occurs for the values between 2100 and 4000.

Reynold number for flow inside pipes.

$$N_{Re} = 928 * \frac{\rho v d}{\mu} \tag{2.16}$$

Where:

N_{Re} – Reynolds number, dimensionless

ρ – fluid density [ppg]

v – average flow velocity [ft/s]

d – inside diameter of pipe [in]

μ – fluid viscosity [cP]

Average velocity to calculate Reynolds number for inside pipe flow is calculated by the equation:

$$v = \frac{q}{2.448d^2} \tag{2.17}$$

Where:

q – flow rate [gpm]

Reynold number for annular flow is calculated by the equation:

$$N_{Re} = 757 * \frac{\rho v(d_2 - d_1)}{\mu} \tag{2.18}$$

Where:

d_1 – outside diameter of pipe [in]

d_2 – inside diameter of hole or casing [in]

And average velocity for annular flow

$$v = \frac{q}{2.448(d_2^2 - d_1^2)} \tag{2.19}$$

2.4.2. Bingham plastic fluids

For Bingham plastic, the viscosity needs to be calculated before calculating the Reynolds number. Apparent viscosity is defined to account for plastic viscosity and yield point.

Apparent viscosity inside pipe

$$\mu_a = \mu_p + \frac{6.66\tau_y d}{v} \tag{2.20}$$

Reynolds number for inside pipe flow

$$N_{Re} = 928 * \frac{\rho v d}{\mu_a} \tag{2.21}$$

Apparent viscosity for annular flow

$$\mu_a = \mu_p + \frac{5\tau_y(d_2 - d_1)}{v} \tag{2.22}$$

Reynold number for annular flow

$$N_{Re} = 757 * \frac{\rho v(d_2 - d_1)}{\mu_a} \tag{2.23}$$

Boundaries for the flow regime are the same as for Newtonian fluids, laminar flow occurs for Reynolds numbers below 2100 and turbulent flow for values above 4000.

2.4.3. Power Law fluids

Apparent viscosity is also used in Power Law model. Then, the formulae 2.20 and 2.22 respectively become

Apparent viscosity inside pipe:

$$\mu_a = \frac{Kd^{1-n}}{96v^{1-n}}\left(\frac{3+\frac{1}{n}}{0.0416}\right)^n \tag{2.24}$$

Apparent viscosity for annular flow:

$$\mu_a = \frac{K(d_2-d_1)^{1-n}}{144v^{1-n}}\left(\frac{2+\frac{1}{n}}{0.0208}\right)^n \tag{2.25}$$

Reynolds number for inside pipe flow:

$$N_{Re} = 928 * \frac{\rho v d}{\mu_a} \tag{2.26}$$

Reynold number for annular flow:

$$N_{Re} = 757 * \frac{\rho v(d_2-d_1)}{\mu_a} \tag{2.27}$$

Critical Reynolds number is estimated with equations (2.28. and 2.29.), which is then used for determining the nature of the occurring regime. The upper limit of Critical Reynolds determines laminar flow, the lower limit determines turbulent flow, and values in between determine transitional flow.

Upper limit for laminar flow is given by:

$$N_{Rec} = 3470 - 1370n \tag{2.28}$$

Lower limit for turbulent flow is given by:

$$N_{Rec} = 4270 - 1370n \tag{2.29}$$

2.4.4. Herschel-Bulkley Fluids

For Herschel-Bulkley fluids, Reynolds numbers are calculated using the following formulae:

Inside drill pipe:

$$N_{Re} = \frac{2(3n+1)}{n}\left[\frac{\rho v^{(2-n)}\left(\frac{d}{2}\right)^n}{\tau_y\left(\frac{d}{2v}\right)^n + K\left(\frac{(3n+1)}{nC_c}\right)^n}\right] \tag{2.30}$$

In the annulus:

$$N_{Re} = \frac{4(2n+1)}{n}\left[\frac{\rho v^{(2-n)}\left(\frac{d_2-d_1}{2}\right)^n}{\tau_y\left(\frac{(d_2-d_1}{2v}\right)^n + K\left(\frac{2(2n+1)}{nC_a}\right)^n}\right] \tag{2.31}$$

Where constants Cc and Ca are given by:

$$C_c = 1 - (\frac{1}{2n+1})\frac{\tau_y}{\tau_y + K\left[\frac{(3n+1)q}{n\pi\left(\frac{d}{2}\right)^3}\right]^n} \tag{2.32}$$

$$C_a = 1 - (\frac{1}{n+1})\frac{\tau_y}{\tau_y + K\left[\frac{(2n+1)2q}{n\pi[\left(\frac{d_2}{2}\right)-\left(\frac{d_1}{2}\right)][\left(\frac{d_2}{2}\right)^2-\left(\frac{d_1}{2}\right)^2]}\right]^n} \tag{2.33}$$

Flow regime is definite. If the Reynolds number is higher than the critical Reynolds number, the regime of flow is turbulent otherwise it is laminar flow.

Critical Reynolds number inside drill pipe

$$N_{Rec} = \left[\frac{4(3n+1)}{ny}\right]^{\frac{1}{1-z}} \tag{2.34}$$

Critical Reynolds number in annulus

$$N_{Rec} = \left[\frac{8(2n+1)}{ny}\right]^{\frac{1}{1-z}} \tag{2.35}$$

Where:

$$y = \frac{loglog\,(n) + 3.93}{50} \tag{2.36}$$

$$z = \frac{1.75 - loglog\,(n)}{7} \tag{2.37}$$

2.5. Pressure loss

Pressure loss is calculated using fluid velocity, Reynolds number and flow regime. Circulating fluid must overcome frictional forces between the fluid layers, drill pipe walls and hole walls or casing walls, and the forces between solid particles and fluid. The highest-pressure loss occurs at the drilling bit nozzles. The pressure on the pump must be equal to the sum of all pressure-inflicting forces in order to overcome all pressure losses.

$$p_p = \Delta p_s + \Delta p_{dp} + \Delta p_{dc} + \Delta p_{mt} + \Delta p_b + \Delta p_{dca} + \Delta p_{dpa} \tag{2.38}$$

Where:

p_p- pump pressure [psi]

Δp_s- pressure loss in surface equipment [psi]

Δp_{dp} – pressure loss in drill pipe [psi]

Δp_{dc} – pressure loss in drill collars [psi]

Δp_{mt} – pressure loss in mud motor [psi]

Δp_b – pressure loss at drill bit [psi]

Δp_{dca} – pressure loss in drill collar annulus [psi]

Δp_{dpa} – pressure loss in drill pipe annulus [psi]

All pressure losses in the drilling string and the annulus is called parasitic pressure.

$$\Delta p_d = \Delta p_s + \Delta p_{dp} + \Delta p_{dc} + \Delta p_{mt} + \Delta p_{dca} + \Delta p_{dpa} \tag{2.39}$$

Consequently, the pump pressure equation is simplified:

$$p_p = \Delta p_d + \Delta p_b \tag{2.40}$$

With the given fluid type and geometry of circulating system, we can find flow regime and calculate the parasitic pressure loss inside drilling pipes and in annulus. To calculate the pressure loss, firstly, we need to calculate the Fanning friction factor which is a function of Reynolds number and relative roughness. The relative roughness is a function of absolute roughness and pipe diameter:

$$\varepsilon = \frac{\delta}{d} \tag{2.41}$$

Where:

ε - relative roughness, dimensionless

δ – absolute roughness [in]

d – pipe diameter [in]

For the laminar flow formula for friction factor is simple, but for turbulent flow are derived from several empirical correlations. The most known formula, Colebrook (1938), is the basis for all other correlations.

Friction factor for laminar flow is given by:

$$f = \frac{16}{N_{Re}} \tag{2.42}$$

Where:

f- friction factor, dimensionless

Colebrook (1938) friction factor for turbulent flow:

$$\frac{1}{\sqrt{f}} = -4log(\frac{0.269\delta}{d} + \frac{1.255}{N_{Re}\sqrt{f}}) \tag{2.43}$$

Where:

$$N_{Re} = 928 * \frac{\rho v d}{\mu} \tag{2.44}$$

In turbulent flow, the smooth pipe friction factor is given by the following equation:

$$\frac{1}{\sqrt{f}} = 4\ log\ log\left(N_{Re}\sqrt{f}\right) - 0.395 \tag{2.45}$$

Simplified friction factor function for smooth pipes gives us Colebrooks's (1938), but it was first presented by Blasius (1913) with the equation:

$$f = \frac{0.0791}{N_{Re}^{0.25}} \tag{2.46}$$

Chens's (1979) explicit correlation gives a friction factor with high accuracy:

$$f = \left(-4\log\left\{\frac{\varepsilon}{3.7065} - \frac{5.0452}{N_{Re}}\log\left[\frac{\varepsilon^{1.1098}}{2.8257} + \left(\frac{7.149}{N_{Re}}\right)^{0.8981}\right]\right\}\right)^{-2} \tag{2.47}$$

When we have friction factor values, we can calculate pressure loss for each rheological model and for both geometries.

2.5.1. Newtonian fluids

Pressure loss under laminar flow inside drilling string and in the annulus, can be calculated if. friction factor Eq. (2.42.) is replaced in the equation:

$$\frac{dp_f}{dL} = \frac{f\rho_f\overline{v}^2}{25.8d} \tag{2.48.}$$

Where:

L pipe length [ft]

V_{avg} – average velocity [ft/s]

d- equivalent pipe inner diameter [in]

We will get for flow inside drilling pipe

$$\Delta p_f = \frac{\mu v}{1{,}500 d^2}\Delta L \tag{2.49}$$

And for the annulus:

$$\Delta p_f = \frac{\mu v}{1{,}000(d_2 - d_1)^2}\Delta L \tag{2.50}$$

Where:

p_f- pressure loss [psi]

L – length of section [in]

Using Blasius correlation for turbulent flow we will get the following equations for flow inside drill pipe and in annulus respectively:

$$\Delta p_f = \frac{\rho^{0.75} v^{1.75} \mu^{0.25}}{1{,}800 d^{1.25}}\Delta L \tag{2.51}$$

$$\Delta p_f = \frac{\rho^{0.75} v^{1.75} \mu^{0.25}}{1{,}396(d_2 - d_1)^{1.25}}\Delta L \tag{2.52}$$

Using Chen's correlation, we could have more accurate results, but these equations are adequate enough.

2.5.2. Bingham plastic fluids

Pressure loss under laminar flow inside drill pipe:

$$\Delta p_f = \left(\frac{\mu_p v}{1{,}500 d^2} + \frac{\tau_y}{225 d}\right)\Delta L \tag{2.53}$$

Pressure loss under laminar flow in annulus:

$$\Delta p_f = \left[\frac{\mu_p v}{1{,}000(d_2 - d_1)^2} + \frac{\tau_y}{200(d_2 - d_1)}\right]\Delta L \tag{2.54}$$

Pressure loss under turbulent flow inside drill pipe:

$$\Delta p_f = \frac{\rho^{0.75} v^{1.75} \mu_p^{0.25}}{1{,}800 d^{1.25}} \Delta L \tag{2.55}$$

Pressure loss under turbulent flow in annulus:

$$\Delta p_f = \frac{\rho^{0.75} v^{1.75} \mu_p^{0.25}}{1{,}396 (d_2 - d_1)^{1.25}} \Delta L \tag{2.56}$$

2.5.3. Power Law fluids

Pressure loss under laminar flow inside drill pipe:

$$\Delta p_f = \left[\left(\frac{96v}{d} \right) \left(\frac{3n+1}{4n} \right) \right]^n \frac{K}{300d} \Delta L \tag{2.57}$$

Pressure loss under laminar flow in annulus:

$$\Delta p_f = \left[\left(\frac{144v}{d_2 - d_1} \right) \left(\frac{2n+1}{3n} \right) \right]^n \frac{K}{300(d_2 - d_1)} \Delta L \tag{2.58}$$

Pressure loss under turbulent flow inside drill pipe:

$$\Delta p_f = \frac{f \rho v^2}{25.8d} \Delta L \tag{2.59}$$

Pressure loss under turbulent flow in annulus:

$$\Delta p_f = \frac{f \rho v^2}{21.1(d_2 - d_1)} \Delta L \tag{2.60}$$

2.5.4. Herschl-Bulkley fluids

Pressure loss under laminar flow inside drill pipe:

$$\Delta p_f = \frac{4K}{14400d} \left\{ \left(\frac{\tau_y}{K} \right) + \left[\left(\frac{3n+1}{nC_c} \right) \left(\frac{8q}{\pi d^3} \right) \right]^n \right\} \Delta L \tag{2.61}$$

Pressure loss under laminar flow in annulus:

$$\Delta p_f = \frac{4K}{14400(d_2 - d_1)} \left\{ \left(\frac{\tau_y}{K} \right) + \left[\left(\frac{16(2n+1)}{n \times C_a^*(d_2 - d_1)} \right) \left(\frac{q}{\pi(d_2^2 - d_1^2)} \right) \right]^n \right\} \Delta L \tag{2.62}$$

Pressure loss under turbulent flow inside drill pipe:

$$\Delta p_f = \frac{f_c q^2 \rho}{1421.22 d^5} \Delta L \tag{2.63}$$

Where friction factor f_c inside drill pipe is calculated:

$$f_c = \gamma (C_c N_{\mathrm{Re}})^{-z} \tag{2.64}$$

Pressure loss under turbulent flow in annulus:

$$\Delta p_f = \frac{f_a q^2 \rho}{1421.22 (d_2 - d_1)(d_2^2 - d_1^2)^2} \Delta L \tag{2.65}$$

Where friction factor f_a in the annulus is calculated:

$$f_a = \gamma (C_a^* N_{\mathrm{Re}})^{-z} \tag{2.66}$$

2.5.5. Pressure drop at the bit

As pressure loss can be calculated for all type of fluids, for each flow regime, and for any geometry of the well, parasitic pressure can be calculated with the simple addition of all the pressure losses except for the pressure drop at the drill bit. Then, the drop at the bit can be calculated. The sum total of all pressure losses then gives the pump pressure.

Highest pressure drop occurs on the drill bit nozzles due to high velocity achieved by the small diameter of nozzles. Jet nozzles on a bit improves cleaning of the bottom hole which increase erosion rates, thus, increase the pressure loss. Drill bit velocity can be expressed as:

$$v_n = 0.32086 \frac{q}{A_T} \tag{2.67}$$

Where

vn – nozzles velocity [ft/s]

q – mud flow rate [gpm]

At – total nozzle area [in^2]

Pressure drop on the bit is expressed as:

$$\Delta p_b = \frac{\rho q^2}{12{,}031\, C_d^2 A_T^2} \tag{2.68}$$

Where:

Cd -nozzle discharge coefficient, dimensionless

The discharge coefficient has the highest value of 0.98, but 0.95 is generally used as the practical limit. These values are determined experimentally.

The hole capacity cleaning is represented by the horse power of drilling fluid at the drill bit. This can be expressed as:

$$P_{Hb} = \frac{\Delta p_b q}{1{,}714} \tag{2.69}$$

Where:

P_{Hb} – bit hydraulic power [hp]

The next indicator of hole drilling capacity of drilling fluid is hydraulic impact force.

