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Master's Thesis

PETMAS

An Introduction to Engineering challenges in Extended Reach Drilling (ERD) wells and a simulation study of the effect of varying hole size in a well section

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June 15, 2015

Abstract

This thesis investigated Extended Reach Drilling (ERD), an embedded technology for drilling high-inclination, long horizontal directional wells. The objective was to introduce important engineering challenges in ERD wells and study the effect of varying hole size in a well section. A ConocoPhillips standard is to drill a 12 ¼” x 13½“ hole for the 10¾” production liner. Is this the optimum hole size considering torque, drag and buckling, hole cleaning and ECD (equivalent circulating density) management? Will a change in section depth have an impact?

Three important types of engineering studies will be introduced and further explained in this thesis. These studies have to be performed during the planning of ERD wells and will also become critical when studying an ERD well. It is also important to closely follow it up during operation to see if any deviation from trends. The three studies include:

1. Torque, drag, buckling and corresponding limitations
2. Mud weight selection and hydraulic calculations
3. Hole cleaning

There are three main reasons for drilling extended reach wells [9]: surface location constraints, reduced infrastructure costs and increased reservoir contact. ERD makes it possible to reach a larger area from one surface drilling location and to enter reservoirs at locations remote from a drill site, eliminating additional platforms and costly offshore operations [24], [64]. Both the well-site footprints and the environmental effects are reduced through ERD technology in addition to enhanced reservoir drainage at reduced cost [63]. As mentioned above, ERD technology offers the possibility for reservoir production [63]. It is possible to keep a well in a reservoir for a longer distance than earlier to maximize both the productivity and the drainage capability [24], [64].

Ekofisk was the first oil field at the NCS, discovered late in 1969 and it is the focus of this thesis. There are four producing fields in the Greater Ekofisk Area: Ekofisk, Eldfisk, Embla and Tor [27]. Today the Ekofisk field produces oil and gas corresponding to about 200.000 barrels of oil equivalents per day [31]. To maintain production and increase the oil recovery, the use of extended reach wells has become more and more common. However, the geological and design complexities on the Ekofisk field may create difficulties when the wells are somewhat longer than previously drilled.

This thesis has used WellPlan to perform simulations on a specific well section on the Conoco Phillips' ERD well Z-25 on Ekofisk studying the effect of varying hole size. It involves a sensitivity analysis comparing a total of 12 different hole sizes ranging from 12¼" to 15" with increments. The overall objective for all the simulations is to study the effect of varying hole size in the 12¼" x 13½" hole section (under-ream to 13½" while drilling with a 12¼" bit). The simulations include torque, hook load, side forces, ECD, hole cleaning and pressure loss. It resulted in important observations, relevant for future ERD decisions. Main challenges with ERD also discussed in this thesis are summarized below:

1. Transferring weight on bit (WOB)
2. Buckling
3. Tensile limit on the drillstring during tripping out (POOH)
4. Surface torque limit on drillpipe/couplings
5. Rig capability
6. ECD in annulus for long wells
7. Hole cleaning
8. Pump pressure vs. flowrate requirement

Acknowledgement

This thesis was written as a part of the completion of a five-year long master study weighted with 30 credits at the Department of Petroleum Engineering, University of Stavanger, Norway. The last five years have been educational, challenging, interesting and joyful.

First I would like to thank my supervisors Professor Kjell Kåre Fjelde at University of Stavanger and ConocoPhillips’ Chief Engineer Stein Tjelta Håvardstein for their support, knowledge sharing and technical guidance during this process and for always helping me whenever I hit a tough spot. I would like to thank ConocoPhillips AS for providing me with office space, software programs and the relevant data for this thesis.

Due to my background in petroleum engineering and my specialization in drilling, I wanted to write a thesis related to well drilling, planning and implementation, preferably a theoretical thesis. This thesis combines drilling design and what is happening “down the hole” in ERD wells and complex wells.

Last but not least, I would like to thank my parents and siblings (Sigurd, Ingrid, Glenn and Linn) for the support and encouragement you have given me during my six years at the University of Stavanger. Thanks for always believing in me and being there for me. Finally I would also like to thank my friends for your motivation, well-wishes, texts and phone calls. Thank you for listening, offering me advice, and supporting me through the entire process. I love you!

June 15, 2015

Veronica Hauge

Nomenclature

A.D.	Anno Domini (in the year of the Lord)
AGS	Adjustable gauge stabilizer
AV	Annular velocity
B	The buoyancy force
BHA	Bottom hole assembly
BOP	Blow out preventer
BP	British Petroleum
bpm	barrels per minute
B&H	Build and hold
COF	Coefficient of friction
COP	ConocoPhillips
DGS	The Dallas Geological Society
DLS	Dog leg severity
DP	Drillpipe
DPP	Drillpipe protector
EA	Upper Ekofisk
ECD	Equivalent circulating density
EDM™	Engineer's Drilling Data Model™
EL	Lower Ekofisk
EM	Middle Ekofisk
EMW	Equivalent Mud Weight
ER	Extended Reach
ERD	Extended Reach Drilling
ERW	Extended Reach Well
ESD	Equivalent static density
et al.	and others
ft.	feet
G	The gravity force
gpm	gallons per minute
HC	Hydrocarbon

HD	Horizontal departure/displacement
HL	Hook load
HTHP	High temperature high pressure
HWDP	Heavy weight drillpipe
IADC	International Association of Drilling Contractors
ID	Inside diameter
kip	kilo pound (1 kip = 1000 lbs)
KOP	Kick off point
K&M	Krepp and Mims (authors)
lb/lbs/lbf	pounds
LOT	Leak off (pressure) test
lpm	liters per minute
MD	Measured depth
MPD	Managed Pressure Drilling
MSL	Mean sea level (depth reference)
MUT	make-up torque
MW	Mud weight
MWD	Measurement while drilling
N.B.	Nota Bene (to note/note well)
NCS	Norwegian Continental Shelf
NORSOK	NORsk SOkkels Konkurranseposisjon
OBM	Oil-based mud
OD	Outside diameter
PDC	Polycrystalline Diamond Compact (bit)
POOH	Pull out of hole – tripping out
ppg	pounds per gallon
psi	pound force per square inch
PWD	Pressure while drilling
P&A	Plug and abandonment
RIH	Run in hole – tripping in
RKB	Rotary kelly bushing (drill floor depth reference)
ROB	Rotate off bottom
ROP	Rate of penetration for drill bit

RPM/rpm	Revolutions/rotations per minute – a unit, but often used as a parameter, for instance by asking for the RPM of the drill string, instead of the correct “rate of rotation”
RSS	Rotary steerable system
SBM	Synthetic-based mud
SPE	Society of Petroleum Engineers
SPP	Stand pipe pressure – the frictional pressure drop in the hydraulic circuit [92]
TD	Total depth/Target depth
TFA	Total flow area – nozzle area
TVD	True vertical depth
T&D	Torque and drag
uERD	ultra Extended Reach Drilling
UR	Under-reaming
vERD	very Extended Reach Drilling
WARP	Weighting Agent Reduction Particle – lowers the ECD in open hole and reduces swab/surge and pump pressures [97]
WBE	Well barrier element
WBM	Water-based mud
WBS	Well barrier schematic
WOB	Weight on (drill) bit
β	The buoyancy factor
ρ	Density
σ	Stress
ε	Strain

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1 Introduction

A large part of oil and natural-gas production nowadays comes from directional wells drilled both onshore and offshore, including environmentally sensitive locations. In order to enhance production, the drilling for oil and gas has changed drastically the past decade, more and more wells are drilled horizontally or with high inclination angles [61]. Initially, horizontal wells were only a few hundred feet long [61], but drilling technology has advanced quickly in the last 15-20 years, resulting in longer and more complex wells covering a larger drainage area. This drilling concept is known as Extended Reach Drilling (ERD) and involves directional drilling to greater distances [61].

The growing trend in the oil industry is to drill more complex and challenging wells. In order to reach these targets, the well planning and the drilling design require constantly enhancement, in a more efficient and cost effective way.

Throughout the years the horizontal departure has progressively increased to enable drilling of so-called Extended Reach Wells (ERWs) [61]. Extended Reach Drilling is normally used nowadays to reach shallow or long onshore and offshore oil and natural-gas deposits [61]. The length of an ERD well may reach 20.000 to 40.000 ft. or more. If the step-out exceeds 40.000 ft., the well is classified as ultra-extended-reach drilling (uERD). Drilling ERD and uERD wells involves a lot of significant challenges regarding mechanical loads on the drill string, wellbore instability, cuttings transport, drilling fluid selection, ECD management, lost circulation and stuck pipe [61].

Extended Reach Drilling is all about pushing drilling properties close to their limits and involves (the) drilling of high-inclination wellbores with long horizontal displacements [24]. It is thus extremely important to develop a strong relationship between locations, technologies and local knowledge/experiences in order to expand the ERD envelope. There are eight elements considered as the most critical factors when drilling ERD wells according to [24]: well trajectory design, bottom hole assembly (BHA) design, bit hydraulics, drillstring design, torque and drag (T&D), hole cleaning and ECD management.

Some pros/arguments for continuing to develop the ERD procedures can according to [10] be:

- Develop offshore reservoirs now considered uneconomical;
- Drill under shipping lanes or under environmentally sensitive areas;
- Accelerate production by drilling long sections of nearly horizontal hole in producing formations;
- Provide an alternative for some subsea completions;
- Reduce the number of platforms necessary to develop a large reservoir.

Topics to be discussed in this thesis are:

- ERD definition
- The differences between ERWs (Extended Reach Wells) and “conventional wells”
- Limitations for reaching a target
- Main challenges with ERD in general
- Torque, drag and buckling
- ECD and the effects of it
- Why ECD is a particular concern for ERD
- Hole cleaning
- What are the optimized hole sizes for an ERW? Will a change in section length have an impact?

In addition, this thesis will consider some simulations performed in association with the planning process of the ERW Z-25 at Ekofisk operated by ConocoPhillips. It involves a sensitivity analysis comparing a total of 12 different hole sizes ranging from 12¼” to 15” with increments. The overall objective for all the simulations is to study the effect of varying hole size in the 12¼” x 13½” hole section (under-ream to 13½” while drilling with a 12¼” bit). The simulations include torque, hook load, side forces, ECD, hole cleaning and pressure loss. A more detailed description on the objectives for the simulations can be read from Table 12, Table 13 and Table 14 in chapter 6. The tables and graphs were developed using three different software programs; WellPlan (mainly), Compass and WellView (both for information), in addition to Microsoft Excel.

A large part of the information and useful ideas mentioned and discussed in this thesis was taken from K&M Technology Group's material:

- Mims, M. & Krepp, T., 3rd edition, 2003-2007, *Drilling Design and Implementation for Extended Reach and Complex Wells,* K&M Technology Group, LLC, Houston, Texas [1].

- 3 Day Operations Course, 2015, (3 Day Horizontal and Extended Reach Drilling Industry Training), K&M Technology Group, LLC, Houston, Texas. <Attended it at Quality Airport Hotel Stavanger, 24-26 March, 2015> [9].

K&M (Krepp & Mims) Technology Group is an Extended Reach and Complex Well Consultants Company. Specializing in the Conceptualization, Design, Optimization, and Implementation of Extended Reach, Horizontal and Deepwater Projects. It was founded in 1988 when its founder, Michael Mims, became involved in the development of leading edge technologies for extended reach wells for UNOCAL in California. The company was originally founded in California, but moved its central operations to Perth, Western Australia in 1992. It now has 55 employees worldwide and offices located in the Woodlands, TX and London, UK [1], [9].

The K&M Approach

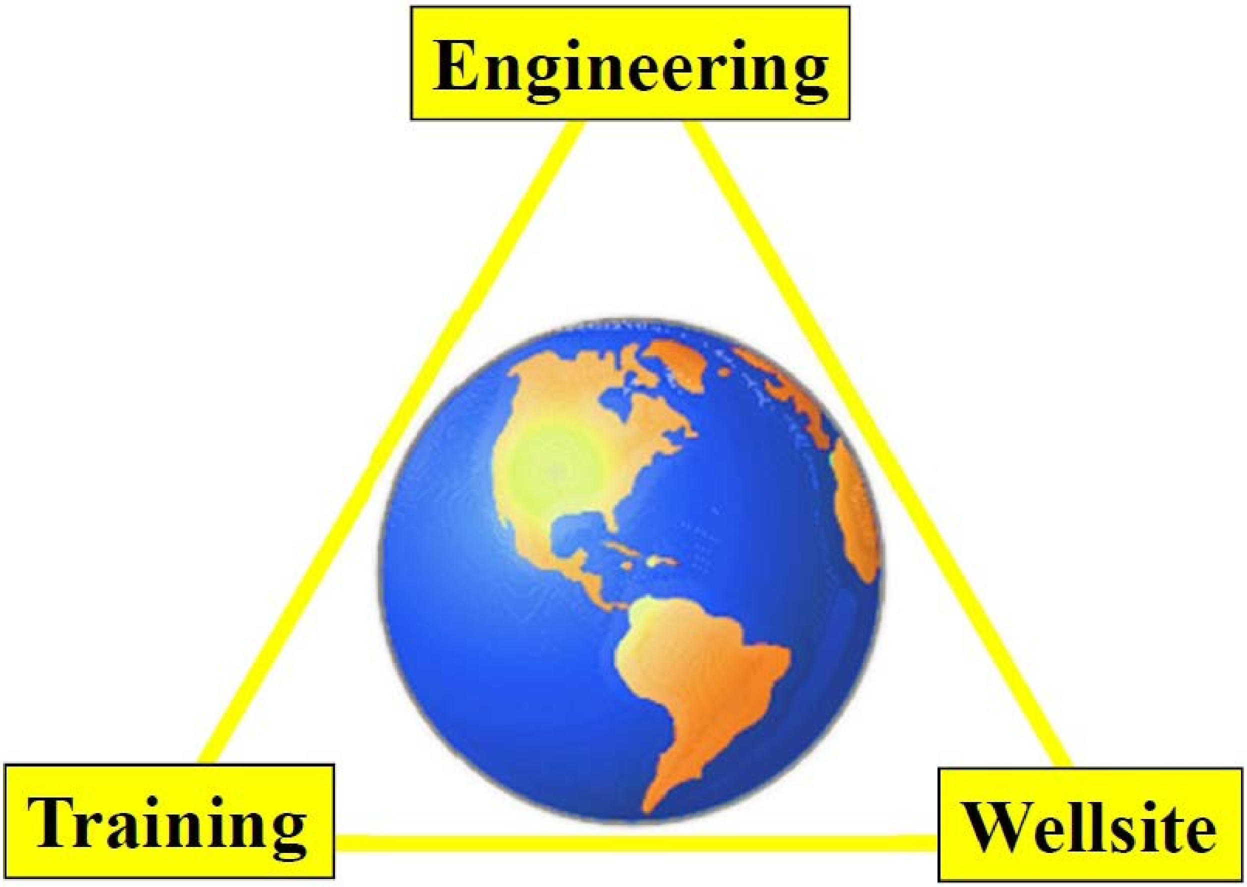


Figure 1: The K&M Approach [9].

The thesis is organized as follows:

Chapter 2 describes the theory and background material for the thesis. It includes topics like drilling; well planning; force, stress and strain fundamentals (forces acting on the string); torque, drag, buckling and corresponding limitations; mud weight selection and hydraulic calculations; and hole cleaning.

Chapter 3 describes ERD in general, including current status and challenges.

Chapter 4 presents Conoco Phillips ERD on Ekofisk.

Chapter 5 gives an introduction to the WellPlan software, the basis for the simulations performed in WellPlan and the plan for the Z-25 well.

Chapter 6 presents the results from the simulations and includes discussion and evaluation of the results.

Chapter 7 concludes the simulations and summarizes the findings of the thesis.

Chapter 8 presents a suggestion for future work with ERD, in relation to the simulations discussed in this thesis.

The appendix covers a table showing the MD, inclination, azimuth, TVD and DLS for well Z-25 (the base case).

2 Theory

2.1 Drilling

Drilling can basically be described as “the removal of rock and cuttings from solid materials and transportation to the surface for disposal by drilling fluid circulating up from the drill bit” [38]. One of the most important functions of the drilling fluid is to remove the drilled cuttings out of the wellbore [2], [37]. If they are able to accumulate, the drillstring may get stuck. Secondly, excess cuttings in the annulus (the space between two concentric objects, such as between the wellbore and the drillpipe or between the casing and the drillpipe, where fluid can flow [89]) may lead to an increase in bottom-hole pressures, which again may result in circulation losses [2].

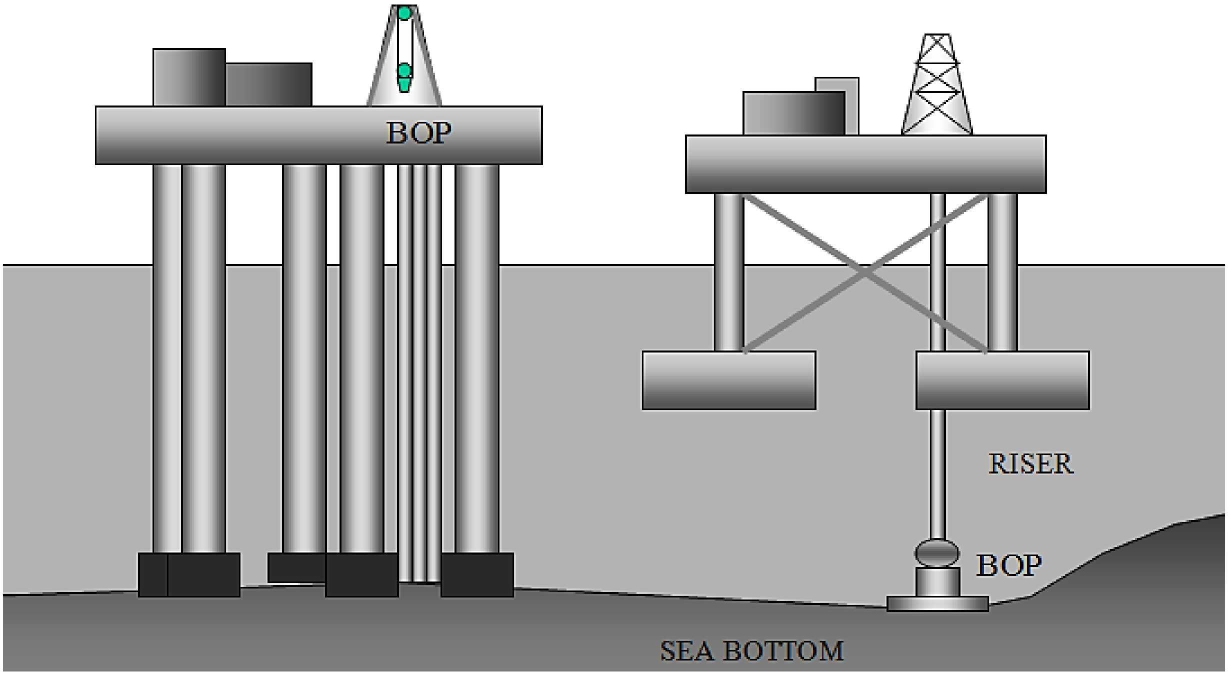


Figure 2: Sketch of a fixed platform (production platform) and a moveable platform. Note the different placements of the BOP and of the wellhead, which in both cases is placed directly below the BOP [45].

History of drilling goes thousands of years back in time. The very first recorded oil wells were drilled in China around 347 A.D. [6]. They reached depths of up to approximately 240 m (790 ft.) by using a bamboo rig and bamboo poles/pipes connected to primitive drill-bits of iron [6]. The drilling technique primarily went out on lifting the bamboo pipe (using hands or wheels) and then drop it into the hole, aiming to crush rock and gravel [4]. The extracted oil was burnt and used to evaporate brine and was a major contributor in the production of salt [39]. By the 10th century, the Chinese used the mentioned bamboo pipelines to connect gas and oil wells with/to the salt springs [4], [39].

The first oil wells in recent/modern times were drilled with a method called cable-tool drilling using impact-type tools [5]. A weighted, chisel-shaped bit was connected with a cable to a lever at the surface [5]. The wells were drilled percussively, by dropping and raising a cable tool into the earth that caused the bit to chip away the rock at the bottom of the hole [5].

Figure 3: Cable drilling tools [61].

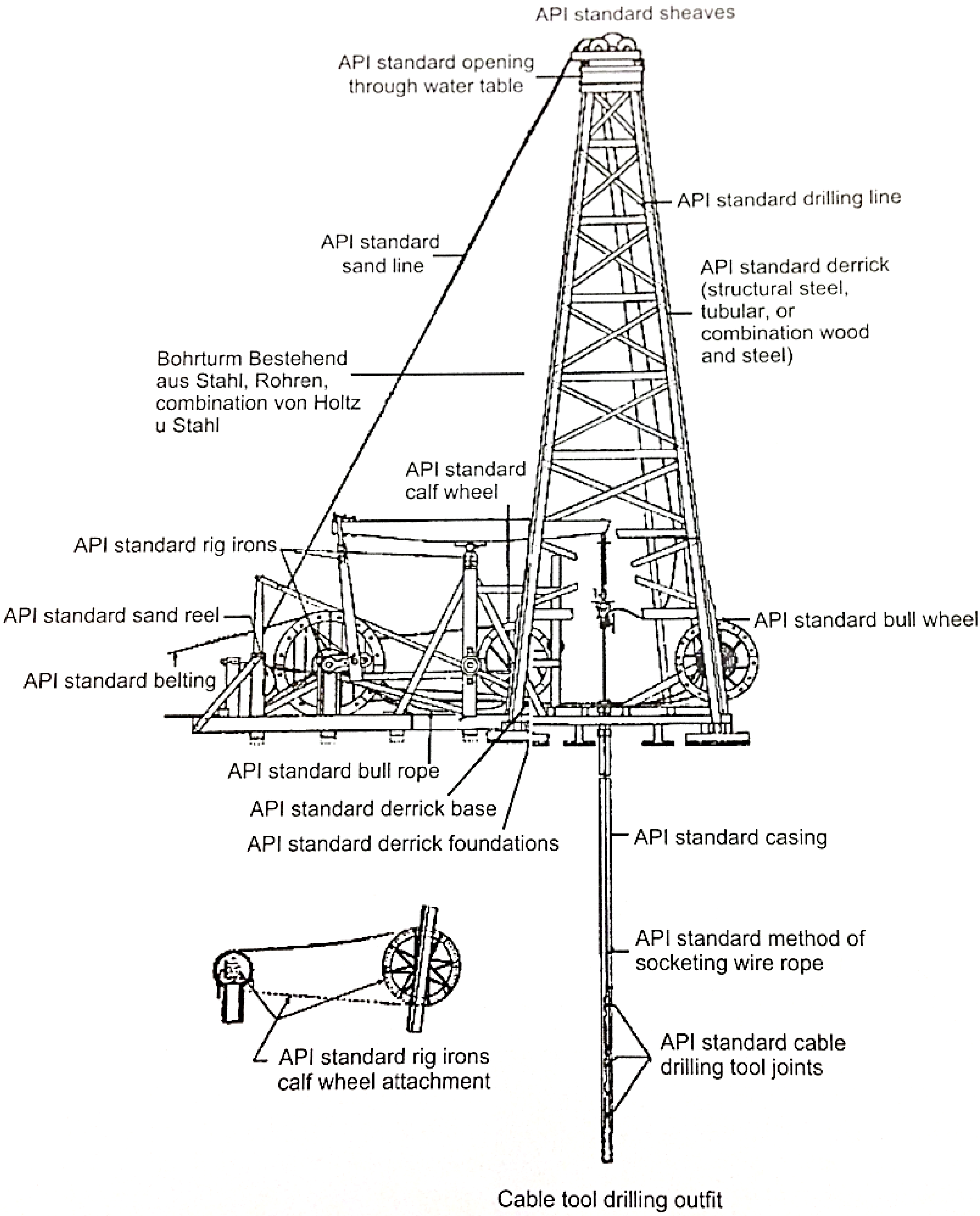


Figure 4: Cable-tool rig schematic [61].

In 1859 Edwin Drake reached a historical milestone [7], [8]. He opened the very first commercially successful oil well in the United States with confirmed presence of hydrocarbons [6]. “The Drake Well” is a 21.2 m (69.5 ft.) long well located on the edge of the town of Titusville, Pennsylvania, and was drilled for the purpose of finding oil using an iron pipe [8]. The drilling of “The First Oil Well”/”The Drake Well” started the international search for petroleum and the oil industry on its spectacular history throughout the following decades [7].

During the 20th century the cable-tool drilling were replaced by rotary drilling systems providing clockwise rotational force to the drill string aiming to simplify the drilling process, which made it possible to reach greater depths, more efficient and faster/in less time [39].

The deepest borehole in the world (as of 09.02.2015) is the Kola Superdeep Borehole [3]. The drilling began on May 24th 1970 using non-rotary mud motor drilling reaching depths of over 12.000 m (39.000 ft.) [3]. In terms of true depth, it is still the deepest artificial point on Earth with its 12.262 m (40.230 ft.). For about two decades, it was also the longest borehole in the world, in terms of measured depth along the wellbore [3]. It was first surpassed in 2008 by the 12.289 m long (40.318 ft.) Al Shaheen oil well located in Qatar, and secondly in 2011 by the 12.345 m long (40.502 ft.) Sakhalin-I Odoptu OP-11 well at Sakhalin, Russia [3].

Most of the (oil) wells were drilled vertical up until the 1970s [39]. Nowadays, the drilling technology allow for highly deviated wells (a wellbore that is not vertical), which can also become horizontal, depending on sufficient depth and suitable tools [39]. These aspects, along with others, led to extended-reach drilling – directional drilling to greater distances. This has made it possible to reach reservoirs located miles or kilometers away from the drilling location/rig.

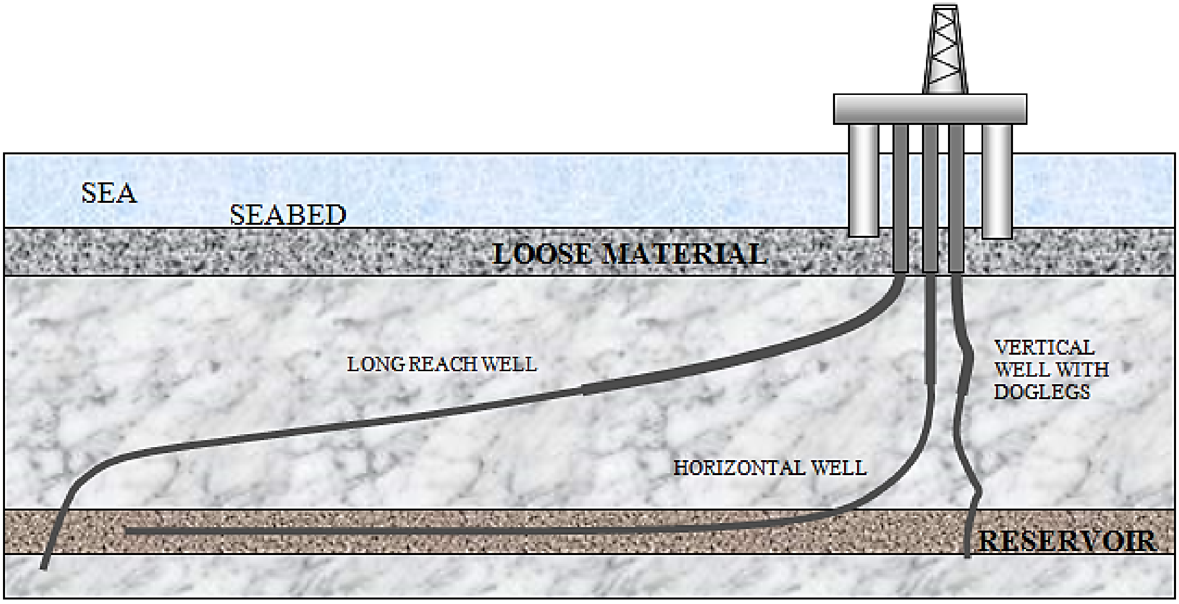


Figure 5: Different types of well paths [45].

Back in 1989/1990 Statoil's well C10 reached a 5000 m departure. The first 6000 m and 7000 m departure well in the world was also achieved by Statoil with the wells C3 (6100 m) and C2 (8700 m MD and a departure of 7300 m at 2700m TVD) respectively in 1991 and 1992/1993. Norsk Hydro broke these records in 1994 and set a new world record for well departure. Well C26 reached 9300 m MD and achieved a departure of 7850 m at 2770 m TVD [18].

Operators are planning on drilling wells from 13.000-20.000 m (40.000-70.000 ft.) reach or even longer in the near future. If the technological progress continues in the same direction/path as in recent years, this is a very realistic goal, even though the main problems of ERW are still the same engineering challenges: hole cleaning, WOB (the downward force created by the weight of the drill stem acting on the bit), torque and drag, buckling, ECD management, pump pressure control and wellbore stability [1], [9].

Table 1: Well classification according to their purpose. Modified after [61].

Objective	Trajectory	Environment
• Exploration	• Vertical	• Onshore
o Wildcat	• Directional	• Offshore
o Appraisal	o Inclined	
o Extension	o Horizontal	
• Development	o Long reach	
• Injection	o Special design	
• Special purpose		
o Stratigraphic		
o Blowout relief		

2.2 Well planning

After a brief introduction about well planning in general, there will in the following be introduced and further explained three important types of engineering studies that has to be performed during the planning of ERD wells. It is also important to closely follow it up during operation to see if any deviation from trends. The three engineering studies include:

1. Torque, drag, buckling and corresponding limitations
2. Mud weight selection and hydraulic calculations
3. Hole cleaning

These studies will also become critical when studying an ERD well.

2.2.1 Well planning in general – well design premises

The life of a well can primarily be divided into five phases [39]:

1. Well planning

Well planning is the foundation or groundwork for the entire drilling process. It describes all of the activities related to drilling the specific well and is a quite time consuming and demanding process, and last but not least the key to success in a drilling operation. According to [1] the design must be fit-for-purpose and specific to the well of interest. It requires a combination of risk management, experiences from previous wells, integration of engineering principles, the operator's resources, time available, logistics, location, local field experiences and the nature of the well [1], [66]. The methods used for well planning may vary among the different operators and vendors in the drilling industry, but the final result should be a safely drilled, minimum-cost hole that satisfies the reservoir engineer's requirements for oil and gas production [66].

2. Drilling

As stated before; drilling can basically be described as "the removal of rock and cuttings from solid materials and transportation to the surface for disposal by drilling fluid circulating up from the drill bit" for the purpose of producing oil and gas [38].

3. Completion

When the well has been drilled and cased, it must be "completed". This process is about preparing the well to produce oil and gas. According to NORSOK D-010 [69] this activity commences after the well is drilled to total depth and logged. The completion phase ends when the tree is installed, well barriers tested and the well handed over to the production organization.

4. Production

This is the most important stage of the well's life; this is the phase when the oil and gas are being produced. A collection of valves called a Christmas tree or production tree is usually placed at the top of the wellbore. They helps regulate pressures, control flows, and makes it possible to access the wellbore in case further completion or intervention (maintenance) work needs to be done [39].

5. Abandonment

This is the final part of a wells life. It is about preparing a well to be closed permanently, usually after either logs determine there is insufficient hydrocarbon potential to complete the well, or after production operations have drained the reservoir [68].

2.2.2 Objective of well planning

Aadnoy et al. [2] states that the two most costly drilling problems are stuck pipe and circulation losses. High costs and expenditures are associated with these problems due to the fact that these unplanned events may take 10-20% of the total time spent on a well.

During the drilling process, the design must ensure that the well is able to withstand possible abnormal events that may occur. The two most common incidents that may lead to severe problems are significant loss of mud returns and taking a high pressure kick [2]. Both of the cases mentioned may result in well pressure control problems [2].

Important areas that need to be addresses by engineering studies during well planning are [76]:

- Well path
- Casing design and pressure tests
- Drilling fluid selection
- Cementing
- Drillstring design
- Torque and drag
- Hydraulics (Cuttings transport and ECD management)

2.2.3 Planning ERD wells

"ERD Well Design" by Statoil [14] covers a lot of important aspects that need to be assessed when conducting an extended reach drilling operation. Important focus areas are according to [14] planning, ECD management, hole cleaning, torque and drag management, directional control, casing and drillpipe wear, risk mitigation and cost efficiency. A lot of ERD projects have exceeded the planned budget time, while others have been very successful [9]. That's why risk management is the key factor during the design process of an ERD well. The most important tools for a successful outcome is according to [14] "detailed planning, local field experiences, careful analysis of drilling data in combination with good contingencies and repeated operations."

ER wells require "more" in many aspects [9]:

- More torque, more pressure, more pipe, more volume, etc. (generally due to longer wellbore trajectories/reach)
- More time to plan
- More specialized equipment
- More specific practices (regarding hole cleaning, tripping and back-reaming)

The “MORE” factor in terms of well planning

The biggest difference between planning vertical and high-angle wells is the practices used and the design according to [9]:

- More time to plan:
    - Usually 1 year minimum
- More specialized equipment:
    - Casing and hole sizes
    - Drillpipe selection
    - Directional tools
    - Completion equipment and accessories
- More specific practices:
    - Hole Cleaning
    - Tripping and back-reaming
        - According to [9] tripping practices are paramount: tripping practices in a high-angle well is totally different than in a vertical well – bad tripping practices are the kiss of death and may lead to sidetracks etc.;
            - Pack offs
            - Wellbore instability
            - Stuck pipe
            - Lost BHA’s, loss of the hole and loss of the well

Mims and Krepp [1] states that *“Too often, decisions are made for the sake of convenience that ultimately compromise success.”* It is very important that the decisions being made are based on what we have rather than on what we need.

Practices are paramount

Most problems are self-inflicted according to K&M [9]:

- Planning mistakes
- Practices mistakes
- Decision-making mistakes
- Many misconceptions are made, which again leads to bad decisions:
    - Often the result of vertical hole mentality
    - Often leads to misdiagnosis or spontaneous reactions

"What gets us into trouble <u>is not</u> what we don't know. It's what we know for sure that just ain't so" [9].

– Mark Twain, American author and humorist –

What's different when planning ERD wells?

There are various issues that are more critical for ERD wells compared to conventional directional wells. Even though wells get longer, physics still stays the same. Step-changes are required as limits are reached. The margin of error decreases with reach [9].

The following section of this thesis deals with the planning process for an ERD well. According to [1] the "key to a successful" well planning is to not treat an ERD well as just "another well in the program". As mentioned above: the design in an ERW must be fit-for-purpose and must apply specific to the well of interest [1]. **Detailed planning is thus the key to ERD success!**

Listed below is an outline for the general planning process for an ERW, recommended by K&M [1]:

- Organizational structure
- Risk management
  - “Aggressive strategies to reduce risk”
- Rig capability [1]
  - Hydraulics capability: a general industry standard for ERW is that a flowrate of at least 1000gpm is required to clean a 12¼” section
  - Rotary and hoisting capability: the top drive must be powerful enough to keep high rpm at the expected maximum torque
  - Power capability: can the mud pumps provide enough power to withstand the friction and reach the target?
  - General rig capability challenges: is the pipe deck large enough to handle the large amount of casing required to reach the desired target?
- ERD planning – general requirements [1]
  - Hole size selection: the traditional hole sizes for ERW is mainly 17½”, 12¼” and 8½”. Using smaller hole sizes requires lower flowrates to achieve the same hole cleaning conditions (this is mainly due to faster penetration rates: according to [1] a 9⅞” hole has 50% less volume than a 12¼” hole)
  - Well-path design
    - Build and hold (B&H) profile: reduces the total depth and the directional work
    - Catenary profile: may reduce the torque and casing wear
    - S-turn profile: may make hole cleaning easier (reduced cuttings on the low side of the wellbore with poor flowrates)
    - Complex 3D well designs: generally limited by the available WOB to slide the drillstring down the wellbore at depth

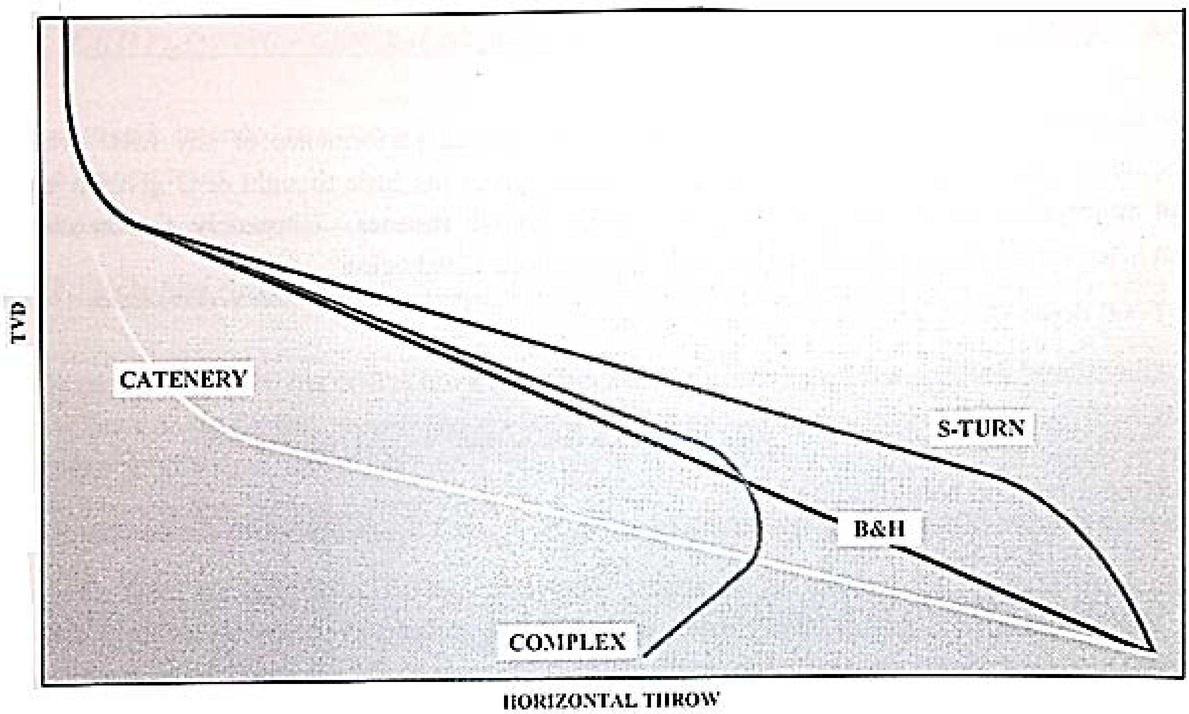


Figure 6: Well profile options [1].

- Casing design
    - Casing depths
    - Casing running: running the casing string to target depth is one of the biggest challenges in ERD wells. Methods to help reaching target can be: use lighter weight casing, to run the casing as a liner, and to apply top drive weight [1]
    - Casing wear – depends strongly on the drilling routine
    - Hydraulics issues – ECD management
- Drilling fluid selection
- Wellbore stability
- Hole cleaning
- Torque and drag modeling
- Directional drilling strategy
- Negative weight wells: troubles regarding transfer of enough WOB to overcome the friction working against pipe movement

- Drillstring design
- Surveying and target
- Formation evaluation
- Cementing

2.2.4 System's approach

Each element mentioned above will affect the entire drilling operation in some degree. According to [9]; *"No design aspect or practice can be treated in isolation."* The elements must be seen together in a bigger picture and it is a good practice to focus on "the hub of the wheel" seen on Figure 7 below [9].

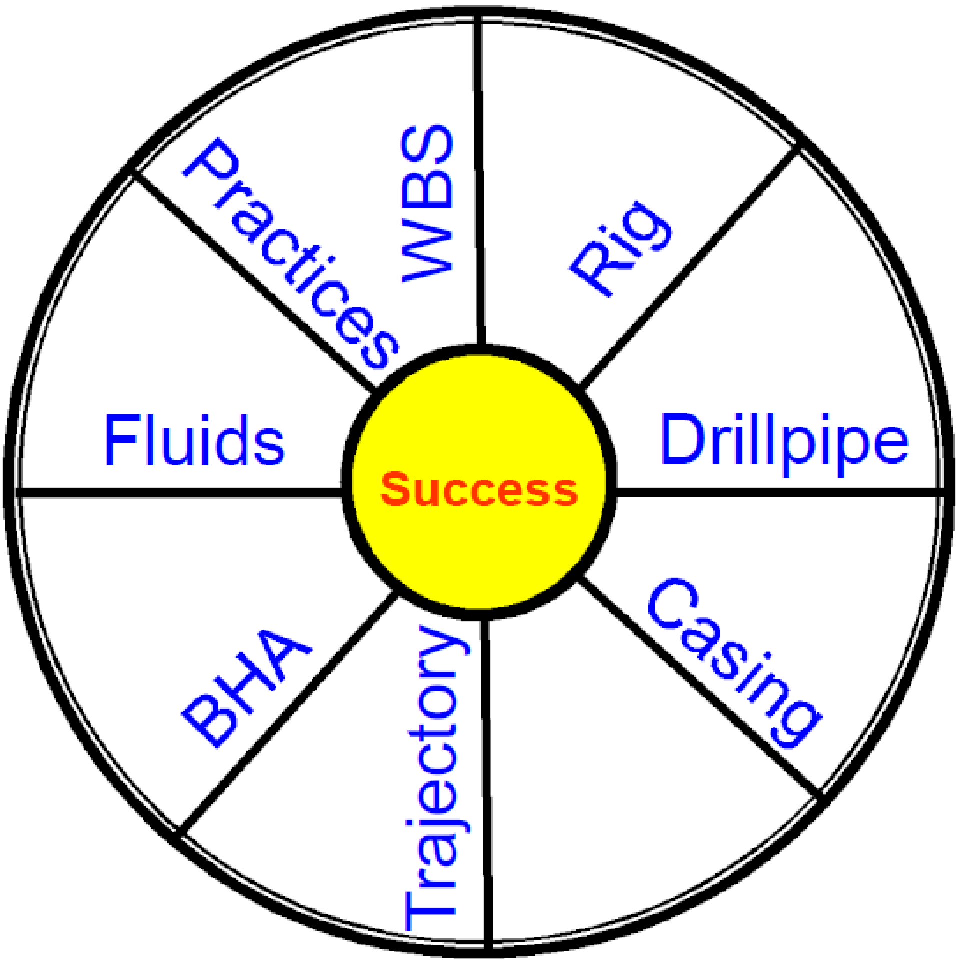


Figure 7: "The hub of the wheel" [9].

Before presenting the three important engineering studies mentioned in section 2.2 in detail, a basic introduction on force, stress and strain fundamentals will be given to ensure a better understanding of various terms and concepts that will be used later in the thesis.

2.3 Force, stress and strain fundamentals (forces acting on the string)

2.3.1 Basic well trajectory design concept

Definitions of some important abbreviations and terms regarding the well trajectory design:

- KOP (kick off point) is the depth at which the well trajectory departs from vertical in the direction of the target [61];
- RKB (rotary kelly bushing) is the center of the rotary table, i.e. the drill-floor is the depth reference (zero point);
- TVD (true vertical depth) is the vertical distance from the rotary table to the target, i.e. the vertical depth of target;
- MD (measured depth) is the length of the entire wellbore and the distance from the rotary table. In vertical wells, the TVD equals the MD;
- HD (horizontal departure) is the horizontal departure of target;
- The build section is the part of the hole where the inclination angle increases;
- In practical application, horizontal wells are high-angle wells with inclination angles of approximately 80 to 100°. In an ideal horizontal well, as the name indicates, the inclination angle is equal to 90° [61].

The step-out ratio generally determines whether or not a well is an ERW or not. It can be calculated using two different aspect ratios [24], the unwrapped reach ratio and the depth ratio. In both cases; if these ratios exceed 2, the well is considered to be an ERD well.

$$\text{Unwrapped reach ratio}_{\text{step-out ratio}} = \frac{\text{HD}}{\text{TVD}} \tag{1}$$

$$\text{Depth ratio}_{\text{step-out ratio}} = \frac{\text{MD}}{\text{TVD}} \tag{2}$$

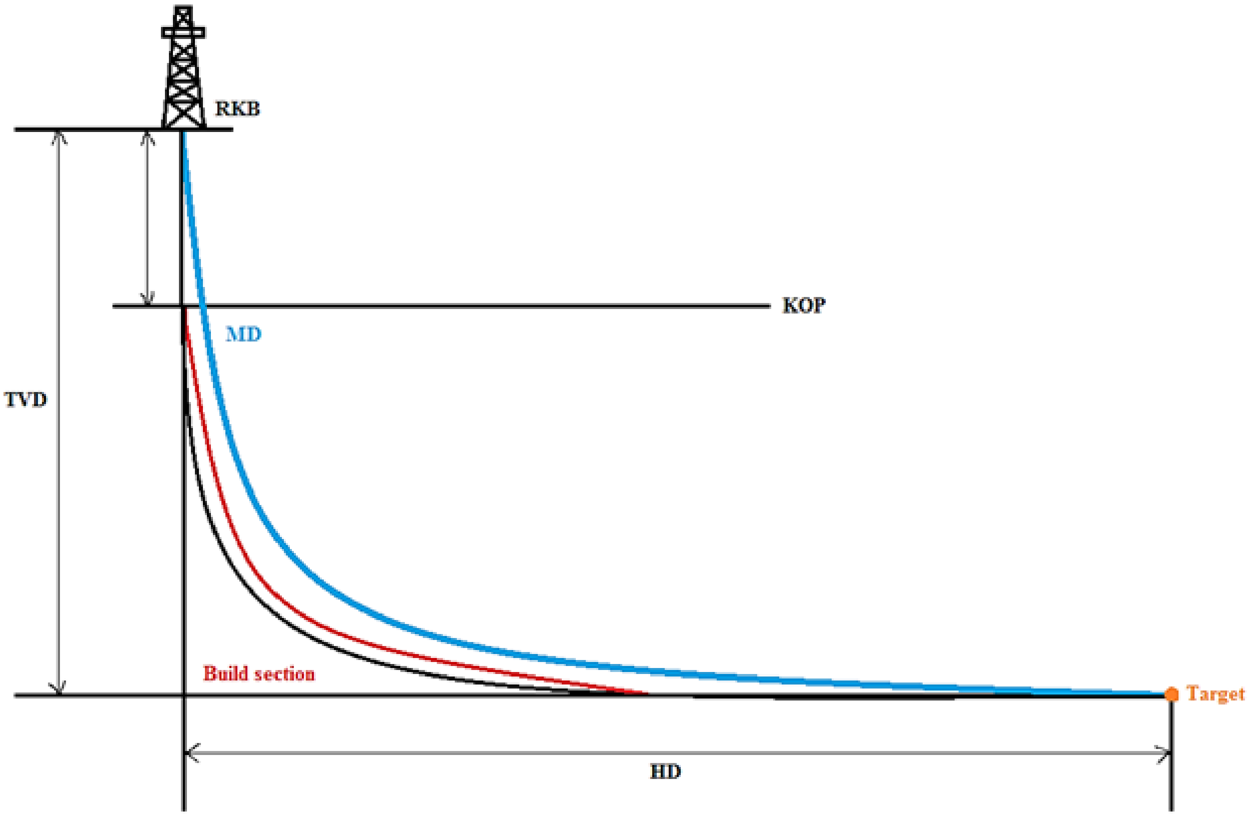


Figure 8: An illustration of a well trajectory.

2.3.2 Stress and strain

Most of the components used in the drilling industry have a cylindrical form as seen in Figure 9 below. According to Aadnoy & Looyeh [54]; *"The two key elements of solids mechanics are the internal resistance of a solid object, which acts to balance the effects of imposing external forces, represented by a term called* _stress_*, and the shape change and deformation of the solid object in response to external forces, denoted by* _strain_ *[54]"*. Stress is defined as the average force acting over an area that can result in deformation or strain [58], and is independent of the size of the body [54]:

$$\sigma = \frac{\text{Force}}{\text{Area}} = \frac{F}{A} \tag{3}$$

where

- σ is the stress (Pa or psi)
- F is the force (N or lbf)
- A is the surface area (m^2 or in^2)

Strain is a permanent change and/or deformation of the body due to high applied loading or stress [54], [58]. During deformation any point on/in the pipe body will be shifted to a different position than previously:

$$\varepsilon = \frac{\text{Deformation}}{\text{Original or non-deformed dimension}} = \frac{\Delta l}{\Delta l_0} \tag{4}$$

where

- ε is the strain
- Δl is the deformed dimension (measured in m or in)
- l_0 is the initial dimension (measured in m or in)

2.3.3 Combined stresses

The loading conditions in a well are a complex assembly of various types of loading, including loads from both the environment and loads from temperature changes [61]. Figure 9 shows the principle stresses a tubular can be subjected to as a result of combined actions of internal, external and axial loading. The stresses act in three orthogonal directions in a tubular: axial/vertical (σ_a), radial (σ_r) and tangential (σ_t) [61].

Axial stresses act parallel with the axis of the tube, radial stresses act through the wall thickness, and tangential stresses act around the tube, as seen in Figure 9 [61]. The tangential stress is also known as the “hoop” or “circumferential” stress.

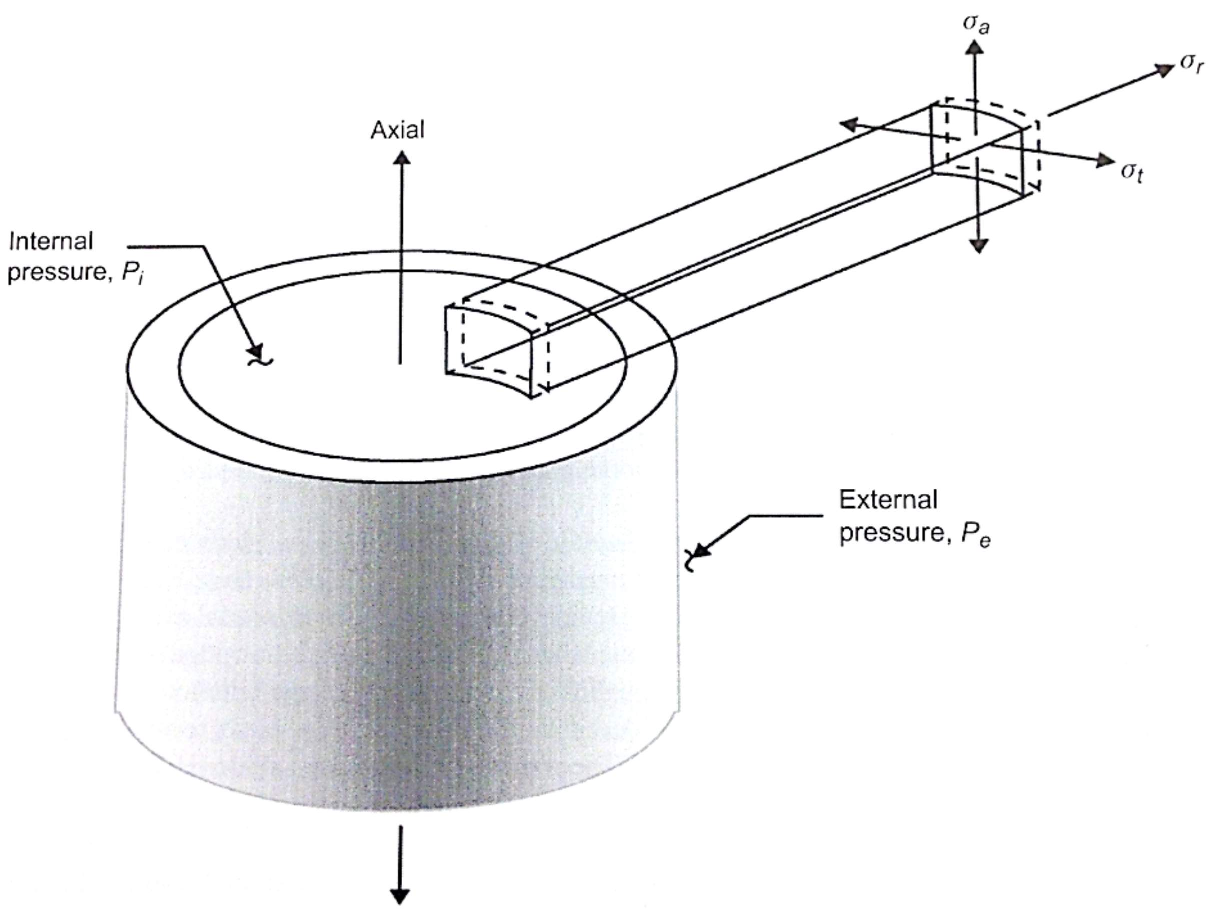


Figure 9: Stresses in a pipe [61].

2.3.4 Material technology

Figure 10 below shows that the relation between stress and strain is linear up until a certain limit is reached. This limit is known as the yield stress, σ_Y. For values below this limit the steel is linear elastic, as seen in the dark green area in Figure 10 [45]. If the stress exceeds this parameter, the stress does not increase as fast for increasing strain and their relation is no longer linear. This behavior/phenomenon is called yielding, shown by the light green rectangles, one for stretching and one for compression. When the stress becomes too high, the rod breaks, which implies that this is the ultimate strength of the rod [45].

Stress is shown as a function of strain for both cases. The black curve shows continuous stretching or compression [45]. The red and orange curves show stretching and then relaxing until the stress is zero before stretching it again and correspondingly for compression [45]. The dark green rectangle shows the region of linear elasticity and the regions of yielding are represented by the light green rectangles [45].

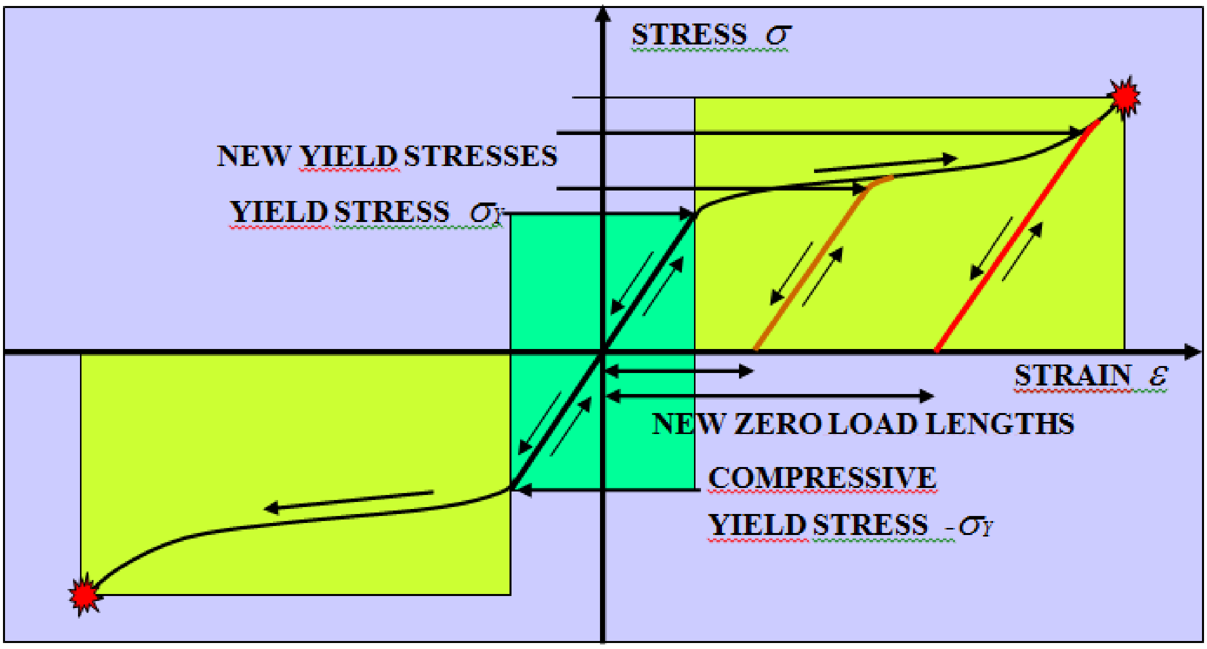


Figure 10: The steel's behavior during stretching or compression [45].

2.3.5 Borehole instabilities

The stresses and/or strains around the borehole can be used to analyze various borehole problems, such as instability problems, fracturing, lost circulation, collapse and sand production [54]. Wellbore instabilities are affected by various factors (e.g. wellbore deviation, HTHP reservoirs, challenging and complex stress conditions) and may arise during drilling or completion. Deviated and high-angle wells are less stable than vertical wells, and the degree of instability increases in highly deviated and/or horizontal wells [54]. This may lead to challenging operations which may cost more than planned. The minimum and maximum pressures beyond which the borehole will fail are given by equation (5) [54].

$$P_{wc} < P_w < P_{wf} \tag{5}$$

where

- P_{wc} is the failure of the borehole due to collapse
- P_w is the borehole pressure
- P_{wf} is the failure of the borehole due to fracturing

Figure 11 below shows the failure of the borehole due to either fracturing (P_{wf}) or collapse (P_{wc}) [54].

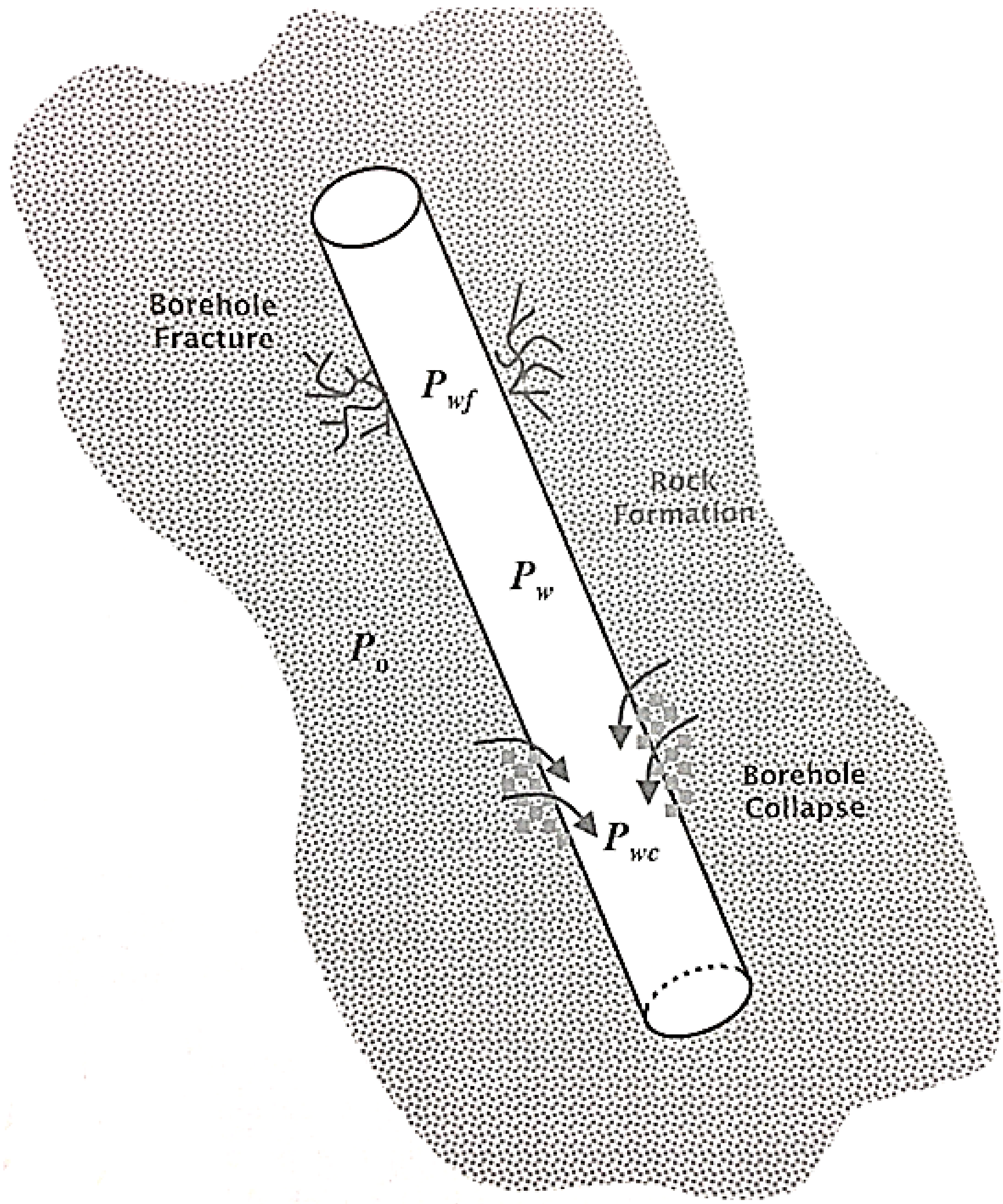


Figure 11: Schematic showing instability problems during drilling and in production due to borehole fracture (at high pressures) and borehole collapse (at low pressures) [54].

2.3.6 Hook load

The hook load is the total force pulling down on the hook and is the total sum of all the forces that acts on the drillstring [57]. It is basically the weight of the drillstring plus or minus the friction. The “real hook load”, however, only depends on the buoyed weight of the drillstring plus well friction. The total force comprises the weight of drillstring in air or drilling fluid, the drill collars, mechanical and hydraulic frictional forces and any additional equipment [57]. Examples on weight changing forces is frictional forces along the wellbore wall and buoyancy forces acting on the drillstring due to the submersion in drilling fluid [57].

During tripping in/slacking (RIH) off the friction has a decreasing effect on the hook load, whilst it has an increasing effect during pick-up (POOH). This can be seen from the two following equations:

$$\text{Hook load}_{RIH} = \text{weight} - \text{friction} \tag{6}$$

$$\text{Hook load}_{POOH} = \text{weight} + \text{friction} \tag{7}$$

The friction generally decreases with increasing hole size since the string has more room to move when the annular clearance increases, i.e. reduced potential for contact and side forces depending on the operational parameters. This implies that a 12¼” will have higher frictional forces than a 15” hole. Equation (6) shows that the less the friction, the higher hook loads when RIH, while equation (7) shows that the less the friction, the lower hook loads when POOH. If the friction decreases with increasing hole sizes, the hook load should increase with increasing hole size while RIH; and it should thus decrease with increasing hole size while POOH.

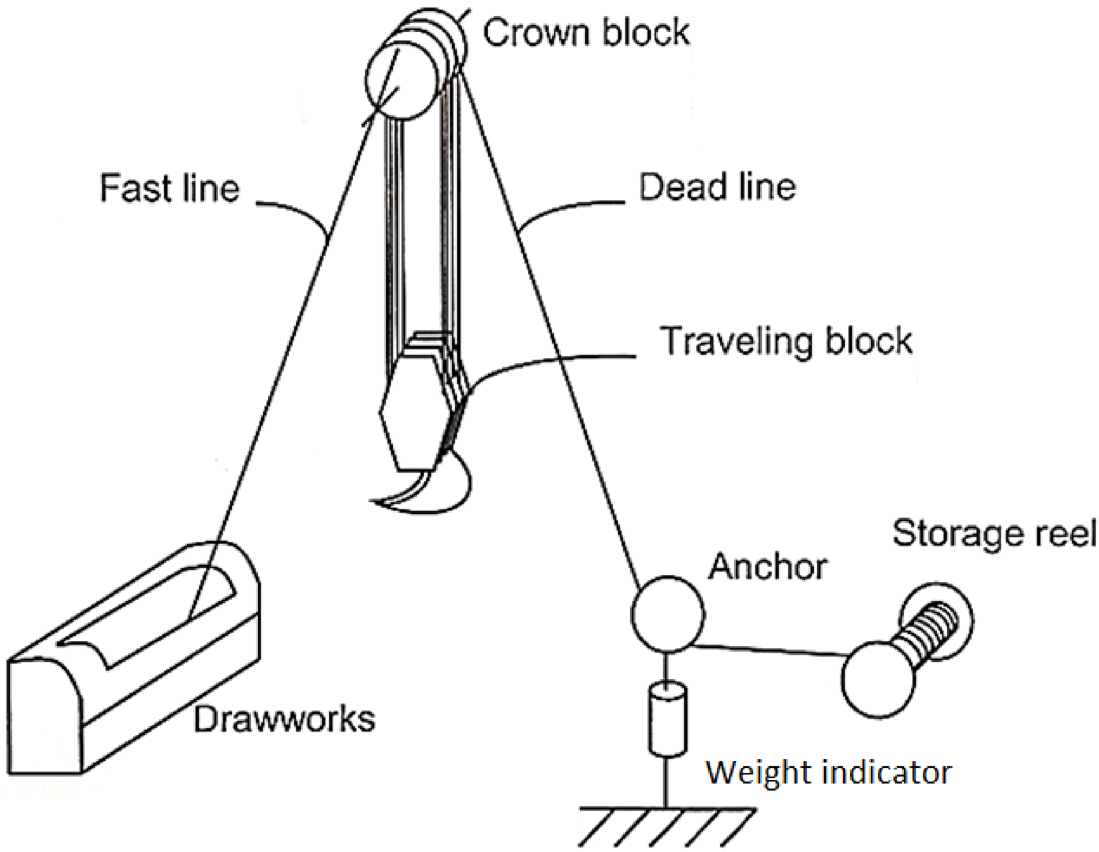


Figure 12: A sketch of the hoisting equipment on drill floors on a rig. The total load (hook load) is obtained by a weight indicator mounted at the deadline and is usually measured by using the tension in the drill lines or from the drill line anchor [61].

The hook load measurement depends on various factors like the weight of the drillstring, sheave friction, direction of block movement, the length of the wellbore, the amount of cuttings and the friction (i.e. the contact) between the drillstring and the borehole wall [59], [91]. The weight indicator mounted at the dead line (as seen in Figure 12 above) measures the hook load from the tension in the deadline. The hook load equals the number of lines between the sheaves/blocks, n, times the deadline tension, F_{dl} [59].

$$\mathrm{HL} = \mathrm{F_{dl}} \times \mathrm{n} \tag{8}$$

where

- HL is the hook load
- F_{dl} is the deadline tension
- n is the number of lines between the blocks/sheaves

N.B. This is a simplified equation. In order to have a better estimate, one needs to take into account the friction in the sheaves [71], [91].

2.3.6.1 Hook load calculations in WellPlan

This section is more or less directly taken from the user manual in WellPlan and gives an introduction to how the hook load is calculated in WellPlan.

"Hook load is, according to WellPlan, the actual weight displayed on the rig floor's weight indicator during drilling operations. The hook load typically represents the buoyed weight of drill pipe or casing suspended from the hook plus the weight of the traveling block, hook, drilling line, and kelly (transmits torque to the drillstring) [WellPlan user manual].

Assume that the casing is not moving up or down. Examination of the forces in a free body diagram show inside and outside drag forces and three weight forces (friction, contact and buoyancy forces) due to the fluid in the annulus, the fluid in the casing and the weight of the casing. In this simulation model, both drag forces are calculated over the measured length of the segment, while the three weight forces are calculated using true vertical lengths [WellPlan user manual].

Starting at the surface and working down the well; segment the well into regions of constant density fluids on the inside, fluids on the outside and the same geometry. Hook load is calculated for each of these segments. The total hook load is the summation of all of the incremental hook loads. The hook load chart shows the tensile or compressive yield limits at each of the string depths analyzed. From the graph, you can determine the load that will fail the drillstring/liner string, but you will not be able to determine exactly where the failure occurred in the string [WellPlan user manual].

The minimum weight on bit (WOB) chart displays the minimum WOB to induce/initiate sinusoidal or helical buckling at any point in the work-string (drillstring or casing/liner) for a range of bit depths [WellPlan user manual]."

2.3.7 Weight of drillstring

The weight of the drillstring (which is suspended by the hook) is given by the weight of the string combined with the buoyancy created by the drilling fluid density. These forces in a vertical wellbore can be seen on Figure 13 on the following page. The two forces that affect the hook load in this scenario are the gravity and buoyancy forces [91].

