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ERD Wells & Drag Calculations

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Abstract

This thesis investigated Extended reach drilling (ERD), which is the term for drilling high-angle, long horizontal directional wells. ERD wells has had tremendous developments, as new technology continues to break worlds records. Since the breakthrough at Wytch farm in 1997, the then world record extended reach well with a horizontal displacement of more than 10.1 km, the world record has been beaten many times. As of writing, the current world record for longest step out ERD well is drilled by ExxonMobil at Sakhalin island, with a step out of more than 14.1 km.

The objective of this thesis was to introduce different challenges in planning and drilling of a well, and then look at the further challenges in an ERD well. ERD wells often have the same challenges as other directional wells, but at a higher scale. The thesis will explore different aspects related to directional drilling and associated challenges. In addition, it introduces some types of engineering studies that must be performed during the planning of ERD wells, such as torque, drag, buckling, and corresponding limitations.

Furthermore, this thesis investigated an example of a 2D extended reach well profile, which was used to calculate the axial load on the drillstring during tripping out (POOH), and the total force on the drillstring during tripping in (RIH). For these two scenarios, sensitivity analysis was made to observe what where to happen if one changed some of the parameters set beforehand. Both variation in sail angle and friction coefficient were analyzed in the tripping out scenario, while both liner length and friction coefficient were analyzed in the tripping out scenario.

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Nomenclature

BHA	Bottom Hole Assembly
BOP	Blow Out Preventer
B&H	Build and Hold
DLS	DogLeg Severity
ECD	Equivalent Circulating Density
ERD	Extended Reach Drilling
ERW	Extended Reach Well
g	Gravity constant
HD	Horizontal Departure
HR	Horizontal Reach
KOP	Kick Off Point
LWD	Logging While Drilling
MD	Measured Depth
MOP	Margin of OverPull
NORSOK	NORsk SOkkel Konkurranseposisjon
NOV	National Oilwell Varco
POOH	Pulling Out Of Hole
P&A	Plug and Abandonment
RIH	Running Into Hole
RKB	Rotary Kelly Bushing
RPM	Rotations Per Minute
RSS	Rotary Steerable Systems
SF	Safety Factor
TD	Total Depth
TVD	True Vertical Depth
T&D	Torque and Drag
w	weight
α	angle
β	Buoyancy factor
μ	Friction coefficient

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1 Introduction

ERD wells was first used as a term in the early 1980s for “drilling directional wells in which the drilled horizontal reach (HR) attained at total depth (TD) exceeded the true vertical depth (TVD) by a factor greater than or equal to 2.0.” [1]. Since then, more and more production of oil and gas comes from directional drilling. ERD wells has evolved quickly in recent times to reach the targets further and faster. The reason why is that by utilizing directional drilling, and drilling more horizontal wells, the operator increases the drainage area of the reservoir for the well, overall increasing total output from the reservoir. In addition, ERD wells are often drilled in scenarios where there either is not a possible surface location vertically above the target or to reduce the infrastructure and operational footprint [2].