It is expressed as:

$$F_j = 0.01823\, C_d q \sqrt{\rho \Delta p_b} \tag{2.70}$$

Where:

Fj – bit hydraulic impact force [lbf]

2.5.6. Minimum mud flow rate required for cuttings carrying capacity of mud

Minimum flow rate can be calculated by using minimum required velocity. This velocity should be higher than drill cutting slip velocity. The slip velocity can be calculated only for ideal conditions due to their complex geometry and boundary limitations. Slip velocity for Newtonian fluids is given by following equation:

$$v_{sl} = 1.89 \sqrt{\frac{d_s}{f_p}\left(\frac{\rho_s - 7.48\rho_f}{7.48\rho_f}\right)} \tag{2.71}$$

Where:

$$d_s = 0.2\frac{ROP}{RPM} \tag{2.72}$$

v_{sl} – cuttings slip velocity [ft/s]

d_s – equivalent cuttings diameter [in]

ρ_s – cuttings density [lb/ft^3]

ρ_f -fluid density [ppg]

f_p – particle friction factor, dimensionless

ROP – rate of penetration [ft/hr]

RPM – rotary speed of bit [rpm]

Equivalent cuttings diameter depends on the rate of penetration and rotary speed, and other factors like formation lithology and bit type. Using this information regarding drill bit and lithology of formation, we can reduce cuttings size by increasing the rotary speed and decreasing the rate of penetration.

The particle friction factor f is a function of the Reynolds number and particle sphericity ψ. The sphericity is defined as the surface area of a sphere containing the same volume as the particle divided by the surface area of the particle.[5] (boyun and gefei 2011,55) Charts are been generated for finding the values of the friction factor (Bourgoyne et al., 1986). However, Fang et al. (2008) developed the following correlations to replace the use of charts.

$$f_p = 10^\wedge\left(A' + B'\log(N_{ReP}) + C'[\log(N_{ReP})]^2\right) \quad (2.73)$$

$$A' = 2.2954 - 2.2626\psi + 4.4395\psi^2 - 2.9825\psi^3 \quad (2.74)$$

$$B' = -0.4193 - 1.9014\psi + 3.3416\ \psi^2 - 2.0409\psi^3 \quad (2.75)$$

$$C' = 0.1117 + 0.0553\psi - 0.1468\psi^2 + 0.1145\psi^3 \quad (2.76)$$

$$N_{ReP} = \frac{928\rho_f v_{sl} d_s}{\mu} \quad (2.77)$$

μ-viscosity of Newtonian fluid

Slip velocity is implicitly involved in Eq. (2.71.) and (2.73.) and can be solved by trial and error method.

Methods to calculate the slip velocity of non–Newtonian fluids are yet to be developed.

The minimum required mud velocity should be higher than drill cuttings transport velocity. It is calculated by the equation:

$$v_{min} = v_{sl} + v_{tr} \quad (2.78)$$

Where:

vmin – minimum required mud velocity [ft/s]

vtr – transport velocity [ft/s]

The required transport velocity has been expressed as:

$$v_{tr} = \frac{\pi d_b^2}{4C_pA}\left(\frac{ROP}{3,600}\right) \tag{2.79}$$

Where:

d_b – bit diameter [in]

C_p – cutting concentration, volume fraction

A- Annulus cross-sectional area at the depth of interest [in^2]

In directional well drilling, the minimum required mud velocity for drilling the vertical holes is usually taken as 1.8 times the minimum required mud velocity, and 1.5 times for horizontal well.

The minimum required mud flow rate in the extreme wellbore geometry can be calculated using following equation:

$$q_{min} = 3.1167 v_{min} A \tag{2.80}$$

Chapter 3 Requirements and Optimization

3.1. Introduction

For the required hole cleaning and high rate of penetration, mud pump is the most important equipment. It provides the bit hydraulics.

Drilling hydraulics can be improved by optimizing the hydraulic program. It is done by changing the pump liner, flow rate and nozzles size according to the depth of drilling.

3.2. Mud flow rate requirements

For efficient hole cleaning, some requirements of mud flow rate must be satisfied. Cutting transport depends on mud properties and flow velocity, but this parameter changes with depth, geometry and mud properties. The most practical approach to create conditions that satisfy all requirements is to find properties suitable for extreme conditions.

3.2.1. Extreme mud properties

Mud properties affect transport velocity for drill cuttings in annulus. To clean the hole efficiently, mud type for different well geometry and depth need to be considered. By choosing the extreme conditions, minimum required transport velocity for the drill cuttings can be measured. That then gives the minimum required mud flow that satisfied all stages of drilling. Mud properties that influence the choice of pump type are mud weight and rheological model.

3.2.2. Extreme annular geometry

By knowing the drilling assembly and borehole geometry for each drilling section, and taking into account extreme values which are minimum required velocity and maximum possible cross-sectional area, required minimum flow rate can be calculate. In this case, the minimum required flow rate is expressed as:

$$q_{min} = 3.1167 v_{min} A_{max} \qquad (3.1)$$

3.2.3. The minimum required flow rate

Minimum flow rate is evaluated according to the required minimum mud velocity which needs to be higher than the slip velocity.

3.3. Pressure requirements

Similar to mud requirements, certain pressure conditions need to be satisfied in order to overcome pressure loss, as well as pressure drop at the dill bit. Pressure loss depends on mud flow rate and mud properties, and also on drilling string and borehole geometry. Pressure drop at the bit nozzles should be optimized according to total pressure loss in the system to ensure maximized bit hydraulics.

3.3.1. Extreme borehole configuration and conditions

In each drilling section, maximum pressure loss takes place at the target depth. At this depth, maximum circulating pressure is also experienced. While tripping out, it is necessary to increase mud weight so that the pressure will be high enough to maintain the borehole stability.

3.3.2. Circulating pressure

The maximum circulating pressure is at extrema borehole configuration and it is equal to the sum of total pressure loss and pressure drop at the bit. In normal conditions, fluid regime in the drilling string is turbulent, in annulus is laminar. Thus, in locations inside the drill pipe where the regime is turbulent flow, often higher-pressure losses are observed.

Pressure loss for turbulent flow can be expressed as:

$$\Delta p_d = cq^m \tag{3.2}$$

Where:

c- is a constant that depends on mud properties and well geometry

m- is a constant

Constant m theoretically takes values of 1.75 for turbulent and less than 1.75 for laminar flows. But it can be estimated by matching calculations for pressure loss at the flow rates with following equation:

$$m = \frac{\log\left(\frac{\Delta p_{d2}}{\Delta p_{d1}}\right)}{\log\left(\frac{q_2}{q_1}\right)} \tag{3.3}$$

Then constant c takes the value:

$$c = \frac{\Delta p_{d1}}{q_1{}^m} \tag{3.4}$$

Or

$$c = \frac{\Delta p_{d2}}{q_2{}^m} \tag{3.5}$$

With this generalized pressure loss constant m, pressure drop on the bit needs be expressed as the total pressure loss in the system. According to the maximum bit hydraulics horsepower criterion pressure should be held as: (Kendall and Goins 1960)

$$\Delta p_b = \frac{m}{m+1} p_p \tag{3.6}$$

Where

p_p -pump pressure [psi]

According to the maximum jet impact force criterion the following relation should be held:

$$\Delta p_b = \frac{m}{m+2} p_p \tag{3.7}$$

3.3.3. Minimum required pressure

The minimum required pressure is expressed as:

$$p_p = \Delta p_d + \Delta p_b \tag{3.8}$$

Combining Eq. (3.6) and (3.8), the following relation is derived for maximum bit hydraulic horsepower criteria:

$$\Delta p_d = \frac{1}{m+1} p_p \tag{3.9}$$

Combining Eq. (3.7) and (3.8), following relation is derived for maximum jet impact force criteria:

$$\Delta p_d = \frac{2}{m+2} p_p \tag{3.10}$$

Eq. (3.9) and (3.10) give the expressions required for pump pressure for hydraulic horsepower and maximum jet impact criterium as:

$$p_p = (m+1)\Delta p_d \tag{3.11}$$

and

$$p_p = \frac{m+2}{2}\Delta p_d \tag{3.12}$$

3.3.4. Horsepower requirements

Mud pumps are limited with maximum horse power and maximum working pressure. It is essential to maintain the pump pressure lower than maximum working pressure at all times as a safety factor. Mud pump hydraulic horsepower is expressed as:

$$P_h = \frac{qp}{1{,}714} \tag{3.13}$$

Where:

Ph- hydraulic horsepower [hp]

p-pump pressure [psi]

q- mud flow rate [gpm]

Knowing maximum Hp and p_{pm} we can calculate maximum flow rate with following expression:

$$q_{max} = \frac{1{,}714 E_p P_H}{p_{pm}} \tag{3.14}$$

Where:

q_{max}- maximum mud flow rate [gpm]

P_H- horsepower rating of pump [hp]

E_p- pump efficiency, dimensionless

p_{pm} – maximum working pressure of pump [pis]

Because the pump will always run at flow rate less than maximum, available pump pressure is expressed as:

$$p_{max} = \frac{1{,}714 E_p P_H}{q} \tag{3.15}$$

Maximum horsepower of duplex and triplex pump are described in Chapter 1.

3.4. Optimizing the drill bit hydraulics

To get sufficient hole cleaning, the drill bit hydraulics need to be optimized and hydraulic horsepower on the bit must be maximized. Because we are limited for pump power with the pump horsepower and with liners for the flow rate and pressure, the only thing left to be optimized is the drill bit hydraulics. This can be achieved by maximizing the bit impact force, the bit hydraulic power and the jet velocity.

3.4.1. The maximum bit hydraulic horsepower

The maximum possible horsepower bit hydraulics is the most common design procedure to clean the bottom hole. Maximizing the bit hydraulic horsepower will increase the efficiency of the hydraulic system. It increases the penetration rate and removes the cuttings as fast as they are produced. However, it doesn't necessarily mean that the maximum pump horsepower will provide maximum bit horsepower. The conditions for maximum bit horsepower were derived by Kendall and Goins in (1960). The pressure drop at the bit is expressed as:

$$\Delta p_b = p_p - cq^m \tag{3.16}$$

Substituting this expression into Eq. (2.69) gives:

$$P_{Hb} = \frac{q(p_p - cq^m)}{1{,}714} \tag{3.17}$$

Using calculus to determine the flow rate at which the bit horsepower is a maximum gives:

$$\frac{dp_{Hb}}{dq} = \frac{p_p - (m+1)cq^m}{1{,}714} = 0 \tag{3.18}$$

Solving the root of this equation yields:

$$p_p = (m+1)cq^m = (m+1)\Delta p_d \tag{3.19}$$

Or

$$\Delta p_d = \frac{p_p}{m+1} \tag{3.20}$$

It can be shown that $(d^2P_{Hb}/dq^2) < 0$ at this root, so the root corresponds to a maximum. Bit hydraulic horsepower is a maximum when the parasitic pressure loss is 1/(m+1) times the pump pressure. Since

$$\Delta p_b = p_p - \Delta p_d = p_p - \frac{p_p}{m+1} = \frac{m}{m+1} p_p \tag{3.21}$$

the bit hydraulic horsepower is a maximum when the pressure drop at that bit is m/(m+1) times the pump pressure.

3.4.2. The maximum jet impact force

Jet impact fluid force cleans the bottomhole by direct erosion and by cross flowing beneath the bit. The conditions for maximum jet impact force were also derived by Kendall and Goins (1960). Substituting Eq. (3.16) into Eq. (2.70):

$$F_j = 0.01823 C_d q \sqrt{\rho(p_p - cq^m)} \tag{3.22}$$

Using calculus to determine the flow rate at which the bit impact force is a maximum:

$$\frac{dF_j}{dq} = \frac{0.009115 C_d [2\rho \Delta p_p q - (m+2)\rho c q^{m+1}]}{\sqrt{\rho \Delta p_p q^2 - \rho c q^{m+2}}} = 0 \tag{3.23}$$

Solving the root of this equation yields:

$$\Delta p_d = \frac{2 p_p}{m+2} \tag{3.24}$$

It can be shown that $(d^2Fj)/(dq^2) < 0$ at this root, so the root corresponds to a maximum. Thus, the jet impact force is a maximum when the parasitic pressure loss is 2/(m+2) times the pump pressure. Since

$$\Delta p_b = p_p - \Delta p_d = p_p - \frac{2p_p}{m+2} = \frac{m}{m+2} p_p \tag{3.25}$$

bit jet impact force is a maximum when the pressure drop at that bit is m/(m+2) times the pump pressure. This criterion is used in shallow to middle depths.

3.4.3. The maximum nozzle velocity

The bit velocity needs to be set in a way that provides minimal annular velocity for transportation of cuttings from bottom hole to have minimal flow rate. By decreasing the flow rate, the velocity also decreases as shown in following equation:

$$v_n = C_d \sqrt{\frac{p_p - cq^m}{8.074 \times 10^{-4} \rho}} \tag{3.26}$$

High nozzle velocity is typically used at deeper depths.

Chapter 4 Model details and used Methodology for solving

4.1. Introduction

Calculation for Reynolds number, pressure loss, satisfying requirements and optimizing the parameters will be done on the real data for the real problems in this chapter. Briefly describing the problem and data for the well we can see what are requirements that we need to satisfy and to calculate. Also it has been calculated dynamic pressure while drilling the each segment and it will be shown by graphs.

4.2. Model details

The well will be vertical (figure 4.1.) with target depth at 12993 ft (3943 m). It will have 7 sections.

Firstly, 36” holes will be drilled through unconsolidated sand and sticky clay for the installation of 30” conductor with setting depth at ± 190 ftBRT (±48 mBRT). This will provide structural support near the ground level.

After cementing, the second section will be drilled with 28’’ drill bit through the loose friable and for the installation of 24” casing at the depth of ± 780 ftBRT (±240 mBRT).

Then will be drilled for surface casing 18 5/8”; that will be settled at the depth of ± 1624 ftBRT (±495 mBRT). It will isolate several potential loss zones below the 24’’ casing and will provide sufficient shoe strength to withstand any pressure that might occur while drilling 16’’ hole, and support weight of wellhead and subsequent casing. This third section will be drilled with 23’’ drill bit.

The fourth section will be drilled with a 16” drill bit for installation of intermediate casing 13 3/8” at depth ±7997 ftBRT (±2438 mBRT) to case off the low-pressure regime before starting to drill through high pressure zone.

The fifth section, the high-pressure zone, will be drilled with 12 ¼’’ bit up to target depth of ± 11690 ftBRT (±3564 mBRT) to isolate the zone before penetrating in the zone of interests.

The sixth section will have 8 ½” hole up to the depth of ± 12615 ftBRT (± 3845 mBRT).

The last will be drilled with 6” bit and it will stay open for well test and in the future, it will act as the production well with target depth of ± 12933 ftBRT (±3943mBRT).