Weight of drillstring, or the unit mass of the drillstring, should always be adjusted for buoyancy. The principle of Archimedes says that when a body is submerged into a fluid, the buoyancy force equals the weight of the displaced fluid [55]. Buoyancy is in other words the upward force that opposes an object submerged in drilling fluid [73]. The buoyancy factor is given by the following equation:

$$\beta = 1 - \frac{\rho_{\text{mud}}}{\rho_{\text{drill pipe or steel}}} \quad (9)$$

and the buoyed weight of the string is:

$$w = \rho_{\text{steel}} A_{cs} \beta g L \quad (10)$$

where

- β is the buoyancy factor
- w is the weight of drillstring in drilling fluid
- ρ_{steel} is the steel density
- A_{cs} is the cross sectional area of the drillstring body

- g is the gravity acceleration constant
- L is the length of the drillstring
- B is the buoyancy force
- G is the gravity force
- OD is the outside diameter
- ρ_{fluid} is the fluid density

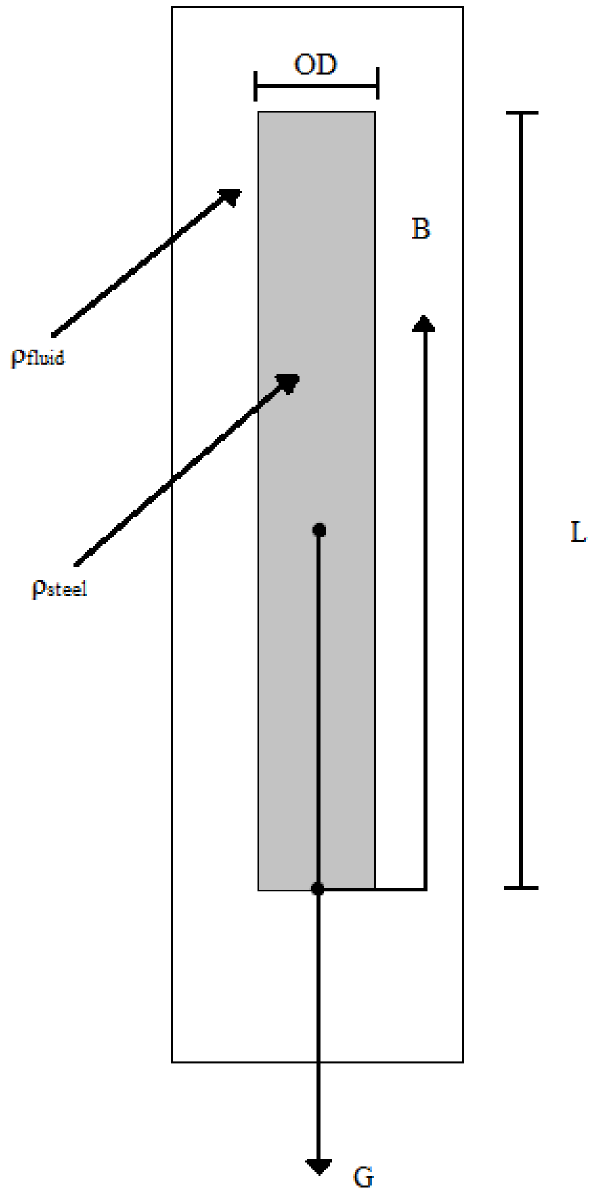


Figure 13: The forces acting on the drillstring submerged in drilling fluid in a vertical well. Modified after [91].

2.3.8 Friction and side forces

The friction plays an important role in the drilling operation and the loads working on the drillstring. The friction force must always be considered, whether tripping out, tripping in or rotating on or off bottom [67]. Reduced annular clearance between the drillstring and the wellbore wall effectively stiffens the pipe (drillstring), increasing the friction (the wellbore supports the drillstring, i.e. increased contact between the two of them) depending on the well geometry [1]. Hook load is, as mentioned earlier, the weight of the drillstring plus or minus the friction (ref. equation (6) and (7)). The friction factor (COF) thus basically represents all the forces acting against string movement.

2.3.8.1 Friction

Friction is the force resisting the relative motion of solid surfaces, fluid layers, and material elements sliding against each other [74]. The work performed by friction is released in the form of heat; it transfers kinetic energy into heat (as the temperature increase, the COF decreases) [74]. The two types of friction that will be discussed later are so-called dry friction forces, which mean that they resist the relative motion of solid surfaces sliding against each other [74].

The force of dry friction can be calculated using the Coulomb friction model, given by the following relationship [91]:

$$F_f \leq \mu F_s \qquad (11)$$

where

- F_f is the Coulomb friction force (the frictional force)
- μ is the coefficient of friction (COF)
- F_s is the side force (also known as the normal force)

The friction works upwards when the drillstring is lowered, and hence downwards when the drillstring is hoisted. According to [47] the friction is higher during hoisting compared to when the pipe/drillstring is lowered. Figure 14 shows the forces acting on an inclined object.

Equation (12) below defines the side force. The side force equals the gravity component that works in the opposite direction of the side force [91].

$$F_s = G_y \tag{12}$$

where

- G_y is the gravity component in the y-direction

$$F_s = mg\sin\theta \tag{13}$$

There will be friction forces working continuous as long as there is relative motion between the drillstring and the wellbore. Even if the well is vertical, the drillstring still touches the wellbore, which implies that there will always be some sort of communication between the wellbore and the drillstring. As the inclination angle (θ) of the wellbore increases, so does the side force (which can be seen from equation (13) above). This is a result of the fact that larger parts/portions of the drillstring will be in contact with the wellbore when the wellbore-angle increases (due to bending in the string) [91]. This strongly depends on the wellbore geometry and trajectory (inclination, azimuth and DLS).

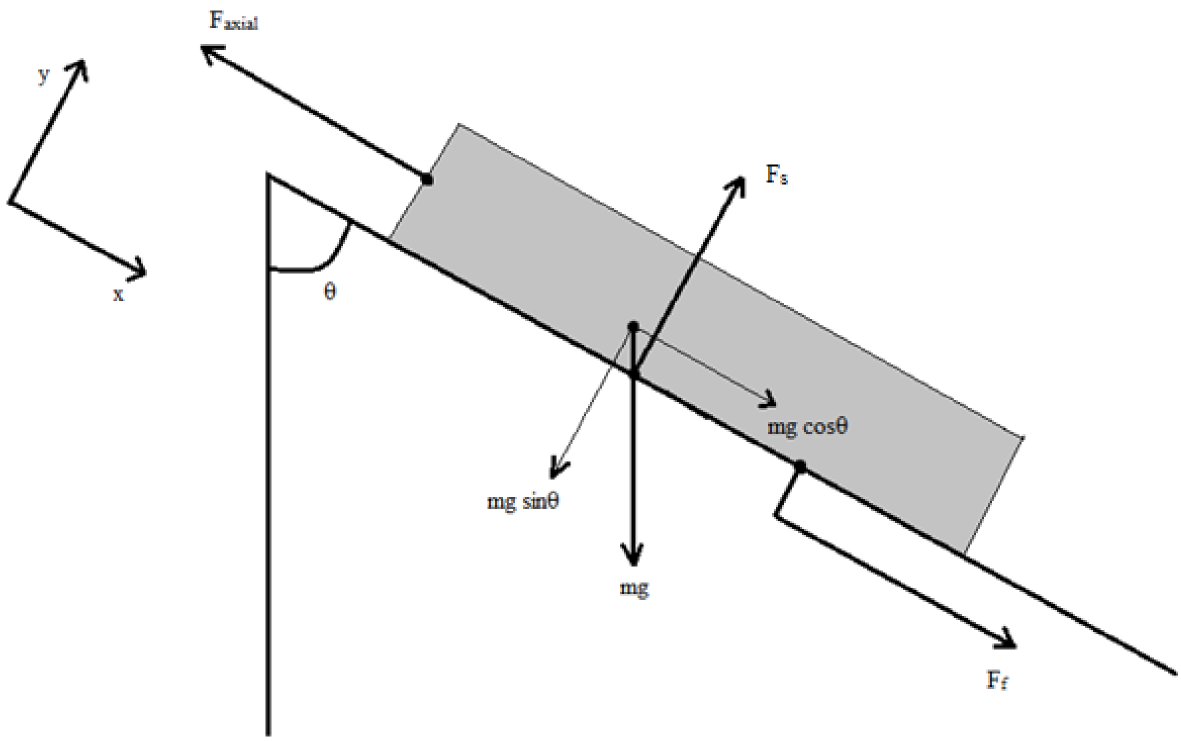


Figure 14: The forces acting on an inclined object on a tilted plane. It illustrates the forces that act between the drillstring and the contact surface in the borehole. F_{axial} is the force pulling on the drillstring component. Modified after [91].

2.3.8.2 Side forces

The side force or normal force is a measurement of the force exerted by the wellbore onto the drillstring and acts in a direction perpendicular to the inclined surface (as seen in Figure 15). The drillstring is forced towards the wellbore wall in curved sections of the borehole. This additional force, created between the two surfaces due to bending in the drillstring if and when the azimuth and the inclination change, is better known as side forces (normal forces) [91].

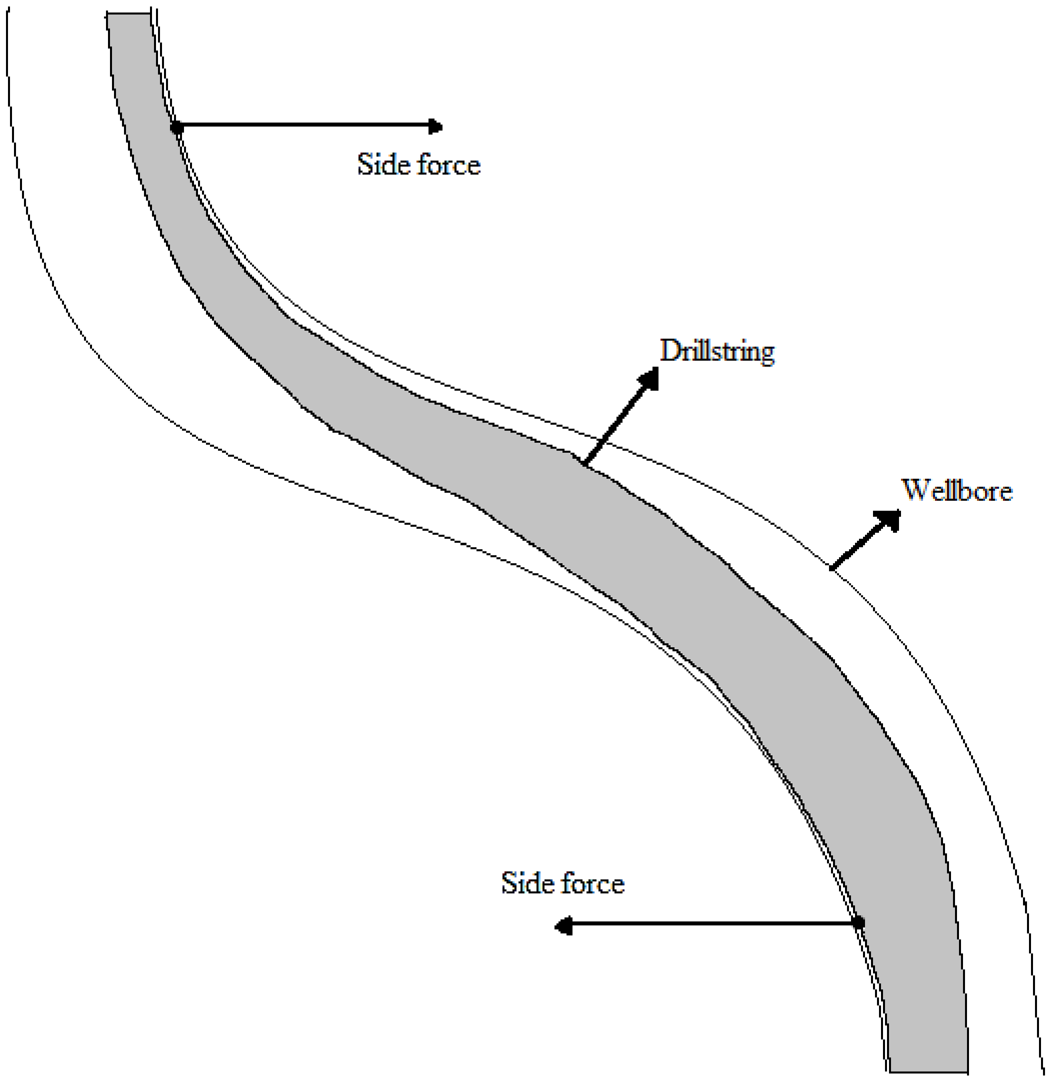


Figure 15: An illustration of the side forces acting on a drillstring in tension. Modified after [91].

2.3.8.3 Coefficient of friction

The friction factor (COF) or the Coulomb friction is defined as the ratio of the force required to move the object, divided by the side force between the object and the surface on which it is resting [72]. The friction force acts against the direction of movement of the object as presented earlier. If proper friction factors are not used, it may result in fatal outcomes like underestimation of frictional drag, further creating problems regarding running casing to its target depth [67].

The COF depends on the surface but is independent of the surface area according to [67] and can be divided into two types:

- Static friction
- Kinetic/sliding friction

2.3.8.4 Static friction

Static friction is the friction arising between two surfaces with no relative motion and is given by the relationship between the static force and the side force:

$$\mu_s = \frac{F_{sf}}{F_s} \tag{14}$$

where

- μ_s is the static COF
- F_{sf} is the static force

2.3.8.5 Kinetic friction

Kinetic friction is the friction between two surfaces with relative motion and is given by the relationship between the kinetic force and the side force:

$$\mu_k = \frac{F_{kf}}{F_s} \tag{15}$$

where

- μ_k is the kinetic COF
- F_{kf} is the kinetic force

The COF usually has higher magnitude if there is no movement, and decreases when the two surfaces move relatively to each other.

$$\mu_s > \mu_k \tag{16}$$

Figure 16 shows the ideal behavior of the Coulomb friction model. The force trying to get an object into movement must exceed the static friction to accomplish this. When the object is static, the friction force equals the applied force. When the object starts to move, the static friction terminates and the friction is now provided by the kinetic friction.

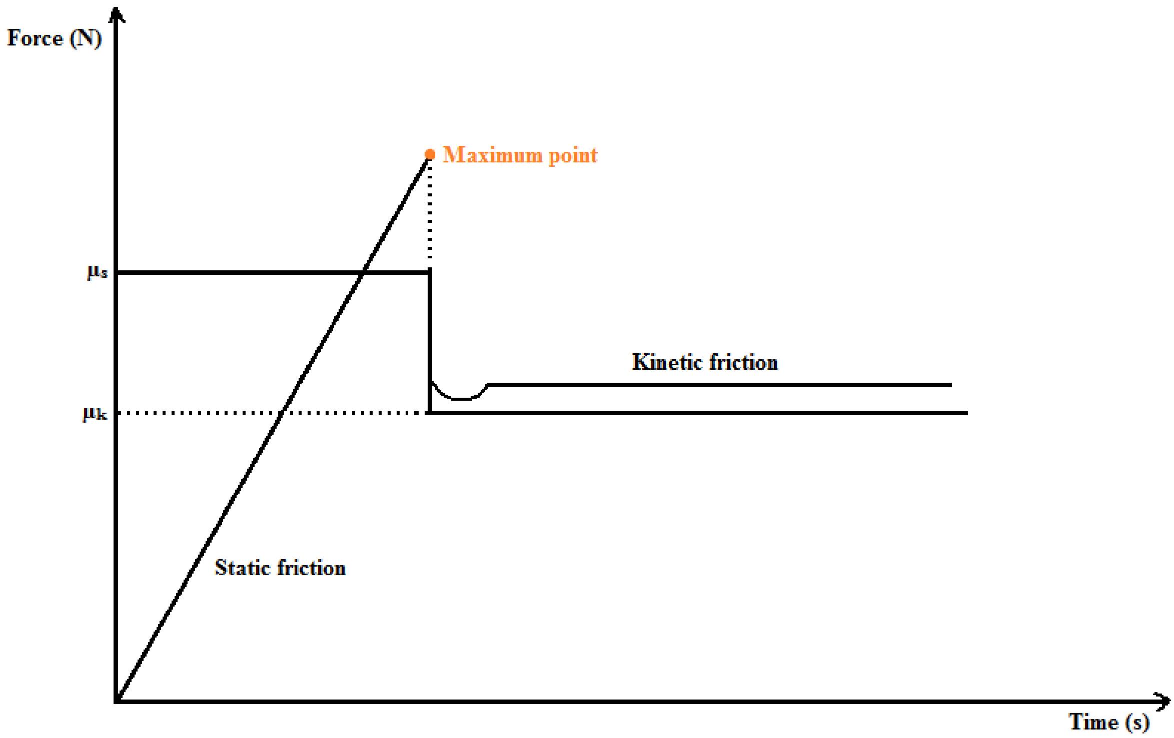


Figure 16: The ideal behavior of the Coulomb friction. The maximum point is the maximum force the static friction can handle. When the force exceeds this maximum value, the object will start to slide. Acceleration creates the “dump” that arises when kinetic friction takes over [67]. Modified after [91].

2.4 Torque, drag, buckling and corresponding limitations

Torque, drag and buckling are all central challenges that must be carefully planned for, dealt with and considered in the planning and operational phases in order to achieve a successful ERW. It is important to make sure that every single phase of an ERW (i.e. drilling, casing, completion and possibly work-over operations in further perspective) can be safely performed, with realistic designs and goals [1]. T&D calculations are usually used to predict the over-pull and slack-off forces for freeing stuck pipe and to apply force and torque for backing off [67].

According to [1], [9] ERD wells often fail due to one of the following scenarios along with the fact that “low-angle” or “vertical hole” practices wrongly have been used in the operational phase:

- The torque is so high that it exceeds the capability of the top drive and/or drillpipe (this can also result in twist-off (worst case scenario));
- Unable to run the casing to bottom (often incorrectly perceived as “hanging up” or cuttings beds);
- Unable to drill since we are not able to transfer enough WOB;
- Buckling;
- Exceeding the tensile limit of the drillstring.

Torque and drag are caused by well friction between the hole and the pipe and is one of the major limiting factors in extended reach drilling. T&D are closely related – what increases one will increase the other similarly [9]. A rule of thumb regarding T&D, according to K&M [9] is: high-angle wells have high T&D, while low-angle wells have low T&D. Torque and drag are thus kind of like fish and chips – they go together – and are particularly marked in long-reach wells [9].

Torque and drag are caused by side forces (also referred to as normal forces described in detail in section 2.3.8.2) and are created by three different mechanisms according to [9], [14]:

1. Weight of pipe on the low-side (Low-Side T&D)
2. Tension-related side-forces through build, turn and drop doglegs (Brake Drum T&D)
3. Pipe pushing into the side of hole, driven by stiffness and diametrical clearance (Stiffness T&D)

Low-side T&D is created due to the resistance to movement created from the "friction," as a result of being pushed into the low-side of the hole [9]:

- Sensitive to angle, weight and buoyancy;
- Each joint creates T&D independent of each other;
- Creates the same side-force, independent of direction.

String tension creates additional contact force and friction in inclined sections, like a Brake Drum (which is the maximum side-forces when picking up) [9]:

- T&D forces are created by the tension of other elements situated below this interval;
- Pick-up, slack-off and rotating forces are different in curved sections, due to the fact that the tension in the string is different;
- Slack-off is more sensitive to friction (the Brake Drum effect) than pickup;
- The bigger the DLS, the greater the friction becomes.

This leads to the basic T&D equation [9], which can be used to calculate the contact force between the wellbore and the drillpipe or between the casing and the drillpipe:

$$\mathrm{N} = \sqrt{(\mathrm{T} \times \Delta\alpha \times \sin\theta)^2 + (\mathrm{T} \times \Delta\theta + \mathrm{W} \times \sin\theta)^2} \tag{17}$$

where

- N is the contact force (i.e. formal force)
- T is the tension difference along component
- $\Delta\alpha$ is the azimuth change across component
- $\Delta\theta$ is the inclination change across component
- W is the buoyed weight of component

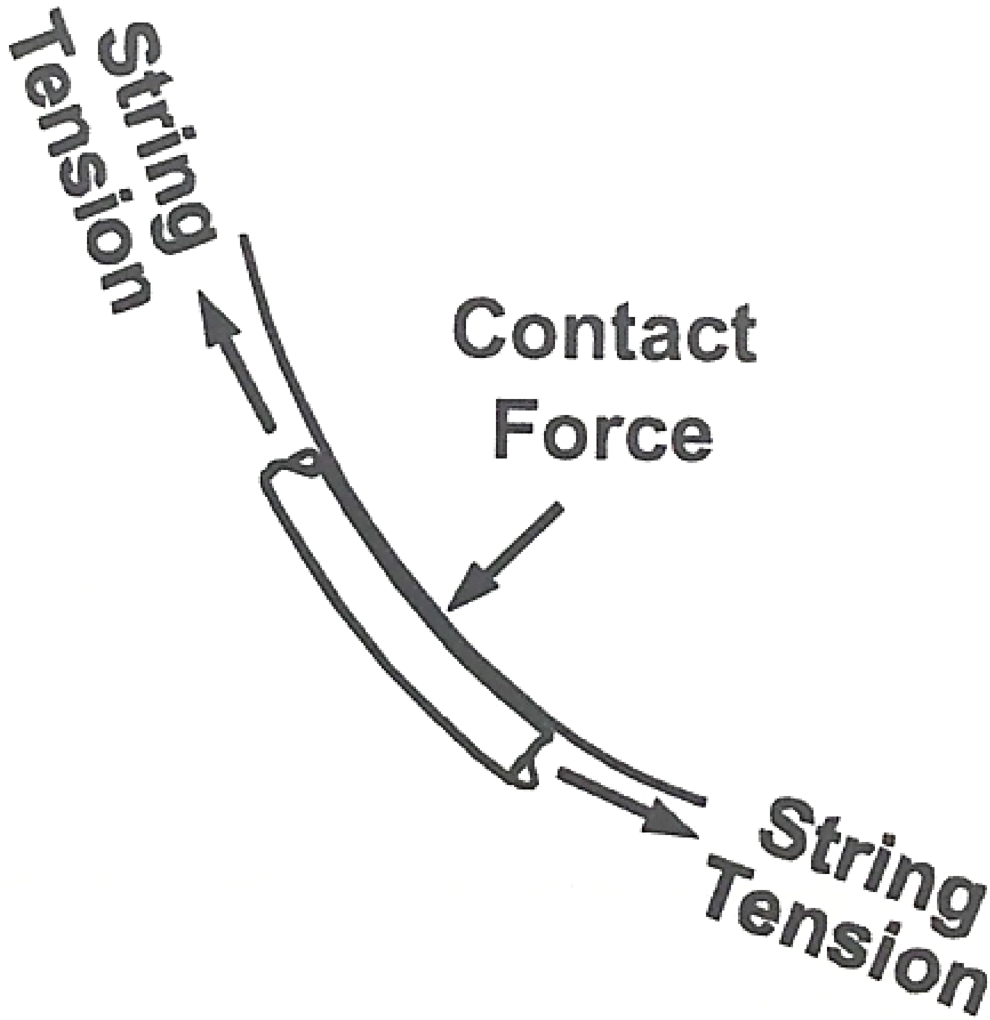


Figure 17: The sketch for the basic T&D equation [9].

2.4.1 Torque, drag and buckling theory

Horizontal wells are more prone to forces like torque and drag compared to vertical wells, due to the fact that the pipe theoretically hangs in the center of the wellbore in a vertical well [1]. The drillstring is generally not in contact with the wellbore, and the only forces acting on the drillstring is tension and/or compression.

In a deviated wellbore, other forces are seen in addition due to the increased (potential for) contact between the drillstring and the wellbore (as seen in Figure 18 on the following page). These additional forces, such as torque and axial drag, are cumulative and generally act in the opposite direction compared to the movement and weight of the pipe [1]. The magnitude of these forces strongly depends on the wellbore geometry and trajectory (inclination, azimuth and DLS).

The ratio between the length of the wellbore and the forces acting on the drillstring is linear, which implies that the longer the wellbore, the higher are the forces acting on the string [1].

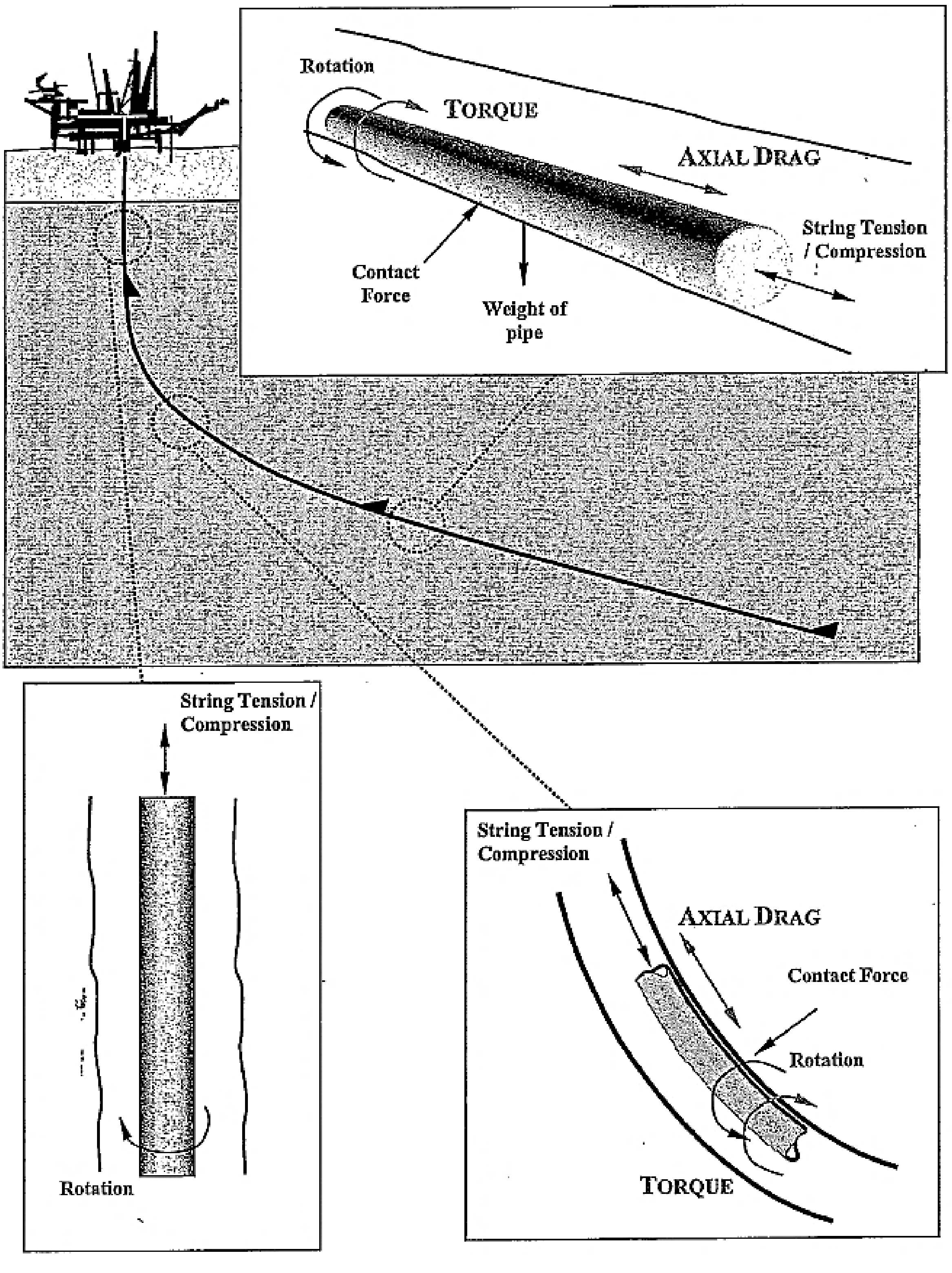


Figure 18: The forces acting on the drillstring in a deviated hole [1].

2.4.1.1 Soft String model

This section is more or less directly taken from the user manual in WellPlan and gives an introduction to the difference between the Soft String model (the one WellPlan uses) and the Stiff String model.

"The torque, drag and buckling simulations performed in WellPlan are based on Dawson's cable model, or "Soft String" model as it is commonly known. The work-string is treated as an extendible cable with zero bending stiffness [WellPlan user manual].

Additionally, a Stiff String model is provided as an option. This model includes the increased side force from stiff tubulars in curved hole, as well as the reduced side forces from pipe wall clearance [WellPlan user manual].

In the Stiff String model the buckling stresses are integrated with the pipe curvature and hence included in bending. The Soft String model treats buckling stress independent to bending stress and adds the two together for fatigue analysis [WellPlan user manual].

Bending stresses are caused by pipe running through curved hole on one side of the pipe it is bent into tension and other side is reversed into compression. Bending stresses are at maximum at the outside of the pipe body and undergo a simple harmonic motion as the pipe rotates [WellPlan user manual].

If you ran the Stiff String model in comparison to the Soft String model, you will see the following differences [WellPlan user manual]:

1. *Normal planned well-path (no tortuosity) would yield slightly higher results (+1%).*
2. *Normal surveyed well-path would yield slightly lower results (-10%), this is because the Stiff String model straightens the pipe in the wellbore through doglegs. It will also lessen the affect of tortuosity if applied.*
3. *Stiff tubulars in higher dogleg holes is where you will see torque/drag results greater than 10% of the Soft String model."*

According to [98] the Soft String model neglects pipe bending stiffness in the side forces calculation. The Stiff String model, on the other hand, accounts for the tubular bending stiffness and thus gives a more realistic estimation of pipe failure risks and standoff prediction [98]. The Soft String model also assumes that centralizers are in contact with the wellbore (in the Stiff String model the centralizers are not in contact with the wellbore initially and the model does not systematically impose contact between the centralizers and the wellbore), which again may lead to standoff underestimation [98].

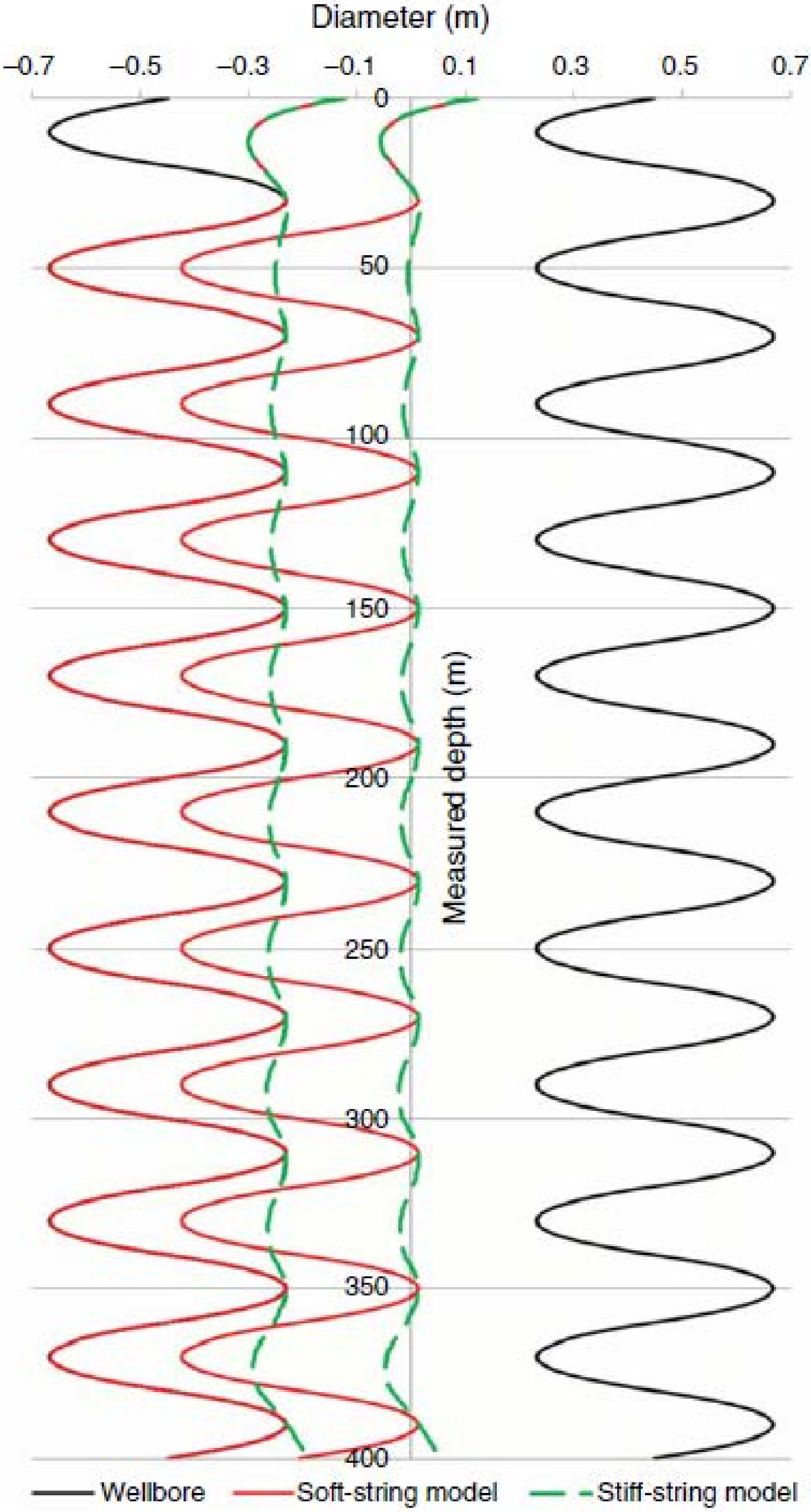


Figure 19: Soft string model [96].

2.4.2 Torque fundamentals

Torque is a so-called rotational force and is generated from various sources inside the wellbore: frictional torque, mechanical torque and bit torque [1]. Torque can only be seen during drillstring rotation.

- Frictional torque: this is a frictional force that is a result of the contact between the drillstring and the casing or open hole [1]. The value of this torque component is given by the following factors: tension or compression in the drillstring, dogleg severity (DLS), hole and pipe size, string weight, inclination, lubricity or friction factor.

- Mechanical torque: is a result of the interaction between the drillstring and the BHA with cuttings beds, unstable formations, or differential sticking [1].

- Bit torque: is generated by the contact between the bit and the formations being drilled. The magnitude of the torque strongly depends on the bit design with a rule of thumb saying that PDC's generally generate more torque than tri-cones does [1].

2.4.3 Drag fundamentals

Drag is an axial force that is the outcome of the same sources as torque (i.e. the higher contact forces, the higher the drag) [1]. It can roughly be said that drag takes the place of torque when the drillstring stops rotating and the pipe is being moved in the axial direction [1], [9]. Drag consists of both a mechanical and a frictional component and always works in the opposite direction of pipe movement [1], [9]. It is often possible to reduce and/or minimize the drag forces by simply rotating the drillstring or casing string (i.e. induce rotation).

2.4.4 Buckling fundamentals

Buckling is the outcome of the compressional forces in the drillstring. Compression in the drillstring or casing is built up by drag forces until it reaches a point where the Critical Buckling Load (F_b) is exceeded and buckling will arise. The buckling tendency generally increases with increasing hole size (due to higher drag forces with increased annular clearance) [1]. This means that the buckling tendency will be lower in a 12¼" compared to a 15" hole (the pipe has less room to move) thereby allowing a more efficient transfer of weight on bit [1].

Buckling often occurs in wells without the drilling team even noticing it. They commonly spend time and money on dealing with hole problems by dealing with bit changes, wiper trips and optimizing mud, when the real problem may have been buckling the entire time (this being said, buckling does not have to be severe to affect operations and can be difficult to predict) [1].

Buckling usually occurs under the following conditions according to [1]:

- While sliding or running liners down in high-angle/inclined or horizontal hole sections;
- When "small" OD pipe is being used (small OD pipe is thus more prone to buckling);
- In deepwater ERD wells while landing casing with drillpipe or HWDP (drillpipe that has thicker walls, and is thus stronger and has higher tensile strength than conventional drillpipe);
- If the drillpipe is in a state where it is being compressed due to hole size enlargement (e.g. above a liner hanger);
- During completions or work-overs (most likely to occur in smaller completions; 2⅞" or 3½" – small completions are quite prone to buckling in ERW).

Aadnøy and Andersen states that the following conditions are observed in a long horizontal well regarding buckling [48]:

- Buckling may occur at the start of the horizontal section. Use large diameter thin-walled pipe to increase pipe stiffness, and to minimize pipe weight. Small clearance between hole and drillstring also reduces buckling.

- Maximum bit force is given by the critical buckling force. During drilling, the force will be constant throughout the horizontal section.

- Weight of drill collars required is also defined by the buckling force. As a minimum, let the vertical height of drillcollars times the buoyed weight equal the buckling force. The buckling force is the major controlling factor (or limitation) and is the design parameter for bit force, and drill collar weight. To reduce axial friction when buckling occurs, always rotate pipe. Rotation has negligible effect on buckling.

Buckling can be calculated using numerous equations and is a function of the following parameters according to [1]:

- **E and I –Young's Modulus** and **Moment of Inertia** which measures the tubular stiffness; stiffer pipe is less prone to buckling and stiffness increases with OD [1],[9];

- **w – Tubular weight in mud.** A rule of thumb: the higher the weight of the drillstring, the less prone it is to buckling. On the other hand: higher weight of tubular will lead to increased drag and increased compressional forces, which again may increase the risk of buckling [1];

- **θ – Average wellbore inclination.** Buckling resistance increases with increased wellbore inclination [1];

- **R – Radius of curvature of the hole.** Buckling is less likely to occur in curved wellbore sections [1]. The radius of curvature implies the distance from the center of a circle to the surface of the curvature/bending that mathematically best fits the curve as seen in Figure 20. The radius of curvature changes during movement along the wellbore (if and when the wellbore trajectory changes) [93];

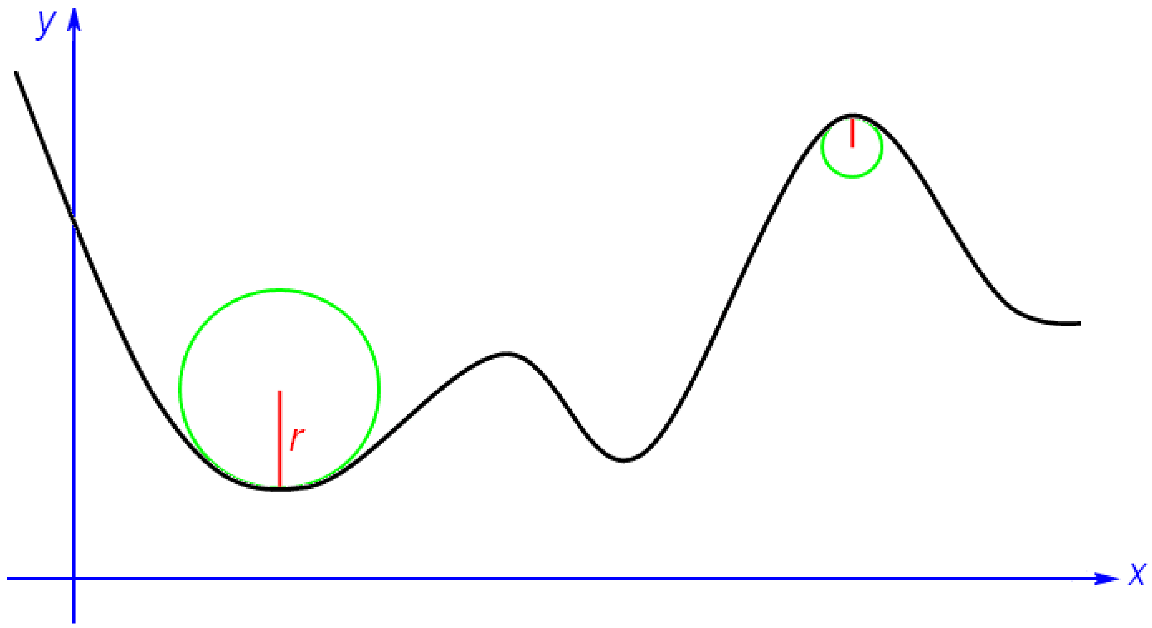


Figure 20: Radius of curvature [93].

- **r – Radial clearance between the wellbore and tubular.** Increased annular clearances will result in less buckling tolerance since the tubular is less constrained in the wellbore (the drillstring has more room to move/bend inside the wellbore) [1].

There are two types of pipe buckling:

- Sinusoidal (also known as lateral, snaky or two-dimensional buckling)
- Helical (coiled spring/spiral)

2.4.4.1 Sinusoidal buckling

This is the 1st phase of buckling (due to the fact that it occurs at lower compressional loads than helical). The pipe "snakes" from side-to-side along the low-side of the wellbore and the gravity prevents the pipe from climbing to the top of the hole [9]. This limits the ability to effectively transfer weight on bit [1]. Sinusoidal buckling allows transfer of weight (inefficiently) that shows up as poor tool face control (motor stalling) and is often diagnosed incorrectly as "bad hole" [9].

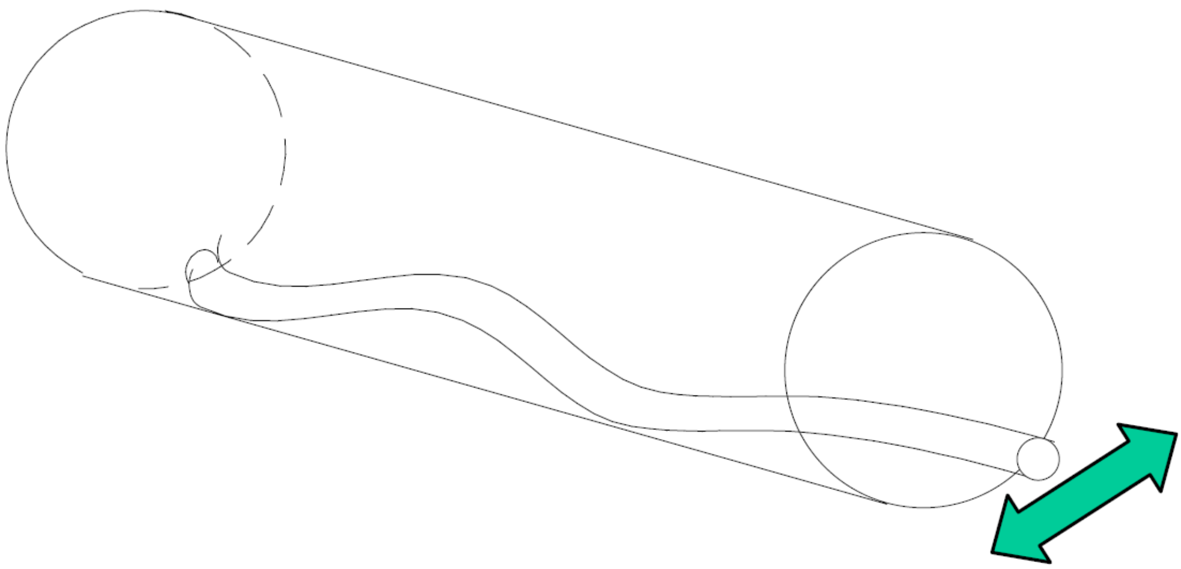


Figure 21: Sinusoidal buckling [1], [9].

2.4.4.2 Helical buckling

This is the 2nd phase of buckling (as the compression increases, the pipe suddenly snaps into a full coil (pretty much the same as a "slinky" toy)). Helical buckling prevents all further transfer of weight, not even if top drive weight is applied at the surface. The increased compression gives the coil a better grip on the hole (like a set of slips) [1].

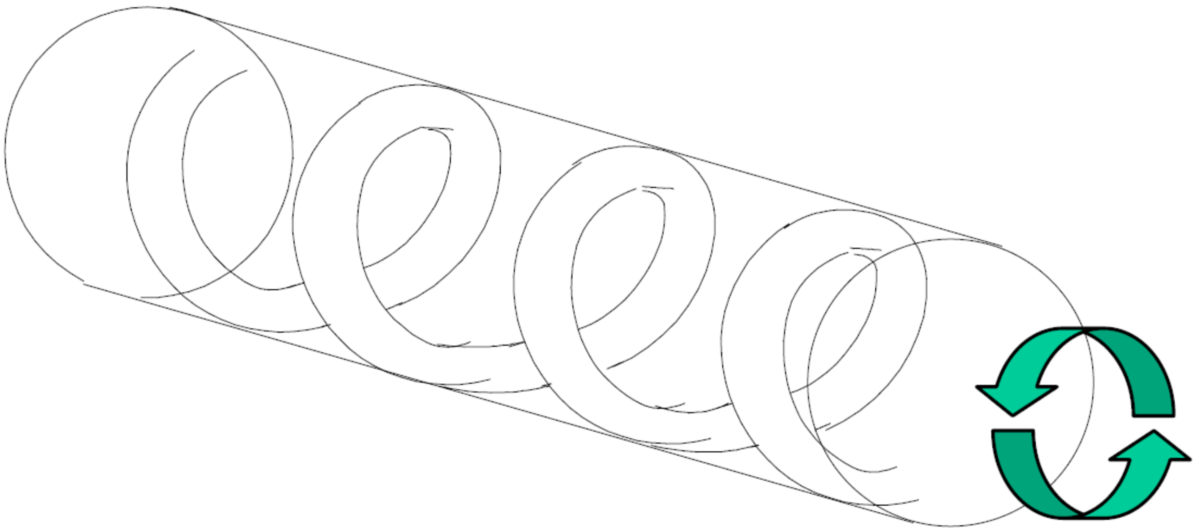


Figure 22: Helical buckling [1], [9].

2.4.4.3 Effect of connections on type of buckling

Mitchell & Weltzin [88] describes two loading (buckling) tests on a drillstring in build and inclined sections of the Ullrigg U2 test well in 2009. The conventional wisdoms suggests that buckled pipe first forms a plane-buckled configuration (sinusoidal/lateral buckling) and then transitions to a helical shape when the axial load increases [88]. The results from the Ullrigg U2 tests show that connectors have primary importance in the buckling behavior of the drillpipe and that lateral (sinusoidal) buckling actually is the primary mode of behavior! [88].

Ullrigg U2 is a 2020 m research well with a buildup and 60° tangent geometry [88]. Both of the two tests performed were loaded until drillstring lockup. Lockup means that no increase in load could be transmitted to the load sensor attached to the bottom of the drillstring with further decrease in hook load at the surface [88]. Lateral buckling was the primary buckling mode in both of the tests, helical buckling only occurred in short intervals in the build-section [88].

The lateral-buckling solution that was developed in [88] includes pipe with connectors. In previous drillstring analysis, the connectors have not been considered important, even though the tool joint is bigger and more rigid than the drillpipe body. The connector is approximately 4.5% of the total length of the joint [88]. Another important aspect is that there is less clearance between the tool joint and the wellbore compared to the smaller OD drillpipe body, which limits the ability to rotate [88].

The results from the tests performed at the Ullrigg show that the conventional wisdom with regards to buckling is “wrong” and needs to be modified [88]. It concludes with the following observations according to [88]:

1. Buckling occurred between connectors;
2. Buckling was primarily lateral buckling, with only limited helical buckling;
3. Contact forces between the wellbore and drillstring and resulting friction were significantly greater than anticipated.

This implies that the interaction between the connectors and the surrounding casing is of primary importance and that it is necessary to include connectors in any enhanced buckling analysis to be used in torque and drag modeling in the future [88].

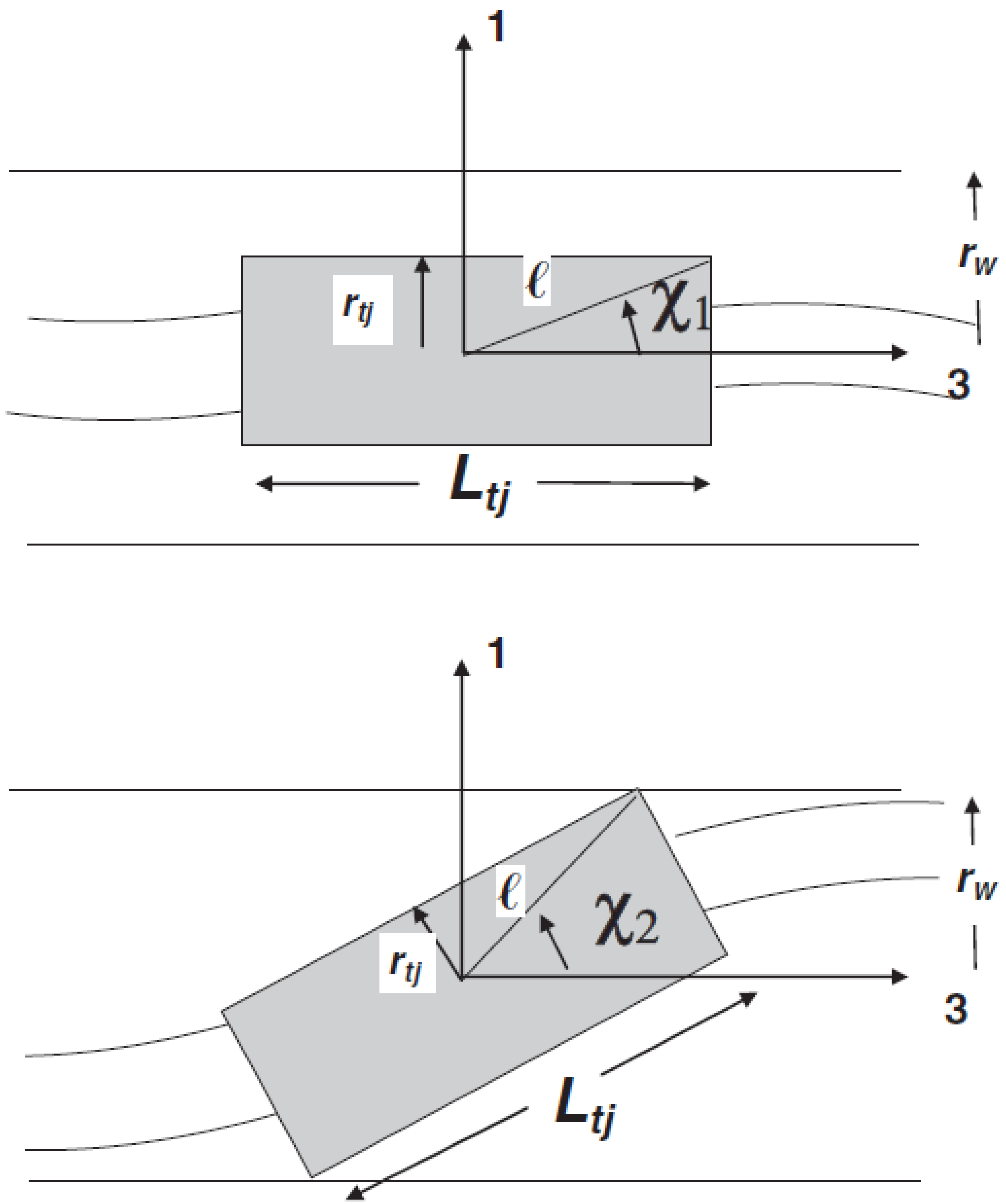


Figure 23: Connector rotation within the wellbore [88]. r_w is the wellbore (or casing) radius, r_{tj} is the tool-joint radius, L_{tj} is the length of the tool-joint, ℓ is the half-diagonal length of the tool-joint and X_1 and X_2 represent angles [88].

2.4.4.4 What can buckling do to the pipe?

Buckling is usually not harmful to the pipe, at least not as long as the pipe is not being rotated. The buckling stresses usually lie far below the DP's yield strength. When the drillpipe is being rotated it results in back and forth bending; buckled pipe will be significantly damaged if the pipe is being rotated due to cyclic stresses.

If enough force is applied any pipe can buckle and result in a permanently deformed pipe (due to the compressional forces, i.e. the pipe must be in compression for buckling to occur [9]). It is therefore important to avoid rotation of the drillpipe until all of the buckling has been worked out of the string [1].

2.4.4.5 What affects buckling?

- The drillpipe/string must be in compression;
- Big holes are more prone to buckling than small holes because the pipe is not as well confined in big holes and higher WOB may be desired in a large hole (which again increases the risk of buckling) [1];
- Small OD pipe are as mentioned above more prone to buckling than big OD pipe due to the fact that the stiffness increases with increasing OD (e.g. 5" DP is twice as stiff as 3½" DP [9];
- It is harder to buckle as the wellbore angle increases (but not totally impossible);
- It is also harder to buckle in a curved hole compared to a straight section. This is because bending forces exerted by the curved hole help the pipe resist buckling [9]. Drillpipe that is bent is thus more resistant to buckling mainly due to the fact that it is supported by the wellbore wall.

Common buckling intervals in an ERW

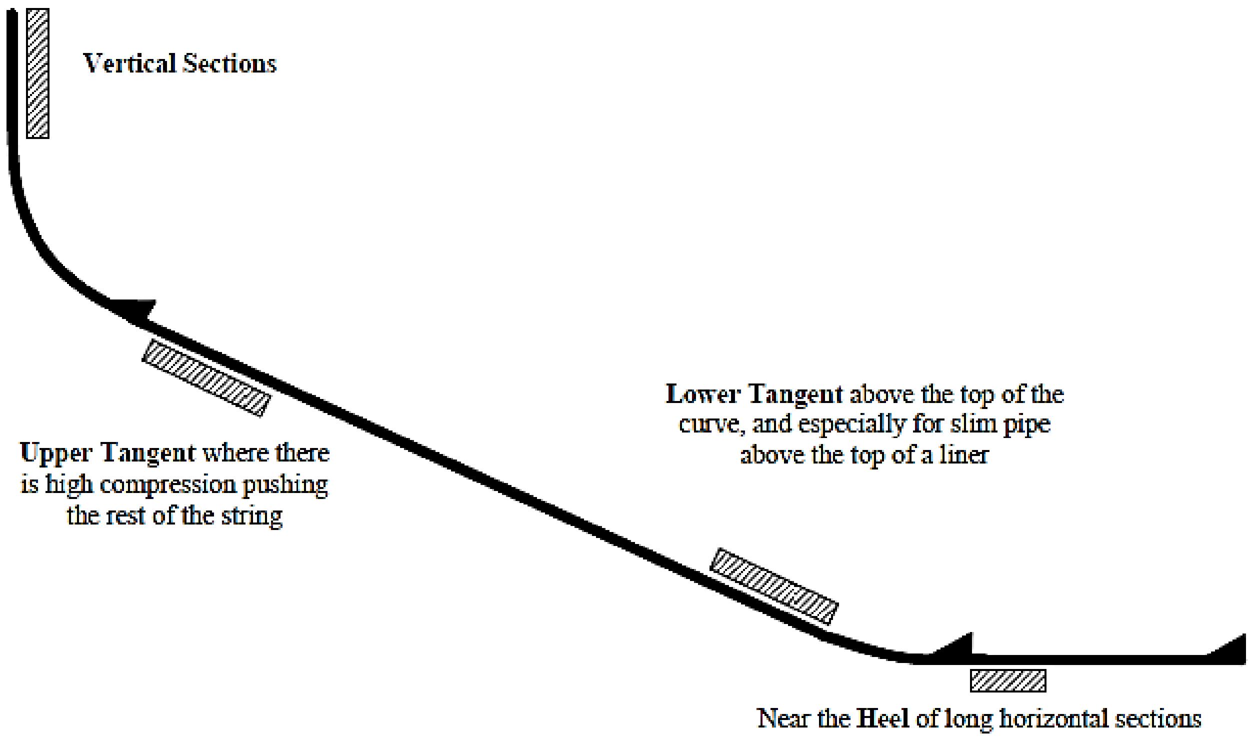


Figure 24: Intervals where buckling is most likely to occur in an ERW. It usually occurs immediately above KOP in vertical intervals and near the heal for long horizontals. This is when sliding or tripping into hole (i.e. without rotation) [1].

2.4.4.6 Techniques to avoid or reduce buckling according to K&M [1], [9]

- HWDP can be placed at strategic intervals in the drillstring to reduce the possibility for buckling to occur (to achieve increased stiffness). Disadvantages of this can unfortunately be more T&D, and in addition increased surface pump pressure (which may be a limitation);
- Using larger OD drillpipe to increase the stiffness (also needs to account for a possible increase in ECD's);
- Using a tapered drillstring (which means less weight to push);
- Stiffening the pipe in critical intervals in the drillstring will increase the buckling performance [1], [9];

$$\text{Stiffness} \propto \frac{R^4}{r^4} \tag{18}$$

  - As seen from equation (18); the stiffness of the pipe is a function of the radius to the power of four. This implies that the 4" drillpipe is better for buckling compared to 3½" and that the 6⅝" DP and/or casing are virtually resistant to buckling [1], [9].

- Reducing friction with the aim to reduce the compressional forces by the use of lubricants or OBM instead of WBM or use roller assemblies on the pipe [9];
- The best way to limit pipe buckling is to preserve the ability to rotate [1]; pipe rotation reduces the string compression and drag forces;
- Using a roller cone bit on the steerable motor when and if sinusoidal buckling occurs;
- Using a rotary drilling strategy instead of steerable motors (RSS or AGS);
- Follow the rules for high-angle BHA design [9]:

  - Using minimum BHA for directional controls and surveys
  - Only use 3 stands of HWDP in order to provide stiffness transition and jar action (1 stand below jars)

- A rule of thumb for high-angle wellbores according to [9]:

    - Excess BHA and HWDP will increase the T&D and may create buckling up the hole and may affect the hydraulics.

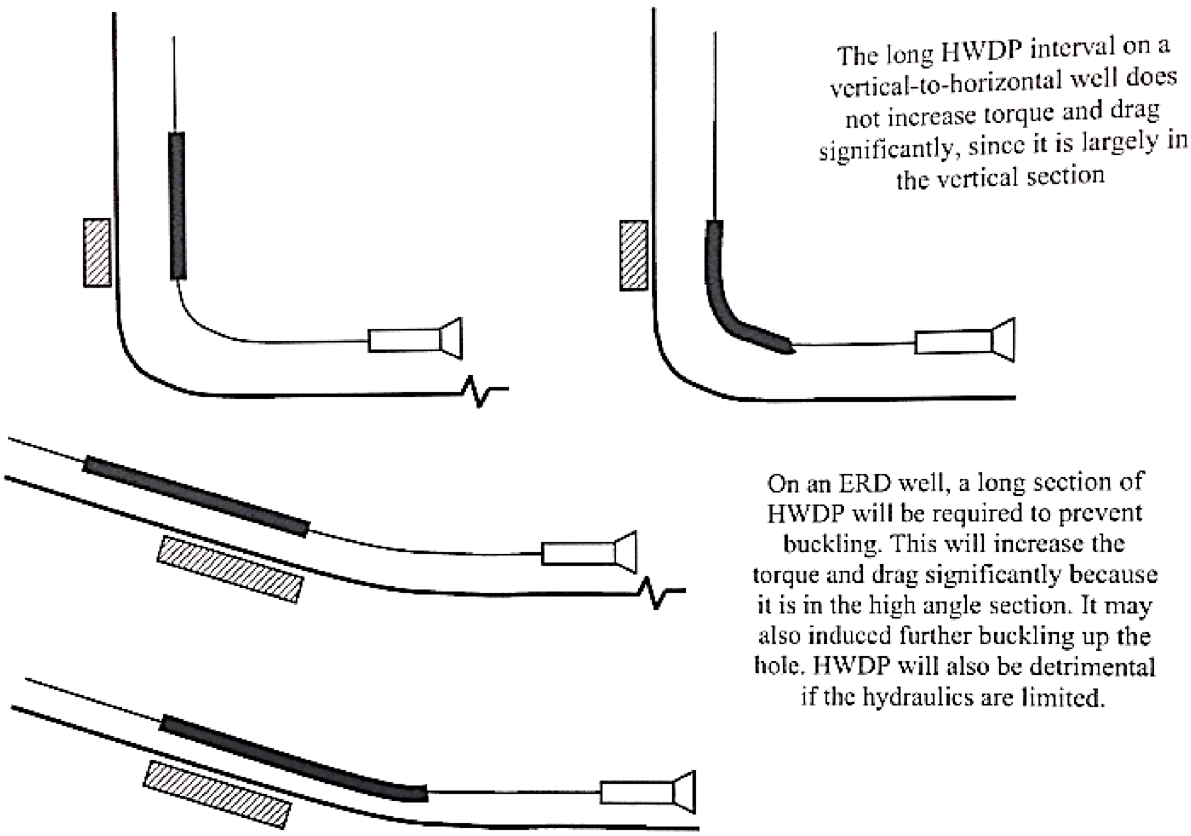


Figure 25: An illustration on how HWDP can be used to prevent buckling [1].

2.4.5 Limitations for reaching a target

There are three major limitations for reaching the desired target in ERD wells, which will be discussed in short below:

1. Load on surface (torque and tensile limits)

High drilling torque is often a limiting factor and a significant issue in ERD wells. At Wytch Farm the torques were pretty close to the limit of the top drive on wells M14 and M16, around 40-45 kft-lbs [65]. They solved this problem by using a combination of two different mud additives: Barafibre (crushed almond shell) and Lubraglide (small plastic beads) [65]. This resulted in a torque reduction safely below the top drive limit.

At first, on M14, they used Barafibre as the primary method of torque reduction. On M16 they decided to try using Lubraglide, by stripping out the Barafibre replacing it with Lubraglide. When the Barafibre was stripped out of the system, the torque rose from ± 40 kft-lbs to the top drive limit 45 kft-lbs, where the top drive stalled out. As the Lubraglide entered the system, the torque fell down to 25 kft-lbs, but was surprisingly enough not sustained. For the rest of the well they combined Barafibre and Lubraglide to manage and control the torque [65].

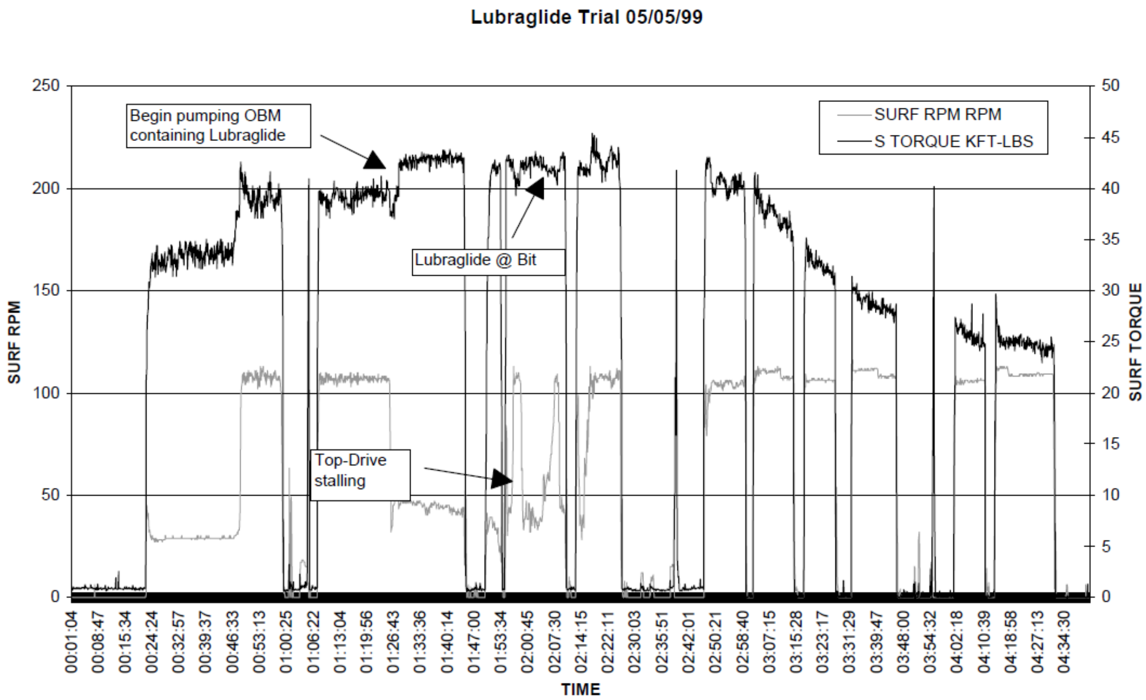


Figure 26: A plot of surface torque and RPM during Lubraglide addition [65].

Few drilling rigs can handle torques of too large magnitudes. The torque is generally generated from the tension in the sail angle converted into torque in the build section [48]. An action taken is the use of lighter drillpipe, which drastically reduces the torque down below safe/allowable limits. A study [48] showed that by using lighter drillpipe, it should be possible to drill several kilometers further. The hydraulic system is believed to be the main limitation in this case: one probably needs a higher pressure mud pump in order to reach target depth [48].

2. Buckling

Buckling is as mentioned earlier a deformation of the drillstring or casing string and can be divided into sinusoidal (snaky) and helical (coiled spring) buckling [1]. It is a result of excessive compressional forces in the string that builds up due to axial friction. As the measured depth increases, so does the risk of buckling (generally). The pipe must literally be “pushed in” in the horizontal section since there is no gravitational effect here and the drillstring is therefore placed in compression here resulting in a higher probability of buckling to arise [48]. Buckling is thus a common limitation in ERW in terms of reaching TD [48].

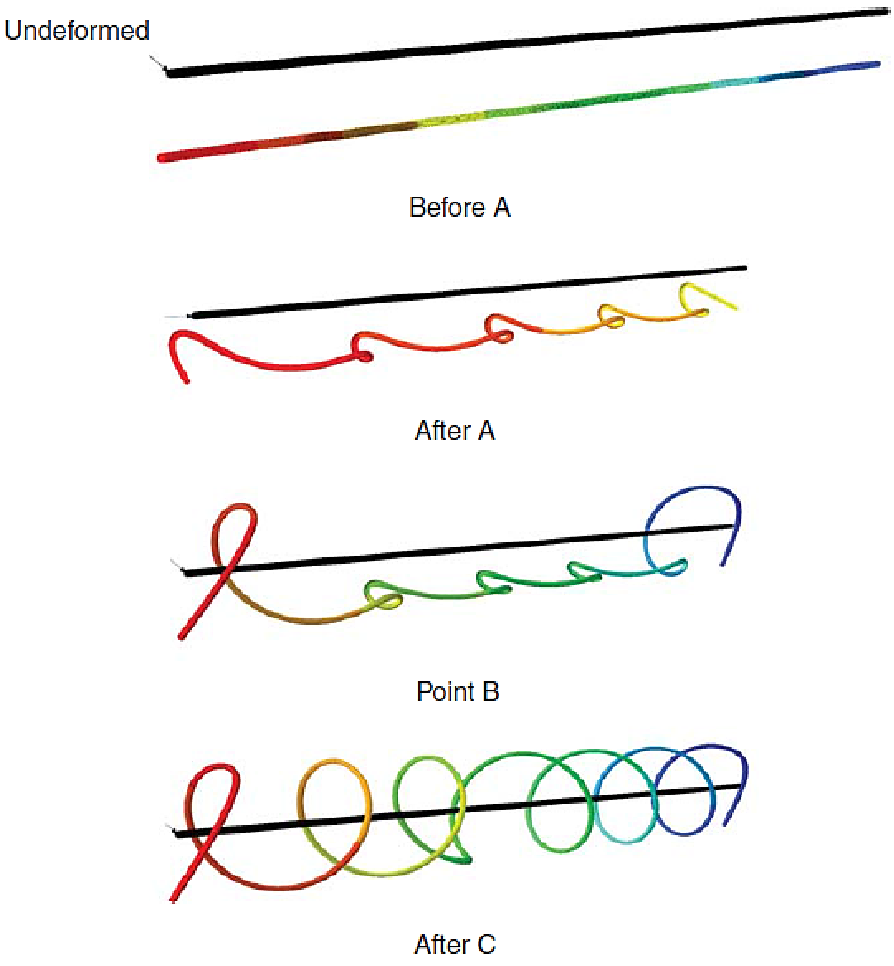


Figure 27: Different buckling steps from un-deformed to sinusoidal to helical buckling. The number of helixes increases after point B and reaches a fully helix shape configuration in point C [80].

Buckling was a central issue at Wytch Farm. The technique they chose to apply was to use non-rotating drillpipe protectors (DPPs) [79]. This technique often result in torque reduction, but the downside is increased ECD values caused by the protectors mounted on the drillpipe [79]. The DPPs also suppressed the buckling tendencies at Wytch Farm, which improved the drillstring ability to slide down the wellbore [79].

