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Abstract

Over the last few years the petroleum industry have experienced a drastically increase in drilling costs. At the same time the oil prize has been highly unstable resulting in an increased focus on reducing drilling costs.

The aim of this thesis is to look for cost reducing measures when drilling in hard rock formations offshore. Drilling in hard formations is both challenging and time consuming as a consequence of Low Rate of Penetration (ROP) and high None Productive Time (NPT). Typically hard rock stones encountered offshore are limestone, basalt, chart and chalk which for instance can be found in the NCS, on Iceland and offshore Faroe Islands.

This thesis presents:

- The status of the current drilling technologies and its potential while identifying the current problems experienced when drilling in hard rocks.
- Mitigation for hard rock drilling problems
- Development of a procedure that can be used for planning wells offshore with aim to reduce cost
- Case study of the procedure with a well from the NCS

The developed procedure is based on analysis of old well and when planning new well. By doing this, one can implement percussive drilling along with rotary to increase ROP and reduce NPT, and reduce the overall drilling operational cost.

The result from the case study indicates a cost reduction of 18,8% when implementing percussive drilling. Due to several assumptions more detailed research is required before percussive drilling can be concluded as a solution.

Acknowledgement

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Kjetil Omdal

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Acronyms

BHA – Bottom Hole Assembly

DTH – Down The Hole

EGS – Enhanced Geothermal Systems

HC – Hydrocarbons

HMSE – Hydraulic Mechanical Specific Energy, MPa

HPHT – High Pressure High Temperature

IRIS – International Research Institute of Stavanger

LWD – Logging While Drilling

MPD – Managed Pressure Drilling

MSE – Mechanical Specific Energy, MPa

MT – Milled Tooth

MWD – Measure While Drilling

NPT – None Productive Time

NPD – Norwegian Petroleum Department

PARD – Percussive Assisted Rotary Drilling

PDC – Polycrystalline Diamond Compact

RC – Roller Cone

ROP — Rate Of Penetration, ft/hr

RPM — Rounds Per Minute

RPS – Rotary Percussion System

TCI – Tungsten Carbide Insert

UBD – Underbalanced Drilling

UCS — Unconfined Compressive Strength, Mpa

UiS – University of Stavanger

WOB — Wait on Bit, lbs

WOW – Wait on Weather

List of symbols

A_b = bit surface area, inches

a_j = constant

D = Diameter, inches

D = Depth, feet

d_b = diameter of bit, inches

d_n = Nozzle diameter, inches

dt = time interval, seconds

g_p = Pore pressure gradient of formation, ppg

H = height, ft

$H_1 = H_2 = H_3$ = constants

$k_1 = k_2 = k_3$ = constants

$J_1 = J_2$ = a function of bit weight per inch and rotary speed

N = Rotary speed, Rounds per Minute

P_b = Pressure drop across the bit, psi

Q = flow rate, gallons per minute

q = discharge, gal

x_j = drilling parameter

T = Torque, $lbs * ft$

T = time, hr

t_b = drilling time, hr

Δt_c = travel time, µs/ft

t_w = The fractional teeth heigh that has been worn away

V_p = Velocity, km/s

$(\frac{W}{d_b})_t$ = Threshold WOB per inch of bit diameter

$\frac{dh}{dt}$ = Rate of penetration, ft/hr

$\left(\frac{w}{d}\right)$ = WOB per inch of diameter, 1000 lb/in

ρ_c = Equivalent circulating mud density, ppg

ρ_m = Mud density, ppg

η = dummy factor for energy reduction, dimentionless

ρ = density, kg/m^3

μ = Apparent viscosity at 10000 sec^{-1}, cp

μ_p = Plastic viscosity, cp

τ_H = abrasivity, dimentionless

1 Introduction

This thesis deals with technology for drilling in hard and soft formation. The main focus is the application of percussive drilling with respect to soft to hard formation. The first part focuses on theory for different drilling technologies and address problems related to drilling in soft and hard formation.

Examples of hard rock drilling problems are vibrations, bit wear, bit damage or stuck pipe. This thesis will keep a main focus on vibrations, it`s effect and mitigation while other drilling related problems will be briefly explained. Vibration is one large side effect when drilling in hard formations and is important to control.

For determining if implementing percussive drilling will be economical feasible, a procedure will be developed including analysis of hardness, ROP and cost. The idea is to use drilling data from an old well when planning a new neighbor well and study the effect when implementing percussive drilling. The hardness of the formation will be categorized and analyzed. Based on the hardness it will be decided if percussive drilling can be implemented. ROP will be analyzed to check if it`s optimized and a proposed ROP optimization method will be presented. When ROP has been optimized it will function as input data when performing cost analysis. Risk€, a cost analysis program develop by International Research Institute of Stavanger (IRIS), will be used for estimating cost. Several scenarios will be analyzed comparing how rotary and percussive can be combined in hard formation to find the most efficient combination. The result will give an indication if percussive drilling should be implemented or not.

1.1 BACKGROUND

The background for this thesis is hard rock drilling where percussive drilling is the preferred drilling technique. Percussive drilling is today mostly used for drilling shallow wells, geothermal wells, coal mines and in the water industry.

The world has a constantly increasing demand of energy. To meet the demand, new energy sources are required. One solution could be geothermal energy.

Geothermal energy potential in Norway

For a geothermal well to function it needs a temperature of at least 50 °C. Lower temperatures will result in low productivity. The ultimate geothermal window is achieved when water is at supercritical conditions, above 374 °C and 220 bar. Reaching temperatures above 200 °C usually requires a depth of more than 5000 meters. Figure 1 shows the potential for geothermal energy in Norway. As can be seen from Figure1 the best potential is achieved south in Norway, from Bergen in west to Oslo in east. As example there are several mini geothermal wells in Norway designed for heating up single households, especially in Oslo [1] [2].

IRIS, in cooperation with Z-Energy and Bakke, recently started a geothermal project south-west in Norway at Ålgard, just outside Stavanger. The goal for the project is to find temperatures above 100 °C which could be a future energy source for the local community. The well will be the deepest land well in Norway, with 5700 meters [3].

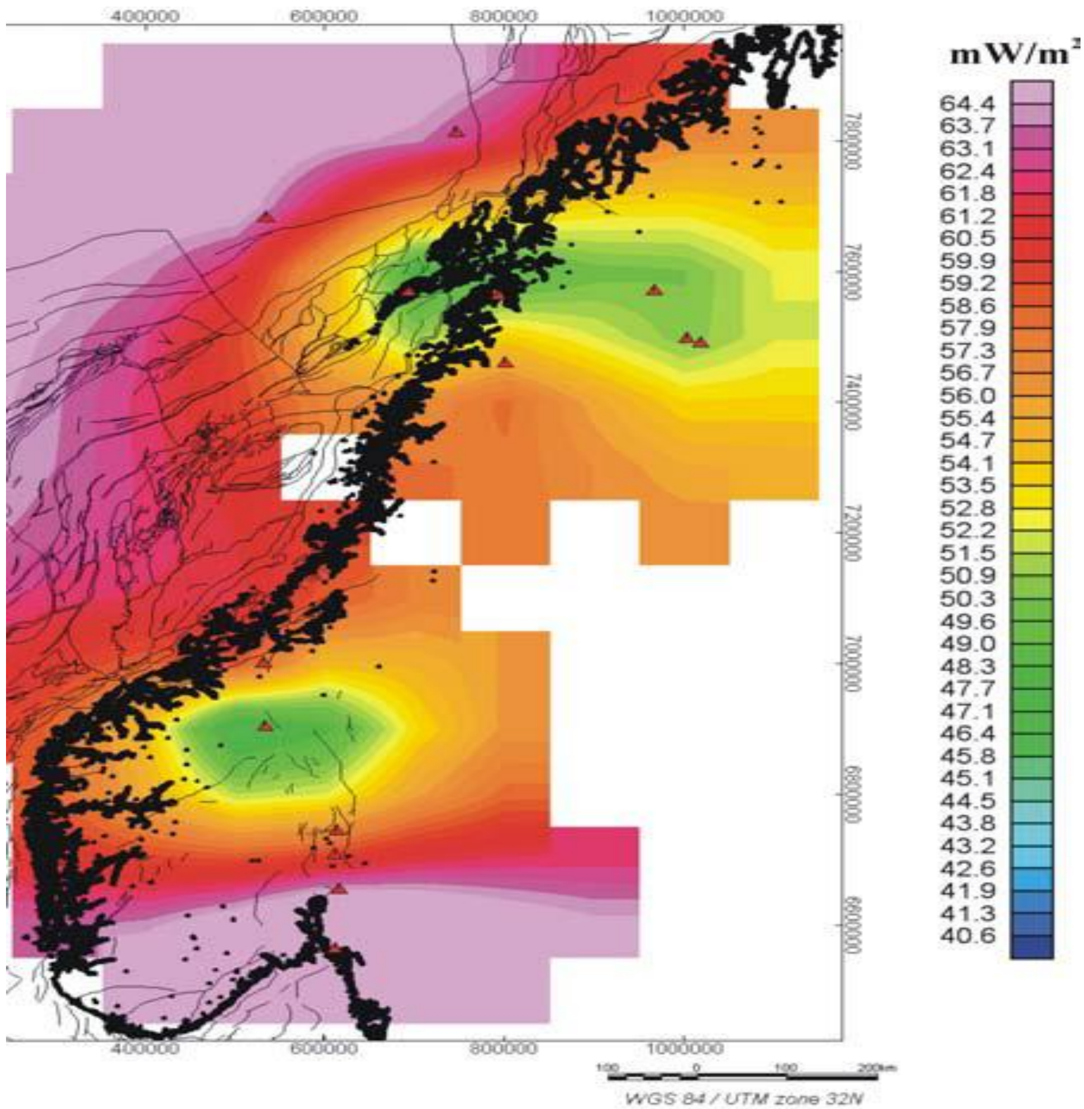


Figure 1— Overview over the geothermal potential in Norway [2].

There are two kinds of geothermal energy, hydrothermal and enhanced geothermal system (EGS). The most common is hydrothermal, also known as "conventional geothermal source". Hydrothermal energy is hot fluid trapped within a reservoir rock, preferably with high porosity and a high geothermal gradient. A geothermal source requires proper permeability, decent porosity, a high geothermal gradient and liquid. EGS is similar to hydrothermal system, but lacking one of the mentioned requirements.

There are two sources for heating up the reservoir rocks:

- Heat stored in the Earth`s mantle and core from making of the Earth
- Radioactive heat engendered from uranium and thorium being degraded

The thermal energy can be determined by looking at the conductive and convective systems which reveals the quality of the reservoir. Igneous intrusion can increase the normal heat flow but only locally. The availability of the geothermal resource is important to study for checking the economical outcome. This can be done by studying the drilling program and the reservoir quality. The reservoir needs to fill certain requirements, like containing hot fluid and being able to re-heat the reservoir fluid quickly. If these requirements are not met the production rates makes it uneconomical [4] [5] [6].

To extract the geothermal energy to surface it is required a geothermal plant, as can be seen in Figure 2 below.

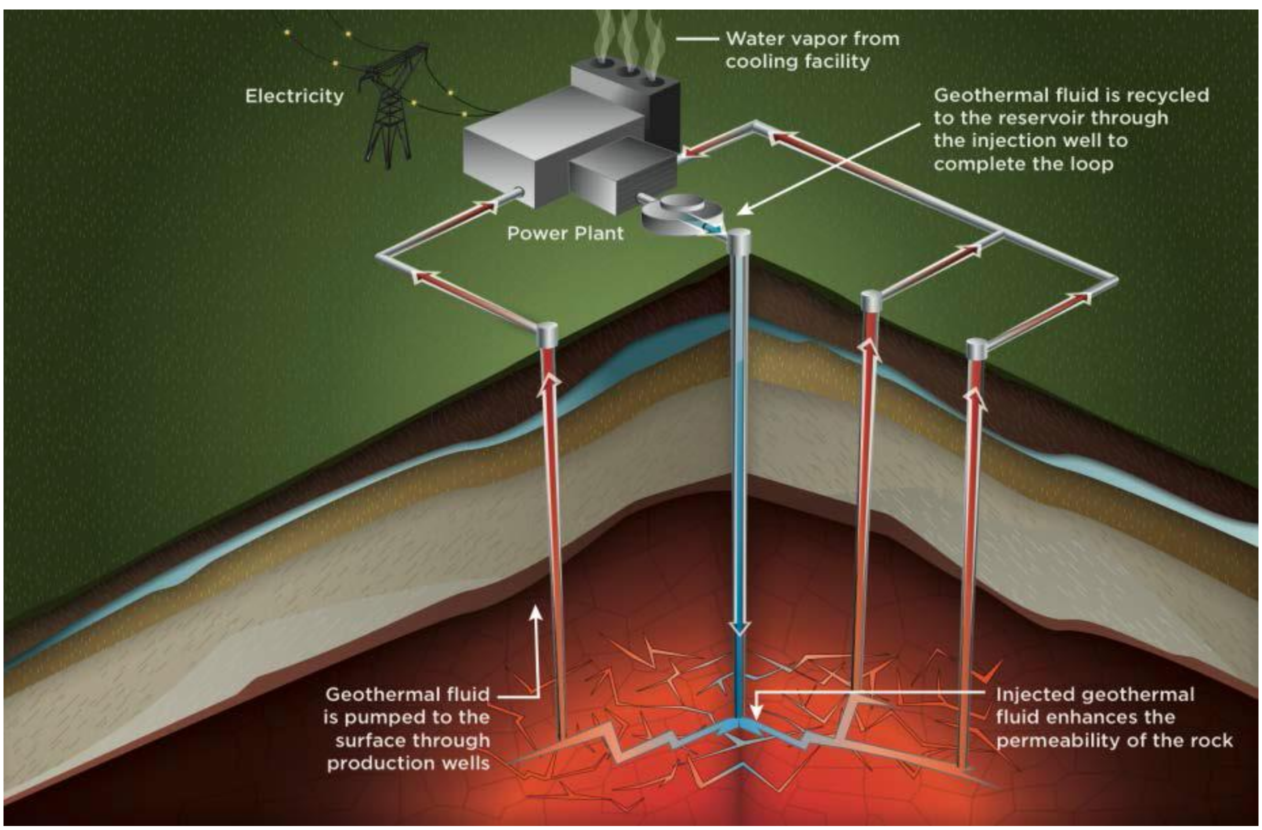


Figure 2 —Overview of a geothermal plant [5].

In the scenario in Figure 2, one injection well and three production wells has been drilled. Cold fluid is injected from the injection well into the reservoir. The cold liquid is heated up due to the geothermal gradient and is able to migrate due to high porosity and permeability. The production wells pumps the hot fluid up into the power plan where energy is extracted and electricity generated. The cold fluid is then re-injected into the reservoir.

There are two important criteria's for a geothermal well to function properly; good communication (permeability) and a high geothermal gradient. If the communication is low, the productivity is low. The communication can be increased with two methods, acid stimulation and fracturing. Acid stimulation is injecting chemicals in the reservoir to increase permeability, while fracturing means applying high pressure to fracture the formation resulting in better communication. To achieve high geothermal gradient this usually means drilling deep. Low geothermal gradient results in less hot reservoir fluid, reducing productivity.

One difference between drilling a geothermal and petroleum is that while a petroleum reservoir usually is located in sedimentary rocks, a geothermal reservoir is located in igneous or metamorphic rocks. Igneous and metamorphic rocks have a higher hardness than sedimentary rocks and are consequently harder to drill. Lower ROP and increased bit wear are some of the new problems encountered. Seeing as the reservoirs are located at deep wells, this also causes extra expenses. Figure 3 shows a typically cost-depth relation regarding drilling. Another difference between geothermal and hydrocarbon reservoirs is that geothermal wells are more monolithic than hydrocarbon wells because oil and gas reservoirs requires layered varieties to form [7].

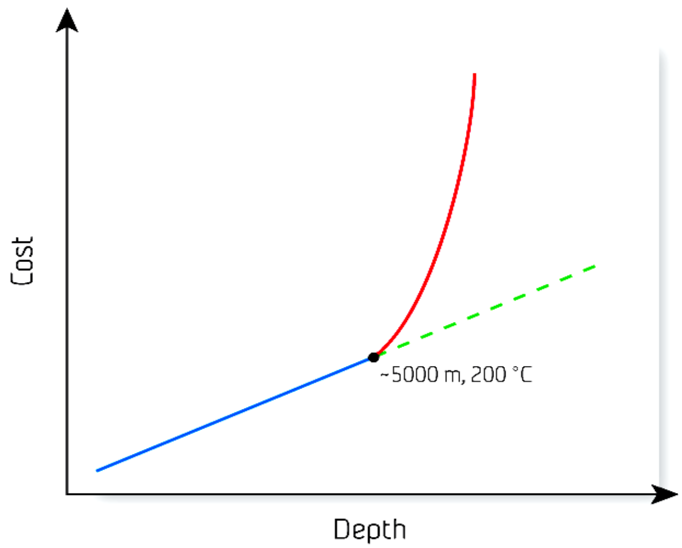


Figure 3 — Overview over drilling costs vs depth [2].

As seen from the figure, cost is constant until reaching 5000 meter. After this depth the formation tends to be harder and ductile, making it more challenging to drill.

Geothermal has some challenges regarding future investments of geothermal energy. Drilling the geothermal wells adds up to most of the costs related to developing a geothermal plant. New technology is required for equipment and electronic devices to better handle the high temperatures and pressures they are exposed to at reservoir depths, and thus reducing the drilling costs [2].

1.2 PROBLEM FORMULATION

The objective in this thesis is based on the project "NextDrill" by SINTEF with IRIS as research partner. "NextDrill" is a knowledge-building project between SINTEF and the Norwegian oil industry aimed to increase the knowledge of hard rock drilling by "*numerical-experimental technology platforms for cost effective deep hard rock drilling"* [8]. This thesis addresses issues such as:

- Common drilling technologies
- Application area for the drilling technologies
- Drilling related challenges and mitigation
- Limitations regarding usage of percussive
- ROP sensitivity
- Costs related to drilling and offshore environment
- How to determine hardness of the formation
- Evaluation and optimization of ROP
- Cost simulations when implementing percussive drilling

1.3 OBJECTIVE

The main objective for this thesis will be to investigate if percussive drilling is economical feasible for offshore operation. The thesis will start by explaining which drilling method is most common offshore today, functionality and application area for percussive drilling and the main challenges related to hard rock drilling.

To decide if implementing percussive drilling will be economical feasible, a procedure will be developed consisting of several credentials needed to be fulfilled. The credentials are related to rock hardness, efficiency, sensitivity and costs. The procedure will then be executed with input data from one well from the NCS, assuming that a new neighbor well is to be drilled. The outcome of the cost analysis will be categorized as the main result.
Main objective can be listed to:

- Study different drilling techniques
- Study challenges related to hard rock drilling
- How to determine if percussive drilling should be implemented
- Study ROP and how it can be optimized
- How cost will be affected by implementing percussive drilling

2 Drilling technologies

Drilling can be described as a process of making a circular hole in the Earth's crust. The hole is drilled by giving energy to a bit from a driving mechanism from the surface through a string. A bottom hole assembly (BHA) is placed above the bit to be able to steer the bit to planned target. In the energy business, drilling technology is used to reach source of hydrocarbons (HC) and geothermal energy. There are several types of drilling technologies and selecting the right technology is important for reducing cost by optimizing efficiency. This chapter will focus on describing two drilling technologies along with indicating some typically drilling related problems and limitations.

2.1 SELECTING RIGHT TECHNOLOGY

This thesis will focus on describing rotary and percussive drilling which are the two most common drilling technologies used in the energy business. As a rule of thumb, rotary drilling is suitable for drilling in soft to hard formations, while percussive drilling is suited for medium-hard to very hard formations. The main difference is that rotary drilling slices the formation, while percussive drilling hammers the formation.

When selecting right drilling technology there are a few important parameters to study:

- Compressional strength or hardness of formation
- Pressure in formation
- Temperature in the hole
- Depth of hole
- Alternating formation, stringers

<u>Hardness:</u>

The hardness of a rock can be found by calculating the Unconfined Compressive Strength (UCS) value of the formation. If a rock is classified as hard or very hard this will result in low ROP, increased bit wear and bit damage and higher vibration. Low ROP reduces efficiency, high bit wear and bit damage can result in problems as under gauge borehole, fishing operation and time consuming tripping operations while vibrations can damage down hole equipment and borehole. More energy required also causes increased temperature. The rocks abrasiveness along with the hardness will affect the bit wear and bit damage. Hardness will be more detailed described in chapter 3.2.2.

Pressure:

The downhole pressure will affect how rock behaves. The confined compressive strength is a rock`s strength while under pressure from a confined medium. When a rock is exposed to pressure, it displays an increasing strengthening effect, called the confinement effect [9].

Temperature:

When drilling in high temperature environments, the high temperature can cause electronic devices to malfunction. High temperatures cause the formation to be more ductile giving reduced ROP. Lack of lubricating the bit also increases the probability for bit damage.

Depth:

The depth is of great importance as pressure and temperature normally increase with depth. The depth effect especially evolves when drilling geothermal wells, as the hot reservoir liquid is located at deep depths. It will also be more time consuming when problems occur in a deep well as the tripping time will increase drastically.

Alternation Environment:

Lastly it is important to detect alternation environment, also known as stringers. Alternation environment alternates between soft and hard formation and is more challenging to drill and requires right drilling technology. Alternation environment will affect ROP and can cause problems like wash out, stuck pipe and vibrations.

2.2 ROTARY DRILLING

Rotary drilling is based on rotating the bit with an applied Wait on Bit (WOB). The inserts on the bit rotate, while slicing or crushing the formation into pieces. The bit has small nozzles where drilling mud enters the borehole for cooling and lubrication of the bit and cutting transport. Rotary drilling is suited for drilling in most types of formation, ranging from soft to hard rocks. It is also the most common drilling technique in the oil and gas industry offshore on the NCS.

Steering in rotary can be done in two ways, “point-the-bit” or “push-the-bit”. Point-the-bit cause a direction change by bending the main shaft. With push-the-bit the direction change is caused by pads placed outside the tool which press in the opposite direction resulting in a direction change [10].

When using rotary drilling, there are several types of bits that can be used. The bit is located at the end of the BHA and is the tool that slices and crushes the formation. Because of its vital function it is important to choose the right bit type, as a wrong bit will reduce efficiency of the drilling operation.

Some parameters to keep in mind before selecting bit are: [11]

- Keep cost pr. feet as low as possible
- Minimize the need for tripping operations
- Operate with stable conditions and keeping the vibration to a minimum with planned drilling parameters.
- Strength of section to be drilled

2.2.1 Drill bit types

There are several types of bits in the industry designed for different types of formation. Some are best suited for soft formations, some for hard formations and some for alternating formation. There are mainly four types of drilling bits used in rotary drilling, roller-cone (RC), fixed-cutter bits, hybrid bits which is a combination of RC and fixed and lastly, diamond bits. Due to high increase in drilling costs, the drill bit technology has improved greatly over the past few years and an example is the hybrid bit which recently entered the marked. The overall motivation is to increase ROP and NPT.

The bits are fitted with different inserts, or buttons. The buttons can be designed in many different ways depending on how the bit should behave. Figure 4 illustrates three different button types and their characteristics used when designing RC bit.

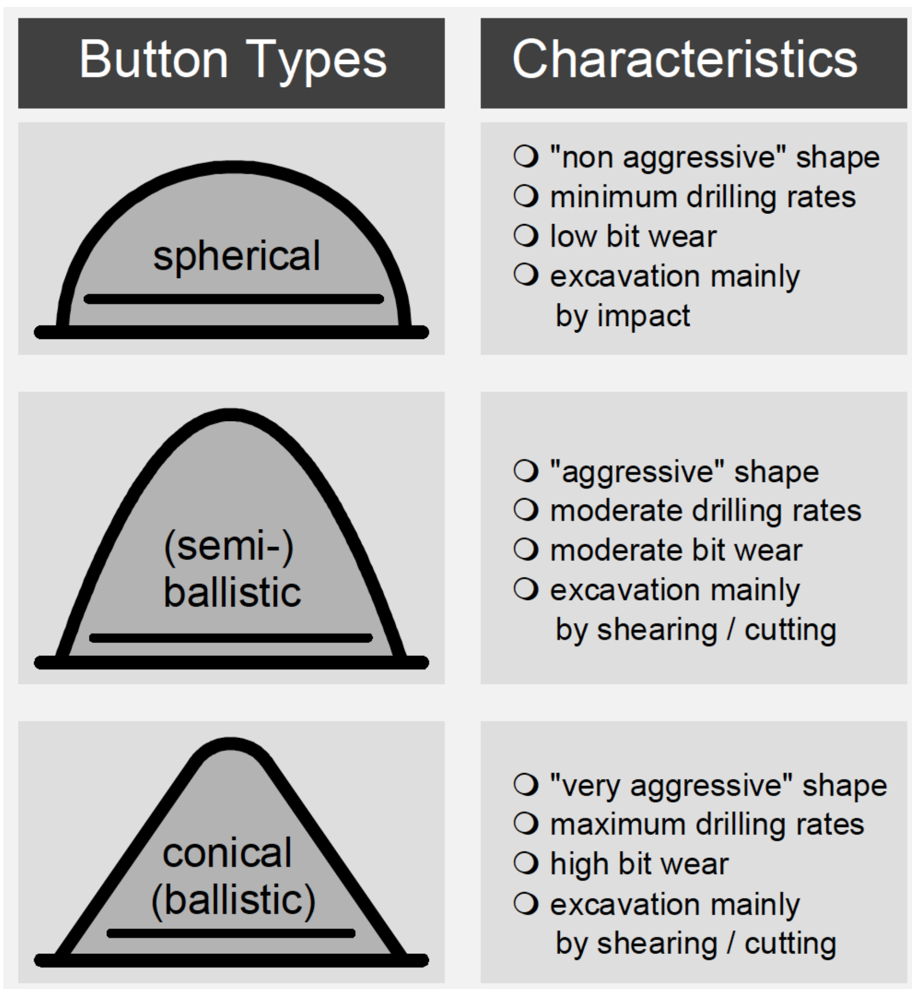


Figure 4 — Overview over RC button types and characteristics [12].