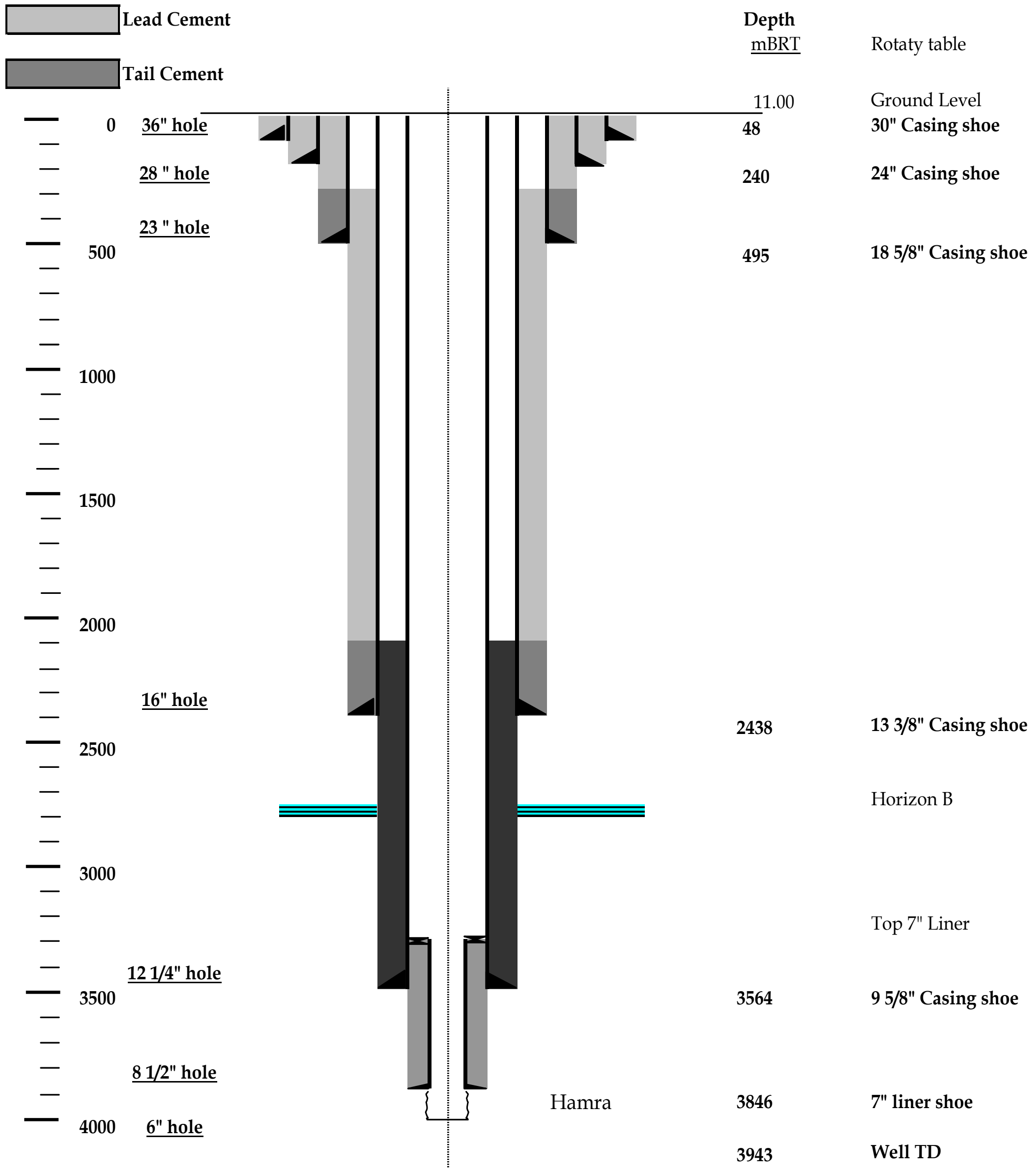


Figure 4.1 Well diagram

4.1.1. Drilling 36'' hole

A pre-hydrated bentonite mud with a low mud weight of 8.7 ppg with will be used to drill this section. The flow rate needs to be kept as low as possible, just sufficient enough to clean the hole to avoid hole washout. The drilling string, and drill bit data used for drilling 36'' hole section are presented in table 4. 1..

Table 4.1 BHA program and drill bit program for hole 36''

	OD "	ID "	Number of equipment	Length m	Length ft
Drilling collars	8	2.8125	4	38.6	127
Drilling collars	9.5	3	2	19.3	63
total			6	57.90	190

Drilling bit	
Drill bit diameter	36
Nozzles "	0.75
Number of nozzles	3
Total area nozzles in^2	1.325
Cd	0.95

4.1.2. The Second section 28" HOLE:

The mud system used for drilling should be 8.9 ppg, and pre-hydrated bentonite mud will be used to drill the 28" hole. Mud weight will be required to be kept as low as possible (and pump rate will be controlled to minimize the washout in this top-hole section.) Good cleaning of the hole will be mandatory to minimize the risk of losing returns. The drilling string, and drill bit data used for drilling 28'' hole section are presented in table 4. 2..

Table 4.2 BHA program and drill bit program for hole 28''

	OD "	ID "	Number of equipment	Length m	Length ft
Drilling pipes	5	3.25	10	92	302
Heavy wall drill pipe	5	2.5	12	114	374
Drilling collars	8	2.8125	1	9.5	31
stabilizer	9.5	3	1	5.5	18
Drilling collars	9.5	3	2	19	62
total			16	240	787

Drilling bit	
Drill bit diameter	28
Nozzles 24/32"	0.75
Number of nozzles	3
Nozzles 20/32"	0.625
Number of nozzles	1
Total area nozzles in^2	1.82
Cd	0.95

4.1.3. The Third section 23" HOLE:

The same mud system used for drilling 28" hole will be used for drilling 23" through the potential loss interval to 18-5/8" casing depth of 1624 ftBRT. Stuck pipe has been experienced in that section. Jarring is required to get the string free. The drilling string, and drill bit data used for drilling 23” hole section are presented in table 4.3..

Table 4.3 BHA program and drill bit program for hole 23’’

	OD "	ID "	Number of equipment	Length m	Length ft
Drilling pipes	5	4.25	25	238	780
Heavy wall drill pipe	5	2.5	12	114	374
Drilling collars	8	2.8125	1	9.5	31
jar	8	2.8125	1	10.1	33
Drilling collars	8	2.8125	11	104.5	343
stabilizer	9.5	3	1	5.5	18
Drilling collars	9.5	3	1	9.5	31
shock sub	9.5	3	1	4.12	14
total			27	495	1624

Drilling bit	
Drill bit diameter	23
Nozzles 20/32"	0.625
Number of nozzles	3
Nozzles 18/32"	0.5625
Number of nozzles	1
Total area nozzles in^2	1.3615
Cd	0.95

4.1.4. The Fourth section 16” HOLE:

Loss of circulation may be observed in this section if the mud weight is raised over 10.5 ppg. The 13-3/8” casing will be run and cemented up to 150 m above the previous shoe. The drilling string, and drill bit data used for drilling the 16” hole section are presented in table 4.4..

Table 4.4 BHA program and drill bit program for hole 16’’

	OD "	ID "	Number of equipment	Length m	Length ft
Drilling pipes	5	4.25	228	2168	7111
Heavy wall drill pipe	5	2.5	12	114	374
Drilling collars	8	2.8125	1	9.5	31
jar	8	2.8125	1	10.1	33
Drilling collars	8	2.8125	11	104.5	343
stab	9.5	3	1	5.5	18
Drilling collars	9.5	3	1	9.5	31
stab	9.5	3	1	5.5	18
pony DC	9.5	3	1	6	20
stab	9.5	3	1	5.5	18
total			257	2438	7997

Table 4.4 BHA program and drill bit program for hole 16''

Drilling bit	
Drill bit diameter	16
Nozzles 12/32"	0.375
Number of nozzles	9
Nozzles/32"	0
Number of nozzles	0
Total area nozzles in^2	0.9936
Cd	0.95

4.1.5 The Fifth section 12-1/4" HOLE:

The mud weight will be 17.6 ppg. The 9-5/8" production casing will be run to section TD and cemented to 150 m above the 13-3/8" casing shoe. The drilling string, and drill bit data used for drilling the 12 1/4" hole section are presented in table 4. 5.

Table 4.5 BHA program and drill bit program for hole 12 1/4''

	OD "	ID "	Number of equipment	Length m	Length ft
Drilling pipes	5	4.25	344	3265	10711
Heavy wall drill pipe	5	2.5	12	114	374
Drilling collars	6.5	2.25	3	28.5	93
Drilling collars	8	2.8125	1	9.5	31
jar	8	2.8125	1	10.1	33
Drilling collars	8	2.8125	11	104.5	343
stab	8	2.8125	1	5.5	18
Drilling collars	8	2.8125	1	9.5	31
stab	8	2.8125	1	5.5	18
pony DC	8	2.8125	1	6	20
stab	8	2.8125	1	5.5	18
total			376	3564	11690

Drilling bit	
Drill bit diameter	12.25
Nozzles 16/32"	0.5
Number of nozzles	8
Nozzles/32"	0
Number of nozzles	0
Total area nozzles in^2	1.57
Cd	0.95

4.1.6. The sixth section 8-1/2” HOLE:

The mud weight will be 13.5 ppg. The 7” liner will then run and be cemented. The drilling string, and drill bit data used for drilling the 8 1/2” hole section are presented in table 4. 6..

Table 4.6 BHA program and drill bit program for hole 8 1/2’’

	OD "	ID "	Number of equipment	Length m	Length ft
Drilling pipes	5	2.5	373	3547	11635
Heavy wall drill pipe	5	2.5	12	114	374
Drilling collars	6.5	2	1	9.5	31
jar	6.5	2	1	10.1	33
Drilling collars	6.5	2	14	133	436
stab	6.5	2	1	5.5	18
Drilling collars	6.5	2	1	9.5	31
stab	6.5	2	1	5.5	18
pony DC	6.5	2	1	6	20
stab	6.5	2	1	5.5	18
total			405	3846	12615

Drilling bit	
Drill bit diameter	8.5
Nozzles 14/32''	0.40625
Number of nozzles	5
Nozzles/32''	0
Number of nozzles	0
Total area nozzles in^2	0.64777832
Cd	0.95

4.1.7. The seventh section 6” HOLE :

The mud weight will be 13.5 ppg. The 6” hole will be drilled and cored to well TD ±3,943 mBRT. The drilling string, and drill bit data used for drilling the 6” hole section are presented in table 4. 7.

Table 4.7 BHA program and drill bit program for hole 6''

	OD "	ID "	Number of equipment	Length m	Length ft
Drilling pipes	3.5	2.5	376	3569	11706
Heavy wall drill pipe	3.5	2.5	15	142.5	467
Drilling collars	4.75	2	1	9.5	31
jar	4.75	2	1	10.1	33
Drilling collars	4.75	2	19	180.5	592
RR	4.75	2	1	5.3	17
Drilling collars	4.75	2	1	9.5	31
RR	4.75	2	1	5.3	17
pony DC	4.75	2	1	6	20
RR	4.75	2	1	5.3	17
total			416	3943	12933

Drilling bit	
Drill bit diameter	6
Nozzles 14/32''	0.4375
Number of nozzles	3
Nozzles/32''	0
Number of nozzles	0
Total area nozzles in^2	0.450761719
Cd	0.95

Casing program is shown in Table 4.8. whit all specifications.

Table 4.8 Casing program

Casing size (in)	Depth ftBRT	Length Ft	Name of string	Grade	Weight ppf	Casing Pressure		
30	157	197	Conductor	X-56	196.1	N/A	N/A	N/A
24	787	787	Surface	X-56	94.6	N/A	N/A	N/A
18 5/8	1624	1624	Surface	K-55	87.5	2250	630	1367
13 3/8	7997	7997	Intermediate	P- 110	72	7400	2880	2284
9 5/8	11690	11690	Production	P – 110	53.5	10900	7930	1710
7	12615	1417	Production liner	P - 110	29	11220	8510	929

4.2. Methodology

This model will calculate pressure drop in the drilling string and annulus due to flow. Additionally, it will optimize the flow rate to have less pressure loss due to friction, and to spend all power to the bit to have the best performances. The problem is split seven sections, and pump pressure and flow rate will be calculated for total depth of the hole. The mud pump should be capable of providing enough pressure to overcome pressure loss and pressure drop at the bit. In the circulating system and flow rate should be strong enough to lift the cuttings up to the surface, and to provide sufficient cleaning. During every drilling point, hydrostatic pressure and frictional forces will be present that will have influence on the total pressure of the system. The predicted normal hydrostatic pressure for a give depth, or rather the pressure exerted per unit area by a column of freshwater at sea level for a given depth,

can be calculated with the following formula:

$$p_h = 0.052 * \rho * D \tag{4.1}$$

Where:

p_h – hydrostatic pressure [psi]

ρ – density of the fluid [ppg]

D – true vertical depth [ft]

0.052 – unit conversion factor

Friction loss occurs due to flow of fluid and it is described in Chapter 2. Because of the geometry of the flow path, calculation will be split into two big sections, inside pipes and in the annulus. Furthermore, calculation will be split into fluid path segments that have that same inner diameter in the pipe as the inner and outer diameters as of the annulus. Further, fluid path will be split into a big number of smaller steps where we assume that each one exhibits constant pressure, velocity and angle. Drill bit will divide the pipe calculations from annulus calculations. Fluids flow through the nozzles where occur pressure drop depends on flow rate and total nozzle.

For these calculations, the starting point is pump pressure and flow rate of the pump, but before that some constraints to be satisfied. Flow rate should be high enough to lift up the cuttings from the bottom of hole up to the surface. Minimum required flow rate is calculated for the worst possible scenario: the maximum cross-sectional area and minimum velocity, by using Eq 3. 1.. The minimum velocity is the summation of transport and slip velocity. All velocities are calculated using equations 2.71-2.79. With the received results, we can run our calculations. For each segment, the hydrostatic pressure and velocity are calculated. Friction pressure loss depends on rheological models and flow regimes. By summing up the entering pressure with hydrostatic pressure and pressure loss we will have pressure on the end of the segment, and that pressure it will be starting pressure for the next segment. Pressure drop on the bit will be calculated with Eq 4.2. By the end of the calculations, we will get pressure that will not be zero, which will be solved by setting the equation to zero, and by changing the first entering pressure. We will have the pressure for running the pump which is optimum and efficient. We can optimize the drill bit hydraulic horsepower, hydraulic jet impact force and maximum nozzle velocity with equations 3.21 3.25 and 3.26 respectively; by expressing pump pressure with Eq. 3.11 for maximum horsepower and Eq. 3.12 for maximum jet impact. We calculate total pressure loss due to friction with the generalized pressure loss equation Eq. 3.1 using minimum flow rate. However, we need to check if the values satisfy the constraints, if they are higher than the minimum required flow rate or not. We return to the generalized pressure loss formula for calculating the pressure drop at the bit using Eq. 3.8. Using Eq. 4.1, flow rate will be calculated. When we get flow rate, we will carry out comparisons and choose which one is the best one for us.

$$\Delta p_b = 8.311 * 10^{-5} * \frac{\rho * q^2}{C_d^2 * A_t^2} \tag{4.2}$$

Where:

p_b – pressure drop at the bit [psi]

ρ – density of the fluid [ppg]

q- flow rate [gpm]

Cd- nozzle discharge coefficient, dimensionless

At- total nozzle area [in^2]

Chapter 5 Results and discussion

This chapter looks at the results of the constructed model, which has been split into 7 stages. The results will be focused on:

i. minimum flow rate
ii. pressure loss due to friction
iii. pressure gain due to hydrostatic pressure
iv. pressure drop at the bit
v. velocity at the bit nozzles
vi. drill bit jet impact force
vii. bit hydraulic horsepower
viii. and on the end pump pressure.