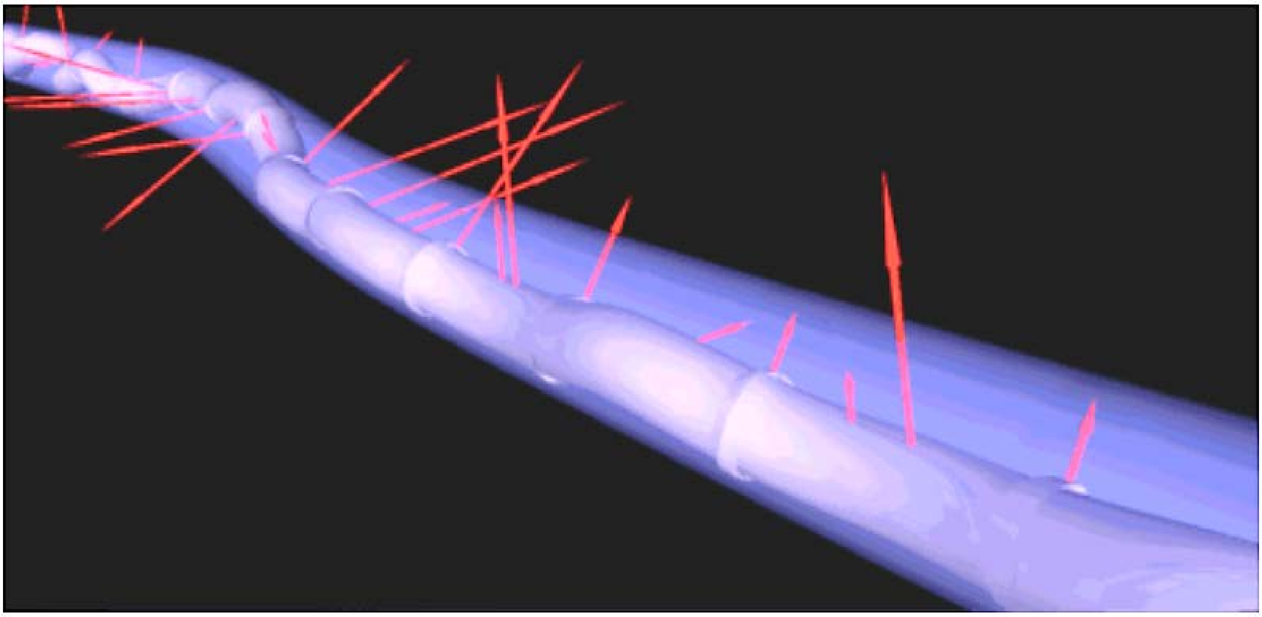


Figure 28: An illustration of a buckled drillstring in a horizontal wellbore [82].

3. Negative weight wells (is it possible to transfer (enough) WOB to overcome the friction working against the direction of movement?)

This is wells where the drillstring or casing string cannot reach TD by its own weight due to excessive drag forces acting against it [1]. Friction is one of the most limiting factors in these wells. Is there enough weight in the drillstring to overcome the friction acting against the direction of movement? If not, we will not be able to transfer WOB. Solutions to this problem can be rotation of the drillpipe to provide sufficient surface weight or floating casing (one method is to fill the casing with drilling fluid through a valve placed between the pin and box ends on the casing; floating the bottom part of the casing will reduce the drag against the wellbore, while filling the upper part of the casing with drilling fluid provides extra weight to the casing string and pushes it into the hole) [83].

The (transfer of) weight on bit (WOB) can also be limited by the Critical Buckling Load (F_b) mentioned earlier. When the Critical Buckling Load is exceeded the pipe loses elastic stability and can result in fatigue failure, ineffective axial load transfer to the bit and buckling over time [81]. A buckled drillstring creates larger side forces than an unbuckled string (due to increased contact with the wellwore wall), thus leading to increased friction losses and potentially a lockup of the drillstring and additional equipment [80]. The risk increases with depth/departure implying that ERW are more prone to this than conventional wells [80].

According to Aadnoy [48] the following condition is required for the drillstring to slide downwards: $\cos\alpha \geq \mu \sin\alpha$, which gives the maximum sail angle (given by the friction coefficient) of a well in order to reach TD:

$$\alpha_{\mathrm{maximum}} \leq \tan^{-1}\left(\frac{1}{\mu}\right) \tag{19}$$

where

- α is the inclination of string from vertical (rad) – the sail angle
- μ is the coefficient of friction

The sail angle should be as high as possible, in order to reduce the axial tension and friction in the curved hole section according to [48].

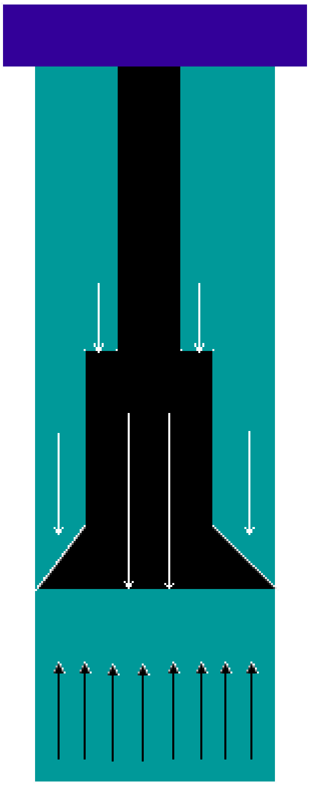


Figure 29: A simplified negative weight well (vertical well) where the friction effects working upwards > the weight of drillstring downwards. The white arrows represent the weight of the drillstring working downwards, while the black ones represent buoyancy and friction effects working upwards. In order to reach TD the weight of the drillstring must overcome the friction forces.

The ability to slide the drillstring at depth was a problem at Wytch Farm [79]. As the departure increases, so does the difficulty in transmission of weight to the drill bit and thus makes it difficult to slide down the wellbore [79]. At Wytch Farm they chose to use HWDP near surface to increase the weight of the drillstring and slacking off top drive weight on to the string in order to run the casing to bottom [79]. Casing floatation and rotation was also successfully used in order to run the casing down to TD.

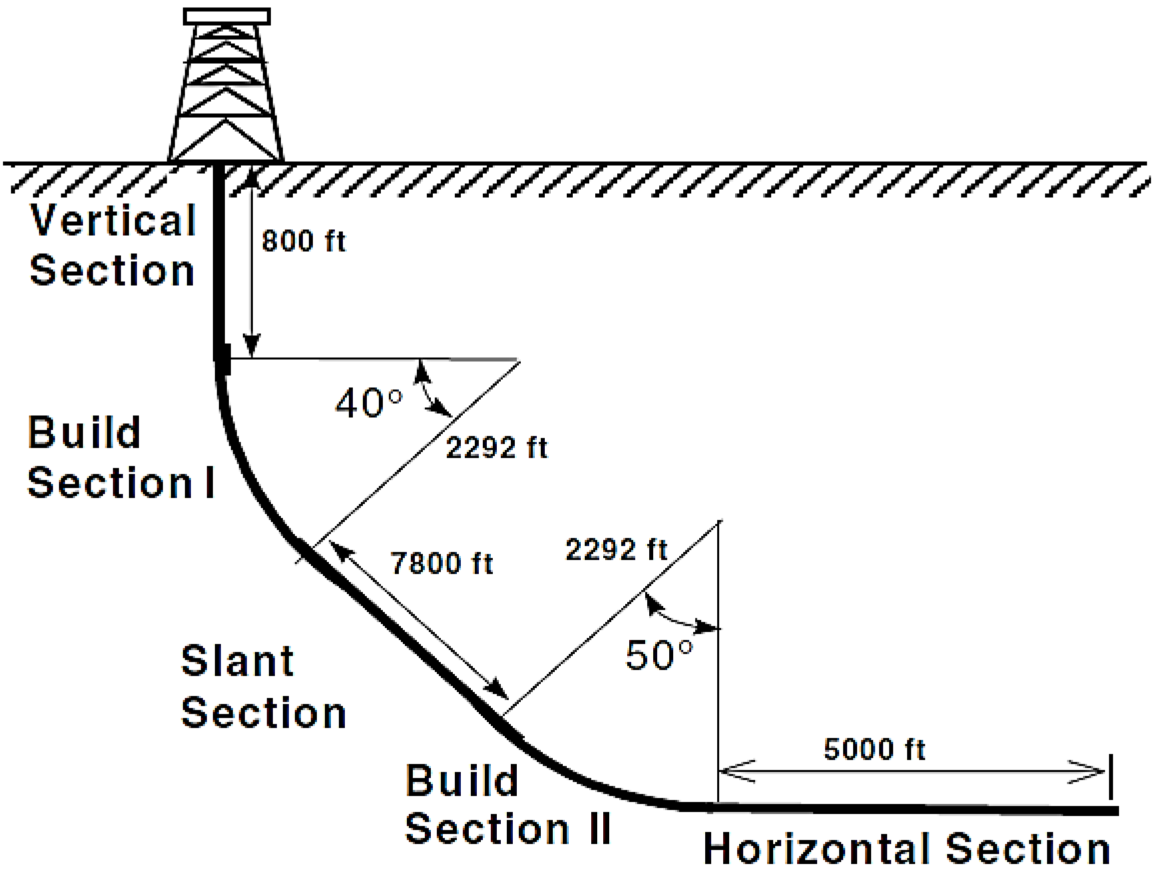


Figure 30: A typical build-hold-build well trajectory [81]. HWDP are usually placed in the vertical or in the build-up section near the surface with the aim of providing extra weight to the string.

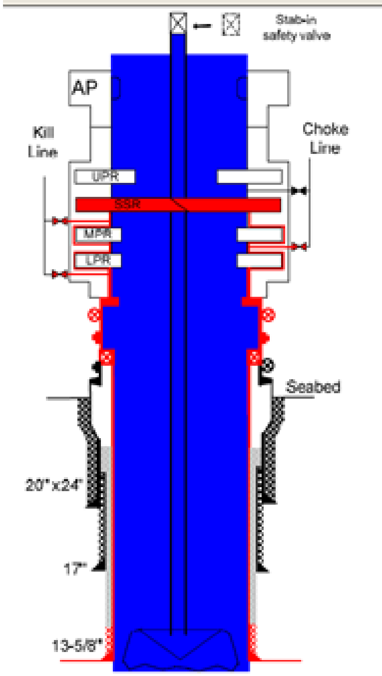
2.5 Mud weight selection and hydraulic calculations

Two important and critical elements when designing and drilling a successful and problem-free well are; mud weight selection and hydraulic design [2]. These two elements will be explained in detail after a description on well pressures and stresses acting on the borehole wall, and will further be followed by an explanation on pump pressure and a section on ECD.

2.5.1 Pressures in a well

As presented under the section well planning, the life of a well can primarily be divided into five phases: well planning, drilling, completion, production and abandonment. It is very important that the well pressures in the various phases are controllable and ensures that no hydrocarbons are released to the surroundings. This is achieved through the well barrier concept saying that there shall be minimum two well barriers (where each barrier can consist of several barrier elements (WBEs)) in hydrocarbon bearing formations and abnormally pressured formation with potential to flow to surface [77]. The NORSOK D-010 standard [69] defines the barriers that must be present in the different phases of the well's life.

Operation: Drilling and tripping with shearable drill string in 12-¼" x 13-½" hole



Installation: Ekofisk Zulu (West Linus)		
Last updated: 26.02.15	**Revision: 0**	
Prepared by: Zulu team		
Reference documentation: Norsok D-010 Rev.4 / COPNO 6488		
Well integrity issues: None		
Well barrier elements	**Ref. Table** NORSOK D-010	**Comments** acceptance criteria, initial verification or monitoring, deviation etc.
Primary well barrier		
Drilling fluid column	1	OBM system
Secondary well barrier		
In-situ formation	51	
13-5/8" casing cement	22	TOC planned above 17" TOL
13-5/8" casing	2	To be pressure tested prior to drilling out shoe
Wellhead	5	Body and seals leak tested during installation
High pressure riser	26	BOP test according to procedures
Drilling BOP	4	BOP test according to procedures
Other Elements		
Stab-in safety valve	40	Readily available on the drill floor

Figure 31: The well barrier schematic (WBS) for section 12¼" x 13½", Z-25 Ekofisk Zulu, that will be studied closer later in this thesis, in chapter 5 [28].

Down in the formation, there are two important pressures that are worth mentioning: pore pressure and fracture pressure. The pore pressure is the pressure of fluid (water, oil and/or gas) in any pore space in the formation. The fracture pressure is the pressure in the wellbore at which the rock formation will fracture hydraulically [77]. There is a risk of having an influx/kick or tight hole problems if the pressure inside the well lies below the pore pressure. However, if the pressure inside the well lies above/exceeds the fracture pressure the risk of lost circulation and mud losses to the formation arises [77]. It is thus very important to monitor and control these well pressures continously. They can both be controlled by adjusting the mud weight up or down or by changing the mud rheology (the rheology mainly affects the friction, not the weight).

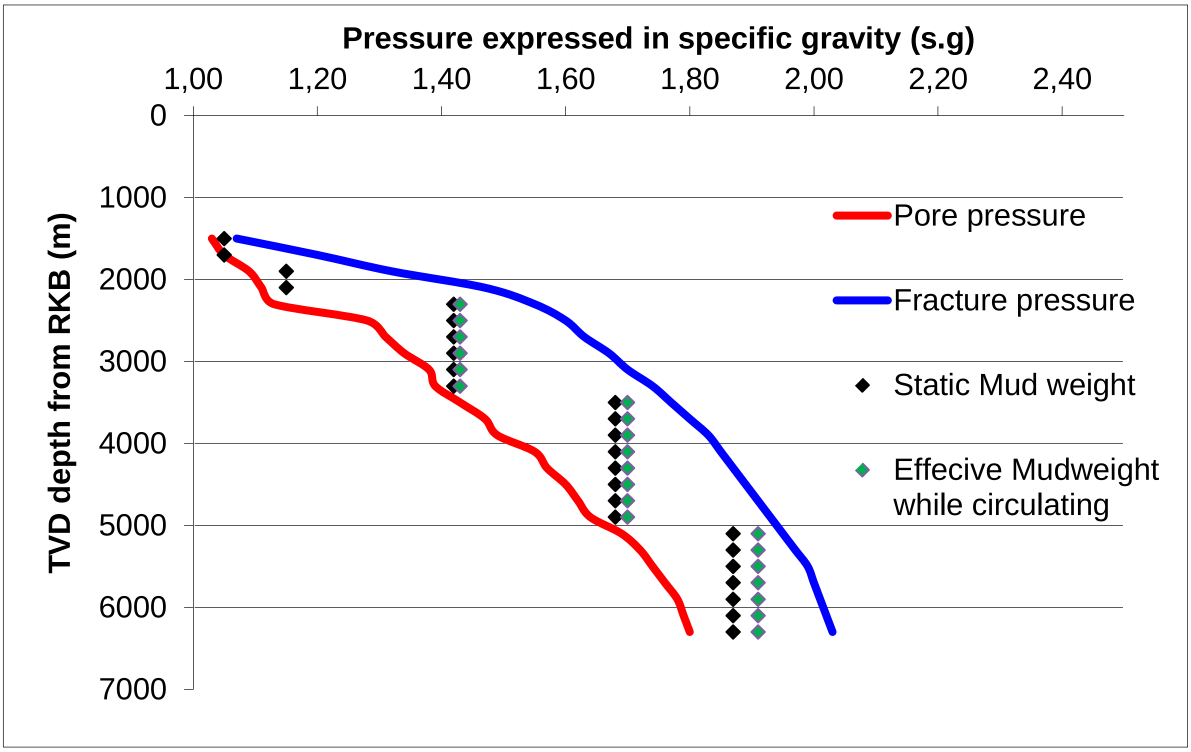


Figure 32: Depth vs. pressure (mud weight and pore/fracture gradients) [77]. The fracture gradient means the pressure that makes a rock fracture at a given depth [90].

2.5.2 Stresses acting on the borehole wall

The level of stress defines the loading on the borehole wall, and the rock strength determines the rocks ability to withstand this load. Wellbore instability often rleads to hole problems/challenges during drilling (and thus increased costs) [49]. The stability of a borehole and the stresses acting on it falls into two main groups according to [2]:

- Borehole fracturing at high borehole pressures. This is a tensile failure, which may result in loss of circulation;
- Borehole collapse at low borehole pressures. This is a shear failure and is a result of high hoop stresses exceeding the strength of the rock around the borehole.

Figure 33 shows the three main stresses that act on the borehole wall [2]. The radial stress is the pressure applied by the drilling fluid. The axial stress equals the overburden load (given a vertical well). The tangential stress or hoop stress mainly depends on the borehole pressure and acts around the circumferences of the hole. These three stresses can be expressed through the following relations [2]:

Radial stress:	$\sigma_r = P_w$	(20)
Tangential/hoop stress:	$\sigma_\theta = 2\sigma_a - P_w$	(21)
Vertical stress/axial stress:	σ_v = constant	(22)

where

- $\sigma_r = P_w$ is the borehole pressure
- σ_θ is the tangential stress
- σ_a is the average horizontal in-situ stress
- σ_v is the vertical stress

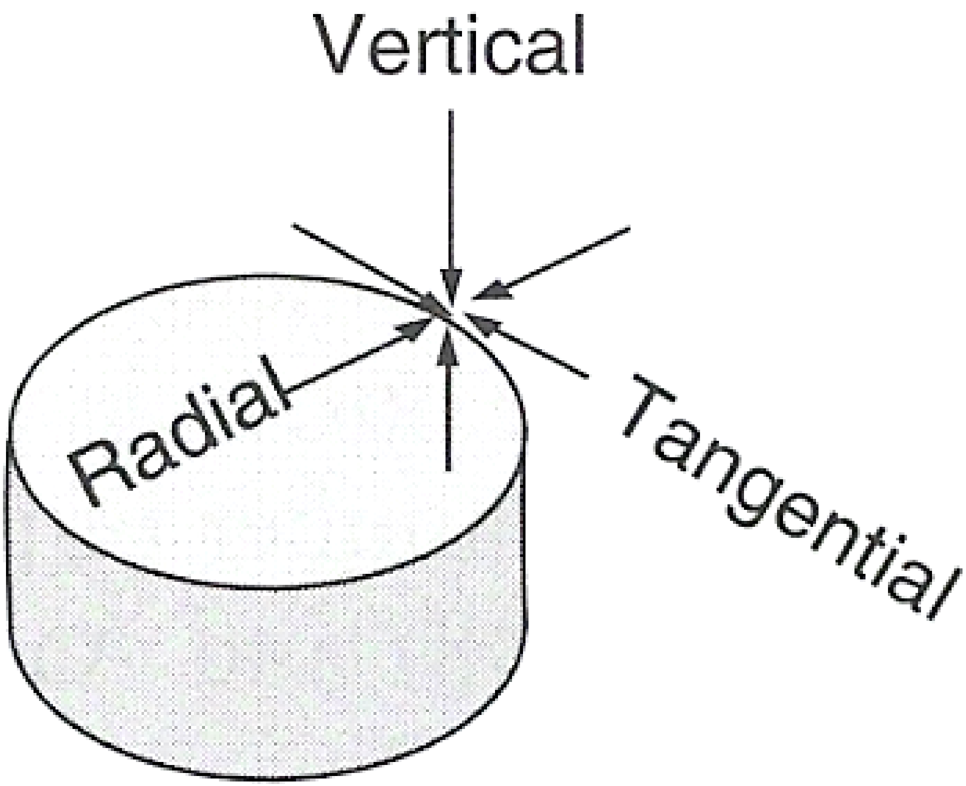


Figure 33: Stresses acting on the borehole wall [2].

2.5.3 Mud weight selection

As mentioned in section 2.5.1, changing the mud rheology can help control the pressures in the well. The importance of the mud weight selection will in the following be discussed in detail.

The mud weight program is usually designed by using a principle called the median line principle [2]. Borehole stability problems have successfully been minimized by keeping the mud density as close as possible to the virgin in-situ stresses. The primary function of the hydraulic design is to provide a suitable flowrate to maintain a good hole cleaning [2].

A lot of elements affect the success of a drilling operation in the wider perspective. The main function of the drilling rig itself is to penetrate and to seal off formations; any single technical failure may prevent the progression thereby resulting in the risk of additional expenditure. The cost of an offshore drilling operation is determined by the rig rate. Thus, the outcome of a drilling operation is highly dependent on the ability to avoid problems that may result in expensive down time [2].

Figure 34 below shows some common problems during drilling. The relationship between well control and wellbore stability usually controls the MW or the bottom-hole pressures [61]. If the volume of mud return during drilling is less than the volume of mud pumped, a circulation loss has arisen. Circulation losses may lead to loss of well control, a blowout, or lead to challenges regarding hole cleaning, which in worst case may lead to stuck pipe [61]. To avoid or reduce this, one common solution can be to reduce the MW. On the other hand, in another scenario, increasing the MW may help avoiding mechanical borehole collapse if the borehole pressure is too low [61]. This shows how important it is to establish a/ the optimum/ideal MW.

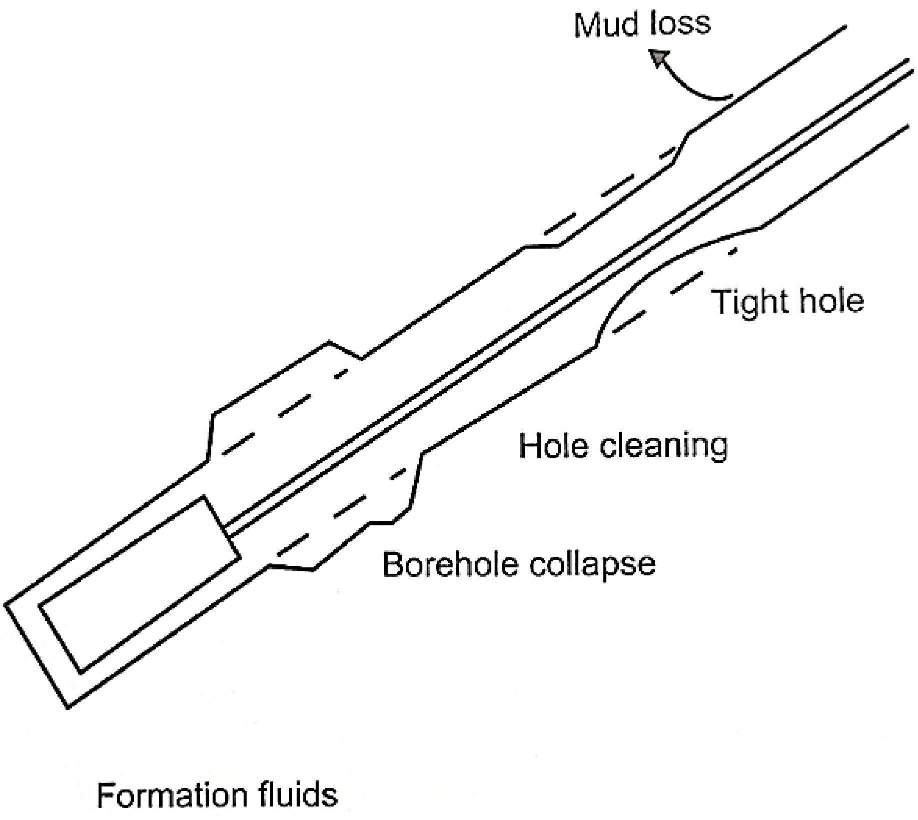


Figure 34: Typical borehole problems [61].

The mud weight is the foundation of a drilling operation [2]. The border between success and failure is nearly always related to the mud weight schedule. If the mud weight is to low, the result may be collapse and fill problems, while a too high mud weight may result in mud/circulation losses or stuck pipe [2].

Some beneficial effects of high mud weight according to [2]: reduce borehole collapse, reduce fill, reduce pressure variations, reduce washouts, reduce tight hole and reduce clay swelling. However, a high MW may lead to trouble regarding lost circulation, differential sticking, background gas readings in exploration drilling and naturally fractured formations.

2.5.4 The median line principle

"The median line principle" says that the mud weight should be held as close as possible to the in-situ stress field in the surrounding rock mass, i.e. half way between the pore pressure and the fracture gradient according to [2]. The Figure 35 below shows three different methods used to select the mud weight: low mud weight, median line mud weight (favorable) and high mud weight [61]. Experiences have shown that choosing a high mud weight to reduce the collapse potential of the well instead often led to fluid-loss problems [61]. The middle curve (the median line profile) showed better results, probably because it is based on the theory of minimal influence on the stresses acting on the borehole wall [61].

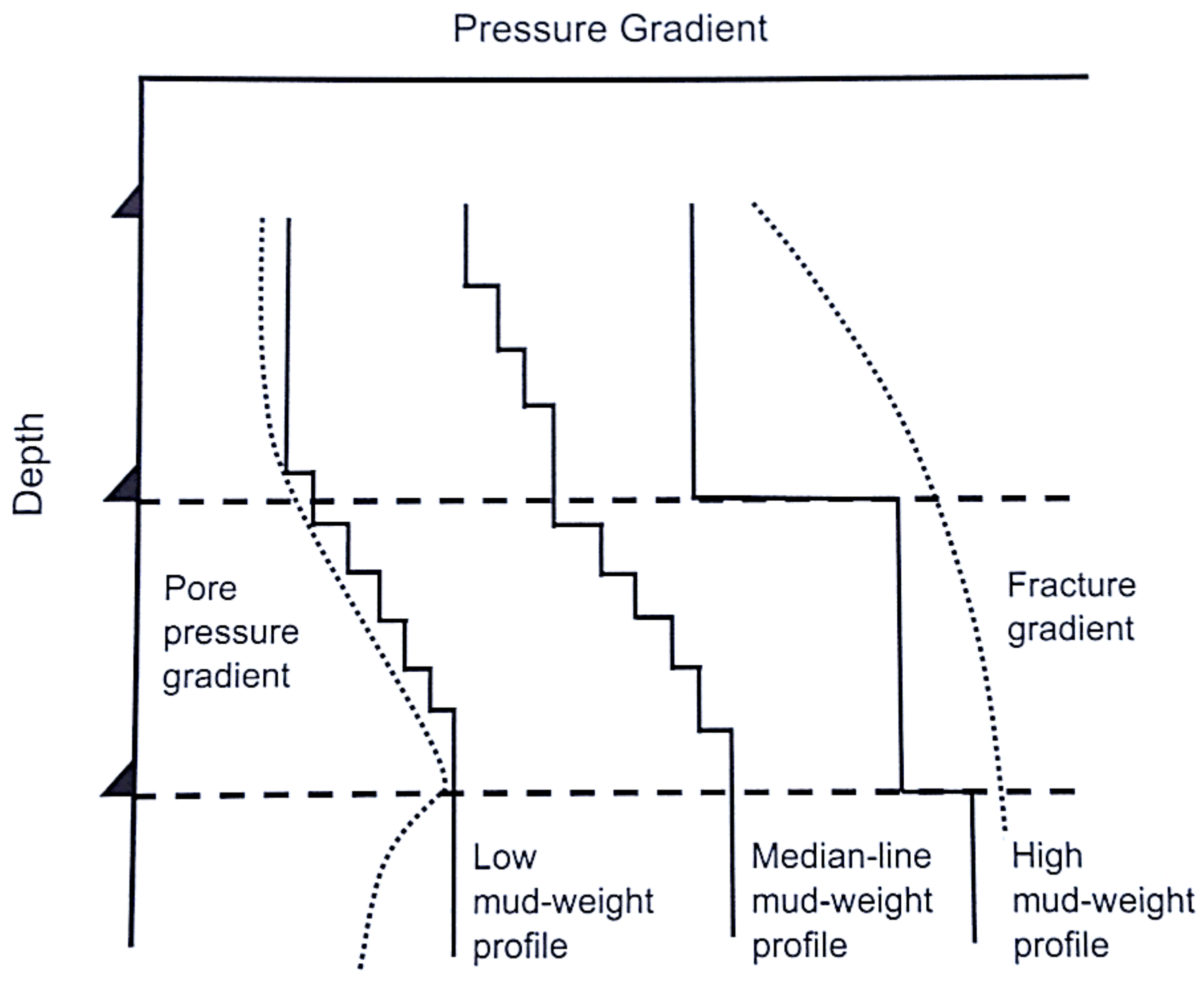


Figure 35: Alternative mud-weight schedules [61].

Figure 36 below illustrates the outcome of variations in the borehole pressures according to [2], [61]:

(a) No disturbance if the MW equals the horizontal stress and applies the same load as the stresses before drilling. This is the ideal MW;
(b) The borehole will shrink (or collapse/fail) if the borehole pressure is lower than the in-situ stresses. Low borehole pressures lead to high hoop stress, which again decreases the borehole diameter. This may result in either borehole collapse or tight hole;
(c) When the borehole pressure is held high, the borehole will expand and eventually fracture/fail if the MW becomes too high.

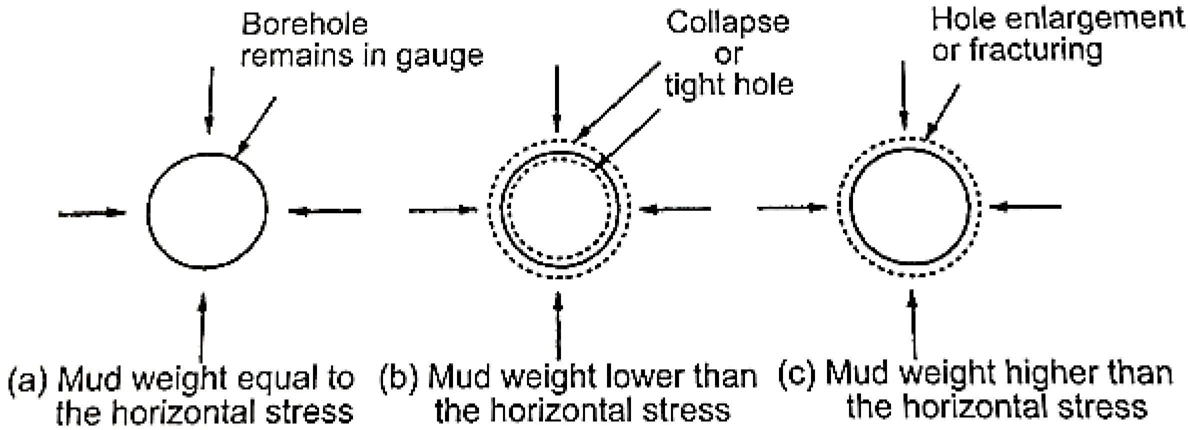


Figure 36: Borehole response to varying borehole pressures [61].

Examples of some important mud properties that may help minimizing hole wall problems [2]:

- Chemical inhibition
- Low filtrate loss in permeable zones
- Coating in impermeable zones

2.5.5 The hydraulic system and flow patterns

A robust circulation system is very important in order to achieve a safe and effective drilling operation. Figure 37 shows a typical circulation system and the different equipment required. The drilling mud is pumped from the mud pit on the drilling rig through the standpipe and then into the drillpipe [95]. When the mud reaches the bottom of the wellbore, it helps transport the drilled cuttings from down-hole to the surface through the annulus between the wellbore and the drillpipe and enters the shale shaker(s) through the mud line return [95].

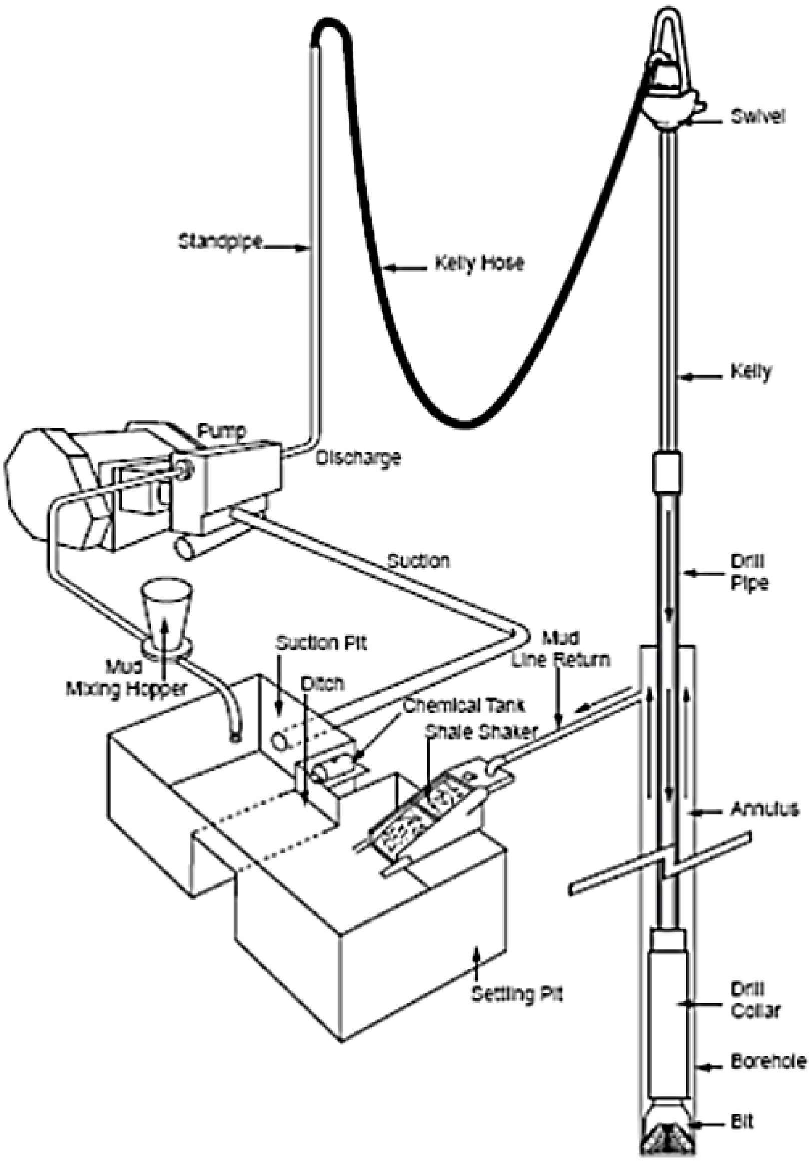


Figure 37: The circulation system [95].

There are in general two different types of flow regimes for the drilling fluids that are flowing through the circulation system in a drilling operation; laminar and turbulent flow regime, shown in Figure 38 [2]. The flow regime is generally controlled by the velocity of the fluid.

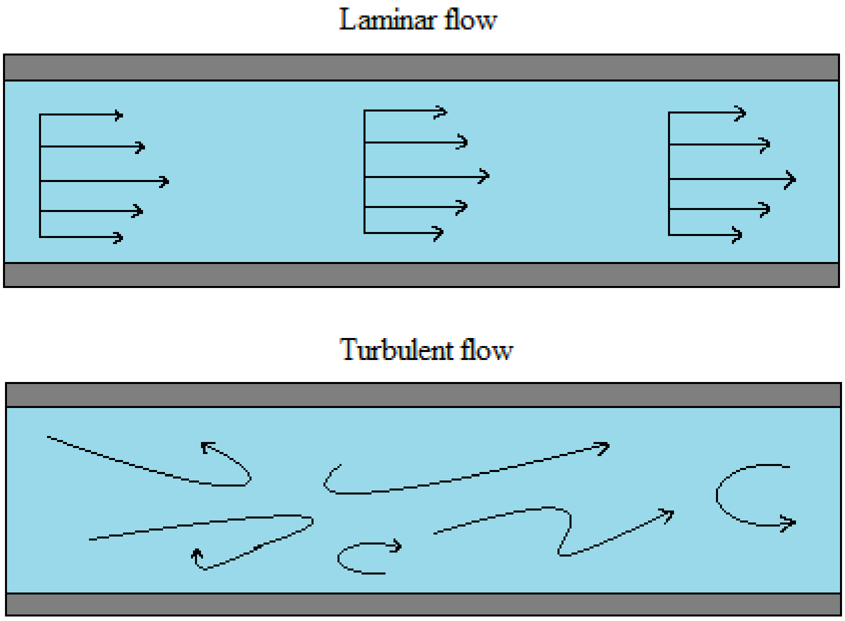


Figure 38: Laminar vs. turbulent flow.

In a laminar flow regime, the fluid moves along defined paths and is given by the following relation [2]:

$$P \sim \mu q \qquad (23)$$

In a turbulent flow regime, the path is totally chaotic and is given by the following relation [2]:

$$P \sim \rho f q^2 \qquad (24)$$

where

- P is the pressure drop
- μ is the viscosity
- q is the flowrate
- ρ is the fluid density
- f is the friction factor

The flow regime has a major impact on the pressure drop for flow in pipes. For laminar flow; the pressure drop equals the viscosity multiplied to the flowrate, while for turbulent flow; the pressure drop equals the density multiplied to the flowrate squared [2].

This can be applied to the hydraulic system during drilling. The cross-sectional area inside the drillpipe is rather small, resulting in a high turbulent flow velocity according to [1]. The flow in the annulus may be both laminar and turbulent (this applies to the section along the BHA and is generally controlled by the velocity of the fluid), but the rest of the annulus (including the riser) is generally in laminar flow [1].

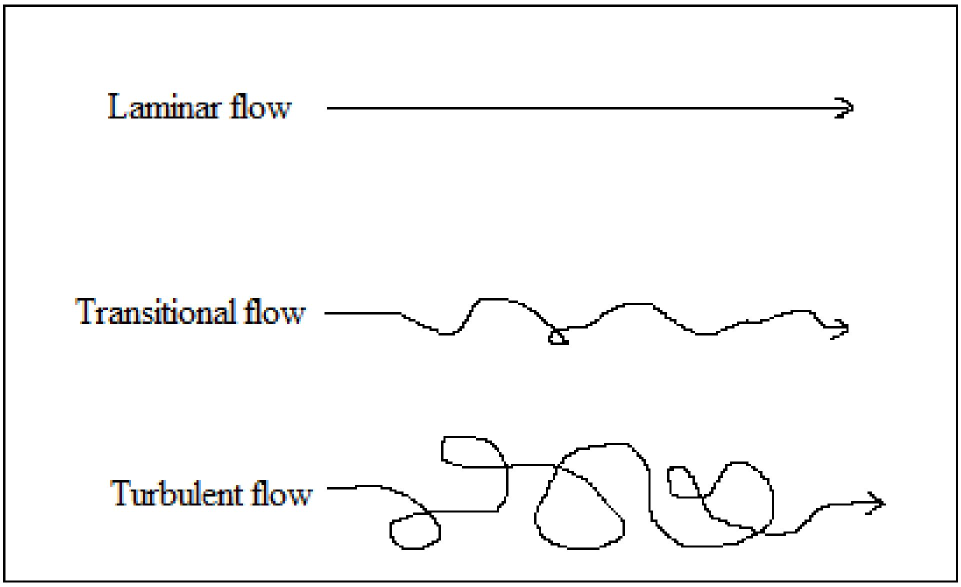


Figure 39: Transition from laminar to turbulent flow.

Figure 40 below shows the anticipated trends for the fracture gradients in a relaxed depositional basin [2], [61]. As seen, the fracture pressure increases with depth, and decreases with increased wellbore inclination. The LOT is a very important pressure test. It is a hydraulic test, and is performed after each casing is installed and cemented in place [2]. This test must verify if the hole strength (well integrity) is adequate in order to drill the next open hole section [2].

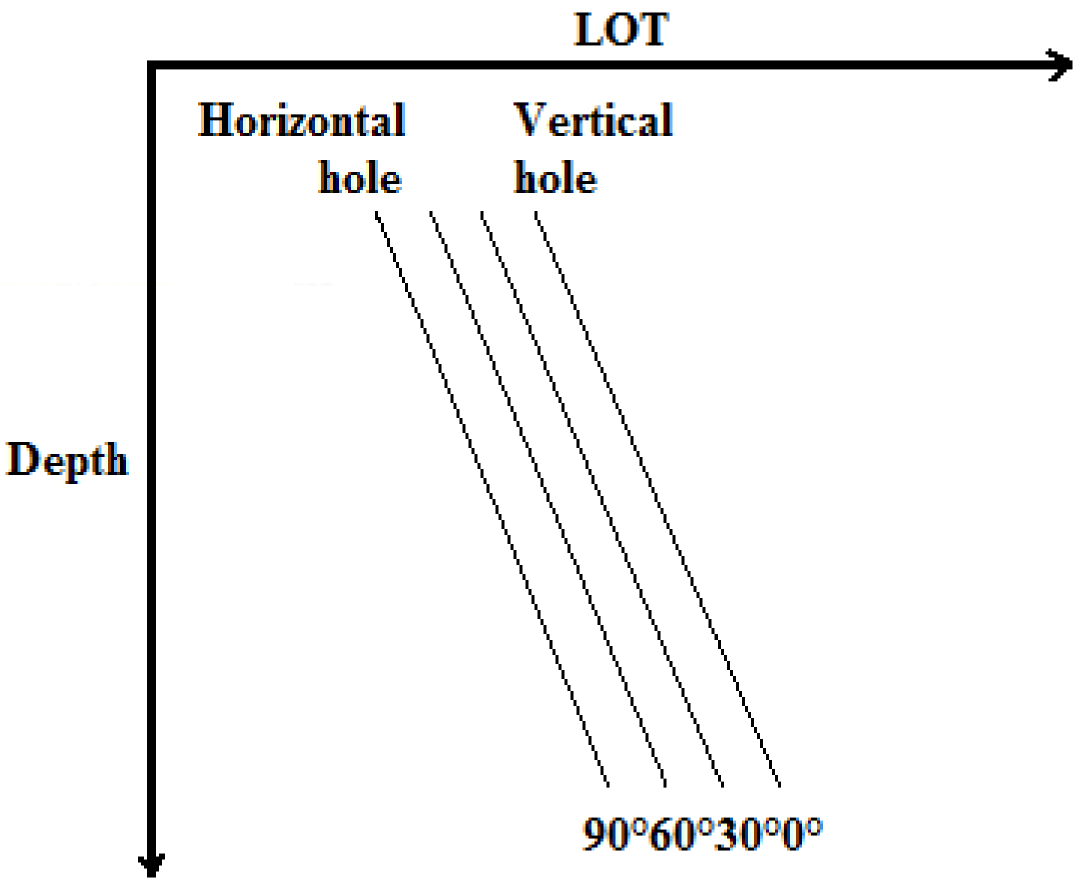


Figure 40: Fracture gradients for a relaxed depositional basin [2].

2.5.6 Pump pressure

The mud pumps located on the (drilling) rig are critical and important equipment in any drilling operation. Their ability to supplement power and/or pressure ensures that the drilling mud is circulated to the bottom of the hole and up the annulus [45]. They contribute to maintain the right flowrate to effectively carry cuttings and debris from the wellbore to the surface. The pump pressure will reflect the frictional resistance in the circulation system [45]. Important hydraulic calculations made during well planning is thus to find the maximum pressure the mud pump(s) can experience and deliver, which then makes it possible to assess whether the drillstring and mud pump(s) can withstand this pressure or not, and also to determine the size of the nozzles to be used on the drill bit [45].

2.5.6.1 Limitations regarding pump pressure

The pump pressure is affected by various factors and paremters, among others: the length of the wellbore, mud rheology, flowrate, flow-area and nozzle or bit size. The pump pressure is very often the limiting factor regarding the ability to achieve the required flowrate to fully clean the wellbore during drilling. As the length of the wellbore increases, the pump pressure needed in order to get a proper hole cleaning also increases; this can be limited by the pumps capacity to deliver enough power or pressure. If the pumps cannot provide enough power you are not able to transport the cuttings from down-hole to the surface [45].

2.5.7 ECD

2.5.7.1 What is ECD?

Mims & Krepp [9] define the Equivalent Circulating Density (ECD) as *"the additional mud weight seen by the hole, due to the circulating pressure losses of the fluid in the annulus, and/or surge pressures"*. ECD can be calculated using the following equation [1]:

$$\text{ECD (ppg)} = \text{MW (ppg)} + \frac{\text{Annulus } \Delta\text{P (psi)}}{0.052 \times \text{TVD (ft)}} \tag{25}$$

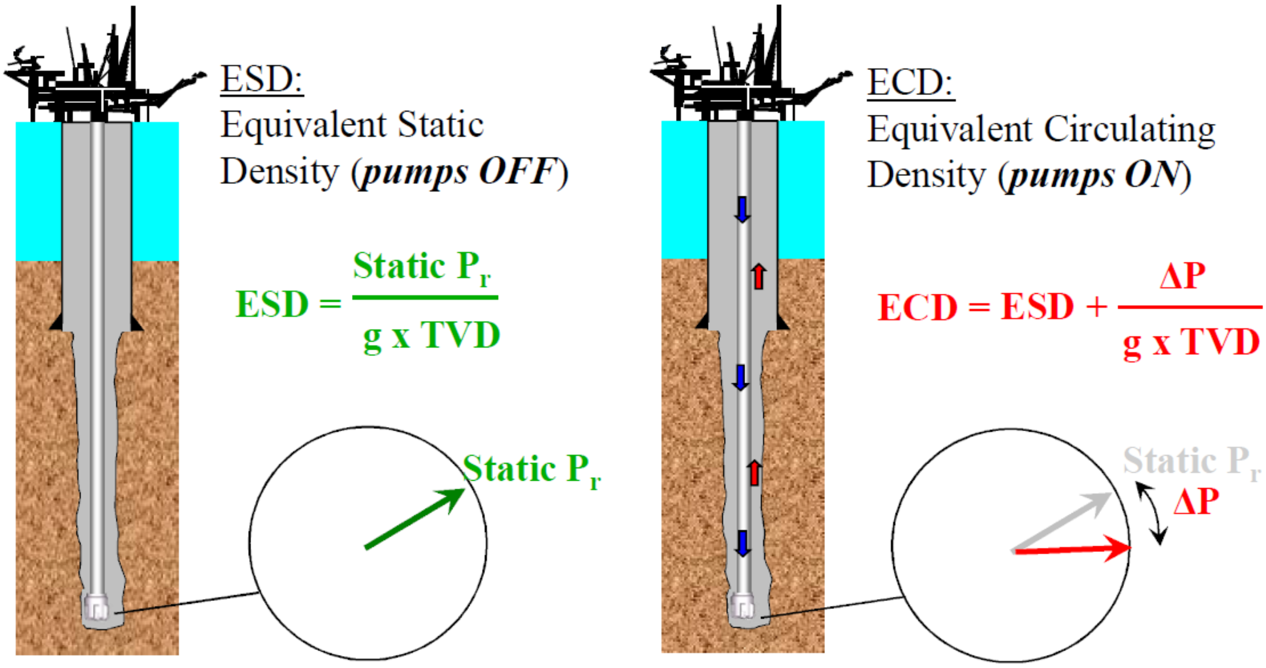


Figure 41: ECD vs. ESD, i.e. with pumps on and off, respectively [9].

The ECD is a function of the following variables [14]:

- The drilling fluid density
- The build-up of suspended cuttings in the annular flow
- The annular pressure drop

Annular pressure drop (ΔP) is the main variable in equation (25), which is affected by the following factors according to [1], [14]:

- **The length of annulus or well**
- **Annular clearances** (drillpipe and/or casing sizes)
- **Mud/fluid properties** (rheology and MW primarily)
- Flowrates
- Rotation of the pipe
- Backpressure through surface return lines
- ROP
- Pipe movement (Surge and swab pressures)

It is important to control the ECD in formations with a tight gap between the formation fracture pressure and the pore pressure (i.e. a tight drilling window – further explained in section 4.3) [14]. This is the case in the Gulf of Mexico and in the Kristin and the Gullfaks field in Norway, as a result of the pressure decline from production [14]. The virgin pore/fracture pressure can in other words be changed due to depletion and injection.

MPD tools can be applied to manage the backpressure and to control the downhole pressure profile and in addition help reduce ECD. ECD reduction tools can also be used to reduce the ECD, e.g. pumps mounted on the drill pipe, that helps lift the hydrostatic head in the annulus during drilling [14]. The ROP (Rate of penetration) can also be used to control the ECD (that is; you mainly control the concentration of cuttings present in the wellbore, which again affects the ECD) [14].

ER wells generally have higher ECD fluctuations than conventional wells due to the longer well trajectories in ERW [1], [14]. The strength of the formation integrity determines if the formation actually is able to stand the fluctuations or not. In the world famous record-breaking projects at the Wytch farm and the Sakhalin Island the formation integrity in itself is sufficient to handle the ECD fluctuations [14]. For fields that cannot handle the ECD fluctuations itself in specific TVD regions, a solution can be to create a casing schematic that helps secure the weak zones. According to Statoil's "ERD Well Design Technology Gap Analysis" [14]; *"The most critical ERD operations with regards to ECD would be in well trajectories with short TVD where little formation integrity is expected due to small overburden pressures."*

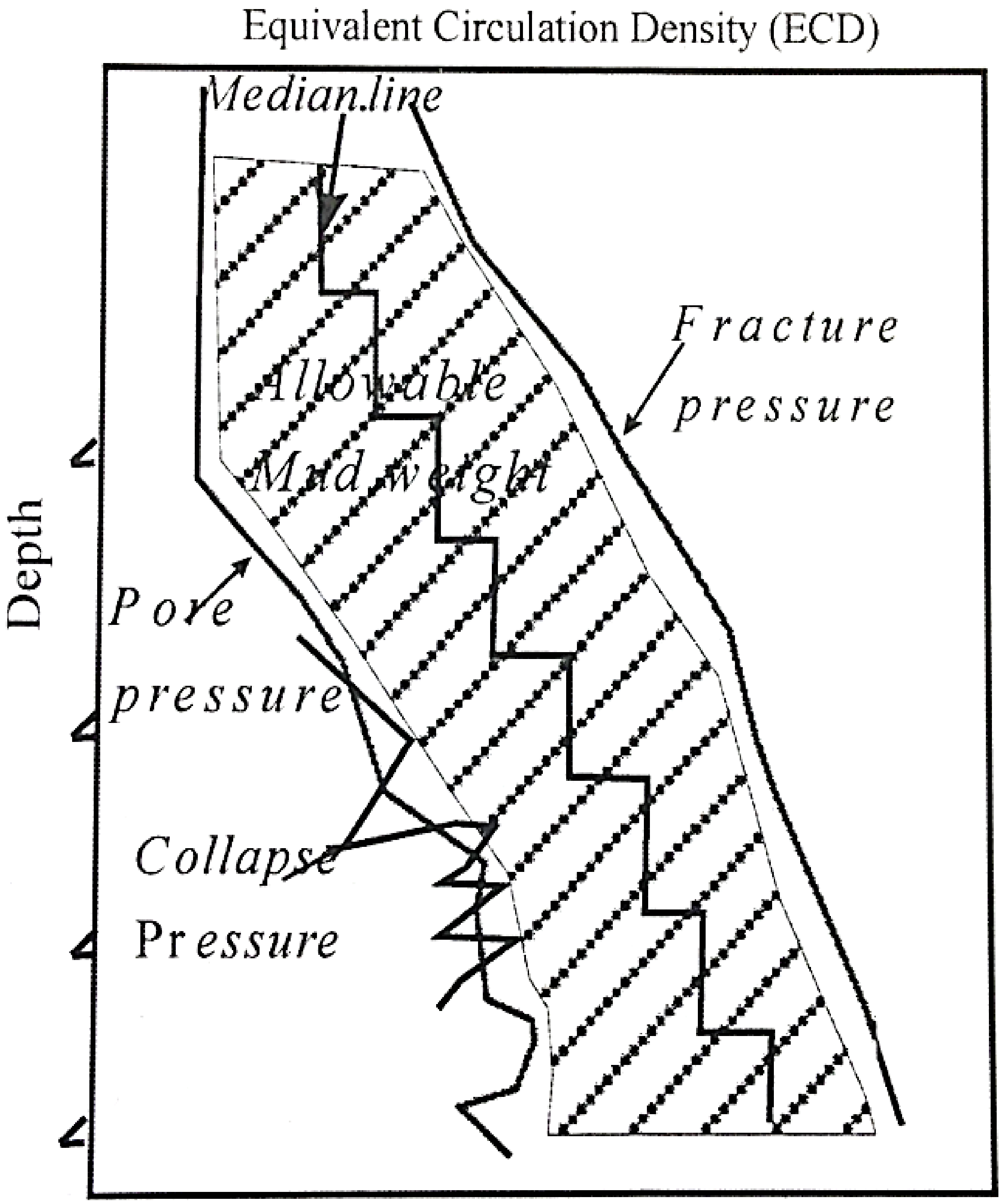


Figure 42: Depth vs. ECD and mud weight vs. fracture gradient [78]. The shaded area represents the safe mud window; the risk of borehole instability problems is reduced here.

2.5.7.2 What are the effects of ECD?

ECD leads to various challenges in ERD wells [1]:

- Higher ECD fluctuations increase the risk of lost circulation; according to [1] especially while:

  a) Drilling 8½“ or smaller hole sizes
  b) Running or circulating long casing strings

  (The reservoir may also be damaged if the ECD values stay high for a long time).

- Due to the constant bending and relaxation of the wellbore every time the pumps are turned on and off, the probability for wellbore instability is large, especially if the formation is brittle (brittle materials and formations are more prone to breakage than ductile, they usually just bend).

- Reducing the flowrate, in an effort to reduce losses due to high ECD’s, will have a negative impact on torque and drag, and may reduce the drilling performance (due to less than ideal bit and motor performance at reduced flowrates – more cuttings in the wellbore).

2.5.7.3 Problems created and triggered by ECD

ECD directly creates the following problems [1], [9]:

- Lost circulation (uncontrolled flow or loss of fluid to the formation with no return to surface):

  - May arise when the bottom hole pressure exceeds the fracture gradient
  - Can be a result of excessive wellbore pressures caused by high fluid flowrates (resulting in excessive annular-friction loss) [1]

- Wellbore instability is often a more significant issue for ERD wells due to the following factors [1], [9]:

  - The increased wellbore angle
  - Increased hole exposure time
  - Increased ECD fluctuations and corresponding effects
  - The hydraulic (water) hammer effect (shock type ECDs): the pressure wave that is created when the velocity of the fluid moving through the drillpipe suddenly is forced to change speed (e.g. when the pumps are turned on). The pressure wave causes vibration, a banging noise (sounds like the drillpipe is beaten with a hammer – hence the phrase) and may burst the drillpipe [84], [85].
  - Fatigue failure of the wellbore: a result of the constant flexing and relaxing of the wellbore when the mud pumps are turned on and off. The wellbore may eventually fail, dependent upon [1]:
    1. How severe the bending is
    2. The number of times bent (it will break if it is bent enough times)
    3. The strength and elasticity of the material (brittle materials are more prone than ductile materials)
  - The use of a MW that is too low as an easy and “cheap” solution to improve a critical ECD situation (is very common in today’s industry even though it is a very risky strategy)
  - Wellbore “breathing” (ballooning): it is a phenomenon that happens when and if losses occur (the formation takes mud) when the pumps are on - then flow back into the wellbore when the pumps are off (since the fracture closes) [9], [75]

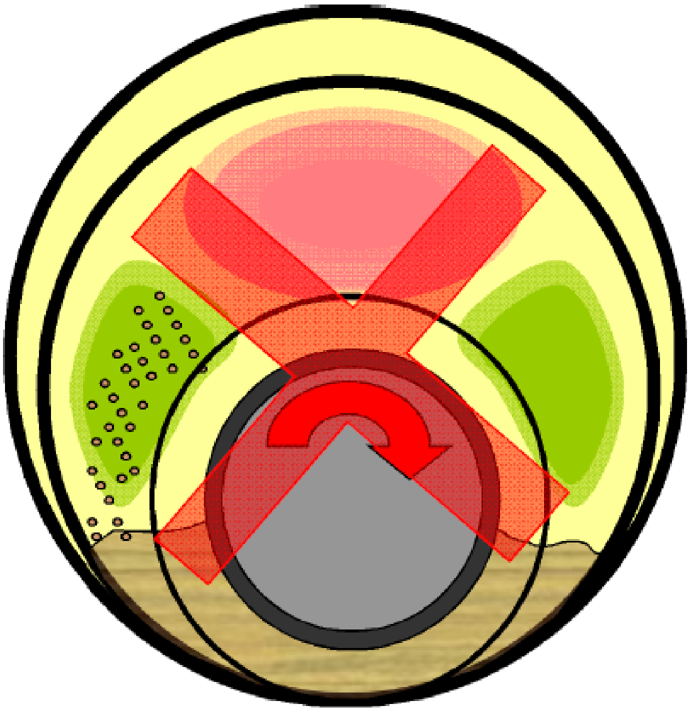


Figure 43: Wellbore "breathing" – it occurs as a result of small fractures in sands and shales. It doesn't involve "inflation" of the wellbore like a balloon, so "breathing" is a more appropriate and correct term to use [9], [75].

- Well control [1], [9]:
  - A repeating trend has been that high ECD values have resulted in operations with reduced MW and reduced swab margin
  - Wells with high ECD also tend to have high swab loads (they are influenced by the same factors)
  - It is harder to detect and measure (upcoming) kicks in high-angle wells
  - The problem mentioned right above again implies that it is harder to manage and kill the arisen well control problem
  - The risk of swabbing a kick in an ERW is also increased due to the reduced flow-by area around the bit caused by the static cuttings bed

- Reservoir and formation damage due to fluid inversion [9]:
    - This is particularly the case in so-called "barefoot" horizontal wells – lower MW can reduce the damage.

2.5.7.4 Why ECD is a particular concern for ERD

ECD fluctuations are generally a bigger challenge on ERD wells compared to conventional wells. This is a result of the following, according to [1], [9]:

- Longer MD intervals relative to TVD than for conventional wells;
- ER wells are normally shallow by nature. These types of ERW are more prone to ECD problems due to the fact that they have low formation integrity (critical);
- ER wells generally use drillpipe with larger diameter with respect to hydraulics or buckling reasons, which again may increase the ECD;
- More aggressive drilling parameters (flowrate and rpm) are generally required to accomplish and manage proper hole cleaning in ERD wells;
- Longer exposure times with long intervals on ERD wells;
- Temperature and pressure variations (and their effect on mud properties) are more extreme in these wells compared to conventional wells;
- Inappropriate mud properties.

It is very important to understand ECD and how it affects ERW. Numerous ERW have been lost due to misconceptions regarding ECD that probably has been blamed on other factors (inadvertently) [9].

2.5.7.5 ECD Management

There are numerous different ways to help reduce the fluctuations in ECD’s on ERD wells [1]. Not all of them fit each well type, but the following proposals may be a possible strategy to solve and/or reduce the problem if the ECD’s become too critical. N.B. ECD management can be performed both in the planning and in the operational phase, but the only way to reduce the ECD induced problems are in the planning phase [1].

2.5.7.5.1 Planning phase

Well path design

The well trajectory affects the total depth that has to be drilled, and will therefore affect ECD’s at depth (the ECD’s increases with increasing depth) [1]. It also affects the required casing design (high wellbore angles may require an additional casing string for stability purposes, but it is mainly determined by the relationship between the drilling window (further explained in section 4.3) and target depth). According to Sheppard et al. [70] the well path should ideally be as short and simple as possible and within the limits of other important parameters like T&D, casing wear, buckling, hole cleaning and wellbore/borehole stability [16].

Hole size optimization

It is not given that the standard hole sizes (20” for the 17” liner, 16” for the 13⅝” liner, 13½“ for the 10¾” liner and 9½“ for the 7⅝“ liner) is the optimum choice regarding management of ECD [1], [28].

According to [1] increasing the hole size from 8½” to 9⅞” increases the annular area by 53% for 5” drillpipe, and 108% for 7” casing. This shows that ECD’s can be drastically decreased by upsizing from a 8½” hole to a 9⅞” hole or from a 12¼” to a 15” hole [1].

Mims and Krepp [1] states that wellbores with small clearances (between the drillstring and the wellbore) may produce high ECD values. This is particularly a problem on long hole sections or shallow hole sections [1].

Casing plan

It is possible to adjust the casing plan in order to reduce the ECD's when the deeper hole sections are being drilled [1], [9]. The ECD generally increases with depth (is a function of the TVD) and may thus have critical values in the deepest hole sections:

a. **Run the intermediate casing as a liner:** Running the intermediate casing as a liner may contribute to a reduction in ECD's (since the long string of casing is exchanged to a shorter one that starts from the last set casing). This will ensure a larger OD in parts of the annulus, seen in Figure 44.

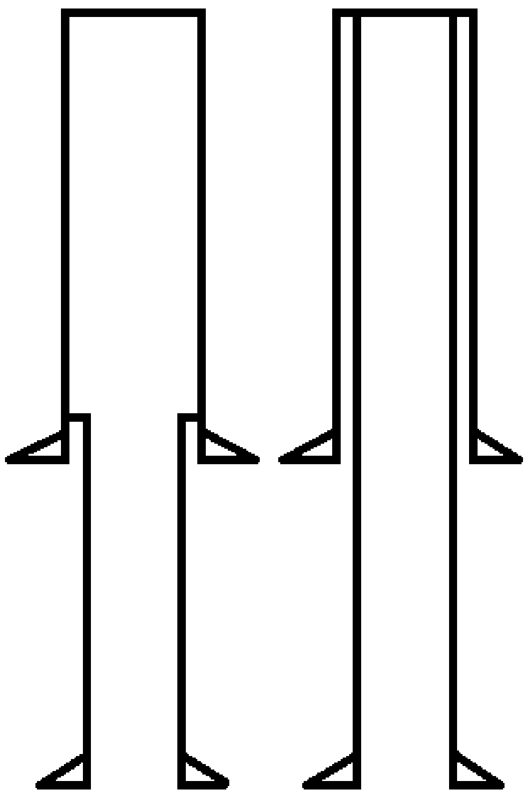


Figure 44: Running the intermediate casing as a liner vs. running it as a casing.

b. **Use alternative casing connections and centralizers:** The connections and/or centralizer type of the casing may affect the downhole pressure while running or circulating the casing [1]. The first step to minimize ECD's is to therefore to reduce the number of centralizers to the minimum (required for cementing objectives) [1].

c. **Use different sizes of casing:** Using smaller casing sizes may have certain advantages (e.g. run a 6⅝" liner in a 8½" hole rather than running a 7" liner); it will reduce the ECD while both running and cementing the liner according to [1].

d. **Casing flotation and ECD:** The ECD's created while running casing is often ignored. This can be a problem when running long strings of floating casing. The collapse pressure is usually acceptable in a static situation, but if the ECD's increase to a certain limit it may result in casing collapse.

Drilling fluids

According to Payne et al. [18] the drilling fluid must:

1. Provide a stable wellbore for drilling long open hole intervals at high angles;
2. Maximize lubricity to reduce toque and drag;
3. Develop proper rheology for effective cuttings transport;
4. Minimize the potential for problems such as differential sticking and lost circulation;
5. Minimize formation damage of production intervals;
6. Limit environmental exposure through the fluid system design and the well-site waste minimization program.

The selection and design of drilling fluids is very important in order to achieve a robust ECD management [1].

a. **Rheology:** According to K&M [1] the fluid used in an ERW should always be as thin as possible (within the hole cleaning limits), and thinned even more right before running and cementing the casing. If the fluid has good shear thinning capabilities it will further improve the ECD conditions downhole.

b. **Gel strengths:** The gel strengths should be flat and easily broken down when the fluid is sheared [1] (by either pipe rotation or by breaking circulation) in order to minimize ECD effects.

c. **Sweeps:** Sweeps are pretty effective in vertical wells, but causes more harm than good in high-angle wells. They have problems in dealing with the cuttings, and struggles with the transportation out of the wellbore. Avoid using sweeps as far as possible to avoid spikes in the annular pressure and ECD fluctuations.

Drillstring design

The drillstring design is an important factor regarding ECD management, especially in shallow ERW, due to the following [1]:

(a) Low formation integrity
(b) Large OD pipe is used to avoid and reduce buckling – reduced annular clearance may result in increased ECD

A common solution to overcome buckling tendencies in (shallow) ERW is to use HWDP or larger OD pipe to increase the stiffness and weight of the drillstring (which again may lead to increased ECD's) [1]. The drillstring design must therefore be viewed in perspective with ECD constraints in order to obtain a safe and effective drilling operation.

Bit and stabilizer design

Designing the ERD well for maximum junk slot area reduces the risk of tripping problems and for swabbing in a kick when the drillstring is being pulled through cuttings beds [1].

Pressure while drilling (PWD) technology

PWD can be an important tool in order to fully understand what is going on downhole with that particular well's circumstances. PWD technology will provide the operations and engineering personnel with applicable information in order to improve planning and practices regarding ECD reduction [1].

2.5.7.5.2 Operational phase

Flowrate and RPM (rotations per minute)

The first action taken when ECD's are an issue is usually to reduce the flowrate within the hole cleaning limitations of the drilling "system." The minimum acceptable flowrate is a function of various parameters, like mud rheology, rpm, slide frequency, hole size, ROP [1]. ECD's are increased for long wells when the pipe rotation exceeds a certain limit due to the increased distance that the fluid must travel to surface due to a spiraling flow path when the pipe rotation is too high. Reducing the pipe rpm may therefore help reducing ECD's [1], [9].

In horizontal wells it is a good practice to slowly increase the flowrate from a low speed to the maximum, instead of breaking circulation at the planned drilling flowrate since some mud systems may gel up during static conditions [1]. When the mud is static and gelled, circulation will create large ECD spikes. Breaking circulation means getting the drilling fluid into movement (circulation) after a period of static conditions (e.g. taking a survey or making a connection) by starting the pumps or the rotary [86]. Increasing the flowrate gradually will help to break down the mud's gel strength and reduce the surge effects when the pumps are started. This will ensure a minimal effect on ECD and cuttings loading [1].

ROP

The amount of cuttings in the hole is directly associated with the downhole annular pressure [1]. The cuttings weight adds weight to the fluid, so the more cuttings located in the hole, the higher is the bottom-hole pressure. Controlling the ROP may therefore help reducing ECD's.

Slide drilling practices

Slide drilling can result in the build-up of a cuttings dune right above the BHA, and lead to increased ECD's if the cuttings dune is interrupted [1].

Back-reaming

According to [9] back-reaming and/or pumping out (no rotation) should be avoided when possible in high-angle wells because it is the single-most dangerous operation in an ERW. The result may be plugging the wellbore around the drillstring (pack-off) or collapse of the wellbore wall around the drillstring. It also leads to a maximum risk of stuck pipe, BHA equipment failures, key seating, lost returns and of destabilizing the wellbore [9].

Back-reaming is to be avoided if possible since it increases the risk of cuttings dune to form and therefore increase the bottom-hole pressure/pack-off if the dune is suddenly interrupted (which again may lead to increased ECD's).

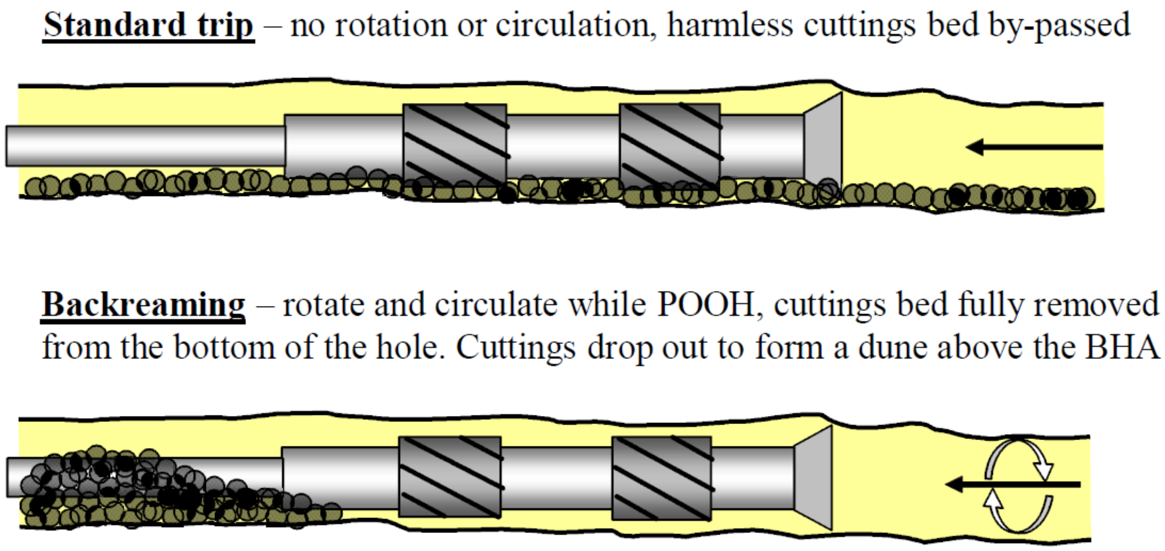


Figure 45: Standard tripping vs. back-reaming [9].

Down-reaming

Down-reaming means enlarging the wellbore because the hole was drilled to small or to move the pipe in order to clean the drilled hole (with both rotation and circulation) [52], [87]. Down-reaming may have a negative impact on ECD, may deteriorate the well and may increase the risk of packing off [1], [9]. As for back-reaming, down-reaming increases the risk of cuttings dune to form and therefore increase the bottom-hole pressure/pack-off if the dune is suddenly interrupted (which again may lead to increased ECD’s).The best way to avoid down-reaming is to make sure that the well is as clean as possible before tripping [1].