The button types can also be designed with different types of materials depending on what type of formation is to be drilled. For very hard formations tungsten carbide buttons are most common.

2.2.2 Roller Cone (RC) bit

The most used bit globally is the RC bit. It can be divided into two categories; tungsten carbide inserts (TCI) and milled tooth (MT).

The difference between TCI and MT is that a TCI design has inserts placed into the bit, while a MT design has steel teeth pre milled and covered by a protective hard face. The bit can be designed with several types of inserts and materials, and can therefore be used in most types of soft to hard formations. A typically RC bit design is shown in Figure 5.

Figure 5 — Shows a tri-cone bit [13].

The RC bit design consists of cones, bearings and a body. The most common type has three cones and is called a tri-cone. The cones are connected to bearings which are a fragile part of the bit. If exposed to high force and vibration, the bearings can come lose or teeth can break or become lose and lost

Advantages using RC is that it can be used in both soft and very hard formation, it is cheaper compared to fixed-cutter bits, has lower torque and good steerability. Drawbacks are that the teeth's or cones can come loose, caused by axial and lateral vibrations [2] [14].

2.2.3 Fixed-cutter bit

The most common fixed-cutter bit is the Polycrystalline Diamond Compact (PDC) bit. The PDC bit does not crush the rock, but slices it into pieces when WOB and rotation is present.

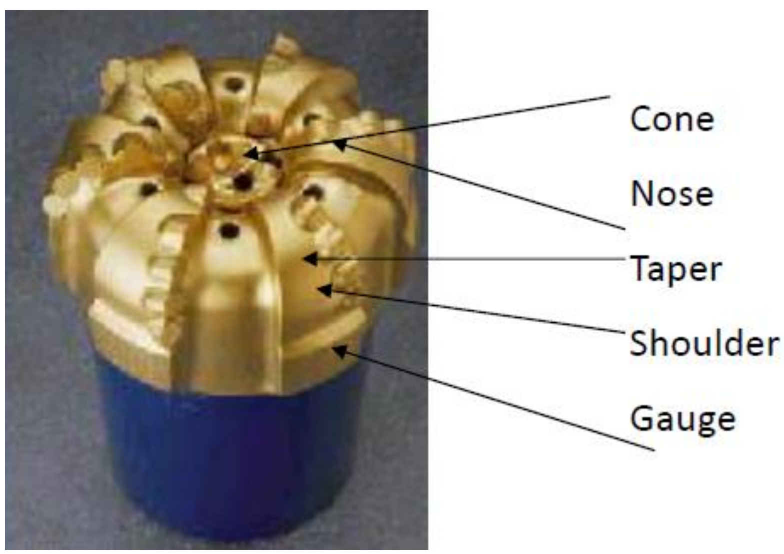
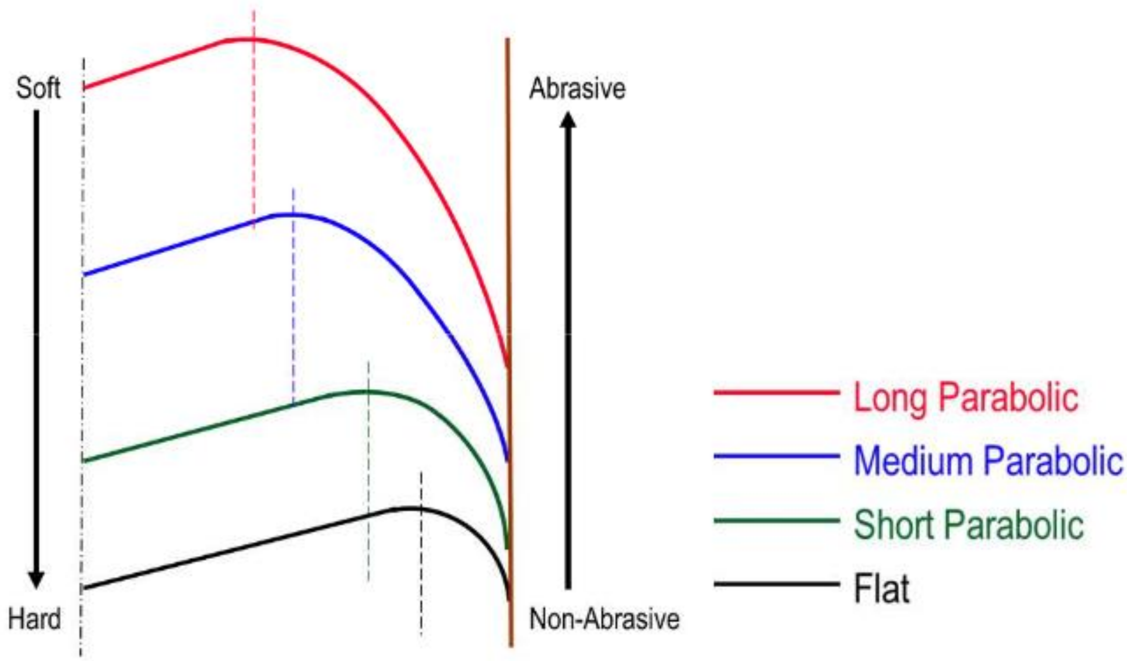


Figure 6 — Shows a detailed description of a PDC bit [14].

Compared to RC, PDC has no rotating cones. The inserts are placed at the short edge of the tapers, see Figure 6. The inserts are placed with a certain angle, depending on how aggressive the design should be. The gauge protector makes sure the bit is drilling the wanted borehole size. A PDC bit usually has between 3-8 nozzles depending on the design. On a generally basis

PDC has a wide range of different designs, depending on the application area. An example of how to design PDC bit is shown below in Figure 7.



(With courtesy to Smith Drill Bits, Houston)

Figure 7 — Describes the relations between PDC bit design and formation hardness [14].

Studying the figure reveals that long parabolic design is suited for soft and abrasive formations, while a flat design is best for hard and non-abrasive formation. PDC bits are suited for drilling in soft to medium-hard formations, has a high average ROP and is more robust than RC. Drawback with PDC is that the design of the cutters is very sensitive. To aggressive cutters will increase lateral vibrations while to passive cutters will reduce ROP and make the bit unstable. It is not applicable to be used in very hard and abrasive formations.

2.2.4 Natural diamond bit

Diamond bits are suited for drilling in soft to medium-hard formation. The concept behind diamond bit is that when the diamonds wear out, a new diamond will appear below increasing the expected life time of the bit. Diamond bits have high resistance for abrasive and erosive wear. Diamond bits are much more expensive than PDC and rotary, and performing cost analyses before choosing diamond bit is crucial. A typically diamond design is shown in Figure 8 below [14] [15].

Figure 8 — Shows a typically diamond bit design [16].

Turbine drilling, which provides high RPM and reliability, can be combined with PDC or diamond for achieving optimum drilling efficiency. By using turbine drilling, the mechanical horsepower and speed can help increasing ROP in hard rock formations.

2.2.5 Hybrid bit

Hybrid bit was invented to reduce drilling costs. The hybrid is a combination of RC and PDC, and is designed to drill in hard and alternation formations. The bit has three cones, like the RC bit, but is also equipped with cutter inserts like the PDC. The hybrid bit can also be designed in many different ways depending on the formation. Figure 9 shows a hybrid design.

Figure 9 — Shows a typically hybrid bit design [14].

Advantages using hybrid bit is less vibration, higher average ROP, better toolface control and improved torque control [14] [15].

2.3 PERCUSSIVE DRILLING

Percussive drilling is based on raising and lowering the bit with a high impact force. There is a lot of energy involved, and the impact force can be of great value. Because of this, percussive drilling is perfectly suited for drilling in hard rock formation. It is today mostly used for drilling geothermal wells, coal mines and drilling for the water industry. Percussive drilling is still in development phase regarding drilling deep wells, but has shown promising results.

There are two different types of hammer set up, down-the-hole (DTH) hammer, also called in-the-hole (ITH) hammer, and top hammers (TH). There are four types of percussive drilling methods, hydraulic, pneumatic, electrically and fluid driven pistons.

2.3.1 Hammer set up

In TH drilling the piston accelerates to wanted velocity before striking the shank adapter or drill rod. A compressive stress wave is transported down the drill string and bit, consequently fracturing the rock, as seen in Figure 10. TH drilling is mostly used in small blast holes and in areas with hard rocks and access problems. TH drilling is typically used in small diameter holes. The technology is simple, reliable, cheap and easy to repair. In TH drilling the penetration rate will decrease with increased hole length as the compressive strength wave will decline.

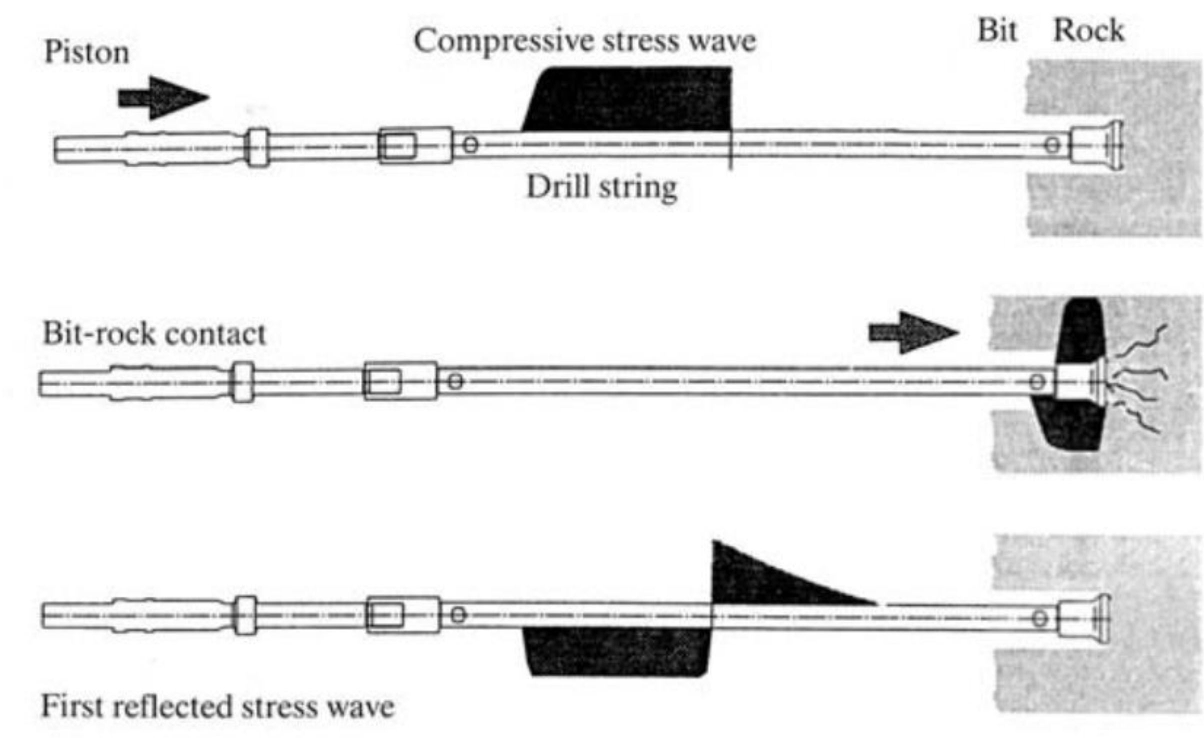


Figure 10 — Illustrates how top hammer drilling works [17].

In DTH hammer drilling the rotation is created outside the hole, while the percussion is created inside the hole. In DTH drilling the piston strikes the drilling bit, which here is a continuation of the shank, directly. The percussion is created pneumatically while the rotation can be created either pneumatically or hydraulically. Because the piston is almost in direct contact with the bit, the penetration rate is more or less constant regardless of hole length, where in TH drilling the penetration rate will decrease with increase hole length as the compressive strength wave will decline.

A normal DTH set-up can be seen in Figure 11 on the next page.

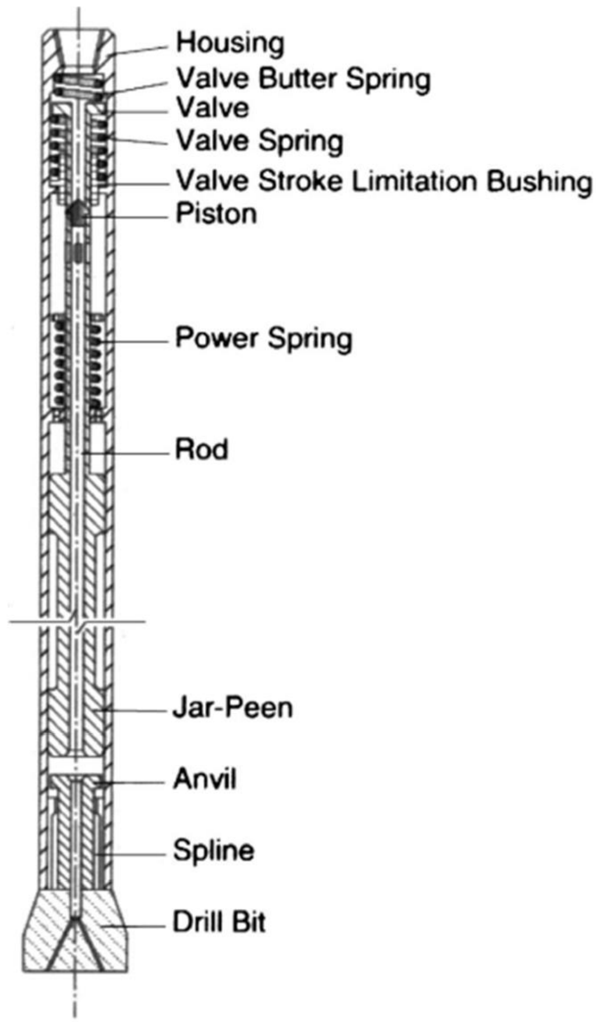


Figure 11 — Illustrates a typically down-the-hole set-up [18].

2.3.2 Percussive drilling methods

As mentioned, there are mainly two different percussive drilling methods, pneumatic and hydraulic. Pneumatic drilling, also called air hammer drilling, was originally developed to help drill in shallow environments but because it had some disadvantages, hydraulic hammers were invented. Air hammers needs air to function, while hydraulic hammers can use fluid. Foam can replace air as cutting transport substance in air-hammers, which extends the depth air-hammers can be used in. With stable conditions it is possible to drill deep wells using air hammer, and it shown good results when used in high temperature environments. Hydraulic hammers are suited for reaching larger depths than air hammers. Fluid driven hammer can solve some cutting transport issues [19] [20].

There are two main types of hammer bits. One is a reinforced three-cone bit, which is the old design, while the new design is a flat-bottomed bit with tungsten carbide inserts. Below is a figure illustrating the different bit designs.

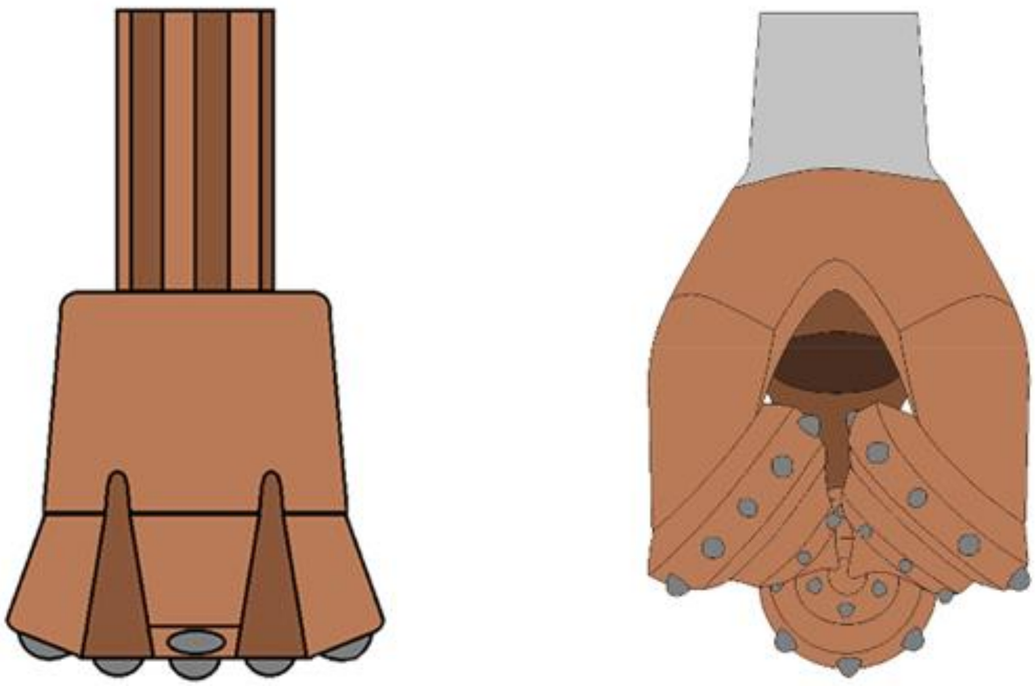


Figure 12 — Shows two typically bits in percussive drilling. To the left a flat-bottomed bit, and a tri-cone bit to the right [18].

ROP is very dependent on bit design. The bit can be designed in three ways, concave, convex and flat.

Concave design is most common and is suited for drilling in medium-hard rocks. It is also suited for use in easy-drilled sections with high expected cutting generation due to good cutting transport properties.

Convex bits can be used in medium-hard rocks, but can also be used in harder rocks by using inserts with stronger materials.

For very hard rocks it is recommended to use flat profiled bits, but it is important to be aware that flat designs may cause cutting transport problems. [48]

2.3.3 Benefits of Percussive drilling

There are several reasons why percussive drilling should be used when drilling in hard rock formations, one being the high ROP potential. With optimal environment the ROP can be increased drastically compared to rotary drilling. This is mainly because of the frequency the hammer can impact the soil with. New technology claims to be able to achieve frequencies up to 4x times what is normal [18]!

Another benefit using percussive drilling is the low WOB compared to rotary drilling. While rotary drilling depends on a high WOB to drill, percussive drilling can function with very low WOB and is more dependent on the percussive mechanism occurring at the bottom, caused by a piston located just above the bit, as seen in Figure 11. The piston is run from energy transported by the drilling fluid. Flow rate and volume decide how much energy is transported. DTH also works best if little WOB is applied, as rock fracture are easier to occur when deforming in tension rather than compression. Consequently, percussive drilling is perfect in combination with Managed Pressure Drilling (MPD) or Underbalanced Drilling (UBD). MPD and UBD is a drilling technique operating with a hydrostatic pressure close to and below pore-pressure.

Lower WOB also reduces fatigue, and the expected life time for drill string and equipment are increased. Because percussive drilling is not dependent on high WOB, this will also benefit percussive drilling at shallow depths where rotary could have problem applying sufficient WOB.

Bit wear is also reduced using percussive drilling and test has shown that the DTH is in contact with the rock only 2% of the time compared to rotary drilling. But this does only work until a certain extent. If large percussive forces are used, this could wear the bit rapidly.

Three typically cost-saving parameters for using air-hammer drilling are increased ROP, air as drilling fluid and a lower WOB [18].

In Oman, eight wells were drilled by using percussion drilling instead of rotary, and showed great results with a drastic reduction in drilling time.
In Yemen they used percussive drilling for drilling the surface hole, which showed a 3x increase in ROP compared to rotary drilling [21].

2.3.4 Drawbacks of Percussive Drilling

One of the main drawbacks using percussive drilling is that the percussive action causes vibrations and shock. By using unlimited energy when striking, the wear of both bit and BHA could be increased. The continuously hammering with great energy is a largely challenge for the rig, drill string, BHA and bit. Therefore, materials selection and bit design is important for increasing expected life time. By installing a shock absorber, described in chapter 2.5.3, some of the axial vibration will be reduced. Using high energy could also damage the bit, forcing a bit change or fishing operation [21] [18].

Even though low WOB is suitable, percussive drilling require a very accurate WOB control. It is also more difficult to perform fishing operations and gage wear on the solid-head bits are a problem. It is not possible to perform reaming operation when using solid-head bits, and because of this, proper gauge wear control is very important when using percussive drilling [20].

Using air hammers can also cause hole stability problems. As air has a density lower than conventional drilling mud, the hydrostatic pressure will be lower. The problem increases in unconsolidated or fractures formations where the borehole easily can collapse. At larger depths the pore pressure will also increase more than the hydrostatic pressure, intensifying the problem [18].

The largest drawback by using percussive drilling is the lack of reliability. The technology needs huge improvements in this area for percussive drilling before the technology can be used more frequent.

2.3.5 Alternative hammer design

Along with the two main types of hammers, there are new types of hammers under developments. This chapter will describe a few of them.

Mud-hammers are believed to be a solution for drilling in hard rock formations at deeper depths. Compared to air-hammers, it is able to operate at higher operational pressures, which makes it suitable to use in deep high pressure formations. A reported problem with using mud-hammer is that is it very fragile to wear. Especially if there are abrasive rock particles present in the mud, this could speed up the wear rate. By switching to oil-based mud, the wear problem could be solved [15].

The **pen-rock hammer** is according to the developer, "*designed to run at approximately 100 Hz and to produce 'impact to power' efficiency higher than 80% and deliver an ROP of 35 m/h for a 10 km drilling trajectory".* This would result in great improvements of the overall ROP. Figure 13 shows how the pen-rock hammer looks [2].

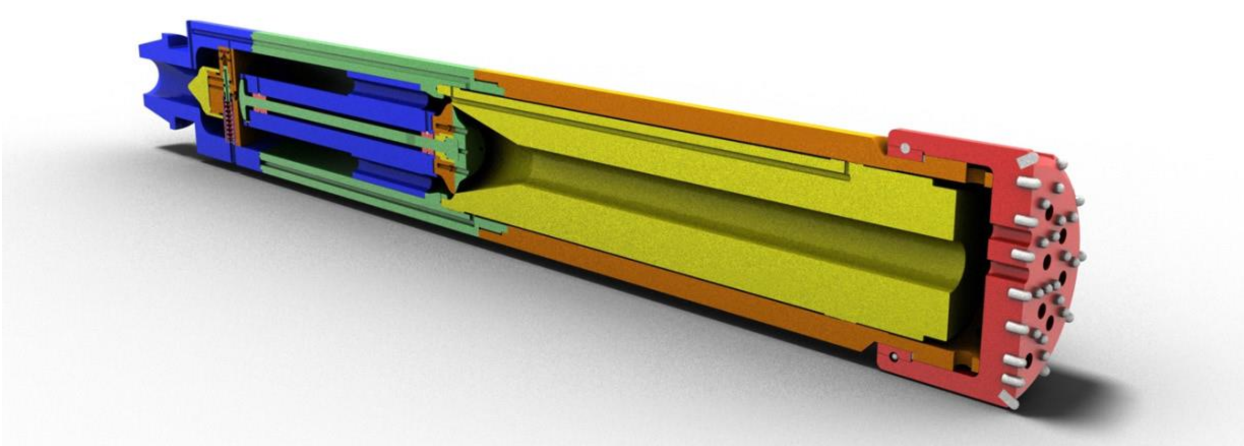


Figure 13 — Illustration of the pen-rock hammer [22].

The resonator is another new hammer developed to being able to operate with high frequencies and long stroke length. This could increase the ROP drastically.
The high frequenzy is achived by "*a linear motor runned by an electromechanically oscillating piston and a patented double gas spring*" [2] [23].

2.4 ROTARY-PERCUSSIVE

Rotary-percussive can be described as "*a hybrid form of drilling, where the WOB and the angular velocity are acting as in conventional rotary drilling and a percussive force on the bit moves it into the rock at an angle to the surface* " [24].

There are several new concepts based on combining rotary and percussive drilling, where two of them will be introduced;

- Percussive Assisted Rotary Drilling
- Rotary Percussive System

Percussive assisted rotary drilling (PARD) is a drilling system design for being able to produce a higher level of energy than any DTH or rotary bit. By combining the high energy and a special designed tri-cone bit, this implements the best from percussive and rotary drilling. It is designed to fit normal rotary rigs, and tests from Sweden [25] has shown that combining percussive and rotary technology together increased the overall penetration rate and increased the overall productivity. It is designed for air as drilling fluid, where the air is channeled into two champers, one to drive the hammer and the other to clean the borehole. The system does not require a higher pressure than rotary, cleans the well properly and has an excellent cooling effect. The specially designed tri-cone bit is also able to withstand the vibrations from percussive drilling and has the same expected service life as a normal tri-cone bit. PARD is especially suited for drilling in medium-hard to hard formations. Figure 14 shows the PARD drilling tool

Figure 14 — Illustrates the concept of PARD drilling [26].

Rotary Percussion System (RPS) is designed to drill in any type of rotary drilling environment with an overall increased ROP with reduced costs. It also is designed to better handle hard rock formations, and like the PARD system, it combines rotary and percussive for max ROP potential. It is driven by air and can function on any rig with an installed air system. It uses a tri-cone which is designed to handle both soft and hard formation with increased ROP. It also claims to more effectively navigate in transition zones and in environments with frequent fractures, which overall should result in straighter boreholes thereby reducing bending stresses on drill steel [27].