This data will be compared for three cases: minimum pump flow rate, and for two optimized parameters: maximized jet impact force and maximized usage of bit hydraulic horsepower. The optimal data will be used for drilling that stage.

5.1. First stage

In this stage, a 36'' hole for the installation of conductor will be drilled. Methodology described in the Chapter 4, and the rheological model for Power law fluids for oil-based mud will be used. The following results from Table 5.1 will be attained.

Table 5.1 First stage results

	Mud pump flow rate (gpm)	Pressure loss due to friction (psi)	Pressure drop at the bit (psi)	Velocity at the bit nozzles (ft/s)	Jet Impact force (lbf)	Bit Hydraulic horsepower (HP)	Pump pressure (psi)
Minimum required flow rate	1590	689	1154	385	2759	1070	1843
Maximized Horsepower on the bit	2229	1244	2268	540	5423	2950	3512
Maximized Jet impact force	1576	678	1134	382	2711	1043	1812

We can see that the minimum required flow rate is 1590 gpm. Only one parameter for optimization satisfied this condition, hence, we can't optimize by using jet impact force. Due to the high flow rate, we have a turbulent flow, and high frictional losses. Also, we have huge jet impact force and bit hydraulic power that is used on the drill bit. We will choose minimum flowrate, and the pressure that the pump needs to deliver is 1843 psi. In Figures 5.1, 5.2 and 5.3 we can see how pressure change in the system with changing depth and geometry of the well for all three cases.

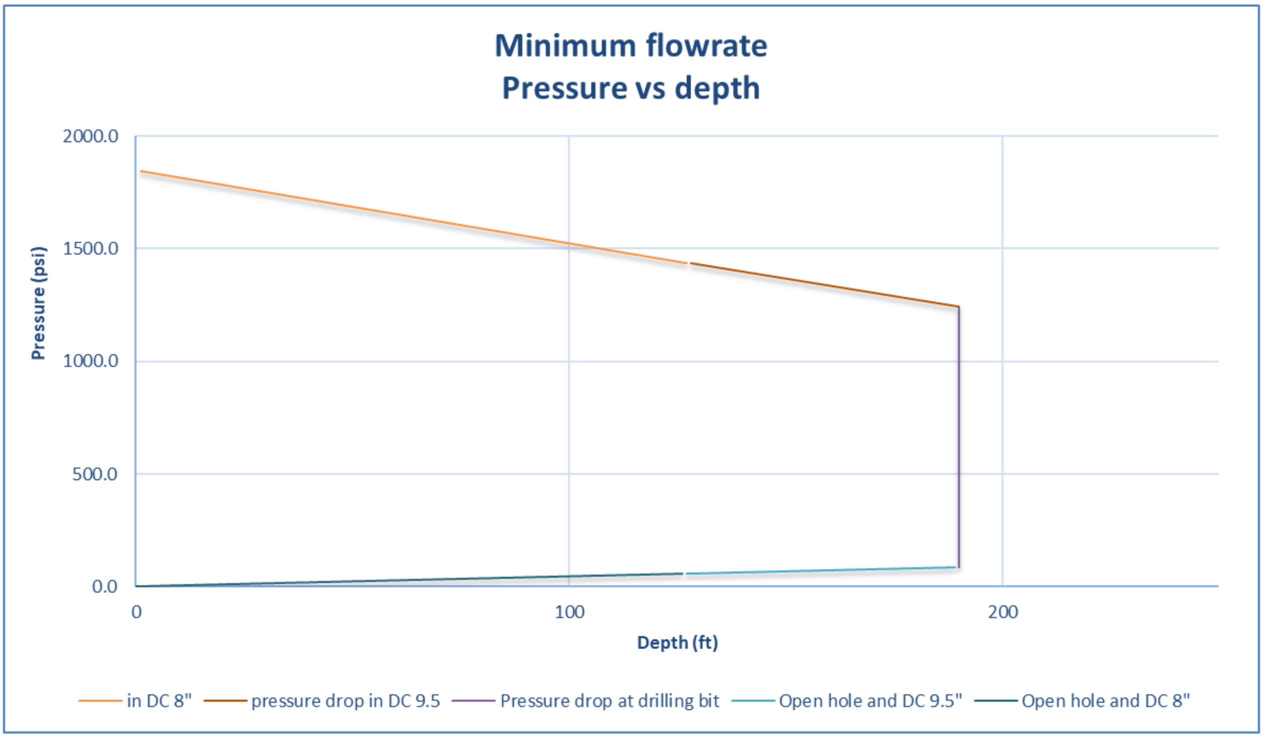


Figure 5.1 Dynamic pressure profile with depth when is minimum required flow rate applied

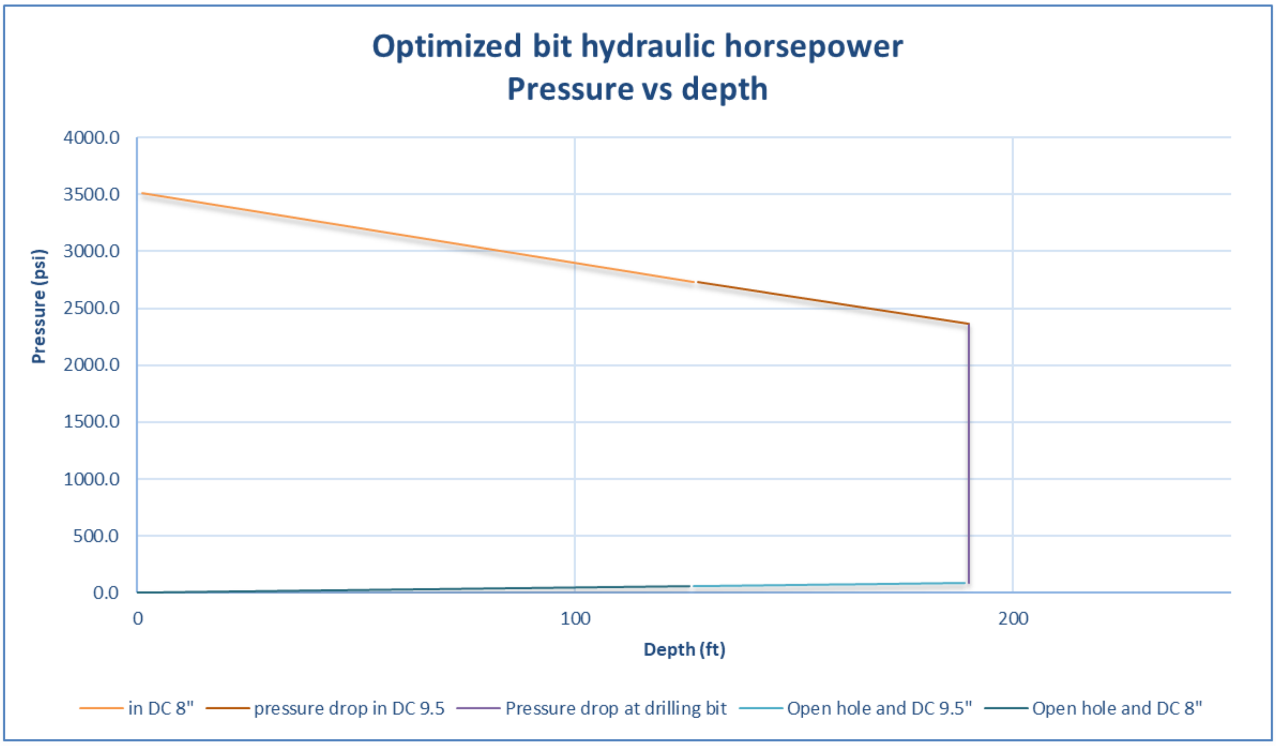


Figure 5. 1 Dynamic pressure profile with depth when is optimized bit hydraulic horsepower

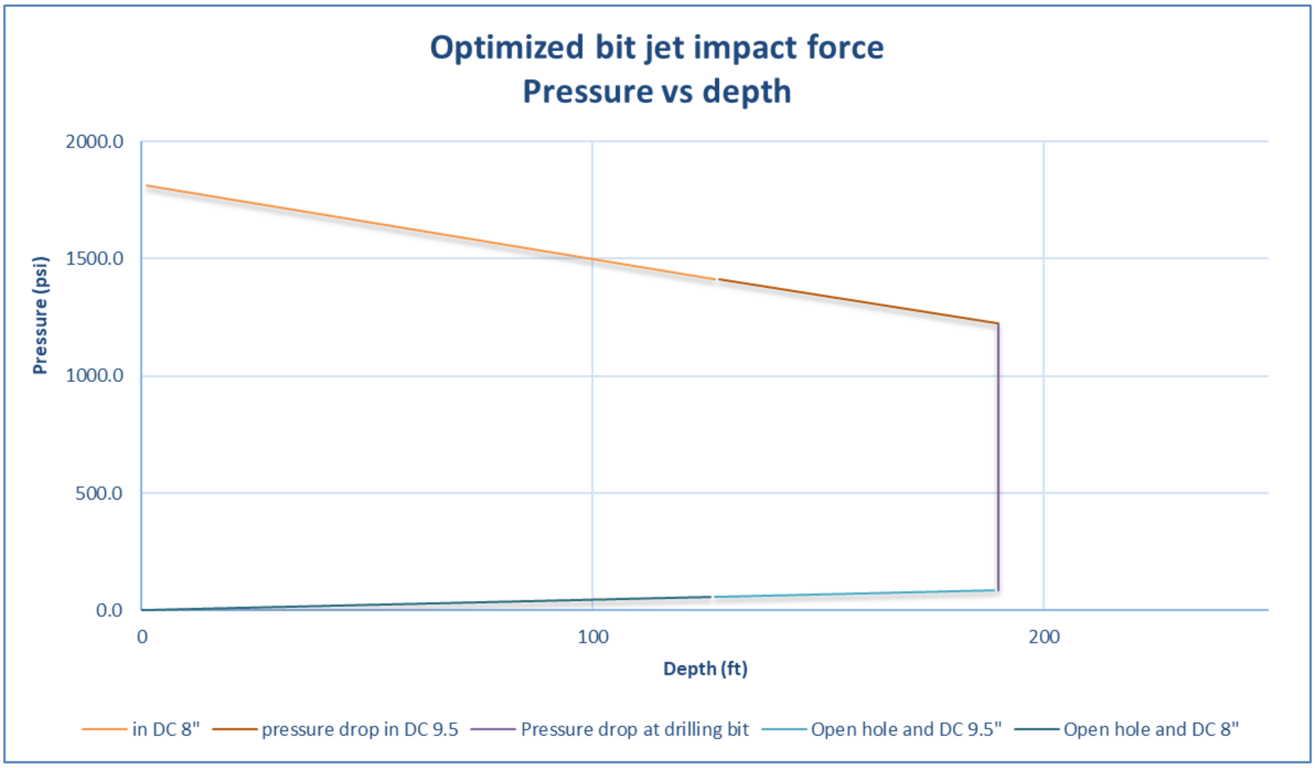


Figure 5.3 Dynamic pressure profile with depth when is optimized jet impact force power

5.2. Second stage

In this stage, a 28’’ hole for the installation of surface casing will be drilled. Methodology described in the Chapter 4 and rheological model for Power law fluids will give us results as presented in Table 5.2.

Table 5.2 Second stage results

	Mud pump flow rate (gpm)	Pressure loss due to friction (psi)	Pressure drop at the bit (psi)	Velocity at the bit nozzles (ft/s)	Jet Impact force (lbf)	Bit Hydraulic power (HP)	Pump pressure (psi)
Minimum required flow rate	1141	2131	324	202	1061	216	2455
Maximized Horsepower on the bit	2319	7374	1337	410	4382	1810	8711
Maximized Jet impact force	1640	4021	669	290	2129	640	4690

We can see that minimum required flow rate is 1141 gpm and both parameters for optimization satisfies this condition. Thus, we can choose the criteria that will be used for optimization. Due to high flow rate, we have a turbulent flow and bigger frictional losses. Also, we will have bigger jet impact force and bit hydraulic power that is used on the drill bit. We will choose to have minimum flow rate, and the pressure that the pump needs to deliver is 2455 psi. In Figures 5.4, 5.5 and 5.6 we can see how pressure change in the system with changing depth and geometry of the well for all three cases.

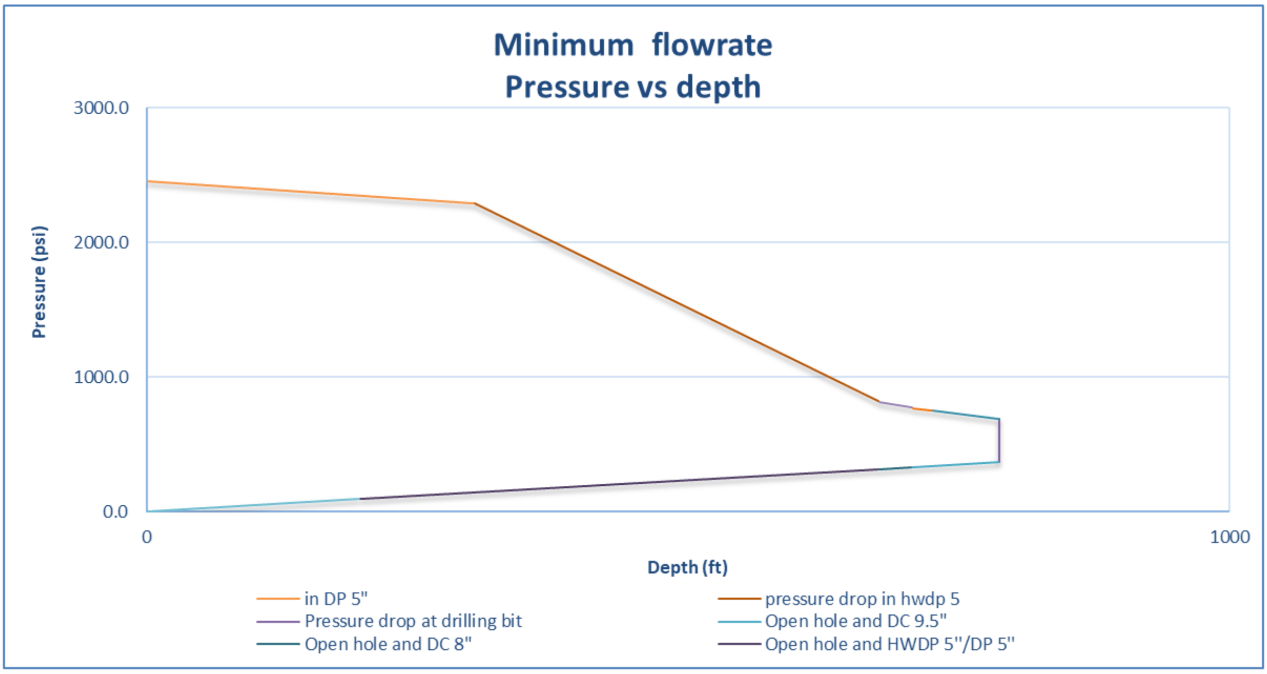


Figure 5.4 Dynamic pressure profile with depth when is minimum required flow rate applied