2.5.7.6 ECD drivers

The various ECD drivers have been discussed above. Figure 46 below shows the different drivers and their contribution with varying hole sizes. Managing the ECD is basically all about give and take priorities; in order to improve a critical ECD situation one must either increase the hole size or decrease the section depth (either solution will reduce the ECD).

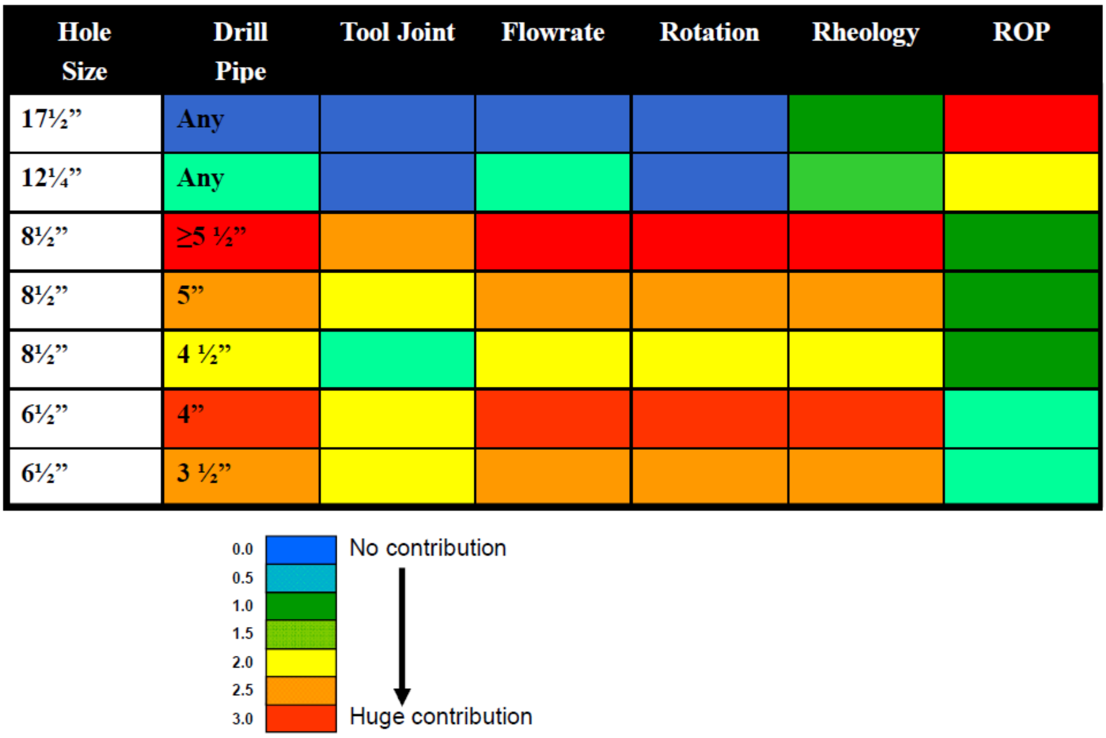


Figure 46: ECD drivers – what drives the ECD will be different for every single hole size [9].

2.6 Hole cleaning

One of the most essential challenges found in an ERD well is hole cleaning. Hole cleaning is the capability of a drilling fluid to suspend the cuttings of drilled rock and transport them from the wellbore to the surface [37]. In “the good old days,” when the drilling process was less scientific and technical, a driller’s main goal was to drill the hole as fast as possible [14]. Today there is hundreds of parameters and sensors continuously feeding us with important information that can be used to analyze the hole conditions [14]. Both the flowrate and the drilling rate must be kept within certain limits in order to ensure good hole cleaning [2]. Hole cleaning is often misunderstood and according to [9]; *“We often don’t rotate fast enough, we rarely circulate long enough and there are a lot of misconceptions about sweeps, wiper trips and mud properties [9].”*

In general, for high angle wells, cuttings will fall to the low side of the hole and away from the primary fluid flow at the top of the hole [1]. When the cuttings are transported to the surface, they also have a tendency to sink due to gravity forces [2]. This phenomenon makes the cutting removal process very difficult and requires special techniques for different well inclinations. The drilling parameters, BHA and bit design, mud rheology and the observed hole conditions will all contribute to the rig system’s capability to clean the hole in an efficient and safe manner. Mims and Krepp [1] state that high flowrates and pipe RPM throughout the entire drilling process will ensure a robust and efficient hole cleaning.

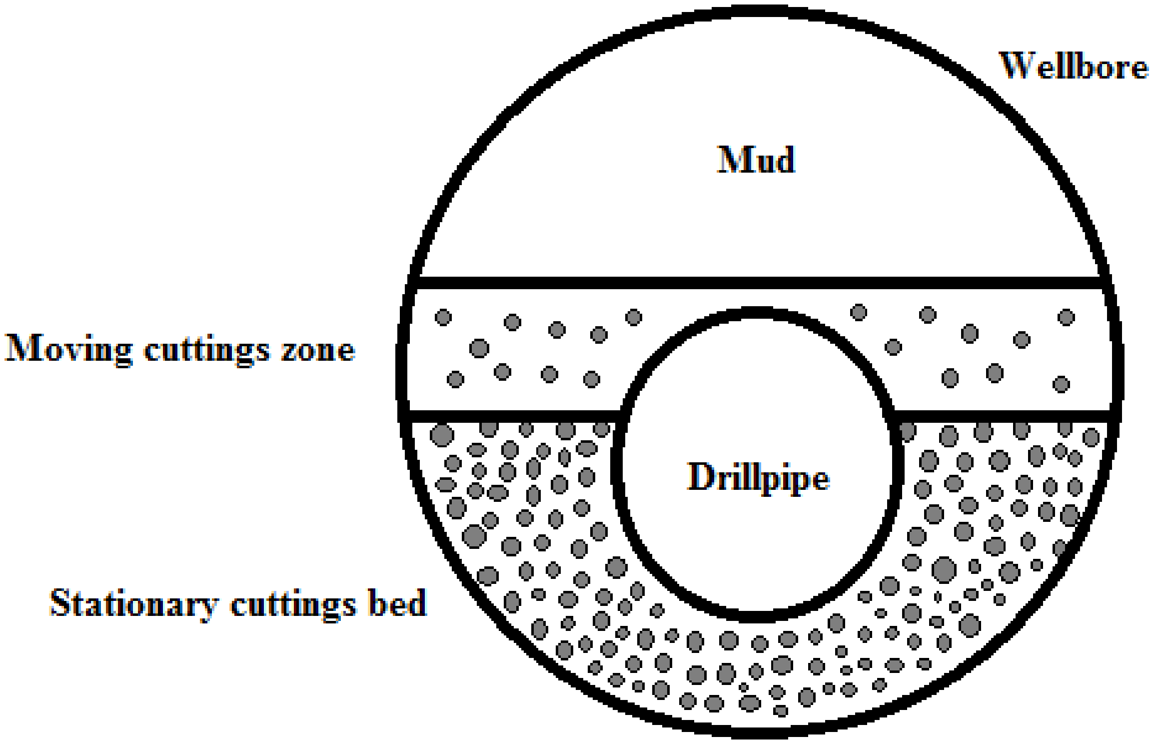


Figure 47: An illustration of the wellbore cross section with cuttings bed showing the basic flow configuration for cutting transport modeling. The critical flow rate for cutting transport does not affect the cuttings bed [61]. In order to obtain an effective hole cleaning, the desired flowrate must exceed this critical flowrate. Modified after [61].

It is ideal to transport the drilled cuttings out of the wellbore as fast as possible. If the cuttings accumulate, it may lead to an increase in the bottom-hole pressure, which again may lead to stuck pipe or circulation losses [2]. In order to obtain an effective drilling operation it is very important to ensure efficient cuttings transport and hole cleaning. Insufficient hole cleaning may cause costly drilling problems, like [37]:

- Mechanical pipe sticking
- Premature bit wear
- Slow drilling
- Formation fracturing
- Excessive torque and drag on drill string

- Difficulties in logging and cementing
- Difficulties in casing landing

The most common problem regarding high-angle/extended-reach drilling is excessive torque and drag on drillstring, which often leads to the inability of reaching the desired/target depth [37].

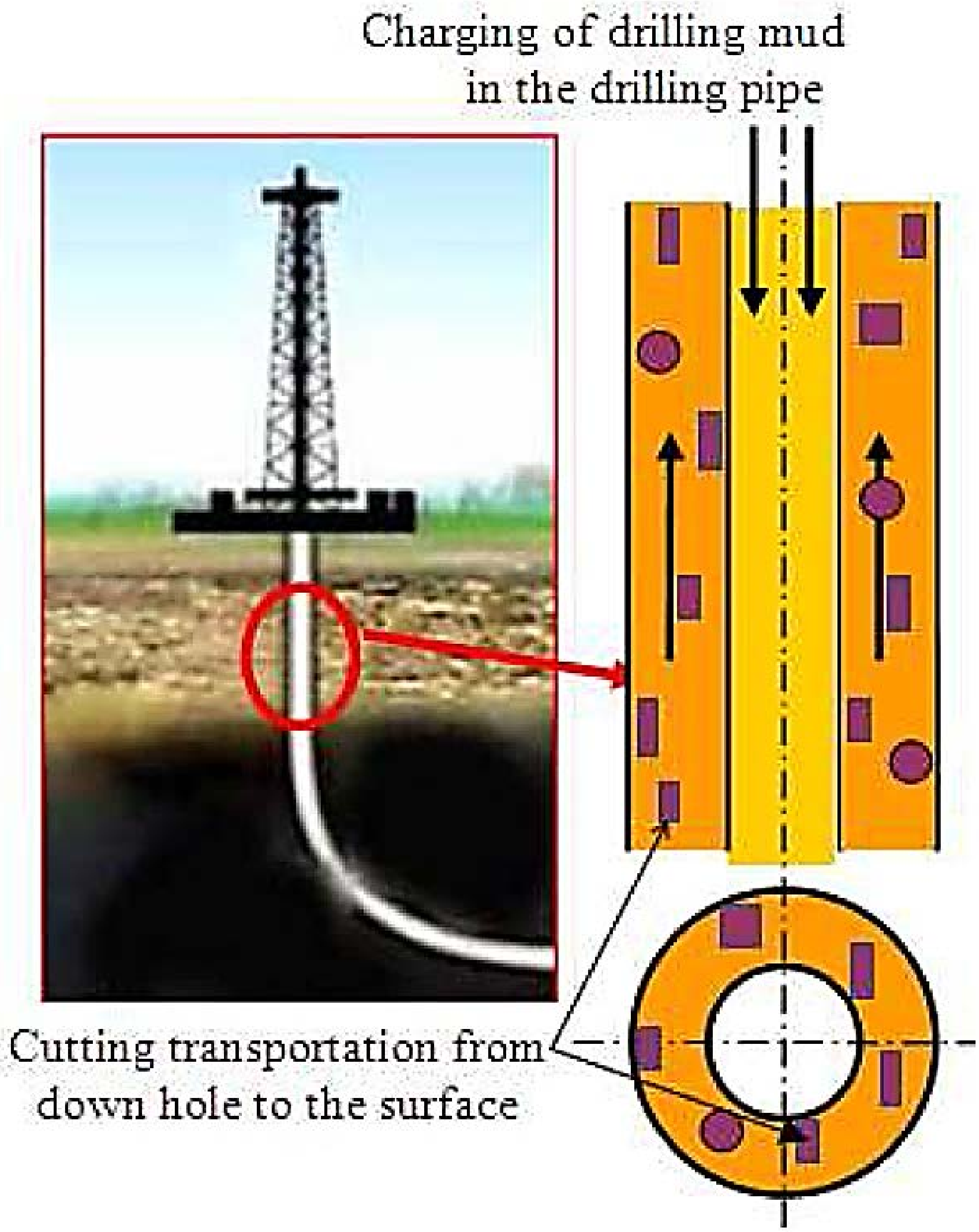


Figure 48: Hole cleaning in a vertical well – drilling mud charging and cuttings upward transportation [11].

The following is essential in order to achieve successful hole cleaning in ER wells according to [9]:

- High flowrate (say > 1000 gpm (3800 lpm) in a 12¼“ hole)
- Gauge hole
- Continuous rotation, and RSS (rotary steerable system) is a necessary requirement for optimal hole cleaning
- Slow ROP
- Ideal mud properties
- Sweeps compensate for less-than-ideal of the above

Hole cleaning efficiency is affected by the following factors [9], [14]:

- **Rotary speed***
- **Flow rate***
- **Mud rheology***
- Hole size
- Washouts
- Drill pipe diameter
- Wellbore angle
- Turbulent or laminar flow
- Cuttings size
- Mud weight
- Pipe reciprocation
- % sliding
- Penetration rate
- Wellbore stability
- Mud solids (colloidal)
- Cuttings dispersion

***The bold ones are the most important factors – all of them can be controlled.**

2.6.1 The key elements of the hole cleaning system according to [9]:

- Drilling fluid properties:
    - Rheology, inhibition, colloidal solids. Need to focus on hole cleaning and detailed ECD management [14].
- Bit and BHA designs:
    - Allowable rpm and rotation, bypass area, ROP.
- Hydraulics:
    - Available flowrate, pressure limits, ECDs, BHA requirements & limits, shaker loading limits.
- Rig systems:
    - Limitations/adjustments for top drive (RPM vs. torque), improved cutting treatment and handling system, solids control, pumps, electrical power.

These elements all go together in a hole cleaning system or a “systems approach,” and should be considered to be inter-related [1]. This means that e.g. a change in the mud schedule or drilling parameters most likely will harm and affect the other components in the system. A change in bit or BHA components may affect the hydraulics downhole and the mud properties. When all operations and design decisions are treated as single (and complex) system, the hole can be drilled efficiently [1], [9].

2.6.1.1 Parameters that must be considered in the hole cleaning system [1]

- **Flowrates:** The flowrates should ideally be as high as possible, subject to ECD related constraints [1]; when drilling an ERW maximum allowable and available flowrates should be used for every section in order to maintain an effective hole cleaning. The table below shows the recommended minimum and maximum flowrates, according to K&M [1], for various hole sizes:

Table 2: Minimum and maximum flowrates [1].

Hole size	Desirable flowrate	Minimum workable flowrate
17½”	900-1200 gpm	800 gpm, with ROP at 20 m/hour
12¼”	800-1100 gpm	650-700 gpm, with ROP at 10-15 m/hour 800 gpm, with ROP at 20-30 m/hour
9⅞”	700-900 gpm	500 gpm, with ROP at 10-20 m/hour
8½”	450-600 gpm	350-400 gpm, with ROP at 10-20 m/hour

- **RPM:** According to [1] pipe rotation is critical due to hole cleaning and should be at least 120 rpm in 12¼” and larger hole sizes (the ideal range is between 150-180 rpm); rotation of the pipe is an important action taken to stir the cuttings into movement [1]. The following table gives K&M’s recommended drillstring rpm for various hole sizes based on field experiences:

Table 3: Minimum and maximum RPM [1].

Hole size	Desirable RPM	Minimum for effective hole cleaning
17½”	120-180 rpm	120 rpm
12¼”	150-180 rpm	120 rpm
9⅞”	120-150 rpm	100 rpm
8½”	70-100 rpm	80 rpm

- **Mud inhibition and lithology type:** The mud inhibition and the lithology type will affect factors like cuttings size, the hole size and shape and the amount of cuttings that needs to be removed from the wellbore;

- **Mud rheology:** The perfect mud rheology can range a lot for complex ERD wells. A general rule of thumb (K&M) is that the 6 rpm reading should be 1.0-1.2 times the hole size in inches [1];

- **Bit and BHA strategy:** This is presumably the most important factor in order to achieve a robust hole cleaning. It affects the hole cleaning by affecting flowrates, allowable pipe RPM, drilling practices and drilling parameters;

- **Drilling and tripping practices:** This is much more complex in ERD wells compared to conventional wells and general practices cannot be applied in ERD wells;

- **Wellbore stability:** The diameter of the hole/wellbore will affect the hole cleaning ability resulting in large washouts acting to collect cuttings [1];

- **Hole size:** As the hole sizes increases the hole cleaning tends to be more difficult due to lower annular velocities, i.e. it is easier to clean a small hole due to smaller clearances (no space for dead zones) between the drillstring (pipe) and the wellbore (seen in Figure 49). The viscous coupling film interacts with the high velocity fluid in the 12¼” (rather than the dead zone fluid in the 15” hole);

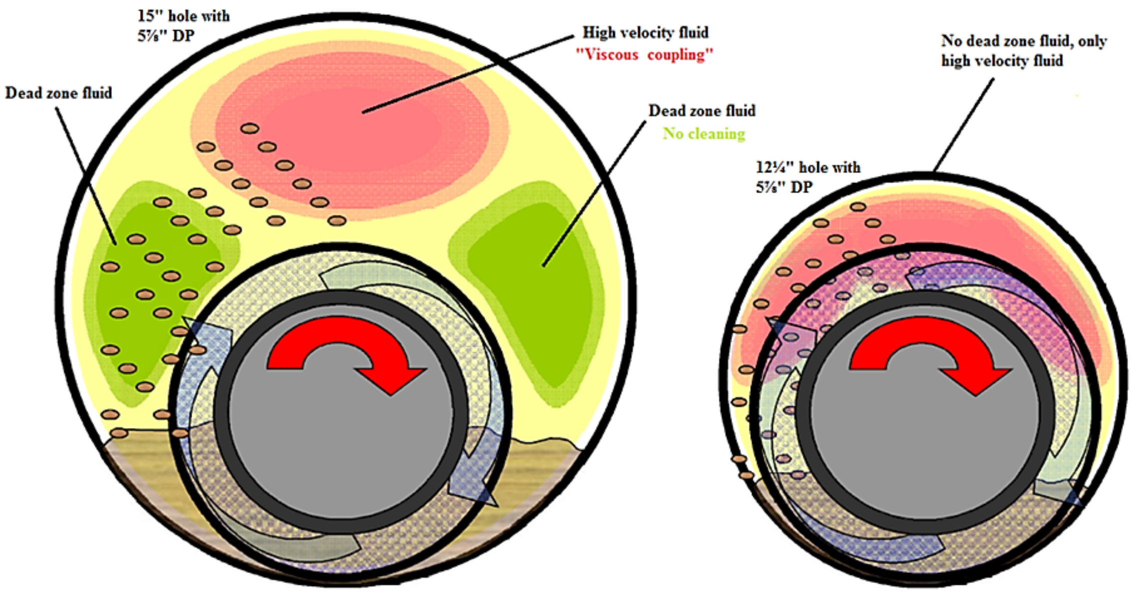


Figure 49: Hole cleaning large hole vs. small hole. Modified after [9].

- **Drillstring design:** The drillstring design plays a big role for the requiredflowrate. It is possible to modify the drillstring design in order to improve the hole cleaning through enhanced hydraulics and a more successful mixing of the cuttings;

- **Wellbore trajectory:** This strongly affects the type and location of the different flow regimes that will be faced during the removal of cuttings from the hole [1].

2.6.2 Hole cleaning mechanisms

Cuttings behave differently depending on well angle and are according to [1], [9] divided into three categories based on the wellbore inclination:

- Low-angle: 0° to ±30°: the hole cleaning is provided by the viscosity and flowrate of the drilling fluid;
- Medium-angle: ±30° to ±65°: the cuttings begin to form dunes;
- High-angle: greater than ±65°: the cuttings form a long, continuous cuttings bed.

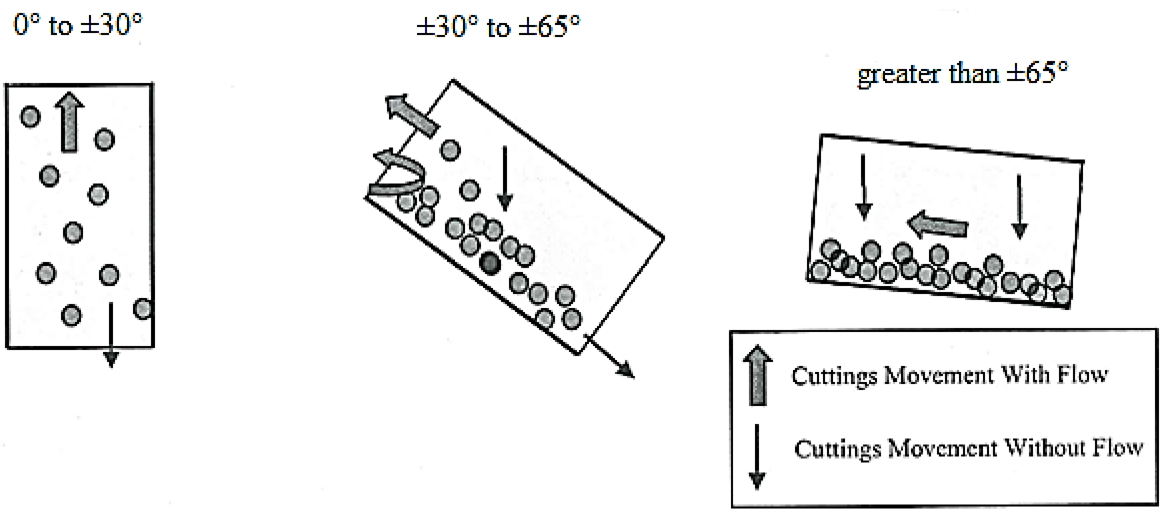


Figure 50: Cuttings transport at different wellbore inclinations. Modified after [1].

As mentioned in section 2.5.5, the flow regime is generally controlled by the velocity of the fluid, but according to [9] the flow is laminar in a horizontal well (may have limited turbulent flow in small hole sizes (with no viscosity)) – the flow is moving in the same direction as the wellbore [9]. Turbulent flow is the ideal flow regarding hole cleaning. In a turbulent flow environment, the mud itself can carry the cuttings out of the hole. Guidelines for effective and robust hole cleaning are therefore pretty complex and depends on the individual situation [9].

2.6.3 Vertical hole cleaning

Hole cleaning and flow in a vertical wellbore according to [9]:

1. The fluid is moving upwards – also known as “annular velocity.”
2. At the same time gravity is pulling downwards.
3. Resulting in cuttings moving slightly slower than the fluid (the efficiency of it is controlled by the mud rheology).
4. Gel strength is a key mud property and affects how it suspends the cuttings (if the cuttings were “alone” they could not be suspended (unless the MW was very heavy).
5. While the cutting falls, it displaces its own volume of fluid upwards.
6. The fluid is crowded with solids in the near surroundings;

   - *“In a crowded solids environment a mechanism called hindered settling occurs”* [9].
   - For each cutting that falls downwards, another cutting is forced upwards. In the end everything will settle on the bottom.

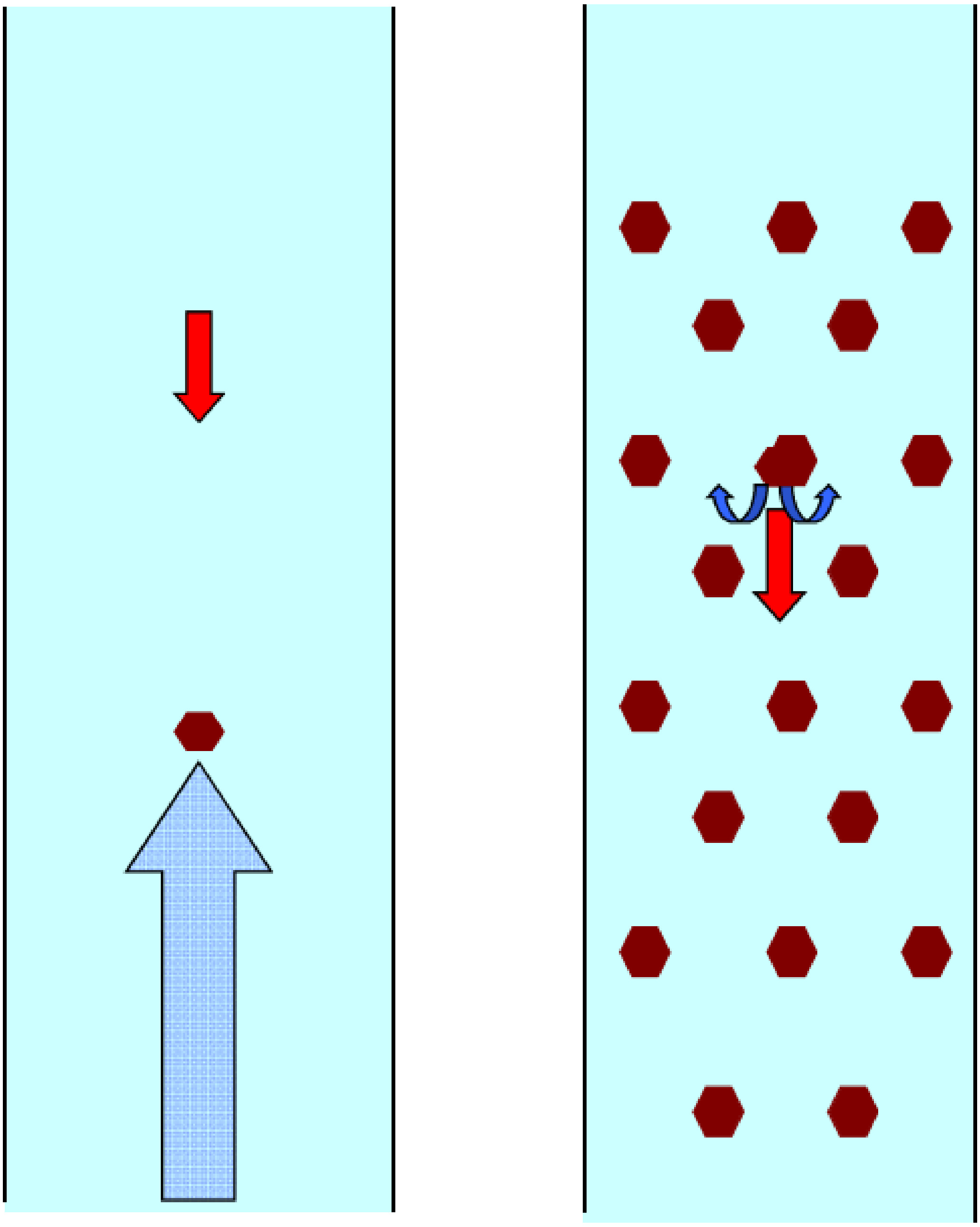


Figure 51: Hole cleaning in a vertical hole [9].

2.6.4 Horizontal hole cleaning

Hole cleaning in horizontal and high-angle wellbores are pretty much the same as for vertical wellbores, except the flow is now horizontal and the hindered settling fails according to [9]:

1. The flow is now horizontal and gravity forces are still pulling downwards.
2. *"There is no longer any fluid velocity direction to counteract slip velocity"*. Cuttings will therefore fall to bottom within 1-2 stands (maximum). A significant issue regarding a laminar flow environment is that the mud cannot transport the cuttings out of the wellbore. This implies that the cuttings are on the low-side of the well, independent of whether or not we are pumping.

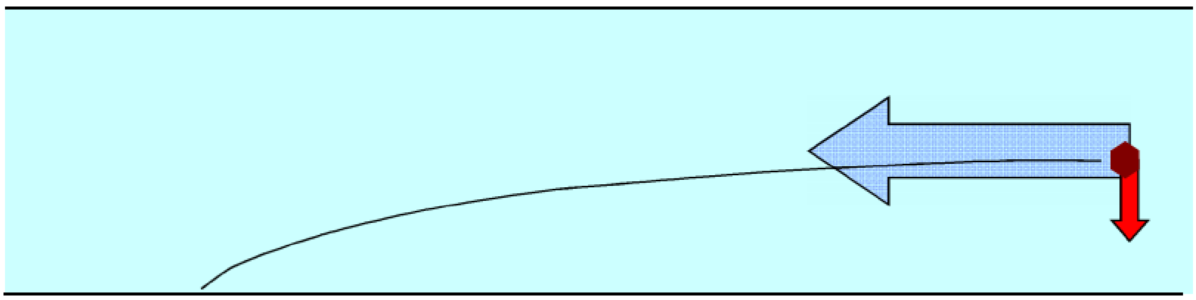


Figure 52: Hole cleaning in a horizontal hole [9].

2.6.5 Pumps off suspension

When the pumps are of, the cuttings only have inches to fall. The “hindered settling” mechanism fails quickly due to the fact that each layer of cuttings touches the bottom [9]. The cuttings cannot be suspended in a high-angle wellbore, regardless of what conditions the mud is in. The situation will be the same no matter how long the pumps have been turned off, whether it is for 5 seconds, 5 minutes or 5 days [9]. Cuttings bed will gradually be formed and it is important to disturb this by inducing turbulent flow and rotation. This also applies to medium-angle hole cleaning [9].

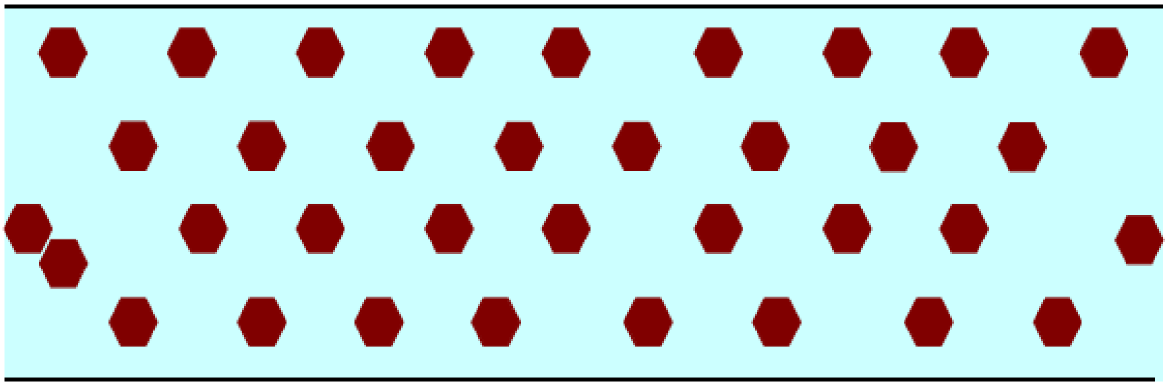


Figure 53: Pumps off suspension [9].

2.6.6 Medium-angle hole cleaning

The fluid velocity is partly working against the gravity forces in this scenario [9]. Cuttings and dirt will be able to travel a longer distance than before, but the cuttings still cannot be carried out of the wellbore. This implies that a medium-angle well has a more effective conveyor belt than a high-angle well.

Cuttings cannot be suspended in a medium-angle hole, as previously seen in the high-angle (horizontal) hole. In this case there is in addition a risk of avalanche of the bed. *"The cuttings bed does not automatically avalanche (just like snow doesn't automatically avalanche on a mountainside – it has to be triggered by something)"* [9]. The avalanche is triggered if the bed-height gets too thick (i.e. the ROP is too fast for too long) or if it gets disturbed (e.g. a tripping in or tripping out).

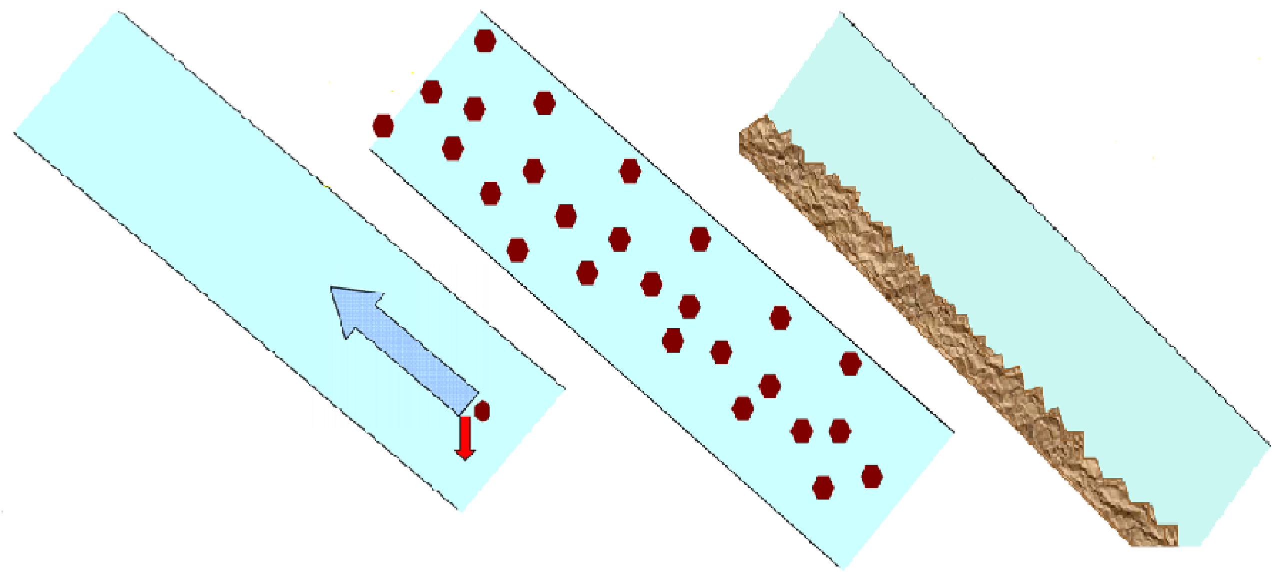


Figure 54: Medium-angle hole cleaning. Hindered settling fails if you stop pumping and you will most likely get packed off (highly undesirable) [9].

2.6.7 Cuttings behavior

Cuttings behave differently depending on the angle of the hole/section, hole size and quantity shown in Figure 55 [9].

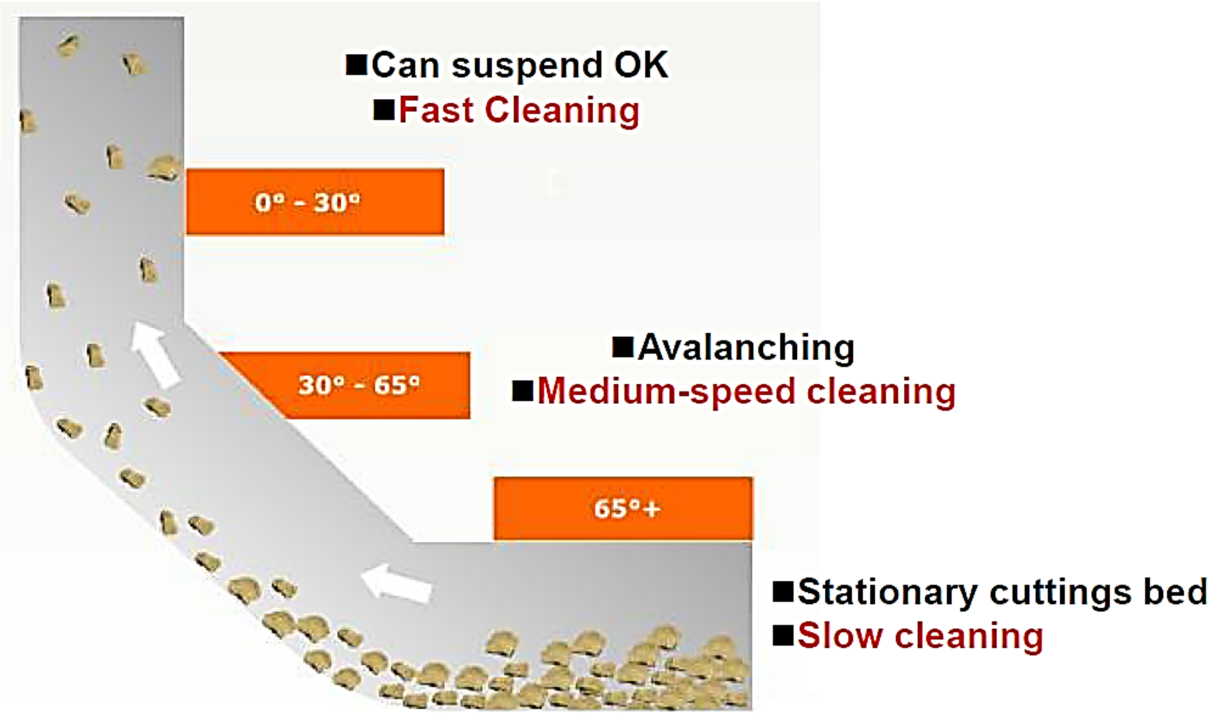


Figure 55: Cuttings behavior at different hole angles [9].

2.6.8 The conveyor belt

According to [9] the high velocity fluid on top of the hole serves as a conveyor belt, also called a carrying medium, that transports the cuttings out of the wellbore. The cuttings will travel a certain distance and eventually fall off (into the low flow zone) due to gravity forces. *"The distance travelled on the conveyor belt is a function of angle,* ***flowrate****, rpm and rheology (mud)"*. The speed of the conveyor belt is mainly a function of flowrate. A rule of thumb regarding the conveyor belt is; the higher the hole-angle, the slower is the hole cleaning [9].

Rotation acts like a switch – it turns the conveyor belt on and off. High speed RPM is the key to operate the conveyor belt [9].

For "big holes" (i.e. > 8½") [9]:

- The conveyor belt is "on" at > 120 rpm
- The conveyor belt is "off" at < 120 rpm

For "small holes" (i.e. < 8½") [9]:

- The conveyor belt is in "high gear" at > 120 rpm
- The conveyor belt is in "low gear" at < 120 rpm

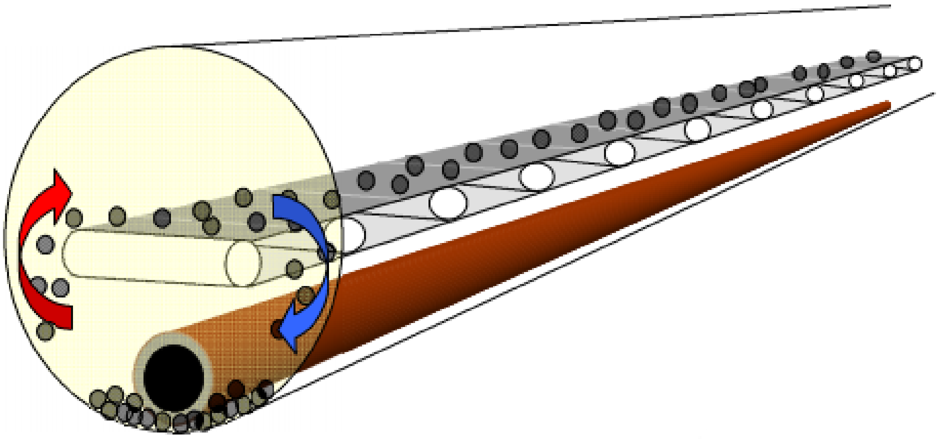


Figure 56: The conveyor belt. The speed of the conveyor belt is a function of the observed flowrate [9].

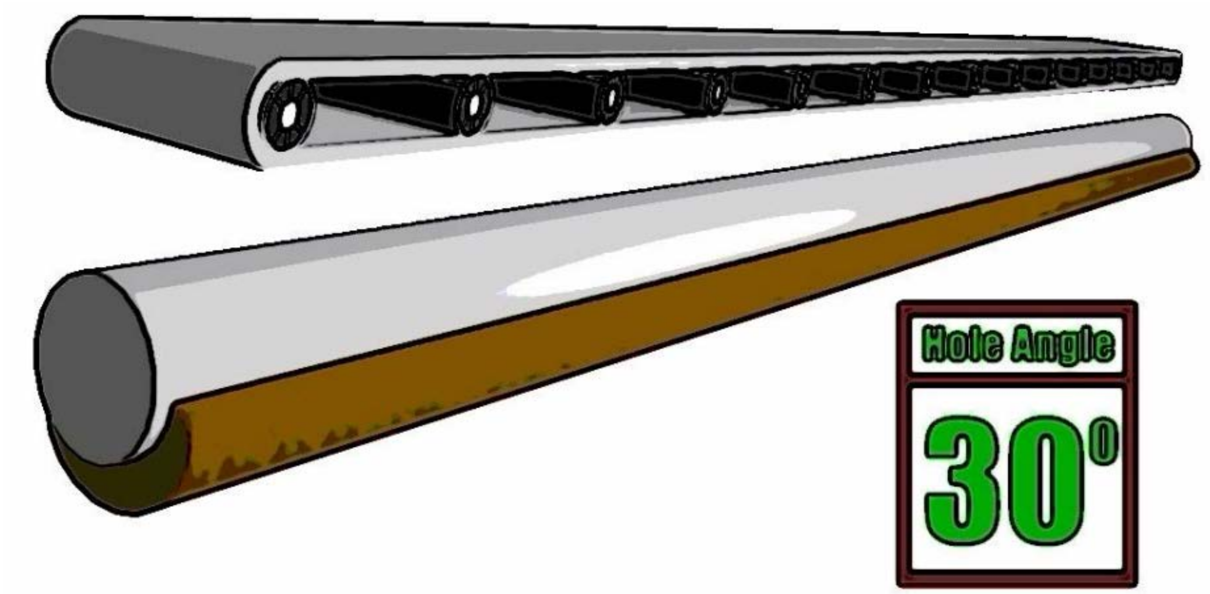


Figure 57: The conveyor belt. The dirt/cuttings get on the belt through/due to pipe rotation [9].

2.6.9 Sweeps

Sweeps are pretty much the same as drilling mud, expect it has different properties than the mud that are currently used in the well [13]. It is an additive that is being used to facilitate the transport of cutting from the wellbore to the surface. The usage varies among the different operators; some barely use it, while others almost always pump sweeps in order to remove cuttings and cutting beds by adjusting the density and the viscosity of the mud [13].

There are a lot of pros and cons regarding the use of sweeps. They don't work properly when the wellbore angle and reach increase [9]. Sweeps are rather ineffective in the directional portion of the wellbore, and they cannot move/transport cuttings very far (no matter what type of sweep we are talking about) [9]. They may cause problems for the mud, ECDs and PWD according to [9]:

- The mud properties are badly affected if the sweeps have absorbing capabilities.
- Spikes in ECD may increase the risk of packing off around the BHA, which again may make it harder to interpret PWD.

2.6.10 Bed behavior

The flow of cuttings in a high-angle well happens via a mechanism called "saltation flow". Saltation flow *"means that only the top layer is moving, and is drifting like sand on the beach or the top of a snow drift"* [9]. You basically have a mobile top-layer, and a static bottom-layer that eventually will form equilibrium levels. This implies that drilling at slow ROPs actually doesn't clean the lower layer and that it doesn't get eroded until "drilling layer" stops altogether [9]. This phenomenon can be compared to the mechanism that the gravel packing is based upon.

The cuttings bed strongly influence the hole cleaning. The drilling fluid interacts with the cuttings in cuttings bed during drilling and forms a cuttings bed gel, which again leads to difficulties in removing the cuttings bed [12]. The hole cleaning will be very challenging in situations where the cuttings bed is well consolidated because the cuttings are not free and cannot be removed from the bed by the flow itself. In the opposite case, if the cuttings bed is porous and loose, the hole cleaning will be easier. It is only necessary to remove the solitary cuttings that are not adhered to the cuttings bed [12].

When drilling, the lower “static” layer of the cuttings bed builds up to an equilibrium height and it will not erode as long as the top layer is present (and moving) [9]. If the driller changes the ROP, it will not affect the lower layer until the top layer is fully removed. Increasing the ROP will result in a thicker top layer, with minimal effect on the lower layer. If the ROP is decreased, the top layer thins out, but the lower layer will not clean up very much [9]. When the top layer has been “cleaned up,” the lower “static” layer will try to clean up and thins to a new equilibrium level (but it will not get cleaned up completely) [9]. This implies that there always will be some sort of cuttings bed, so when tripping, you are tripping through dirt, not in a “clean hole” [9].

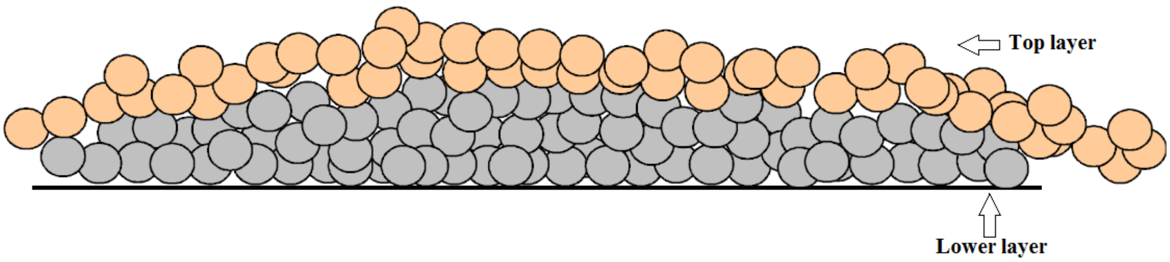


Figure 58: Bed behavior and saltation flow. The observed cutting coming across the shakers while drilling are the top-layer, which is moving freely across a deeper “static” bed [9].

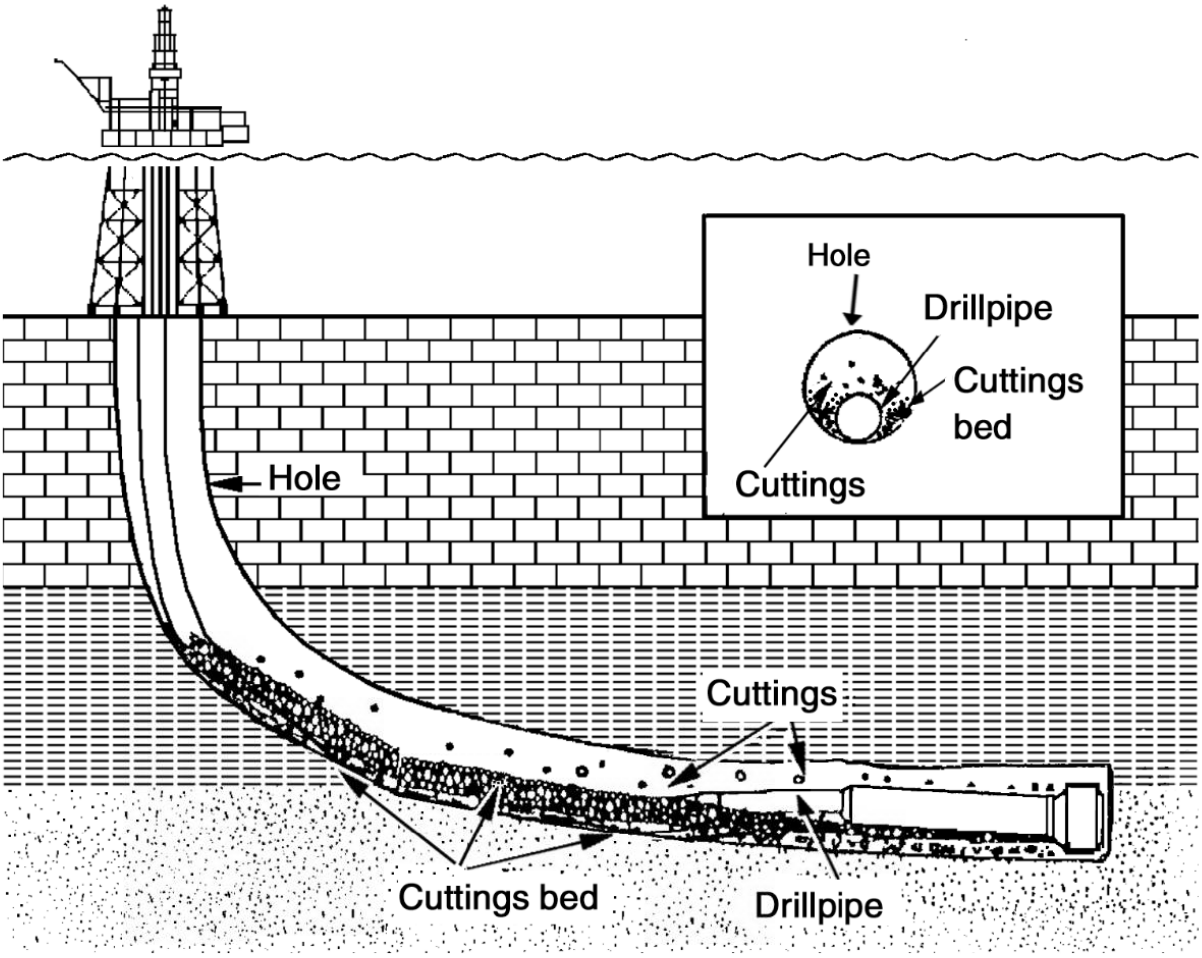


Figure 59: Cuttings-bed build-up in directional wells [37].

2.6.11 Fundamentals of hole cleaning

2.6.11.1 Cuttings transportation

Inefficient transport of small cuttings is a major contributor for the excessive torque and drag during extended reach drilling. Duan et al. [17] studied the transport behavior of small cuttings and the main factors affecting it. They performed experiments with three different sizes of cuttings ranging between 0.45 to 3.3 mm using a field-scale flow loop (8 in. × 4.5 in., 100 ft. long). The results showed major differences when it comes to cuttings sizes. Smaller cuttings gave higher cuttings concentration than larger cuttings in a horizontal annulus when tested with water. The smaller cuttings were more difficult to transport than the larger cuttings.

The key parameters affecting the transport of small cuttings were found to be pipe rotation and fluid rheology [17]. The small cuttings have a tendency to settle at the low-side of the high-angle or horizontal section, which again may create problems when trying to run the casing in place [17].

Duan et al. [17] concluded that drillpipe rotation in combination with a polymeric drilling fluid is the best solution to effectively transport small cuttings during extended-reach drilling or horizontal drilling [17].

2.6.11.2 What is happening downhole?

To be able to design a successful ands robust hole cleaning system, it is beneficial to understand what is really happening downhole in the wellbore during the various operations. A lot of misconceptions are made in the drilling industry, especially regarding high-angle wellbores.

If you compare a vertical wellbore to a horizontal (high-angle) wellbore, both flow paths and flow velocities differ a lot. Studying a vertical well (this also applies to the vertical section of an ERD well) you will observe that the fluid moves freely around the drillpipe. In a horizontal wellbore the fluid is on the other hand only moving above the drillpipe where there are no cuttings (unless there is some kind of pipe movement) [1].

This strongly affects the mud rheology, drilling parameters, as well as bit and BHA selection requirements [1]. In order to get the cuttings into movement in a high-angle wellbore is to mechanically agitate the cuttings bed (i.e. to mix the bed through pipe rotation) as the mud nearly is static on the low-side of the wellbore.

When the pipe rotation is up and running in order to mix up the cuttings, *"the cuttings movement is effectively a moving beach"*. If the mud conditions are ideal, the mixed-up cuttings will (most likely) be lifted into the high velocity fluid and then transported up the wellbore until it eventually falls to the low side again. This will proceed as long as the mixing continues. As mentioned before, if the mud is too thin, the cuttings can be easily lifted up, but will unfortunately fall back into the low side due to the gravity forces.

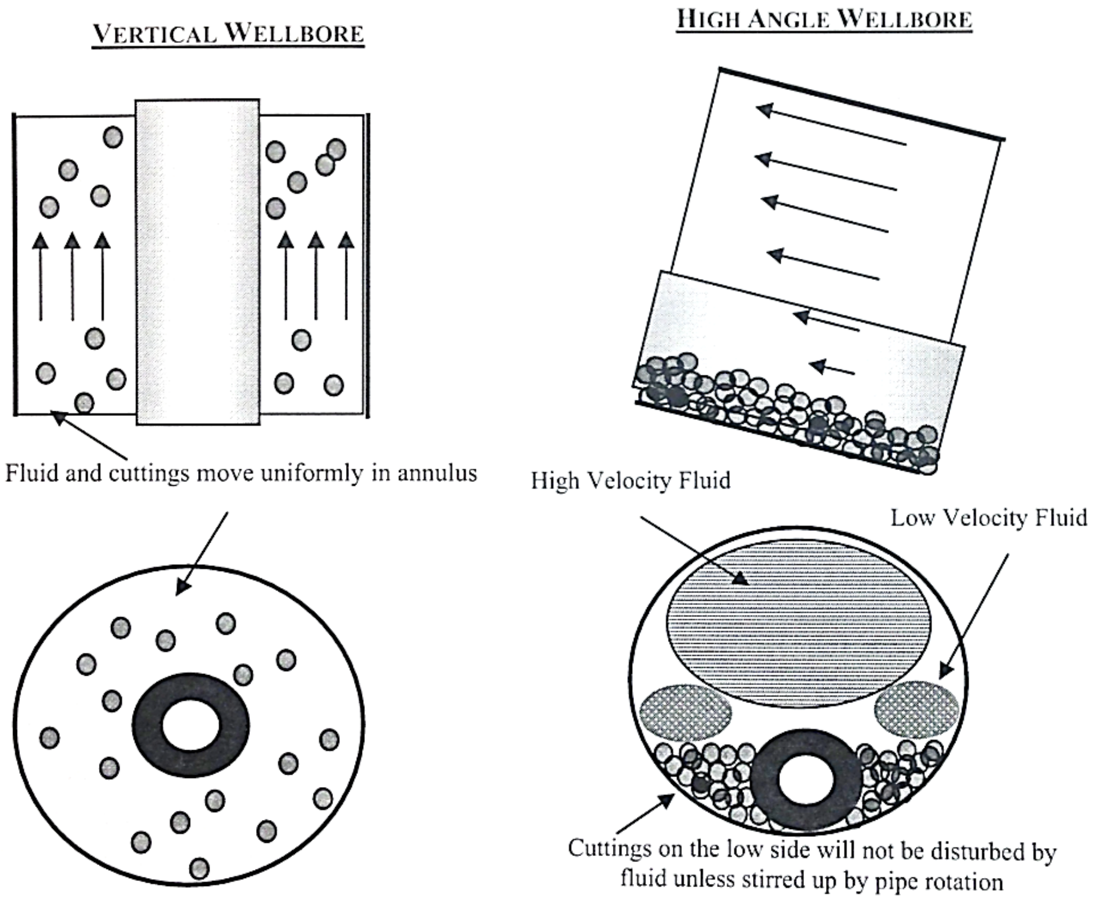


Figure 60: Fluid movement in the annulus in vertical vs. horizontal wellbores [1].

2.6.11.3 What is a "clean" hole?

Each high-angle wellbore will surely form some kind of cuttings bed of some thickness or distribution. Focusing on management of the cutting bed is the key to hole cleaning [1]. A wellbore does in fact not have to be 100% clean (and totally free of cuttings) to be characterized as "clean". Mims and Krepp [1] define a "clean" hole as *"a wellbore with a cuttings bed height and distribution such that operations are trouble free"*. A "clean hole" will vary among the different operations (e.g. drilling, tripping and logging) and it strongly depends on which operational stage you are in [1], [9]:

- **Drilling:** A dirtier hole can be accepted since the drillstring is moving through the cuttings bed;

- **Tripping:** The hole needs to be cleaner than for drilling since drill collars, stabilizers and bits are being pulled through the cuttings bed;

- **Pipe-running:** When running pipe, the hole needs to be as clean as possible in order to verify that the cuttings bed does not keep the casing or liner from reaching the desired target depth.

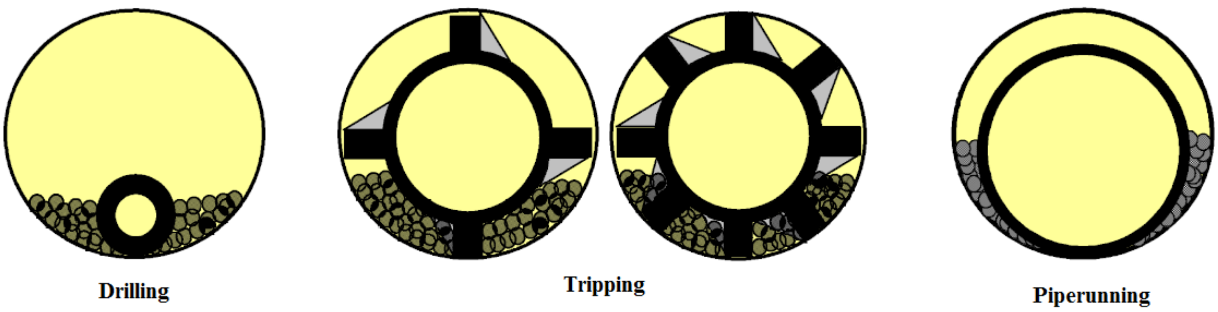


Figure 61: Clean hole [9].

It is important to note that a “clean” hole for drilling is not the same as a “clean” hole for tripping of BHA and casing [9]. This is primarily due to the fact that when you are drilling, the BHA is not being pulled directly through the cutting bed and due to the differences in annular clearance observed in the different operations.

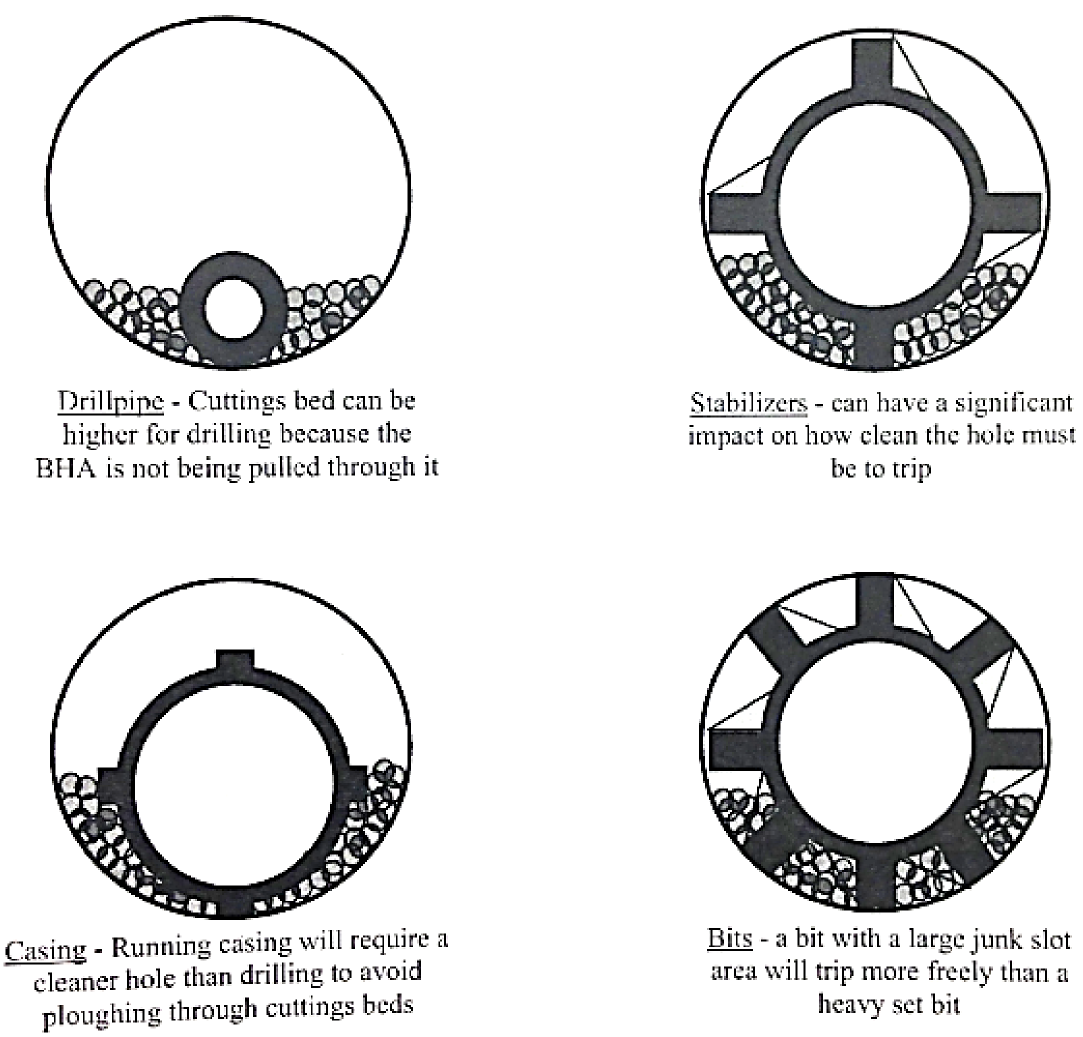


Figure 62: Clean hole and cuttings beds. The hole cleans from the bottom up [1].

2.6.11.4 How is the hole cleaned?

Hole cleaning can roughly be divided into two main mechanisms according to [1]: Dispersion and Mechanical removal.

Dispersion is the mechanism that dissolves cuttings into the mud, which again ensures that it can easily be transported from the wellbore [1]. Two requirements/conditions must be present for this to happen. First, the formation that is being drilled has to be soft and easily dispersed [1]. Secondly, the current mud system used cannot have any inhibitive properties, which may prevent the cuttings from dispersing into the mud [1].

Mechanical removal of cuttings from the hole involves many different parameters that need to work as a team to clean the hole. According to [1] *"Rotation of pipe and flowrate are the two most important parameters for hole cleaning in high-angle wellbores"*. The pipe rotation manages the efficiency of the hole cleaning, while the flowrate is an important parameter regarding the hole cleaning rate. When you increase the pump rate, the cuttings will travel/move faster out of the wellbore when and if they are coupled with ample rotary speed. As long as you can observe cuttings coming over the shakers, you can know for sure that the hole is being cleaned properly [1], [9].

2.6.11.5 Effects of drillpipe rotation on hole cleaning and ECD

According to [9] rotation is the KEY factor in hole cleaning efficiency for the high-angle (horizontal) wellbores/holes due to the fact that the active flow area is on top of the hole, pipe and cuttings lay along bottom of hole, agitation is required to get cuttings into the fluid flow and the required rotary speed is dependent upon hole sizes (ROP).

Without rotation the cuttings on the low side of the wellbore will not be disturbed by the fluid, unless it gets disturbed by rotation of the pipe. With pipe rotation, the cuttings will be pulled up into the high velocity fluid (mechanically and due to the viscous coupling effect, which is a function of the viscosity of the mud) as seen on Figure 63 below [9].

According to Saasen et al. [12]; *"The larger the rotation rate is, the more turbulence like the motion becomes and the frictional pressure losses increase."* This implies that the optimum hole cleaning condition should be to use as high drillpipe rotation as possible.

In a laminar flow environment the flowrate travels along the top side of the hole and the resulting dead zone separates high velocity mud and cuttings from each other [9]. The produced "fluid film" that is rotating around the drillpipe is responsible for cleaning the hole, not the pipe rotation itself. The fluid film is also known as the "viscous coupling" [9].

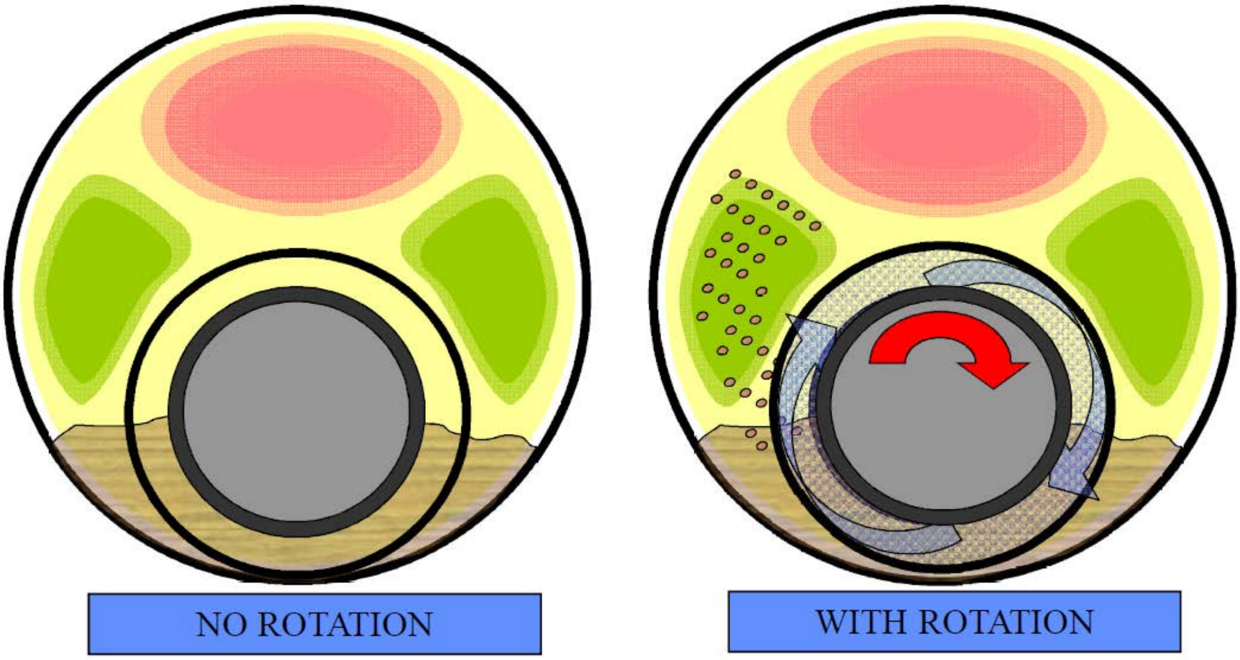


Figure 63: Rotation effects without and with rotation [9].

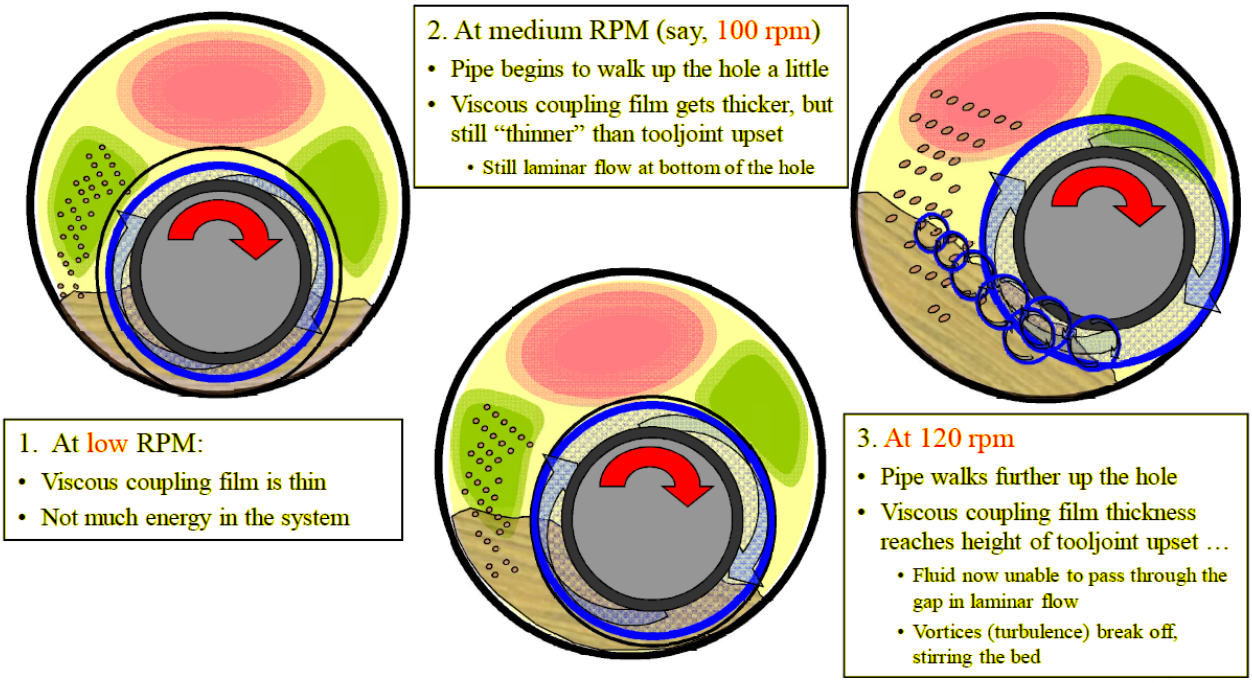


Figure 64: Step change behavior at low, medium and high RPM [9].

According to [1] there is a strong relationship between ECD's and pipe rotation, especially in small hole sizes (≤ 8½" hole). ECD's have a tendency to increase on long wells when pipe rotary speed exceeds 50 rpm [1]. This is mainly due to the fact that high speed pipe rotation will cause fluid to spiral while moving upwards the hole. The distance that the fluid must travel is hence increased, which again leads to increased ECD's [1].