2.5 DRILLING PROBLEMS

During drilling, several problems can occur. This chapter will briefly explain some of the most common problems occurring and a detailed explanation of vibration.

2.5.1 Common drilling problems

Some of the most common drilling problems encountered are:

- Maintaining hydrostatic pressure
- Bit wear
- Bit damage
- Under gauge wellbore
- Fishing operation
- Stuck pipe
- Dogleg
- Sidetrack
- Drilling in alternating environment

It is crucial to **maintain the hydrostatic pressure** in the well between the pore pressure and fracture pressure to prevent kick and fractures. Too low hydrostatic pressure can cause a kick, while too high hydrostatic pressure can cause fractures. Keeping a stable hydrostatic pressure is done with the drilling mud. The density of the mud can be reduced/increased depending on the wanted hydrostatic pressure. It is also important to notice that when drilling the hydrostatic pressure increases due to circulation that this is referred to as Equivalent Circular Density (ECD).

Bit wear is common when drilling in hard rock formation. Due to the hard rocks, the cutter inserts are gradually worn until the drilling parameters are too poor to continue and a trip to change bit is necessary. By increasing the WOB the worn inserts can perform work some time, but this increase wear rate. Drilling with worn inserts can result in an under gauged hole. Changing the bit is time consuming because the whole drill string needs to be pulled out of the hole. It is important to design the bit to be able to reduce bit wear and increase the bit life as long as possible. Pre planning is important before selecting the design. Looking at previous drilled well in the area could help selecting the right design.

Bit damage occurs when the bit is exposed to unintentionally forces. For instant vibration and shocks can result in parts of the bits are left in hole, especially when using RC bit. The loose part is now referred to as a “fish” which requires a fishing operation described below. Bit damage will require a bit change, which is a time consuming operation.

Under gauged wellbore is a result of bit wear. If a bit has been worn down, the insert length on the shoulder of the bit has been reduced, resulting in a well bore with smaller diameter than planned. Usually the bit has gauge protectors resist wear. Under gauged well bore can be a problem when trying to pull out of the hole, resulting in a stuck pipe. Under gauge bore holes can be solved by reaming, but could result in a sidetrack.

A **fishing operation** is when an unwanted object is left the well bore and needs to be retrieved. This can be a part of the equipment or other objects that has fallen into the well bore. The drill string needs to be run out of the hole and fishing equipment pulled into the hole. Fishing the operation can be a very time consuming and could if unsuccessful, results in a sidetrack or, in worst case, abandoning the well.

Stuck pipe is when the drill string is not able to be pulled out of the well bore. This can be due to formation blocking the string or BHA. In the BHA there is a tool, a jar, installed for exposing the drill string to a high axial force, for successfully loosening the pipe. If the pipe is still stuck it needs to be cut loose by running knifes or explosives inside the string. The next step is to perform a sidetrack or, in worst case, abandoning the well [28].

Dogleg is defined as how much a change over a three stand length, around 27 meter. A dogleg can be calculated, which is the angle between two points on a curve, or the dogleg severity, which is calculated from the dogleg angle divide by the distance between the two points. [14]

The term also often refers to a section of the hole that changes direction faster than the rest of the wellbore. A too high dogleg could make it more difficult to reach planned depth [29].

In short terms, a **sidetrack** means that the current well hole no longer can be used. To solve the problem, a whipstock can be installed in the hole. The whipstock is shaped in a allowing the drilling to continue from previously bore hole, by isolating the lower parts of the old well. Alternative be to set a cement plug in openhole and drill a sidetrack or perform an open hole sidetrack. Drilling a sidetrack is an expensive and time consuming operation which is a last resort effort, if anything else should fail.

Drilling in very hard, **alternating** abrasive formation is one of the biggest challenges in the drilling industry. Drilling in environments like that will result in frequent changes in ROP and high bit wear. High bit wear can, if not detected, result in under gauge borehole. Frequent changes between soft and hard formation is a basis for developing vibrations, which can damage the bit, especially when drilling into hard formation. [30] When drilling in alternating environment it is important to do proper pre planning. A proper study of the formation will result in right bit design, reducing drilling related problems. It is important to have a back-up plan if any unwanted situations occur.

The most related problems with hard rock drilling are:

- Bit wear
- Bit Damage
- Low ROP
- Alternating environment
- Vibration

2.5.2 Vibration

The occurrence of vibration is often caused due to acceleration or deceleration of the down-hole equipment. It occurs because the equipment is in direct contact with the formation, and is one of the major problems when drilling in hard rock formations. Because soft formation has lower compaction strength than hard rocks, vibration related issues are less common in soft formations.

Some of the most normal problems caused by vibration are:

- Reduces effectiveness
- Reduce life time of equipment
- Possible damage of bit and equipment
- Main reason for fatigue problems, and can in worst case erupt the string

There are four main types of vibrations:

- Axial
- Torsional
- Lateral
- Eccentered

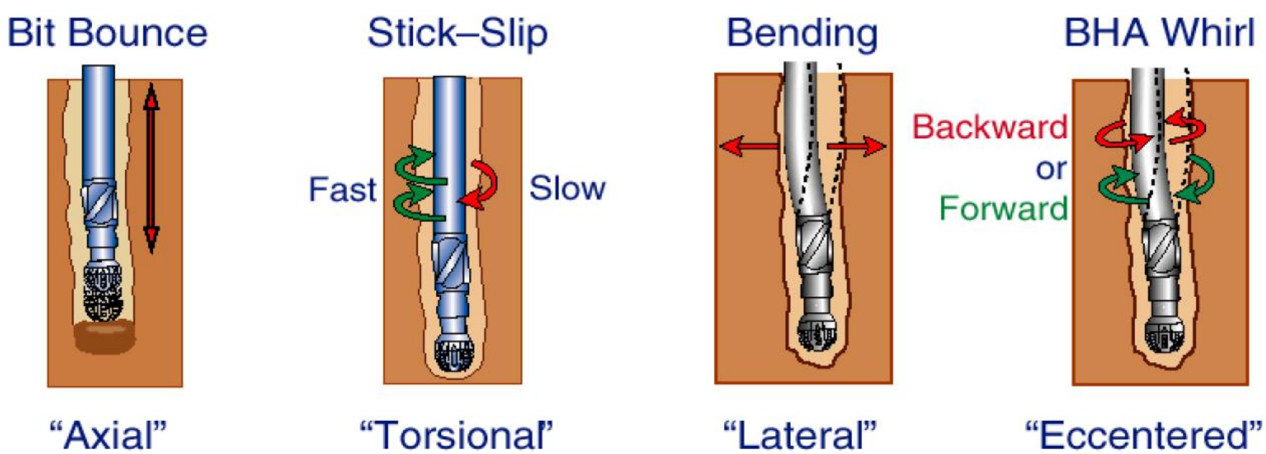


Figure 15 —Illustration over the different types of vibration [31].

Bit bounce

Bit bounce occurs when the bit is repeatedly lifted up and down from the bottom of the hole, and is also referred to axial vibration. —Illustration over the different types of vibration Figure 15 illustrates how it works.

Some typically causes of bit bouncing are:

- Drilling in hard formation
- Drilling vertical holes

- Drilling with tri-cone bits
- Drilling in environment with stringers
- Drilling with high WOB
- Result of BHA whirl or stick-slip, as described in the following paragraph.

Bit bouncing can cause damage to the equipment, and could result in parts loosening and left in the well. It also increases the wear on the down-hole equipment. To prevent bit bouncing from happening some typically solutions are to use proper bit design, increase RPM, reduce WOB and use a shock-absorber [31].

Stick and slip

Stick-slip, known as torsional vibration, is acceleration and deceleration of the BHA, illustrated in Figure 15.

Some causes of stick-slip are:

- Highly deviated well path
- High angle wells
- Use of aggressive PDC bit
- Drilling in environment with high BHA-formation friction

When the BHA is in contact with the formation, the BHA can "stick" to the formation while the upper part of the drill string is still rotating with constant RPM. Torque will slowly build up, until a point where the BHA "slips" from the formation. At this point the lower part of the drill string is behind with numbers of rotations. To compensate for this, the BHA will need to increase its rotation speed, to "catch up" with the above drill string. Figure 16 shows how the BHA downhole RPM varies during a stick-slip scenario.

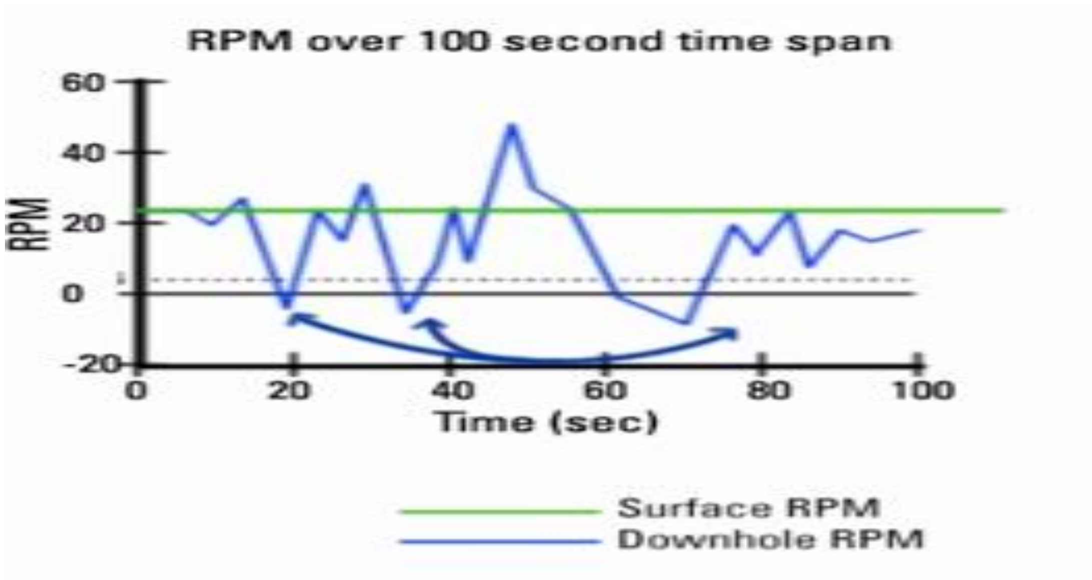


Figure 16 —Shows the behavior of RPM in a stick-slip scenario [31].

As seen from the figure, the BHA RPM or downhole RPM, represented by the blue line, varies several times. At around 15 seconds the downhole RPM reduces, indicating that the BHA is in contact with the formation. It slowly reduces its RPM until around 19 seconds where it's not rotating at all. After 19,5 seconds it even rotates in the opposite direction for a very short period of time, until it releases at RPM increases. After 42 seconds the BHA again releases from the formation, this time compensating for the difference in RPM by suddenly moving with a much higher RPM than at surface. The stick-slip movements can be described as energy absorbed and released.

Stick-slip can do damage to the BHA equipment and bit, and might result in an over torqued and poor connection that could lead to a washout. It is especially challenging for PDC bits, and usually occurs when encountering hard formation. Another cause could be that an aggressive bit is applied with too much weight to attack the formation. The torque of the formation will for some time be larger than the torque of the bit causing it to slow down.

To prevent stick-slip, reducing WOB and RPM, improved bit design and reduce well friction could solve the vibration. Well friction can be reduced by using roller reamers, drilling smoother well paths and increasing lubrication properties of the drilling mud [31].

Bending:

Bending, also known as lateral vibration or whip occurs when the bottom part of the drill string moving lateral colliding with the borehole wall as illustrated Figure 15. The cause of bending is when a section between two stabilizers or supports is in resonance.
The size of the wellbore limit how large the impact will be. Large wellbore will have a higher impact force than a small wellbore. Bending is the major factor for damaging Measure While Drilling (MWD) equipment, and could cause drill collar and connection fatigue. Repeatedly lateral movements result in more shocks, causing more vibrations which is the beginning of a negative loop.

BHA whirl:

The last main vibration type is BHA whirl, also known as eccentric vibration, is complex eccentric lateral rotational movement vibration and is illustrated in Figure 15. Several factors need to be present for BHA to occur. There are three main types of BHA whirl; backward-, forward and chaotic whirl.

Backward whirl is caused mostly by friction. If the BHA is in contact with a wellbore with high friction, torque will build up forcing the drilling assembly into rolling instead of sliding. The upper and lower part of the contact point between the BHA and borehole wall will at one point rotate in the opposite direction. Backward whirl can do serious damage to the BHA and bit.

Forward whirl differs from backward whirl in two ways. The friction is lower and the BHA and drill string is moving in the same direction at all times. What defines forward whirl is that it moves in a given pattern. When rotating it's the same contact point at the drill string that is in contact with the wellbore, while the rest of the drill string is unharmed. If drilling in a rough formation this could cause early wear at the contact point. The contact point can easily be detected at surface by inspection.

Chaotic whirl occurs during mitigation of backward and forward whirl. Mitigation of BHA whirl often includes changing the RPM which could lead to chaotic whirl. The characterization of chaotic whirl is that it does not move in a given pattern, but moves chaotic.

Mitigation of BHA whirl can be done by increasing the WOB, reducing the RPM and using stiffer BHA [31] [32].

Bit whirl

Bit whirl is like BHA whirl, with an eccentric rotation. In normal conditions the bit moves around its geometric center, while in bit whirl the bit movement depends on the interaction between the bit and the wellbore. Bit whirl will also cause more damage to the bit compared with BHA whirl and likely the BHA will cause more damage to the other equipment. Causes of bit whirl are:

- Drilling vertical wells
- Improper bit design
- Wells with stringers
- Aggressive PDC bits

It is not possible to detect bit whirl early, but an aggressive PDC bit can cause under gauge holes, which can be observed from surface. It is easier to detect downhole, due to lateral shocks being generated. The bit can be damaged and the ROP reduced.

To reduce bit whirl it is recommended to use proper design of the bit as well as "common good drilling practice". It is also important to increase RPM and WOB when reaching the bottom, after the bit has been lifted from bottom for some time [31].

Figure 17 shows a general overview over all types of vibrations, including problems and mitigation.

Mode of Vibration	Real-Time Diagnosis	Typical Environment	Potential Cure	Other Solutions
Axial shocks	Topdrive or kelly shaking, downhole shocks	Hard formations, vertical holes, roller cone bits	STOP Change WOB and change rpm	Change to less-aggressive bit, use a shock sub
Bit whirl	LWD caliper shows overgauge hole but bit is undergauge	Aggressive side-cutting bit	STOP Increase WOB and decrease rpm	Change bit, use full-gauge NB stabilizer
BHA whirl	Large downhole shocks, increased STOR	Washed out hole, BHA pendulum or unstabilized	STOP Increase WOB and reduce rpm	Use a stiffer BHA
Stick/slip	Large surface torque and rpm fluctuations, MWD peak-peak rpm	Aggressive PDC bits, high wellbore BHA friction	STOP Reduce WOB and increase rpm	Increase mud lubricity, use less-aggressive bit, improve hole cleaning

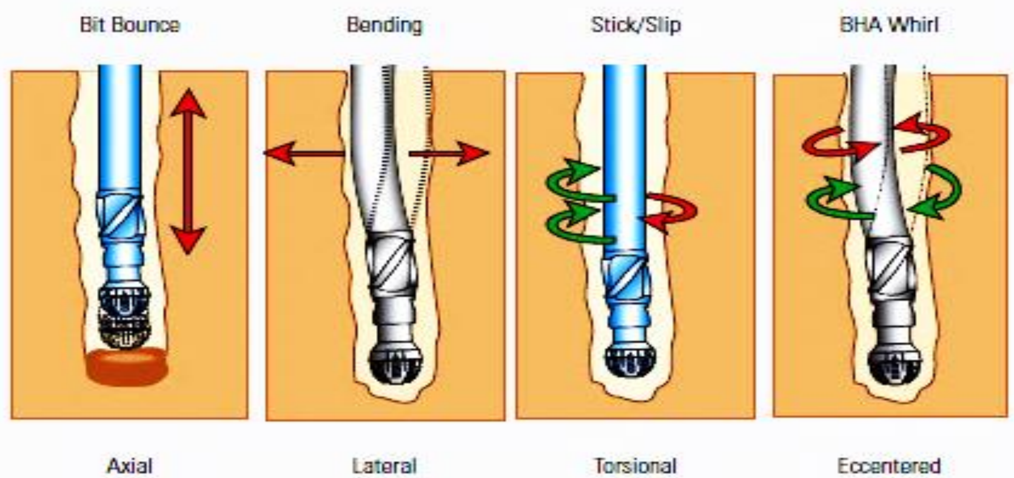


Figure 17 — Gives an overview over all vibration types and mitigation [31].

2.5.3 Tools for vibration mitigation

It is important to mitigate vibrations to reduce problems and increase the overall efficiency. Like all other problems, the results of vibrations can be both time consuming and costly, and is highly undesirable. Monitoring RPM and WOB can help reduce vibrations, but there are tools on the marked aimed to help mitigate vibrations.

The different equipment developed for mitigating vibrations are:

- Active dampening systems
- Anti-stick-slip tools
- Anti-shock tools

Active dampening systems is a computer based mitigation system which aims to reduce drill string damage by continuously monitor the drilling parameters and changing them frequently to maintain stable downhole conditions

Anti-stick slip tools

These tools are designed to optimize and control the drilling operations and keep the drilling parameters stable to prevent stick slip. Computers can monitor the surface RPM and compare it with the downhole RPM. If the downhole RPM should be reduced, the computer notices and reduces the surface RPM to compensate. This way the torque build-up will be reduced thus reducing chance for stick slip. The drilling parameters can also be monitored and changed frequently for mitigation of torques and spikes. Other solutions is to lift the bit of the bottom of the hole for a short period to prevent stick-slip. When the system is back to equilibrium, the bit can be lowered, the drilling parameters normalized and the operation can continue.

Anti-shock tool

This tool prevent and mitigate oscillation using springs, a pressure stabilized piston, one way deaden valves and a pump open hydraulic force. The pressured piston equalizes the pressure inside the tool and inside the string. The piston also lubricates pressure control in the whole tool.

3 Geological Classification

When drilling a well most wells will encounter different types of rocks with different strength and hardness values, ranging from soft to hard. Because of this it is important to classify the formation to be able to choose the right tool and equipment design. Today there are no standardized models for linking the rock classification and selecting bit. Usually the unconfined compressible strength (UCS) boundary values are used to classify the rock.

. The formation can be classified by looking at a few parameters:

- What rock type is it?
- What are the mechanical rock properties?
- What drilling problems are likely to occur?

3.1 ROCK TYPES

There are three types of rock types:

- Igneous
- Sedimentary
- Metamorphic

3.1.1 Igneous

Igneous rocks consist of two main groups, volcanic and plutonic. Volcanic rocks form from cooled down lava, while plutonic rocks are rocks formed from cooled magma. The rate of cooling effect the texture and crystallization rate, where plutonic rocks are coarse grained while volcanic rocks are fine grained. Examples of igneous rocks are granite (plutonic) and basalt (volcanic). Igneous rocks are also subdivided depending on silica content. Silica is one of the main cause for abrasive wear on bits and therefor drilling in igneous rocks can invite to problems. 95% of the Earth`s crust consist of igneous rock. But at the shallowest depths, there are most sedimentary rocks which is the depths where most wells are drilled. This will also mean that drilling deeper wells would result in more igneous rocks present.

3.1.2 Sedimentary

Sedimentary rocks is formed by atmospheric and hydrosphere reactions in the Earth`s crust. As the rocks have been formed under different temperatures and pressures, it tends to be unstable with varying conditions. By diagenesis, sedimentary rocks can erode and form a new sedimentary rock. The most common types of sedimentary rocks are sandstone, clay and limestone. Petroleum reservoirs are most likely to occur in sedimentary rocks. Because of its composition, sedimentary rocks have a lower hardness than igneous rocks and tend to be easier to drill through.

3.1.3 Metamorphic

When igneous and sedimentary rocks are exposed to changes like temperature and pressure, this will cause the rock to recrystallize. This phenomenon is called metamorphism, hence **metamorphic** rocks. The rock formed is better suited for its environment. Pressure, heat and chemical fluid are the active parts in a metamorphism [21] [15].

3.2 MECHANICAL ROCK PROPERTIES

"The mechanical property of a rocks hardness can be defined from the rocks compressive strength. Compressive is the rocks ability to resist deforming strains." This definition is widely used in the oil and gas industry and is a very precise definition. This thesis will mainly focus on three mechanical properties:

- Strength
- Hardness
- Abrasiveness – briefly explained

Other mechanical properties are deformability, a rocks resistance to reshape. Fracture toughness, resistance to fracturing, coefficients of friction, and resistance of sliding a plan with an overlaying surface, crushability, and millability[17].

3.2.1 Strength

A rock strength is its ability to resist to failure while under elementary stresses like compression, tension or shear. A rocks strength can be found by calculating it`s UCS value, described in chapter 4.4. This value can be compared to — Strength classification of rocks Table 1, which is based on classifying a rocks strength value. The values vary from 10-20 MPa, which is classified as "very weak rocks" till 160-320 MPa which are classified as "very strong rocks" [33].

Table 1 — Strength classification of rocks [33].

Strength Classification	UCS [MPa]	Typical rock types
Very weak	10-20	Weathered and weakly compacted sedimentary rocks
Weak	20-40	Weakly cemented sedimentary rock, schist's
Medium	40-80	Competent sedimentary rocks; some low-density coarse grained igneous rocks
Strong	80-160	Competent igneous rocks, some metamorphic rocks and fine-grained sandstones
Very strong	160-320	Quartzite's, dense fine-grained igneous rocks

A rocks UCS value will have a high effect on the ROP. Very strong rocks are more difficult to drill through.

It is also possible to classify a rocks strength by looking at the cementation and composition of the rock. Well cemented rocks have a higher strength than poorly cemented rocks… [34].

3.2.2 Classification of hardness

There are today several methods for determining and classifying the hardness of a rock. The most used method among geologists is the Mohs scale The Mohs scale is based on comparing different materials and seeing which materials can visibly scratch another material. This is the results: [35] [36]

Table 2 — Mohs Hardness scale [35] [36].

Mineral	Mohs`Hardness scale	
Talc	1	Can be scratched with a fingernail and by any stone rated 2+
Gypsum	2	Can be scratched with a fingernail and any stone rated 3+
Calcite	3	Can be scratched with a knife and any stone rated 4+
Fluorite	4	Will scratch any stone rated 3-. Can be scratched with a knife and any stone rated 5+
Apatite	5	Will scratch any stone rated 4-. Can be scratched with a knife and any stone rated 6+
Feldspar	6	Will scratch any stone rated 5-. Can be scratched with a knife and any stone rated 7+
Quartz	7	Will scratch glass and any stone rated 6-. Can be scratched by stones 8+
Topaz	8	Will scratch glass and any stone rated 7-. Can be scratched by stones 9-10
Corundum	9	Will scratch glass and any stone rated 8-. Can be scratched by diamond
Diamond	10	Will scratch glass and all stones 1-9

Abrasiveness

Abrasiveness can be defined as "*the ability of a rock to induce wear on mechanical tools and apparatus*"*.* The range of wear on cutting equipment is often related to the silicate content of the rock. High silica content tends to result in high abrasiveness.
High abrasiveness combined with poor bit design can cause low ROP, early bit change and under gauged wellbore. The abrasiveness of a rock can be found be studying the rocks hardness number as described in chapter 3.2.1 [17].

4 Theory

One of the objectives of this thesis is to develop a procedure for determine if percussive drilling can be implemented in one or more sections of a well. The theory and formulas used in this chapter will be used for the procedure described in Chapter 5.

This chapter will cover:

- ROP and how can it be affected
- MSE and how to determine
- HMSE
- UCS and how to determine
- Drillability
- Bourgoyne and Young - ROP Model
- Cost and sensitive factors

4.1 RATE OF PENETRATION (ROP)

ROP is a measure of the current drilling speed in a given timeframe. Higher ROP equals higher drilling efficiency. The ROP will vary depending on several factors like formation strength, bit type and drilling technology. By increasing the WOB the ROP usually increases as more pressure is added to the formation increasing the penetration rate. There are limits on how much WOB can be applied. Too much WOB can cause several drilling related problems like vibrations, increased bit wear and bit damage. There is also a limit of how much WOB can be applied. To prevent applying to much WOB, active WOB monitoring and pre-calculations of max limit is necessary [15].

It is important to notice that increased WOB does not guarantee increased ROP [37].

Factors affecting the ROP

- Bit type
- Operating conditions
- Formation characteristics
- Rock properties
- Drilling fluid properties

In this thesis the most relevant operating condition will be type of drilling method while most important rock property is hardness [15] [38].