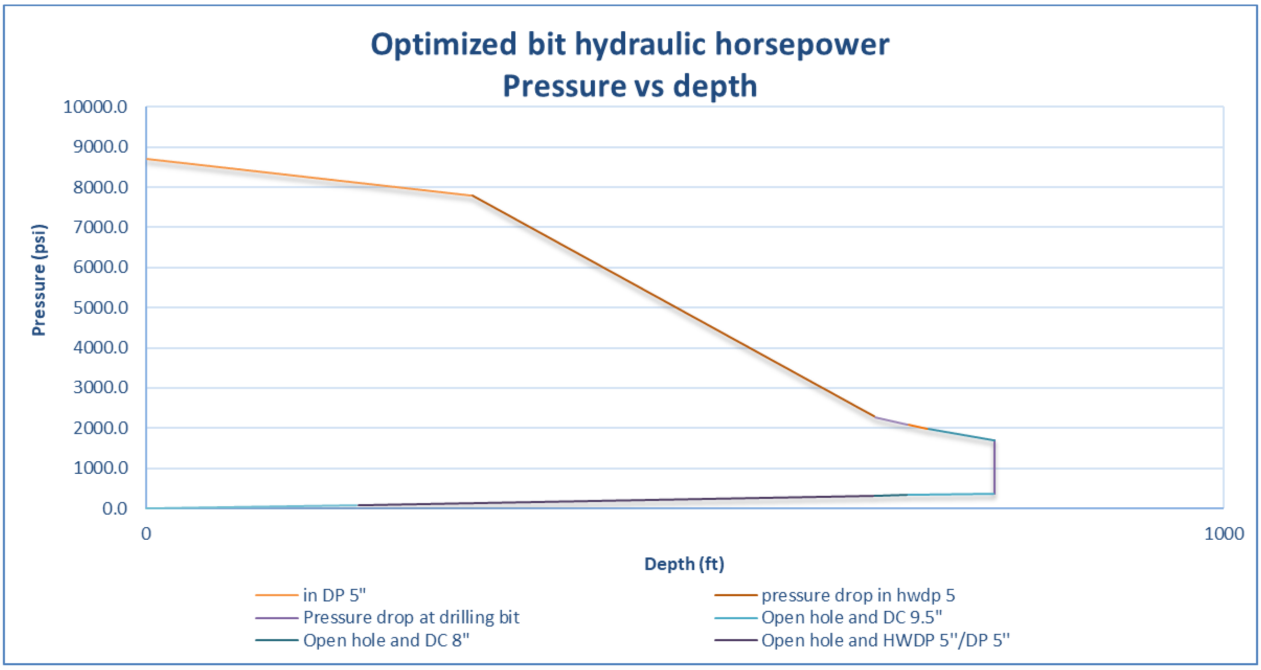


Figure 5.5 Dynamic pressure profile with depth when is optimized bit hydraulic horsepower

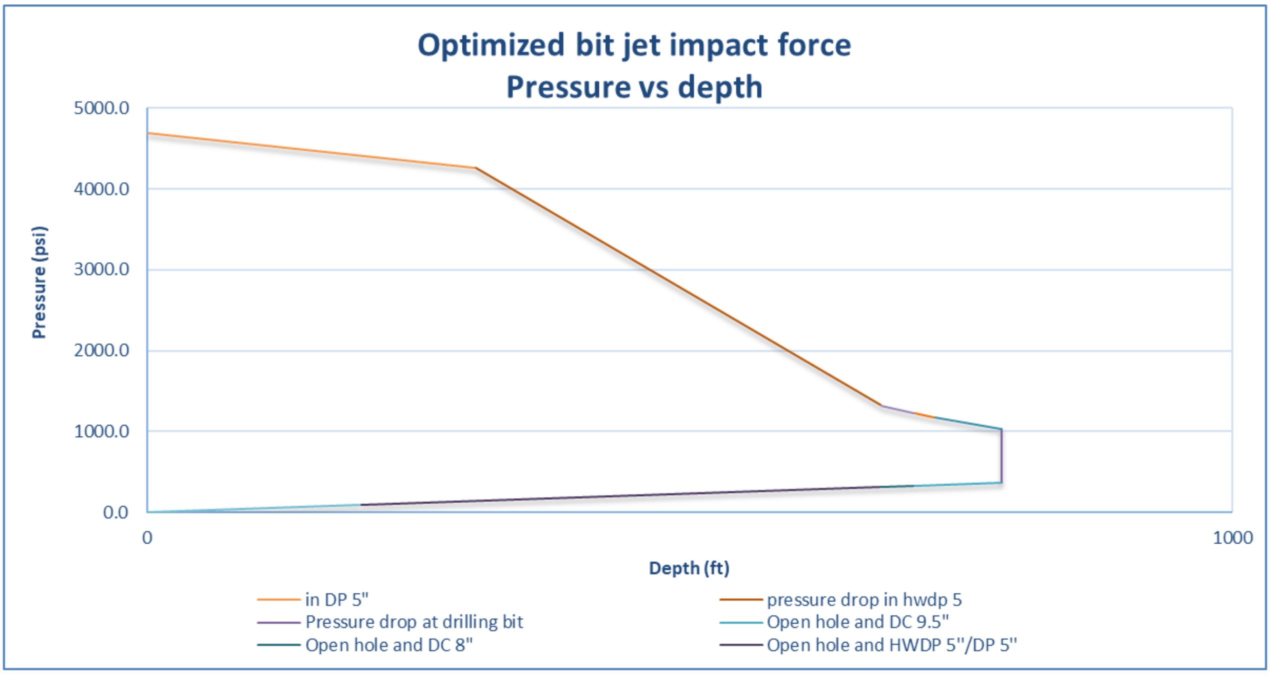


Figure 5.6 Dynamic pressure profile with depth when is optimized jet impact force power

5.3. Third stage

In this stage, a 23’’ hole for the installation of surface casing will be drilled. Methodology described in the Chapter 4, and rheological model for Power law fluids will give the us results as shown in Table 5.3.

Table 5.3 Results for third stage

	Mud pump flow rate (gpm)	Pressure loss due to friction (psi)	Pressure drop at the bit (psi)	Velocity at the bit nozzles (ft/s)	Jet Impact force (lbf)	Bit Hydraulic power (HP)	Pump pressure (psi)
Minimum required flow rate	616	942	168	145	412	60	1110
Maximized Horsepower on the bit	1065	2456	502	251	1232	312	2958
Maximized Jet impact force	753	1339	251	177	616	110	1590

We can see that the minimum required flow rate is 616 gpm and both parameters for optimization satisfy this condition. Hence, we can choose which criteria to use for optimization. We will choose to have maximum jet impact force spent in the bit, and the pressure that the pump needs to deliver is 1590 psi. In Figures 5.7, 5.8 and 5.9, we see how pressure change in the system with changing depth and geometry of the well in all three cases.

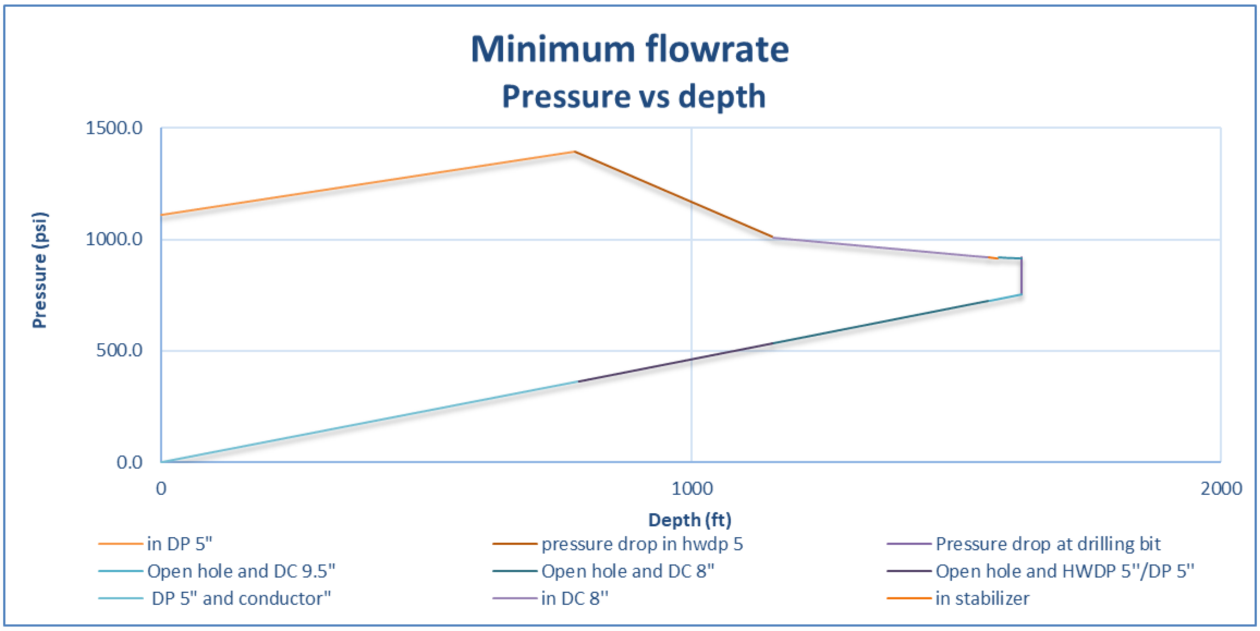


Figure 5.7 Dynamic pressure profile with depth when is minimum required flow rate applied

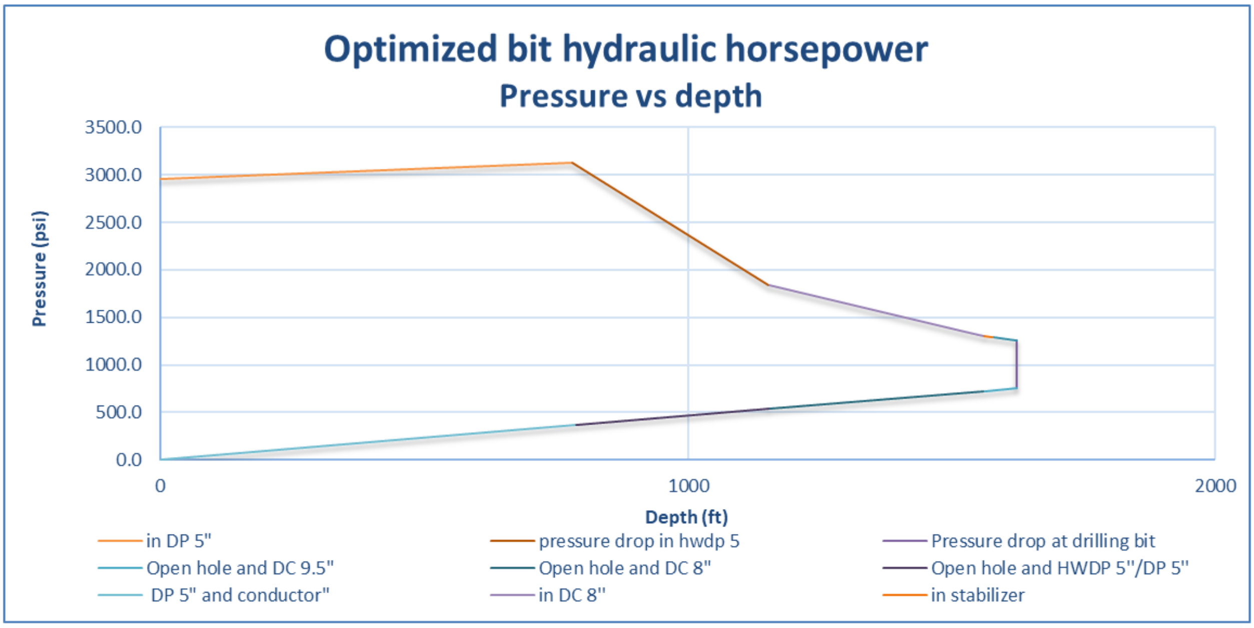


Figure 5.8 Dynamic pressure profile with depth when is optimized bit hydraulic horsepower

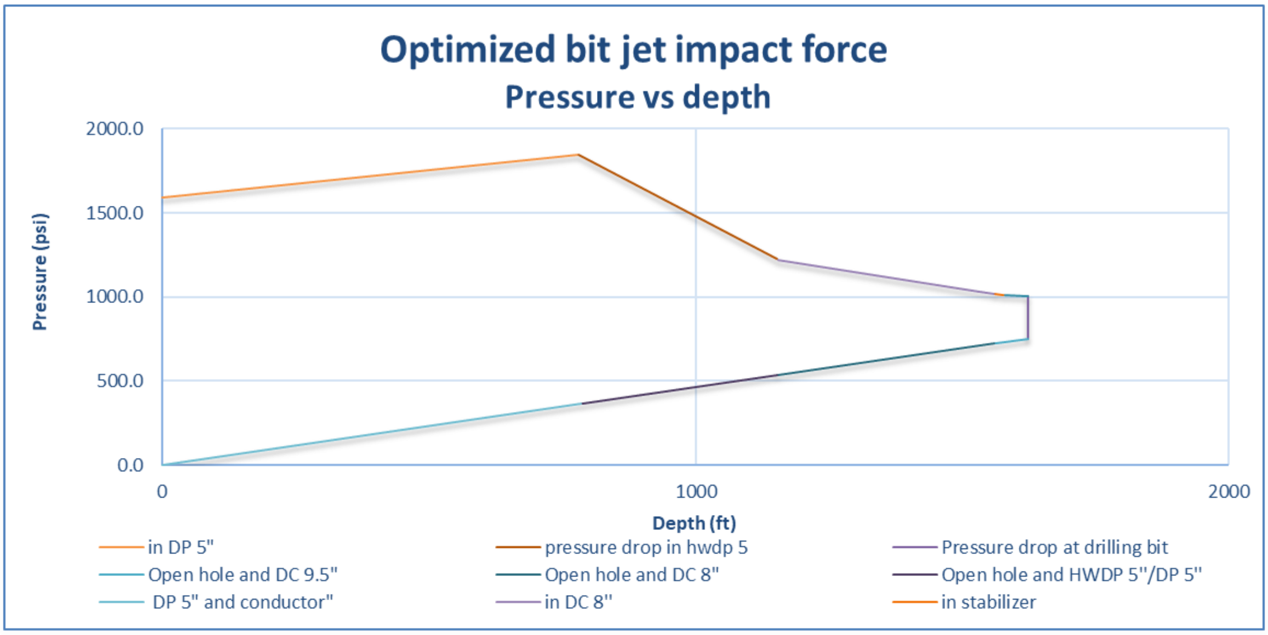


Figure 5.9 Dynamic pressure profile with depth when is optimized jet impact force power

5.4. Fourth stage

In this stage, a 16'' hole for the installation of surface casing will be drilled. Methodology described in the Chapter 4, and rheological model for Bingham fluids that are oil-based mud will give us the results that are presented in Table 5.4.