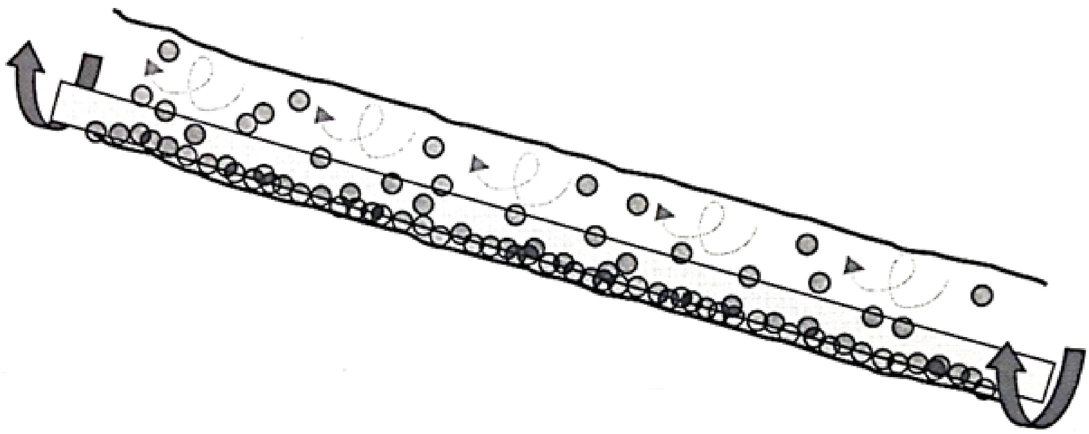


Figure 65: ECD increase due to rotation of pipe [1].

2.6.11.6 Mud/fluid rheology

The rheology of the mud plays a vital role regarding hole cleaning, and is often difficult to improve/optimize. The most important criteria are that it has to be able to lift and transport the drilled cuttings from the wellbore to the surface. When it comes to the mud rheology there is an ongoing discussion whether or not thick or thin mud is preferred. The final choice is usually based on hole sizes according to [1], [9]:

- For 17½” & 12¼” hole cleaning is the 1st priority and a particular challenge
- For 8½” the ECD’s are more important than hole cleaning (since the ECD increases with decreasing hole size)

If the mud is too thick it may tunnel up along the high side of the wellbore, the conveyor belt zone shrinks and dead zones may become impenetrable for cuttings that are thrown up the wellbore [9]. It may also increase the pump pressures and ECD’s to a point where the flowrate has to be reduced. But on the other hand, if the mud is too thin, there is no effective “viscous coupling” that can help lift the cuttings into the flow. Even though the ECD is lower, there is difficulties regarding cleaning the vertical portion of the well. The cuttings have higher potential to drop out of the fluid, which slows down the hole cleaning process (highly undesirable) [1], [9].

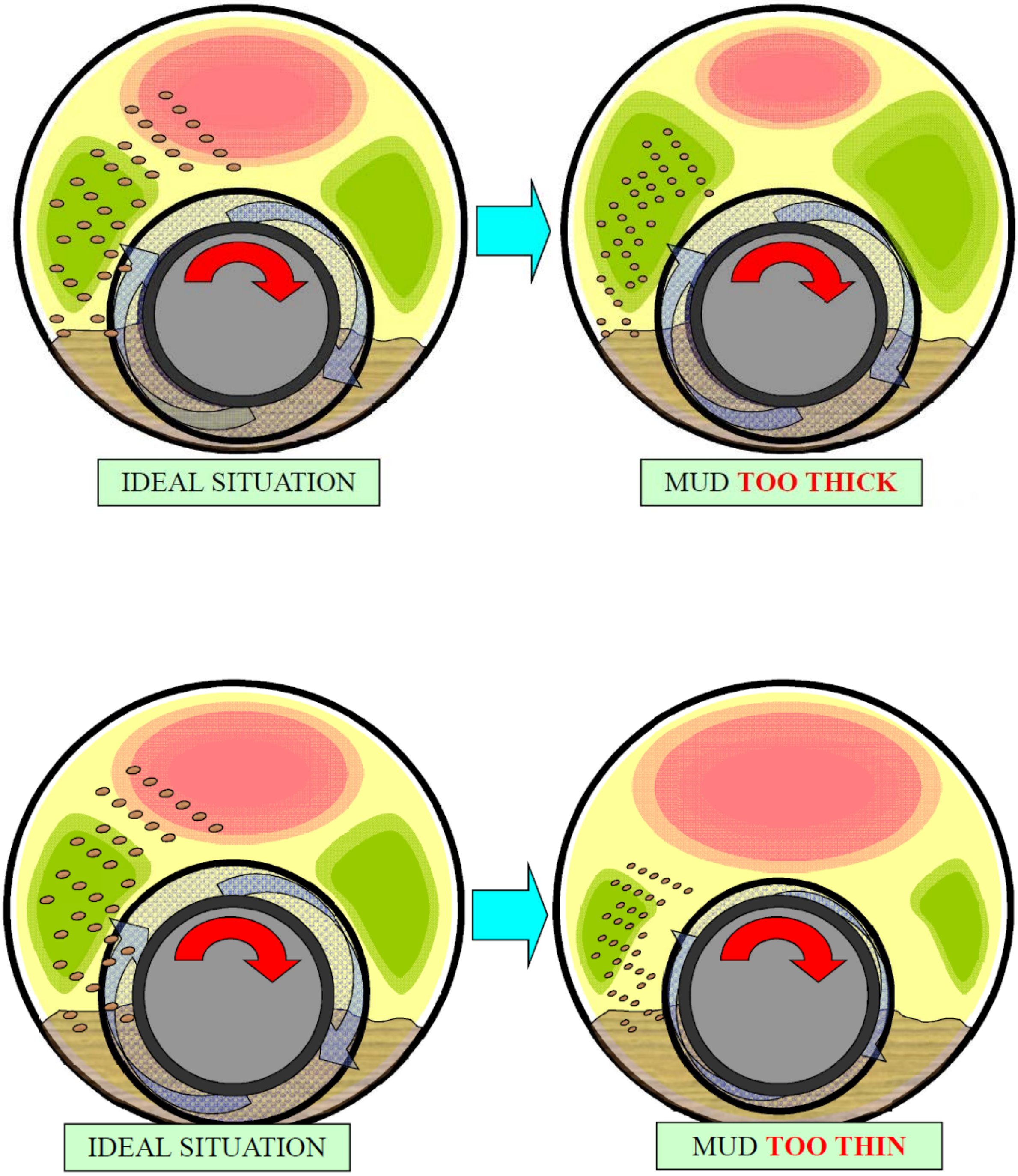


Figure 66: “Thick” and “thin” mud rheology [9].

3 ERD in general

3.1 What is ERD – Extended Reach Drilling?

Extended Reach Drilling has been around for several years, but the most aggressive ERD activity occurred during the 1990s [1]. The driving force behind extended reach wells has been to find cheaper and more efficient ways of drilling oil wells and to reduce the environmental impact/footprint [51]. The main purpose of ER, horizontal and complex design wells is to reach oil and gas reserves many kilometers away in the most cost effective way.

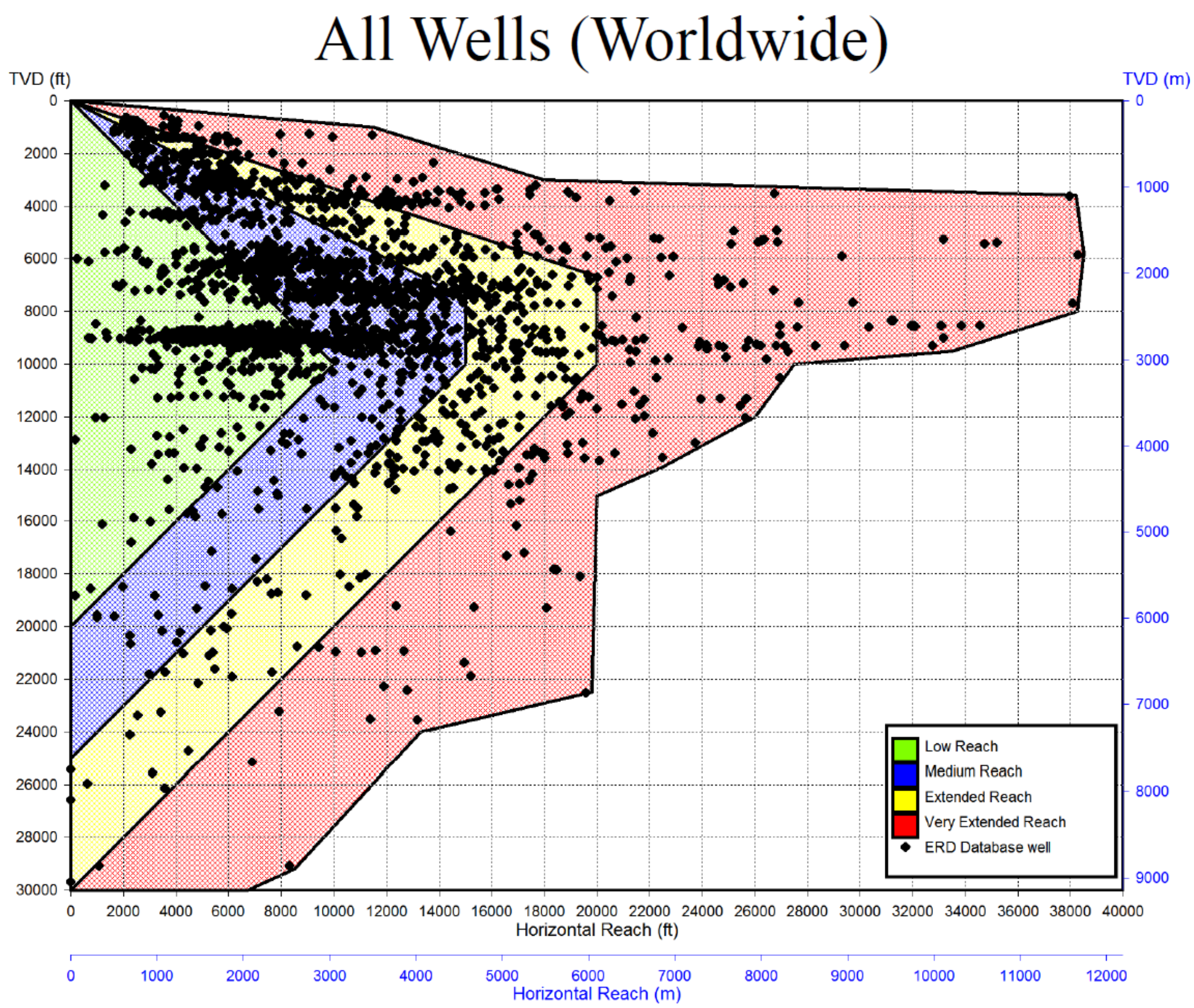


Figure 67: The extended reach drilling envelope (Taken from when the current world record was held by ExxonMobil's OP-11 (TD = 40.520 ft. MD). The current record today is TD = 42.651 ft. MD – which will be presented in detail later) [9].

The definition of an extended reach well can be discussed endlessly, and there is currently no standard and universally accepted definition for these types of wells. What qualifies a well to be extended reach strongly depends on the relationship between locations, technologies, developments and experiences and varies widely over time [62]. There is neither any such thing as an “easy” ERW, and a rule of thumb is that with increased reach/displacement come increased challenges [60].

An extended reach well has traditionally been defined as a well with a Horizontal Displacement or Departure/Total Vertical Depth (HD/TVD) ratio > 2.0 (i.e. step-out ratio of 2:1 = wells with departures that exceeds twice the well TVD [1], [53]). This ratio has also been used as a measurement of the complexity found in an ERD well (i.e. *“the higher the ratio, the more complex and difficult the well”*) [1].

There are a lot different definitions and classes of ERD, and a normal differentiation according to Statoil is [14]:

- Conventional drilling: HD/TVD < 2.0
- ERD wells: HD/TVD > 2.0
- Severe ERD wells: HD/TVD > 3.0

According to Longwell et al. [46] the industry’s general accepted definitions of an ERD well include:

1. Wells having horizontal displacements greater than twice the well's true vertical depth, yielding inclination angles in excess of 63.4 degrees;
2. Wells which approach the limits of what has been achieved by the industry in terms of horizontal displacement;
3. High angle, directional wells that approach the capabilities of the contracted rig.

Agbaji [24] presented a paper in 2011 mentioning two different ratios regarding ERD classification, also called aspect ratios, which can be used to explain ERD wells:

- The unwrapped reach ratio
- The depth ratio

The unwrapped reach ratio is according to [24] the along-hole departure divided by the true vertical depth (TVD) at total depth. If this ratio exceeds 2, the well is considered to be an ERD well. The depth ratio is according to [24] the measured depth (MD) of the well divided by the TVD. The same limit applies to this scenario; if the ratio is greater than 2, then the well is considered to be an ERD well.

Another important aspect regarding the definition of an ERW is that there may be other types of wells (that does not have either step-out or aspect ratios greater than 2) qualifying to be ERD wells due to their characteristics and design. According to [24] these wells include:

1. Wells with an unwrapped reach greater than 25.000 ft.;
2. 3D wells;
3. Wells which approach the limits of what has been achieved by the industry to date in terms of horizontal displacement at a given TVD;
4. Directional wells that challenge the capabilities of the rig.

ERD wells are divided into two basic types, mainly defined by the well profile [1]:

1. Very shallow ER wells
2. Very long ER wells

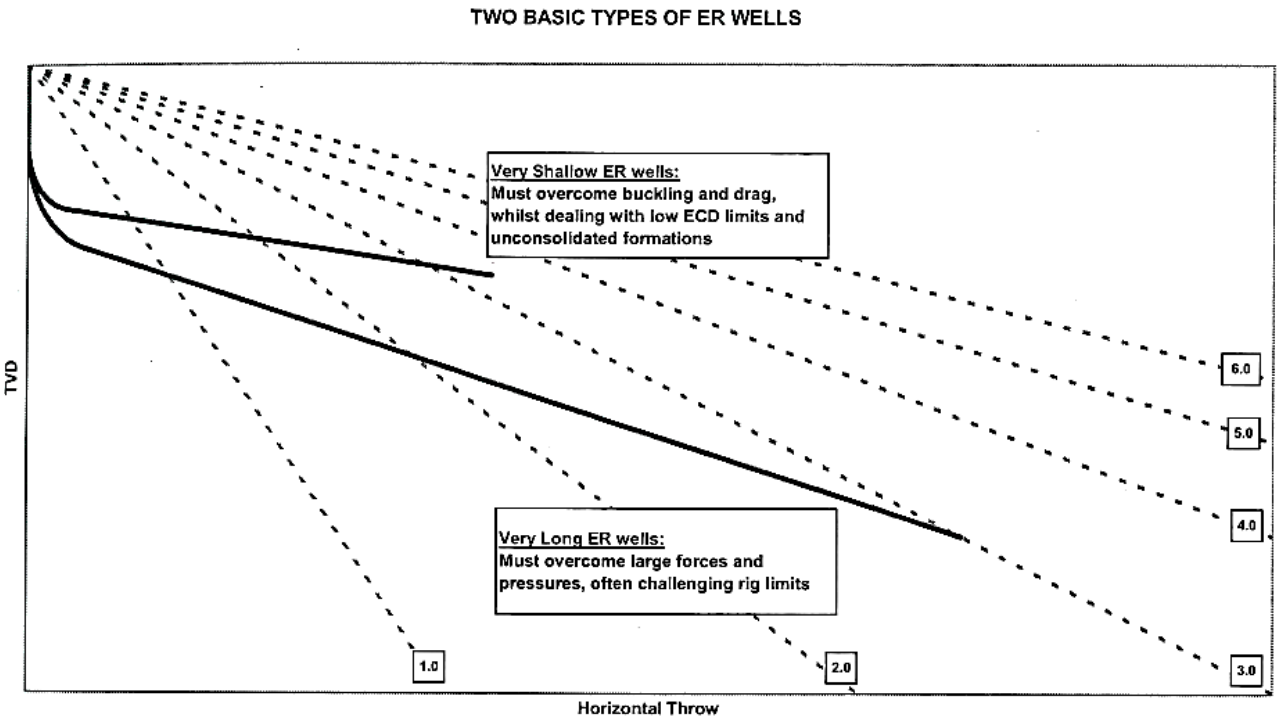


Figure 68: Two basic types of ERD wells [1].

ERD wells can thus be very long (in measured depth) and relatively shallow vertically.

Very long ERD (vERD) wells are usually the type of well design imagined when "Extended Reach" is mentioned [1]. *"Very shallow ERD wells have quite unique problems and are often equally as challenging as very long ERD wells"*. Whilst/as the very long ERD wells need to stand forces and pressures of high magnitude (i.e. brute force is needed) and are often better off for torque and drag (due to the fact that the long vertical section in the riser will contribute to extra surface weight and make negative weight conditions less likely [1]), the shallow wells must often overcome drag and buckling while managing annular pressures within very small ECD limitations due to the shallow vertical depths and relatively long measured depths [1]. In both cases, it is extremely important to drill smart in order to fully optimize performance [1].

Besides the two basic ERD well types listed above, the following additional ERD designs is also worth mentioning according to [1], [9]:

- **Complex well design:** This involves 3D wells designs with large changes in azimuth (the angle between the projected vector and a reference vector on the reference plane is called the azimuth [56]) to line the well up with the specific target(s) [1]

- **Deepwater ERD wells:** The challenges increase with increasing water depth [9]. The deepwater challenges occur in three different areas [1]:

    1. <u>Issues related to the long section of large diameter riser:</u>

        - The hole cleaning is more challenging due to the following [1]:
            - Larger annular clearance between the drillstring and the riser ID, which gives reduced annular velocities (AV)
            - The mud is often run thinner (lower rheology) hoping to overcome ECD limitations (arising from the lower fracture gradient and increased mud rheology from cuttings loading in the riser)

        - Mud temperature and rheology – due to greater water depths, the temperature in the riser can be quite low, which again may lead to a thicker mud that in turn will impact the ECD (i.e. increase the ECD values)

        - Torque, drag and buckling – deepwater ERD wells are often better off with respect to torque and drag [1], but buckling is on the other hand more complicated due to the fact that the deepwater wells usually have a high tangent angle and therefore increased chances for buckling to occur due to high drag forces [1]

2. Directional issues in the build section:

   - Fast build rates are required since targets for deepwater wells often are quite shallow (TVD). To be able to reach these shallow targets with the required step-out it is necessary to build at high rates [1]. This may be challenging as large OD BHA's often are used to stiffen up the drillpipe in order to minimize the effects of torque, drag and buckling [1]

   - Unconsolidated formations – the formations right below the seabed are usually relatively soft and unconsolidated which may lead to high ROP's and create difficulties in building inclination [1]

3. ECD issues:

   - Reduced overburden strength – the formation fracture gradients have a tendency to be lower in deepwater wells, creating trouble managing mud weight and ECD's

   - Cuttings loading in the riser – the cuttings are supported by the bottom of the hole on conventional ERD wells (the cuttings are located on the low-side of the wellbore). In a deepwater ERD well when the cuttings enter the long vertical riser, their weight impact the ECD all the way up the riser because they are suspended in the mud [1]

   - Mud temperature and rheology – the mud in deepwater ERW tend to be thicker since the mud cools in the long vertical riser and negatively impacts the ECD's (i.e. increase the ECD values)

- **Limited rig package/capability:** In order to assess the required rig capability (which strongly depends on the drilling strategies and practices that will be applied), some areas need to be assessed [1]; hydraulics capability, rotary and hoisting capability, power capability and general capability issues. These are discussed in detail in section 2.2.3.

According to Demong et al. [15] the extended reach drilling limit is reached when one of the following occurs:

1. The hole becomes unstable, due either to time exposure, geo-mechanical interaction, adverse pressure differential, or drilling fluid interaction (or incompatibility). The onset of these conditions is usually observed in the sudden increase of torque and drag in the drill string not related to the DLS of the hole or the length of the drilled section.

2. The drill string will no longer travel to the bottom of the hole due to excess drag. This situation is differentiated from the previous case because this effect is not related to the friction factor which remains unchanged. Instead, it is related to the cumulative length drilled along with the DLS of the hole as drilled (Figure 69).

3. When rotation is used to overcome friction and advance the drill string, such as in a rotary steerable application, the limit is reached when you hit the torque capacity of the tubulars (Figure 70).

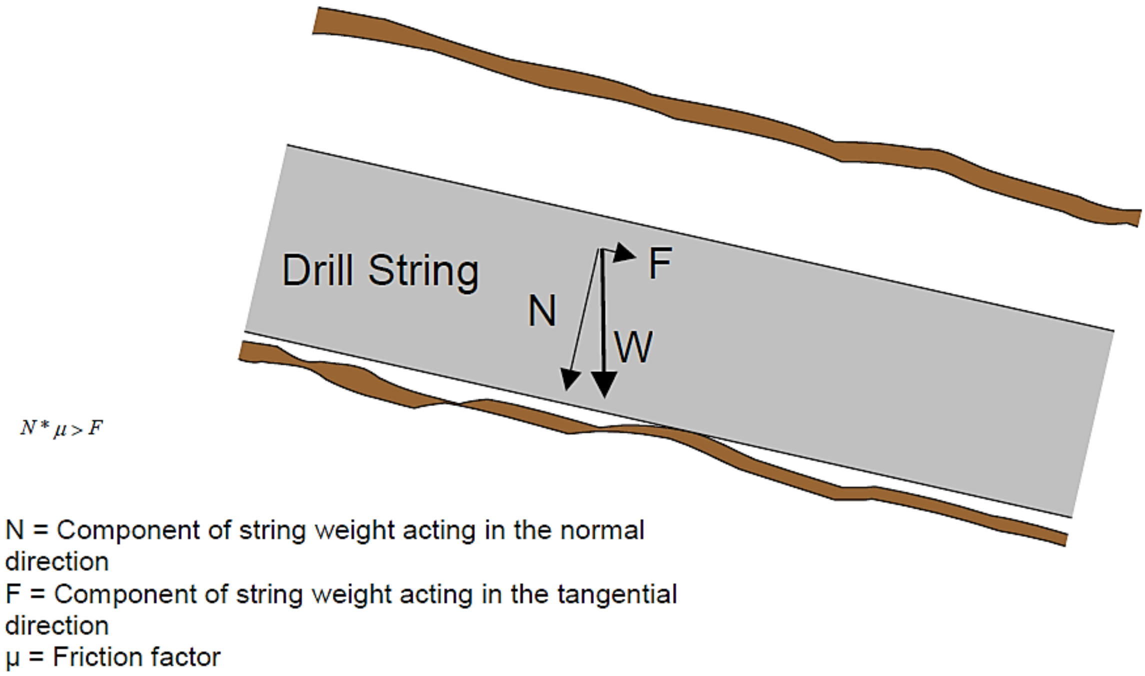


Figure 69: The ERD limit is reached when friction exceeds the force available to push the drill string down the hole [15].

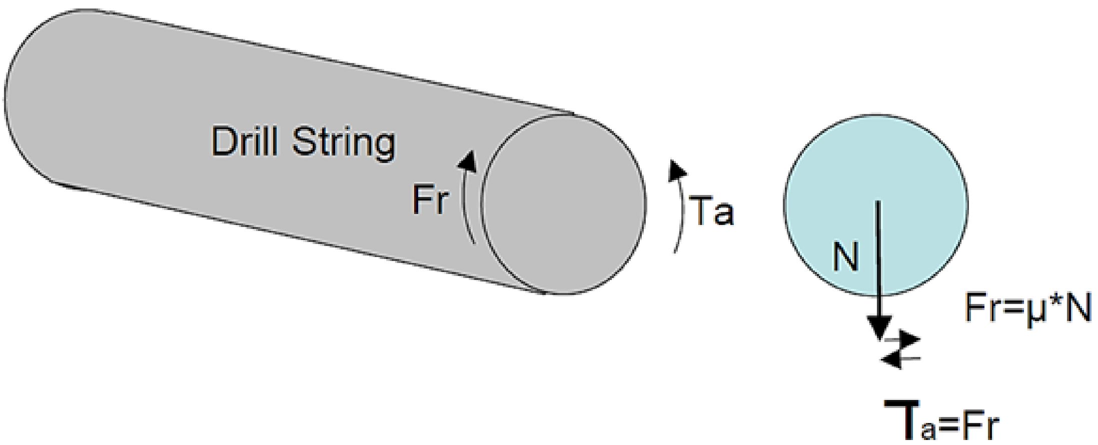


Figure 70: The rotary steerable ERD limit is reached when the torque applied at the surface, T_a, in order to overcome rotational friction, F_r, becomes greater than the thread makeup torque [15].

3.1.1 Why ERD?

Most ERD wells can be quite expensive (upwards of $100-200MM in extreme cases), so why don't the operators choose to drill simpler wells? According to [9] it all comes down to one thing: Economics!

According to [9] there are three main reasons for drilling ERW listed below:

1. Surface location constraints

ERD makes it is possible to reach a larger area from one surface drilling location and to enter reservoirs at locations remote from a drill site [24], [64]. ERD makes it thus possible to access offshore reserves from a well-site on land, eliminating additional platforms and costly offshore operations [63].

Example: Sakhalin Island – ER allows access to an offshore reservoir from land, reducing the surface location costs, risks, and logistical complications (arctic environment) [9]. Wytch farm is another example [65]. They managed to push the ERD limits of drilling and completing – all in an environment of decreasing reserves per well and low oil price [65].

2. Reduced infrastructure costs

Both the well-site footprints and the environmental effects are reduced through ERD technology in addition to enhanced reservoir drainage at reduced cost [63].

Example: Abu Dhabi – ER wells allows massive fields to be developed from 3-4 drill centers compared to more than 30 earlier, shown in Figure 71 [9].

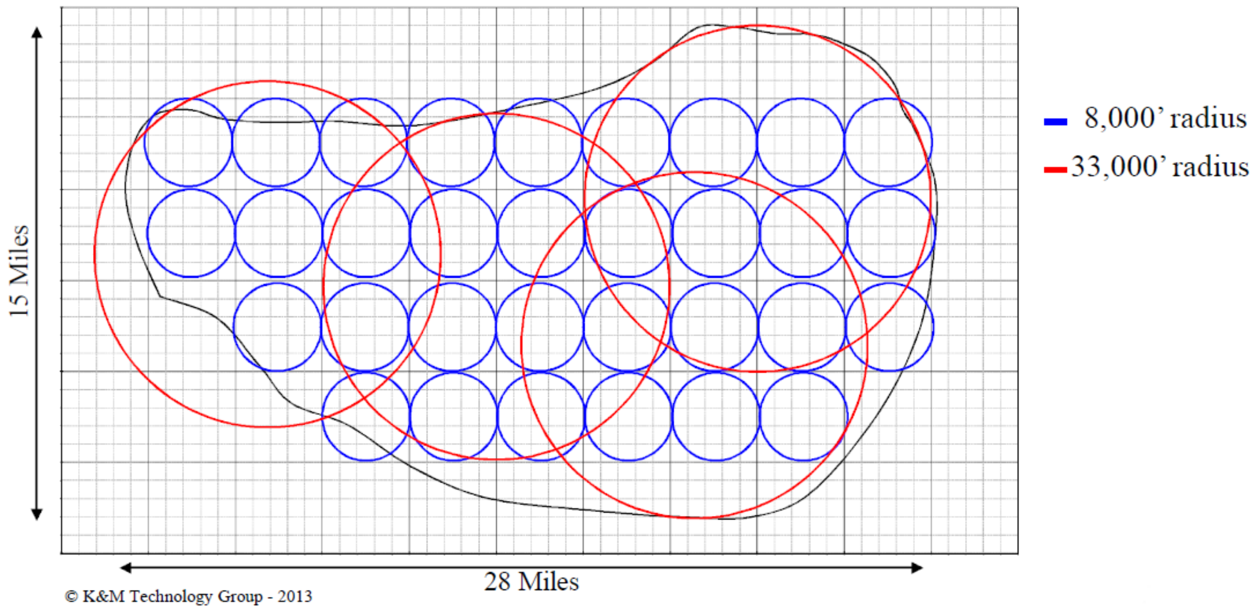


Figure 71: Reduced infrastructure costs [9].

3. Increased reservoir contact

ERD technology offers the possibility for reservoir production [63]. It is possible to keep a well in a reservoir for a longer distance than earlier to maximize both the productivity and the drainage capability [24], [64].

3.1.2 The "MORE" factor

As defined under well planning: ER wells require "more" in many aspects according to [9]:

- More torque, more pressure, more pipe, more volume, etc. (generally due to longer wellbore trajectories/reach)
- More time to plan
- More specialized equipment
- More specific practices (regarding hole cleaning, tripping and back-reaming)

3.2 Extended Reach Drilling in Europe

A total of 431 wells, classified as ERD by the Rushmore Reviews, were drilled in the European region between 2000 and 2007 [14]. The majority of these wells were drilled in the North Sea. Statoil has historically been a front-runner in ERD in Europe with record breaking wells at Statfjord (fixed installation) [19], Gullfaks (fixed) [20] and Visund (floating) [22]. Wells drilled offshore have mainly been focused on individual targets adding on to the production from large field developments [14].

Statoil and Norsk Hydro have thus achieved good developments in the ERD activity, both in the Statfjord and Gullfaks fields [14], [18]. 23 out of 26 wells drilled longer than 7500 m MD among the wells mentioned above, were drilled in the NCS by Statoil and Norsk Hydro. Looking at wells drilled before the year 2000, the Wytch Farm in southern UK had the highest density of extended reach wells [14].

ERD records in the European region have been performed in the North Sea from installations like Statfjord (Statoil) [19], Gullfaks (Statoil) [20] and platforms in the Oseberg field (Norsk Hydro) [21]. In 2008 the Oseberg field's well B-47 held the world record drilled from an offshore location, drilled to 10.007 m MD. Visund's well A-6 had the world record from a floating vessel, drilled to 9082 m MD [22]. To maintain production and increase the oil recovery, the use of extended reach wells has become more and more common also in the North Sea. COP is currently drilling an ERW, Z-25, which is the focus of this thesis in the simulations performed in WellPlan presented in chapter 6.

3.3 Status on Extended Reach Drilling

The current world record for the world's longest measured depth ERD well is the ExxonMobil's Chayvo Z-40 drilled in April/May 2014 with a total measured depth of 13.000 m (42.651 ft.) [40], [41]. The well is located offshore at the Chayvo Field, Sakhalin Island, Russia. The step-out ratio is 5.2:1 (reach = 12.152 m (39.869 ft.) at 2336 m TVD (7664 ft.) [9], [40]. Exxon Neftegas Limited managed to complete this well in about only 60 days by using ExxonMobil's fast-drill technology in order to fully maximize the drilling process and economic recovery [42], [50].

The previous world record was held by the Chayvo Z-42 well (Exxon Neftegas Limited) drilled during 2012-2013 with a total measured depth of 12.700 m and 11.739 m horizontal departure [43] (Figure 72). Exxon Neftegas Limited managed to complete this well in 70 days by using the same technology as mentioned above (fast-drill) [42].

A previous record well in Qatar was Maersk's BD04A. It had a total measured depth of 12.292 m (40.320 ft.). The step-out ratio was 10.8:1 (reach = 11.571 m (37.956 ft.) at 1067 m TVD (3500 ft.). The well was spud to TD in less than 30 days, and they didn't get further down due to the fact that they ran out of pipe [9]!

As of October 2013, 16 of the 20 longest ERD wells in the world were drilled at the Sakhalin-1 project [43]. The Sakhalin-1 project includes the Chayvo, Odoptu, and Arkutun Dagi fields and is located off the northeast coast of Sakhalin Island, Russian Federation [40].

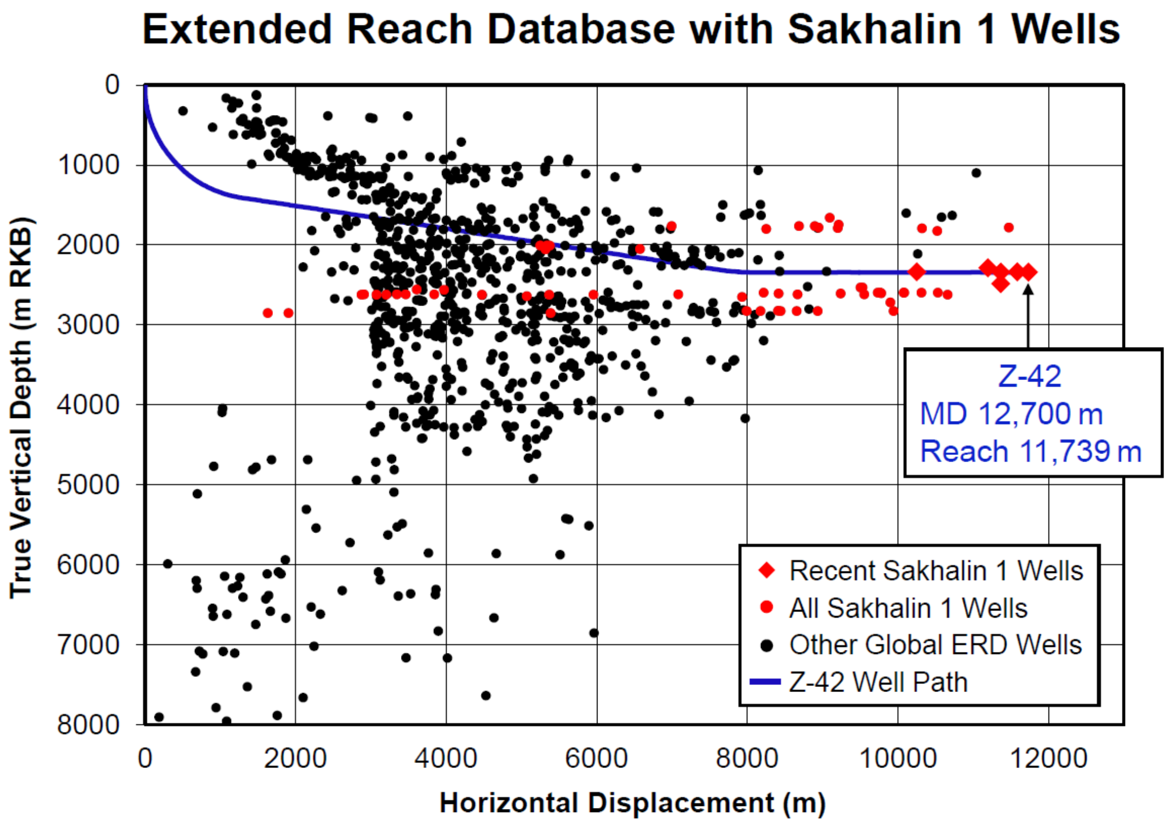


Figure 72: Extended-reach nose plot and well Z-42 (Held the measured depth world record from 2012-2013, 12.700 m) [44].

3.3.1 ERD – Where are we going and what is the limit?

If the downhole system was assumed frictionless, both in terms of mechanical friction and pressure loss (zero shear stresses), there would in theory be no limitations with regards to the length of the well. *"However, in the real world, there is no technology that can provide close to frictionless gliding systems, and eliminating the shear stresses in the drilling fluids would truly challenge the hole cleaning (which already is a big challenge itself) [14]"*.

British Petroleum published an article in 1998 [23], dicussing and elaborating on the limit of extended reach drilling and the assumed maximum length of a well. The aim was to answer the following question "Using ERD, how far can we drill using an existing rig and what is the impact of upgrading various rig components?"

BP's article concluded that the vertical depth of the reservoir strongly will influence the ultimate ERD achievements. For a shallow vertical ERD well with a 1500 m TVD, the theoretical departure limit is set at 18.300 m. For a deeper vertical ERD well with a 3000 m TVD, the theoretical departure limit is set at 14.000 m [14], [23].

BP introduced some ideas for future breakthroughs in order to push the ERD limit [23]:

- **Near Frictionless Drilling** by improving the mud lubricity and by applying drillpipe with low friction rollers or trying to use lighter materials like aluminum or titanium in ERW.
- **Enhanced Hole Cleaning** through the use of multi-stage downhole circulation subs.
- **Use Drag Reducing Agents** in order to reduce the pressure drops in pipelines and to optimize torque and drag.
- **Improved Downhole Real Time Analysis** in order to reduce and prevent downhole problems, especially important in long wellbores.
- **Non-Conventional Extended Reach Drilling.** The idea was to link two wellbores together by using active electromagnetic ranging tools.

Statoil's "ERD Well Design Technology Gap Analysis" [14] suggested some technologies that were proposed to increase the horizontal reach:

- ECD management tools (ECD reduction tools)
- Drillpipe fatigue measurement tools
- Improved drillpipe (fatigue, light weight)
- Improved transmission
- Better models of torque and drag
- Intermediate drilling liners (expandable casing)
- Swivel for rotation of liner
- Improved prediction of rock mechanics during drilling
- Floating equipment

All wells are feasible with existing technology; many are on hold for economic reasons and some are in the late stages of planning [9], [14].

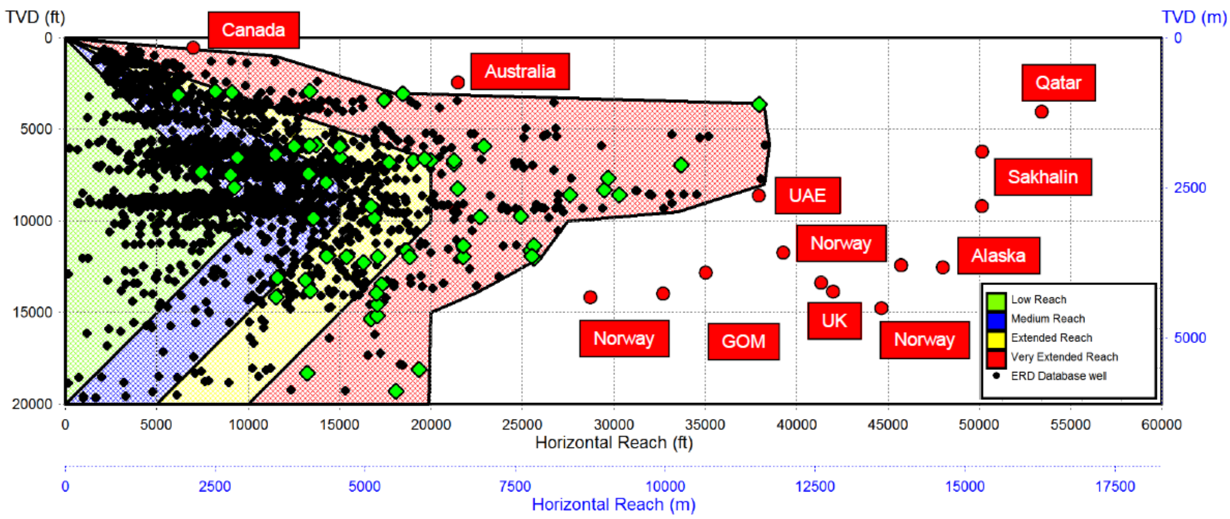


Figure 73: ERD – Where are we going from now on? [9].

3.4 Main challenges with ERD in general

The main challenges with ERD are summarized below:

1. Transferring weight on bit (WOB)
2. Buckling
3. Tensile limit on the drillstring during tripping out (POOH)
4. Surface torque limit on drillpipe/couplings
5. Rig capability
6. ECD in annulus for long wells
7. Hole cleaning
8. Pump pressure vs. flowrate requirement

4 Conoco Phillips ERD on Ekofisk

The Ekofisk 2/4 Zulu is a wellhead platform designed and constructed to carry out multiple simultaneous operations, such as production, drilling, well maintenance and well intervention activities [33]. It is connected to the Ekofisk complex by bridge and is monitored and remotely operated from the central control room on the 2/4 J platform [33]. If necessary, it can also be monitored and controlled from the company's onshore operations center in Tananger [33]. The well that will be analyzed in this thesis (Z-25) is represented by the black "vertical line" in Figure 74 on the following page.

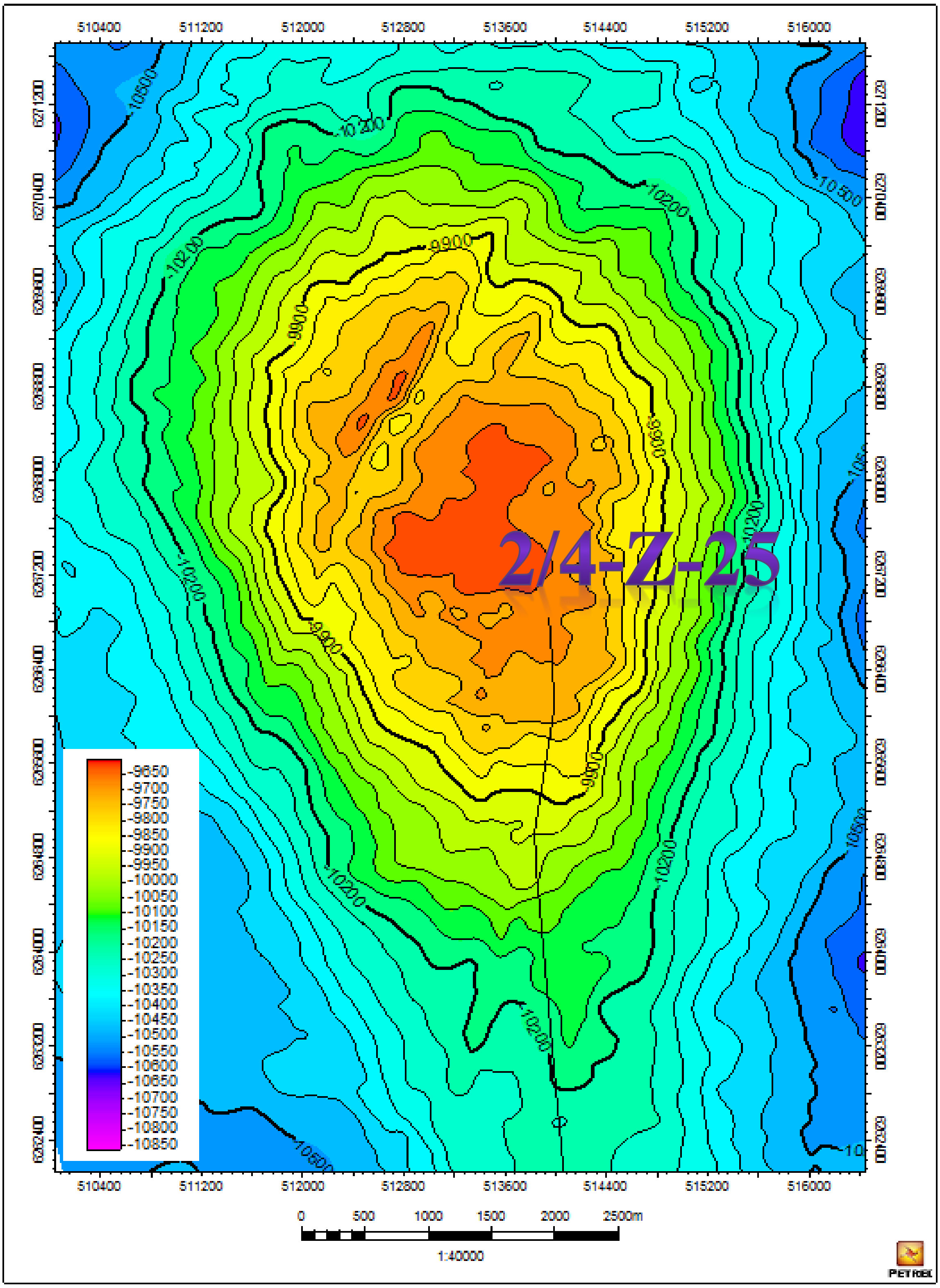


Figure 74: A map of the Ekofisk field created in Petrel. The box with different colors and numbers down left represents true depths. The black "vertical line" represents the well that will be analyzed in this thesis, Z-25.

4.1 The Ekofisk Field

The first oil field at the NCS, the Ekofisk Field, was discovered late in 1969 by the operator Phillips Petroleum Company (now ConocoPhillips) [29]. The production first started on June 9, 1971, when the Prime Minister, Trygve Bratteli, officially opened the field [31]. There are four producing fields in the Greater Ekofisk Area (which may consist of one or more installation each): Ekofisk, Eldfisk, Embla and Tor [27]. Today the Ekofisk field produces oil and gas corresponding to about 200.000 barrels of oil equivalents per day [31].

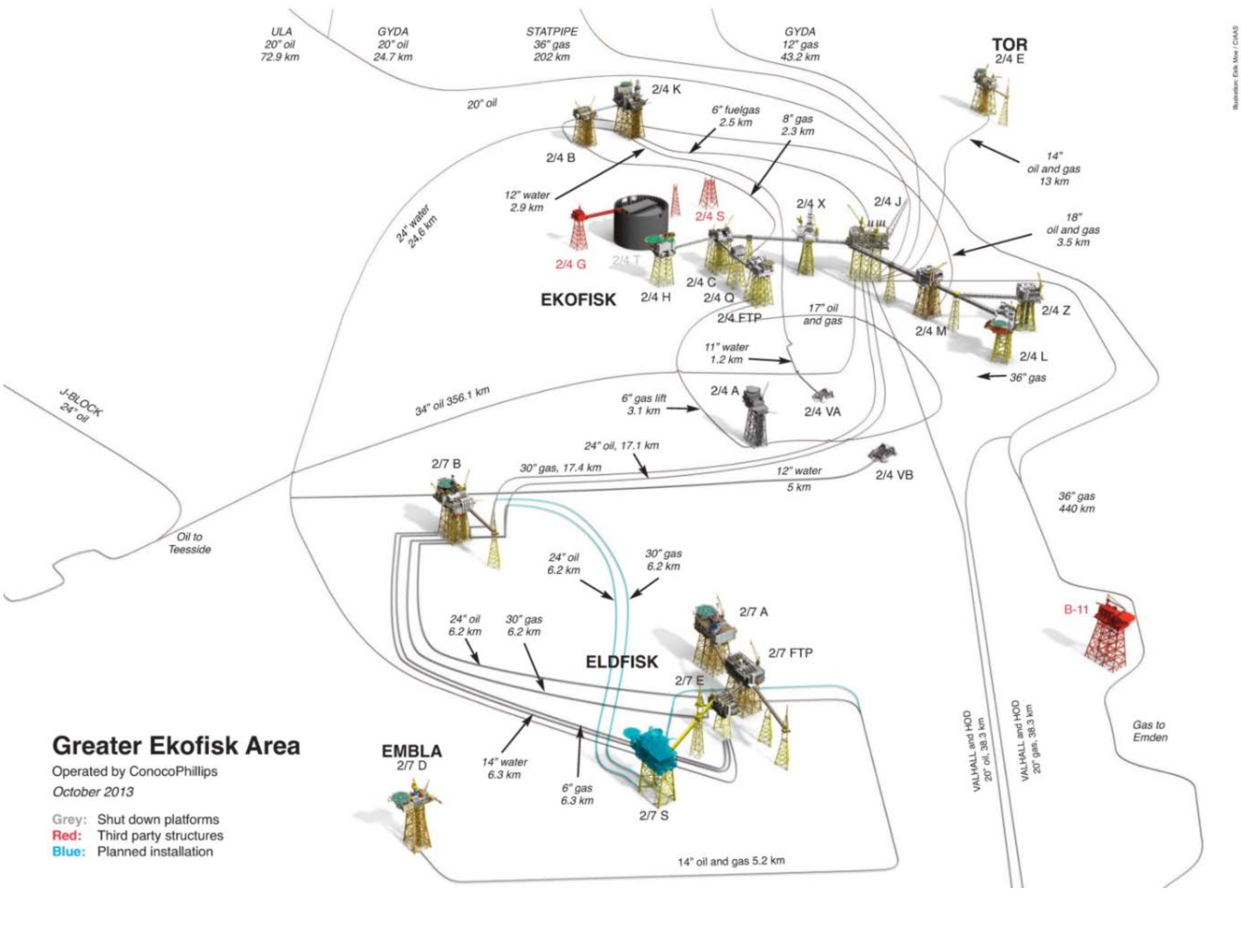


Figure 75: The Greater Ekofisk Area per October 2013. 'Photo credit: ConocoPhillips' [26].

Ekofisk South comprises a wellhead platform, the Ekofisk Zulu, operating 36 well slots including 35 for production and one dedicated to the reinjection of cuttings [30], [33]. The platform was installed during the summer of 2013 and started operation in October 2013 [33]. The subsea installation Victor Bravo, containing eight water injectors, provides water-drive supporting the producers at the Ekofisk Zulu Platform [34]. The wells at Ekofisk Zulu will be drilled by a jack up drilling rig placed next to the 2/4 Z-platform [33].

Figure 76: The Ekofisk 2/4 Z Platform. ‘Photo credit: ConocoPhillips’ [25].

4.2 Planned ER wells on Ekofisk – Well 2/4-Z-25

This section presents the geological overview for well Z-25 and is taken from both the geology chapter in [28] and from [35]. Well 2/4-Z-25 is planned as a Lower Ekofisk (EL) producer in the central part of the Ekofisk South area (Figure 77). The two Ekofisk Layers EA (Upper Ekofisk) and EM (Middle Ekofisk) will be drilled through, before ending up in the primary target that lies in the EL layer with an inclination of 89.75° [35].

The reservoir section of the planned well path is located between the 2/4-A-2 AT2 and 2/4-A-21 AT2 producers and the reservoir will be entered at 71° inclination. There are no active producers within 1000 ft. of the planned well path (as seen on Figure 77) [35].

The well 2/4-Z-25 is placed between two active injectors, 2/4-VB-7 H in Region 26 and 2/4-VB-5 HT5 in Region 25. The shortest distance between the well path and 2/4-VB-7H is 754 ft., and maximum distance of 1033 ft. to the west of the toe of the planned well. At the toe of the well the 2/4-VB-7H will be furthest from the path at 1033 ft. to the west. The injector to the east, 2/4-VB-5HT5, is 804 ft. from the heel of the well, which increases to 1115 ft. away to the east near the toe. Both injectors are perforated in the EL layer, and are expected to provide pressure support to the well [35].

The TD of the well is planned at ~25.758 ft. MD at 10.708 ft. TVD, giving a reservoir section of ~5500 ft. MD. In the reservoir the planned well path yields a maximum DLS of 3.0°/100 ft. [35], [36].

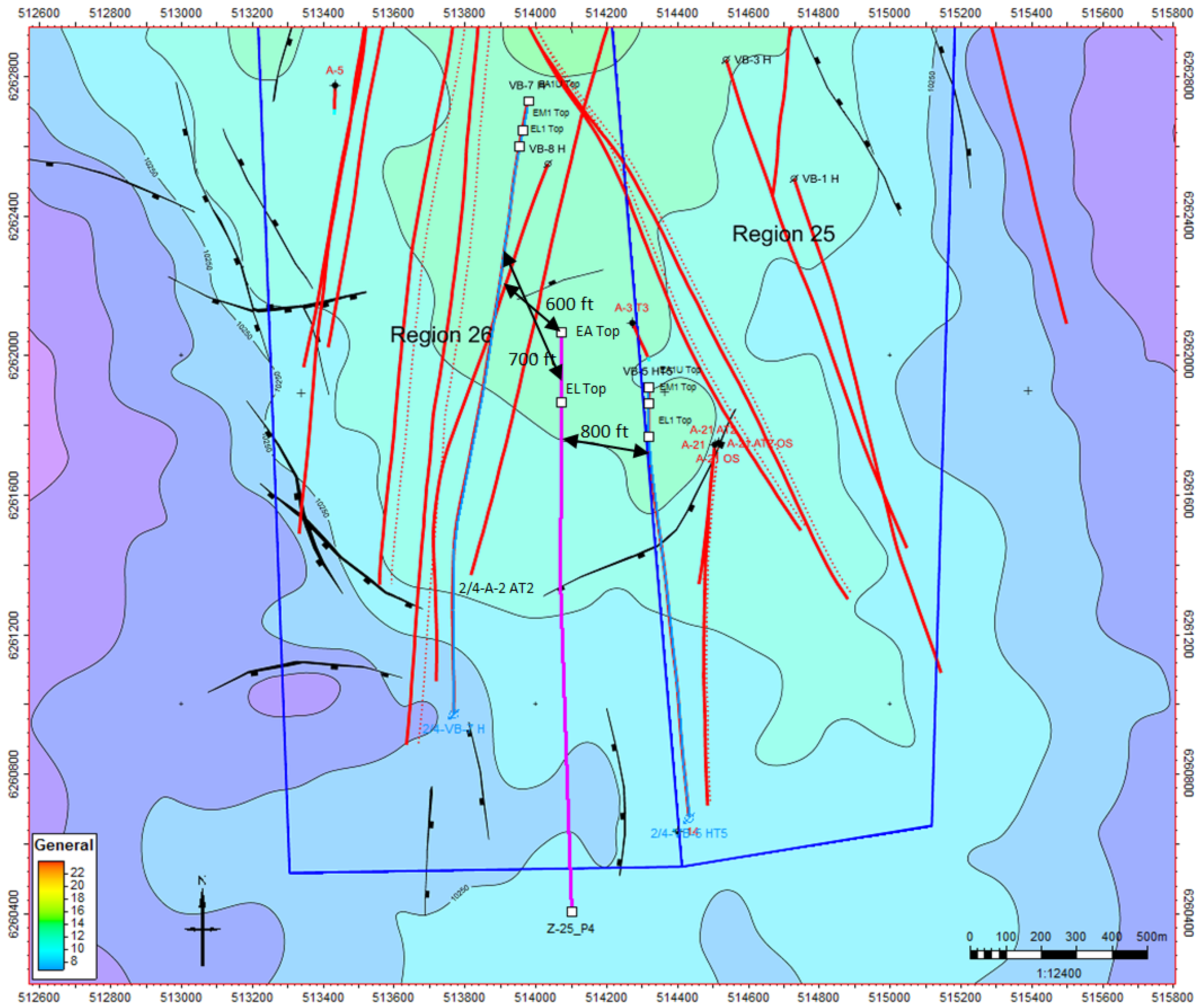
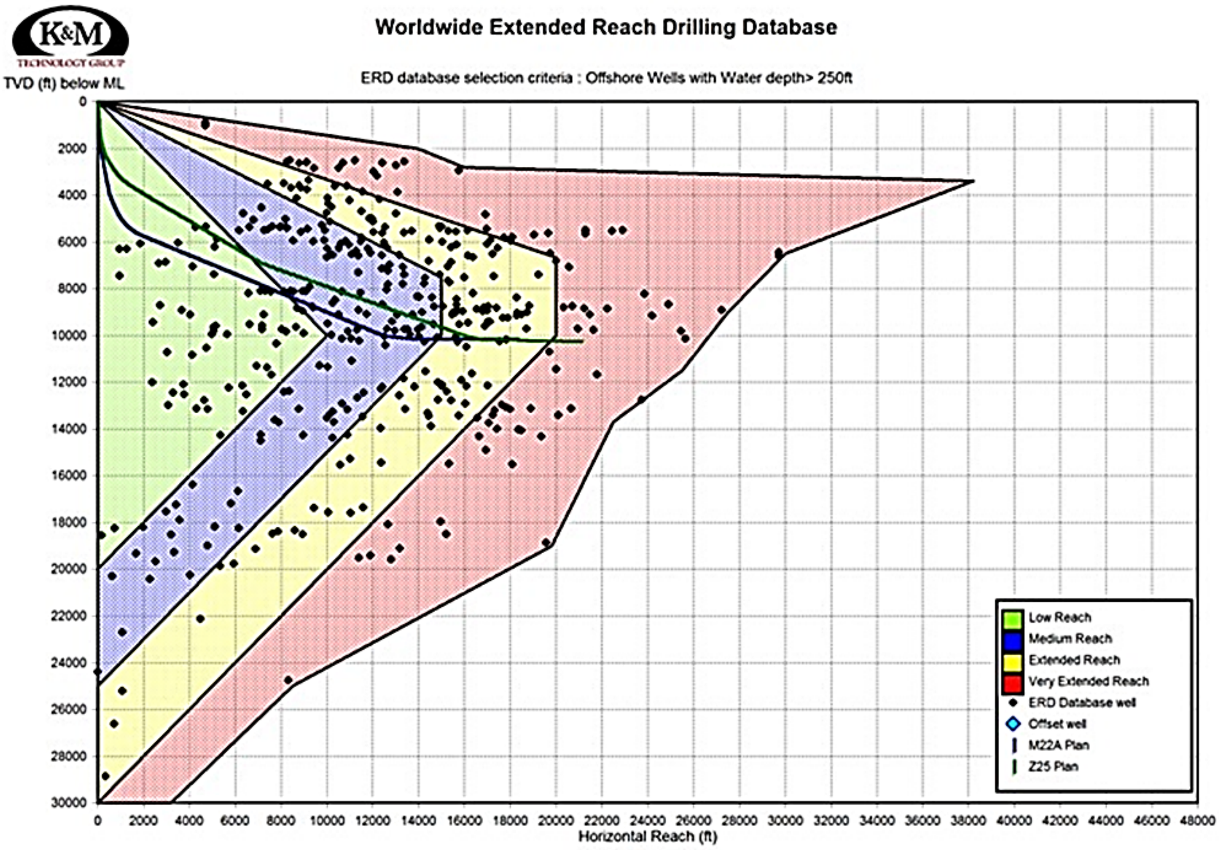


Figure 77: The planned well location and top Ekofisk horizon. 'Photo credit: ConocoPhillips' [35].



Z-25: 25,758’ MD at 10,708’ TVD

M22A: 24,073’ MD at 10,620’ TVD

Figure 78: Ekofisk ERD vs. Industry ERD. Z-25: 25.758 ft. MD at 10.708 ft. TVD [36].

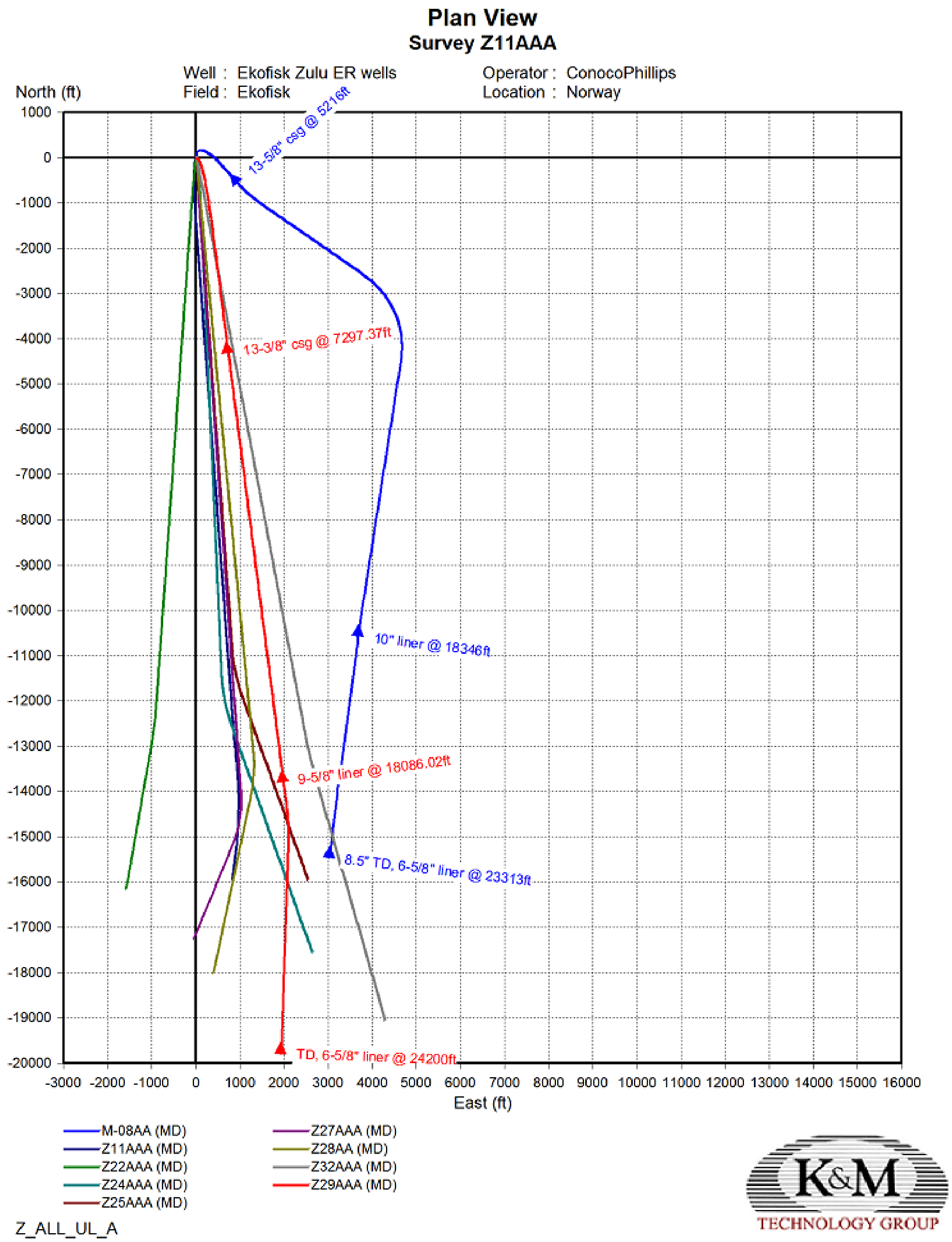


Figure 79: The above plot shows the proposed ERD wells of the Ekofisk Z platform. Most wells are relatively 2-dimensional, all drilled to the southern part of the field. For comparison, the M-08 well is shown in blue (M-08 is a well from "M" platform to be drilled in the near-future) [32].

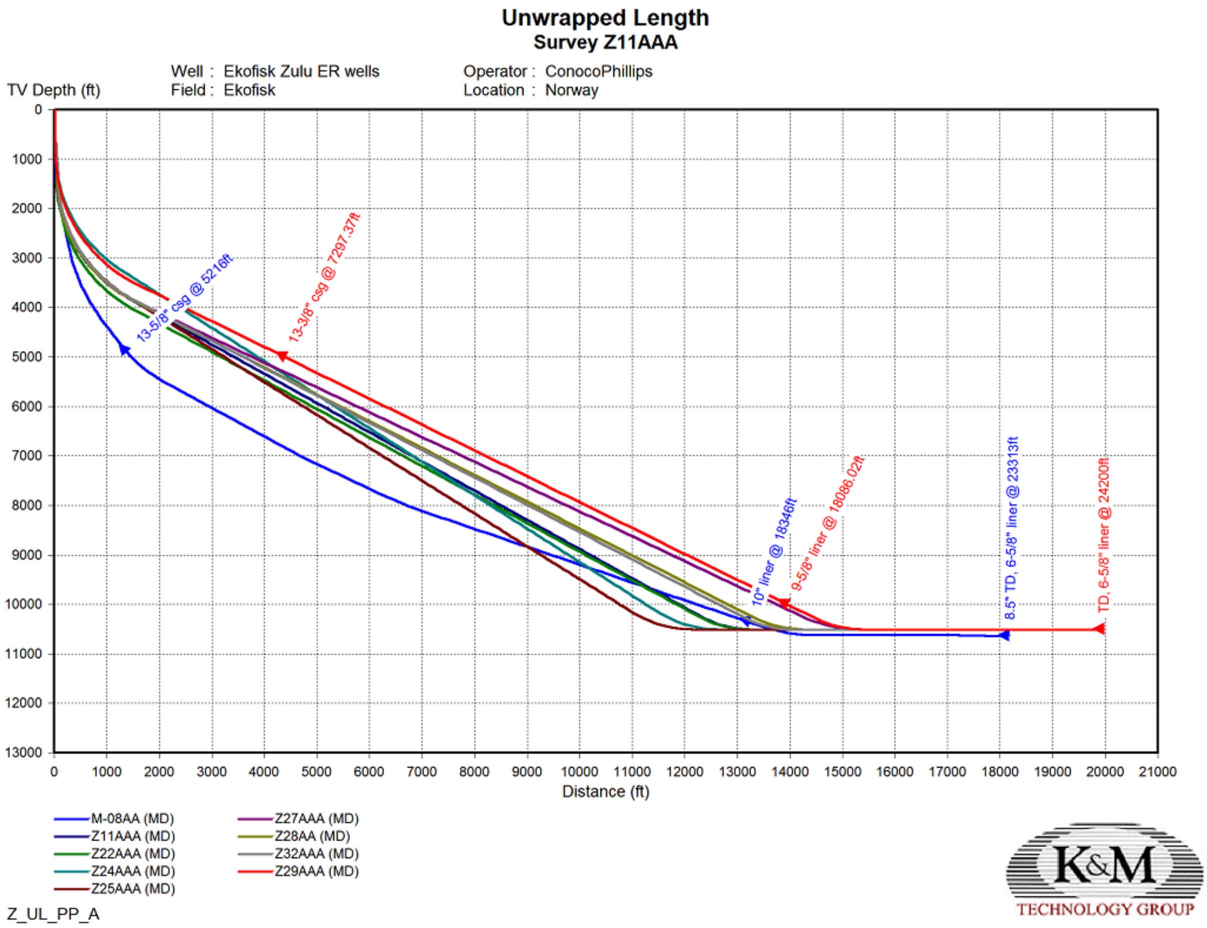


Figure 80: The above plot shows the proposed ERD wells of the from Ekofisk Z platform, in an unwrapped reach view [32].

4.3 Challenges with ERD in general on Ekofisk

The Ekofisk wells are not considered as 'extreme' ER compared to the industry standards. However, the geological and design complexities make this a potentially difficult project. This includes man-made abnormal pressure and subsidence issues, as well as planning for multiple sidetracks in the near future [32].

- Well design:
    - Containment: Are all barriers in place to avoid getting pressures and HC where we don't want them?
    - Slot recovery: Cement behind production casing to minimize time for P&A plugs in slot recovery or permanent P&A
    - Completion needs: Water shut-off capabilities, size, complexity

- Overburden challenges:
    - They are changing over time due to:
        - Subsidence (sinking of surface ground);
        - Gas issues (gas leakage through cap rock);
        - Drilling window near top of reservoir (depleted reservoir – the formation strength weakens due to reduction in pressure in the reservoir caused by production). The drilling window for the base case can be seen in Figure 88; the fracture gradient is the upper bound and the collapse pressure is the lower bound. When the collapse pressures are below the pore pressure, the pore pressure represents the lower bound of the safe drilling window [99];
        - Some unstable zones;
        - Drilling practice to avoid pack-offs;
        - Loss situations, connecting faults to a low pressure reservoir.

- Reservoir pressure:
    - Water floods make reservoir pressure predictions uncertain (may be a challenge)

4.4 Key challenges for drilling well Z-25

Generally

The key issues for drilling well Z-25 include hydraulics, well path and casing wear challenges.

Table 4 below shows the planned sections for well 2/4-Z-25 and Figure 81 shows the placement of the different casing/liner shoes and the planned inclinations. The drilling program for Z-25 begins at 24” x 20” conductor shoe (placed/set at 2055 ft. MD) [28].

Table 4: Planned sections for well Z-25 [28].