4.2 MECHANICAL SPECIFIC ENERGY (MSE)

MSE, also called drilling specific energy, can be described as the energy spent moving 1cm^3 of rock. Lab tests performed showed that the energy required to destroy the rock is constant, unrelatedly of changes in Rounds Per Minute (RPM), WOB or ROP. This tells us how much energy is required to crush different formation types and can be more useful than ROP measurements. Monitoring the MSE can lead to an increased understanding of the downhole activity and help optimize the drilling parameters and increase efficiency. [15] [39] [40]

A formula was proposed by Teale [40].

$$MSE = \frac{WOB}{A_B} + \frac{120\pi \cdot N \cdot T}{A_B \cdot ROP} \quad (1)$$

$\mathrm{A_b} = $ bit surface area, inches

$\mathrm{MSE} = $ Mechanical Specific Strength, MPa

$\mathrm{N} = $ Rotary speed, Rounds per Minute

$\mathrm{ROP} = $ Rate Of Penetration, ft/hr

$\mathrm{T} = $ Torque, lbs

$\mathrm{WOB} = $ Wait on Bit, lbs $-$ ft

4.3 HYDRAULIC MECHANICAL SPECIFIC ENERGY (HMSE)

HMSE is a modified version of MSE where hydraulic energy term is added to the mechanical energy term. The main reason for including hydraulic energy is because hydraulic energy is required for removing cuttings. Both hydraulic and mechanical energy need to be evaluated when drilling. Example is for when drilling in very soft formation. In some cases the hydraulic power is enough for conceding the rock strength without any additionally MSE. Hydraulic power is used to increase ROP. HMSE covers both hydraulic and mechanical energy term. It is the total energy required to remove a unit volume of rock from the cutting face. Experience from field data has showed that using HMSE makes it possible to discover inefficient drilling conditions. By including the hydraulic term, the correct value for total energy used when drilling is obtained.

The new HMSE model is based upon the formula for MSE but with a little addition. Results showed that the hydraulic force exerted by the impact of the drilling fluid on the formation also should be added to the equation. The impact from the jet nozzles also causes changes in the formula, based on Newtons third law (*"for every action, there is an equal and opposite reaction"*). The impact from the nozzles reduces the overall WOB [39].

$$HMSE = \frac{WOB}{A_B} + \frac{120\pi NT + 1154\eta\Delta P_b Q}{A_B ROP} \tag{2}$$

$HMSE$ = Hydraulic Mechanical Specific Energy, MPa

P_b = Pressure drop across the bit, psi

Q = flow rate, gallons per minute

η = dummy factor for energy reduction, dimentionless

Due to lack of data, HMSE was not estimated in this thesis and was consequently left out of the procedure

4.4 UNCONFINED COMPRESSIVE STRENGTH (UCS)

UCS is the rocks strength to resist uniaxial force, and is commonly used to determine the strength of a rock. It is possible to use log-based rock strength modeling to determine the UCS value instead of using core samples and finding results in a lab, which is expensive and time consuming.

It is known that the ROP reduces with depth due to increasing UCS values because of increased compressional strength. Figure 18 below represents ROP and UCS values calculated from the well used in the procedure later on and clearly illustrate the relation between ROP and UCS.

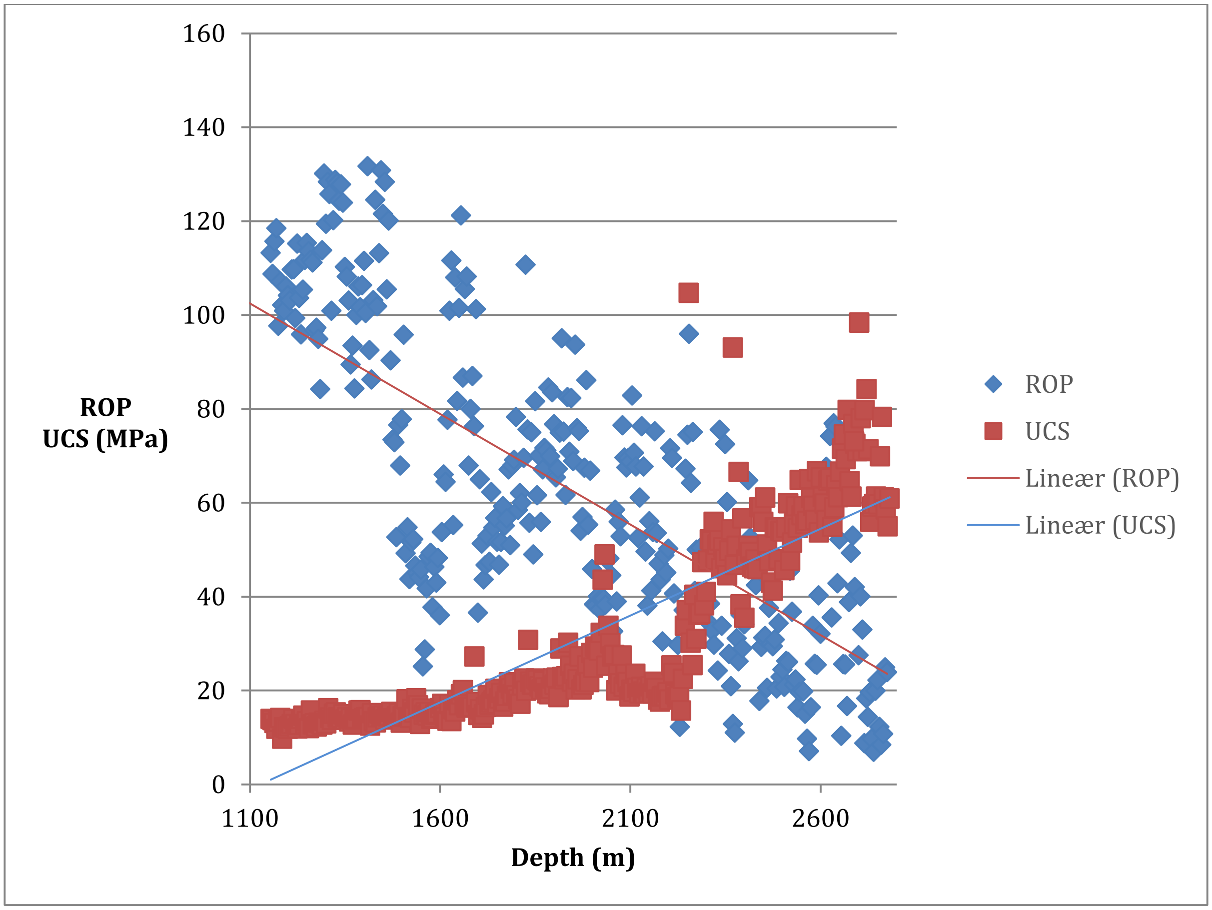


Figure 18 — Shows how UCS and ROP behaves with increasing depth.

This thesis uses three different formulas for determining UCS. These formulas can be used for all wells with sonic and density log data available.

The first equation is based on output data from the sonic log [49].

$$UCS = 0{,}77 * v_p{}^{2{,}93} \quad (3)$$

UCS = Unconfined Compressive Strength, Mpa

V_p = Velocity, km/s

$$v_p = \frac{10^6}{\Delta t_c} \tag{4}$$

Δt_c = travel time, μs/ft

Second formula is based on output data from density log

$$UCS = 0,77 * \left(\frac{\rho}{0,23}^4 * \frac{0,3048}{1000}\right)^{2,93} * 145 \tag{5}$$

ρ = density, kg/m^3

The third method can be used if sonic log is available and function as a complementary formula to check if the same UCS value is obtained as using (3) . The formula is converted from US units to MPa

$$UCS = \frac{1}{k_1 * (\Delta t_c - k_2)} + k_3 \tag{6}$$

$k_1 = k_2 = k_3$ = constants

The k factors in Table 1 can be determined from studying the stratigraphy of the formation.

Table 3 — Overview over input data for use in equation (6)

	K_1	K_2	K_3
Sandstone	0,0011	50	3,42
Shale	0,13	50	-2,66
Combined	0,12	50	0,22

The relation between UCS and MSE can be used for determining UCS or MSE if one of them is known and the other unknown with the following equations [41].

$$UCS = \frac{MSE}{2,86} \tag{7}$$

$$MSE = \frac{UCS}{0,35} \tag{8}$$

When talking about UCS it is important to keep in mind the difference between unconfined compressive strength and confined compressive strength, which are unpressurized and pressurized conditions.

4.5 DRILLABILITY

Drillability indicates whether penetration is easy or hard. An accurate prediction of drillability can give a good idea of expected ROP, hardness and possible drilling problems. Drillability consists of several parameters combined together to determine the drillability. Three main parameters affecting the drillability were determined to be: [12]

- Rock and Rock Mass
- Drilling Rig
- Working Process

An illustration of the parameters and factors effecting them can be seen in Figure 19.

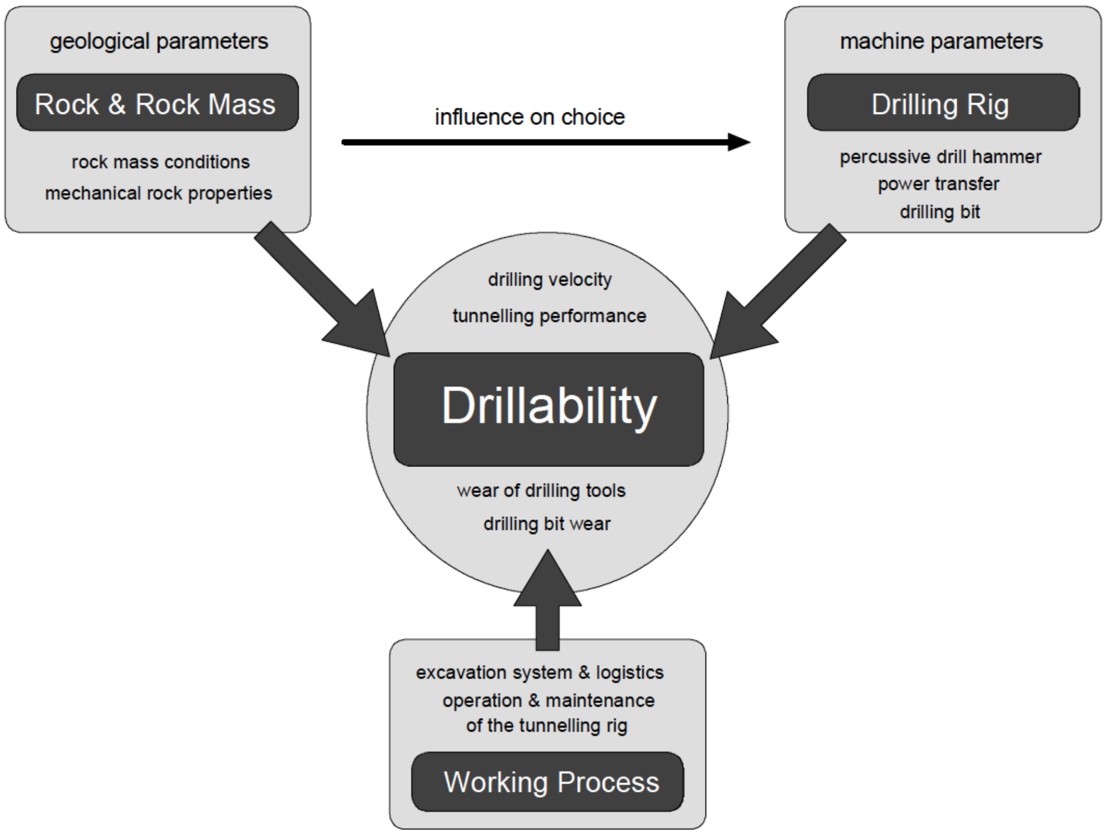


Figure 19 — Detailed overview over the parameters effecting drillability [12].

The illustration shows what parameters needs to be in focus for achieving maximum drillability, thus increasing effiency and reducing drilling problems related to poor drillability.

The rock and rock mass is dependent on the geological parameters, which needs to be studied closely. Combining several geological factors like the geological history, weathering, decomposition and structure of discontinuities it is possible to get a picture of expected drillability in a formation.

It is also important to select the right drilling technology. As described earlier, percussive drilling is more suited to hard rock drilling and would increase the drillability compared to rotary. The bit should also be designed to best suit the formation thus increasing drillability.

The working process means to mitigate the operation against any problems. By performing regularly maintenance and optimizing the efficiency this will result in a good working process increasing the drillability. Studies have shown that high penetration rate at tunnel face does not guarantee high performance at the heading [12].

With having basic drilling parameter data available the drillability can be calculated using the follow equation:

$$Drillability = \frac{\log\left(\frac{N}{60}\right)}{\log\left(\frac{12WOB}{10^6 D}\right)} \tag{9}$$

$\text{D} = \text{Diameter, inches}$

The drillability can also be determined if hardness is available [12]:

$$Drillability = \frac{1}{Hardness} \tag{10}$$

4.6 ROP MODEL – BOURGOYNE AND YOUNG

Bourgoyne and Young created a model for optimization of ROP in 1974. This model can help determine how to optimize ROP when planning to drill a neighbor well given that data is available.

The basis of the ROP optimization model is following equation [42]:

$$\frac{dD}{dt} = f_1 * f_2 * f_3 * f_4 * f_5 * f_6 * f_7 * f_8 \tag{11}$$

The equation of each parameter is:

$$f_1 = e^{a_1} \tag{12}$$

$$f_2 = e^{a_2(10000-D)} \tag{13}$$

$\mathrm{D} = \mathrm{Depth, feet}$

$$f_3 = e^{a_3 D^{0.69}(g_p-9)} \tag{14}$$

$\mathrm{g_p} =$ Pore pressure gradient of formation, ppg

$$f_4 = e^{a_4 D(g_p-\rho_c)} \tag{15}$$

$\rho_c =$ Equivalent circulating mud density, ppg

$$f_5 = \left[\frac{\left(\frac{W}{d_b}\right) - (\frac{W}{d_b})_t}{4 - (\frac{W}{d_b})_t}\right]^{a_5} \tag{16}$$

$\left(\frac{\mathrm{w}}{\mathrm{d}}\right) =$ WOB per inch of diameter, 1000 lb/in

$(\frac{\mathrm{W}}{\mathrm{d_b}})_\mathrm{t} =$ Threshold WOB per inch of bit diameter

$$f_6 = \left(\frac{RPM}{100}\right)^{a_6} \tag{17}$$

$\mathrm{RPM} =$ Rounds per Minute

$$f_7 = e^{-a_7 h} \tag{18}$$

$$f_8 = \left(\frac{F_j}{1000}\right)^{a_8} \tag{19}$$

To be able to find a_n, equation (11) is converted into the following equation:

$$ln\frac{dD}{dt} = lnf_1 + lnf_2 + lnf_3 + lnf_4 + lnf_5 + lnf_6 + lnf_7 + lnf_8 \tag{20}$$

By putting equation (12-19) into equation (20) and multiplying by x, the following expression is the result:

$$ln\frac{dD}{dt} = x_1a_1 + x_2a_2 + x_3a_3 + x_4a_4 + x_5a_5 + x_6a_6 + x_7a_7 + x_8a_8 \tag{21}$$

Equation 21 can be expressed as:

$$\left(\frac{dh}{dt}\right) = e^{a_1 + \sum_{j=2}^{8} a_j x_j} \tag{22}$$

As a_j is a constant, x_1-x_8 can then be expressed as:

$$x_1 = constant \tag{23}$$

a_1x_1 says something about the effect of formation strength. The constant includes drilling variables as mud, solids etc. [42].

$$x_2 = 10000 - D \tag{24}$$

D = Depth, feet

$$x_3 = h^{0.69}(g_p - 9) \tag{25}$$

a_2x_2 and a_3x_3 shows the effect of compaction on penetration rate. a_2x_2 assumes that the penetration rate decrease with depth. a_3x_3 assumes an increase in penetration rate with pore pressure gradient.

$$x_4 = D(g_p - \rho_c) \tag{26}$$

D = Depth, feet

A_4x_4 model the effect of pressure differential across the bottom on penetration rate. It assumes an exponential decrease in penetration rate with excess bottom-hole pressure.

$$x_5 = \ln\left(\frac{\left(\frac{w}{d}\right) - \left(\frac{w}{d}\right)_t}{4 - \left(\frac{w}{d}\right)_t}\right) \tag{27}$$

A_5x_5 models the effect of bit weight and bit diameter on penetration rate. It assumes that penetration rate is directly proportional to $\left(\frac{w}{d}\right)^{a_5}$

$$x_6 = \ln\left(\frac{N}{100}\right) \tag{28}$$

A_6x_6 represents the effect of rotary speed on penetration rate. It assumes that penetration rate is directly proportional to N^{a_6}.

$$x_7 = -t_w \tag{29}$$

t_w = The fractional teeth heigh that has been worn away

A_7x_7 models the effect of tooth wear on penetration rate. It assumes that the teeth wear exponent, a_7, is zero and that the remaining exponent's a_1 to a_8 are regressed.

$$x_8 = \frac{\rho_m q}{350\mu d_n} \tag{30}$$

ρ_m = mud density, ppg

q = discharge, gal

μ = Apparent viscosity at 10000 $\sec^{-1}$, cp

d_n = Nozzle diameter, inches

a_8x_8 models the effect of bit hydraulics on penetration rate.

The viscosity can be expressed using the following equation: [42]

$$\mu = \mu_p - \left(\frac{\tau_y}{20}\right) \tag{31}$$

μ_p = Plastic viscosity, cp

Multiple Regression:

To solve the equations above it is necessary to perform a multiple regression analysis. Regression is based on using a complete equation in a matrix multiplication operation. The following equation is used for solving multiple regression:

$$\begin{bmatrix} x1_1 & x2_1 & x3_1 & . & . & x8_1 \\ x1_2 & x2_2 & x3_2 & . & . & x8_2 \\ x1_3 & x2_3 & x3_3 & . & . & x8_3 \\ . & . & . & . & . & . \\ . & . & . & . & . & . \\ x1_n & x2_n & x3_n & . & . & x8_n \end{bmatrix} \begin{bmatrix} a_0 \\ a_1 \\ . \\ . \\ a_k \end{bmatrix} = \begin{matrix} y_1 \\ y_2 \\ . \\ . \\ y_k \end{matrix} \tag{32}$$

With constant values in equation (32), the results can be described as,

$$Y = [A^T A]^{-1}\, x\, [A^T b] \tag{33}$$

Optimization of WOB and RPM

It is possible to obtain the optimal WOB, $\left(\frac{w}{d}\right)_{opt}$, and RPM, N_{opt}, by using equation (34) and (35).

$$\left(\frac{W}{d}\right)_{opt} = \frac{a_5 H_1 \left(\frac{W}{d}\right)_{max} + a_6 \left(\frac{W}{d}\right)_t}{a_5 H_1 + a_6} \tag{34}$$

$$N_{opt} = 100\left[\frac{\tau_H}{\tau_b}\frac{\left(\frac{w}{d}\right)_{max} - \left(\frac{w}{d}\right)_{opt}}{\left[H_3\left(\frac{w}{d}\right)_{max} - 4\right]}\right]^{\frac{1}{H_1}} \tag{35}$$

$H_1 = H_2 = H_3 =$ constants

The values of H_1, H_2 and $\left(\frac{w}{d}\right)_{max}$ depend on used bit type and the classification of bits wear.

The equation below is used to calculate the formation of abrasiveness, τ_H.

$$\tau_H = \frac{t_b}{J_2(h_f + \frac{H_2 {h_f}^2}{2})} \tag{36}$$

Where J_2 can be expressed as:

$$J_2 = \left[\frac{\left(\frac{W}{d_b}\right)_m - \left(\frac{W}{d_b}\right)}{\left(\frac{W}{d_b}\right)_m - 4}\right]\left(\frac{60}{N}\right)^{H_1}\left(\frac{1}{1+\frac{H_2}{2}}\right) \tag{37}$$

$J_1 = J_2 =$ a function of bit weight per inch and rotary speed

H_1, H_2, H_3 and $\left(\frac{w}{d}\right)_{max}$ can be find by using Table 4.

Table 4 — Overview over input data for use in equation (37)

Bit class	H_1	H_2	H_3	$(w/d)_{max}$
1-1 to 1-2	1,9	7	1,0	7
1-3 to 1-4	1,84	6	0,8	8
2-1 to 2-2	1,8	5	0,6	8,5
2-3	1,76	4	0,48	9
3-1	1,7	3	0,36	10

3-2	1,65	2	0,26	10
3-3	1,6	2	0,20	10
4-1	1,5	2	0,18	10

Optimizing WOB and RPM may increase the ROP, but the drilling process will not gain optimum when tooth wear condition can be increased. The level of bit wear can be represented from the depth interval which drilled by the bit (ΔD). Those depth intervals can be estimated by the following equation:

$$\Delta D = J_1 J_2 \tau_H \left[\frac{1 - e^{-a_7 h}}{a_7} + \frac{H_2\left(1 - e^{-a_7 h} - a_7 h_f e^{-a_7 h}\right)}{a_7^2}\right] \quad (38)$$

Where J_1 can be expressed as:

$$J_1 = f_1 * f_2 * f_3 * f_4 * f_5 * f_6 * f_7 * f_8 \quad (39)$$

4.7 COST

Like all other industry in the world, the petroleum industry's first priority is profit. Without a positive result the industry would not exist, and keeping the costs as low as possible if important for achieving good economical results.

4.7.1 CAPEX - OPEX

The cost for a business can be divided into two types groups, CAPEX and OPEX. CAPEX, or capital expenditure, are all costs related to the installation of a company, like buildings, machines and equipment, while OPEX is all costs related to operating the company.

In the oil and gas business, the CAPEX can vary a lot depending on the field development plan, the complexity of planned drilling operations etc. Drilling a well can be highly time consuming and represents a high part of the total capex.

OPEX, or operational expenditure, are all costs related to operating the company, like wages, repairs and maintenance. An oil company will always want to have as low CAPEX and OPEX as possible. With a high OPEX, the time spent before all investments are paid back will be high. The oil companies operate with a “break-even” margin, which represents the oil prize the company requires to generate a positive income. With the unstable oil prize it is in the best interest to keep the “break-even” prize as low as possible. The low oil prize has also caused a lot of oil projects on the NCS to be put on hold due to uncertainties regarding profitability. The break-even prizes for Brent-oil at the NCS range from 30$ all the way up to 100$. [43] At the time this thesis was written, the oil prize was in the range 63-67$. The fields with high break-even prize were developed from 2010-2013 when the oil prize was high, and expected to stay high. These developments would not be developed today…

4.7.2 Drilling costs

One of the most expensive operations when developing a field is drilling the wells. Drilling is time consuming, and requires a wide range of equipment available if a problem should occur. A lot of people are also needed in both the planning of the well and during the drilling operation. As will be described in chapter 4.7.3, the offshore costs are highly sensitive to time. When experiencing drilling problems, that result in low ROP and NPT, this will increase the overall expenses for drilling the well drastically. It is because of this very important to keep the ROP has high as possible and reduce NPT.

4.7.3 Offshore

Maintaining an offshore rig causes a lot of extra expenses contra an onshore rig. Maintaining a rig offshore is highly expensive, with high day rates. The day rate is often the highest overall costs, with crew members, equipment, and supplies etc. as smaller cost posts. Due to high daily costs, reducing the drilling time will off best interest to reduce rent time. Time is very important in an offshore drilling operation, while onshore the equipment will be a larger part of the overall cost. Consequently, problems occurring offshore needs to be handles as quick as possible to save time. In the North Sea, Wait on Weather (WOW) is a huge cost post, as operations needs to be put on hold during the bad weather. WOW is not possible to adjust, compared to other posts, where adjustments can be made to reduce NPT.

5 Proposed drilling optimization procedure

Like mentioned, drilling in hard formation can cause numerous of drilling problems like increased bit wear, vibration and shock, bit damage and lower ROP. All these problems results in additional time spent on drilling operations, increasing the overall costs. As will be described in this chaper, costs are highly related to the time spent in offshore environment. Therefor it is benefitual to minimize operational time as much as possible, still within safe operational manners. Based on this, a procedure for selecting the right drilling method when encountering hard rock formations will be introduced.

5.1 PROCEDURE DEFINITION

To increase the efficiency of a drilling operation it is vital to increase ROP and reduce NPT. If these criterias are met, the overall drilling time will be reduced thus reducing cost. The idea behind the procedure is to look for the possibility for combining rotary and percussive drilling in an offshore environment to fulfill the criteria's. Replacing rotary drilling with percussive has shown great result other places, like in Sweden [25] and Oman [21].

As described in chapter 4.7.3, drilling costs are more sensitive to time than equipment when drilling offshore. Based on this, a question arises that will be answered using cost simulations. "Will the time saved by increasing ROP by changing drilling technique in the middle of a section compensate for the time spent tripping and changing equipment?" This would most likely not be economical feasible onshore, but due to the high rig rates offshore it might be beneficial. Changing equipment could be done before starting to drill a new section where the target depth of the previously section should, if possible, be changed to increase ROP.

The procedure contains a four step plan which is illustrated in a decision tree in Figure 20.

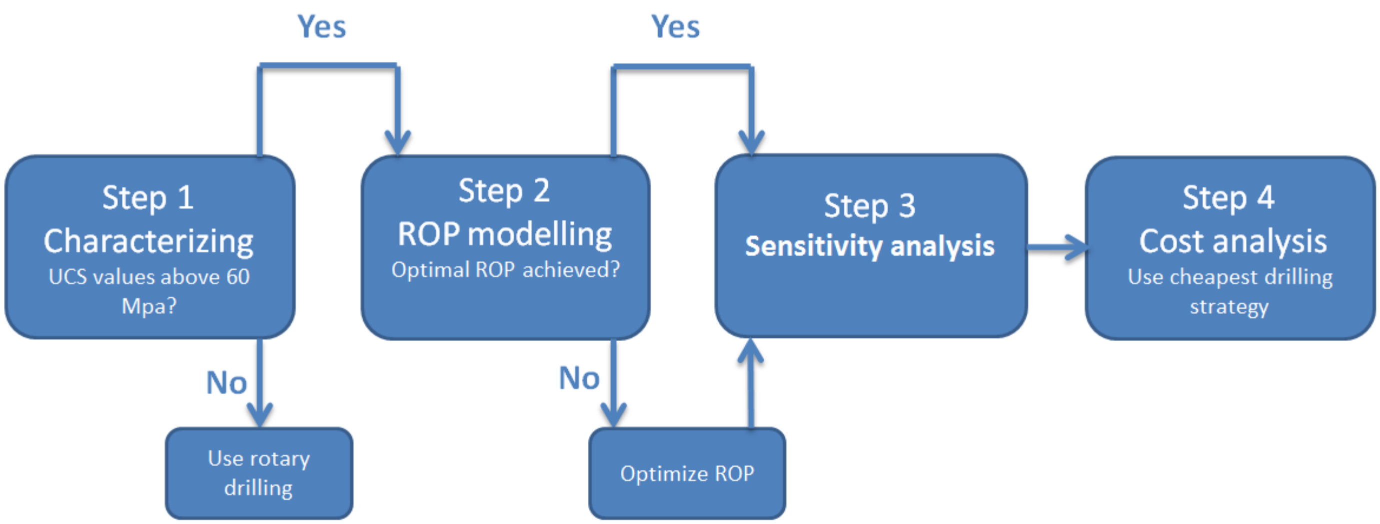


Figure 20 — Decision tree based on the procedure

The results will be achieved by using data from an old well, given that a new neighbor well is to be drilled. An illustration of the concept is in Figure 21.