Table 5.4 Results for fourth stage

	Mud pump flow rate (gpm)	Pressure loss due to friction (psi)	Pressure drop at the bit (psi)	Velocity at the bit nozzles (ft/s)	Jet Impact force (lbf)	Bit Hydraulic power (HP)	Pump pressure (psi)
Minimum required flow rate	407	819	162	131	291	39	981
Maximized Horsepower on the bit	559	1427	306	181	549	100	1733
Maximized Jet impact force	395	777	153	128	274	35	930

We can see that minimum required flow rate is 407 gpm and only one criterion for optimization satisfies this condition. We will have to choose between whether to stay with the minimum flow rate or to take maximized horse power on the bit. As noticed from the Figures 5.10 5.11 5.12., we can see that the pressure inside drilling string increases due to hydrostatic pressure, and is decreasing after the bit: in the annulus. We will choose to have minimum flow rate and the pressure that the pump needs to deliver is 981 psi.

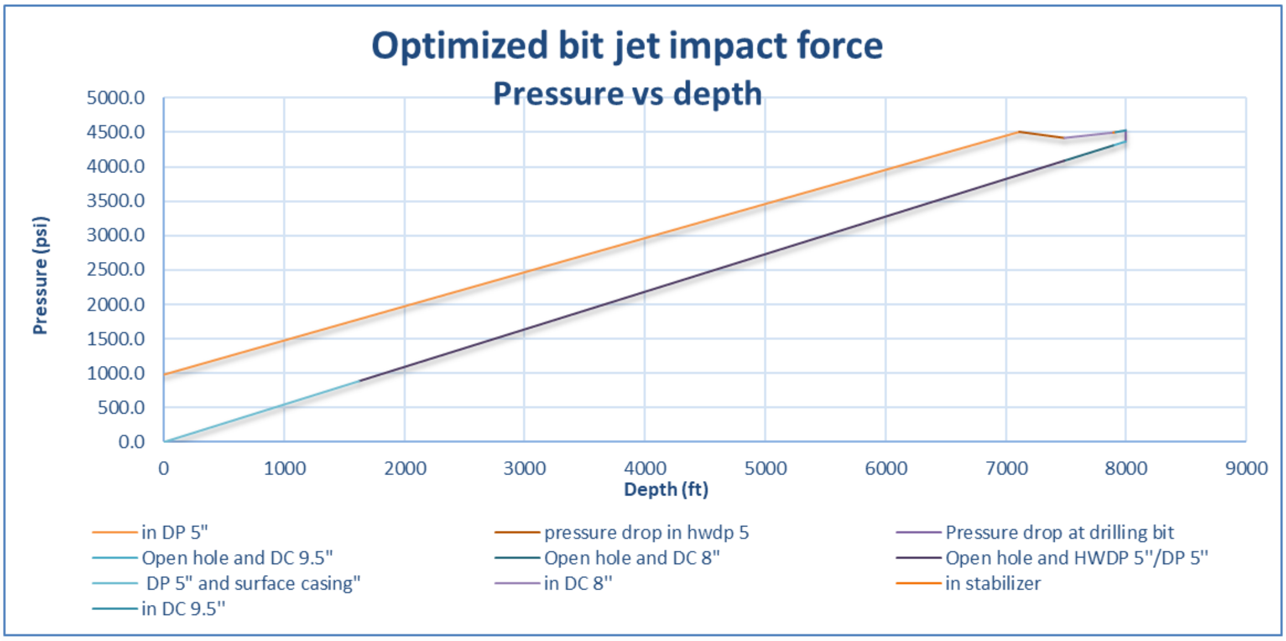


Figure 5.10 Dynamic pressure profile with depth when is minimum required flow rate applied

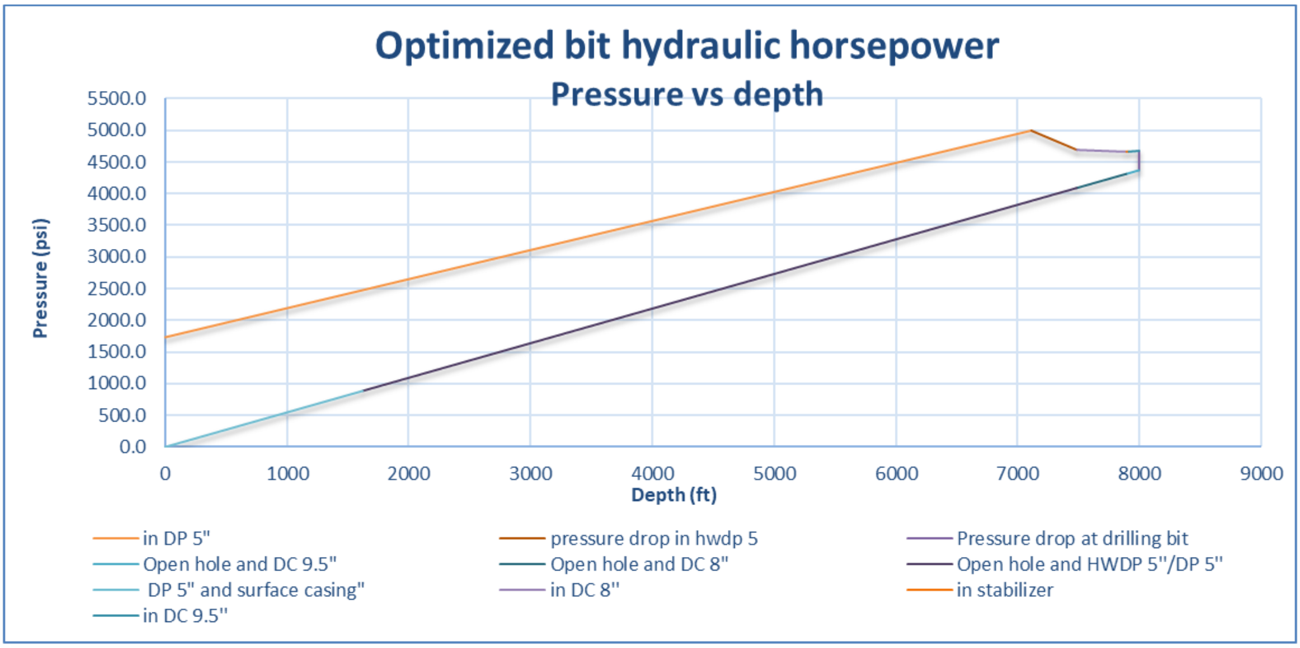


Figure 5.11 Dynamic pressure profile with depth when is optimized bit hydraulic horsepower

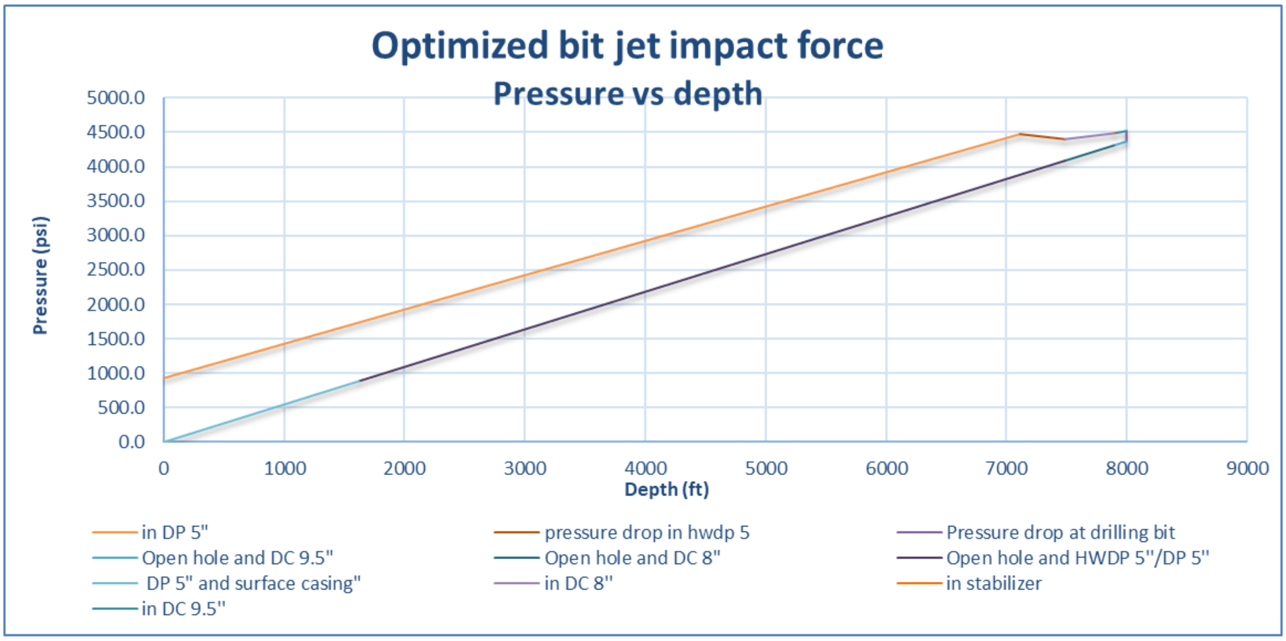


Figure 5.12 Dynamic pressure profile with depth when is optimized jet impact force power

5.5. Fifth stage

In this stage, a 12 1/4’’ hole for the installation of production casing will be drilled. Methodology described in the Chapter 4 and rheological model for Bingham fluids that are oil-based mud will give the results that are presented in Table 5.5.

Table 5.5 Results for fifth stage

	Mud pump flow rate (gpm)	Pressure loss due to friction (psi)	Pressure drop at the bit (psi)	Velocity at the bit nozzles (ft/s)	Jet Impact force (lbf)	Bit Hydraulic power (HP)	Pump pressure (psi)
Minimum required flow rate	189	306	24	39	67	3	330
Maximized Horsepower on the bit	479	1558	151	98	427	42	1709
Maximized Jet impact force	339	851	76	69	214	15	927

We can see that minimum required flow rate is 189 gpm and both criterions for optimization satisfy this condition. Thus, we can choose between these three options. We will choose to stay with minimal required flow rate because for deeper depths, the usual parameter for optimization is velocity on the bit nozzles which usually goes with the minimal flow rate. The pressure that the pump needs to deliver is 330 psi.

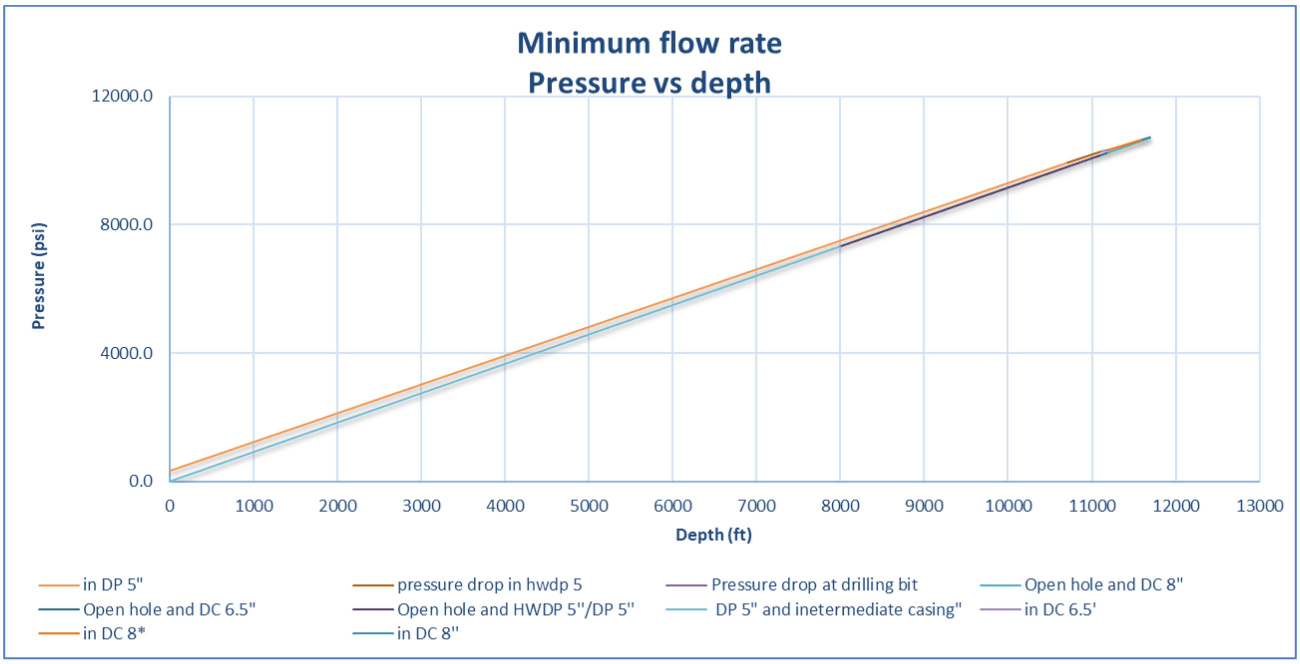


Figure 5.13 Dynamic pressure profile with depth when is minimum required flow rate applied

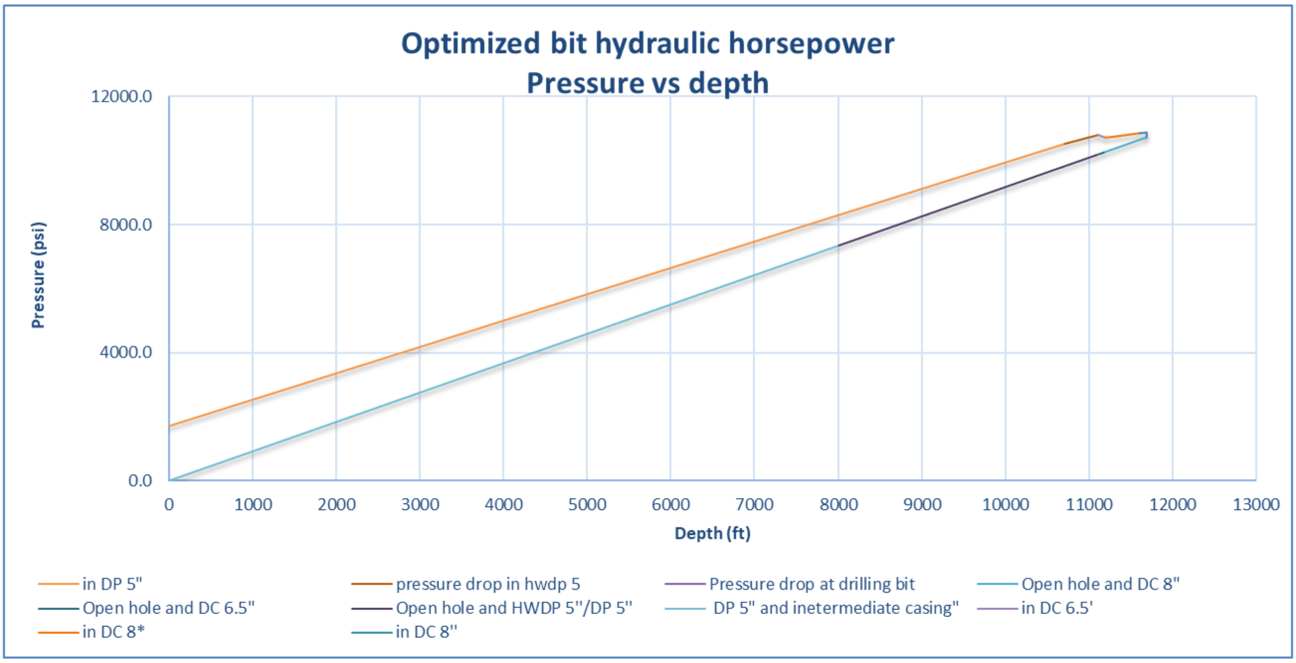


Figure 5.13 Dynamic pressure profile with depth when is optimized bit hydraulic horsepower