Drilling hole section	Casing/liner size	Shoe setting depth
17½” x 20”	17” liner	3298 ft. MD
16”	13⅝” production casing	6693 ft. MD
12¼” x 13½”	10¾” production liner	20.199 ft. MD
9½”	7⅝” reservoir liner	25.758 ft. MD

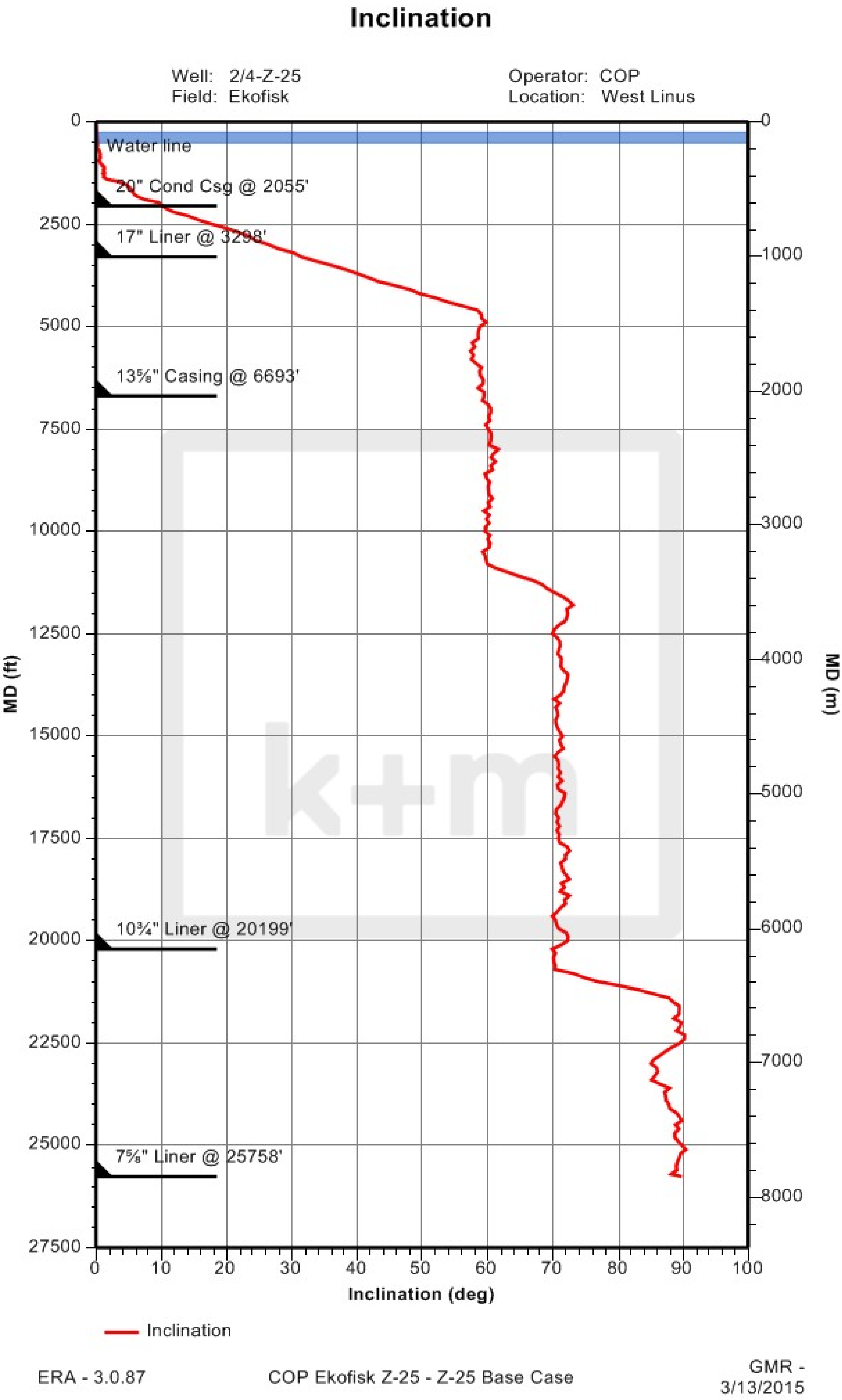


Figure 81: Z-25 Trajectory [9].

The two operations that will be further explained and simulated on in this thesis are “Drilling the 12¼” x 13½” hole section” and “Running the 10¾” production liner”. Listed below is a summary of the anticipated challenges for these two operations. The plan for drilling the 12¼” x 13½” hole and running the 10¾” liner will be presented in detail in section 5.3 and 5.4, respectively.

Drilling the 12¼” x 13½” hole section

- Hydraulics:
    - As for any ER well, hole cleaning is a key issue. Will the hole cleaning be effective/robust and optimized with WARP mud (designed for turbulent flow) at relatively low AV’s (annular velocities) in deviated wellbores?
    - Hole cleaning practices need to be fit-for-purpose. Avalanching of the cuttings bed is still possible at this angle, so all the drilling parameters should be controlled at all times
    - Fluid selection is important. The use of turbulent-type mud systems are appropriate for hole cleaning in large-hole sizes in ERW
    - ECD management becomes an issue when landing the well, and especially for the subsequent 10¾” liner run
    - Would drilling with conventional SBM and displacing to WARP for 10¾” liner run be more effective?

- Well path:
    - Very large side forces due to deep TVD
    - Torque and drag
    - Running the 10¾” liner string

- Casing wear:
    - Casing or DP wear is a critical issue in this section, with very high side loads/forces across the build section. This is especially important, given that future sidetracks are essential to the development strategy. The quality of the upper build needs to be very smooth, especially with the planned build rates

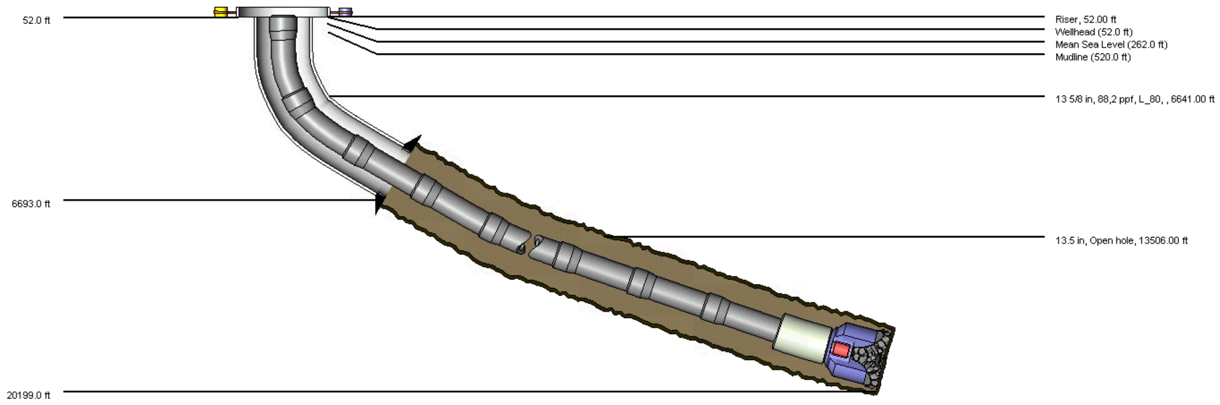


Figure 82: Well schematic for drilling the 12¼" x 13½" hole section [WellPlan].

Running the 10¾" production liner with use of 5½" HWDP as running string

- Hydraulics:
    - The surge ECD's exceed expected fracture gradient at the 13⅝" shoe (if the autofill does not work) – may be a problem. The autofill is a valve that basically cuts and/or reduces the formation surge pressures and is activated by a certain given pump rate (differential pressure). It allows the wellbore fluids to flow into the casing or liner while RIH, reducing both the fluid flow up the annulus and, as mentioned, the surge pressures [94]. The mud losses are reduced and you avoid damaging the formation.
    - There is a risk of swabbing below expected pore pressure and wellbore collapse while picking up
    - It is extremely important that the hole is fully clean before running the 10¾" liner, in order to reach TD, to be able to set the shoe at the required depth and to be able to pull the casing out of the hole (POOH). The shoe cannot be placed at a shallower depth due to a sensitive reservoir with reduced pressure and a fracture gradient that is smaller than normal

- Well path:
  - Friction challenges: Will the liner be able to slide to bottom? Running casing to target depth is one of the biggest challenges in ERD wells. Methods to help reaching target can be: floating casing, to run the casing as a liner (will be done on Z-25), and to apply top drive weight [1]
  - Will the 5½” HWDP be able to pick up the liner (enough yield strength)?

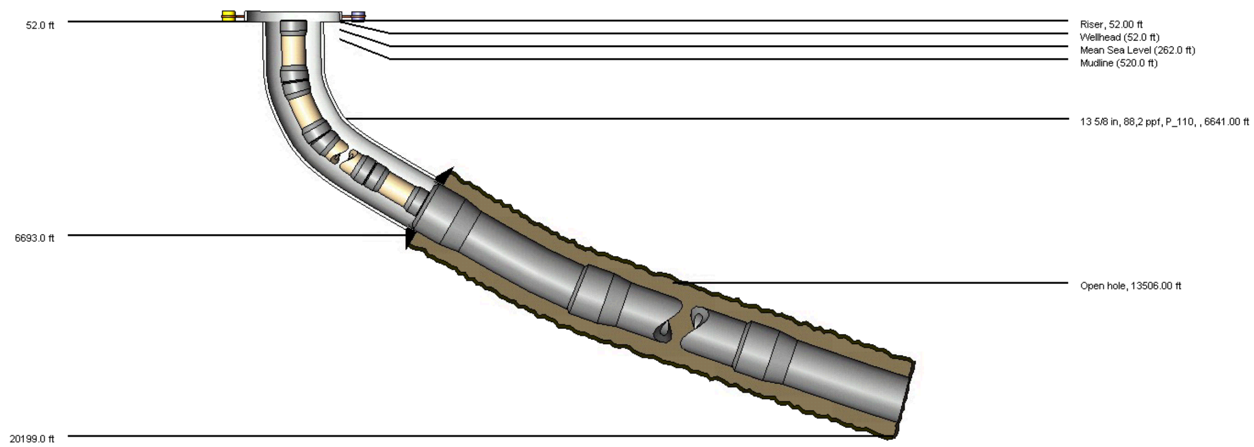


Figure 83: Well schematic for running the 10¾” production liner [WellPlan].

5 Basis for the simulations

The following chapter presents an introduction to the WellPlan software, the basis for the simulations performed in WellPlan and the plan for the relevant operations of the Z-25 well.

5.1 Halliburton Landmark Software & Services

The tables and graphs presented in chapter 6 were developed through simulations performed in WellPlan (using the hydraulics and T&D modules), in addition to Microsoft Excel. Section 5.1.1 presents a basic introduction to the software program and is directly taken from the user manual in WellPlan. The Soft String model and the Stiff String model are also explained in detail in section 2.4.1.1.

5.1.1 WellPlan

*“**WellPlan** software is a client-server engineering software system for drilling, completion, and well service operations. WellPlan software can be used at the rig site and in the office to provide integration between engineering functions.*

WellPlan software is based on a database and data structure common to many of Landmark’s drilling applications. This database is called the Engineer’s Drilling Data Model™ (EDM™) and supports the different levels of data that are required to use the drilling software. This is a significant advantage while using the software because of improved integration between drilling software products. Currently WellPlan, Compass, StressCheck and CasingSeat software use the common database and data structure.

Drilling oil and gas wells is a very complex and expensive proposition. Drilling costs generally account for a major capital expenditure for an operating company. In today’s competitive environment, companies are facing increasing numbers of technical challenges. Deepwater drilling, extended reach drilling, slim-hole drilling, and environmentally sensitive drilling areas are a few of these challenges. WellPlan software is the drilling engineering *software that provides you with the competitive edge to help solve your engineering problems during the design and operational phases for drilling and well completion.*

- ✓ ***Hydraulics Module:***

The Hydraulics module can be used to simulate the dynamic pressure losses in the rig's circulating system and to provide numerical tools to optimize hydraulics. Several rheological models, including Newtonian, Bingham Plastic, Power Law, Generalized Herschel-Bulkley, and Herschel Bulkley are provided. The rheological model chosen provides the basis for the pressure loss calculations.

You can chose to optimize hydraulics based on maximum hydraulic horsepower, maximum impact force, maximum nozzle velocity, or percent pressure loss at bit. You can also optimize hydraulics based on recorded pressure loss and flow rate data using Scott's method.

Hydraulics provides a quick means for you to determine the requirements you need to alter the existing fluid weight.

***A Hole Cleaning model** is also provided to assist for calculating the minimum flowrate when you evaluate cuttings build-up in an actual well. You can also use this model as a tool to help evaluate mud systems.*

✓ ***Torque Drag Module:***

The Torque Drag module can be used to predict the measured weights and torques that can be expected while:

- *Tripping in*
- *Tripping out*
- *Rotating on bottom*
- *Rotating off bottom*
- *Sliding drilling*
- *Back-reaming*

This information can be used to determine if the well can be drilled, or to evaluate what is occurring while drilling a well. This module can be used for analyzing drillstrings, casing strings, and liners.

Torque Drag is based on Dawson's cable model, or "Soft String" model as it is commonly known. The work-string is treated as an extendible cable with zero bending stiffness.

Friction is assumed to act in the direction opposing motion. The forces required to buckle the string are determined, and if buckling occurs, the mode of buckling (sinusoidal, transitional, helical, or lockup) is indicated.

Additionally, a Stiff String model is provided as an option. This model includes the increased side force from stiff tubulars in curved hole, as well as the reduced side forces from pipe wall clearance."

5.2 Z-25 general data inputs

All of the data that is presented in this section is the data that applies for the base case and is taken from the "*Drilling Program Ekofisk 2/4-Z-25.*" All of the simulations will be compared to this base case and the relevant parameters will be changed according to the various objectives listed in detail in chapter 6.

Table 5: General well data for Z-25 [28].

Quadrant/block	2/4
Platform	Zulu
Well number	25
Well name	Z-25
Well type	Producer – Horizontal Ekofisk EL2
Production license	018
Start date	25.03.2015
Operator	COP
Rig name	West Linus
Drilling contractor	North Atlantic Drilling
Rig capacity	2200 kip (kilo pound)
Rig floor evaluation	259.7 ft. MSL
Water depth	260.3 ft. MSL
RKB – Mudline	520.0 ft. MSL
Total depth	25.758 ft. MD 10.708 ft. TVD

TVD = 10.708 ft.

MD = 25.758 ft.

Using equation (2) presented in section 2.3.1 gives a depth ratio/step-out ratio of:

$$\text{Depth ratio (step} - \text{out)} = \frac{\text{MD}}{\text{TVD}} = \frac{25.758 \text{ ft.}}{10.708 \text{ ft.}} = 2.40549122152$$

The depth ratio for well Z-25 is thus greater than 2, which implies that this is an extended reach well (according to the definition introduced in section 3.1).

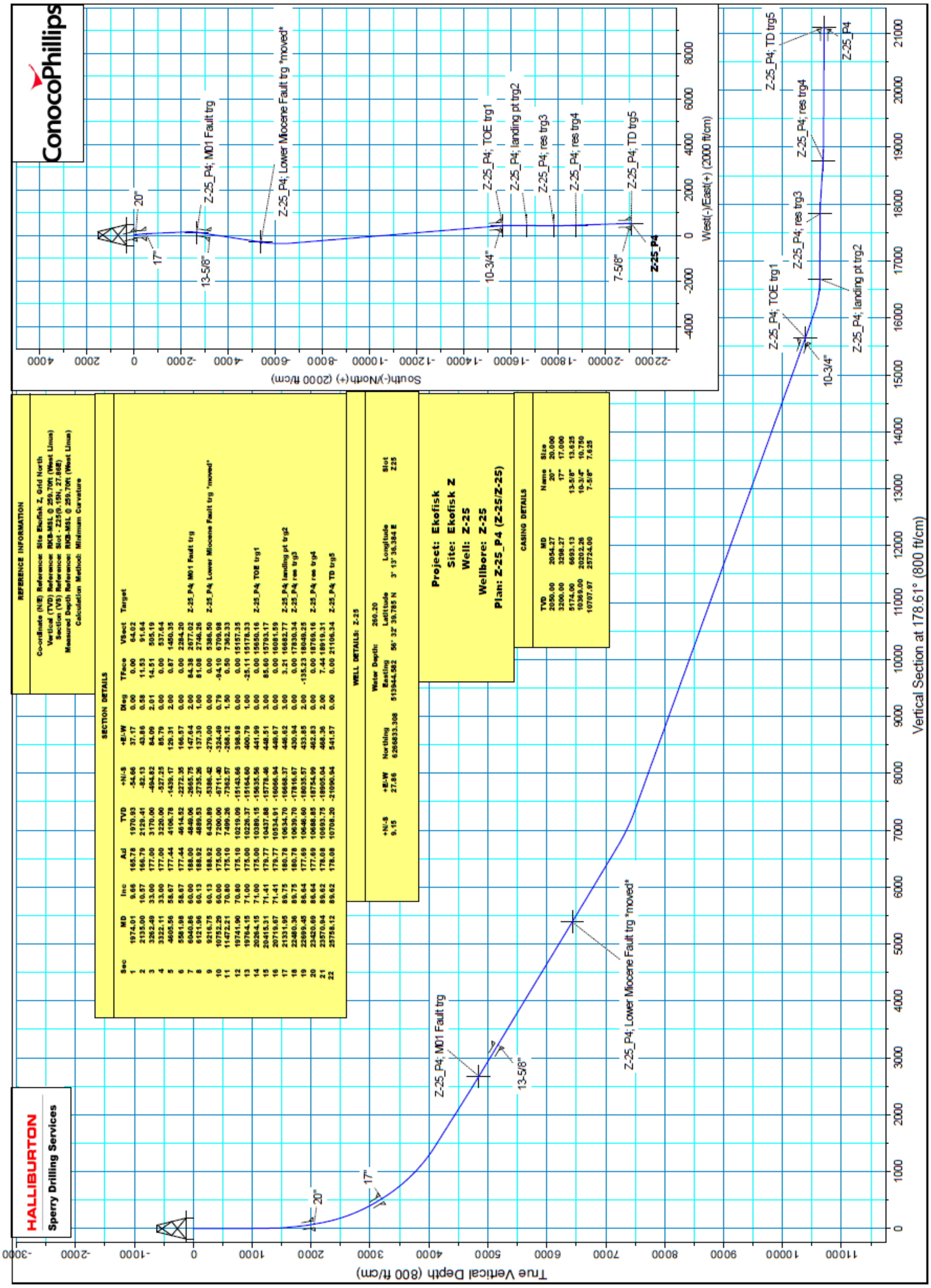


Figure 84: Well profile for Z-25 [28].

Table 6: Fluid editor for well Z-25 [WellPlan].

Fluid	14.6 ppg WARP OBM MI Swaco
Type	Non Spacer
Mud Base Type	Synthetic
Base Fluid	WARP
Rheology Model	Herschel-Bulkley
Rheology Data	Fann Data
Planned MW @ drill-out	14.6 ppg
Planned MW @ TD	14.6 ppg
Planned drilling ECD @ shallow shoe	15.1 ppg EMW

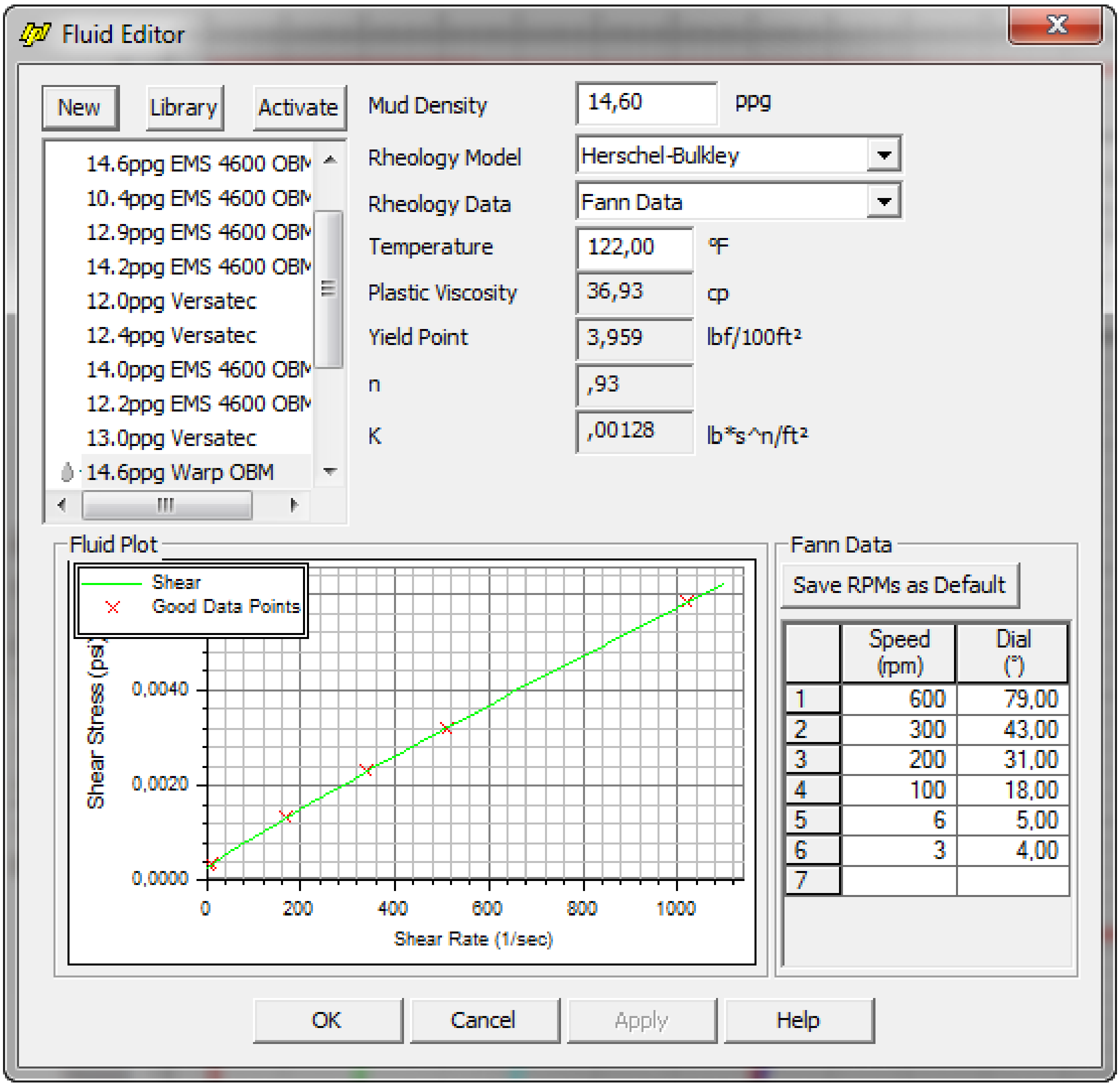


Figure 85: Mud properties (MI Swaco) [WellPlan].

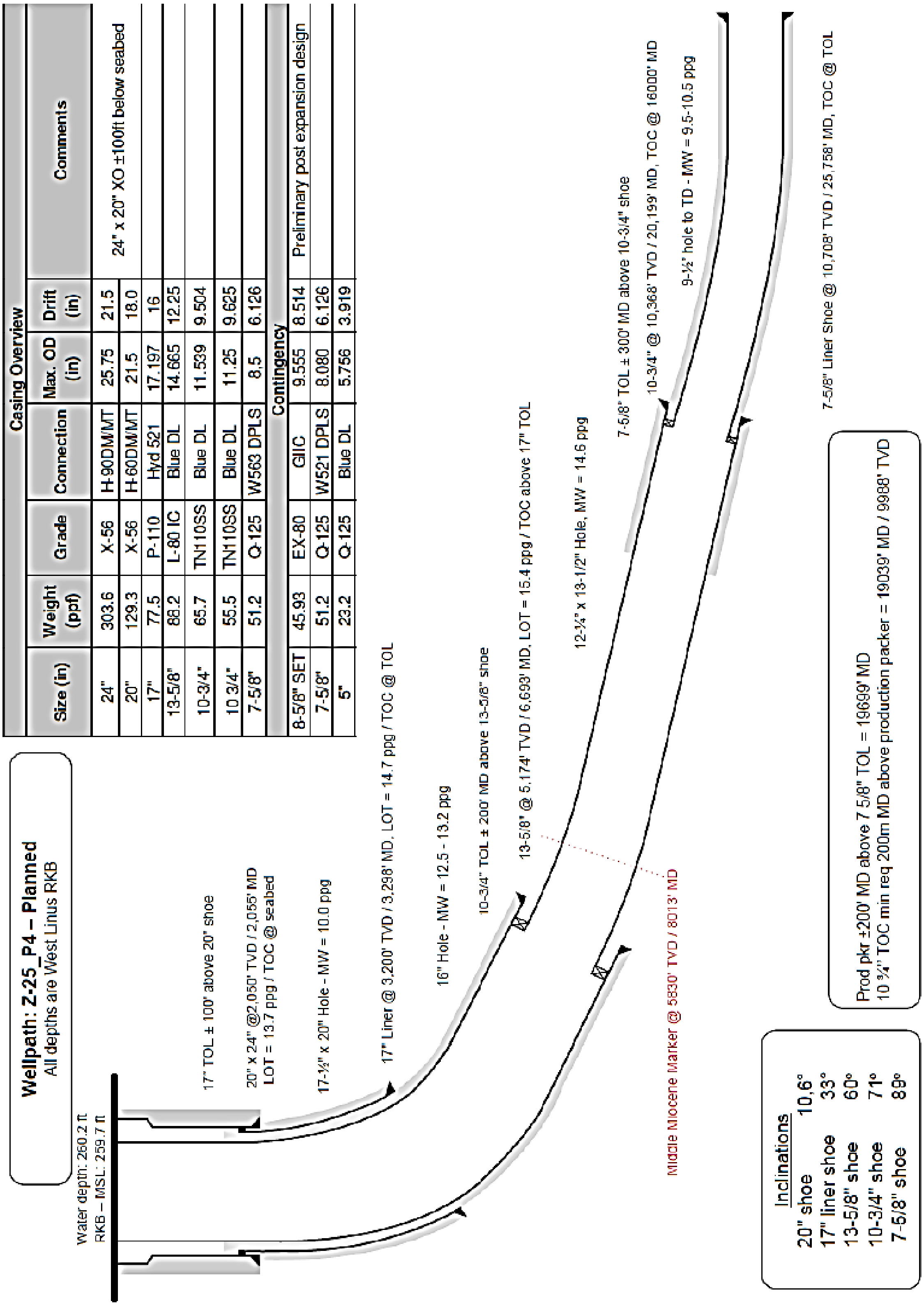
5.3 Plan for drilling the 12¼” x 13½” hole section – The base case

COP’s plan for the 12¼” x 13½” hole is to drill the wellbore with a 12¼” PDC bit and under-ream to 13½” hole while drilling (i.e. in the same operation) to planned section TD with maximum flow and 180 rpm [28]. The 13⅝” casing shoe (for the 16” hole & 13⅝” production casing section (previous section)) is placed at 6693 ft. MD, open hole from here and beyond to TD at 20.199 ft. MD (10.369 ft. TVD). The ID for the cased section is hence constant 12,375” and same for all simulated scenarios down to this point (the values are the same down to the 13⅝” casing shoe). The inclination and azimuth for the various measured depths can be seen in Figure 86 and the well schematic (including lengths and inclinations at the shoe for the different sections) for Well Z-25 can be seen in Figure 87. A detailed table showing the MD, inclination, azimuth, TVD and DLS for the whole base case can be found in the appendix (Table 16).

Measured Depth (ft)	Inclination (°)	Azimuth (°)	Vertical Depth (ft)	+N/-S (ft)	+E/-W (ft)	Dogleg Rate (°/100ft)	Build Rate (°/100ft)	Turn Rate (°/100ft)	TFO (°)	Target
1,974.01	9.66	165.78	1,970.93	-54.66	37.17	0.00	0.00	0.00	0.00	
2,135.00	10.57	166.79	2,129.41	-82.13	43.86	0.58	0.57	0.63	11.53	
3,262.49	33.00	177.00	3,170.00	-494.82	84.09	2.01	1.99	0.91	14.51	
3,322.11	33.00	177.00	3,220.00	-527.25	85.79	0.00	0.00	0.00	0.00	
4,605.56	58.67	177.44	4,106.78	-1,439.17	129.31	2.00	2.00	0.03	0.87	
5,581.98	58.67	177.44	4,614.52	-2,272.35	166.57	0.00	0.00	0.00	0.00	
6,040.86	60.00	188.00	4,849.06	-2,665.75	147.64	2.00	0.29	2.30	84.38	Z-25_P4; M01 Fault tr
6,121.96	60.13	188.92	4,889.53	-2,735.26	137.30	1.00	0.16	1.14	81.08	
9,216.75	60.13	188.92	6,430.89	-5,386.42	-279.00	0.00	0.00	0.00	0.00	Z-25_P4; Lower Mioc
10,752.29	60.00	175.00	7,200.00	-6,711.40	-324.49	0.79	-0.01	-0.91	-94.10	
11,472.21	70.80	175.10	7,499.26	-7,362.57	-268.12	1.50	1.50	0.01	0.50	
19,741.90	70.80	175.10	10,219.09	-15,143.66	398.98	0.00	0.00	0.00	0.00	
19,764.15	71.00	175.00	10,226.37	-15,164.60	400.79	1.00	0.91	-0.45	-25.11	
20,264.15	71.00	175.00	10,389.15	-15,635.56	441.99	0.00	0.00	0.00	0.00	Z-25_P4; TOE trg1
20,415.31	71.41	179.77	10,437.88	-15,778.46	448.51	3.00	0.27	3.16	85.60	
20,719.67	71.41	179.77	10,534.91	-16,066.94	449.67	0.00	0.00	0.00	0.00	
21,331.95	89.75	180.78	10,634.70	-16,668.37	446.62	3.00	3.00	0.17	3.21	Z-25_P4; landing pt tr
22,480.36	89.75	180.78	10,639.70	-17,816.67	430.94	0.00	0.00	0.00	0.00	Z-25_P4; res trg3
22,699.45	86.64	177.69	10,646.60	-18,035.57	433.85	2.00	-1.42	-1.41	-135.23	
23,420.69	86.64	177.69	10,688.85	-18,754.99	462.83	0.00	0.00	0.00	0.00	Z-25_P4; res trg4
23,570.95	89.62	178.08	10,693.75	-18,905.05	468.36	2.00	1.98	0.26	7.44	
25,758.12	89.62	178.08	10,708.20	-21,090.95	541.57	0.00	0.00	0.00	0.00	Z-25_P4; TD trg5

Figure 86: Inclination and azimuth for well Z-25 [28].

Well Schematic



Size (in)	Weight (ppf)	Grade	Connection	Max. OD (in)	Drift (in)	Comments
Casing Overview						
24"	303.6	X-56	H-90DM/MT	25.75	21.5	24" x 20" XO ±100ft below seabed
20"	129.3	X-56	H-60DM/MT	21.5	18.0	
17"	77.5	P-110	Hyd 521	17.197	16	
13-5/8"	88.2	L-80 IC	Blue DL	14.665	12.25	
10-3/4"	65.7	TN110SS	Blue DL	11.539	9.504	
10 3/4"	55.5	TN110SS	Blue DL	11.25	9.625	
7-5/8"	51.2	Q-125	W563 DPLS	8.5	6.126	
Contingency						
8-5/8" SET	45.93	EX-80	GIIC	9.555	8.514	Preliminary post expansion design
7-5/8"	51.2	Q-125	W521 DPLS	8.080	6.126	
5"	23.2	Q-125	Blue DL	5.756	3.919	

Figure 87: Well Schematic for well Z-25 [28].

ERD focuses while drilling the 12¼" x 13½" hole [28]:

- Hole cleaning
- ROP
- ECD management
- Mud consumption tracking
- Torque & drag monitoring
- Evaluate real-time pore pressure prediction
- Mud-logging service
- Avoid high DLS (dog leg severity)
- Avoid pack-offs

Table 7: BHA summary table for drilling the 12¼" x 13½" hole [28].

Flow	1100 gpm @ top 1025 gpm @ TD
Estimated SPP @ TD	6404 psi
MWD range	14.6 ppg: 650-1370 gpm 14.8 ppg: 650-1350 gpm
TD ream type	TDR1200 Ball activated
TD ream – flowrate to activate	450 gpm to chase the balls down. The flow after the ball is landed is limited by the SPP
TD ream – max flow prior to activation	1100 gpm
Under-ream gauge	13½"
Bit	12¼" PDC
Bit nozzle configuration	Nozzles = 9 x 14 TFA = 1.353 in^2

Table 8: String editor for the 12¼” x 13½” hole [WellPlan].

String Name: 2_4-Z-25_0400_12_25 x 13_5 ins_Rev1_ BHA_new

String (MD): 20199.0 ft Specify: Top to Bottom Import String

	Section Type	Length (ft)	Measured Depth (ft)	OD (in)	ID (in)
1	Drill Pipe	19542.75	19542.7	5.875	5.045
2	Drill Collar	4.00	19546.7	8.000	4.250
3	Heavy Weight	157.50	19704.2	6.625	4.500
4	Jar	30.00	19734.2	8.125	3.000
5	Heavy Weight	94.50	19828.7	6.625	4.500
6	Jar	29.00	19857.7	8.125	3.000
7	Heavy Weight	189.00	20046.7	6.625	4.500
8	Drill Collar	3.00	20049.7	8.000	3.000
9	Stabilizer	7.86	20057.6	8.000	3.000
10	Drill Collar	30.00	20087.6	6.750	3.000
11	Underreamer	14.83	20102.4	10.000	2.800
12	MWD	14.36	20116.8	8.000	1.920
13	MWD	1.80	20118.6	8.000	3.250
14	MWD	7.83	20126.4	8.000	2.375
15	MWD	4.37	20130.8	8.000	2.375
16	Stabilizer	7.53	20138.3	8.000	2.375
17	MWD	12.19	20150.5	8.000	2.375
18	MWD	4.98	20155.5	8.000	2.375
19	MWD	1.88	20157.4	8.000	3.250
20	Drill Collar	9.20	20166.6	6.750	3.500
21	MWD	7.16	20173.7	8.219	2.370
22	Stabilizer	8.04	20181.8	9.625	2.375
23	Drill Collar	10.07	20191.8	9.625	2.375
24	Stabilizer	3.64	20195.5	9.625	2.375
25	MWD	2.52	20198.0	8.000	2.750
26	Bit	0.99	20199.0	12.250	

Table 9: Hole section for the 12¼” x 13½” hole and the 10¾” liner [WellPlan].

	Section Type	Measured Depth (ft)	Length (ft)	ID (in)	Drift (in)	Effective Hole Diameter (in)	Friction Factor	Linear Capacity (bbl/ft)	Item Description
1	Riser	52.0	52.00	18.750				0.3415	Riser
2	Casing	6693.0	6641.00	12.375	12.250	12.375		0.1488	13 5/8 in, 88.2 ppf, P_110,
3	Open Hole	20199.0	13506.00	13.500		13.500	0.30	0.1770	Open hole

5.4 Plan for running the 10¾" production liner – The base case

RIH with 10¾" liner (into the 13½" hole section) on 5½" HWDP to 1 stand off bottom. Table 10 and Table 11 below show the pipe body data and the string editor for the 10¾" production liner.

Table 10: Pipe body data for the 10¾" Tenaris Hydril liner [28].

Nominal OD	10.750 in.
Nominal ID	9.560 in.
Plain End Weight	64.59 lbs./ft.
Nominal Weight	65.70 lbs./ft.
Wall Thickness	0.595 in.
Standard Drift Diameter	9.404. in.
Special Drift Diameter	9.504 in.
Body Yield Strength	2088 x 1000 lbs.
Internal Yield	10650 psi
Collapse	7500 psi

Table 11: String editor for the 10¾" liner [WellPlan].

String Name: 2_4-Z-25 10-3/4" Liner_5-1/2" HWDP landing string

Export

String (MD): 20199.0 ft   Specify: Top to Bottom   Import String

Import

	Section Type	Length (ft)	Measured Depth (ft)	OD (in)	ID (in)	Weight (ppf)	Item Description
1	Heavy Weight	6493.00	6493.0	5.500	3.500	56.42	Heavy Weight Drill Pipe, 5,500 in, 56,42 ppf, AISI 4145H MOD, 5-1/2" FH
2	Drill Pipe	13706.00	20199.0	10.750	9.560	65.70	Drill Pipe 10.75 in, 65.7 ppf, TN-110 SS, Blue SC, NEW

5.5 Base case well path graphs

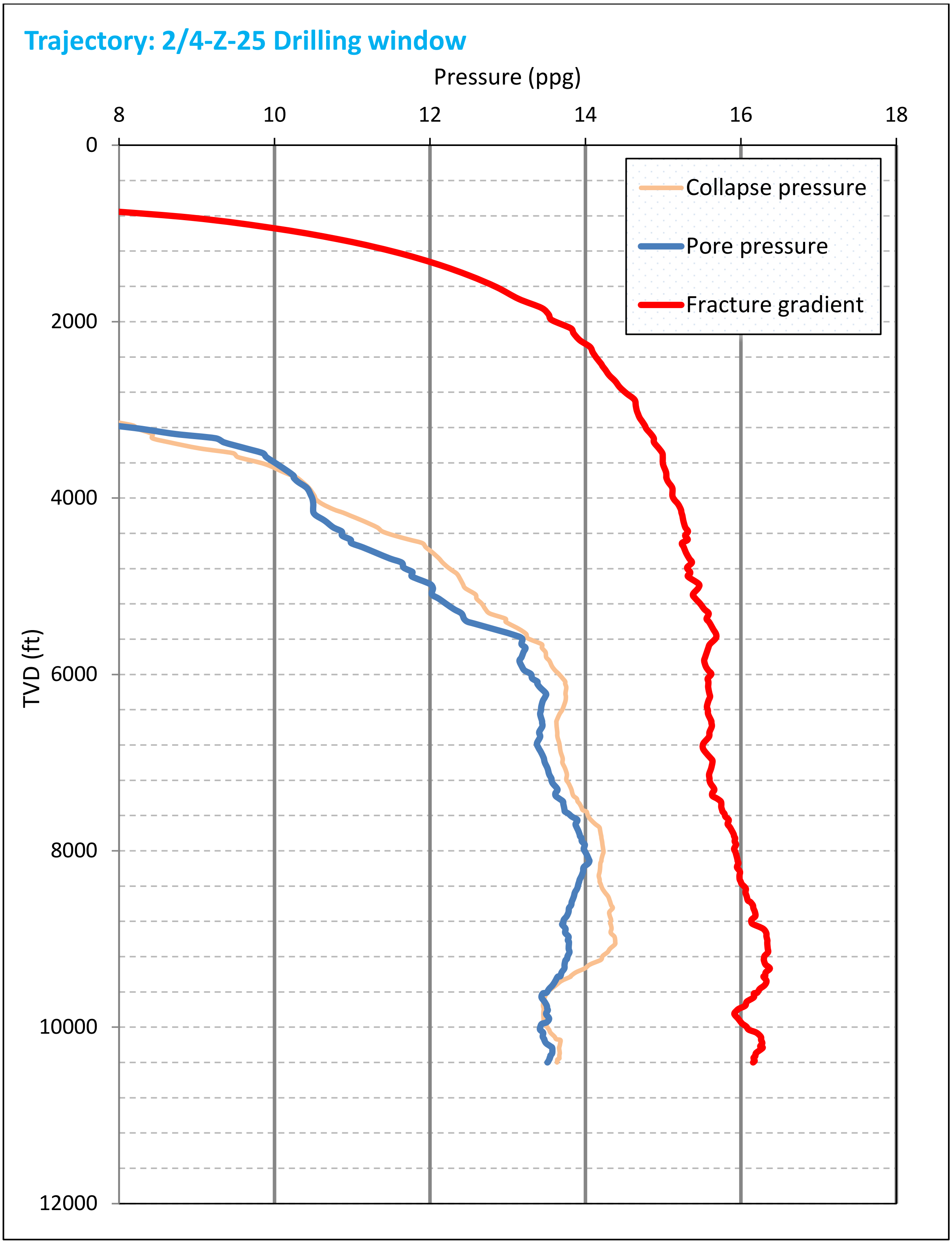


Figure 88: Drilling window: TVD (RKB) vs. expected collapse pressure, pore pressure and fracture gradient [28].

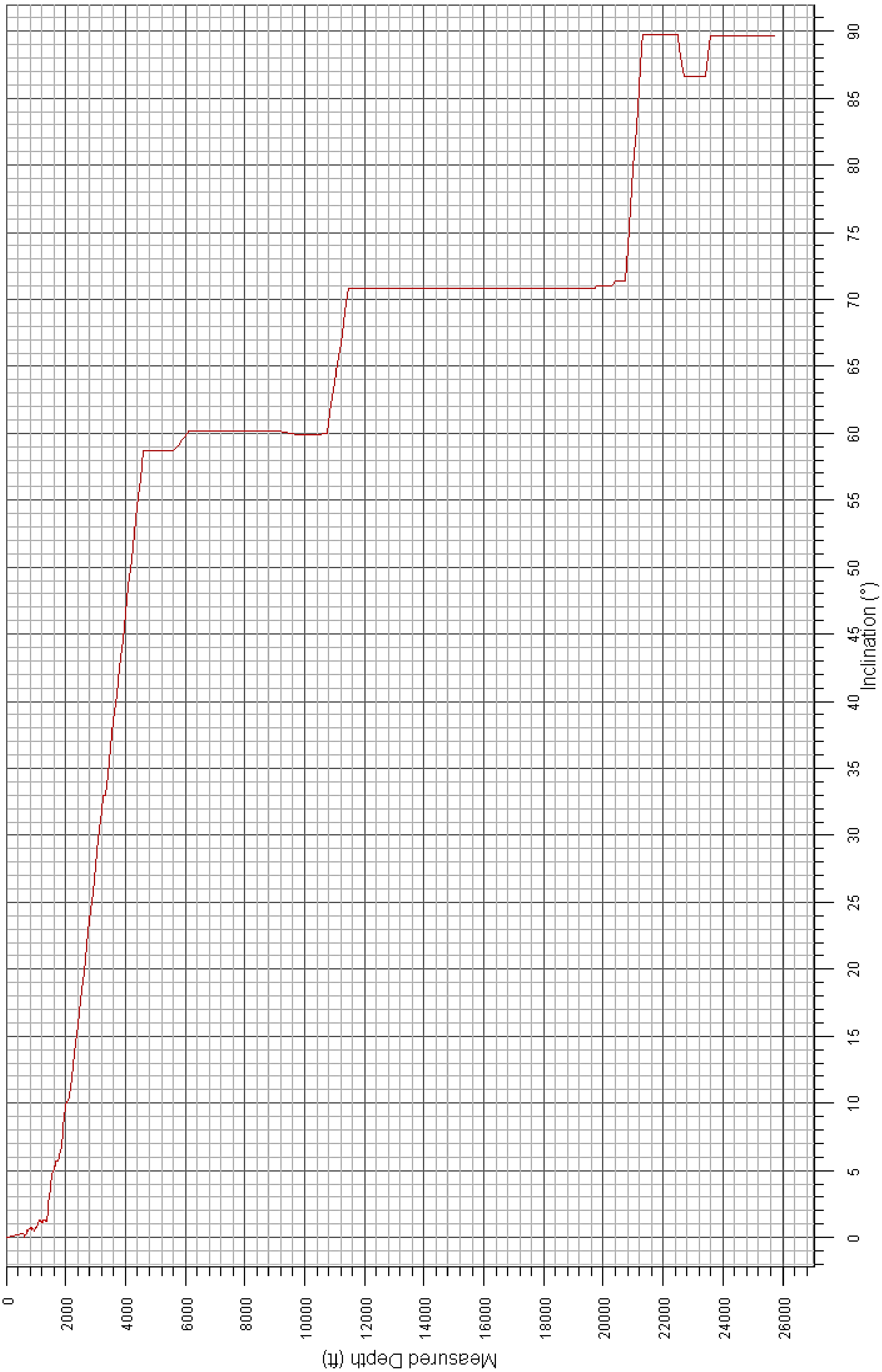


Figure 89: Well path inclination base case [WellPlan].

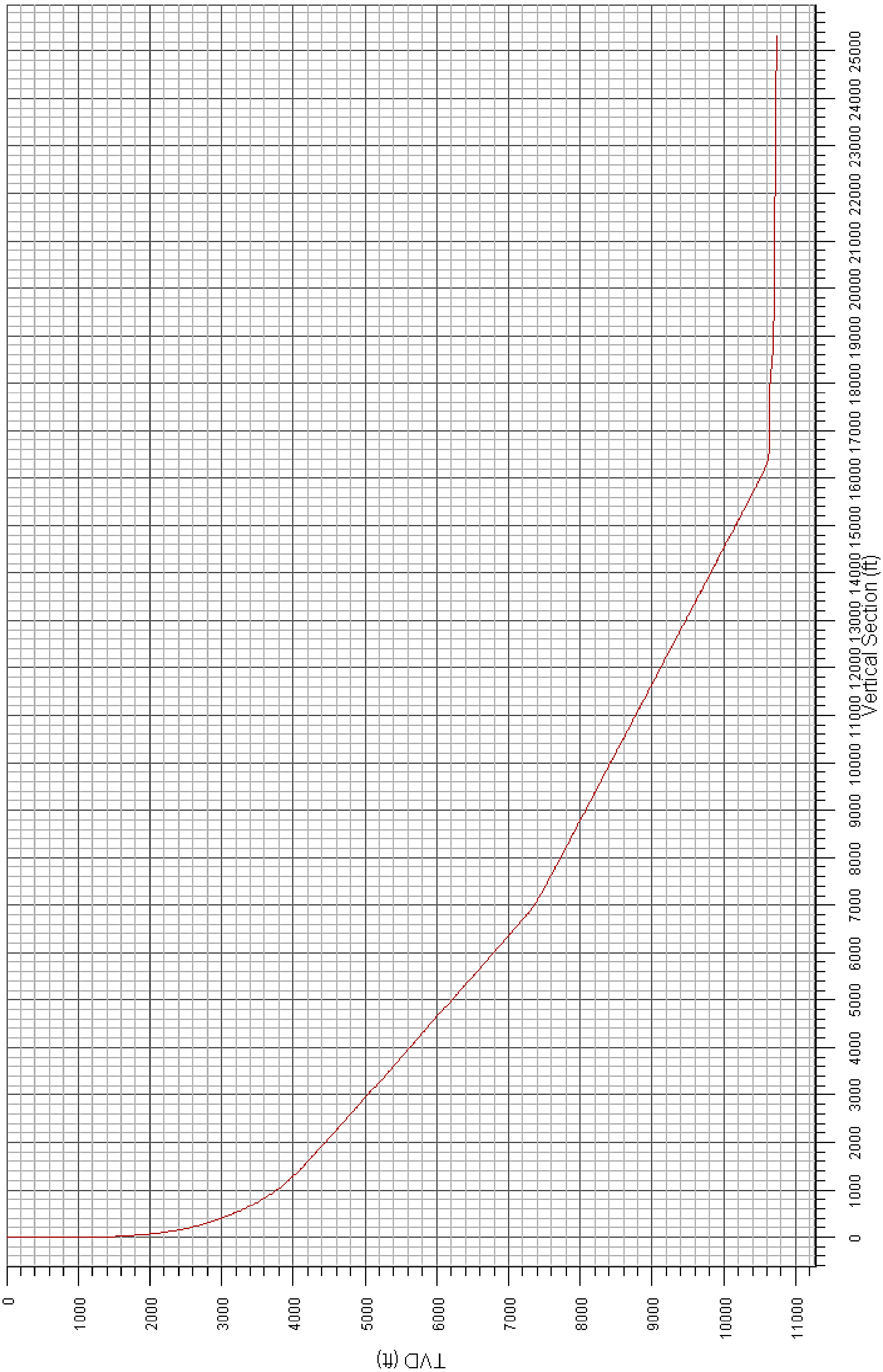


Figure 90: Well path vertical section base case [WellPlan].

6 Results and discussion

The following chapter presents the results from the simulations done in WellPlan and includes discussion and evaluation of the results. N.B. The simulations involve comparing various hole/wellbore sizes ranging from 12¼” to 15” (i.e. changing the size of the under-reamer). The following hole sizes are used:

- 12¼”
- 12½”
- 12¾”
- 13”
- 13¼”
- 13½”
- 13¾”
- 14”
- 14¼”
- 14½”
- 14¾”
- 15”

Hole size 12¼” and 15” are “the most critical” (the extreme) ones in conjunction with the base case, 13½”. The minimum pump rate used in the simulations is 600 gpm and the maximum rate used is 1100 gpm (increment pump rate 100 gpm). The surface equipment working pressure is 7000 psi in each simulation.

The following Table 12, Table 13 and Table 14 show the different simulations performed in WellPlan and their objective. The overall objective for all the simulations is to study the effect of varying hole size in the 12¼” x 13½” hole section.

Table 12: Drilling the 12¼” x 13½” hole section.

Simulation	Objective
WOB to induce sinusoidal buckling	Observe how the minimum WOB to induce sinusoidal buckling at any point in the drillstring for a range of bit depths changes with varying hole size
WOB to induce helical buckling	Observe how the minimum WOB to induce helical buckling at any point in the drillstring for a range of bit depths changes with varying hole size
Surface torque	Observe the maximum torque found at the surface/a point in the drillstring vs. the make-up torque limit and how it changes with varying hole size
Hook load	Observe how varying hole size affects the string load, also including rig capacity and yield limits
ECD	Observe how the ECD progresses with depth and varying holes size
Bed height (annular velocity)	Observe how the bed height of the cuttings in annulus changes with both increasing wellbore inclination and flowrate
Annular velocity	Observe how the velocity of the fluid in the annulus changes along the string and for a range of flowrates and hole sizes
Minimum flowrate	Observe how the minimum (critical) flowrate required to remove cuttings beds during drilling evolves with both increasing wellbore inclination and flowrate
Suspended volume	Observe how the suspended volume of cuttings evolves with both increasing wellbore inclination and flowrate

Table 13: Running the 10¾” production liner.

Simulation	Objective
WOB to induce sinusoidal buckling	Observe how the minimum WOB to induce sinusoidal buckling at any point in the liner string for a range of bit depths changes with varying hole size
WOB to induce helical buckling	Observe how the minimum WOB to induce helical buckling at any point in the liner string for a range of bit depths changes with varying hole size
Surface torque	Observe the maximum torque found at the surface/a point in the liner string vs. the make-up torque limit and how it changes with varying hole size
Hook load	Observe how varying hole size affects the string load, also including rig capacity and yield limits
Side forces	Observe how the side forces acting on the liner string changes with varying hole sizes
ECD	Observe how the ECD progresses with depth and varying holes size
Pressure loss	Observe how the total pressure loss is affected by a change in hole size and pump rate

Table 14: Change in section depth for the 12¼” x 13½” section.

Simulation	Objective
Minimum flowrate	Observe if a change in section depth affects the minimum flowrate for hole cleaning during drilling
ECD	Observe how the ECD at shoe (6693 ft. MD) and at bit for the liner string is affected by a change in section depth
Pressure loss	Observe how the total pressure loss for the liner string is affected by a change in section depth, hole size and pump rate

6.1 Drilling the 12¼” x 13½” hole

The most important ERD focuses while drilling the 12¼” x 13½” hole are, as presented in section 5.3, hole cleaning, ROP, ECD management, mud consumption tracking, torque & drag monitoring, evaluate real-time pore pressure prediction, mud-logging service, avoid high DLS (dog leg severity) and to avoid pack-offs.

6.1.1 Minimum WOB

This simulation shows the minimum weight-on-bit to induce/initiate sinusoidal or helical buckling at any point in the drillstring for a range of bit depths [WellPlan user manual]. These forces (WOB) are compressional forces; parts of the drillstring will be in compression while drilling, other parts will be in tension (and will not affect the WOB to either sinusoidal or helical buckling).

Figure 91 and Figure 92 show that the WOB to induce buckling increases with decreasing hole sizes for both sinusoidal and helical buckling. As presented in section 2.4.4, larger annular clearances will result in less buckling tolerance since the tubular is less constrained in the wellbore. This implies that big holes are more prone to buckling compared to small holes since the pipe has more room to move in big holes (which again increase the risk of buckling) as expected from theory presented in section 2.4.4.5. The WOB to induce sinusoidal buckling decreases with depth. The buckling tendency thus increases with increasing depth; for this specific case.

Higher weight of drillstring will lead to increased drag and increased compressional forces, which again may increase the risk of buckling and deformed pipe. According to theory presented section 2.4.4.6 the best way to limit pipe buckling is to preserve the ability to rotate in order to release and get rid of a lot of friction. The simulation shows that small clearance between the wellbore and drillstring reduces the risk of buckling as expected, implying that the buckling tendency is lower in a 12¼” compared to a 15” hole thereby allowing a more effective transfer of weight on bit.

6.1.1.1 Sinusoidal buckling

The WOB to induce sinusoidal buckling increases with decreasing hole sizes and decreases with depth (overall). The curve could also be seen from surface, but the WOB values are the same down to the 13⅝" casing shoe; represented by the horizontal line in Figure 91. The figure shows that from around 12.300 ft. MD the WOB to induce sinusoidal buckling is more or less constant until the string reaches TD (the WOB to induce buckling appears to drop just before TD).

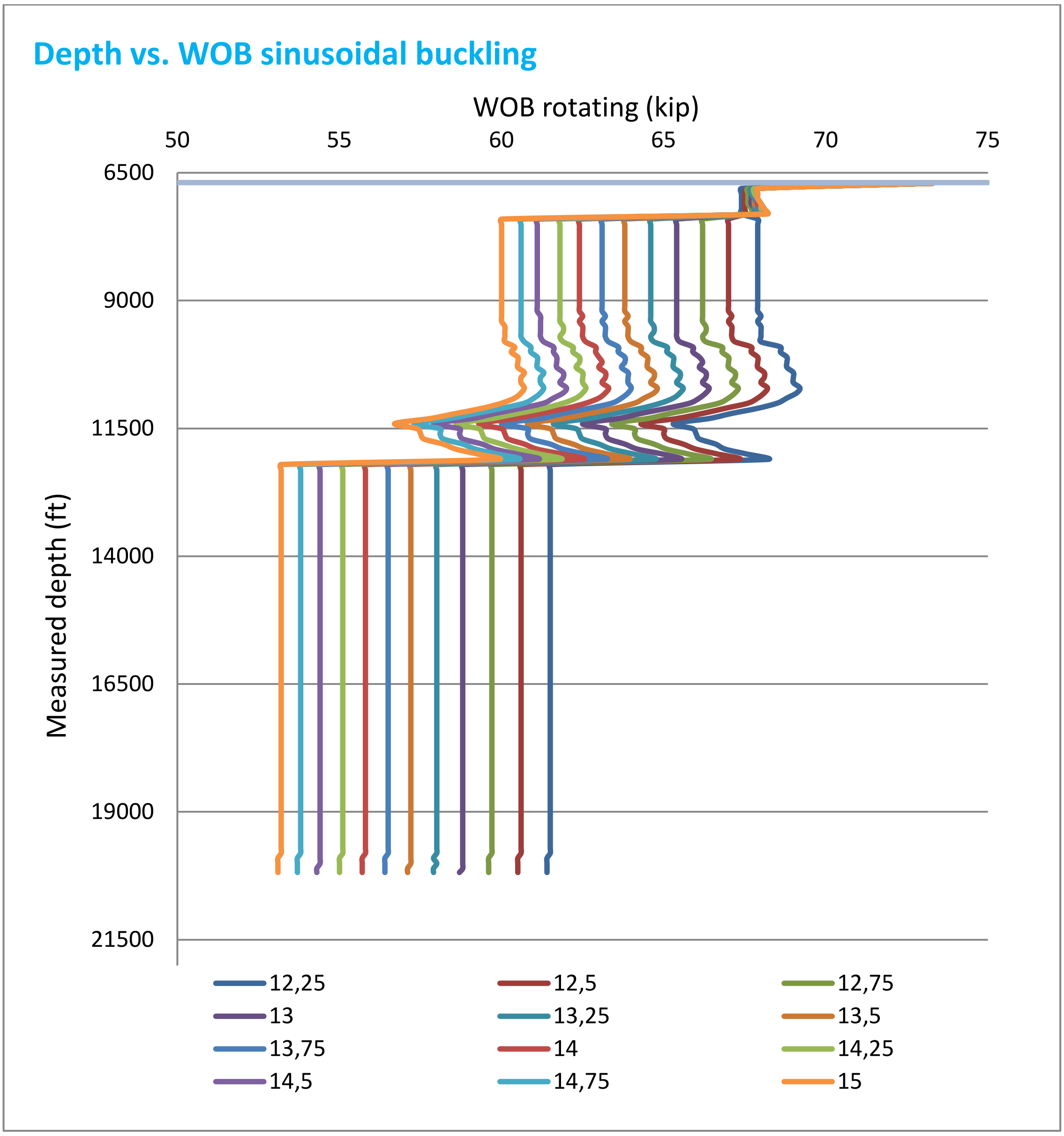


Figure 91: Sinusoidal buckling 12¼" x 13½" hole.

6.1.1.2 Helical buckling

The WOB to induce helical buckling also increases with decreasing hole sizes and decreases with depth (overall). The curve could also be seen from surface, but the WOB values are the same down to the 13⅝" casing shoe; represented by the horizontal line in Figure 92. Figure 92 shows the same pattern as Figure 91, but the values for WOB to induce helical buckling have a higher magnitude than sinusoidal buckling, which is expected since sinusoidal buckling is the 1st phase of buckling and helical bucking is the 2nd phase (explained in sections 2.4.4.1 and 2.4.4.2). This implies that more WOB is required for helical buckling to occur.

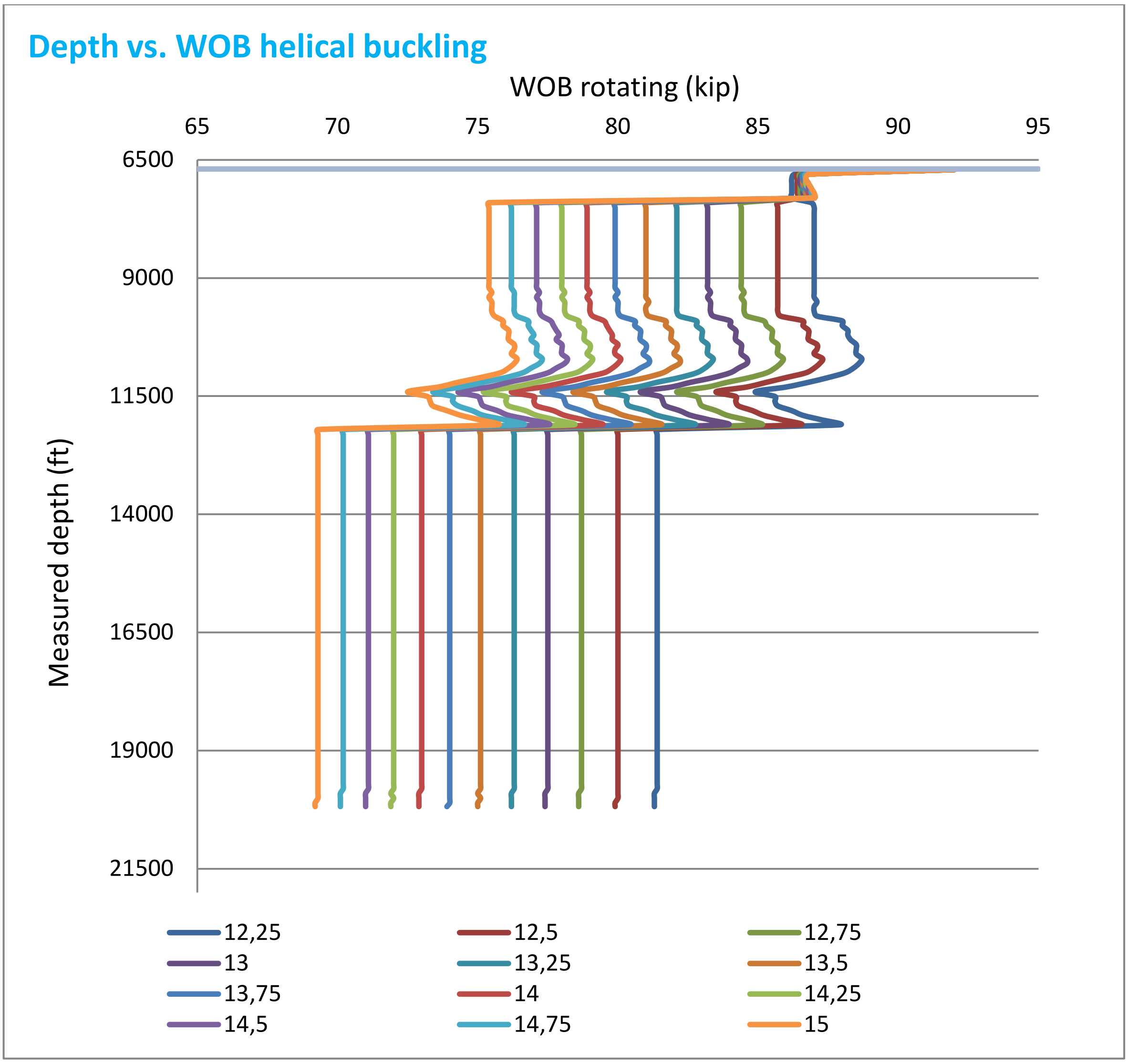


Figure 92: Helical buckling 12¼" x 13½" hole.

6.1.2 Surface torque

This simulation displays the maximum torque found at the surface for all rotary operating modes. This plot also displays the make-up torque limit for reference [WellPlan user manual]. The make-up torque for the 5⅞" DP is 66.000 ft-lbf. The torque limit represents the operating envelope for the string over a range of depths [WellPlan user manual]. Maximum allowable surface/system torque for this specific case will be the MUT (make-up torque) of 5⅞" DP; 66.000 ft-lbf. The top drive may be a limiting factor in other cases, especially on old platform rigs.

The first torque (ROB – rotate of bottom) values in the simulation are taken at the 13⅝" casing shoe. The simulation is run with different under-reamer sizes using each of the 12 simulated hole sizes (listed in the beginning of chapter 6).

According to theory presented in section 2.4, torque is caused by well friction between the wellbore and the string and is one of the limiting factors in ERD. The trend in Figure 93 is approximately linear, but shows a small change in trend from around 10.500 ft. MD, before it continues in a linear path down to TD. The torque trends are very dependent on the well geometry, which is why you see different torque ratios developing through the well section in Figure 93.

Generally, the larger hole sizes show higher torque values than the smaller hole sizes for the specific case. The smallest UR show a lower torque than the biggest UR for each single hole size. The surface torque increase with increasing inclination for all hole sizes. From theory presented in section 2.4.1, the ratio between the length of the wellbore and the forces acting on the string is linear, implying that with increased depth comes increased torque, as seen in Figure 93 and Figure 94. These forces are generated from the contact between the drillstring and the wellbore (depending on the well geometry). The forces are highly affected by the tension or compression in the string, the higher the forces, the greater are the contact forces.

According to [67], [WellPlan user manual]:

"Since the soft-string model does not take the stiffness of the pipe into account (axial and rotational forces are supported by the string and contact forces are supported by the wellbore), its accuracy will degrade when and if the string diameter and/or hole curvature increase. When the stiffness of the pipe and wellbore inclination increase it will generally result in increased normal forces, and thus in increased torque and drag [67]."

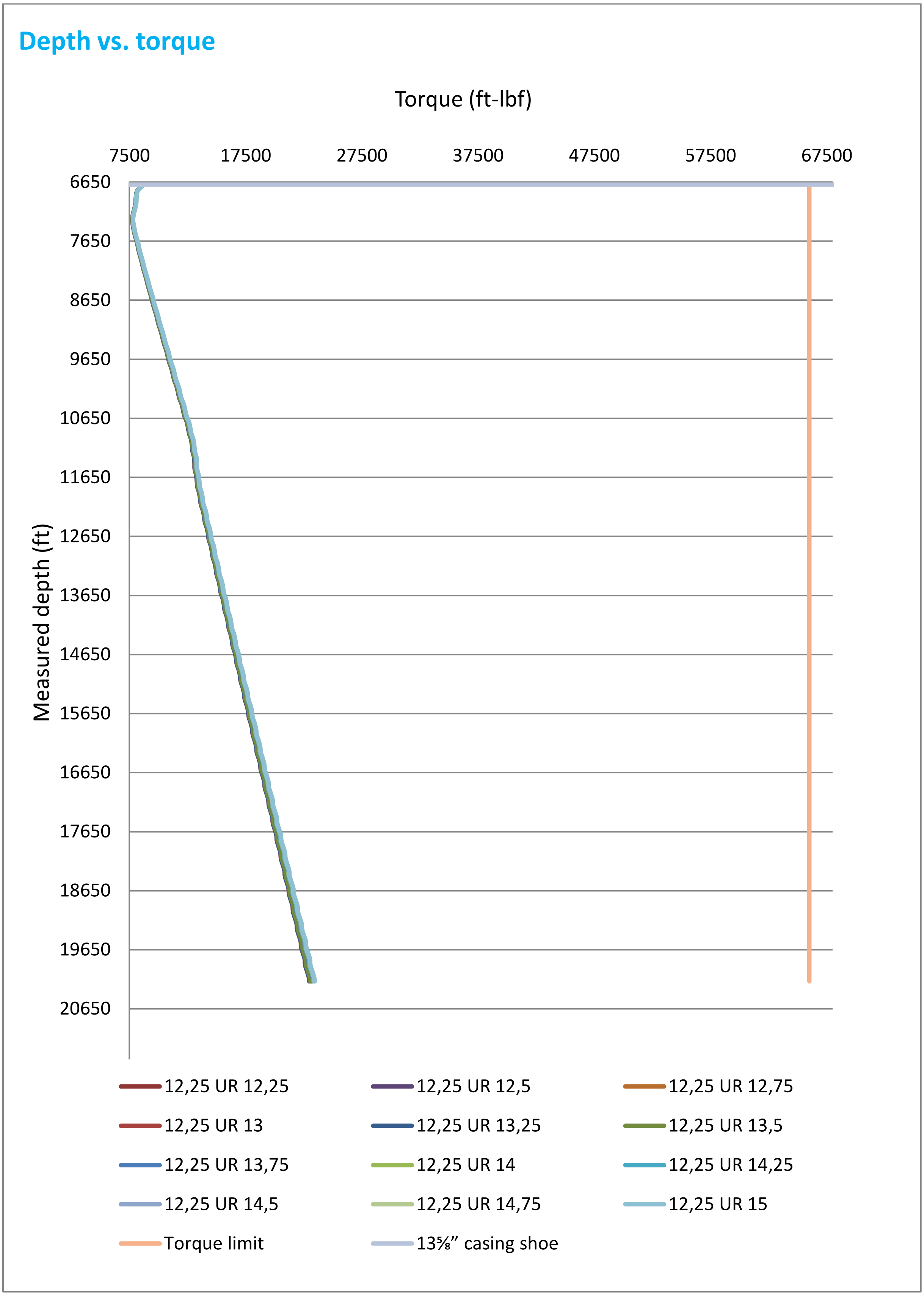


Figure 93: Surface torque 12¼" x 13½" hole.

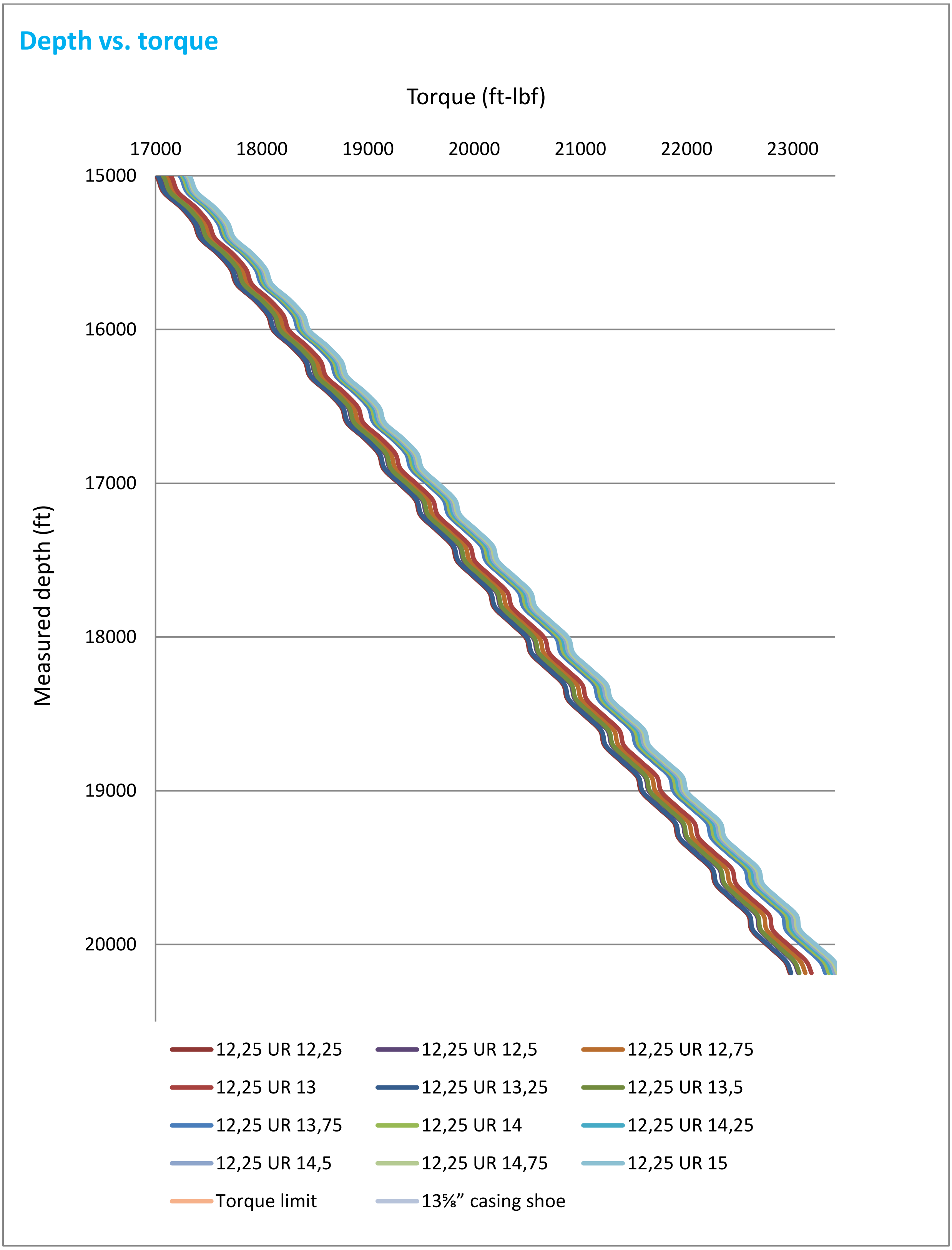


Figure 94: Surface torque 12¼" x 13½" hole. A zoom of Figure 93 showing the measured depth interval from 15.000 ft. to section TD.