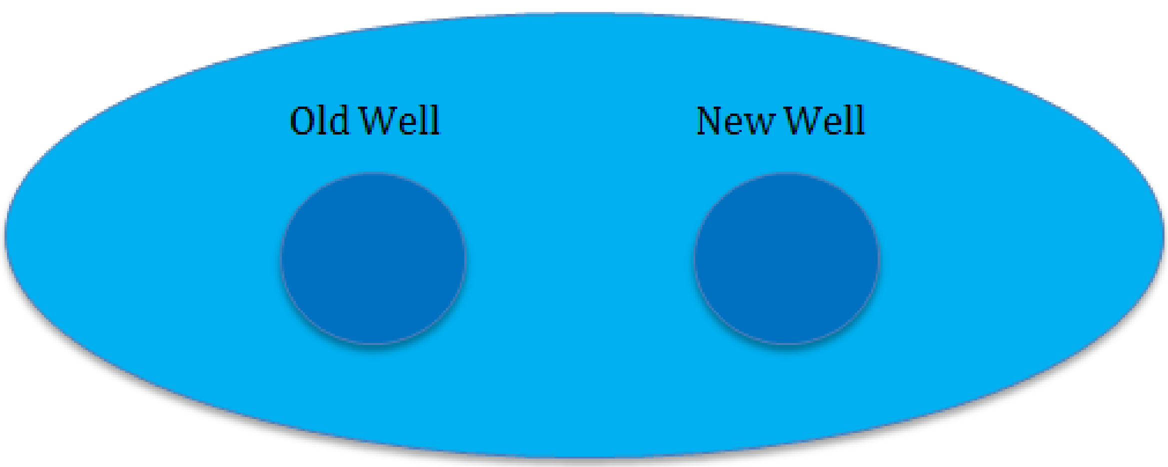


Figure 21 — Illustrates the concept for using the drilling data

The steps will be further described in the next sections.

5.2 DETAILED DESCRIPTION OF PROCEDURE

The following chapters will give a detailed description of each step.

5.2.1 Step 1 - Charectorizing the formation

When carectorizing the formation the main parameters will be hardness and drilling limitations. For determining the hardness of the formation, the UCS of the formation will be calculated and compared to Table 1. UCS will be calculated using equation (3) or (5). Before the carectorizing can begin, the UCS data should be plotted against depth to give a good overview.

Once data is plotted, the following procedure is to:

- Identify the hard formation
- Located the hard formation
- Estimate the thickness of the hard formation
- Look for alternation between soft and hard formation

The first step is to identify the calculated UCS data. As percussive drilling is to be used from moderate-hard to very hard formation it is crucial that the well actually contain these hardness values. If the well does not contain these hardness values there is no need to continue the procedure and rotary should be used as drilling method. An example could be:

Table 5 — Example of strength classification of a well

Depth Interval (m)	Strength Classification	Strength (MPa) **UCS**	Drilling method	Remark
1000-1500	Weak	20-30	Rotary	
1500-2000	Medium-Hard	60-80	Rotary/Percussive	
2000-3000	Hard	80-120	Percussive	

As seen from table 5.1 there is a potential for using percussive from 1500-3000 meter. It could also be benefitual to bring up experience from similar wells to check the operational result.

Once the UCS data has been plotted and hard formation detected, the depth of the intervals should be studied. As percussive drilling has some operational limitations regarding depth this could be detected by finding the depth intervals. The transitional depth between two strength classificiations, with hardness of medium or stronger, should be compared to TD of the casings. If possible, the TD of the casings should be at the same depth as the transition two strength classificiation as it would result in increased drilling efficiency.

Thirdly the thickness of the hard formation should be evaluated. If the well consist of a few thin layers of hard formation the benefit from using percussive drilling will reduced and rotary drilling should be used. There should be performed detailed studies to see how much the thickness influence ROP and how much is gained from changing to percussive.

Lastly, investigation of possible alternation environment should be performed. As described in Common drilling problems 2.5.1, this can cause several problems. Alternating environments reduces the ROP and a section with several different strength regimes can be classified as the highest strength classification regime.

Pressure and temperature effects will not be included in the procedure due to simplifcation.

By following these steps the formation should now be properly. If the well has hard formation present, at an acceptable depth, with decent thickness or an alternating environment, the next step should be executed.

5.2.2 Step 2 - ROP evaluation

This step is to evaluate if the ROP experienced in the well is optimized or if external factors have caused the ROP to be low. Hard formation will automatically reduce ROP so a reduction is expected. But could bit wear or other factors cause decrease of the ROP? By comparing MSE and UCS values it is possible to detect if external factors have caused low ROP. UCS is already calculated in step one, while MSE can be calculated using equation (1). The MSE represents the energy contributed to the drilling system while UCS represents the energy required for breaking up the rock. When plotted vs depth, these values should be more or less two parallel lines. By using equation (7) or (8), UCS can be converted to MSE, or MSE to UCS which improves the overview. If MSE deviates from UCS this is an indication that something is wrong. If more energy is contribued to the system than needed, this "extra" energy is spent on something else…

An example is shown below in Figure 22

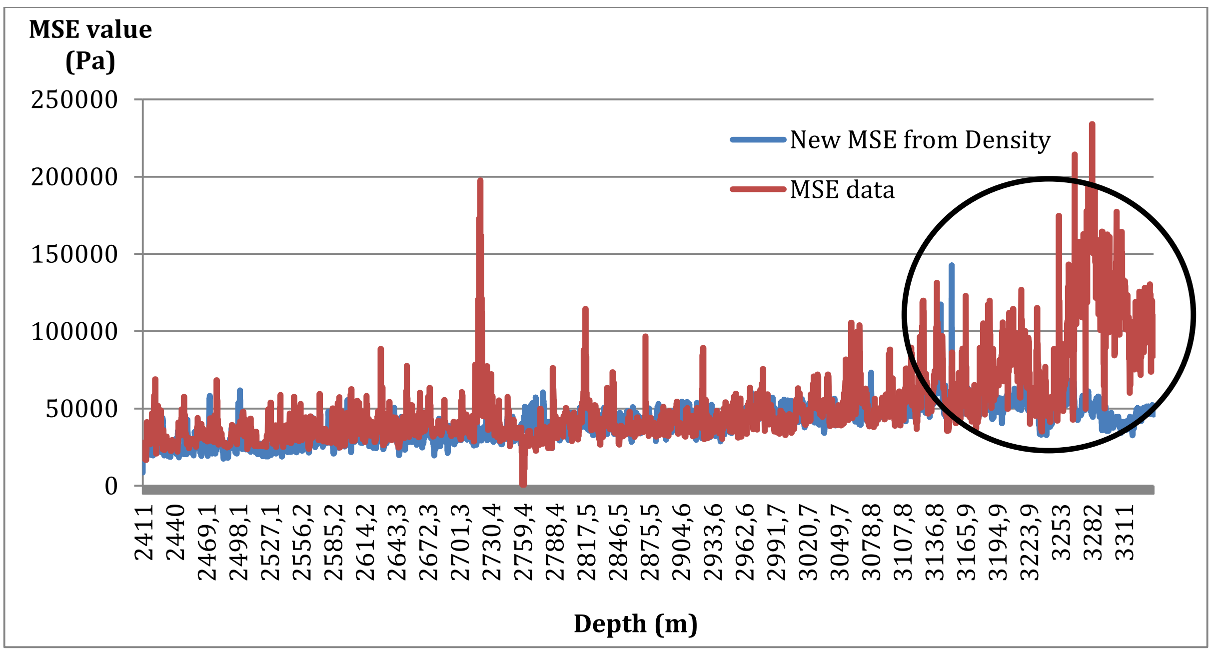


Figure 22 — Example of possible relation between MSE and UCS

The data is gathered from a well in the NCS. It clearly shows a deviation between the UCS and MSE starting at around 3250 mMD. The red line represents MSE calculated from the drilling parameters, while the blue line is MSE data calculated from UCS. The deviation, marked with the black circle, is closer investigated in Figure 23 on next page.

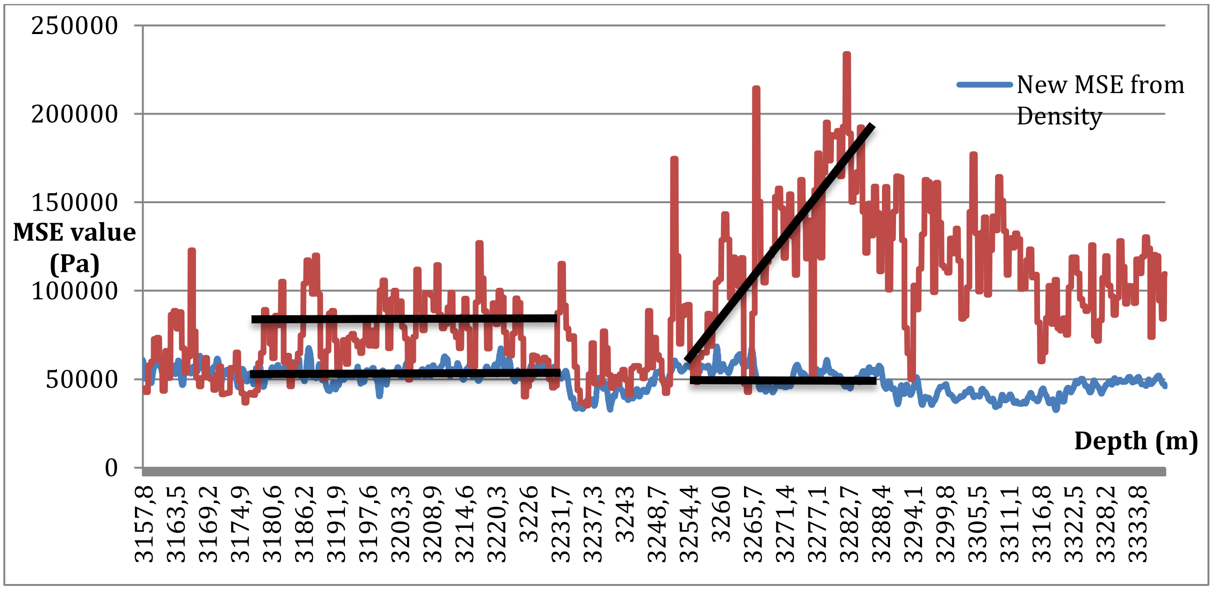


Figure 23— Close up of relation between MSE and UCS

A closer look shows the trend more clearly, where MSE slowly increases with depth while UCS values stays steady. The inserted trend lines illustrate that from 3250mMD something is not fully functionally, as the operation distributes more energy to the system than required. A bit change could solve the problem.

When finding diversions between UCS and MSE it means that the ROP gathered from the drilling parameters will give a wrong result when used in the cost analysis in step 4. To find the “correct” ROP, an optimization of the ROP should be performed. By using Bourgoyne and Young ROP model, described in chapter 4.6, an optimization of the ROP could be calculated resulting in a more realistic output of the cost analysis.

5.2.3 Step 3 - Sensitivity Analysis

Performing a sensitivity analysis will help detect which parameters in a model causes largest uncertainties. Equations used for optimizing the ROP should be analyzed to check sensitivity for the different parameters.

The analysis is performed by changing one of the parameters by a factor X, while keeping all other parameters constant. If you increase one parameter with 20% and see a huge change in the output you will know that this parameter is very sensitive to the result.

Figure 24 shows an example of how increasing the RPM effected the ROP.

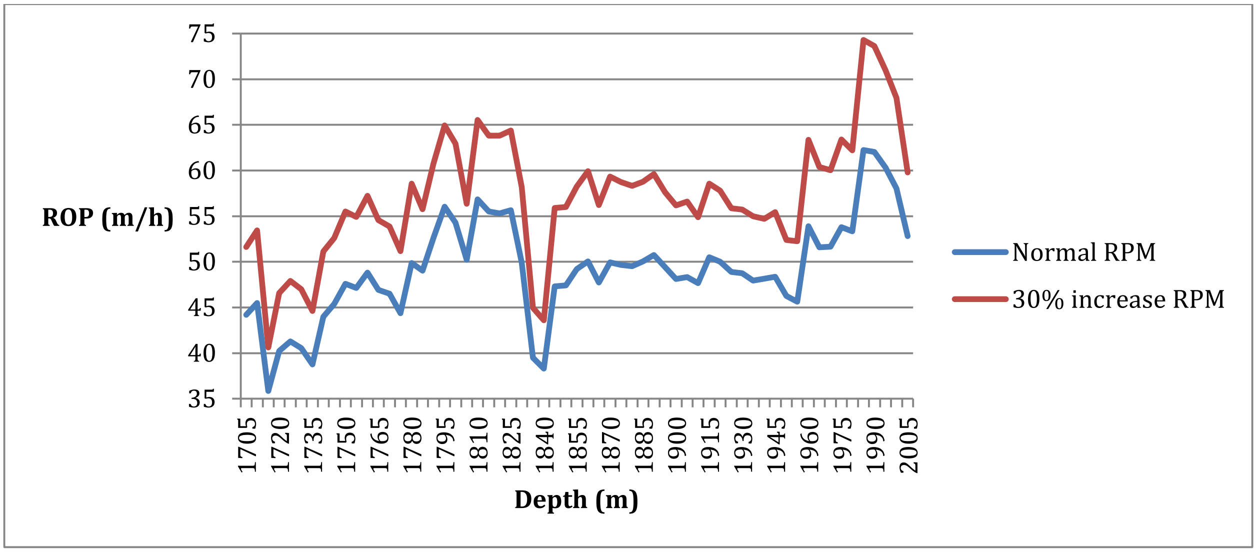


Figure 24 — Sensitivity analysis by increasing the RPM with 30%

By knowing which parameters are most sensitive, this can be usefull information when drilling the new well. There should be a high focus on optimizing the sensitive parameters for increasing ROP.

5.2.4 Step 4 – Cost analysis using Risk€

The simulations in this thesis will be done by using Risk**€.** Risk**€** identifies possible cost and operational durations based on Monte Carlo Simulations and sensitivity analysis with fundament in manual data input. The software was developed in 2008 by IRIS.

Monte Carlo Simulation

Monte Carlo Simulations is a mathematical technique based on analyzing uncertainties, risks and decisions. The output is based on probability and value relationship for key parameters.

A Monte Carlo Simulation works with one or more equations. The input data can be probability distributed or not and all input data are independent but can also be dependent. The output is shown as a probability distribution presenting the possible range of outcomes.

Monte Carlo Simulation also uses sensitivity analysis. By using sensitivity analysis, the model will find the "uncertainty drivers", the input variable which has the highest impact on the outcome results. It also finds which input parameter has most influence on the estimation.

Input data Risk€

This chapter will describe what the different type of inputs are and how they can be determined. There are three different ways the input parameters can be given.

- Deterministic value, ex. 150 meter
- Single probability, ex. 25%
- Probability density functions, ex. N(10/2)

Usefulness and Limitations of the Simulator

Risk€ can be a very useful tool in a cases where a cost estimation of a well is needed. As Risk€ includes the range of risks that can go wrong during an operations, the outcome will be a precise calculations, but dependent that the input data is correct. The input should be based on previous wells and experience and adjusted to suit the current well.

Input of Drilling Phases for Generation of Standard Operation Plan

Risk€ divided the well construction phase into 5 different phases:

- Mobilizing the rig – All costs related to mobilizing the risk, e.g. moving, positioning, anchoring
- Spudding – All costs related to spudding operation, e.g. technology, ROP, running speed, cementing
- Installing BOP – All costs related to installing the BOP, e.g. BOP type, nipple up, pressure test
- Drilling – All costs related to drilling, e.g. ROP, casing/cement costs, tripping
- Abandoning of the well – All costs related to abandoning the well, e.g. cement plug, retrieving BOP, corrosion related

The user chooses which phases should be included in the simulation. Each phase has some specific input and some which are common for all phases. But before this, the well architect needs to be defined. To enter the well architect, five input points are required.

- Casing Shoe Depth
- Casing Hanging Point
- Casing Outer Diameter
- Casing Inner Diameter
- Possible open hole section

Once the well architect has been defined, the phase set-up can begin. The common phase inputs are:

- Rig rate – The cost rate for the rig that is used for the well construction
- Drill string/BHA costs – The cost rate for the drill string including the bottom hole assembly
- Fixed costs – The sum of the fixed costs related to: site survey, rig positioning, rig mobilization/demobilization, different types of logging (e.g. electric logging, cased hole logging, Insurance, Fishing and abandon services, well planning
- Spread rate – The sum of the costs rates related to: vessels, additional (catering etc.), cement services and personnel, mud logging, conductor driving equipment, dock fees and base overheads, rental tools, consultants on rig, ROV; water, fuel (including rig and vessels)
- Wellhead costs – The fixed cost for the wellhead for the phase taken into consideration
- Support costs – The sum of the cost rates related to: Drilling office overhead, office support consultant, other drilling expenses, air transport

Some of the special input in each phase is:

- ROP
- Casing costs
- Cement costs

- Waste treatment costs
- Drilling bit cost

Input of Risk Events for Generation of Risk Operation Plan

When the architect and phase input has been added it is possible to run Risk€ and generate results. But to achieve most realistic results, risks events should be added. There is a tab where expected risks can be added. The most common risks are already integrated in the software, like stuck pipe, change of bit etc. but new risks can also easily be added by inserting probability and costs for the event. When this is done the generated results will also include expected costs for an unexpected event.

Output of Risk€

Once all data and risk events have been added, everything is ready for simulation. The program has two simulation options, 10 000 or 100 000 simulations. By running 100 000 the overall simulation will be more realistic.

The output will look something like this:

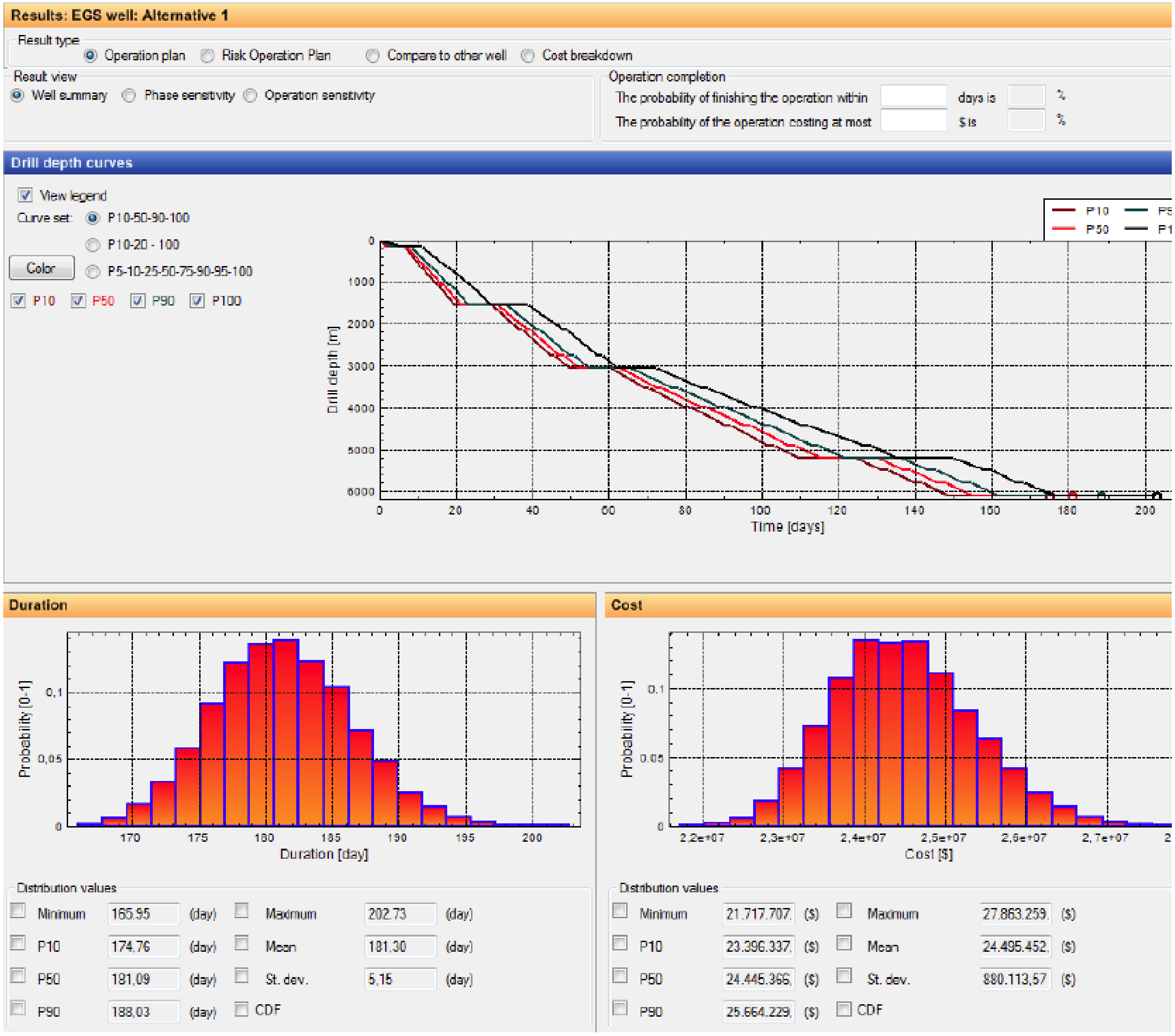


Figure 25 — Screenshot from risk output after simulation

As can be seen from Figure 25, the program shows four different time scale scenarios, P10, P50, P90 and P100. P10 means that there is a 10% chance that the outcome value is lower than the P10 value. P90 consequently means that there is 90% chance that the outcome value is lower than the P90 value, and P50 is 50% chance that the outcome is lower. P10 and P90 say something about the spread of the outcome.

By adding several wells and scenarios the output data can be compared and the cheapest and most efficient solution can be chosen.

5.3 CASE STUDY - WELL X

The decision for selecting this well was done by performing a screening by a total of 15 wells spread across the NCS. By comparing the UCS values the decision fell on a well from the Barents Sea from now referred to as “Well X”. The screening revealed that the reservoir section have around the same UCS values along the whole NCS, which means the result from Well X will give a good picture of the potential for implementing percussive on the NCS. Drilling data was gathered from mud log rapport and sonic log provided by the Norwegian Petroleum Department (NPD).

5.3.1 Assumptions

To be able to run the model, a few assumptions have to be made. It is assumed that percussive drilling can be used offshore without causing any extra expenses other than equipment and with optimal conditions without any reliability problems. Input data missing has been assumed after discussion with supervisor, external expertise and by comparing data from other wells. This thesis does not look at the possibility for implementing percussive at shallow depths where rotary drilling can experience problems due to low WOB.

As the last 200 meters of the well are unlogged, it will be assumed that the TD of 8 ½” section ends where the logging data stop.

5.3.2 Well X: Step 1 - Carectorizing the formation

First thing to be done was calculate UCS for the whole well. This was done by using equation (3), as sonic log data was available, except for the last 200 meters of the well. UCS was plotted vs depth for a good overview over the well. The corresponding stratigraphy and 4 help lines were added to increase the impression of the well. The result can be seen in Figure 26.