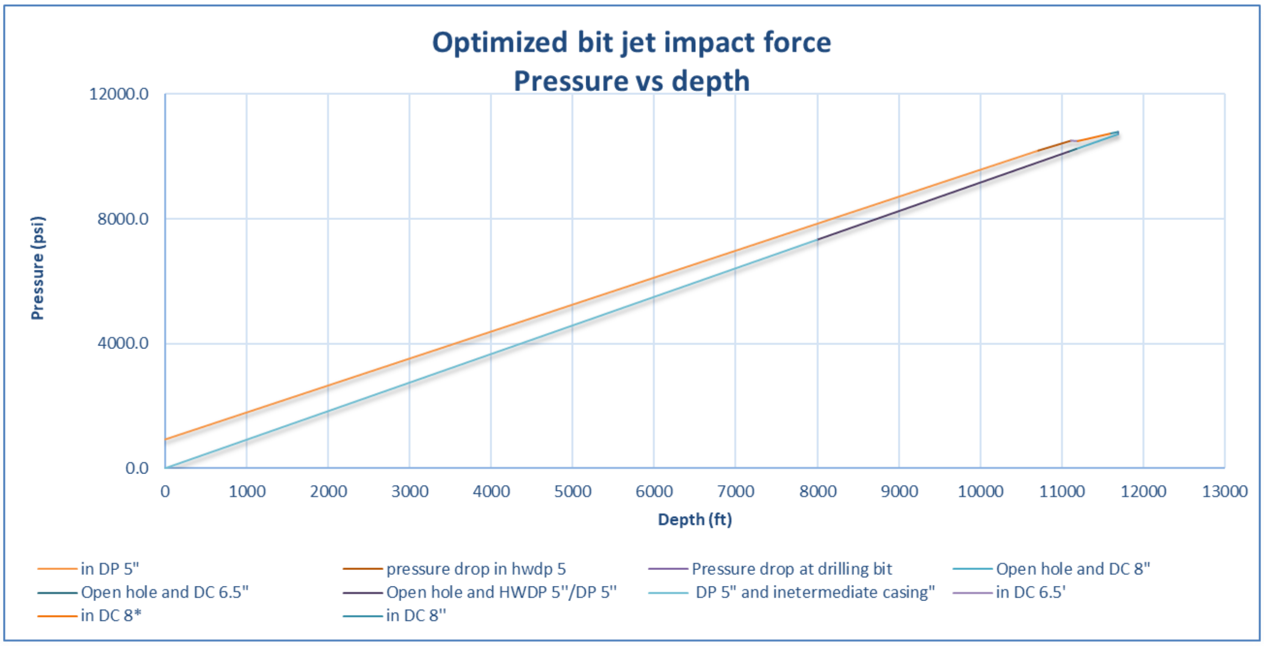


Figure 5.15 Dynamic pressure profile with depth when is optimized jet impact force power

5.6. Sixth stage

In this stage, an 8 1/2’’ hole for the installation of production liner will be drilled. Methodology described in the Chapter 4 and rheological model for oil-based Bingham fluids give us the results presented in Table 5.6.

Table 5.6 Results for sixth stage

	Mud pump flow rate (gpm)	Pressure loss due to friction (psi)	Pressure drop at the bit (psi)	Velocity at the bit nozzles (ft/s)	Jet Impact force (lbf)	Bit Hydraulic power (HP)	Pump pressure (psi)
Minimum required flow rate	210	2737	131	104	153	16	2868
Maximized Horsepower on the bit	215	2852	137	106	160	17	2989
Maximized Jet impact force	152	1563	68	75	80	6	1631

We can see that minimum required flow rate is 210 gpm and one criterion for optimization satisfy this condition. Hence, we can choose between these two options. Gain form hydrostatic pressure is 8855 psi as noticed in the Figures 5.16 ,5.17 and 5.18. We will go with minimal flow rate that needs to be satisfied, which according to that pump pressure should be 2868 psi.

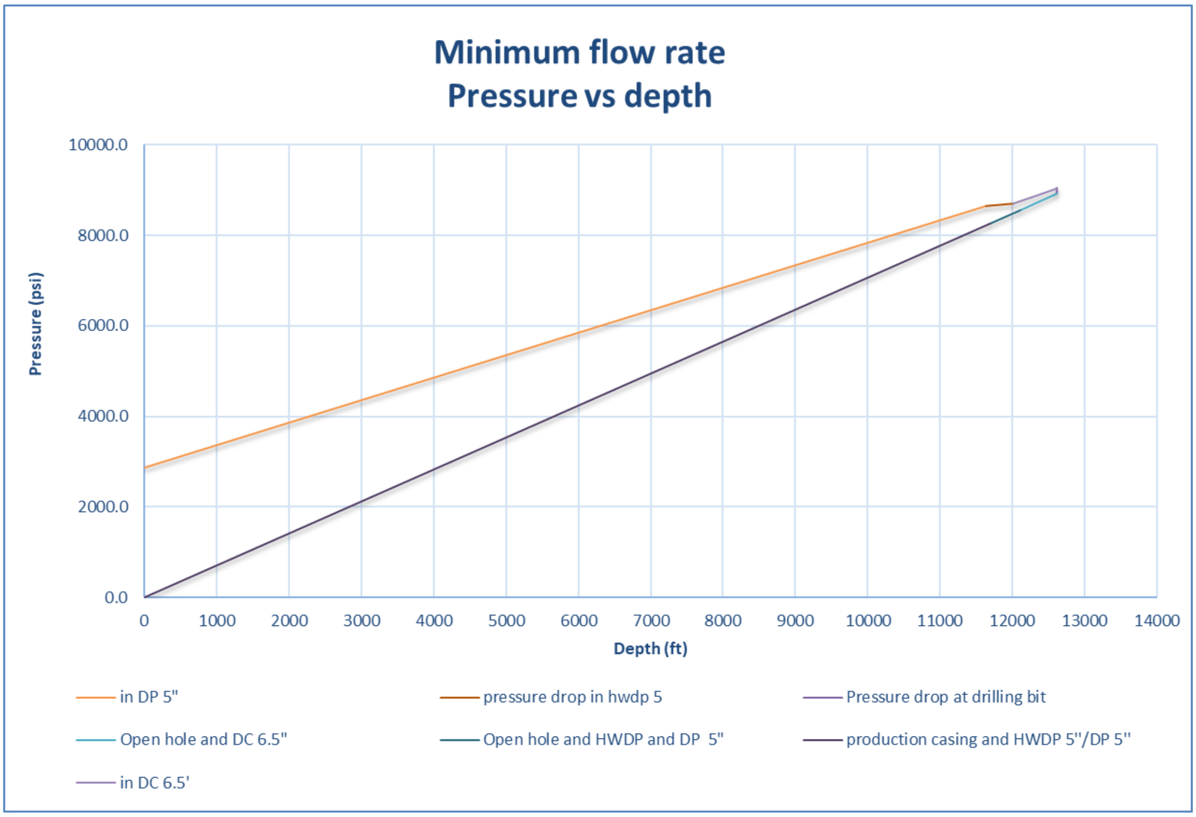


Figure 5.16 Dynamic pressure profile with depth when is minimum required flow rate applied

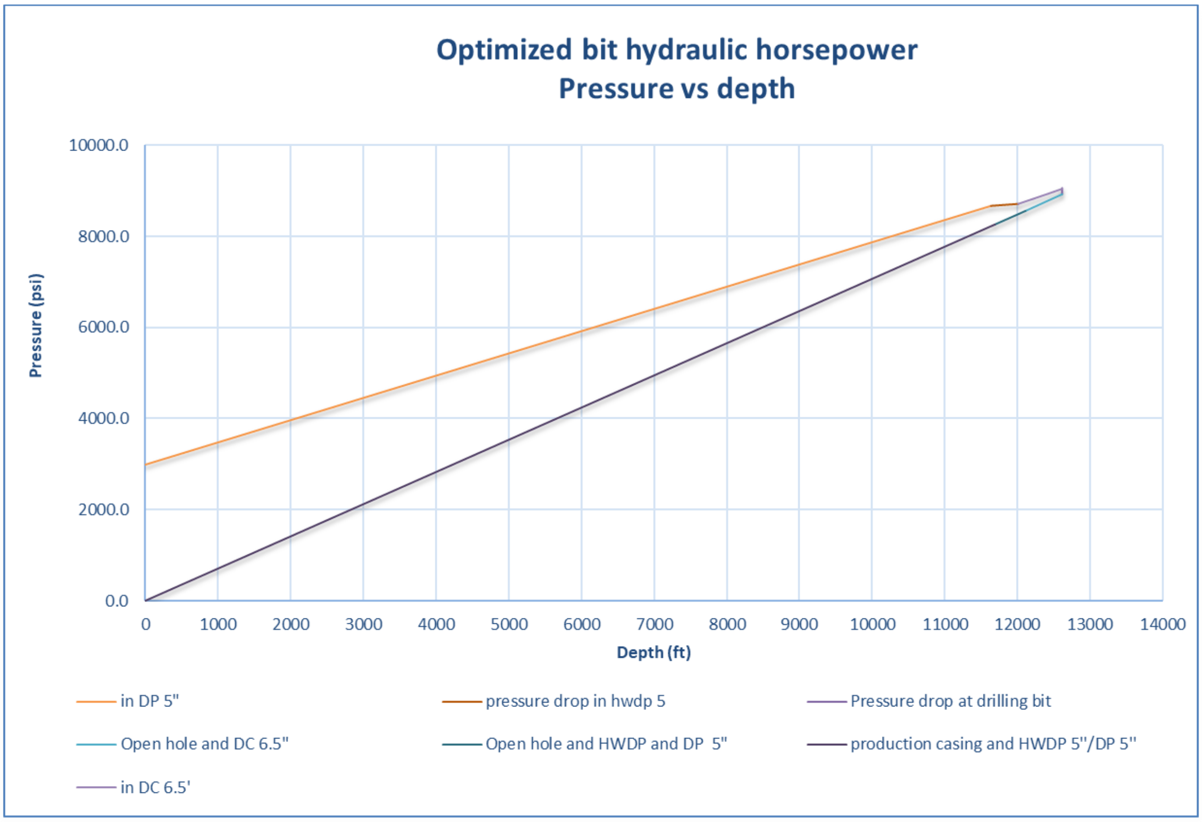


Figure 5.17 Dynamic pressure profile with depth when is optimized bit hydraulic horsepower

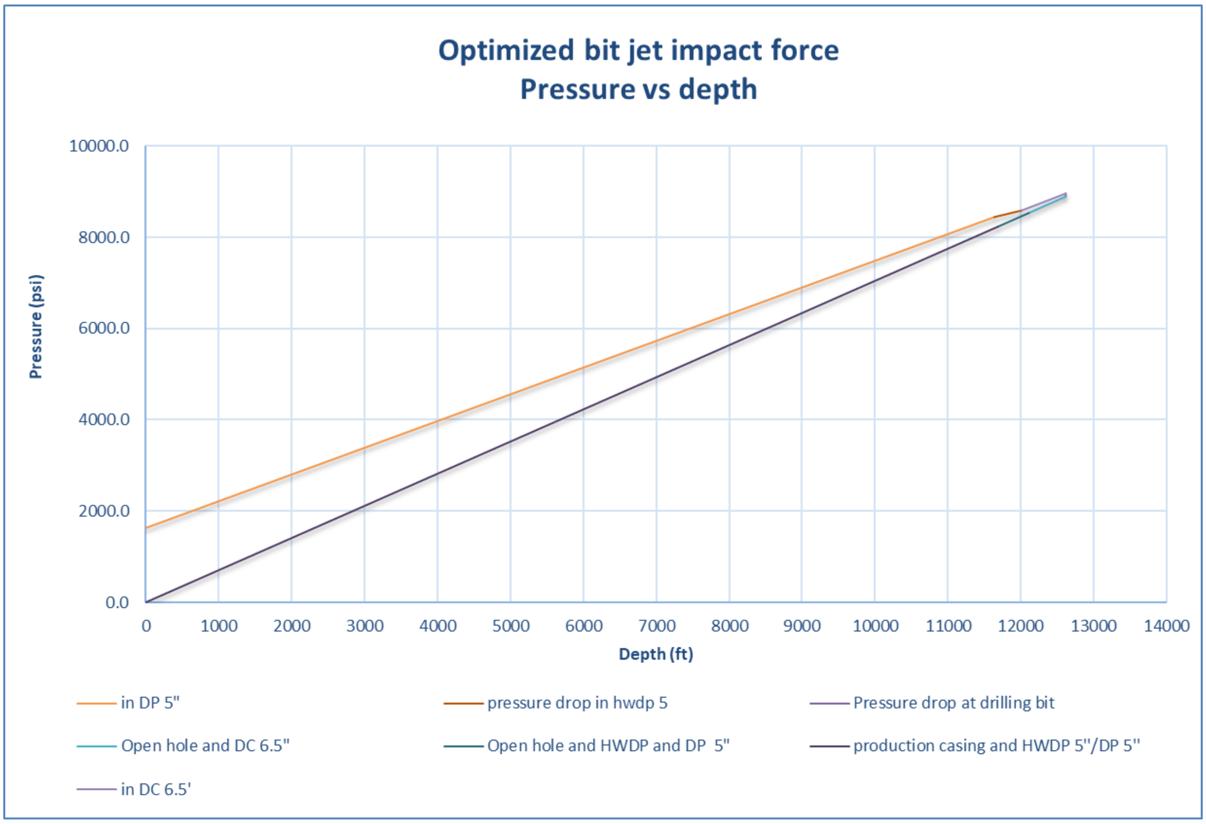


Figure 5.18 Dynamic pressure profile with depth when is optimized jet impact force power

5.7. Seventh stage

In this stage, a 6’’ hole for the installation of production liner will be drilled. Methodology described in the Chapter 4 and rheological model for oil-based Bingham fluids give the following results.