6.1.3 Hook load

These plots show the tensile and compressive yield limits at each of the string depths analyzed [WellPlan user manual]. From Figure 95 and Figure 96, you can tell the load that will fail the drillstring, but you will not be able to determine exactly where the failure occurred (then you have to run a different simulation analyzing the forces acting on each individual component in the string at the specific depth).

The simulation also displays two curves indicating the maximum weight to yield the string while POOH (pull out of hole), and the minimum weight to helically buckle the string while RIH (run in hole). The rig capacity limit of 2200 kip (kilo pound) is also plotted in the graph.

The first hook load values in the simulation are taken at the 13⅝” casing shoe, at depth 6693 ft. MD. Figure 95 shows that the values for RIH, ROB (rotate off bottom) and POOH all increase linearly until about 11.200 ft. MD. In the interval between 10.700 and 11.470 ft. MD the wellbore inclination increases from 59.98°-70.8° resulting in high frictional forces working against pipe movement (and a reduced gravity component); seen from the following observations:

- The RIH values decrease
- The ROB values are more or less constant
- The POOH values increase slightly

As expected, the hook load generally increases with depth; with increasing depth (and in other words increasing weight of drillstring in order to reach further towards TD) comes increased hook load. Figure 96 shows that the biggest hole sizes have the biggest hook load values, and the smallest hole sizes have the smallest values in all three scenarios for this specific case studied giving the following relationships:

Hook loadRIH 12¼” < Hook loadRIH 13½” < Hook loadRIH 15”
Hook loadROB 12¼” < Hook loadROB 13½” < Hook loadROB 15”
Hook loadPOOH 12¼” < Hook loadPOOH 13½” < Hook loadPOOH 15”

According to theory presented in section 2.3.8.1, the friction works upwards when the drillstring is RIH and downwards when the drillstring is POOH. The friction during POOH is higher compared to RIH. In section 2.3.6 the following two general equations (6) and (7) were given:

Hook load$_{\mathbf{RIH}}$

1. Hook load$_{RIH}$ = weight – friction

This implies that the less friction, the higher hook loads. If we have less friction with increasing hole sizes, the hook load should increase with increasing holes size.

- The simulation shows that the biggest hole sizes have the biggest hook load values, and the smallest hole sizes have the smallest values. This implies that with increasing annular clearance comes increased hook load during RIH.

Hook load$_{\mathbf{POOH}}$ (the worst case with regards to tensile limit)

2. Hook load$_{POOH}$ = weight + friction

This implies that the less friction, the lower hook loads. If we have less friction with increasing holes sizes, the hook load should decrease with increasing holes size.

- The simulation on HL$_{POOH}$ shows the opposite results; the hook load has a small increase with increasing hole size, i.e. that the 15” hole have higher HL values than the 12¼” for this specific case. In section 6.2.3 when running the liner, the 12¼” hole has higher HL values than the 15” as expected. This is most likely a result of the different operational parameters used on these two different scenarios.

A drilling operation and a casing/liner-run are two distinct different operations with different conditions like: running speed, pump rate, applied surface torque, and string conditions (size, stiffness and yield strength).

Running casing/liner to target depth is one of the biggest challenges in ERD wells, due to the well path, section length and well friction factor. An explanation for the results of the simulation is that the friction may be more dominating in this particular operation compared to during drilling.

The hook load simulation for the drilling operation was also run with an increased section depth of 30.000 ft. MD. These observations indicate that the hook load weights for RIH and ROB decrease as a result of that the well takes more and more friction due to the well geometry. Eventually there will not be enough weight at surface to move the string. The string may have to be either pushed or floated into the well; may get stuck and may not be able to pull the string out of the hole. The most common POOH limitations are usually the yield strength of the pipe and the rigs pull capacity at surface.

The jack-up West Linus is a modern and powerful rig (delivered in 2014), with large storage area and high deck load, designed to operate in harsh environments. The rig capacity is, as mentioned above, 2200 kip and the rig has a drilling depth capacity of up to 40.000 ft. (12.192 m). Older platform rigs may only have capacities of up to 750 kip. This implies that ERD operations may be way more challenging and that these rigs may not be suited for such challenging operations; at least seen from a load capacity perspective.

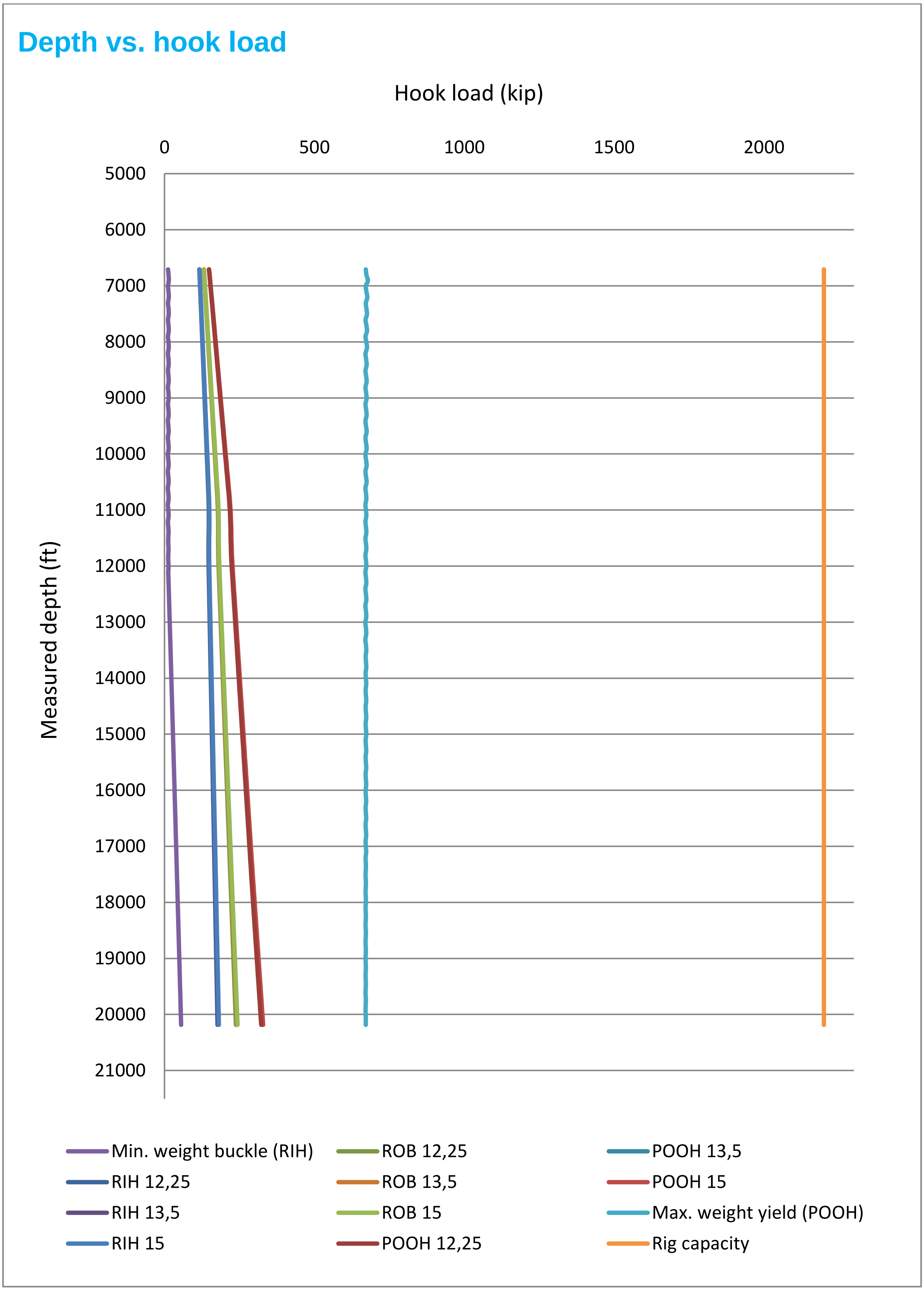


Figure 95: Hook load 12¼” x 13½” hole.

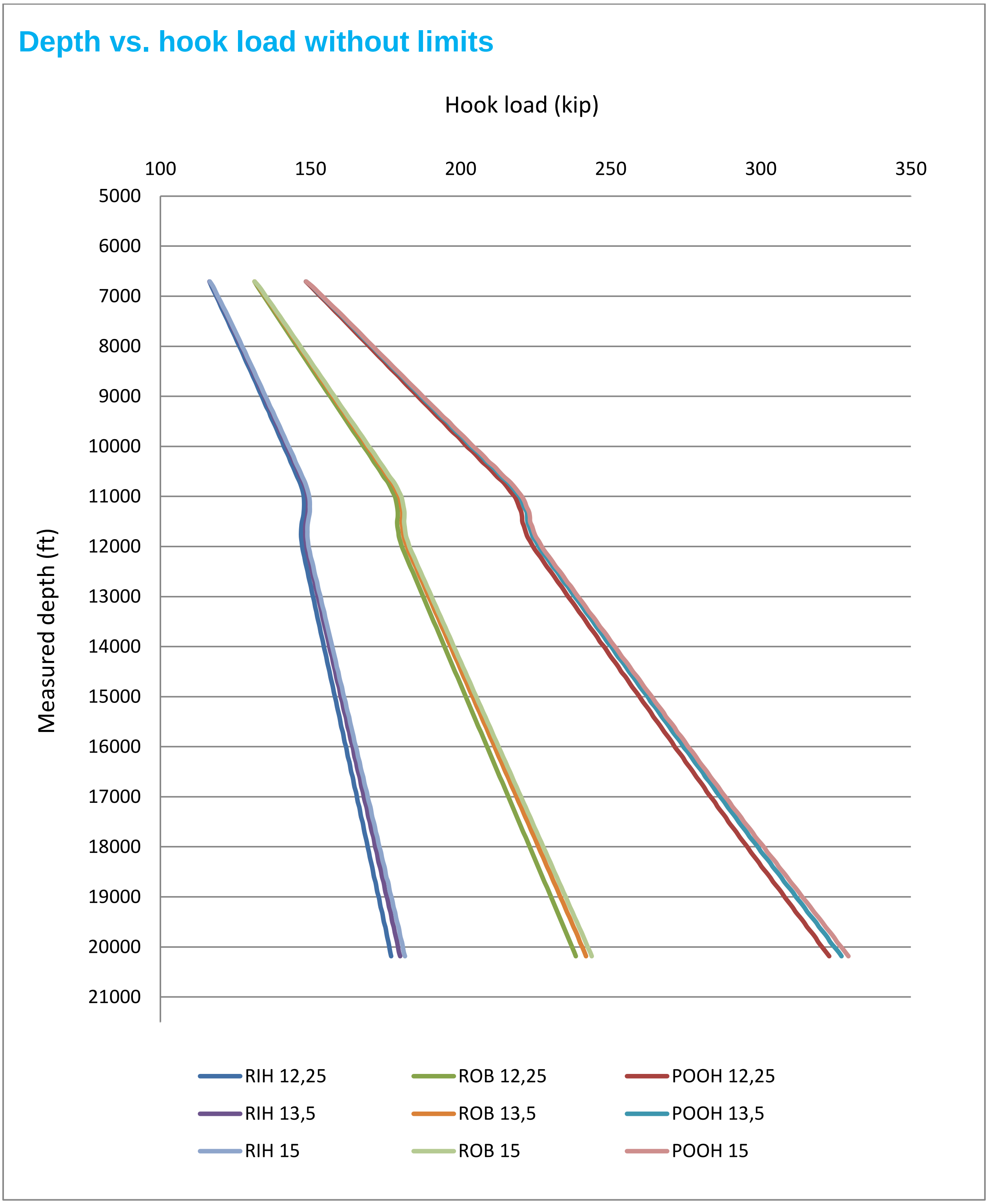


Figure 96: Hook load 12¼" x 13½" hole without limits.

6.1.4 Depth vs. ECD – Flowrate constant 1000 gpm

This simulation can be used to analyze ECD at any point in the string assuming the bottom of the string is at the total depth. ECD is the density that would exert the circulating pressure under static conditions [WellPlan user manual].

Figure 97 shows that the ECD's are larger for the small hole sizes, but the variations are quite small in this case (about 0.01 ppg increase per ¼" decrease in hole size – has no practical impact). For the bigger hole sizes, the ECD's are almost constant with increasing depths. All of the ECD values for the various hole sizes are the same down to the 13⅜" casing shoe and all of the values lie far below the fracture gradient curve ("the safe window" as seen in Figure 97).

According to theory presented in section 2.5.7.5.1, wellbores with small annulare clearances may produce high ECD values. The results show that when the annular clearance increases, the ECD's become less critical, although it generally increases by about 0.01 ppg with increasing depth intervals. For the hole sizes between 13¾" to 15", the ECD values increase until the depth reaches about 8300 ft. MD, where they start decreasing. The simulation was run to determine how the ECD's fluctuate with different hole sizes and depths and show that ECD's can be reduced by upsizing from a 12¼" hole to a 15" hole, as suggested in section 2.5.7.5.1. Regardless of hole size, ECD limitations dictated by the inside diameter of the last set casing shoe (the clearance between the shoe and the running string) must be considered.

The ECD is, as presented in section 2.5.7.1, a function of the drilling fluid density, the build-up of suspended cuttings in the annular flow and the annular pressure drop. The annular pressure drop is again affected by factors like the length of annulus or well, annular clearances (drillpipe/casing size), fluid properties, flowrates, rotation of the pipe and ROP. Changing one of these variables will strongly affect the ECD.

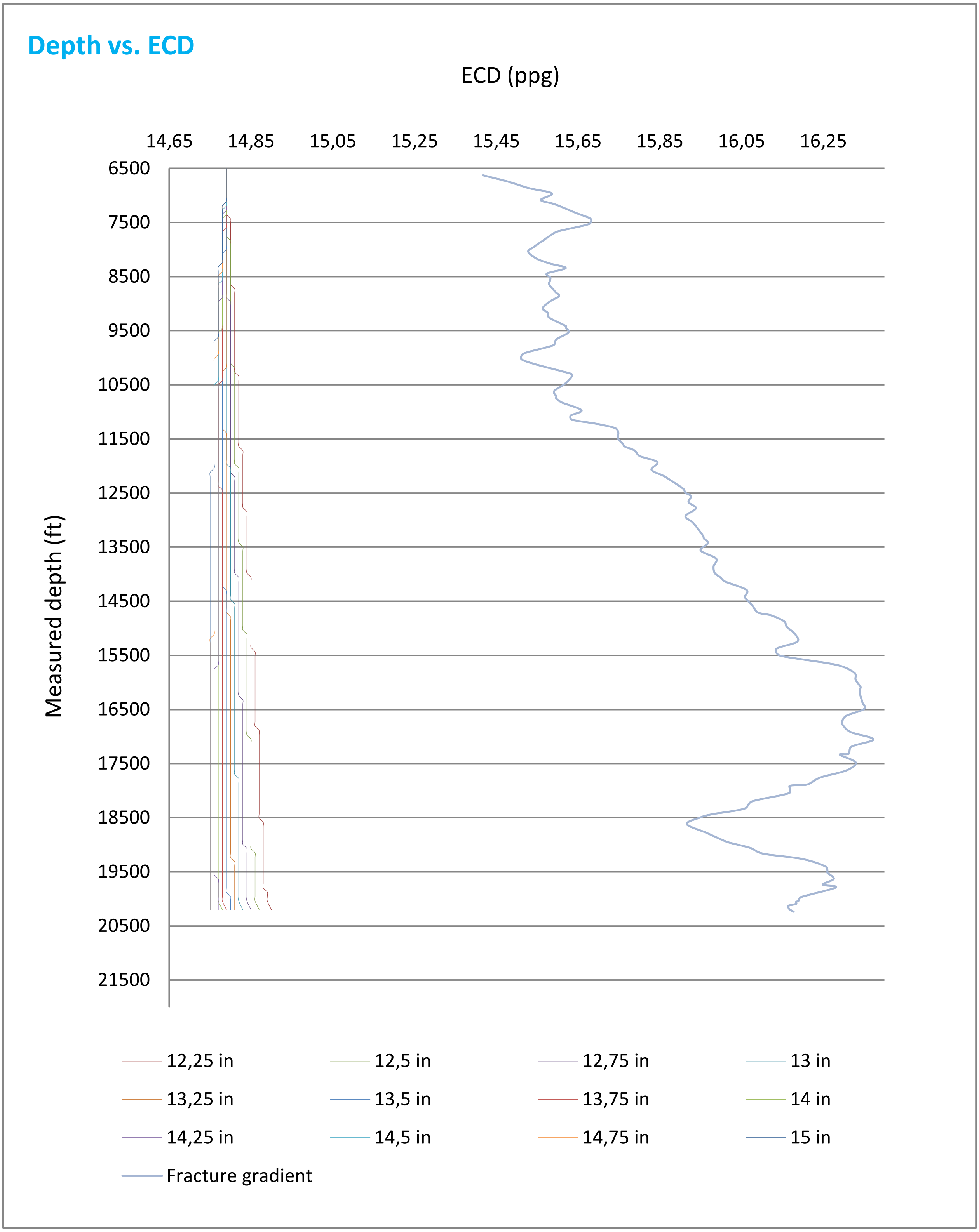


Figure 97: ECD calculations 12¼" x 13½" hole.

6.1.5 Hydraulics cuttings transport – Bed height vs. hole angle (0-90°)

This simulation determines the bed height of the cuttings that will be in the annulus for any wellbore inclination ranging from 0 to 90 degree for a particular flowrate [WellPlan user manual].

Generally; the bed height increases with increasing hole angle as expected and decreases with increasing flowrate. The bed height builds up at the smallest angle in the 15" hole (10°), secondly in the 13½" hole (20°) and last in the 12¼" hole (30°) – roughly.

The minimum pump rate used in the simulation is 600 gpm and the maximum rate used is 1100 gpm (increment pump rate 100 gpm). Figure 98 shows that for the 12¼" case the minimum flowrate is 760 gpm (no bed height). The maximum bed height is 2.692 in. @ 600 gpm and 90° (due to the fact that 600 gpm is the minimum flowrate used in the simulation).

Figure 98: Bed height 12¼".

Figure 99 shows that minimum flowrate is 900 gpm (no bed height) for the 13½" hole. The maximum bed height is 4.202 in. @ 600 gpm and 90° (due to the fact that 600 gpm is the minimum flowrate used in the simulation).

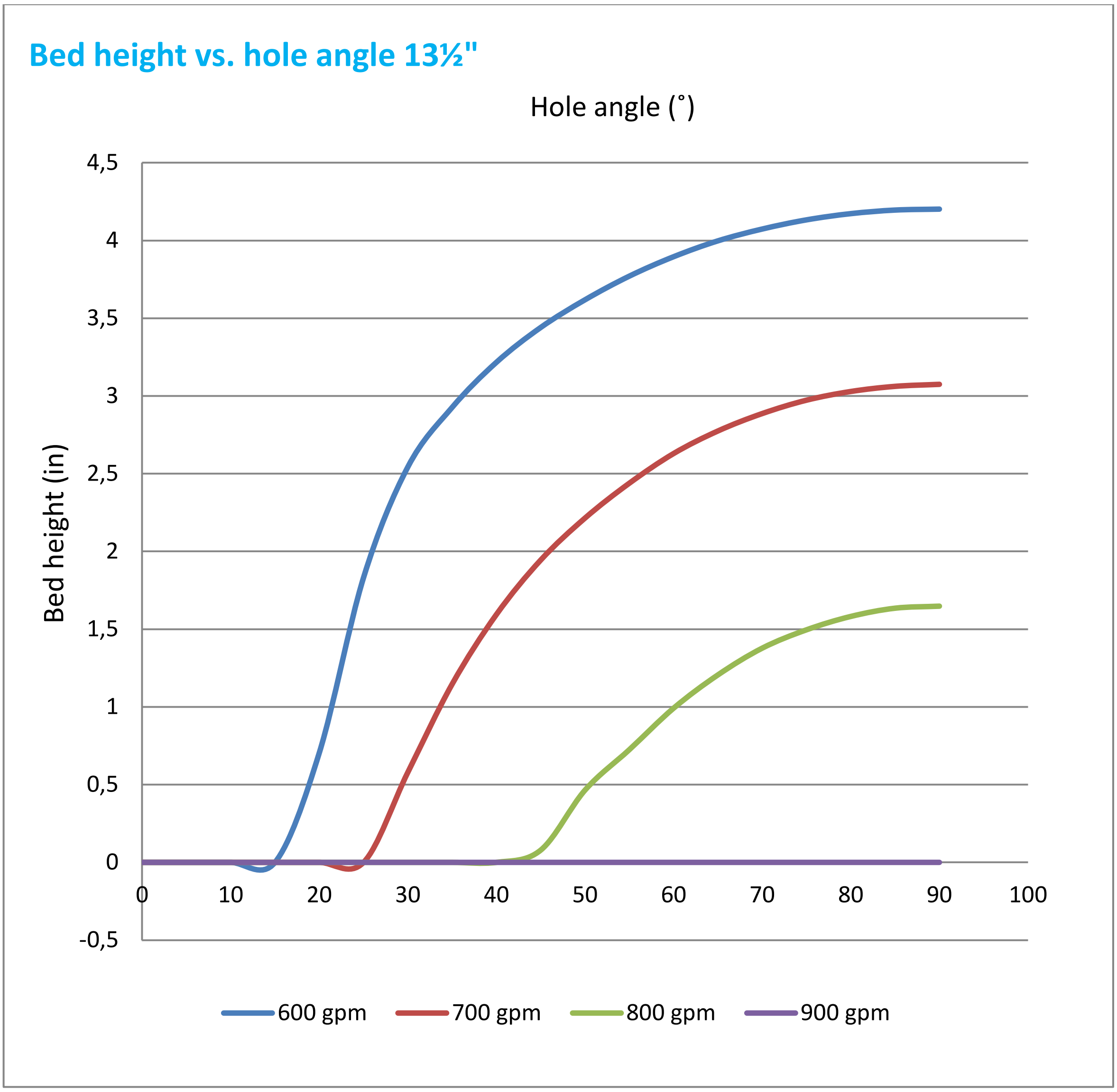


Figure 99: Bed height 13½".

The minimum flowrate for the largest hole (15”) in the simulation is 1060 gpm (no bed height) seen in Figure 100. The maximum bed height is 5.479 in. @ 600 gpm and 90° (due to the fact that 600 gpm is the minimum flowrate used in the simulation).

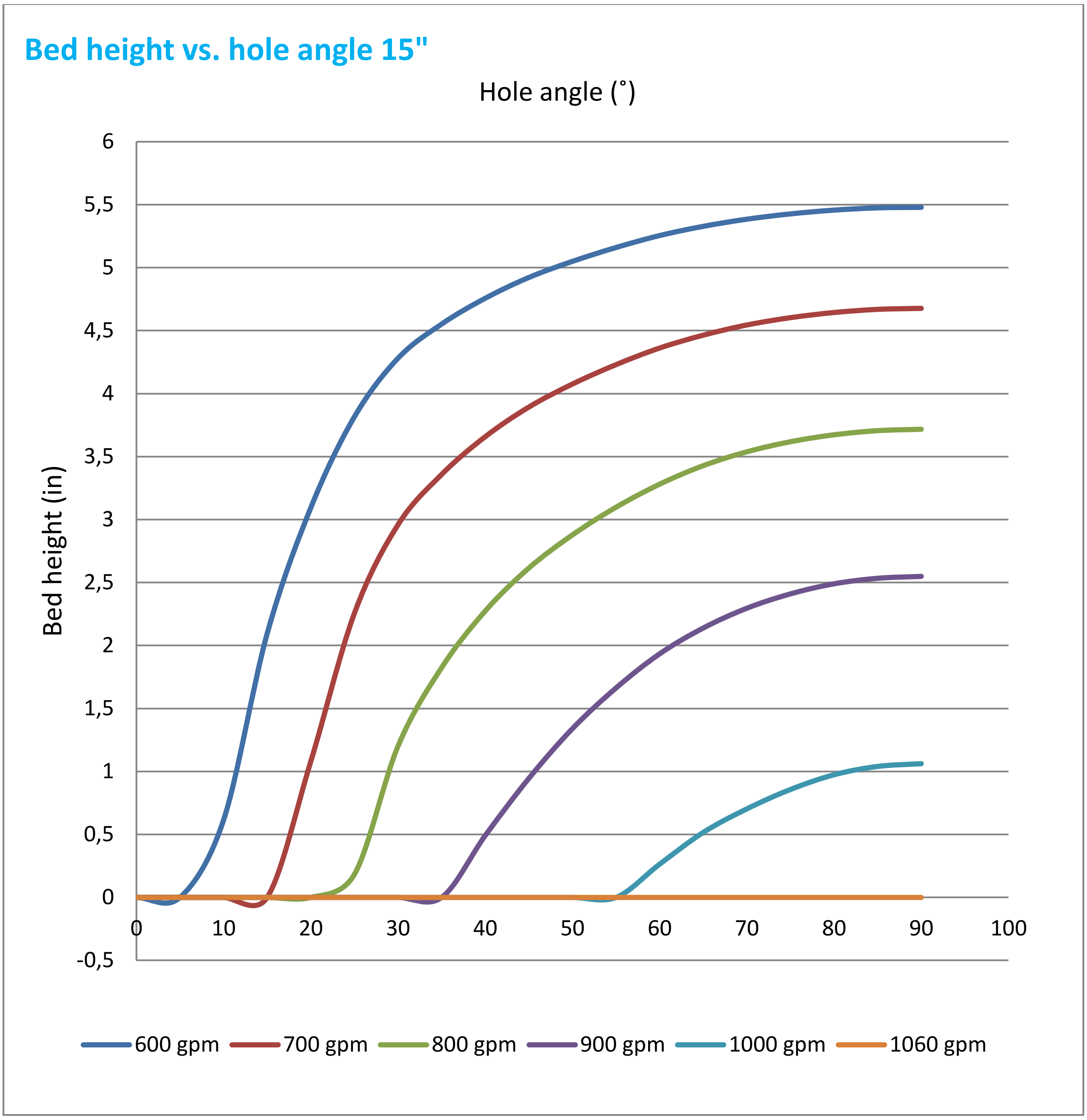


Figure 100: Bed height 15”.

The maximum bed height thus increases with larger annular clearance, and decreases with increasing flowrate. For the same flowrate, we also see that beds are more easily built in large hole sections. The cuttings bed can be disturbed by inducing turbulent flow and rotation.

According to theory presented in section 2.6.10, the cuttings bed strongly influence the hole cleaning system. The interaction between the drilling fluid and the cuttings in cuttings bed during drilling creates a cuttings bed gel, which again leads to difficulties in removing the cuttings bed [12]. A well consolidated cuttings bed complicates the hole cleaning since the cuttings are not free and cannot be removed from the bed by the flow itself. The hole cleaning will be much easier if the cuttings bed is porous and loose because the cuttings are loose and can be removed by the flow itself. In this case it is only necessary to remove the solitary cuttings that are not adhered to the cuttings bed [12].

During drilling, the lower "static" layer of the cuttings bed will build up to an equilibrium height and will not erode as long as the top layer is present (and moving) [9]. A change in ROP will not affect the lower layer until the top layer is fully removed. Increased ROP results in a thicker top layer, with minimal effect on the lower layer. Decreased ROP results in a thinner top layer, but the lower layer will not clean up very much [9]. When the top layer has "cleaned up," the lower "static" layer will try to clean up and thins to a new equilibrium level (but it will not get cleaned up completely) [9]. This implies that there always will be a cuttings bed, so when tripping, you are tripping through dirt, not in a "clean hole."

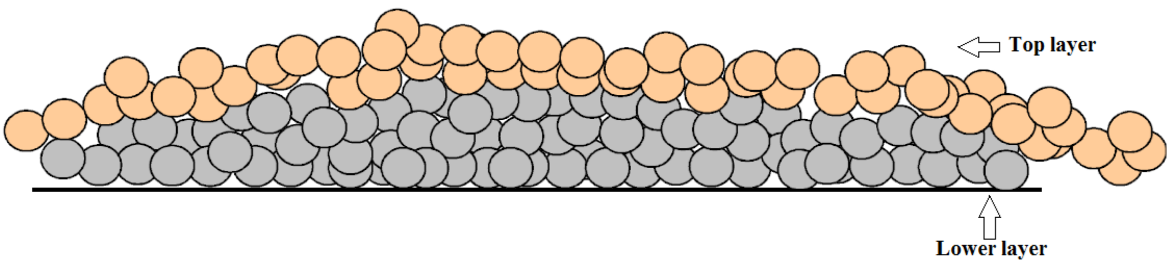


Figure 101: Bed height and bed behavior [9].

6.1.6 Annular velocity (AV)

This simulation can be used to determine the velocity of the fluid in the annulus for any measured depth in the wellbore for a range of flow rates (600-1100 gpm in this case) [WellPlan user manual]. *"This graphical analysis (Figure 102) displays the calculated annular velocity across each annulus section and compares the profile with the critical velocity. When and if an annular velocity curve crosses the critical velocity curve, the flow regime for that annulus section moves from laminar to either transitional or turbulent flow [WellPlan user manual]."*

According to theory presented in section 2.6.1.1 larger hole sizes will tend to be more difficult to clean due to lower AV's. Figure 102 shows that the annular velocity increases with increasing flowrates and that the smallest hole size (12¼") have the highest AV values. The AV values are constant for each hole size down to the 13⅝" shoe placed at 6693 ft. MD. From here on (open hole) the values go either slightly up or down (12¼" values goes up, while 13½" and 15" values go down) until they stabilize again.

The simulation implies, as expected, that larger hole sizes have lower AV's; creating hole cleaning and viscous coupling (which is the produced "fluid film" that is rotating around the drillpipe and that is responsible for cleaning the hole) challenges avoided in smaller holes (as presented in section 2.6.1.1). I.e. it is easier to clean a small hole due to smaller clearances (no space for dead zones) between the drillstring (pipe) and the wellbore (seen in Figure 49). The viscous coupling film interacts with the high velocity fluid in the 12¼" (rather than the dead zone fluid in the 15" hole). High annular velocities are preferable to ensure a better and more efficient hole cleaning.

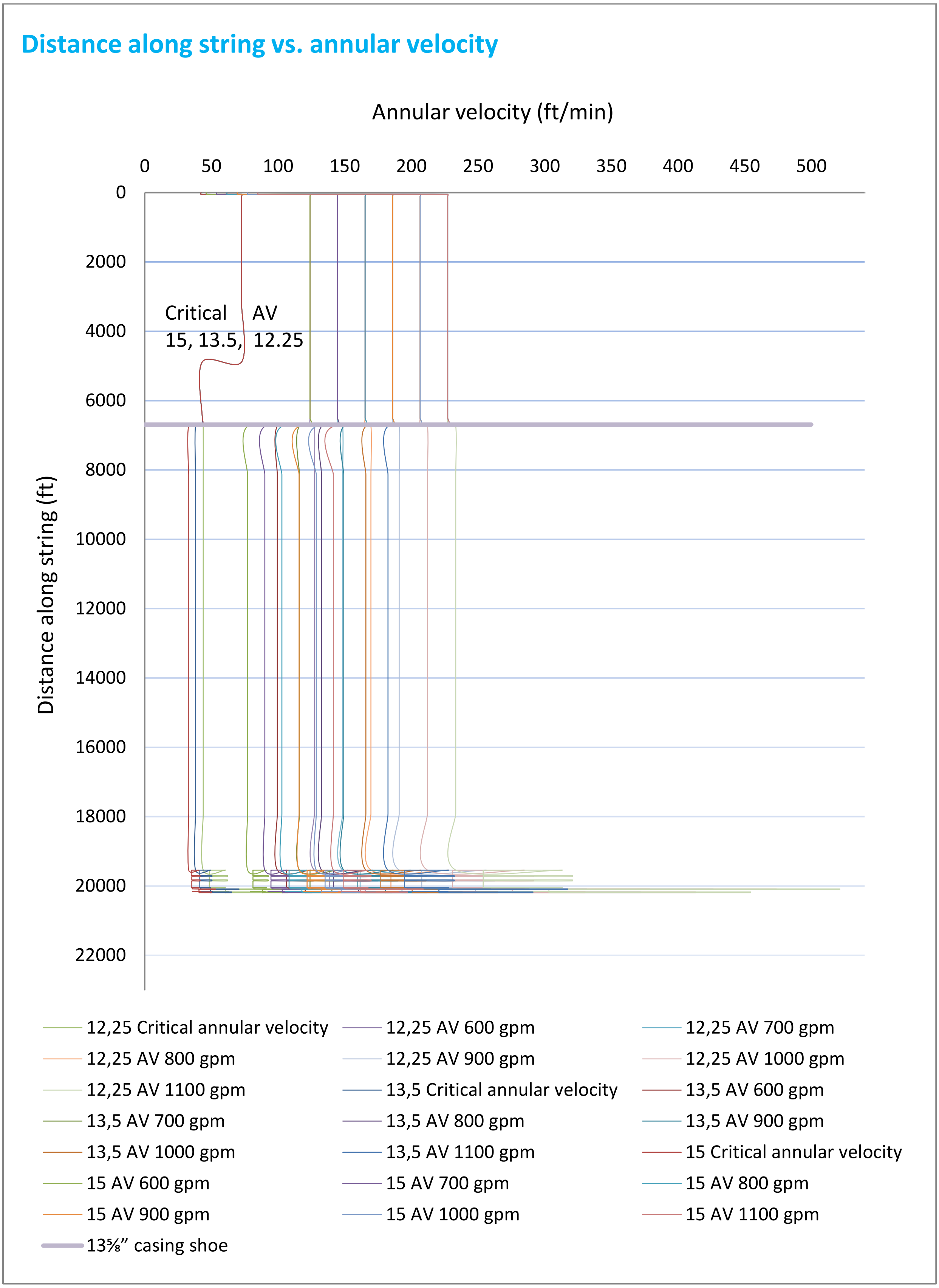


Figure 102: Annular velocity (AV).

6.1.7 Critical flowrate – Minimum flowrate vs. hole angle (0-90°)

According to WellPlan: *"This simulation is based on a mathematical model that predicts the critical (minimum) annular velocities/flowrates required to remove or prevent a formation of cuttings beds during a directional drilling operation. This is based on the analysis of forces acting on the cuttings and its associated dimensional groups. The simulation can be used to predict the minimum flowrate required to remove or prevent the formation of stationary cuttings. This simulation analyzes wellbore inclinations ranging from zero to 90 degree [WellPlan user manual]."*

The inputs considered for the hole cleaning simulation include [WellPlan user manual]:

- Cuttings density
- Cuttings load (ROP)
- Cuttings shape
- Cuttings size
- Deviation
- Drill pipe rotation rate
- Drill pipe size
- Flow regime
- Hole size
- Mud density
- Mud rheology
- Mud velocity (flowrate)
- Pipe eccentricity

Figure 103 shows somewhat dome-shaped curves and that the minimum flowrate required to clean the hole increases with increasing hole angle. The required flowrate also increases with increasing hole size – implying that larger annular clearance require a higher flowrate in order to achieve robust hole cleaning.

Flowrates should be as high as possible on the means of hole cleaning, subject to ECD related constraints. In order to prevent cuttings from forming a cuttings bed, you should maintain a flow rate for a particular depth greater than the critical flow rate. The simulation shows that increasing the hole size requires higher flowrates to achieve the same hole cleaning conditions, as presented in section 2.2.3.

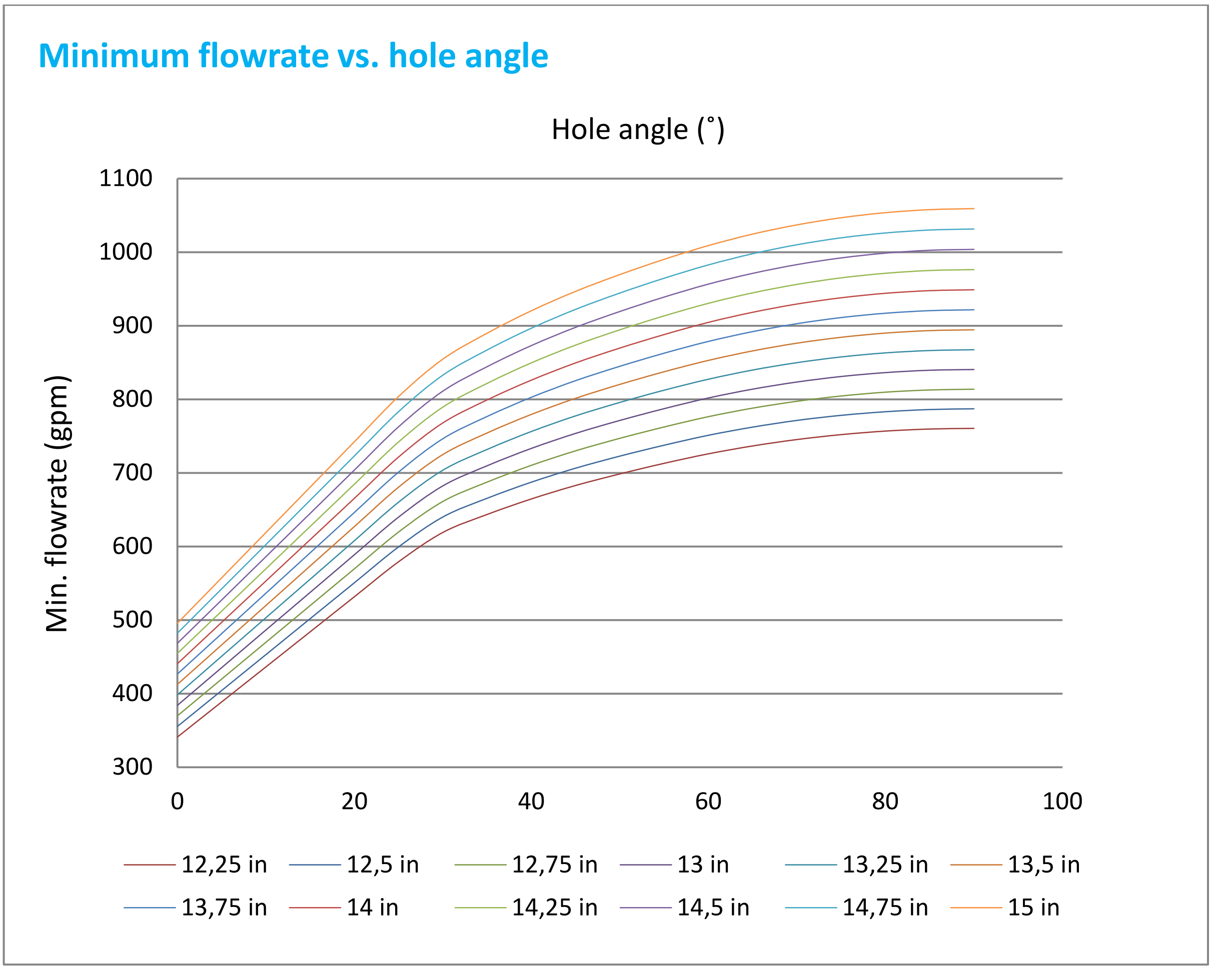


Figure 103: Critical flowrate.

Minimum flowrate to maintain proper hole cleaning for the different hole sizes can be read from the table below and is also plotted in Figure 104:

Table 15: Minimum flowrates for hole cleaning [WellPlan].

Hole size	Flowrate (gpm)
12¼"	696.7
12½"	722.7
12¾"	748.8
13"	775
13¼"	801.4
13½"	827.9
13¾"	904.3
14"	931
14¼"	957.8
14½"	984.7
14¾"	1011.8
15"	1038.9

The simulation thus implies that larger holes require higher flowrates to maintain a proper hole cleaning, but must be viewed in perspective with ECD constraints in order to obtain a safe and effective drilling operation.

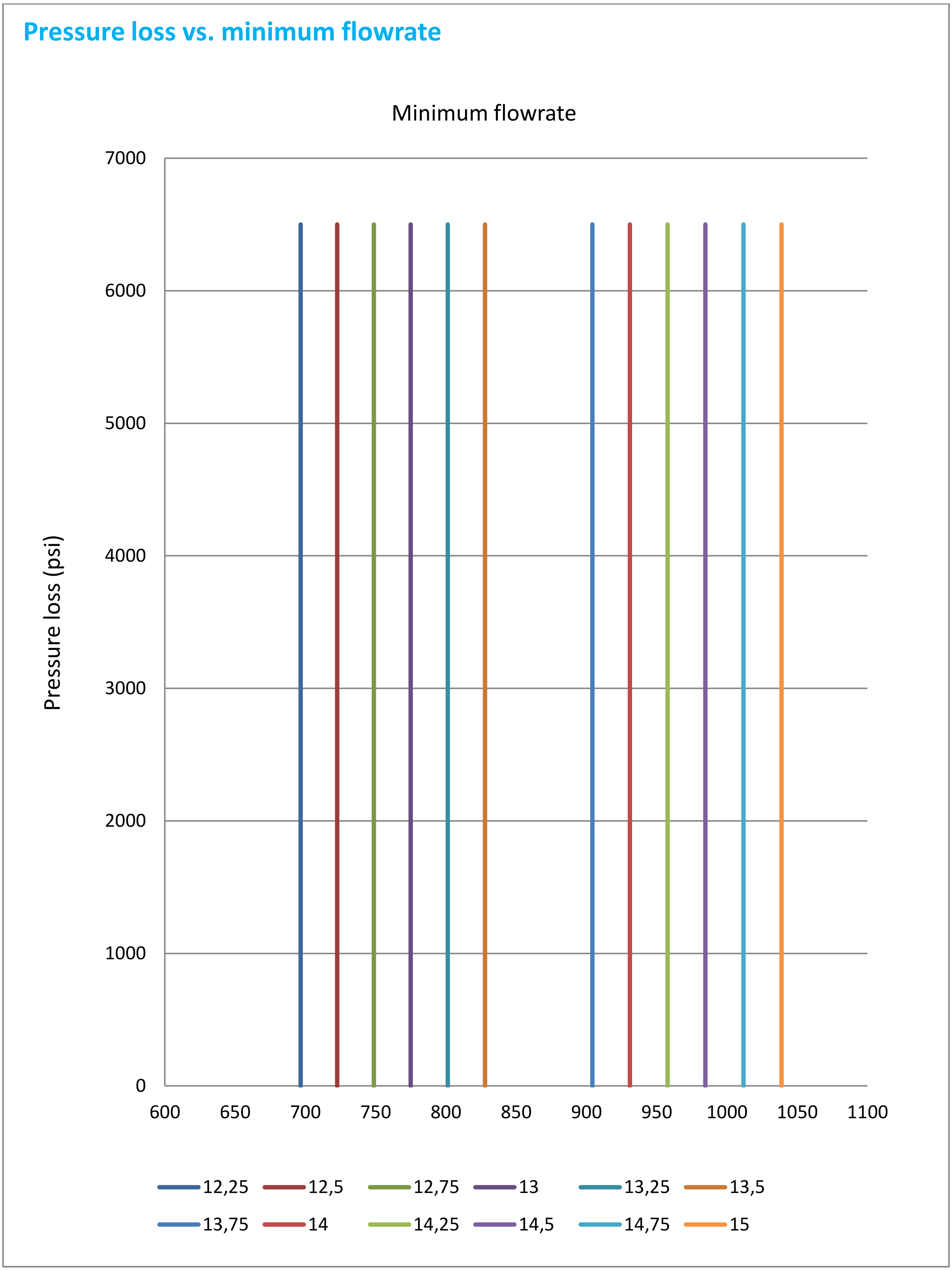


Figure 104: Minimum flowrates for hole cleaning.

6.1.8 Suspended volume vs. hole angle (0-90°)

Suspended volume is defined as the percentage of the annular volume filled with cuttings suspended in the drilling fluid [WellPlan user manual]. The suspended volume does not include cuttings lying in the hole for a particular depth and forming a bed. This simulation analyzes a range of wellbore inclination from zero to 90 degrees [WellPlan user manual].

Figure 105 shows that the suspended volume increases with increasing hole size and decreases with both increasing flowrate and hole angle. As the flowrates increase, the curves tend to become more and more horizontal (for 1000 gpm and 1100 gpm the suspended volume are more or less constant with increasing hole angle). For the lowest flowrates, the suspended volume peaks at first and drops as the hole angle increases. The results imply that high flowrates in small holes are ideal in order to reduce the suspended volume.

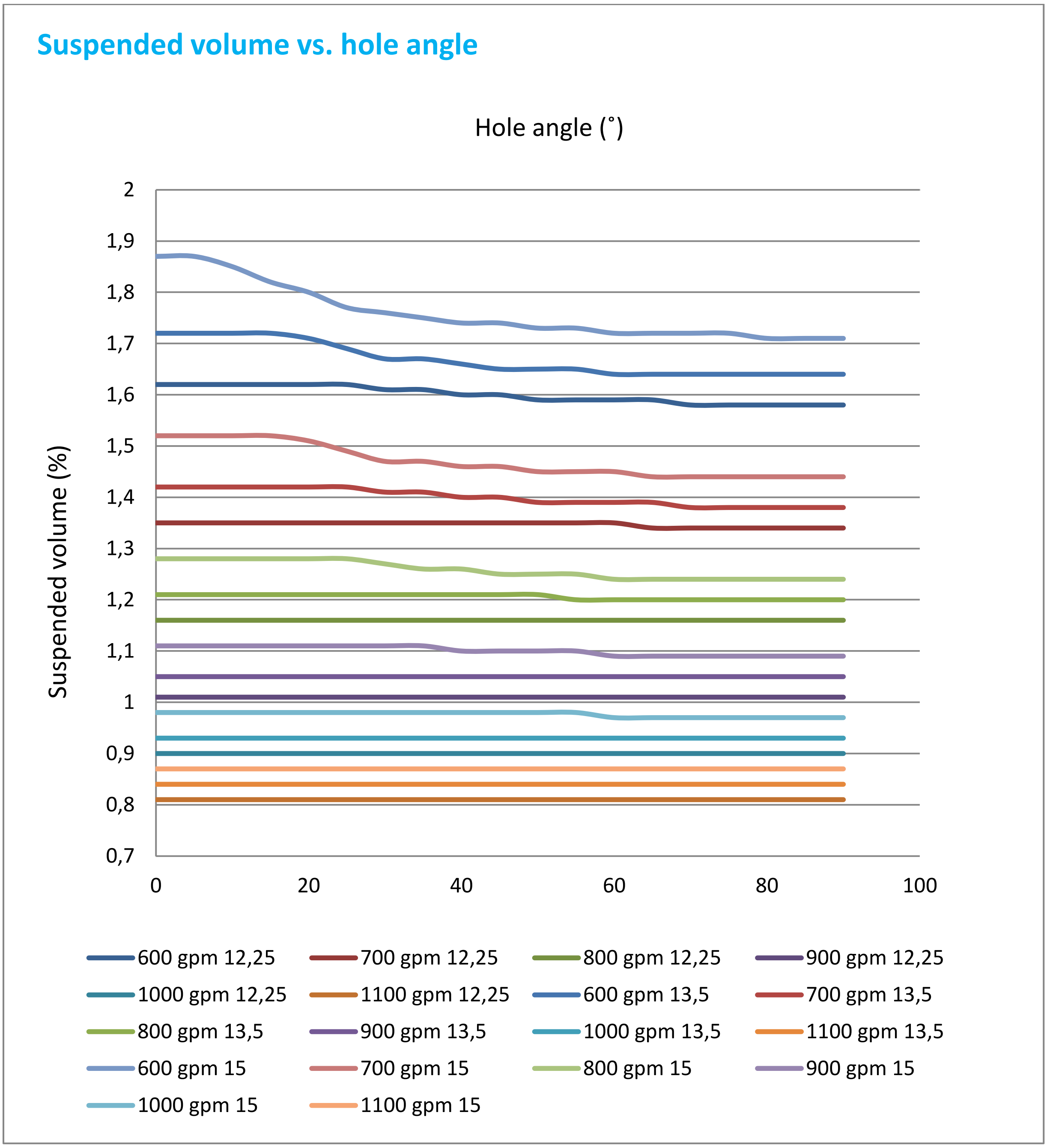


Figure 105: Suspended cuttings volume.

6.2 Running the 10¾" production liner

The biggest concerns for running the liner are if the liner will be able to slide to bottom and reach target depth, friction challenges, if the ECD's exceed expected fracture gradient and the risk of swabbing below expected pore pressure and wellbore collapse while picking up (presented in section 4.4). The size of the liner is held constant 10¾" in all of the following simulations; however, the wellbore size is varied between 12¼" and 15".

6.2.1 Minimum WOB

This simulation displays the minimum weight-on-bit to induce/initiate sinusoidal or helical buckling at any point in the drillstring for a range of bit depths [WellPlan user manual]. These forces (WOB) are compressional forces; parts of the liner will be in compression while RIH, other parts will be in tension (and will not affect the WOB to either sinusoidal or helical buckling).

As for drilling the 12¼" x 13½" hole, Figure 106 and Figure 107 show that the WOB to induce buckling increases with decreasing hole sizes for both sinusoidal (1^{st} phase) and helical (2^{nd} phase) buckling for various hole sizes ranging from 12¼" to 15". Big holes are, according to theory presented in section 2.4.4.5, more prone to buckling compared to small holes because the pipe has more room to move in big holes due to larger annular clearances. The simulation shows that small clearance between the wellbore and liner string reduces the risk of buckling, also the result seen in section 6.1.1, implying that the buckling tendency is lower in a 12¼" compared to a 15" hole thereby allowing a more effective transfer of weight on bit.

6.2.1.1 Sinusoidal buckling

The WOB to induce sinusoidal buckling increases with decreasing hole sizes and increases with depth (overall). Figure 106 shows that the WOB to induce sinusoidal buckling have identical values down to the 13⅜" shoe placed at 6693 ft. MD. As the hole sizes decrease, the WOB to induce buckling increase, implying that small holes are more resistant to buckling.

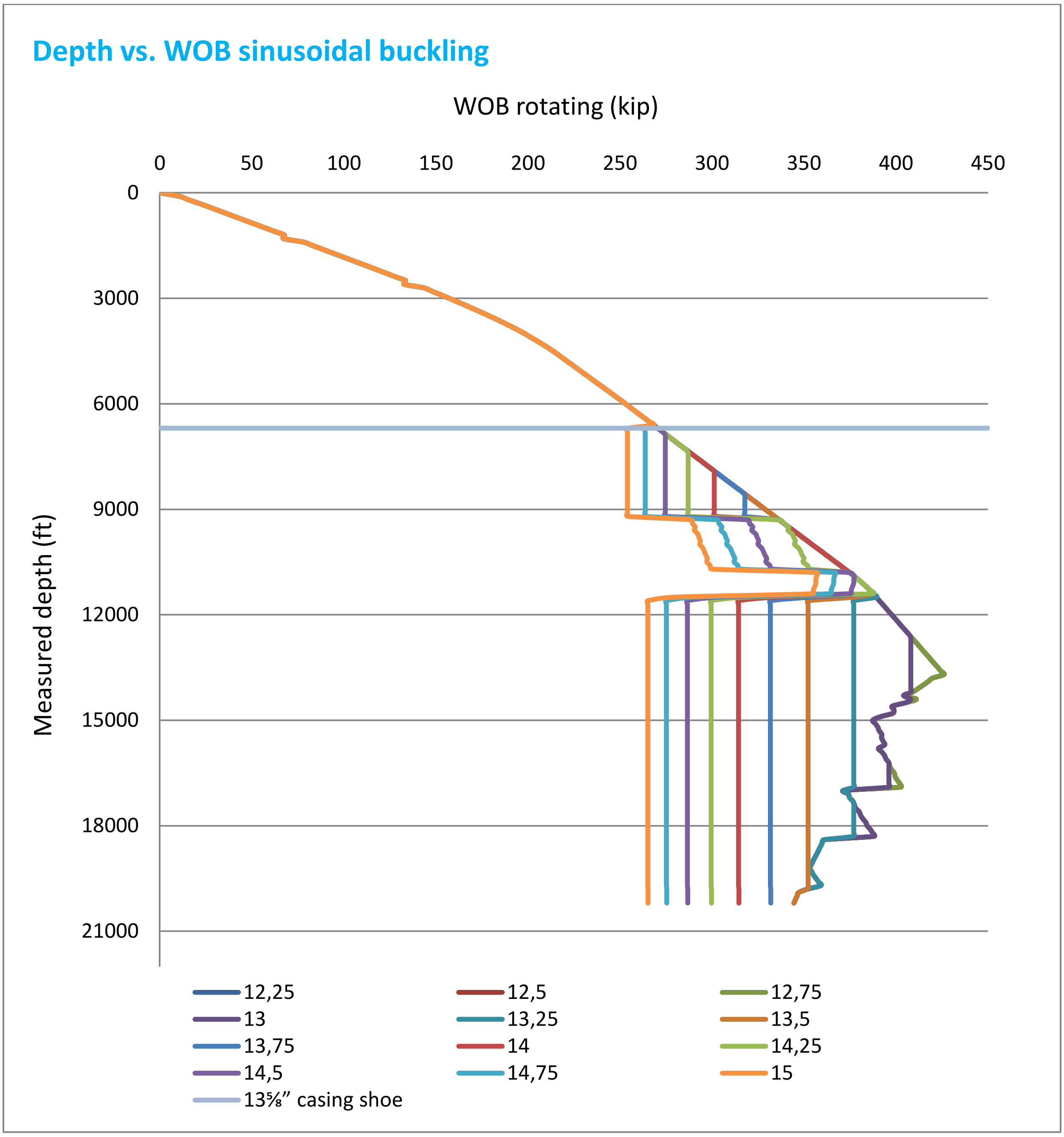


Figure 106: Sinusoidal buckling 10¾" liner.

6.2.1.2 Helical buckling

The WOB to induce helical buckling also increases with decreasing hole sizes and increases with depth (overall). For WOB to induce helical buckling the values are similar all the way down to 11.600 ft. MD. Figure 107 shows the same pattern as Figure 106, but the values for WOB to induce helical buckling have a higher magnitude than sinusoidal buckling, which is expected since sinusoidal buckling is the 1st phase of buckling and helical bucking is the 2nd phase (explained in in sections 2.4.4.1 and 2.4.4.2).

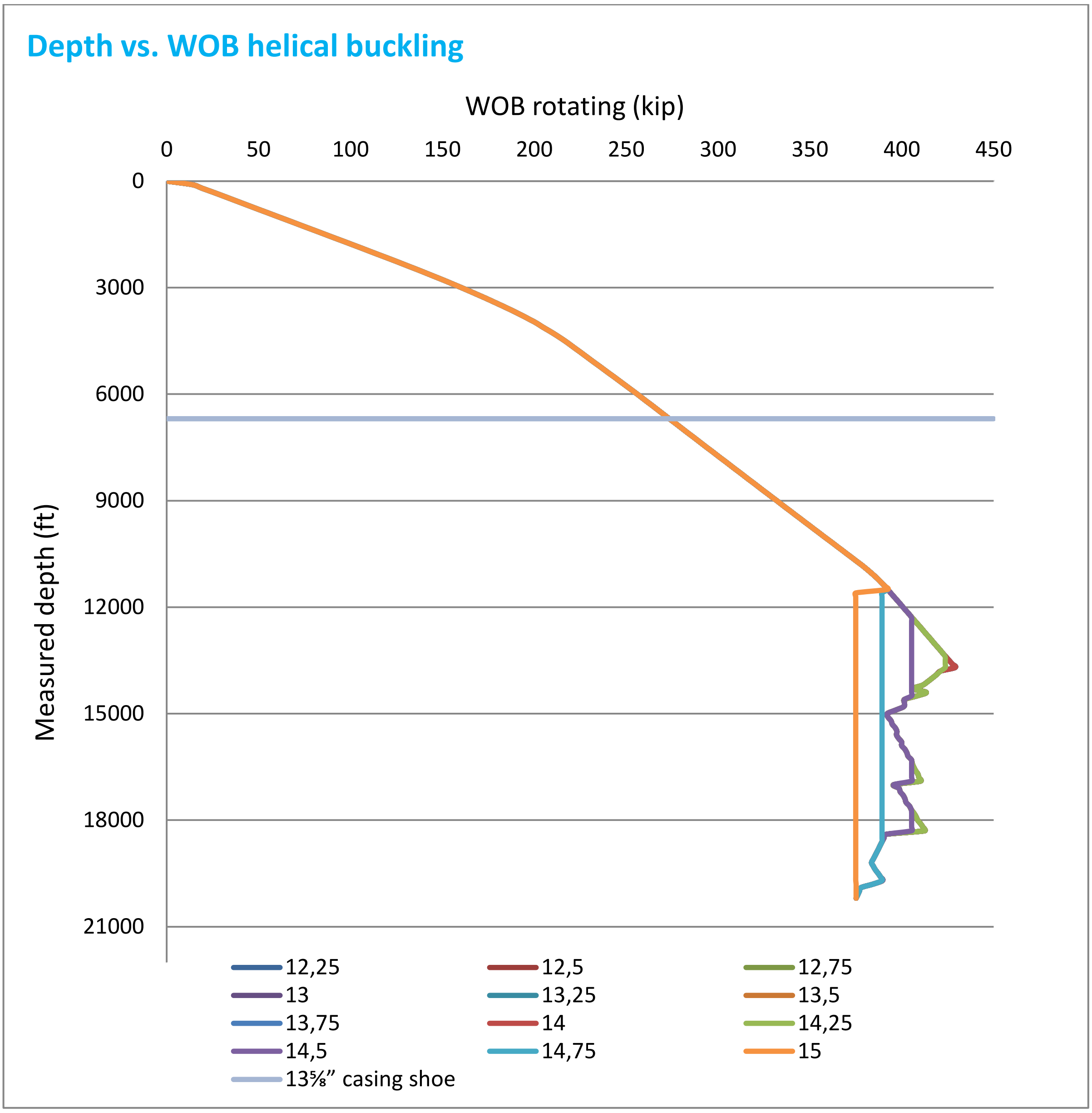


Figure 107: Helical buckling 10¾” liner.

6.2.2 Surface torque

This simulation displays the maximum torque found at the surface for all rotary operating modes. This plot also displays the make-up torque limit for reference [WellPlan user manual]. The make-up torque of the 10¾” liner is 45.740 ft-lbf. The torque limit represents the operating envelope for the string over a range of depths [WellPlan user manual]. Maximum allowable surface/system torque for this specific case will be MUT (make-up torque) of the 10¾” liner; 45.740 ft-lbf. The top drive may be a limiting factor in other cases, especially on old platform rigs.

Torque is as according to theory presented in section 2.4 caused by well friction between the wellbore and the string and is one of the limiting factors in ERD. Figure 108 shows that below 13.000 ft. MD it will not be likely to rotate the liner from this point and beyond down to section TD due to the fact that the torque exceed the make-up torque of the liner at this depth. It will therefore not be possible to rotate liner at the end of the section. Please be aware of the fact that free rotation of liner @ TD in mud will exceed make-up torque of 10¾” liner/liner hanger running tool/5½” HWDP.

The torque values are the same for all of the hole sizes down to a certain depth; to the 13⅝” casing shoe. After this point the torque increases with increasing depths for all of the hole sizes (almost linearly). This implies that the longer the wellbore, the higher the forces downhole will be, as explained in section 2.4.1. These forces are generated from the contact between the liner and the wellbore (depending on the well geometry). The forces are highly affected by the tension or compression in the string, the higher the forces, the greater are the contact forces.

In inclined sections the drillstring creates additional contact forces and friction (bigger DLS results in greater friction). This can be seen from equation (13) in section 2.3.8.1. The simulation shows that larger hole sizes have higher torque than the smaller ones for this specific case, also seen in section 6.1.2. The surface torque increase with increasing inclination for all hole sizes. According to the theory presented in section 2.4.1, the ratio between the length of the wellbore and the forces acting on the string is linear, implying that with increased depth comes increased torque, as seen in Figure 108 and Figure 109.

As mentioned in section 6.1.2, the torque trends are very dependent on the well geometry, which is why you see different torque ratios developing through the well section. The green line in Figure 108 represents the point at which the landing string enters the wellbore resulting in the development of a new torque trend (less friction is built per gradient due to new and smaller pipe size (change from 10¾" liner to 5½" HWDP)).

According to [67], [WellPlan user manual]:
"Since the soft-string model does not take the stiffness of the pipe into account (axial and rotational forces are supported by the string and contact forces are supported by the wellbore), its accuracy will degrade when and if the string diameter and/or hole curvature increase. When the stiffness of the pipe and wellbore inclination increase it will generally result in increased normal forces, and thus in increased torque and drag [67]."

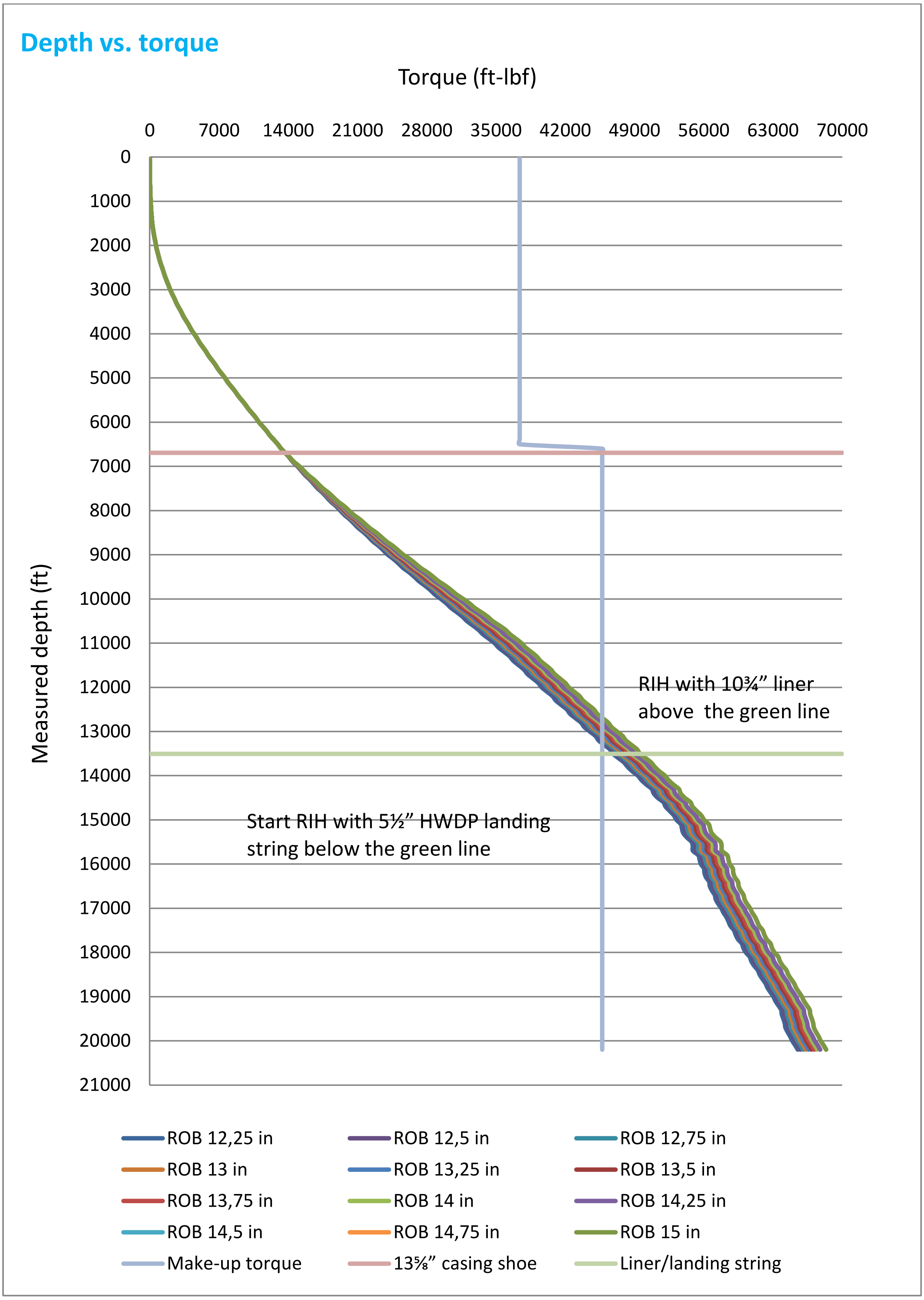


Figure 108: Surface torque 10¾” liner.

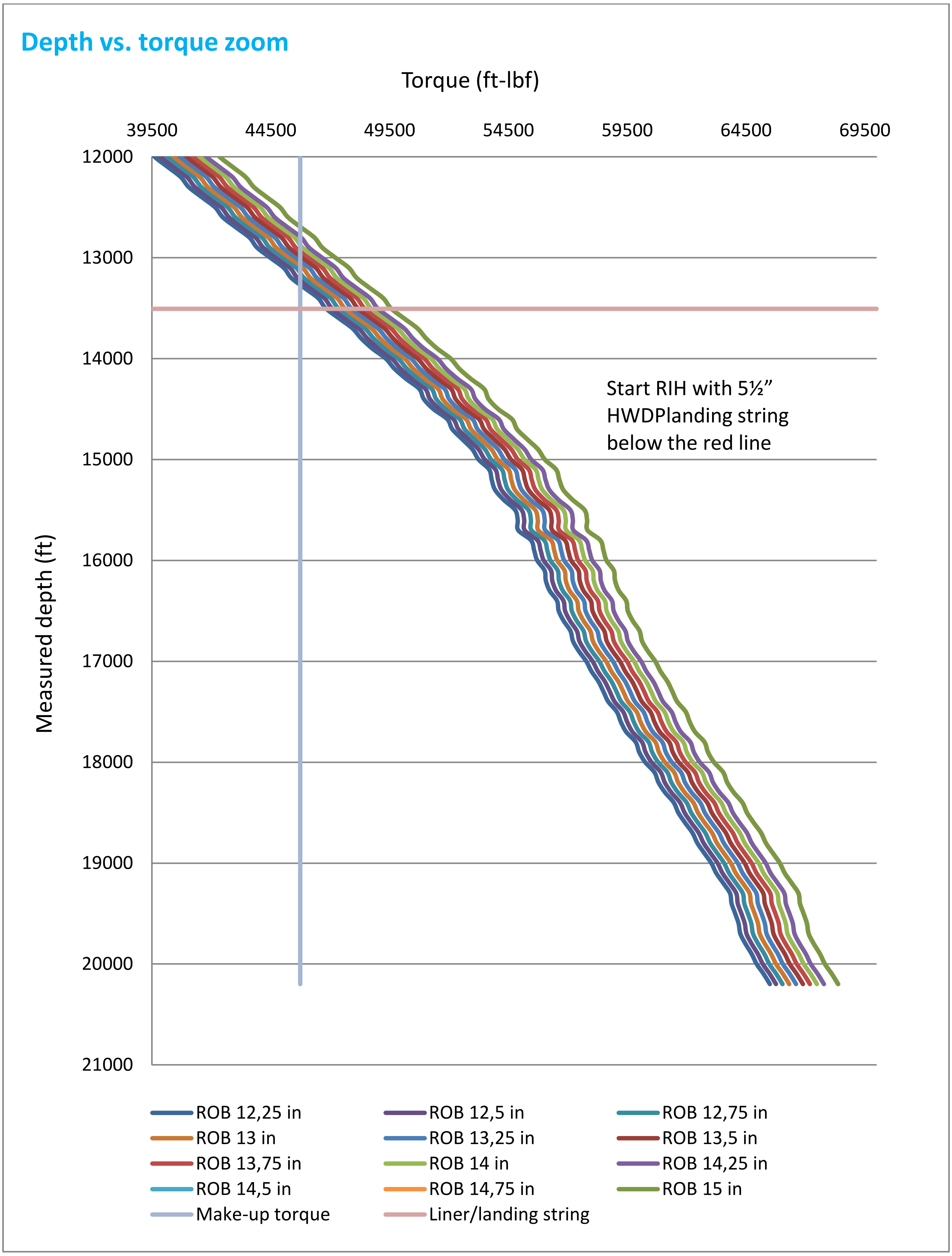


Figure 109: Surface torque 10¾” liner. A zoom of Figure 108 showing the measured depth interval from 15.000 ft. to section TD.