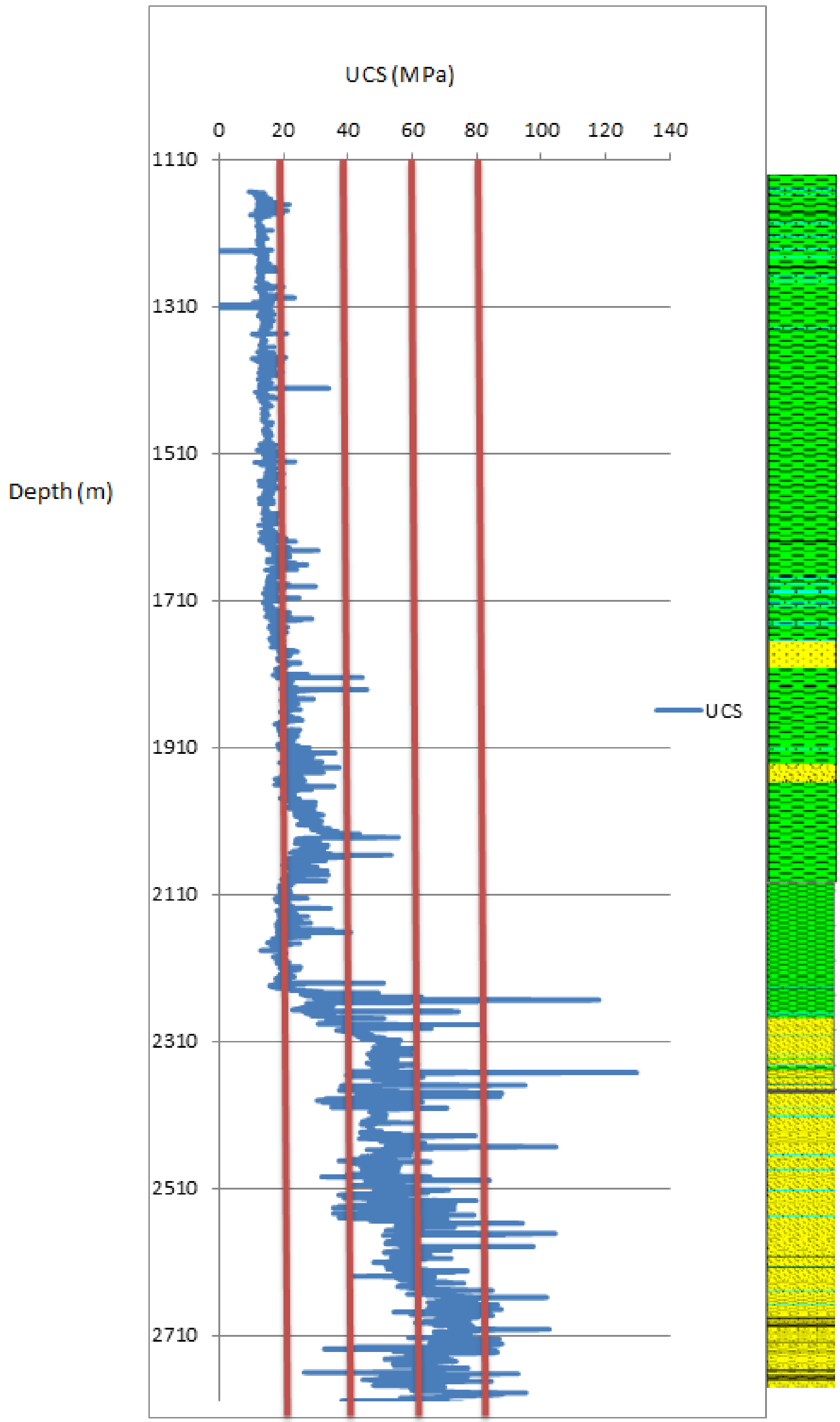


Figure 26 — UCS data for "Well X" plotted vs depth with corresponding stratigraphy

The well was divided into different sections depending on the UCS values. In this case, four different intervals were selected. The UCS values for each interval was compared to Table 1 to determine the strength classficiation. Based on UCS and theory stated in chapter 2.2 regarding usage of percussive drilling, the preferred drilling method were selected. All information is summarized in Table 6.

Table 6 — Strength classification for "Well X"

Depth Interval	Strength Classification	Strength (Mpa) **UCS**	Drilling method	Remark
1100-1800	Very weak	15-20	Rotary	
1800-2250	Weak	20-30		
2250-2510	Medium	45-55	Rotary/Percussive	
2510-2730	Medium-Hard	60-80		

It is worth mentioning that seeing as percussive drilling is most preferred for hard formation, it has been selected as an alternative drilling method in the medium formation to see how it will effect the overall cost.

As stated, it will be assumed that percussive drilling has no depth limitation in the execution of this case study.

Next step were to locate the hard formation and crosscheck against section of previously casing. The 12 ¼" casing is set at 2185 mMD which is 65 meters above the start of the "medium" strength formation. As a result, the 12 ¼" casing will be planned to 2250 mMD in the new well. The pore pressure plot need to be addressed to see if it`s possible. As seen in Figure 27 the pore and frac pressure limits are not exceeded by changing TD of the 12 ¼" casing . The mudweight of 1.26 SG in the old 12 ¼" section could be used, but a mudweight of 1.30 SG is suggested to increase margin.

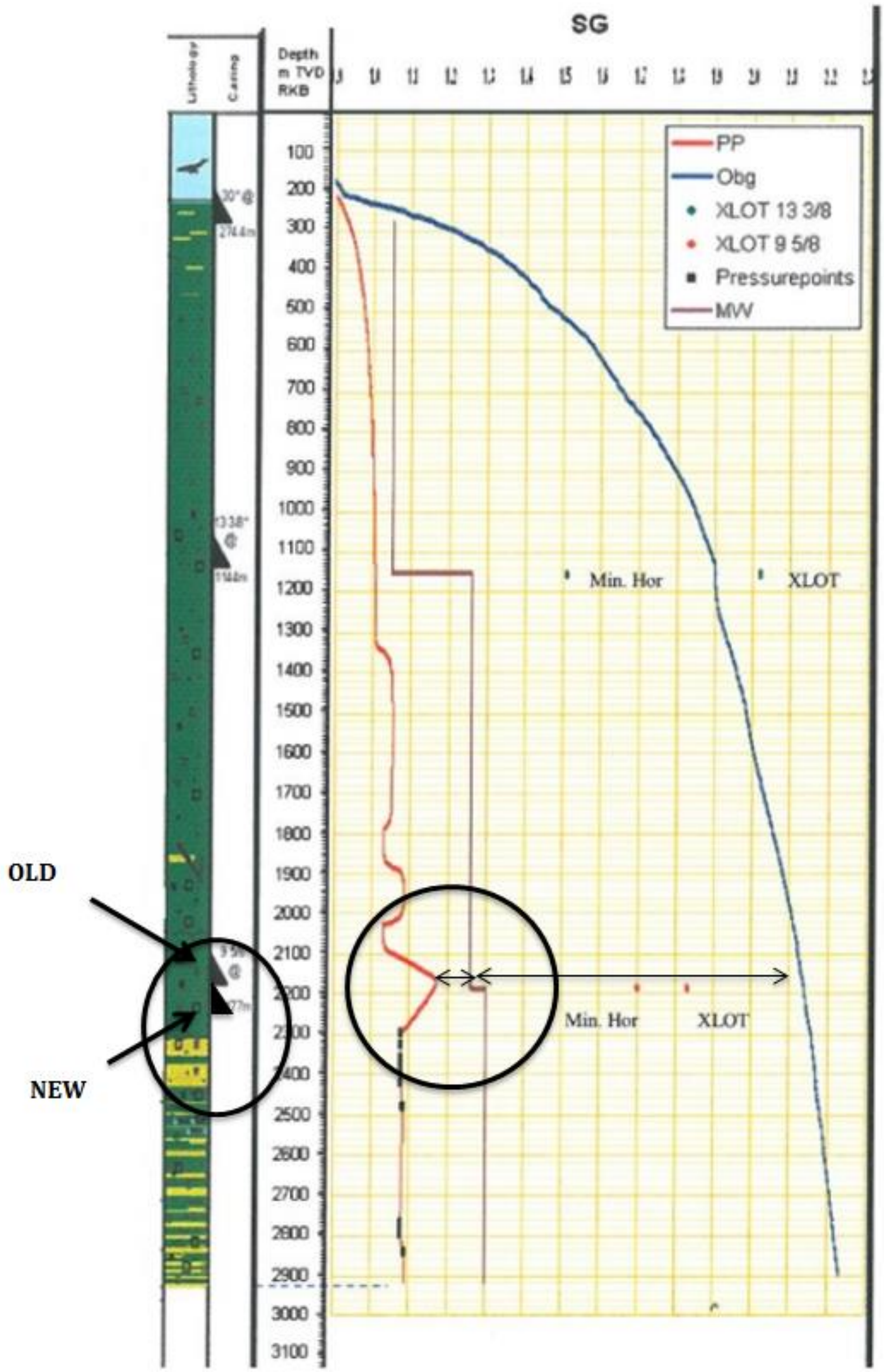


Figure 27 — Pore Pressure plot for well X with proposed change for 12¼" casing

A closer look at the stratigrahpy reveals that from 2250-2510mMD there are several layers of 1-3 meters thick stringers. There is also one very hard limestone string at 2352 mMD with a UCS value of 128 MPa.

The last interval, 2510-2730 mMD has few stringers, but the formation has an altering strength regime, where a few parts are classified as hard, with mostly moderate-hard strength regime.

5.3.3 Well X: Step 2 – Investigation of ROP

Next step is to investigate the ROP obtained from the drilling data. MSE was calculated using equation (1), while the UCS data was converted to MSE using equation (8). The two MSE values were then plotted, shown in Figure 28.

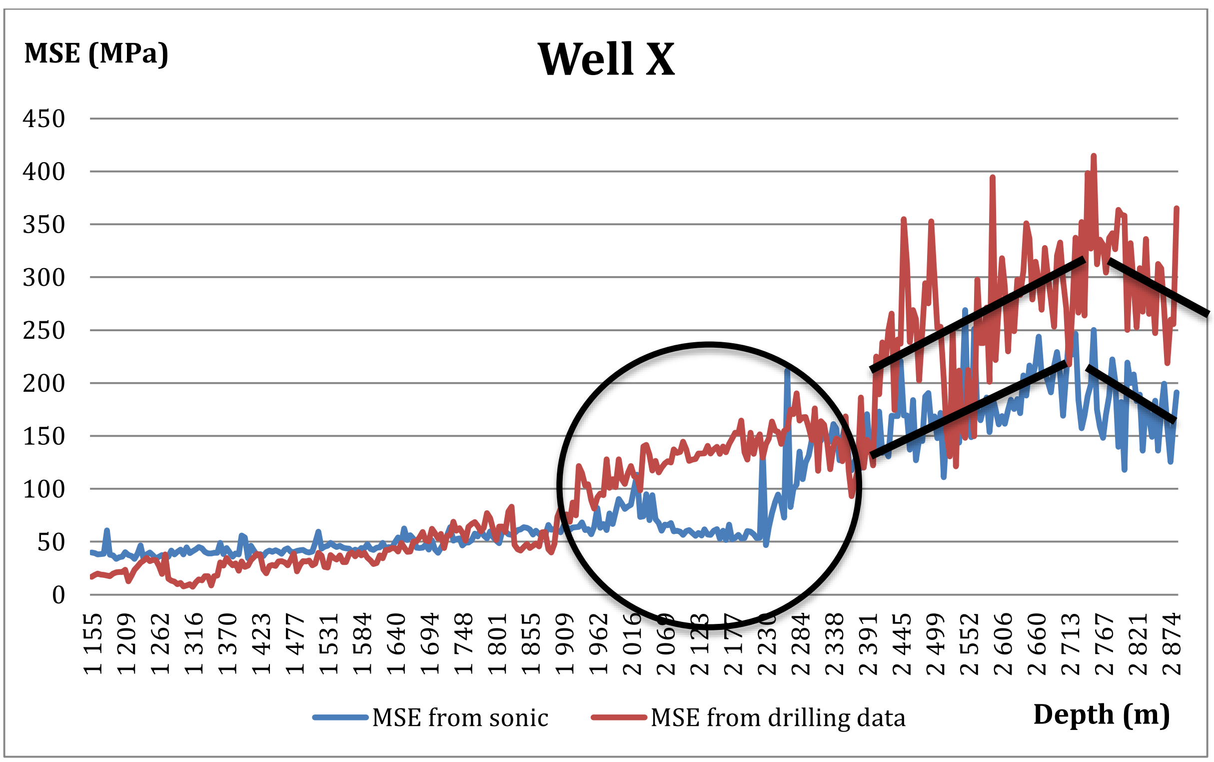


Figure 28 — Relation between MSE and UCS for "Well X"

Trend lines have been added to illustrate the relation between the two data sets for the reservoir section. As can be seen there is no big diversion between the two lines which conclude that the ROP values obtained is representative for the 8 ½” section. The area circled out, at around 2100-2300mMD, shows some diversion but because it has no relevance to the task in this thesis, it will not be further analyzed.

Due to lack of data, using Bourgoyne and Young`s ROP model did not conclude with any possible improvements of the ROP as calculating optimized WOB and RPM was not possible. As a result it will be assumed that the ROP achieved from drilling data is optimized.

The data achieved from using Bourgoyne and Young`s model is listed in Table 7. Regression was used first for the whole well and then for each section separately for a more precise result.

Table 7 — Shows output data from Bourgoyne and Young`s ROP model

	Whole well	**36”**	**17,5”**	**12,25”**	**8,5”**
A1	0,7246	9502,3318	-44,3143	-19,04144	132,86
A2	0,0007615	-0,9183	0,003868	0,002141	-0,0092
A3	0,0004085	25,0479	-0,1406	-0,08027	-0,1143
A4	-8,8087E-05	0,01233	0,0001963	-0,0001490	-5,1278E-05
A5	0,7883	-0,2828	0,4040	0,5672	-0,5107
A6	1,4845	-1,4910	0,2307	-0,3904	1,3719
A7	0,5794	12,8001	-0,3753	0,7650	-0,6080
A8	0,7154	9,8235	7,8043	-0,5391	0,3541

Figure 29 shows the relation between ROP gained from the drilling data and ROP from the model in the 8 ½” section.

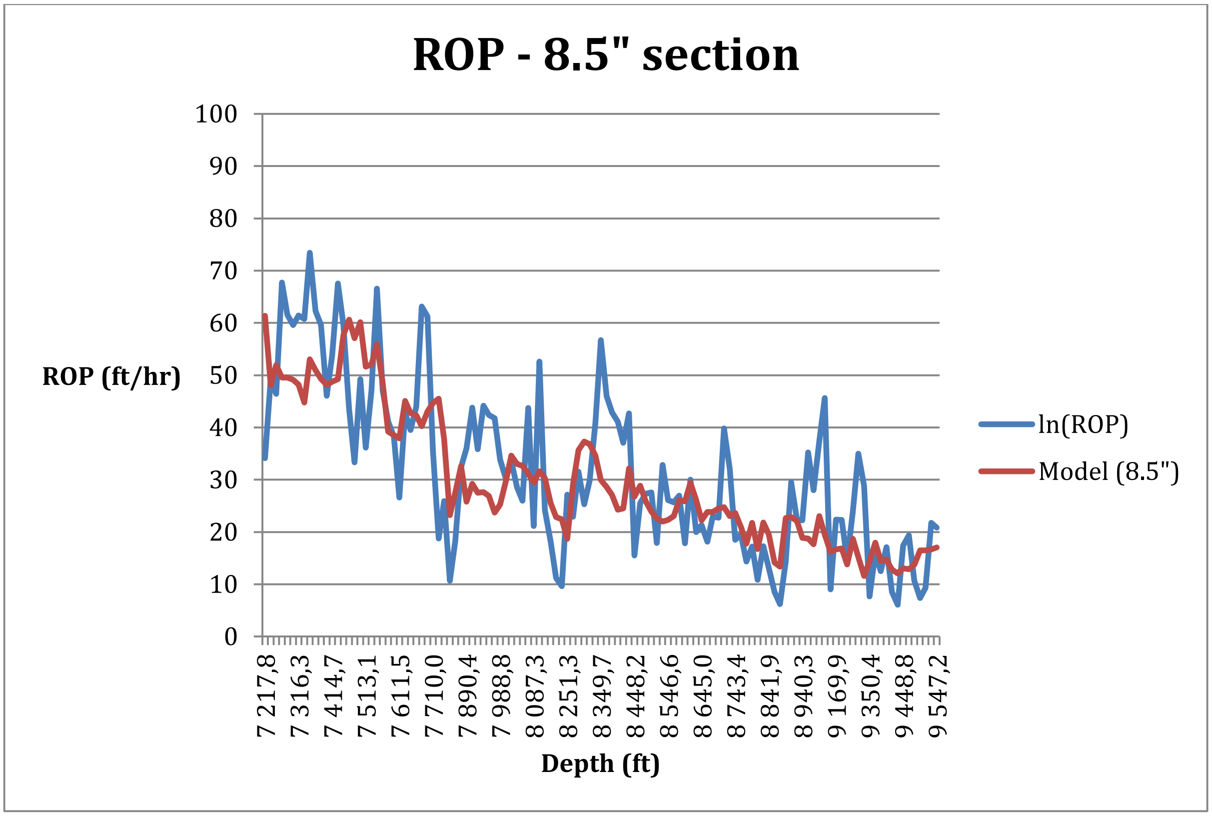


Figure 29 — ROP of model and drilling data plotted vs depth

As can be seen from Figure 29, the relation between the model and drilling data is slightly different. This indicates that the model is not 100% accurate. The relation for the rest of the well can be seen in the appendix.

5.3.4 Well X: Step 3 - Sensitivity analysis

Sensitivity analysis was done for Bourgoyne and Young`s model, where WOB and RPM was increased and reduced with 30%. The output for the 8 ½" section was then compared to the model and plotted in Figure 30.

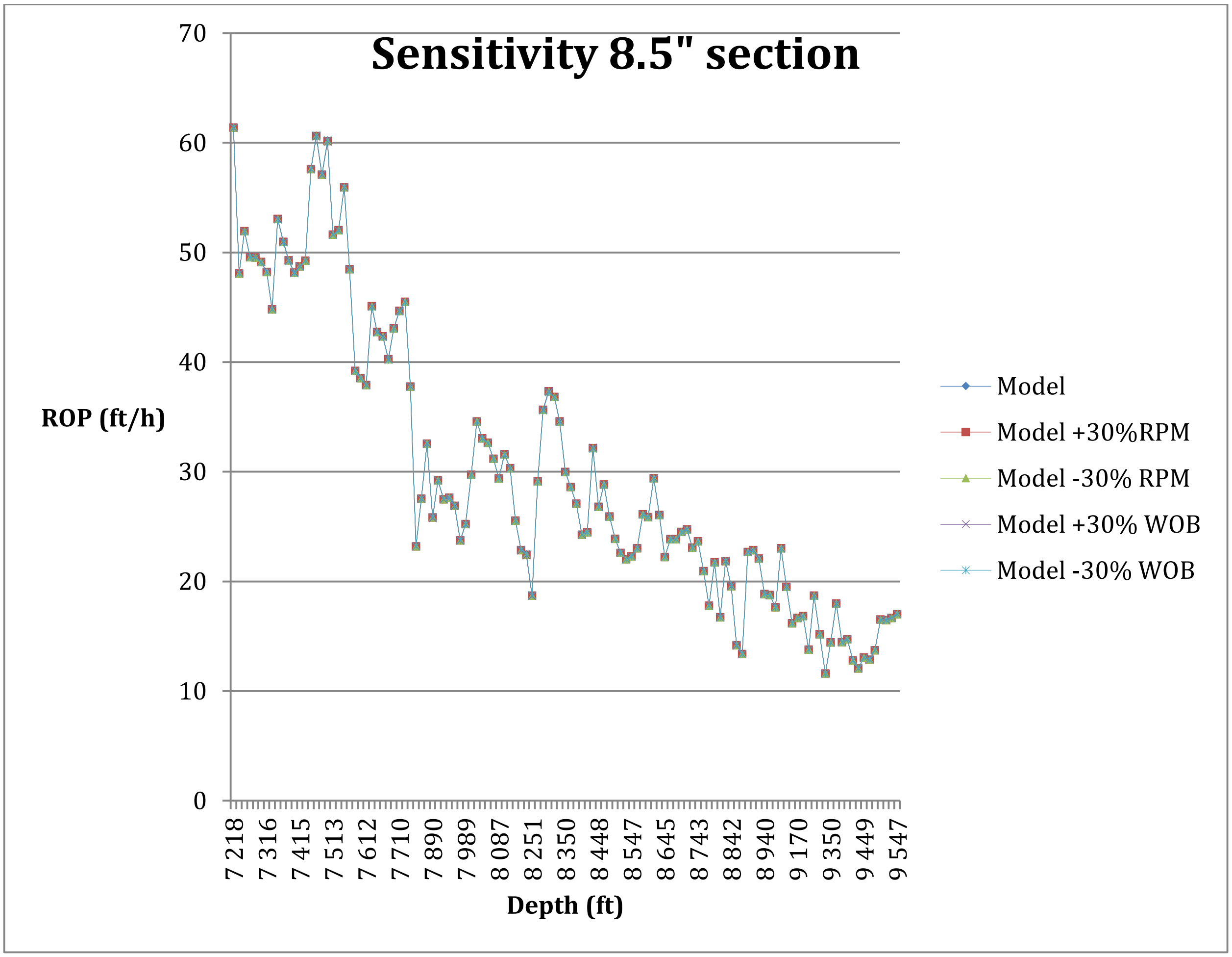


Figure 30 — Output of sensitivity analysis for Bourgoyne and Young`s ROP model

As can be seen in Table 8, there are microscopic changes for changing WOB and RPM, which could indicate that something is wrong with the model.

Table 8 — Overview over how changes in WOB/RPM effects ROP based on ROP model

ROP (m/h) output data from sensitivity analysis					
Model	**30% inc RPM**	**30% dec RPM**	**30% inc WOB**	**30% dec WOB**	**Depth (m)**
22,86	*22,86*	*22,85*	*22,81*	*22,91*	**2450**
22,43	*22,43*	*22,43*	*22,37*	*22,53*	**2455**
18,69	*18,69*	*18,69*	*18,66*	*18,75*	**2460**
29,13	*29,13*	*29,13*	*29,13*	*29,12*	**2465**
35,65	*35,65*	*35,65*	*35,69*	*35,58*	**2470**
37,32	*37,32*	*37,32*	*37,36*	*37,25*	**2475**

As can be seen from Table 8 , changes in the RPM has no effect while changing WOB has some effect. Increasing the WOB will, according to the model, decrease the ROP, while decreasing the WOB will increase ROP.

Sensitivity for the whole well can be seen in the appendix.

5.3.5 Well X: Step 4 – Cost analysis using Risk€

When running the cost analysis, four different scenarios will be evaluated. These are:

1) Rotary drilling in the whole 8 ½" section
2) Percussive drilling in the whole 8 ½" section
3) A combination of rotary and percussive
4) Change of 12 ¼" TD by 100m, then use percussive in the whole 8 ½" section

The difference between the four scenarios will be ROP and risks. Based on these input data, the generated result will indicate which of the four scenarios is cheapest.

Table 9 gives an overview over the difference in input data. All specific input data can be seen in the appendix.

Table 9 — Table showing overview over input data in Risk€

	Drilling Method			**Risk**			
Scenario	*Rotary*	*Percussive*	*ROP (m/h)*	*Bit change*	*Vibration*	*Tight hole*	*Stuck pipe*
Rotary	✓	✘	5,37	75%	40%	5%	5%
Percussive	✘	✓	6,32	50%	20%	3%	3%
Rotary + Percussive	✓	✓	6,61	10% + 100%	30%	4%	4%
Change TD 100m + Percussive	✘	✓	6,33	40%	25%	4%	4%

Following comes the output data from the cost analysis.

Scenario 1 – Rotary

This simulation is based on using the same drilling data as the neighbor well, no adjustments made. The output from the simulation was:

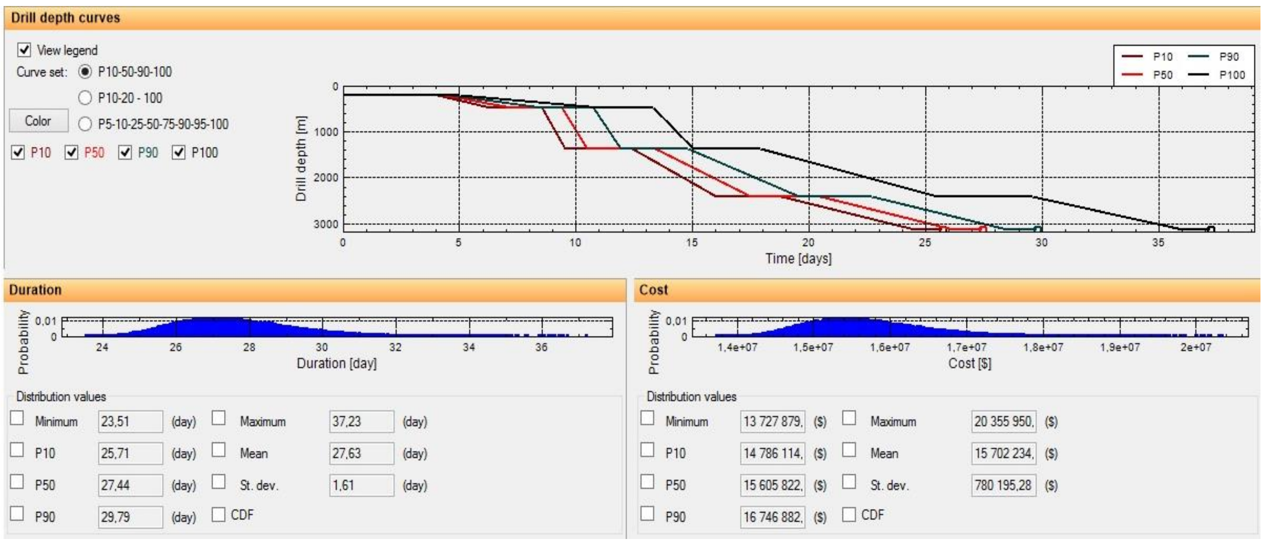


Figure 31 — Output data from scenario 1 in Risk€

As can be seen from Figure 31, the expected cost will be around 15,7 million $ with a maximum cost of 20,4 million $ and a minimum cost of 13,7 million $. The expected drilling operation time is 27,6 days, with a maximum of 37,2 days and a minumum of 23,5 days.

Figure 32 on the next page shows the expected cost breakdown.