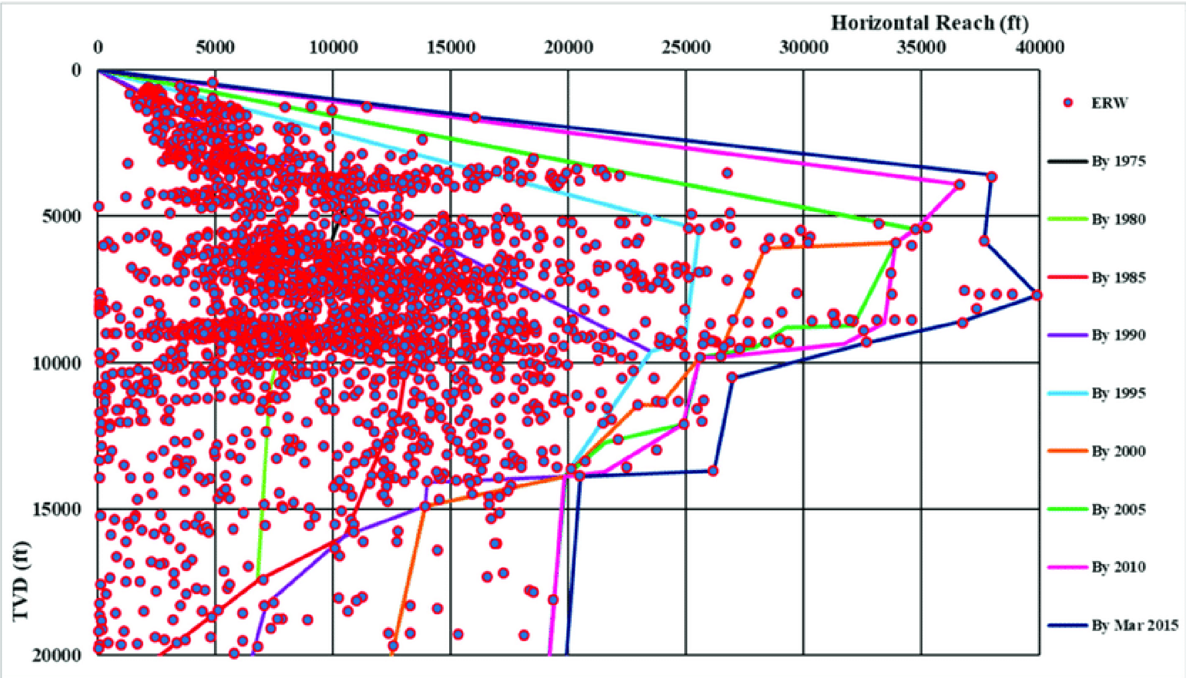


Figure 1: Worldwide ERD Database Update in March 2015. Development of extended reach wells every five years [3].

One of the reasons why extended reach wells (ERW) is particularly challenging is because of the directional drilling part, and it requires a fit for purpose planning to successfully drill the well [1]. As step out increases, the challenges of ERD increases. There are several challenges, such as wellbore stability, hole cleaning and torque and drag. Many advancements in new technology have expanded the possibilities for ERW, such as more advanced planning software, higher specifications drilling rigs and drilling fluids. But contrary to the new innovations, people still hold back further advancements. Choices regarding drilling fluid, flow rates, drillstrings, casing, well trajectories and operational practices are still done by people. This planning is an essential part to ERW, where often the problems arise when trying to pull tools out of the hole. Lack of training, planning and proper procedures for ERW has increased risk to the operator to run into a problem [4].

As new technology continues to advance ERD, ERD still needs a human touch, and cannot already be totally replaced by robots. Moreover, the key to success of ERD is not only the advancements of technology, or the improvements in skills of people, but to bring the two together efficiently. [4]

The objective of this thesis was to introduce directional drilling and ERD wells, with focus on challenges related to well friction. Analytical formulas to calculate axial forces is to be used on a 2D well profile example to demonstrate how friction and weight forces varies for different conditions. The calculation concepts from directional drilling will be used to do the calculations.

The thesis is organized by firstly going through well planning theory and background material in Chapter 2. Chapter 3 will introduce some theory and formulas for torque and drag. Chapter 4 will present ERD wells. Chapter 5 will present a calculation example of a 2D well profile with accompanying results. Chapter 6 concludes the calculations and summarizes the findings of the thesis. Lastly, the appendix contains tables showing the different geometrical calculations for the varied inclinations in the calculation example.

2 Theory

2.1 Well Planning

The life of a well can be broken down into five distinct stages: well planning, drilling, completion, production, and abandonment. [5] When planning the well, one should keep all phases in mind. For instance, the Plug & Abandonment (P&A) process can be simplified if this has been considered in the well design process beforehand.

1. The well plan

Well planning lays the groundwork for the drilling process and is perhaps the most demanding part of drilling engineering. It is a lengthy and challenging procedure that covers all activities associated with drilling the well, not to mention the key to drilling operation success. As there are many types of wells you can drill, each well design must be specific and unique for the well, meaning that each well segment has different specifications needed for equipment, tools, resources etc. These specifications are often decided by a combination of experiences from previous wells, previous local field experiences, time available, integration of engineering principles, risk management and the nature of the well [6].

The well plan should then lead to a description of a proposed wellbore, including shape, depth, orientation, completion, and evaluation. The well plans for vertical wellbores may be relatively simple, while directional or horizontal wellbores often requires a more detailed planning as the target or desired reservoir often deviates horizontally from the start position [7].

Ultimately, well planning should lead to a safely drilled, minimum cost well which meets the drilling engineers desired requirements and optimizes production of hydrocarbons [8].

2. Drilling

The drilling process needs to carry out a few actions simultaneously for the well to be successful. The drilling process needs to [9]:

- overcome the rock's resistance, grinding it into small fragments measuring just a few mm.
- removal of rock fragments by transporting them to surface for disposal by drilling fluid circulating up to surface from bottom.
- maintain stability of formations around the wellbore, the walls of the hole
- prevent fluid from outside formations contaminating circulating fluid or change pressure in the well that may lead to circulation losses

3. Completion

The well must be "completed" after drilling and casing it. Completion is about preparing the well for production after drilling. Completion begins after the well is drilled to total depth and logged [10]. Further the process involves running in the production tubing, installing various valves and other associated down hole tools, in addition to perforating and stimulating as required [11]. The process often ends with well barriers tested and the Christmas tree installed, an assembly of various valves, spools, pressure gauges and chokes on the top of the wellbore. Then the well is given over to the production team, ready for the next phase [12].