Table 5.7 Results for seventh stage

	Mud pump flow rate (gpm)	Pressure loss due to friction (psi)	Pressure drop at the bit (psi)	Velocity at the bit nozzles (ft/s)	Jet Impact force (lbf)	Bit Hydraulic power (HP)	Pump pressure (psi)
Minimum required flow rate	46	994	2	33	3	0.03	996
Maximized Horsepower on the bit	44	920	0.98	31	3	0.03	921
Maximized Jet impact force	31	501	0.48	22	1	0.01	502

We can see that minimum required flow rate is 46 gpm, and none of criterions for optimization satisfies this condition. Hence, we will take minimum fluid flow. Gain form hydrostatic pressure will be 9079 psi as noticed in figures 5.19 ,5.20 and 5. 21. The figures also show that the difference between pressure inside the pump and annulus is small because the bit pressure is minimal. We will go only with minimal flow rate that needs to be satisfied which according to that pump pressure should be 996 psi.

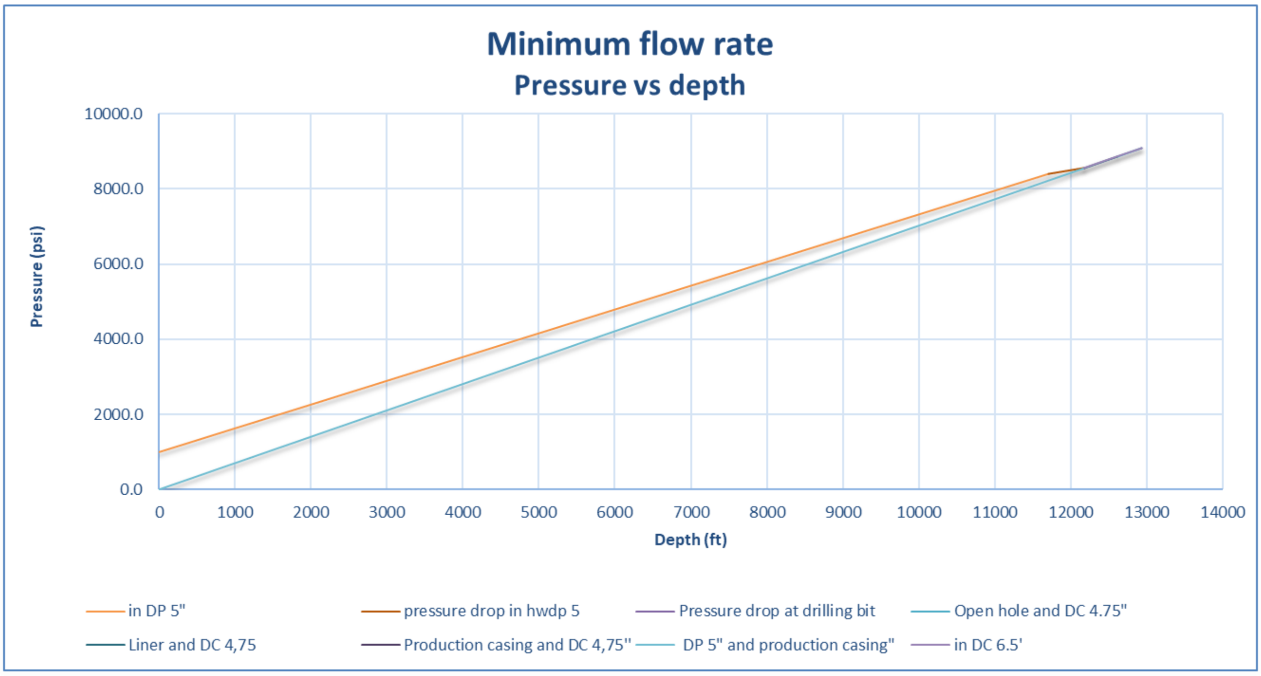


Figure 5.19 Dynamic pressure profile with depth when is minimum required flow rate applied

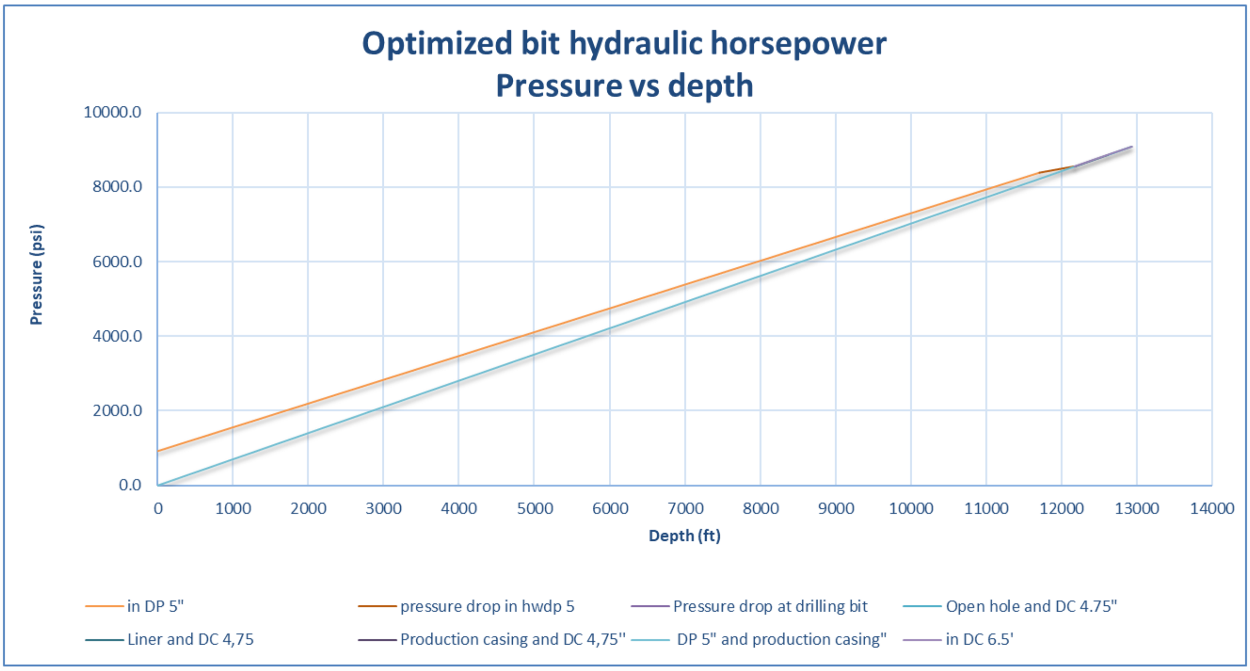


Figure 5.18 Dynamic pressure profile with depth when is optimized bit hydraulic horsepower

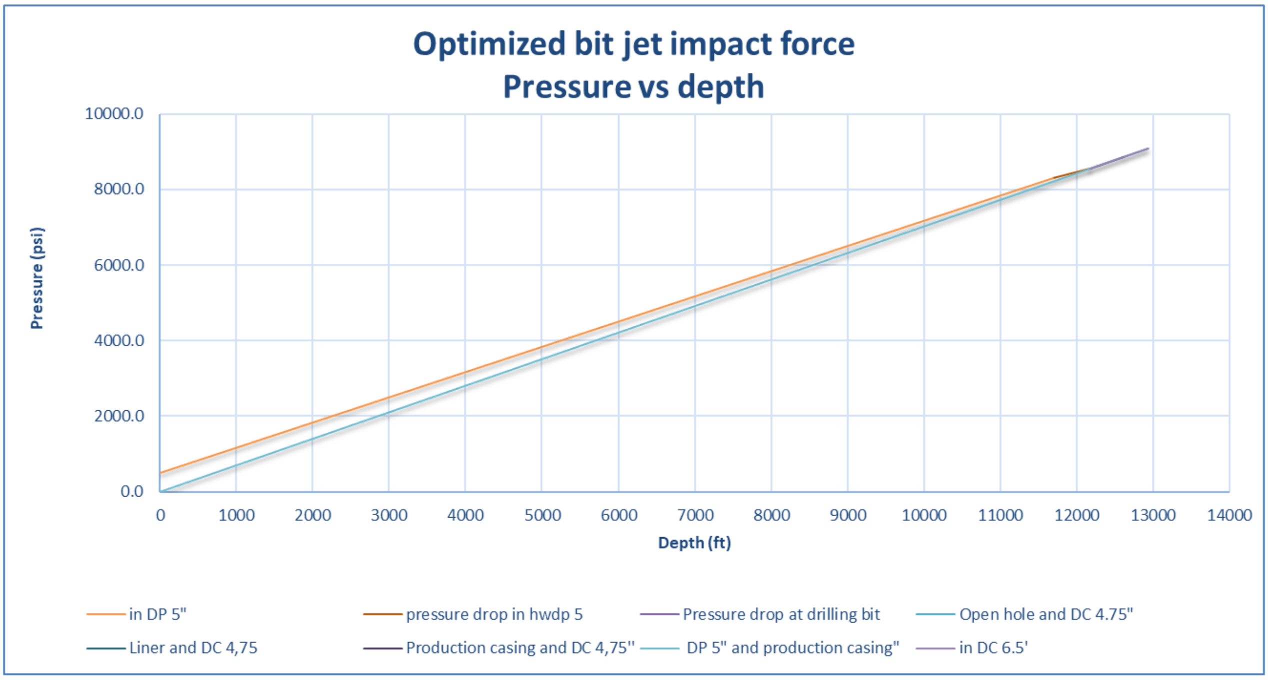


Figure 5.21 Dynamic pressure profile with depth when is optimized jet impact force power

5.8. Overall results

By the chosen program (Table 5.8) for the pump, we learn that we need to have a program strong enough to satisfy the demanded amounts of pressure. To drill this well, we will need the pumps that can provide us with a pressure of 2868 psi. The great amount is demanded due to the wellbore geometry, and the minimum velocity of fluid for cleaning the high well. Later, the hydrostatic pressure is on our side and pressure loss will decrease due to the lower flow rate. For the first stage, we will need high flow rate of 1590 gpm. At least three pumps will be on the drilling site, while one or two will operates, the other one will be for safety and precautions. I would suggest using triplex piston pump W – 3000 with 3000 HP market in the Table 5.9. for all other stages of drilling, adjusting the flow rate and pressure of the pump when needed. Whit the two pumps, the drilling can be completed without complications.

Table 5.8 Full requirements for pump to drill the well.

	Mud pump flow rate (gpm)	Pressure loss due to friction (psi)	Pressure drop at the bit (psi)	Velocity at the bit nozzles (ft/s)	Jet Impact force (lbf)	Bit Hydraulic power (HP)	Pump pressure (psi)
Stage 1	1590	689	1154	385	2759	1070	1843
Stage 2	1141	2131	324	202	1061	216	2455
Stage 3	753	1339	251	177	616	110	1590
Stage 4	407	819	162	131	291	39	981
Stage 5	189	306	24	39	67	3	330
Stage 6	210	2737	131	104	153	16	2868
Stage 7	46	994	2	33	3	0.03	996

Table 5.9 Technical data for triplex pump

W-3000 Triplex Piston Model – Continuous Duty Performance Data Stroke, in (mm): 16 (406.4) Gear Ratio: 4.36 Rated hp (kW): 3000 (2237) @ 100 Spm								
PUMP SPEED (Spm)			100	90	80	70	60	50
MAXIMUM INPUT HP (kW) rating[1]			3000 (2237)	2700 (2013)	2400 (1790)	2100 (1566)	1800 (1342)	1500 (1119)
LINER SIZE in (mm)	MAX DISCHARGE PRESSURE psi (kg/cm²)[3]	VOLUME/ STROKE gal (l) per revolution	OUTPUT gal(l)/min[2]					
9 (228.6)[3]	3501 (246.1)	13.219 (50.035)	1322 (5004)	1190 (4504)	1058 (4003)	925 (3503)	793 (3002)	661 (2502)
8-1/2 (215.9)	3925 (275.9)	11.791 (44.630)	1179 (4463)	1061 (4017)	943 (3571)	825 (3124)	707 (2678)	590 (2232)
8 (203.2)	4431 (311.5)	10.445 (39.533)	1044 (3954)	940 (3558)	836 (3163)	731 (2768)	627 (2372)	522 (1977)
7-1/2 (190.5)	5041 (354.4)	9.180 (34.746)	918 (3475)	826 (3127)	734 (2780)	643 (2432)	551 (2085)	459 (1737)
7 (177.8)	5787 (406.9)	7.997 (30.268)	800 (3027)	720 (2724)	640 (2422)	560 (2119)	480 (1816)	400 (1514)
6-1/2 (165.1)	6712 (471.9)	6.895 (26.098)	690 (2610)	621 (2349)	552 (2088)	483 (1827)	414 (1566)	345 (1305)
6 (152.4)	7500 (527.3)	5.875 (22.238)	588 (2224)	529 (2002)	470 (1779)	411 (1557)	353 (1334)	294 (1112)

[1]Based on 90% mechanical efficiency [2]Based on 100% volumetric efficiency [3]Requires special retention system; liner is induction-hardened, therefore liner life is reduced
All specifications are subject to change. Information important to a particular application should be verified by Cameron.

Chapter 6 Conclusion

The Pressure in the flow path is dependent on the type of fluid and regime of flow. Turbulent flow regime causes high pressure loss due to loss of friction. On the other hand, we have high pressure gain due to gravity; hydrostatic pressure grows with depth.

As mentioned earlier, the drilling design should be aimed at maximizing efficiency. Depending on the designed drilling bit there could be a big drop of pressure on the nozzles, that makes cleaning the well easier, but in turn the drill jet impact force, as well as the horsepower spent, would need to be optimized. Most of the time, hydraulic horsepower or maximum hydraulic impact force is a criterion for shallow to middle depth wells. While at deeper depths, maximum nozzle velocity must be evaluated. Optimized hydraulics lead to a reduce in cost; as it leads to a reduction of causes for future problems, and in turn lowering non-working time.

The model code for calculation used in creating a full flow path and designing the pump for this model, can be further applied to any well type modeling. Data necessary for calculating the hydraulics are wellbore geometry, BHA that will be used for drilling, drill bits, and the type of fluids that are going to be used.

References

1. Blasius, H., 1913. Das Aehnlichkeitsgesetz bei Reibungsvorgangen in Flussigkeiten. VDL Forsch,
2. Bourgoyne Jr., A.T., Millheim, K.K., Chenevert, M.E., Young Jr., F.S., 1986. Applied Drilling Engineering. SPE Textbook Series, Dallas
3. Boyun Guo, Gefei Liu, 2011. Applied Drilling Circulation Systems Hydraulics, Calculations, And Models, Elsevier Inc
4. Chien, S.F., 1971. Annular velocity for rotary drilling operations. Proceedings of the 5th SPE Conference on Drilling and Rock Mechanics,
5. Colebrook, C.F., 1938. Turbulent flow in pipes, with particular reference to the transition region between the smooth and rough pipe laws. JICE
6. EXLOG, 1985.Theory and aplications of drilling fluid hydraulics, EXLOG Series of Petroleum Geology and Engineering Handbooks
7. Pal Skalle, 2012. Drilling Fluid Engineering, Ventus Publishing ApS
8. Paul Anawe, Adewale Folayan, 2018., Advance in Drilling Fluids Rheology, LAP LAMBERT Academic Publishing
9. Renato Bizjak, 2004. Tehnologija Bušenja sa Projektovanjem
10. Robert F. Mitchell, Stefan Z. Miska, 2001. Fundamentals of Drilling Engineering, SPE Textbook Series