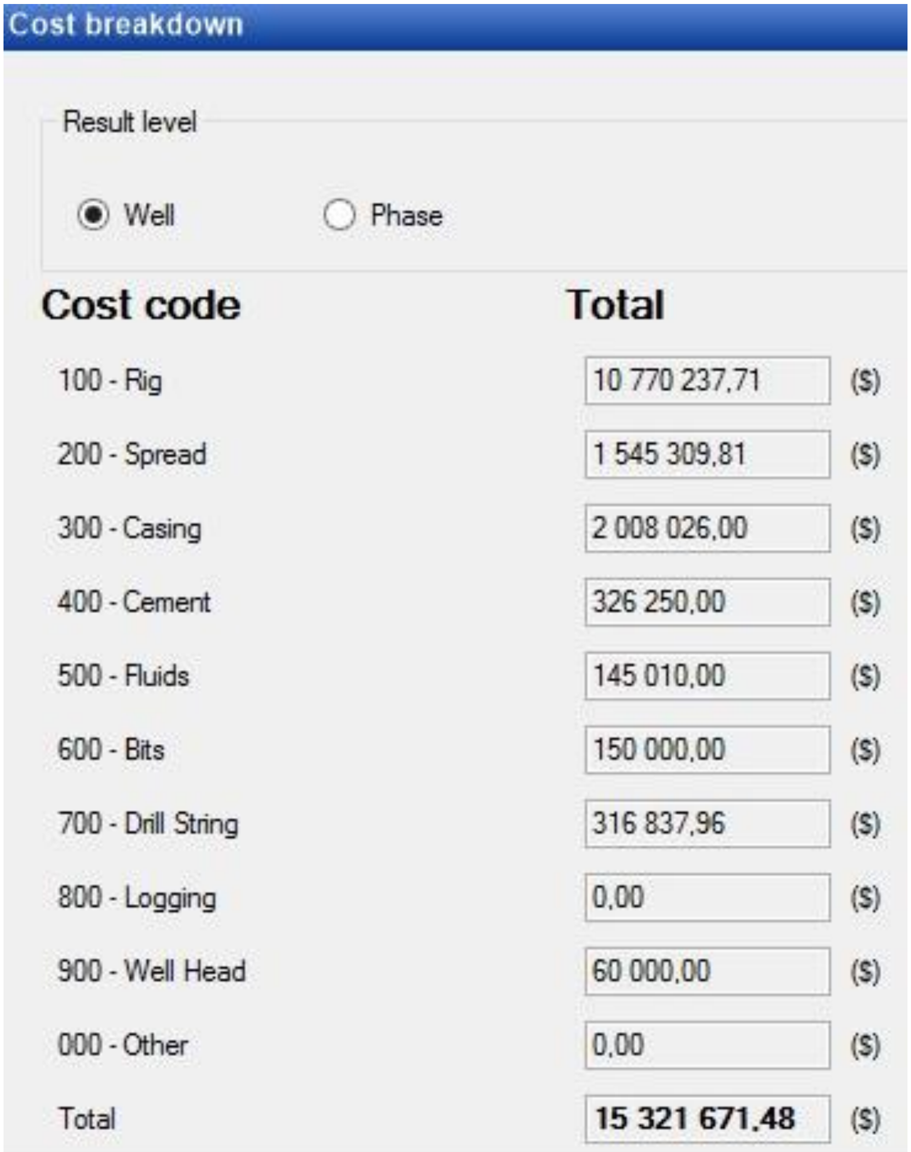


Figure 32 — Cost Breakdown data for scenario 1 in Risk€

As can be seen from Figure 32, the largest cost driver is the rig rate. As stated in theory, drilling offshore is highly depended on spending as little as time as possible for reducing the costs due to high rig rates.

Figure 33 shows the result from sensitivity analysis.

Figure 33 — Sensitivity analysis for scenario 1 in Risk€

As can be seen from Figure 33 , tight hole is most sensitivity to the costs for scenario 1. This is most likely due to the risk of drilling a sidetrack. The largest sensitivity of duration is the risk of needing to change bit. Due to using rotary drilling in moderate-hard formation, there is a great chance for needing to change bit at least once.

The output data from the remaining three scenarios have been added in a table at the end of the chapter. The following describes the input data from the three other scenarios.

Scenario 2 – Percussive

Scenario 2 assumes using percussive drilling through the hole medium to medium-hard formation, from 2250 mMD to 2730 mMD. It is assumed a -10% ROP reduction in the medium section from 2250-2510 mMD and a 50% increase in ROP from 2510-2730 mMD.

Scenario 3 – Rotary – Percussive

Scenario 3 is based on using rotary drilling in the medium section, from 2250-2510 mMD and then changing to percussive drilling. The ROP is assumed to be the same in the medium section and a 50% increase when using percussive in the medium-hard formation. Using this method require change of bit at 2510 mMD.

Scenario 4 – Change TD + Percussive

In scenario 4 it is assumed that the casing depth of 12 ¼" section is increased by 100 mMD then using percussive. It is assumed a 10% reduction in ROP from 2350-2510 mMD and a 50% increase in ROP from 2510-2730 mMD.

The following table shows the outcome data from all the scenarios. Table 10 is for days & cost while Table 11 is for cost breakdown & sensitivity.

Table 10 — Overview over output data for all 4 scenarios from Risk€

Method	**Days**			**Cost (million $)**		
	Minimum	***P50***	***Maximum***	***Minimum***	***P50***	***Maximum***
Rotary	23,5	27,6	37,2	13,7	15,6	20,4
Percussive	22,3	26,4	37,3	13,1	15,1	20,2
Rotary + Percussive	22,2	26,4	38,2	13,1	15,1	21,0
Change TD + Percussive	22,4	26,4	35,3	13,1	15,0	19,6

Table 11 — Overview over cost breakdown and sensitivity for all 4 scenarios from Risk€

Method	**Cost breakdown ($)**			**Sensitivity**	
	Rig cost	***Spread***	***Drill String***	***Cost (%)***	***Duration (%)***
Rotary	10,77	1,55	0,32	Tight hole (35)	Change bit (30)
Percussive	10,43	1,51	0,31	Change bit (31)	Change bit (31)
Rotary + Percussive	10,34	1,51	0,30	Tight hole (31)	Change bit (31)
Change TD + Percussive	10,43	1,51	0,31	Tight hole (31)	Change bit (30)

Looking at Table 10, the results for implementing percussive drilling in well X is an operating reduction of 1 day for all scenarios and a cost reduction of 600.000$ for scenario 4 and 500.000$ reduction for scenario 2 and 3.

Compared to the overall drilling costs for scenario 1, this is a reduction of roughly 3,8% compared to scenario 4 and 3,2% compared to scenario 2 and 3. But as all costs are constant for all sections it is more interesting to compare to 8 ½" section only.

Figure 34 shows the simulated costs for drilling the 8 ½" section using scenario 1.

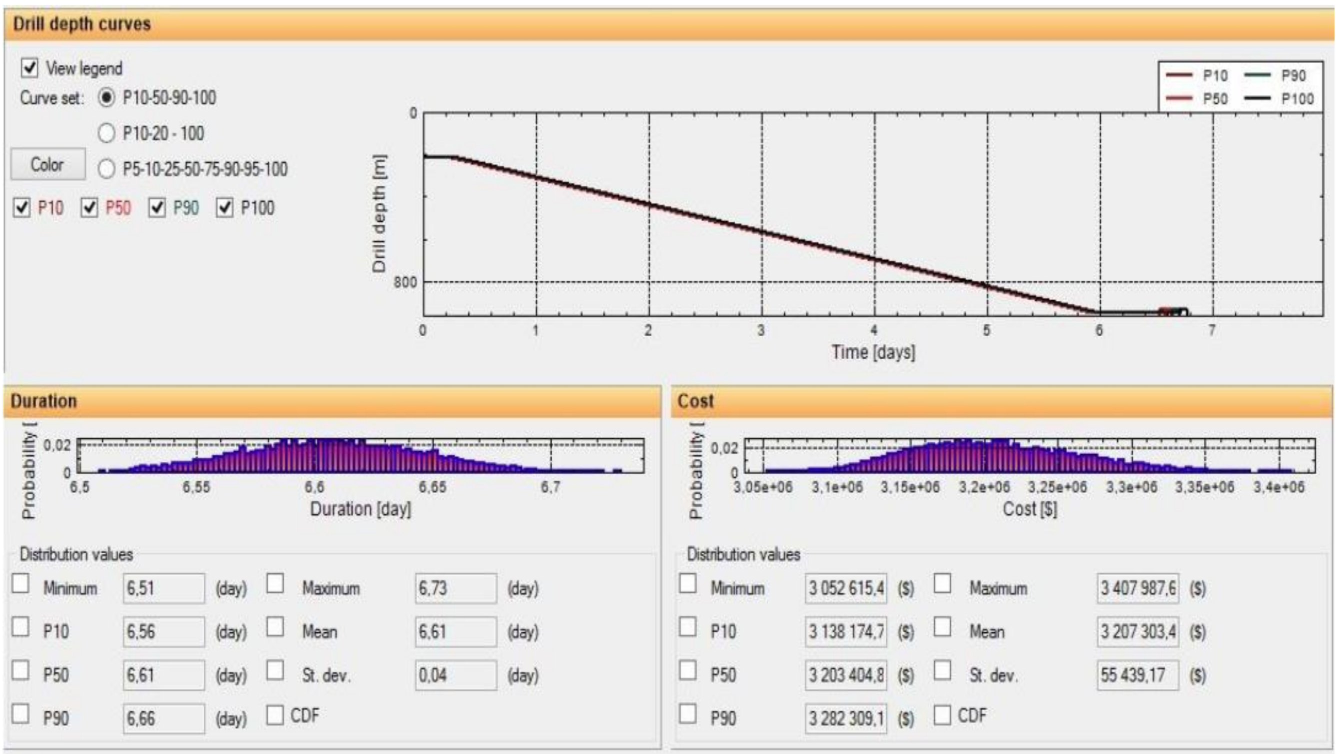


Figure 34 — Output data from Risk€ when only drilling 8 ½" section using rotary drilling

Figure 34 gives an estimated cost of 3,2 million $ for drilling the 8 ½" using scenario 1. The 600.000$ will be saved from these 3,2 million $ which is a reduction of roughly 18,8% compared to scenario 4 and 15,6% compared to scenario 2 and 3.

Estimated time for drilling the 8 ½" is 6,6 days, where all other scenarios need one less day, resulting in 5,6 days.

Table 11 reveals that rig costs are the largest single cost. The sensitivity for tight hole has decreased from scenario 1 by 4% compared to scenario 3 and 4. Scenario 2 has change of bit as its largest sensitivity regarding cost. The sensitivity for duration shows that all 4 scenarios are most sensitivity for change of bit, with only 1% difference between all scenarios.

5.4 DISCUSSION

The aim for this thesis was to look for the possibility for reducing drilling operational costs by increasing ROP and reducing NPT. This was done by theoretically implementing percussive drilling for rotary drilling in hard rock formation in Well X. Based on given assumptions, the result show a cost reduction of 18,8%.

As it was scenario 4 that showed largest decrease in costs, there should be performed studies to see how much TD of the 12 ¼” could be changed. As there are no detailed input data for the 12 ¼”, using real input data might reveal that drilling longer 12 ¼” section would be more expensive.

If the last 200 meters of Well X was included in the cost analysis, this could be an option for further cost reduction.

A question was introduced in the procedure: Would it be beneficial to change drilling technology in the middle of a section, forcing a bit change? Scenario 3 answered this question positively and revealed a cost reduction of 15,6% when changing from rotary to percussive in the middle of the 8 ½” section for Well X.

More complex studies are required before any final recommendation can be made.

Topics to be looked at are:

- The possibility for replacing a percussive BHA directly with a rotary BHA
- Costs related to training personnel
- Space requirements on the rig
- More detailed input data in Risk€
- Cutting transport simulations using percussive drilling at large depths
- Improvements of mud-hammer

The increase in ROP when implementing percussive was decided based on previous cases where percussive replaced rotary and by new percussive technology promising to increase ROP in hard rock using their tools.

The data input data was gathered from mud log rapport, sonic log and from previously Risk€ simulations. Missing data was selected after discussion amongst supervisor and external supervisor.

As ROP is one of the main factors driving the costs up, it was also important to check that the ROP gathered from the drilling data would be valid input data. To confirm this, MSE was calculated and compared to UCS to check for possible problems that could cause low ROP. The result showed no clear trend for the ROP to be classified as unacceptable. Even though it showed no clear trend, the ROP model presented in the thesis was used to try optimizing the ROP. Due to lack of data this was not achieved, and consequently the ROP from drilling data was used directly.

As the main aim was to study the 8 ½” section to see if percussive drilling was possible, several factors that could possible affect the total outcome was left out due to simplification. Only parameters covered in this thesis was included. The risk factors included were:

- Bit wear
- Vibration
- Bit change
- Stuck pipe
- Tight hole

6 Conclusion

The demand for energy is continuously rising. The petroleum industry has been feeding the world with energy for a century and will most likely continue to do so. This requires new technology and ideas for discovering new exploration areas. It is also important to focus on already existing industry and find possibilities for reducing cost and increasing efficiency.

Through this thesis different drilling technologies has been presented along with related problems. The application area for the drilling technologies has been presented. A procedure was developed aimed to predict if a well could benefit from implementing percussive with rotary drilling in the drilling operation. The procedure included, analysis of the formation, optimization of ROP and a cost analysis using Risk€, a cost analysis program from IRIS.

The main task was to investigate the possibility of reducing cost when drilling in hard rock formation offshore by increasing ROP and reducing NPT. As pointed out, the costs related to drilling and oil related operations have increased drastically over the last years. On top of this an unstable oil prize makes it difficult to predict the overall profitability.

The main challenges for drilling in hard rock formations have been listed down to:

- Low ROP
- Vibration
- Increased bit wear

It is important to point out that there is still a lot of testing needed to be done as percussive drilling is not matured for operating at large depths. It is also required to perform detailed studies with precise input data that can give improved outcome regarding the efficiency of using percussive drilling offshore. Space requirements for percussive equipment offshore and time required changing from rotary to percussive drilling are not discussed in this thesis. The overall costs reduction for an operation will be reduced when increasing ROP and reducing NPT. The result from the case study revealed an overall cost reduction of 18,8% in 8 ½” section when percussive drilling was implemented. 15 wells from NCS were screened before the finale well was chosen, and all wells showed similar UCS values. Based on this it can be concluded that wells on the NCS have a similar potential as Well X.

As a final conclusion for this thesis, it is recommended that the oil industry take a closer look at implementing percussive drilling offshore for reducing overall cost.

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8 Appendix

ROP model for "Well X"

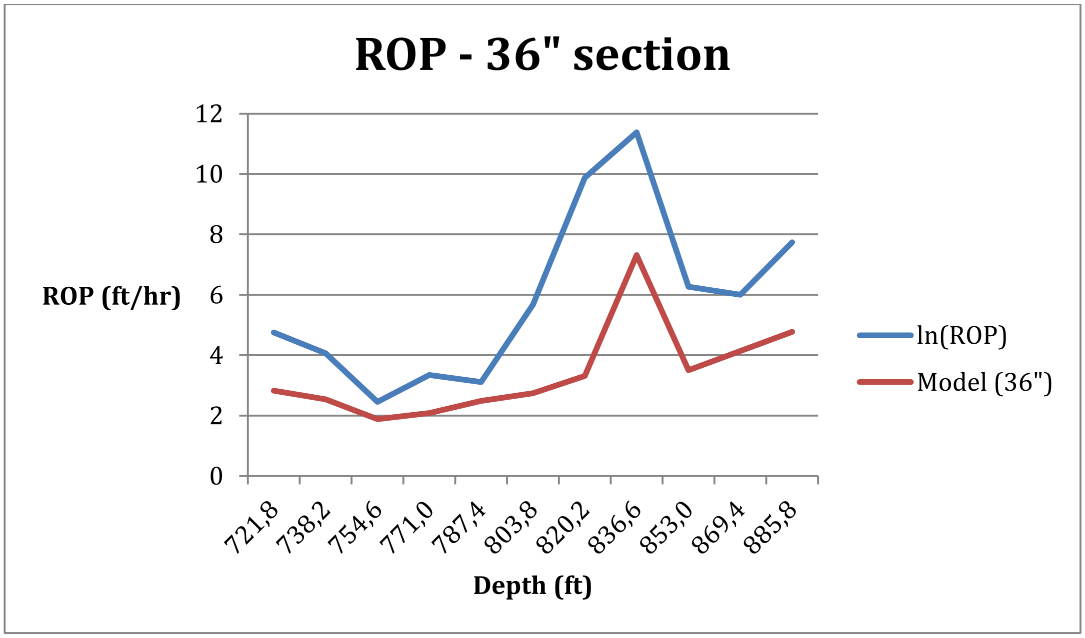


Figure 35 — ROP model for the 36" section

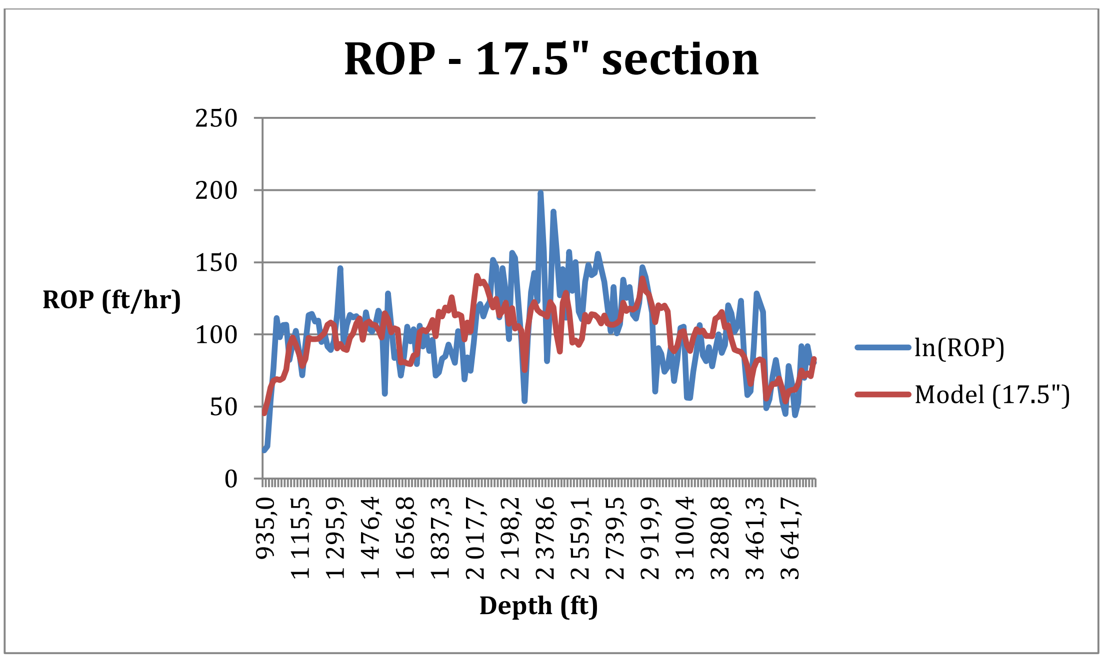


Figure 36 — ROP model for of the 17 ½" section

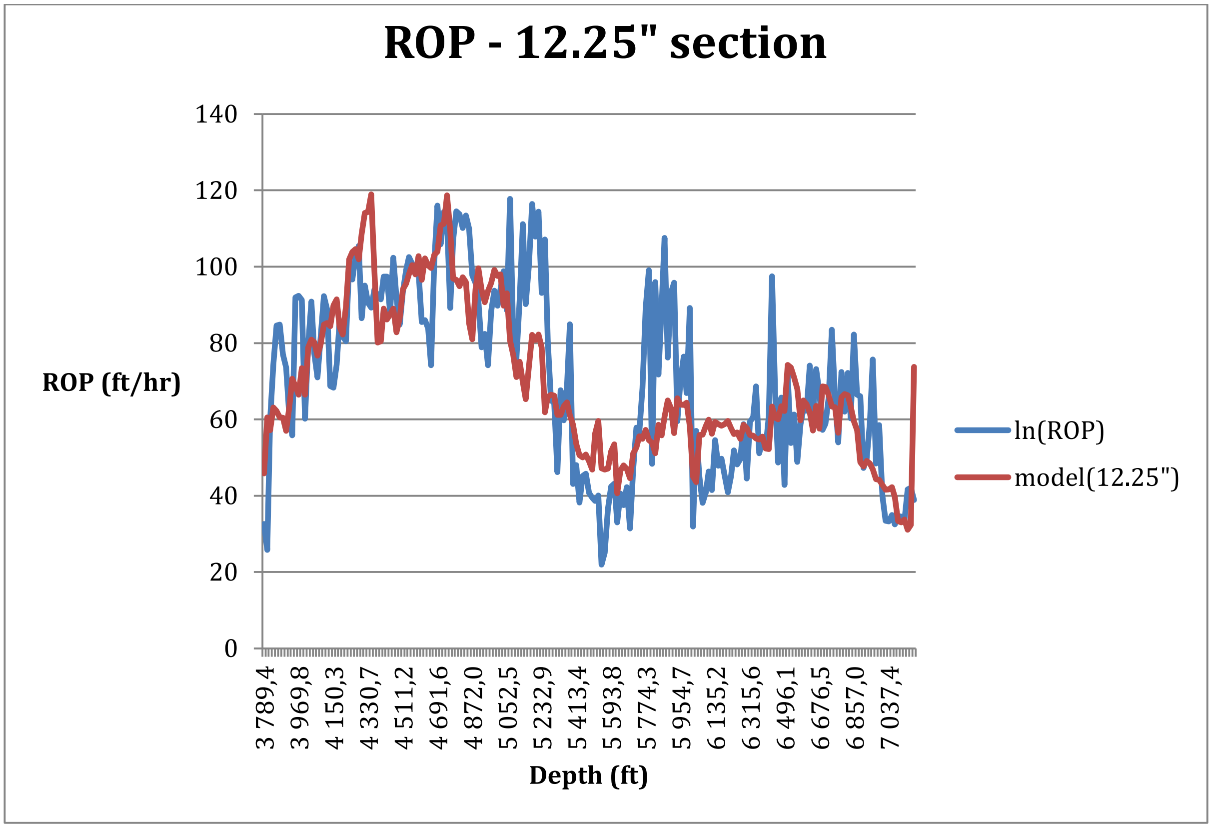


Figure 37 — ROP model for for the 12 ¼" section

Sensitivity analysis for “Well X”

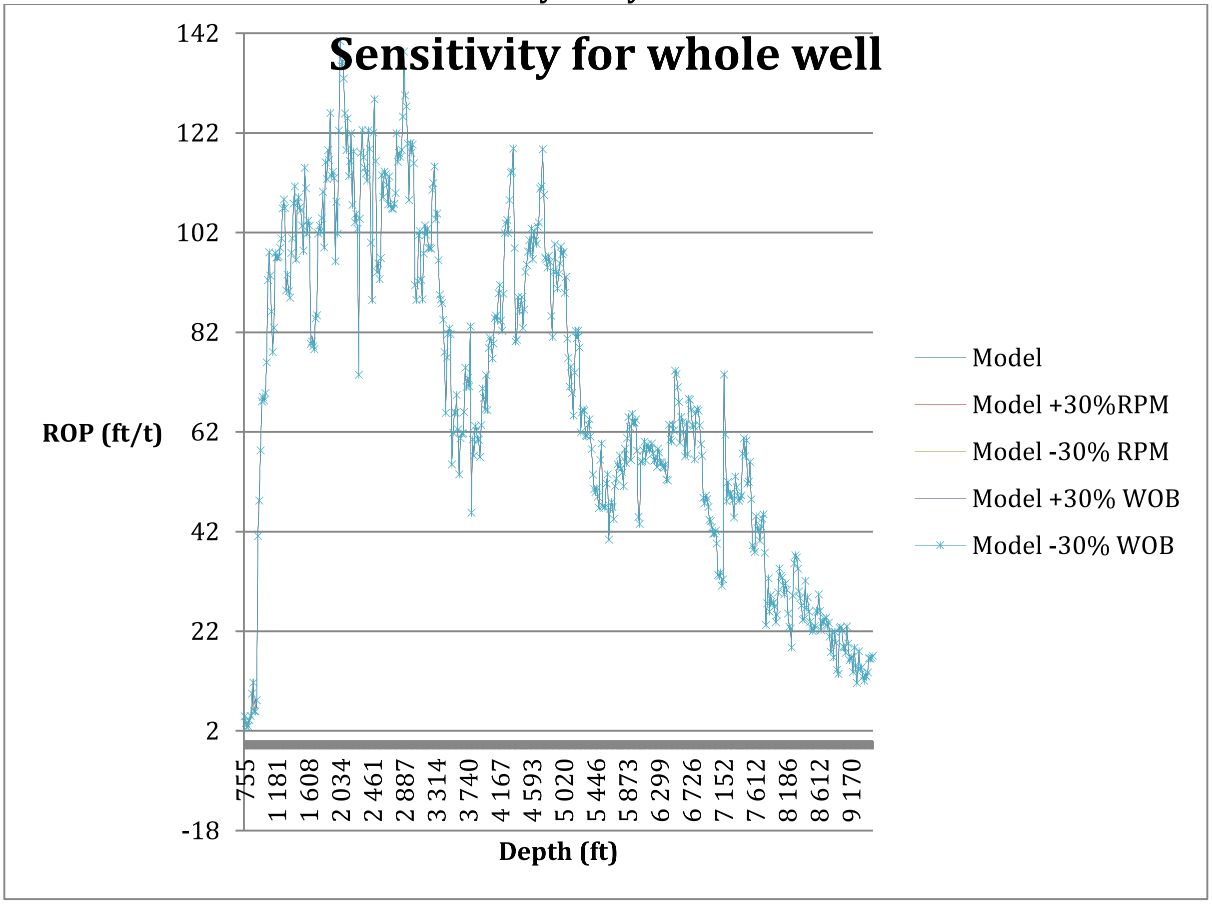


Figure 38 — Sensitivity analysis for the whole well

Input data in Risk€ simulation

Table 12 — Input data in drilling phase

Drilling phase				
Drilling/Circulation and Bit Parameters				
Parameter	**Distribution type**	**Minimum**	**Peak/Mean**	**Maximum**
ROP(m/hr) - 36" section	Triangle	1,8	3,6	7,3
ROP(m/hr) - 17 1/2" section	Triangle	16,4	31,7	60,4
ROP(m/hr) - 12 1/4" section	Triangle	5,1	10,7	16,9
ROP(m/hr) - 8 1/2" section	Single	-	5,37	-