6.2.3 Hook load

Figure 110 and Figure 111 show the tensile and compressive yield limits at each of the string depths analyzed [WellPlan user manual]. From the graphs, you can tell the load that will fail the string, but you will not be able to determine exactly where the failure occurred (then you have to run a different simulation analyzing the forces acting on each individual component in the string at the specific depth).

Figure 110 also displays two curves indicating the maximum weight to yield the liner while POOH (pull out of hole), and the minimum weight to helically buckle the string while RIH (run in hole). The rig capacity limit of 2200 kip (kilo pound) is also plotted in the graph.

The following lines in the graph have more or less identical values, and hence, they are situated on top of each other:

- RIH 14¾" and RIH 15"
- POOH 13¾" and POOH 14"
- POOH 14¼" and POOH 14½"
- POOH 14¾" and POOH 15"

All of the hook load values lie above the minimum weight to induce helical buckling (RIH) and below the maximum weight yield (POOH). None of the HL values cross the minimum weight to induce helical buckling (RIH); and hence, no risk of buckling. The hook load increases with depth in all scenarios; with increasing depth (and in other words increasing string weight – since more liner (and eventually running string) is required to reach further towards TD) comes increased hook load. According to theory presented in section 2.3.8.1 the friction is higher during hoisting (POOH) compared to lowering (RIH). Figure 110 and Figure 111 show the following relationship:

$\text{Hook load}_{RIH} < \text{Hook load}_{ROB} < \text{Hook load}_{POOH}$

Hook load$_{RIH}$

The values for the various hole sizes are the same until about 6700 ft. MD (the 13⅝" shoe is placed at 6693 ft. MD, open hole from here and beyond). During RIH the friction has a decreasing effect; it works upwards. In section 2.3.6 the following equation (6) was given:

Hook load$_{RIH}$ = weight – friction

This implies that the less friction, the higher hook loads. If we have less friction with increasing hole sizes, the hook load should increase with increasing holes size.

- The simulation shows that the biggest hole sizes have the biggest hook load values, and the smallest hole sizes have the smallest values. This implies that with increasing annular clearance comes increased hook load during RIH.

Hook load$_{POOH}$ (the worst case with regards to tensile limit)

The values for the various hole sizes are the same until about 6700 ft. MD (the 13⅝" shoe is placed at 6693 ft. MD, open hole from here and beyond). During POOH the friction has an increasing effect; it works downwards. In section 2.3.6 the following equation (7) was given:

Hook load$_{POOH}$ = weight + friction

This implies that the less friction, the lower hook loads. If we have less friction with increasing holes sizes, the hook load should decrease with increasing holes size.

- The smallest hole sizes have the biggest hook load values, and the biggest hole sizes have the smallest values. This implies that increasing annular clearance results in decreased hook load during POOH.

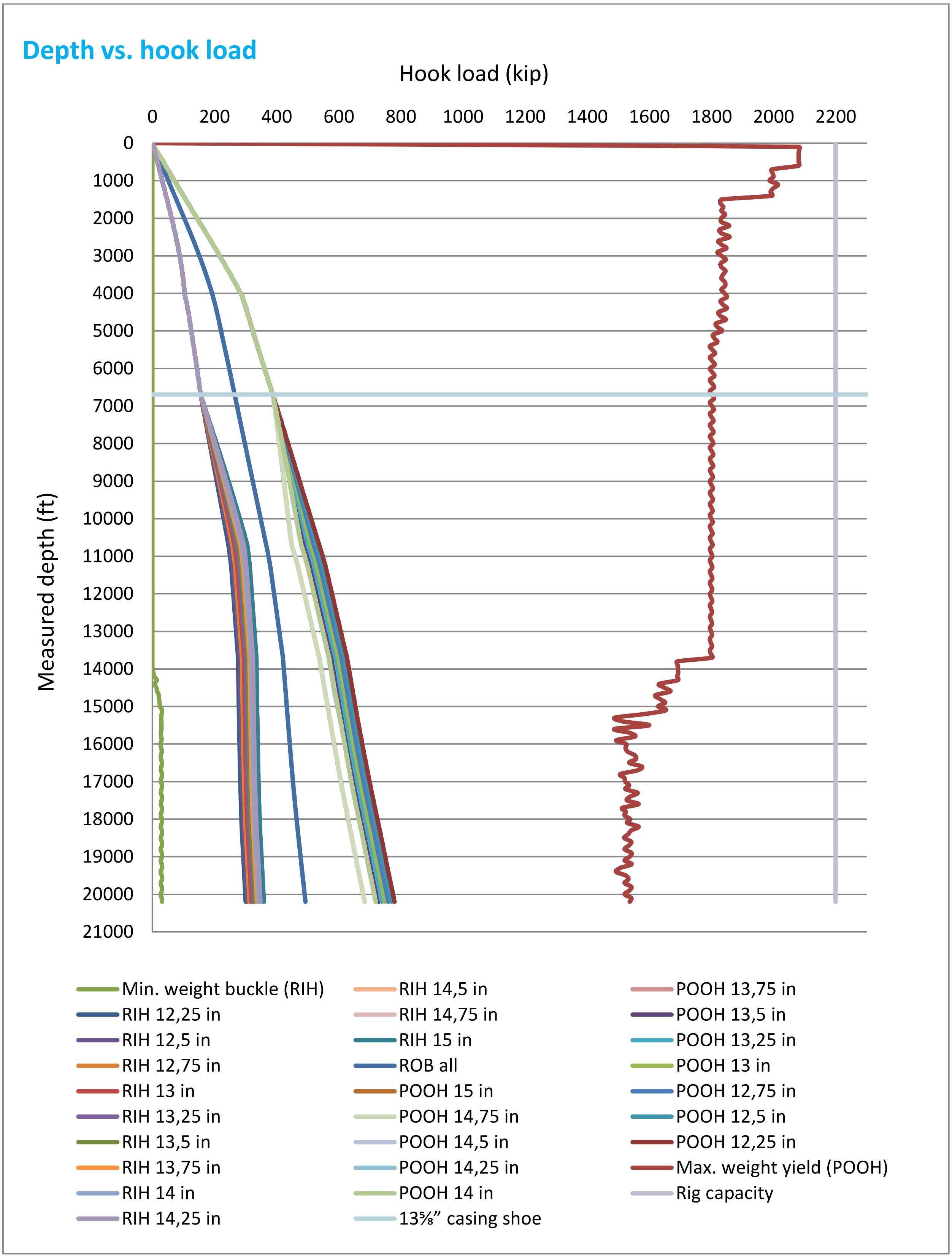


Figure 110: Hook load 10¾" liner.

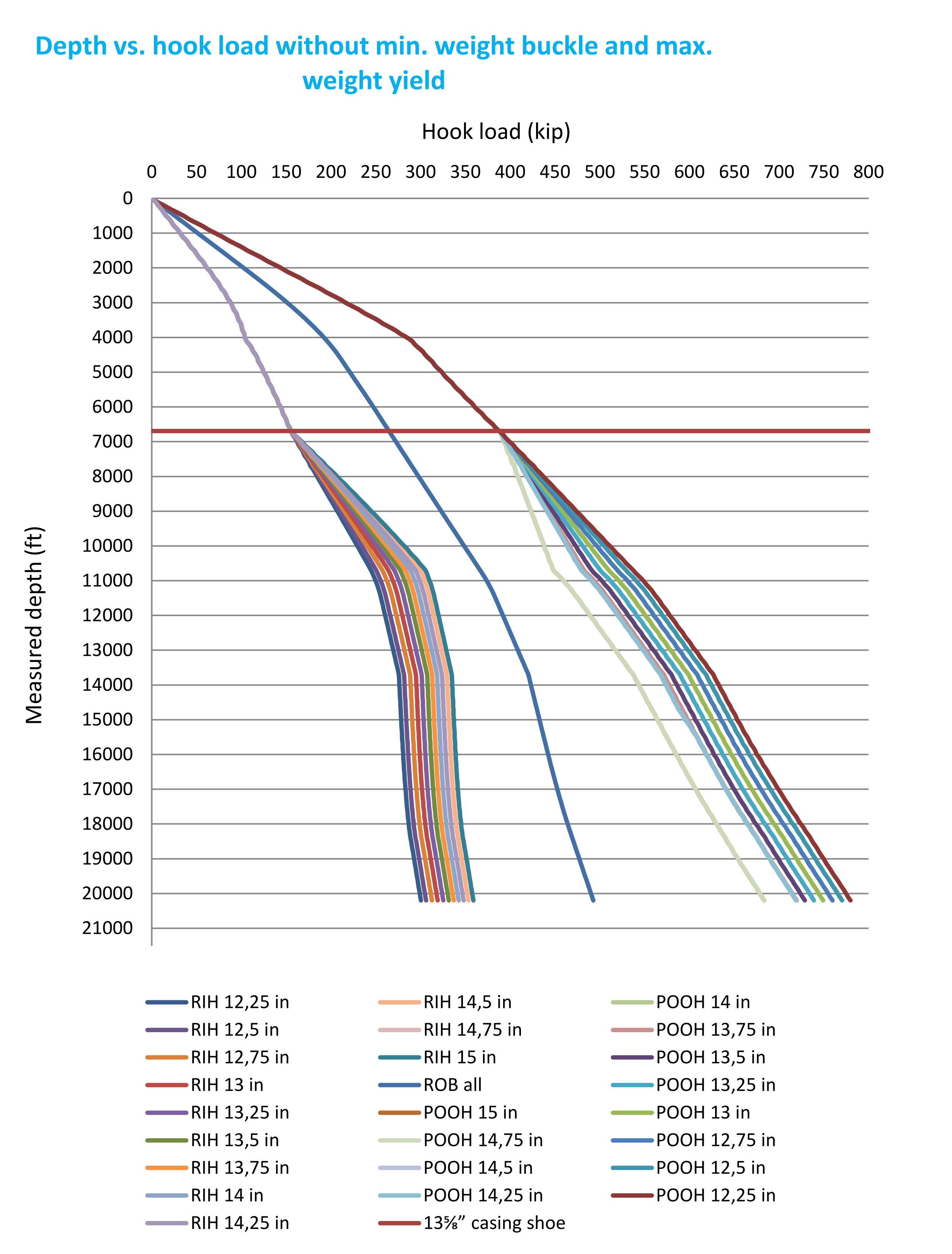


Figure 111: Hook load 10¾" liner without minimum weight buckle, maximum weight yield and rig capacity.

6.2.4 Side forces

The side force or normal force is a measurement of the force exerted by the wellbore onto the liner (work) string. Figure 112 on the following page shows the forces that act on a small segment of work string lying on an inclined plane. This is a simplified diagram; the segment is not moving [WellPlan user manual].

Figure 112 shows that the normal force works in a direction perpendicular to the inclined plane. The weight of the segment (work string) works downward in the same direction as gravity [WellPlan user manual]. The drag force works in the opposite direction of movement, if the string moves downwards, the drag force works upwards (and vice versa). The segment does not slide down the inclined plane due to the work performed by the drag force against string movement. The magnitude of the drag force depends on the normal force, and the coefficient of friction between the inclined plane and the segment. The coefficient of friction (COF) defines the friction between the wellbore and the work string and generally represents all the forces acting against string movement, as presented in section 2.3.8 [WellPlan user manual].

Figure 113 displays the side force per unit length, not at a single point, in all sections of the liner [WellPlan user manual]. This unit length is called the “Contact Force Normalization Length”. This length normally equals the length of a joint of pipe; in this case the value is 44 ft. This simulation can be used to locate points along the well that may be prone to high forces. This useful information can help reduce casing/liner wear or the development of key seats [WellPlan user manual]. This is a different plot than the others presented in this thesis; this plot looks at forces on individual components in the string when string is at one particular depth.

The values are very variable in the beginning due to alterations in the DLS, but stabilize more and more with increasing depths. Hole sizes 14¾” and 15” have the exact same values, and hence, they are situated on top of each other. Figure 113 shows that from around 2000 ft. to 4500 ft. the side forces increase with increasing hole size, before they are constant down to approximately 10.500 ft. From this point and down to 11.500 ft. the side force values decrease (overall) and decrease with increasing hole size. From this point and beyond down to TD the side forces are more or less constant with increasing depth.

Side forces are highly affected by changes in the DLS and in inclination. The DLS is the derivative of the dogleg, which is the absolute change of direction [2]. With increasing DLS come increased side forces. The DLS is affected by changes in the wellbore trajectory in both the horizontal and vertical plane (3D) and will again affect the side forces. It is desirable to avoid large directional changes at an early stage to reduce the risk of unwanted challenges with (increased) reach.

In inclined sections the drillstring will create additional contact forces (and thus side forces) and friction (bigger DLS results in greater friction), which can be seen from equation (13) from section 2.3.8.1 shown below. F_s is the side force and θ is the wellbore-angle.

$$F_s = mg\sin\theta$$

This is a result of more contact (due to bending in the string) between the string and the wellbore when the wellbore-angle increases. This strongly depends on the well geometry and trajectory.

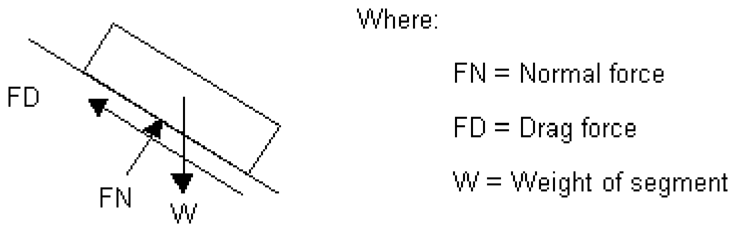


Figure 112: Side force calculations for Soft String model [WellPlan user manual].

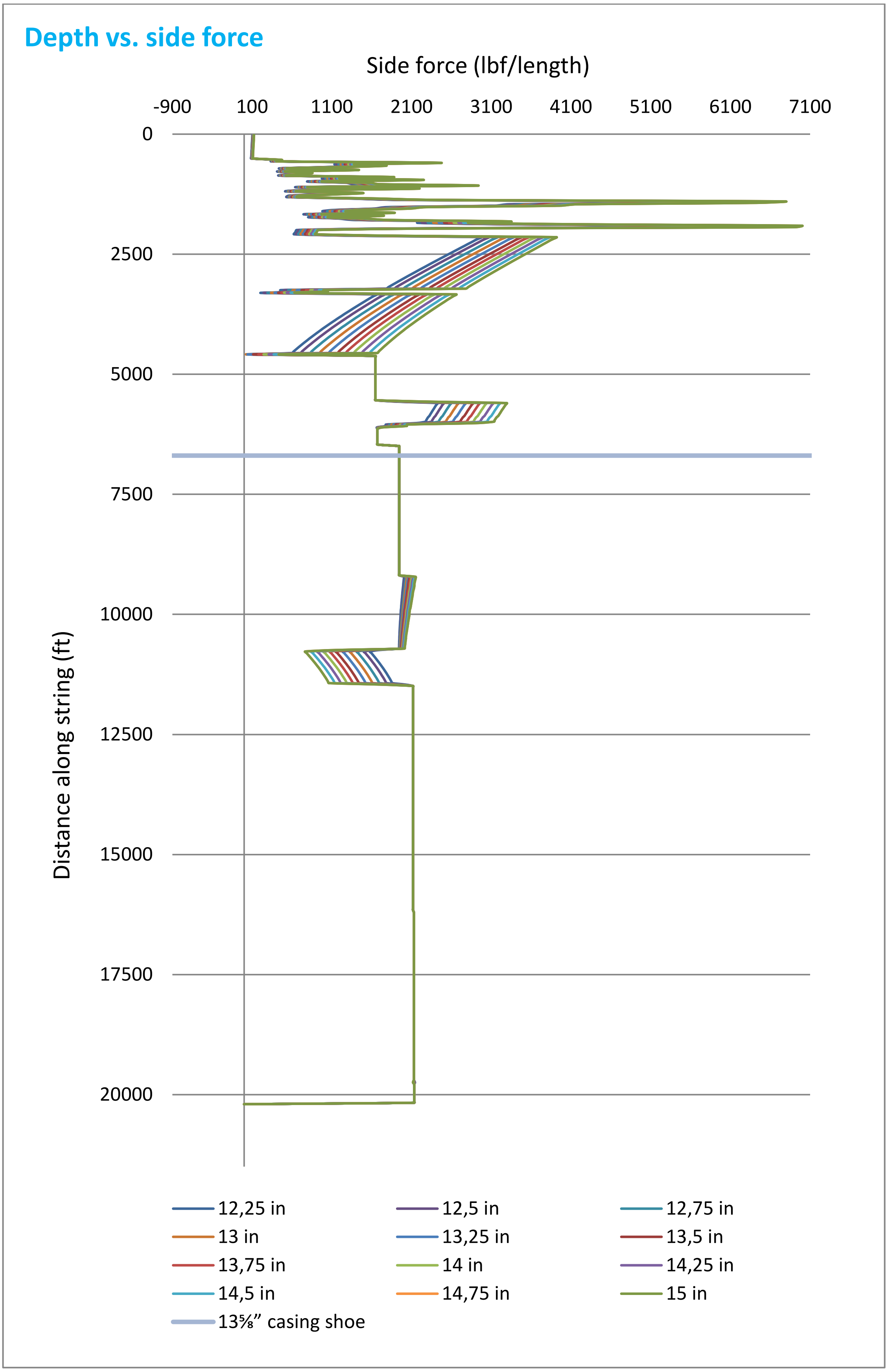


Figure 113: Side forces while running the 10¾" liner.

6.2.5 Depth vs. ECD – Flowrate constant 336 gpm (8 bpm defaulted)

ECD is the density that would exert the circulating pressure under static conditions [WellPlan user manual]. Figure 114 shows the ECD values seen at the 13⅝" shoe (6693 ft. MD), at 10.018.7 ft. MD, at 15.028 ft. MD, at 20.037.4 ft. MD and at bit (20.199 ft. MD), as well as the progression with increasing hole size.

The results show that the ECD's increase with increasing depth and with decreasing hole sizes. For the bigger hole sizes the ECD is almost not affected when reaching further down into the hole. According to theory presented in section 2.5.7.5.1, wellbores with small annulare clearances may produce high ECD values. The 12¼" hole exceeds the fracture gradient at around 18.200 ft. MD, all of the other hole sizes are far below the fracture gradient curve ("the safe window"). Ultimately, it is all about give and take priorities; in order to improve a critical ECD situation one must either increase the hole size or decrease the section depth (either solution will reduce the ECD).

According to theory presented in section 2.5.7.1, both the drilling fluid density, the build-up of suspended cuttings in the annular flow and the annular pressure drop strongly affect the ECD. The annular pressure drop is again affected by factors like the length of annulus or well, annular clearances (drillpipe/casing size), fluid properties, flowrates, rotation of the pipe and ROP. Changing one of these variables will strongly affect the ECD.

The simulation shows that when the annular clearance increases, the ECD's become less critical. ECD's can be reduced by upsizing from a 12¼" hole to a 15" hole, as suggested in section 2.5.7.5.1. Regardless of hole size, ECD limitations dictated by the inside diameter of the last set casing shoe (the clearance between the shoe and the running string) must be taken into account.

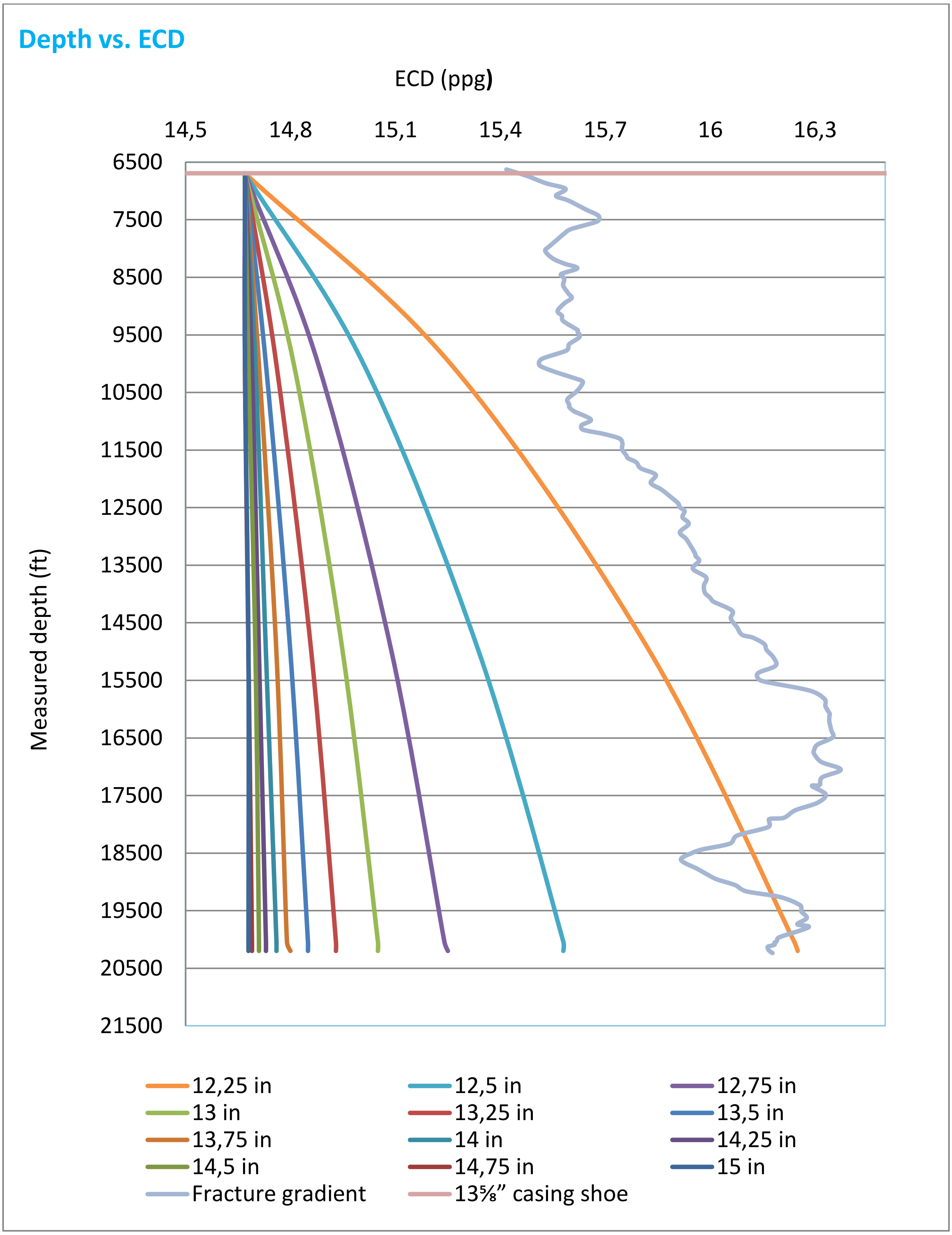


Figure 114: ECD calculations 10¾” liner.

6.2.6 Pressure loss vs. pump rate at TD of section

This simulation determines the pressure loss through the bit for a range of flow rates ranging from 600 to 1100 gpm. The following pressure losses are calculated in this simulation:

- Total pressure loss
- String pressure loss
- Annulus pressure loss
- Bit pressure loss

The total pressure loss is the sum of the annulus pressure loss, the string pressure loss and the bit pressure loss. The maximum pump/surface working pressure is 7000 psi (the pressure the mud pump(s) can withstand). Both the bit and the string pressure losses are the same for all of the three wellbore sizes, and hence, they are situated on top of each other into one shared line (since the string and the bit is the same in all the scenarios).

Figure 115 shows the following:

- Annulus diameter 12¼”:
    - Annulus pressure loss: range from 2250 to 6600 psi
    - Total pressure loss: range from 4500 to 12600 psi
- Annulus diameter 13½”:
    - Annulus pressure loss: range from 360 to 1000 psi
    - Total pressure loss: range from 2500 to 7000 psi
- Annulus diameter 15”:
    - Annulus pressure loss: range from 125 to 350 psi
    - Total pressure loss: range from 2300 to 6350 psi

The pressure losses for both annulus and total (for the 13½” and 15” hole size) pressure are situated pretty close to one another, although the total losses are bigger for the 13½” hole. However, the total pressure losses for the 12¼” hole are significant compared to the 13½” and 15” holes. The 12¼” total pressure loss exceeds the maximum pump/surface pressure at a pump rate of 780 gpm and the total 13½” pressure loss exceeds the maximum pump/surface pressure at a pump rate slightly below 1100 gpm.

The simulation shows that with increased pump rate comes increased pressure losses. The pressure losses also increases with decreasing hole sizes. Decreasing the size of the wellbore will thus increase the risk of exceeding the maximum allowable pump/surface working pressure.

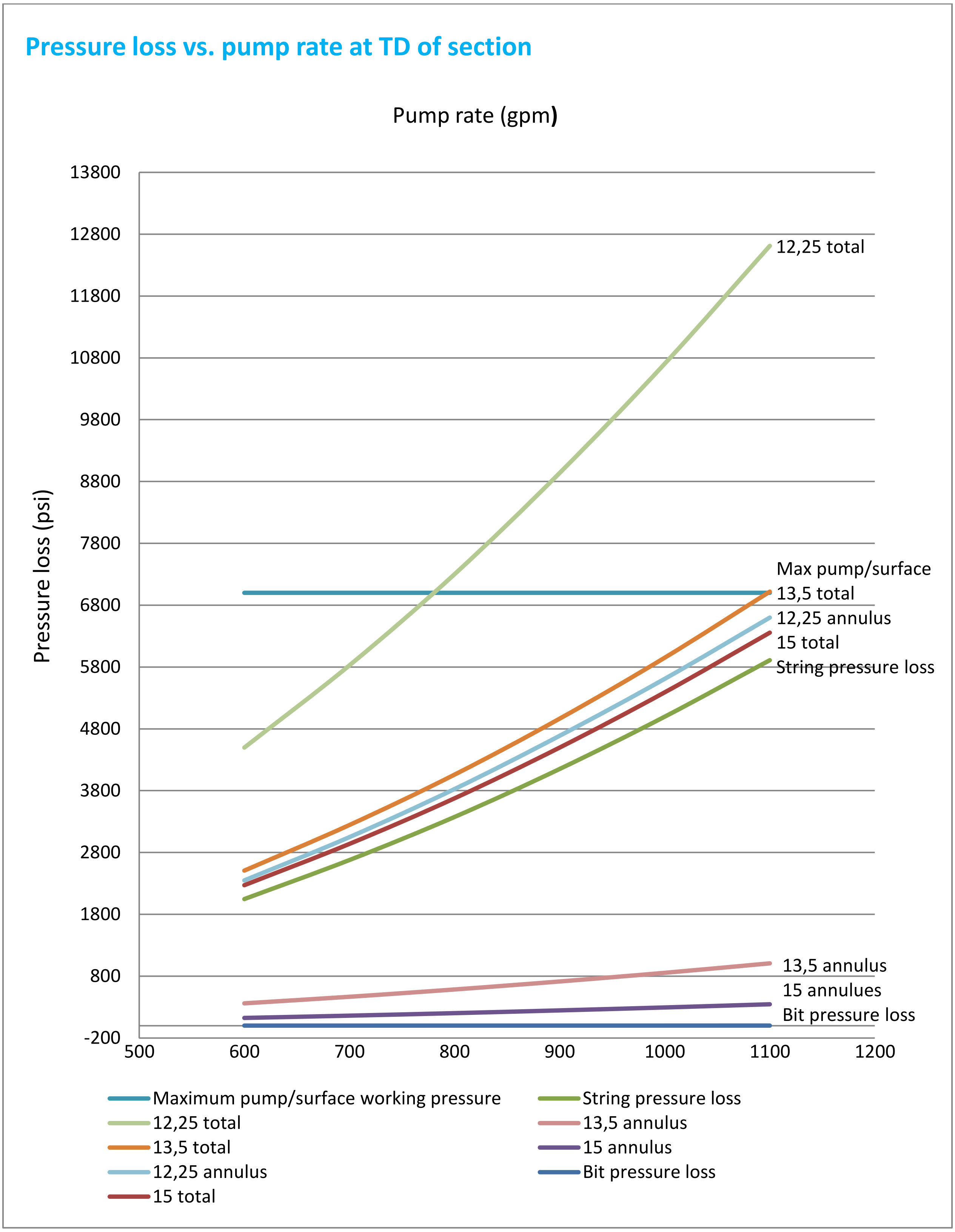


Figure 115: Pressure loss vs. pump rate at TD of section.

6.3 Change in section depth for the 12¼” x 13½” section

According to the theory in section 2.5.7.5.1 the well trajectory affects the total depth that has to be drilled, and will therefore affect ECD’s at depth (the ECD’s increases with increasing depth. The section depth will also affect the required casing design (mainly determined by the relationship between the drilling window and target depth). The well path should ideally be as short as possible and within the limits of other important parameters like T&D and wellbore stability.

Running the casing string to target depth is one of the biggest challenges in ERD wells as presented in section 2.2.3. Methods to help reaching target in these operations can be: use lighter weight casing, to run the casing as a liner, and to apply top drive weight [1]. This should thus be more challenging if the section depth is extended (e.g. from 15.000 to 20.199 ft. MD or from 20.199 to 30.000 ft. MD).

In the following sections, some of the simulations performed in section 6.1 and 6.2 were rerun using different hole section depths (both 15.000 ft. and 30.000 ft. MD), focusing on the hydraulic part. Overall; the 15.000 ft. hole section depth was expected to be less risky than the base case, while the 30.000 ft. hole section depth was expected to be more critical compared to the base case. This is as a result of higher ECD’s, higher pressure losses and higher forces acting on the string as the section depth (distance) increases.

6.3.1 Minimum flowrate for hole cleaning – drilling the 12¼" x 13½" hole

The following Figure 116 shows the minimum flowrates for hole cleaning for various hole sizes and hole section depths, both for TD 20.199 ft. and 30.000 ft. MD. As expected, the minimum required flowrate for hole cleaning increases with increasing section depth and with increasing hole size, due to both larger annular clearance and increased cutting transportation depth (distance).

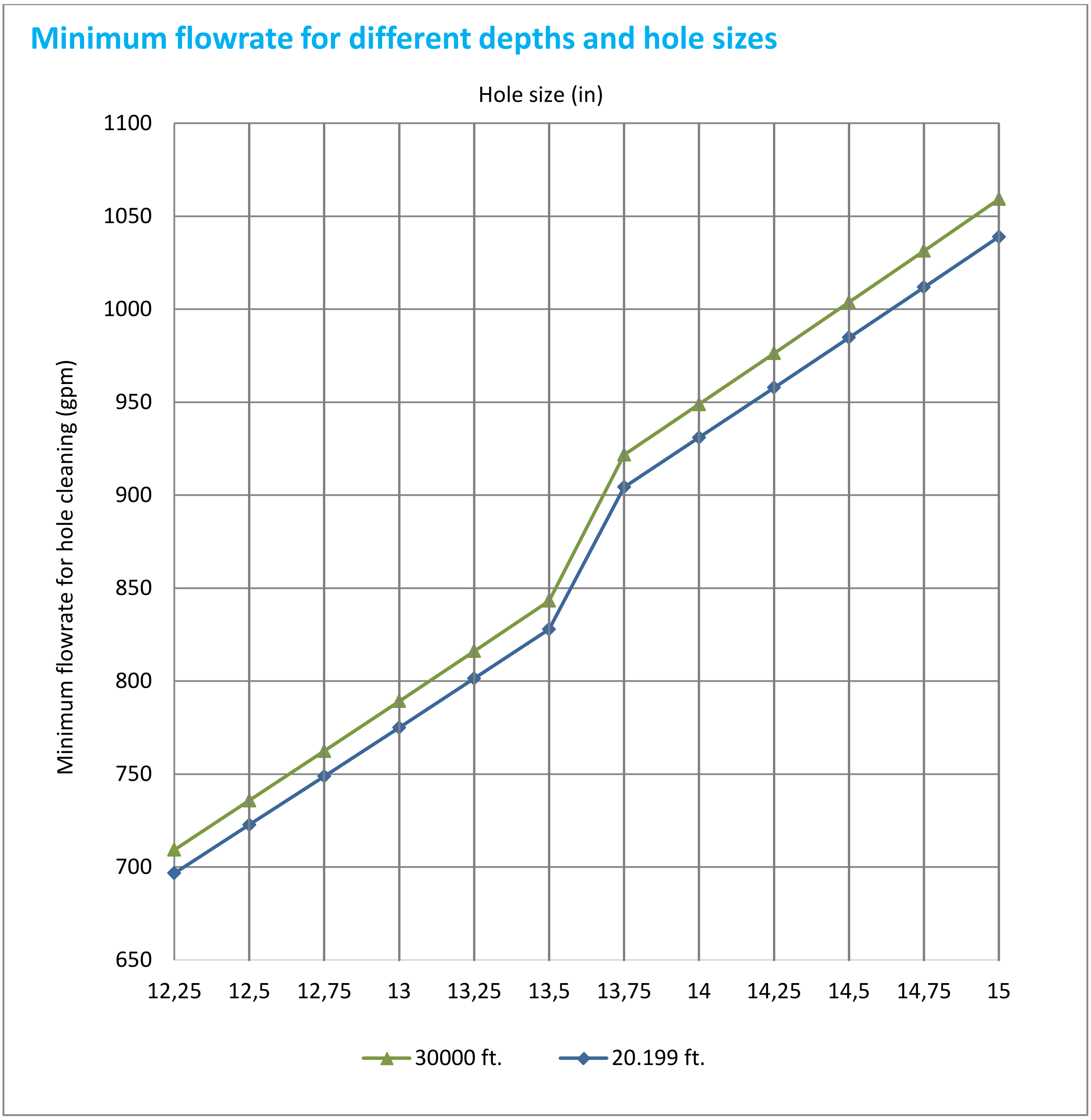


Figure 116: Minimum flowrate for hole cleaning 20.199 ft. and 30.000 ft. MD.

6.3.2 ECD vs. hole size – running the 10¾" production liner

The objective with this simulation was to observe how the ECD affected by a change in section depth), as well as the progression with increasing hole size. The flowrate is constant 336 gpm (8 bpm defaulted). Figure 117 shows that the ECD increases with increased section depth and decreases with increasing hole size. The simulation shows that when the annular clearance increases, the ECD's become less critical. It also shows that the ECD values at the 13⅝" shoe (6693 ft. MD) is constant with increasing hole size as expected.

Referring to Figure 88; the fracture gradient can vary with depth. The simulation shows that the friction contribution from the hole decreases with increasing hole size until the hole size is so large that there is no longer any added friction loss. For a given hole section the reduced ECD effect based on hole size will reach a minimum and any hole size larger than this is not giving any additional ECD reduction.

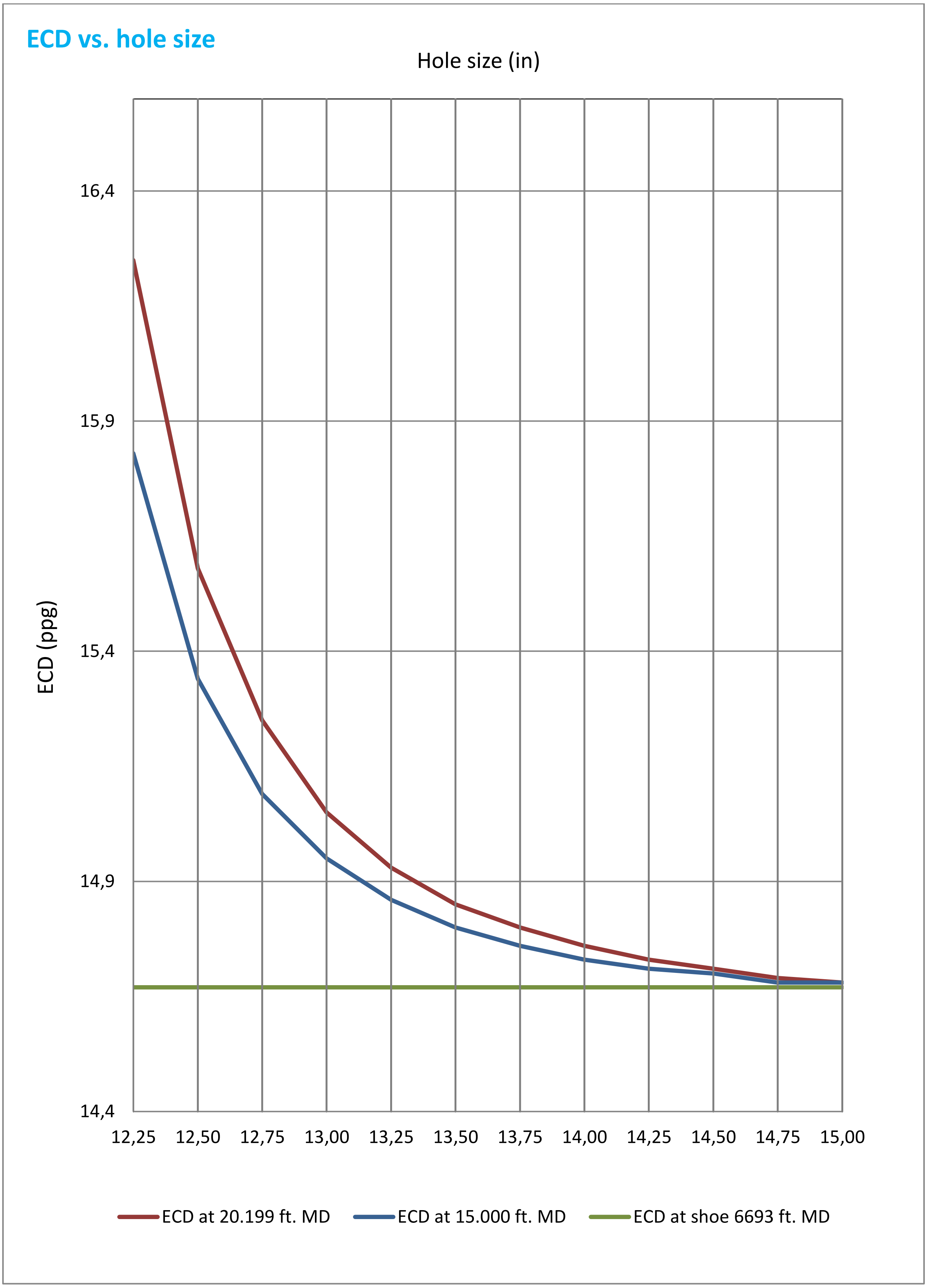


Figure 117: ECD vs. hole size at shoe 6693 ft., 15.000 ft. and 20.199 ft. MD.

6.3.3 Pressure loss vs. pump rate – running the 10¾” production liner

The pressure losses increase with increasing hole section depth and with decreasing hole size as expected from Figure 115. The pressure losses in both Figure 118 and Figure 119 show the same trends as seen in Figure 115, but the pressure losses are less critical for the 15.000 ft. hole section depth and more critical for the 30.000 ft. hole section depth. In Figure 118 only one line exceeds the maximum pump/surface pressure (12¼” total at a pump rate of 1050 gpm), while in Figure 119 as many as 4 lines show critical pressure losses, exceeding the maximum pump/surface pressure. These are listed below in detail:

- 12¼” total pressure loss has exceeded the maximum surface pressure at a pump rate lower than the minimum pump rate used in the simulation which is 600 gpm
- 13½” total pressure loss exceeds at a pump rate slightly below 700 gpm
- 15” total pressure loss exceeds at a pump rate slightly above 700 gpm
- String pressure loss exceeds at a pump rate slightly above 700 gpm

The simulations show that the pressure losses increase with decreasing hole sizes in both, and that with increased pump rate comes increased pressure losses (also seen in section 6.2.6). The simulation shows that the margin of error decreases with reach and that decreasing the size of the wellbore increases the risk of exceeding the maximum allowable pump/surface working pressure, as presented in section 6.2.6.

6.3.3.1 15.000 ft. MD

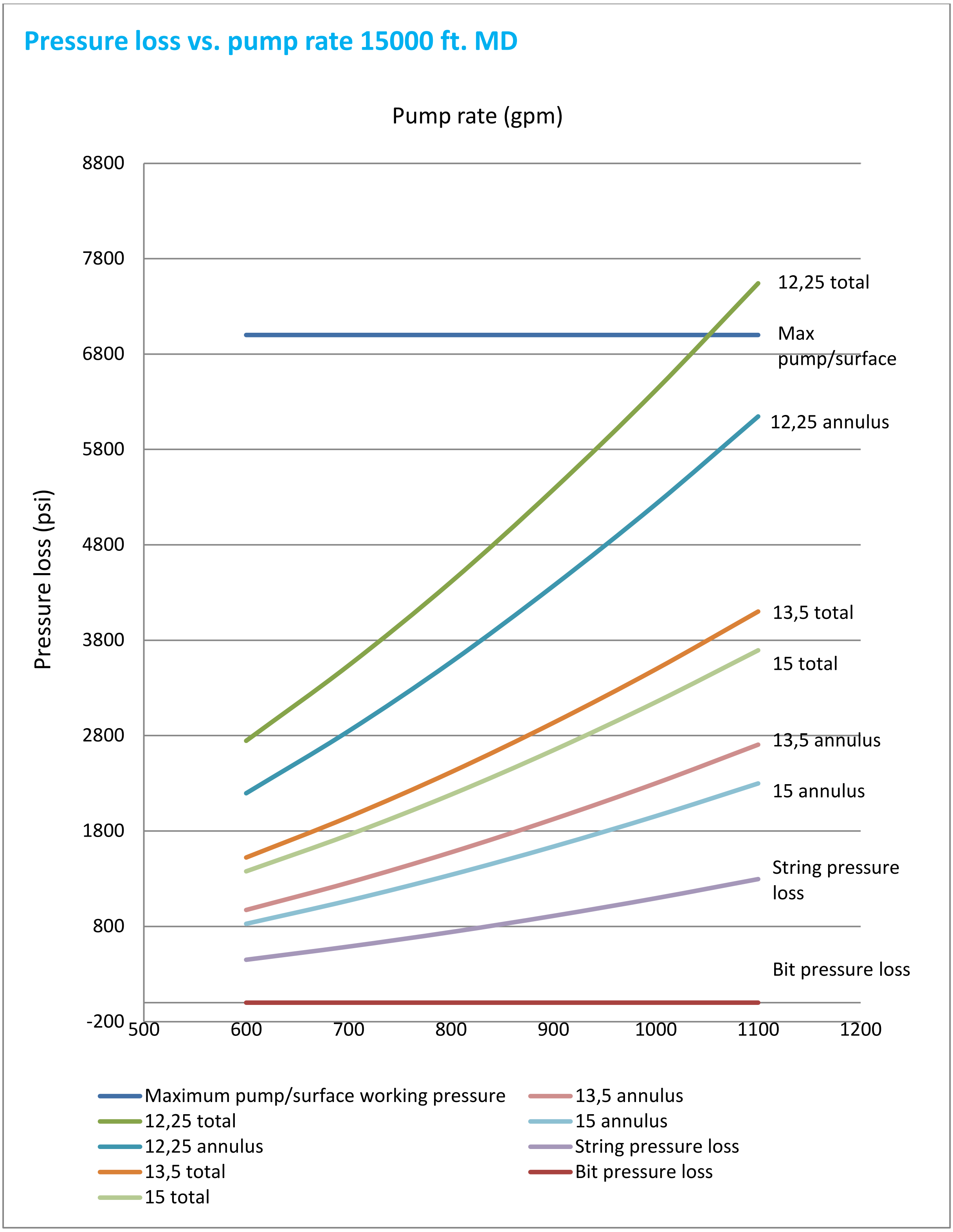


Figure 118: Pressure loss vs. pump rate 15.000 ft. MD.

6.3.3.2 30.000 ft. MD

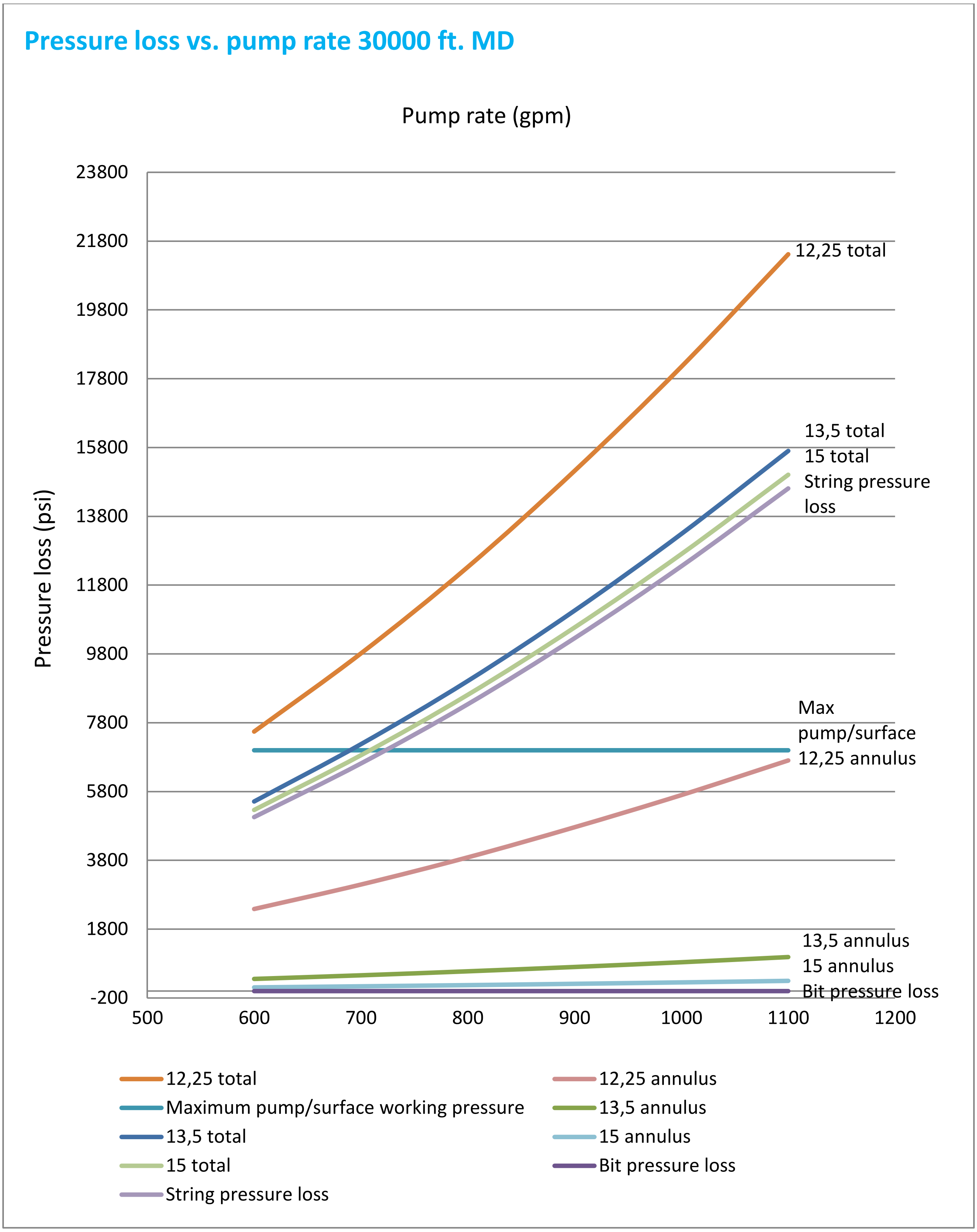


Figure 119: Pressure loss vs. pump rate 30.000 ft. MD.

7 Conclusion

In today's drilling industry more and more wells are drilled horizontally or with high inclination angles. This drilling concept is known as Extended Reach Drilling (ERD) and enables the drilling of so-called Extended Reach Wells (ERWs). The definition of an extended reach well can be discussed indefinitely, but is usually defined by the step-out ratio. It can be calculated using two different aspect ratios; the unwrapped reach ratio (the along-hole departure/TVD) and the depth ratio (MD/TVD). In both cases; if these ratios exceed 2, the well is considered to be an ERD well. It can also be used to evaluate the complexity of an ERW; the higher the ratio, the more complex and difficult well.

This thesis focuses on engineering challenges in Extended Reach Drilling. The importance of a thorough well planning of an ERD well has been explained in detail. The three types of engineering studies presented that has to be performed during the planning of ERD wells are listed below:

1. Torque, drag, buckling and corresponding limitations;
2. Mud weight selection and hydraulic calculations;
3. Hole cleaning.

ERD focuses that need to be paid extra attention while drilling in order to obtain an effective and safe drilling operation have been assessed. They include; hole cleaning, ROP, ECD management, torque & drag monitoring, evaluate real-time pore pressure prediction, mud-logging service, avoid high DLS (dog leg severity) and avoid pack-offs. Other critical factors when planning and drilling ERD wells include well trajectory design, bottom hole assembly design (BHA), bit hydraulics, drillstring design and the ability to transfer weight on bit (WOB).

The simulations performed in this thesis were based on the Conoco Phillips' ERD well Z-25 on Ekofisk – The base case. It involves a sensitivity analysis comparing a total of 12 different hole sizes ranging from 12¼" to 15" with increments. The overall objective for all the simulations is to study the effect of varying hole size in the 12¼" x 13½" hole section (under-ream to 13½" while drilling with a 12¼" bit). The simulations include torque, hook load, side forces, ECD, hole cleaning and pressure loss. It resulted in important observations, relevant for future ERD decisions. The findings of the thesis based on the simulations in WellPlan are summarized below;

1. The WOB to induce/initiate sinusoidal or helical buckling for both drilling and running liner increases with decreasing hole sizes. The simulation shows that as the measured depth increases, so does the risk of buckling during drilling, while it decreases with depth when running liner (overall); for this specific case studied.

2. The surface torque increases with increasing hole sizes. As the measured depth increases, so does the maximum torque measured at the surface. When running the liner it will not be likely to rotate it from 13.000 ft. MD and beyond down to section TD due to the fact that the measured torque exceed the make-up torque of the liner at this depth. It will therefore not be possible to rotate liner at the end of the section; although it is not optimal for the upcoming cement job (rotation will enhance the cement displacement). Not being able to rotate during the cement job also limits the chance for successful zonal isolation.

3. Hook load (HL): The relationship $HL_{RIH} < HL_{ROB} < HL_{POOH}$ applies for both drilling the base case and running 10¾" the liner:

    a. During drilling; the hook load increases with increasing hole sizes for all three scenarios (RIH, ROB and POOH).
    b. When running the liner; increasing hole sizes tend to have increasing HL values when RIH, while decreasing hole sizes tend to have increasing HL values when POOH.

4. Side forces are highly affected by changes in the DLS. With increasing DLS come increased side forces. The DLS is affected by changes in the wellbore trajectory in both the horizontal and vertical plane (3D) and will again affect the side forces. It is desirable to avoid large directional changes at an early stage to reduce the risk of unwanted challenges with (increased) reach.

5. When the annular clearance increases, the ECD's become lower and less critical; the ECD's thus increase with decreasing hole sizes. Managing the ECD is all about give and take priorities; in order to improve a critical ECD situation one must either increase the hole size or decrease the section depth.

   Regardless of hole size there is ECD limitations dictated by the inside diameter of the last set casing shoe (the clearance between the shoe and the running string). The ECD is strongly affected by the length of annulus or well, annular clearances, fluid properties, flowrates, rotation of the pipe and ROP. Changing one of these variables will strongly affect the ECD.

6. Hole cleaning:

   a. The bed height increases with increasing hole angle and decreases with increasing flowrate. Increasing hole sizes require higher "minimum flowrates" to reduce the bed height of the cuttings in the annulus. The simulation shows that as the hole size increases, so does the bed height in the annulus.
   b. The annular velocity increases with increasing flowrates and with decreasing hole sizes. High annular velocities are preferable to ensure a better and more efficient hole cleaning.
   c. The required annular flowrate for hole cleaning increases with increasing hole sizes; implying that larger annular clearance require a higher flowrate in order to obtain a proper hole cleaning.
   d. The percentage of the annular volume filled with cuttings suspended in the drilling fluid increases with increasing hole sizes and decreases with both increasing flowrate and hole angle.

7. The total pressure loss for the system is the sum of the annulus pressure loss, the string pressure loss and the bit pressure loss. The total pressure loss increases with decreasing hole sizes and with increasing flowrates. This implies that decreasing the size of the wellbore increases the risk of exceeding the maximum pump/surface working pressure.

8. The simulations performed and presented in section 6.3 prove that the margin of error decreases with reach, as mention in section 2.2.3. I.e. with increased displacement come increased challenges.

The simulations show a wide range of dependencies; it is all about give and take priorities. It is thus extremely important to identify limitations in early phase and to develop a strong relationship between locations, technologies and local knowledge/experiences in order to achieve safe and effective drilling operations with the best possible outcome.

When and if the situation in the todays drilling industry improves it is possible to expand the Extended Reach Drilling envelope and to push the limits to new world records in the future, even though the main problems of ERW are still the same engineering challenges: hole cleaning, transferring WOB, torque and drag, buckling, ECD management, pump pressure control and wellbore stability.

8 Future work

The following bullet point give a suggestion for future work with ERD, in relation to the simulations and results discussed in this thesis;

- Investigate further the possibility to find a rule of thumb for the relationship between the hole size and the section length. Need to acknowledge the complexity of well operations, dependencies, priorities and local field experiences. As a result of this, detailed engineering is required in the complex drilling environment for ERD wells.

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Appendix

The following Table 16 shows the actual well path for Z-25 [Compass].

Table 16: Actual well path Z-25 [Compass].

MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	DLS (°/100 ft)
0	0	0	0	0
548,7	0,25	246,5	548,7	0,05
550	0,25	245,65	550	0,3
575	0,29	231,07	575	0,32
600	0,22	242,56	600	0,35
625	0,05	43,44	625	1,07
650	0,19	79,65	650	0,61
675	0,25	116,14	675	0,6
700	0,52	120,2	700	1,08
725	0,48	129,85	725	0,37
750	0,53	116,17	750	0,52
775	0,63	105,36	775	0,59
800	0,7	106,28	800	0,28
825	0,64	112,6	825	0,38
850	0,6	116,62	850	0,24
875	0,71	124,67	875	0,57
900	0,62	127,35	900	0,38
925	0,57	104,77	925	0,95
950	0,42	117,07	950	0,73
975	0,64	91,83	975	1,26
1000	0,71	101,63	1000	0,54
1025	0,71	107,02	1025	0,27
1050	0,98	109,28	1050	1,09
1075	0,97	122,15	1075	0,88
1100	1,28	130,4	1100	1,4
1125	1,31	132,65	1125	0,24
1150	1,32	140,64	1150	0,73
1175	1,15	153,91	1174,9	1,33
1200	1,23	150,95	1199,9	0,4
1225	1,3	151,75	1224,9	0,29
1250	1,11	148,95	1249,9	0,8
1275	1,3	148,96	1274,9	0,76

1300	1,18	151,56	1299,9	0,53
1325	1,28	154	1324,9	0,45
1350	1,2	158,12	1349,9	0,48
1375	1,48	161,61	1374,9	1,17
1400	1,7	167,34	1399,9	1,08
1425	2,36	175,79	1424,9	2,89
1450	3,16	180,15	1449,8	3,31
1475	3,59	181,73	1474,8	1,76
1500	4,08	182,93	1499,7	1,99
1525	4,46	185,38	1524,7	1,69
1550	4,69	183,91	1549,6	1,03
1575	4,95	183,6	1574,5	1,05
1600	5,09	183,26	1599,4	0,57
1625	5,3	181,2	1624,3	1,12
1650	5,36	182,16	1649,2	0,43
1675	5,7	181,81	1674,1	1,37
1700	5,72	180,89	1699	0,37
1725	5,69	178,76	1723,8	0,86
1750	5,79	177,89	1748,7	0,53
1775	5,9	177,1	1773,6	0,55
1800	6,13	175,7	1798,4	1,09
1825	6,34	175,79	1823,3	0,84
1850	6,75	173,54	1848,1	1,93
1875	7,08	173,46	1873	1,32
1900	7,53	173,31	1897,8	1,8
1925	8,19	170,19	1922,5	3,14
1950	9	167,56	1947,2	3,6
1974	9,66	165,78	1970,9	3
2000	9,81	165,96	1996,5	0,58
2100	10,37	166,59	2095	0,58
2135	10,57	166,79	2129,4	0,58
2200	11,84	168,39	2193,2	2,01
2300	13,81	170,27	2290,7	2,01
2400	15,78	171,7	2387,4	2,01
2500	17,77	172,81	2483,1	2,01
2600	19,76	173,7	2577,8	2,01
2700	21,75	174,44	2671,3	2,01
2800	23,75	175,06	2763,5	2,01
2900	25,75	175,59	2854,3	2,01
3000	27,75	176,04	2943,6	2,01
3100	29,75	176,44	3031,3	2,01
3200	31,75	176,8	3117,2	2,01

3262,5	33	177	3170	2,01
3300	33	177	3201,5	0
3322,1	33	177	3220	0
3400	34,56	177,04	3284,7	2
3500	36,56	177,09	3366,1	2
3600	38,56	177,13	3445,4	2
3700	40,56	177,18	3522,5	2
3800	42,56	177,21	3597,3	2
3900	44,56	177,25	3669,7	2
4000	46,56	177,28	3739,8	2
4100	48,56	177,31	3807,2	2
4200	50,56	177,34	3872,1	2
4300	52,56	177,36	3934,3	2
4400	54,56	177,39	3993,7	2
4500	56,56	177,41	4050,2	2
4605,6	58,67	177,44	4106,8	2
4700	58,67	177,44	4155,9	0
4800	58,67	177,44	4207,9	0
4900	58,67	177,44	4259,9	0
5000	58,67	177,44	4311,9	0
5100	58,67	177,44	4363,9	0
5200	58,67	177,44	4415,9	0
5300	58,67	177,44	4467,9	0
5400	58,67	177,44	4519,9	0
5500	58,67	177,44	4571,9	0
5582	58,67	177,44	4614,5	0
5600	58,7	177,86	4623,9	2
5700	58,93	180,18	4675,7	2
5800	59,19	182,49	4727,1	2
5900	59,5	184,79	4778,1	2
6000	59,85	187,07	4828,6	2
6040,9	60	188	4849,1	2
6100	60,09	188,67	4878,6	0,99
6122	60,13	188,92	4889,5	1
6200	60,13	188,92	4928,4	0
6300	60,13	188,92	4978,2	0
6400	60,13	188,92	5028	0
6500	60,13	188,92	5077,8	0
6600	60,13	188,92	5127,6	0
6700	60,13	188,92	5177,4	0
6800	60,13	188,92	5227,2	0
6900	60,13	188,92	5277	0

7000	60,13	188,92	5326,8	0
7100	60,13	188,92	5376,6	0
7200	60,13	188,92	5426,4	0
7300	60,13	188,92	5476,3	0
7400	60,13	188,92	5526,1	0
7500	60,13	188,92	5575,9	0
7600	60,13	188,92	5625,7	0
7700	60,13	188,92	5675,5	0
7800	60,13	188,92	5725,3	0
7900	60,13	188,92	5775,1	0
8000	60,13	188,92	5824,9	0
8100	60,13	188,92	5874,7	0
8200	60,13	188,92	5924,5	0
8300	60,13	188,92	5974,3	0
8400	60,13	188,92	6024,1	0
8500	60,13	188,92	6073,9	0
8600	60,13	188,92	6123,7	0
8700	60,13	188,92	6173,5	0
8800	60,13	188,92	6223,3	0
8900	60,13	188,92	6273,1	0
9000	60,13	188,92	6322,9	0
9100	60,13	188,92	6372,7	0
9200	60,13	188,92	6422,5	0
9216,8	60,13	188,92	6430,9	0
9300	60,08	188,17	6472,4	0,78
9400	60,04	187,27	6522,3	0,78
9500	59,99	186,36	6572,3	0,79
9600	59,96	185,46	6622,3	0,78
9700	59,93	184,55	6672,4	0,79
9800	59,91	183,64	6722,5	0,79
9900	59,89	182,73	6772,7	0,79
10000	59,88	181,83	6822,8	0,78
10100	59,87	180,92	6873	0,79
10200	59,88	180,01	6923,2	0,79
10300	59,88	179,1	6973,4	0,79
10400	59,9	178,19	7023,6	0,79
10500	59,92	177,29	7073,7	0,78
10600	59,95	176,38	7123,8	0,79
10700	59,98	175,47	7173,9	0,79
10752,3	60	175	7200	0,78
10800	60,72	175,01	7223,6	1,5
10900	62,22	175,02	7271,4	1,5

11000	63,72	175,04	7316,8	1,5
11100	65,22	175,05	7359,9	1,5
11200	66,72	175,06	7400,6	1,5
11300	68,22	175,08	7439	1,5
11400	69,72	175,09	7474,9	1,5
11472,2	70,8	175,1	7499,3	1,5
11500	70,8	175,1	7508,4	0
11600	70,8	175,1	7541,3	0
11700	70,8	175,1	7574,2	0
11800	70,8	175,1	7607,1	0
11900	70,8	175,1	7639,9	0
12000	70,8	175,1	7672,8	0
12100	70,8	175,1	7705,7	0
12200	70,8	175,1	7738,6	0
12300	70,8	175,1	7771,5	0
12400	70,8	175,1	7804,4	0
12500	70,8	175,1	7837,3	0
12600	70,8	175,1	7870,2	0
12700	70,8	175,1	7903,1	0
12800	70,8	175,1	7935,9	0
12900	70,8	175,1	7968,8	0
13000	70,8	175,1	8001,7	0
13100	70,8	175,1	8034,6	0
13200	70,8	175,1	8067,5	0
13300	70,8	175,1	8100,4	0
13400	70,8	175,1	8133,3	0
13500	70,8	175,1	8166,2	0
13600	70,8	175,1	8199,1	0
13700	70,8	175,1	8231,9	0
13800	70,8	175,1	8264,8	0
13900	70,8	175,1	8297,7	0
14000	70,8	175,1	8330,6	0
14100	70,8	175,1	8363,5	0
14200	70,8	175,1	8396,4	0
14300	70,8	175,1	8429,3	0
14400	70,8	175,1	8462,2	0
14500	70,8	175,1	8495	0
14600	70,8	175,1	8527,9	0
14700	70,8	175,1	8560,8	0
14800	70,8	175,1	8593,7	0
14900	70,8	175,1	8626,6	0
15000	70,8	175,1	8659,5	0

15100	70,8	175,1	8692,4	0
15200	70,8	175,1	8725,3	0
15300	70,8	175,1	8758,2	0
15400	70,8	175,1	8791	0
15500	70,8	175,1	8823,9	0
15600	70,8	175,1	8856,8	0
15700	70,8	175,1	8889,7	0
15800	70,8	175,1	8922,6	0
15900	70,8	175,1	8955,5	0
16000	70,8	175,1	8988,4	0
16100	70,8	175,1	9021,3	0
16200	70,8	175,1	9054,1	0
16300	70,8	175,1	9087	0
16400	70,8	175,1	9119,9	0
16500	70,8	175,1	9152,8	0
16600	70,8	175,1	9185,7	0
16700	70,8	175,1	9218,6	0
16800	70,8	175,1	9251,5	0
16900	70,8	175,1	9284,4	0
17000	70,8	175,1	9317,3	0
17100	70,8	175,1	9350,1	0
17200	70,8	175,1	9383	0
17300	70,8	175,1	9415,9	0
17400	70,8	175,1	9448,8	0
17500	70,8	175,1	9481,7	0
17600	70,8	175,1	9514,6	0
17700	70,8	175,1	9547,5	0
17800	70,8	175,1	9580,4	0
17900	70,8	175,1	9613,2	0
18000	70,8	175,1	9646,1	0
18100	70,8	175,1	9679	0
18200	70,8	175,1	9711,9	0
18300	70,8	175,1	9744,8	0
18400	70,8	175,1	9777,7	0
18500	70,8	175,1	9810,6	0
18600	70,8	175,1	9843,5	0
18700	70,8	175,1	9876,4	0
18800	70,8	175,1	9909,2	0
18900	70,8	175,1	9942,1	0
19000	70,8	175,1	9975	0
19100	70,8	175,1	10007,9	0
19200	70,8	175,1	10040,8	0

19300	70,8	175,1	10073,7	0
19400	70,8	175,1	10106,6	0
19500	70,8	175,1	10139,5	0
19600	70,8	175,1	10172,4	0
19700	70,8	175,1	10205,2	0
19741,9	70,8	175,1	10219	0
19764,2	71	175	10226,3	1
19800	71	175	10238	0
19900	71	175	10270,5	0
20000	71	175	10303,1	0
20100	71	175	10335,6	0
20200	71	175	10368,2	0
20264,2	71	175	10389,1	0
20300	71,09	176,13	10400,7	2,99
20400	71,36	179,29	10432,9	3
20415,3	71,41	179,77	10437,8	2,99
20500	71,41	179,77	10464,8	0
20600	71,41	179,77	10496,7	0
20700	71,41	179,77	10528,6	0
20719,7	71,41	179,77	10534,8	0
20800	73,81	179,91	10558,8	3
20900	76,81	180,08	10584,2	3
21000	79,81	180,25	10604,5	3
21100	82,8	180,41	10619,6	3
21200	85,8	180,57	10629,5	3
21300	88,79	180,73	10634,2	3
21332	89,75	180,78	10634,6	3
21400	89,75	180,78	10634,9	0
21500	89,75	180,78	10635,4	0
21600	89,75	180,78	10635,8	0
21700	89,75	180,78	10636,2	0
21800	89,75	180,78	10636,7	0
21900	89,75	180,78	10637,1	0
22000	89,75	180,78	10637,5	0
22100	89,75	180,78	10638	0
22200	89,75	180,78	10638,4	0
22300	89,75	180,78	10638,8	0
22400	89,75	180,78	10639,3	0
22480,4	89,75	180,78	10639,6	0
22500	89,47	180,51	10639,8	1,98
22600	88,05	179,1	10641,9	2
22699,4	86,64	177,69	10646,5	2

22800	86,64	177,69	10652,4	0
22900	86,64	177,69	10658,3	0
23000	86,64	177,69	10664,1	0
23100	86,64	177,69	10670	0
23200	86,64	177,69	10675,8	0
23300	86,64	177,69	10681,7	0
23400	86,64	177,69	10687,6	0
23420,7	86,64	177,69	10688,8	0
23500	88,21	177,9	10692,3	2
23570,9	89,62	178,08	10693,7	2
23600	89,62	178,08	10693,9	0
23700	89,62	178,08	10694,5	0
23800	89,62	178,08	10695,2	0
23900	89,62	178,08	10695,8	0
24000	89,62	178,08	10696,5	0
24100	89,62	178,08	10697,2	0
24200	89,62	178,08	10697,8	0
24300	89,62	178,08	10698,5	0
24400	89,62	178,08	10699,2	0
24500	89,62	178,08	10699,8	0
24600	89,62	178,08	10700,5	0
24700	89,62	178,08	10701,1	0
24800	89,62	178,08	10701,8	0
24900	89,62	178,08	10702,5	0
25000	89,62	178,08	10703,1	0
25100	89,62	178,08	10703,8	0
25200	89,62	178,08	10704,4	0
25300	89,62	178,08	10705,1	0
25400	89,62	178,08	10705,8	0
25500	89,62	178,08	10706,4	0
25600	89,62	178,08	10707,1	0
25700	89,62	178,08	10707,8	0
25758,1	89,62	178,08	10708,1	0