Bit cost($) - 36" section	Uniform	60.000,00	-	100.000,00
Bit cost($) - 17 1/2" section	Uniform	15.000,00	-	25.000,00
Bit cost($) - 12 1/4" section	Uniform	18.000,00	-	32.000,00
Bit cost($) - 8 1/2" section	Uniform	20.000,00	-	30.000,00
Bit Change(hr)	Uniform	3,0	-	5,0
Circulation time(hr) - 36" section	Uniform	3,0	-	5,0
Circulation time(hr) - 17 1/2" section	Uniform	1,0	-	3,0
Circulation time(hr) - 12 1/4" section	Uniform	2,0	-	4,0
Circulation time(hr) - 8 1/2" section	Uniform	3,0	-	5,0
Expected losses(m^3) - 36" section	Single	-	0	-
Expected losses(m^3) - 17 1/2" section	Single	-	10,0	-
Expected losses(m^3) - 12 1/4" section	Single	-	10,0	-
Expected losses(m^3) - 8 1/2" section	Single	-	15,0	-
Fluid Cost($/m^3$) - 36" section	Uniform	1,00	-	2,00
Fluid Cost($/m^3$) - 17 1/2" section	Uniform	1,00	-	2,00
Fluid Cost($/m^3$) - 12 1/4" section	Uniform	5000,00	-	6000,00
Fluid Cost($/m^3$) - 8 1/2" section	Uniform	5000,00	-	7000,00
Waste Treatment($) - 36" section	Uniform	0,00	-	0,00
Waste Treatment($) - 17 1/2" section	Uniform	0,00	-	0,00
Waste Treatment($) - 12 1/4" section	Uniform	88.000,00	-	96.000,00
Waste Treatment($) - 8 1/2" section	Uniform	80.000,00	-	100.000,00

Table 13 — Input data for Drillpipe/BHA and Tripping Speeds

Drillpipe/BHA and Tripping Speeds				
Parameter	**Distribution type**	**Minimum**	**Peak/Mean**	**Maximum**
MU BHA(hr) - All sections	Uniform	5,00	-	7,00
RIH(m/h) - All sections	Triangle	280	300,00	310,00
POOH(m/h) - All sections	Triangle	200,00	300,00	310,00
Break BHA(hr)	Single	-	8,00	-

Table 14 — Input data for Casing

Casing				
Run casing or liner				
Parameter	**Distribution type**	**Minimum**	**Peak/Mean**	**Maximum**
Accessories($) - 36" section	Uniform	23.000,00	-	27.000,00
Accessories($) - 17 1/2" section	Uniform	43.000,00	-	47.000,00
Accessories($) - 12 1/4" section	Uniform	32.500,00	-	37.500,00
Accessories($) - 8 1/2" section	Uniform	23.000,00	-	27.000,00
Casing cost($/m) - 36" section	Single	-	1000,00	-
Casing cost($/m) - 17 1/2" section	Single	-	700,00	-
Casing cost($/m) - 12 1/4" section	Single	-	322,00	-
Casing services($) - 36" section	Uniform	9.700,00	-	13.700,00
Casing services($) - 17 1/2" section	Uniform	10.000,00	-	14.000,00
Casing services($) - 12 1/4" section	Uniform	10.000,00	-	14.000,00

Table 15 — Input data for Cementing

Cementing				
Duration(hr) - 36" section	Uniform	24,00	-	30,00
Duration(hr) - 17 1/2" section	Uniform	30,00	-	39,00
Duration(hr) - 12 1/4" section	Uniform	7,00	-	10,00
Cement Volume(m^3) - 36" section	Uniform	50,00	-	100,00
Cement Volume(m^3) - 17 1/2" section	Uniform	20,00	-	25,00
Cement Volume(m^3) - 12 1/4" section	Uniform	15,00	-	35,00
Cement Slurry cost($/m^3$) - 36" section	Single	-	4.000,00	-
Cement Slurry cost($/m^3$) - 17 1/2" section	Single	-	450,00	-
Cement Slurry cost($/m^3$) - 12 1/4" section	Single	-	550,00	-

Table 16 — Input data for general costs

General Costs				
Parameter	**Distribution type**	**Minimum**	**Peak/Mean**	**Maximum**
Rig rate($/day)	Single	-	400.000	-
Spread rate($/day)	Triangle	18.000,00	23.000,00	50.000,00
Drillstring/BHA cost($/day)	Triangle	7.000,00	9.000,00	22.000,00
Wellhead cost($) - 36" section	Single	-	20.000,00	-
Wellhead cost($) - 17 1/2" section	Single	-	15.000,00	-
Wellhead cost($) - 12 1/4" section	Single	-	20.000,00	-
Fixed cost($) - 36" section	Single	-	10.000,00	-

Fixed cost($) - 17 1/2" section	Single	-	33.000,00	-
Fixed cost($) - 12 1/4" section	Single	-	55.000,00	-
Fixed cost($) - 8 1/2" section	Single	-	35.000,00	-
Support cost($) - All sections	Triangle	4.000,00	5.000,00	9.000,00

Output data from Risk€ simulation

Scenario 2 – Percussive

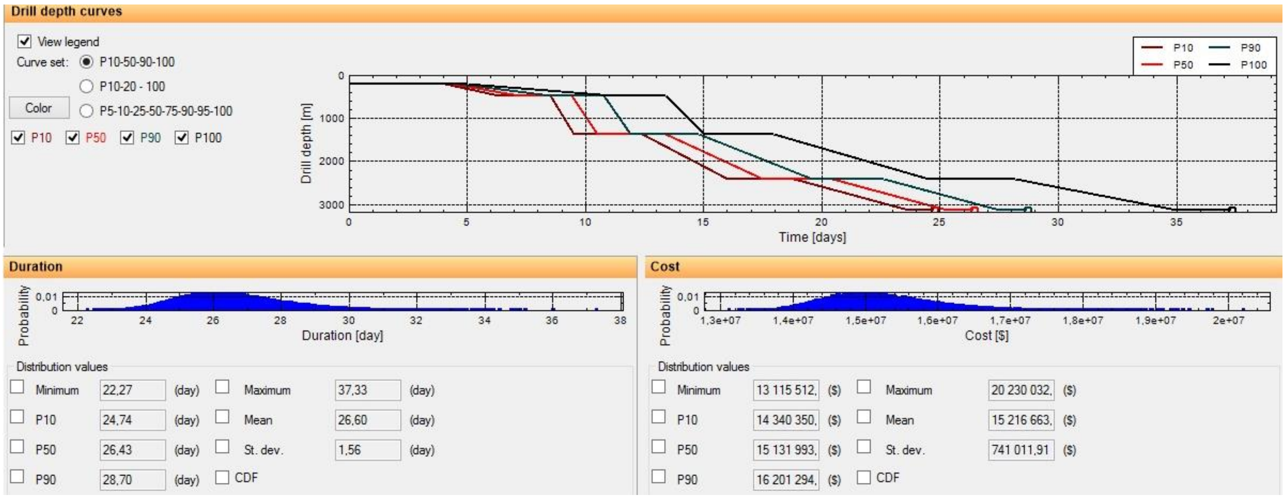


Figure 39 — Output data or scenario 2

Figure 40 — Sensitivity analysis for scenario 2

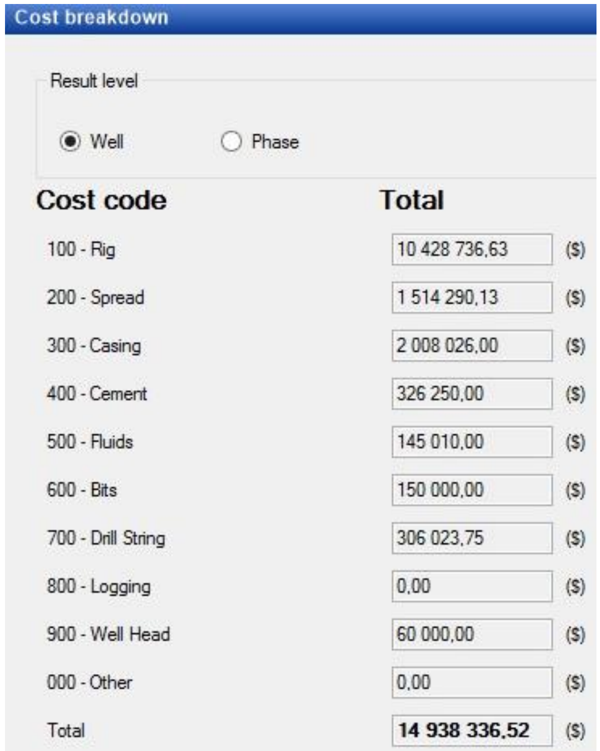


Figure 41 — Cost breakdown for scenario 2

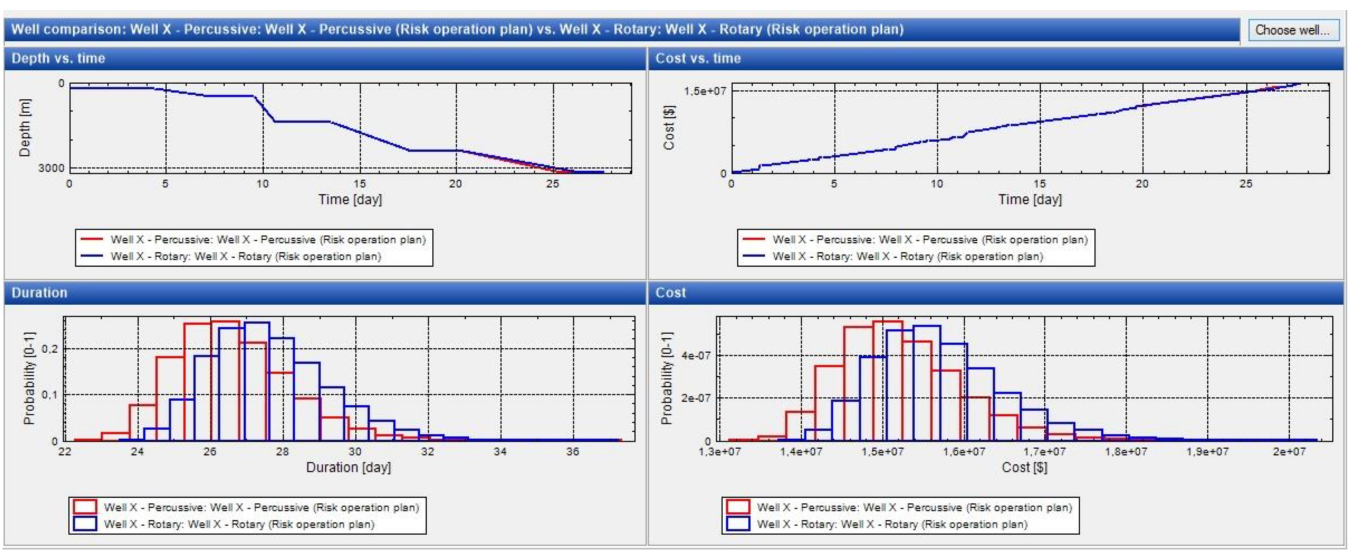


Figure 42 — Comparison of scenario 2 and scenario 1

Scenario 3 – Rotary – Percussive

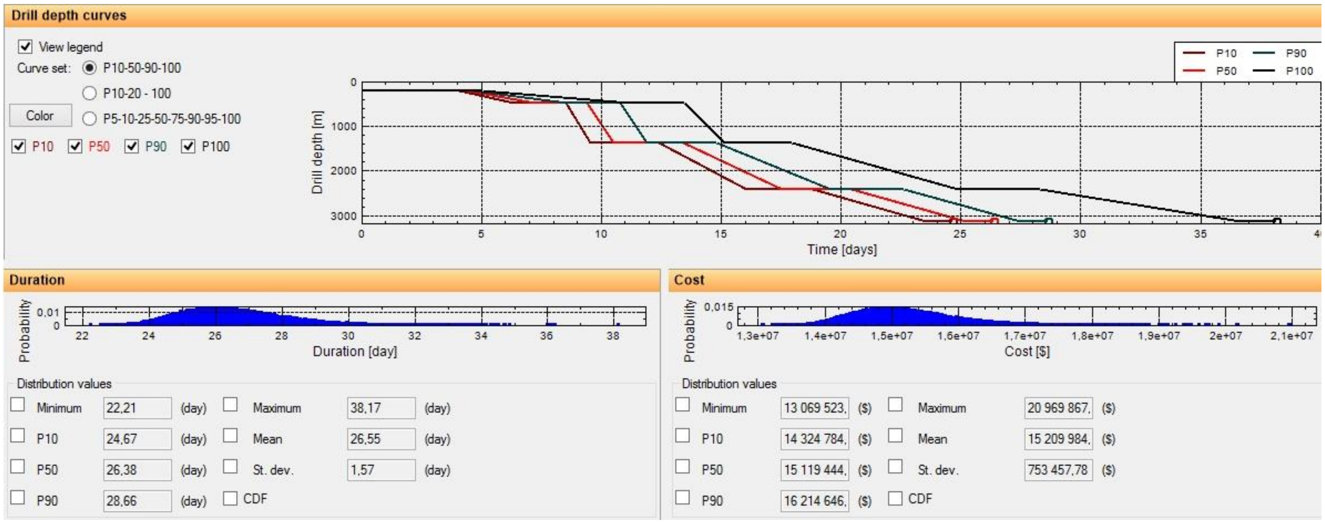


Figure 43 — Output data for scenario 3

Figure 44 — Sensitivity analysis for scenario 3

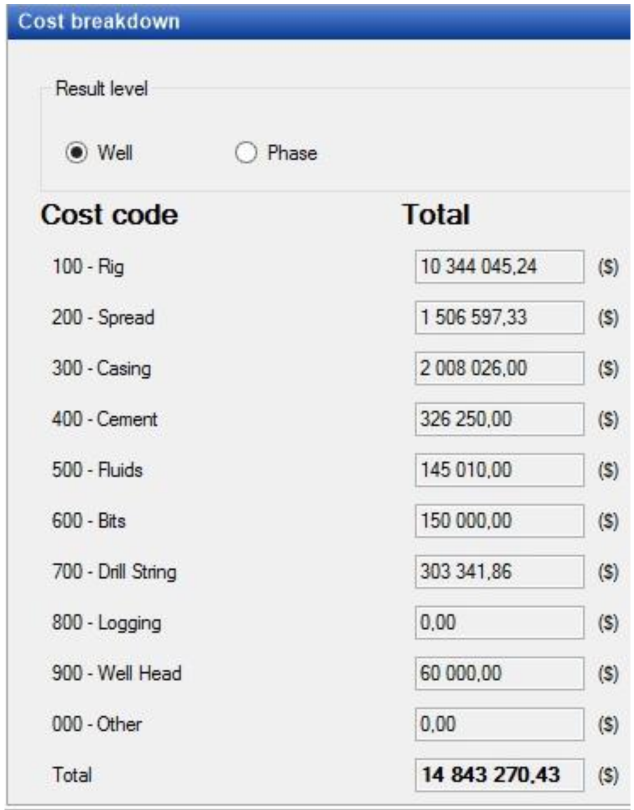


Figure 45 — Cost break down for scenario 3

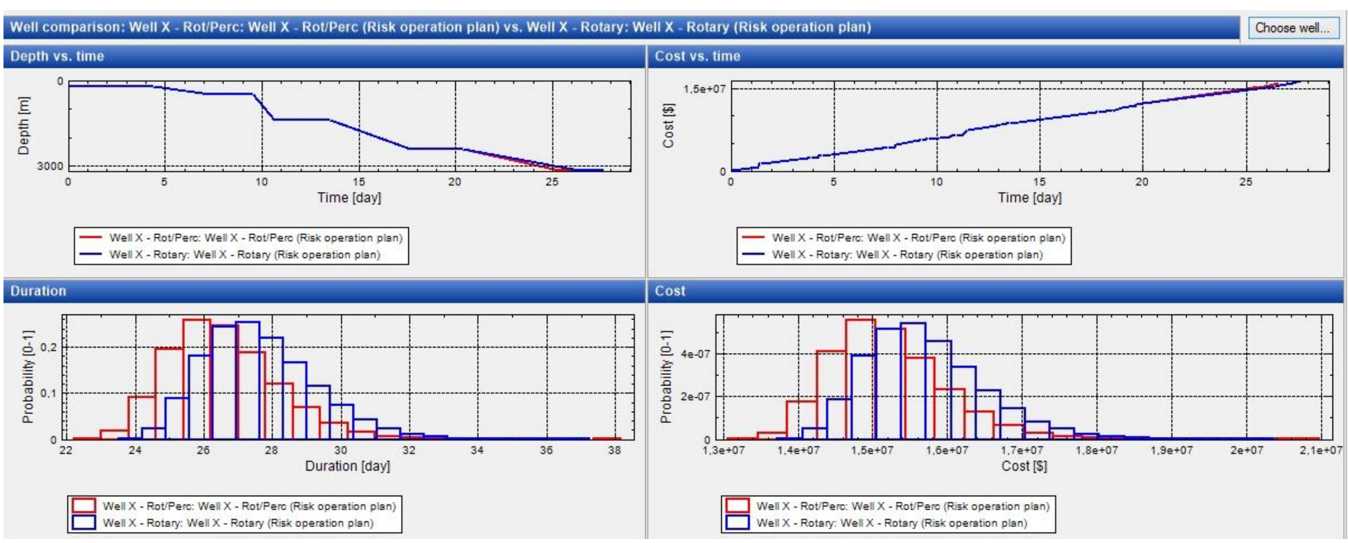


Figure 46 — Comparison of scenario 3 and scenario 1

Scenario 4 – Change TD + Percussive

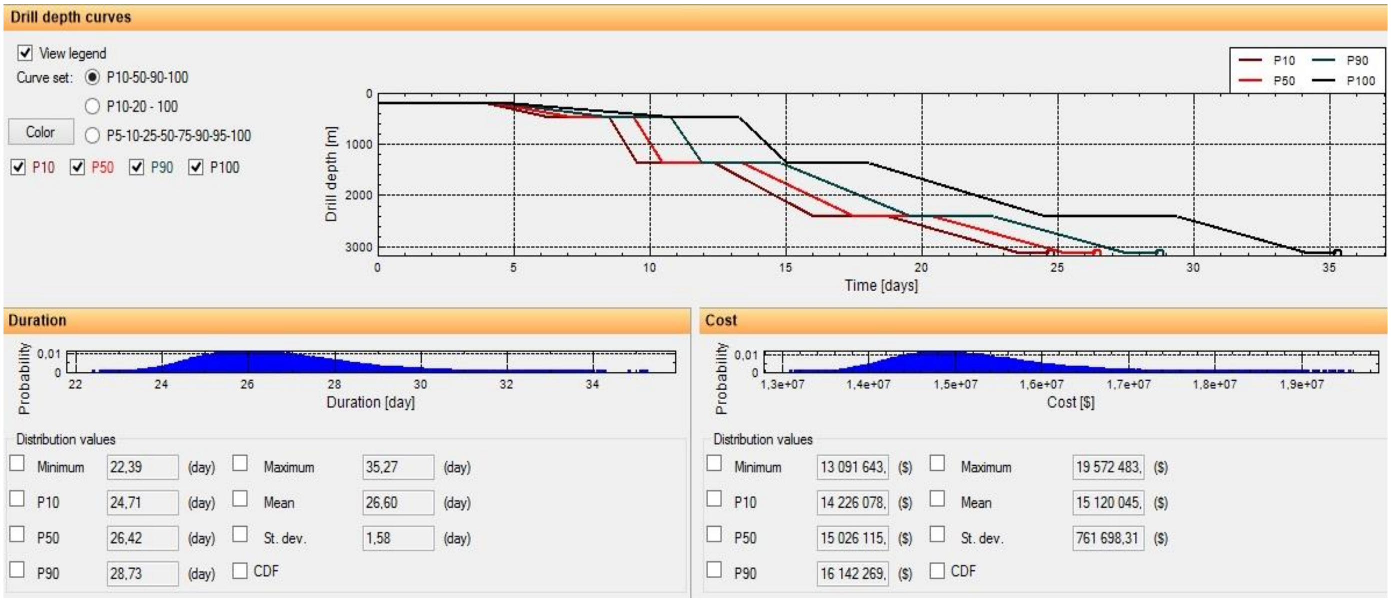
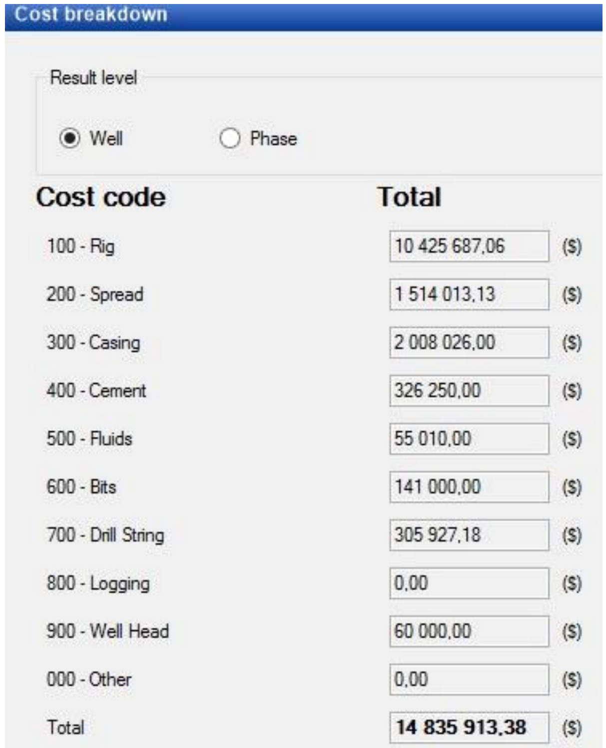


Figure 47 — Output data for scenario 4

Figure 48 — Cost Sensitivity analysis for scenario 4



Cost breakdown

Result level

Well Phase

Cost code	Total	
100 - Rig	10 425 687,06	($)
200 - Spread	1 514 013,13	($)
300 - Casing	2 008 026,00	($)
400 - Cement	326 250,00	($)
500 - Fluids	55 010,00	($)
600 - Bits	141 000,00	($)
700 - Drill String	305 927,18	($)
800 - Logging	0,00	($)
900 - Well Head	60 000,00	($)
000 - Other	0,00	($)
Total	**14 835 913,38**	($)

Figure 49 — Cost break down for scenario 4

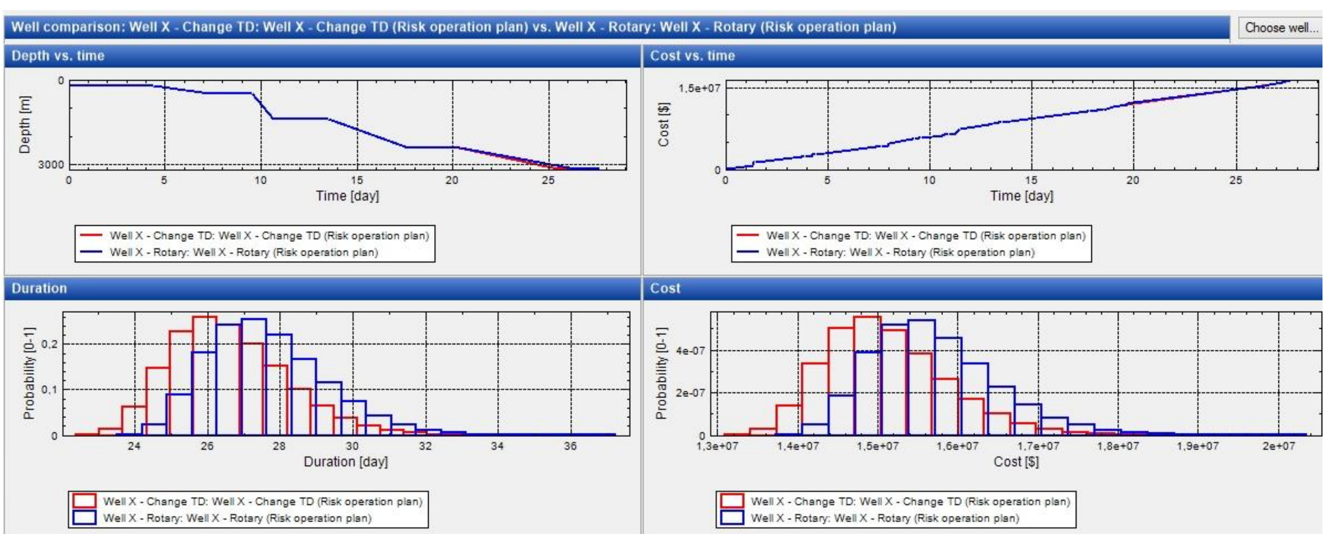


Figure 50 — Comparison of scenario 4 and scenario 1