4. Production

The most important phase of the oil well is the production phase. The Christmas tree can regulate pressures, control flows, and allow access to the wellbore at a later stage in case any additional maintenance or completion work is needed. Christmas trees also have outlet valves, where the flow can be linked to a pipeline distribution network, and tanks to further supply the hydrocarbons to refineries, natural gas compressor stations, or oil export terminals. The flow often comes naturally from the reservoir because of pressure differences, so all you need is the Christmas tree, but in some cases if the pressure in the reservoir does not remain high enough, an artificial lift is needed [13].

5. Abandonment

Abandonment is the final phase of the well's life. The wells are often called orphan, orphaned, or abandoned wells [13], and they are wells that have been abandoned to be closed permanently. Causes of abandonment are often economic viability, logs have determined there are insufficient hydrocarbon potential to complete the well, or it may be because of the production organization has drained the reservoir [14]. The process is often called plug and abandonment (P&A). The objective of the process is to protect all surrounding water zones, future commercial zones, prevent leaks in perpetuity into or from the well, and finally remove the surface equipment [15].

2.2 Geological Target and Pore and Fracture Pressure Prognosis

Before commencing drilling, the operator has an objective or a geological target for the well. The different types of objectives can be sorted as exploration, development or production, injection, and special purpose wells (investigation, stratigraphic, blowout relief).

An exploration well is drilled to discover possible reservoirs of petroleum or obtain any information to delimit an already discovered reservoir. Exploration wells covers both wildcat and appraisal wells. Wildcat wells are drilled where it is not known to be any already discovered reservoir, or where it was beforehand determined to have been completely exhausted, which is a form for high-risk exploratory well drilling.
Appraisal wells are drilled to establish size and potentially delimit the extent of the petroleum reservoir, previously discovered by a wildcat well. An appraisal well can then provide information about the extent of hydrocarbons, flow of fluids, production rate from the field and volume of fluids, etc. [16].

When the extent of the potential hydrocarbon reservoir is established, the operator moves onto the commercial production of oil from the well. This part is often called development or production and is the most important stage of the well's life; the phase when petroleum is being produced. The development wells are drilled in a proven producing area, which is determined by the previous wildcat and appraisal wells [17].
Development wells are often more expensive, and complex, compared to exploration wells. In addition, development wells are further divided into various objectives: flowing production for production of petroleum, artificial lift production to increase production rate, and injection of water, gas, or other medium. Because development wells are so expensive, companies expend significant resources in pinpointing the best locations for drilling, since an unproductive or dry well can be a substantial expense [18].

To ensure that no hydrocarbons are lost to the surroundings, it is very important to operate with full control of the well pressures in the different phases. The NORSOK D-010 standard [3] helps ensure total well control. NORSOK defines different barriers that must be present in the different phases of the well's life, and every barrier can consist of multiple barrier elements. These well barrier elements can be the drilling fluid column, in-situ formation, cement, casing, wellhead, blow out preventor (BOP) and so on. NORSOK requires a minimum of two barriers available during all well activities and operations.

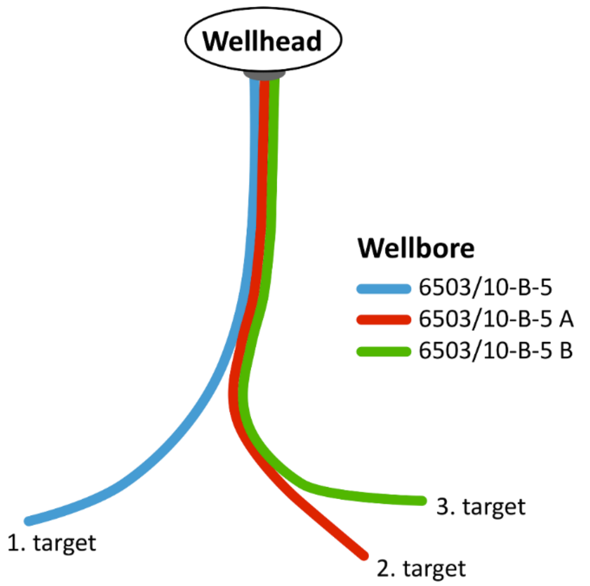


Figure 2: An illustration of wellhead at surface, with the different wellbores, and geological targets at bottom [19].

A geological target is the well path's endpoint which, if successfully reached, enables the drilling operator to start producing oil or gas from the wellbore. The geological target is found beforehand by using different geological survey and is also used to design the well plan. For the drilling operator to ensure that they hit desired target, "*... the effective target size for considering deviation from plan must be reduced by the expected amount of positional uncertainty when the wellbore reaches total depth so that after accounting sfor survey uncertainty, the geological objectives are still met. This process is known as "Driller's target erosion"."* [20]

In some cases, standard surveying techniques might lead to a higher positional uncertainty of the desired target, which in turn could lead to troubles reaching target. So, the more precision used in the surveying, the less target erosion occurs. In the cases of higher target erosion, a more precise surveying method or extra navigational data must be utilized, for example Logging While Drilling (LWD). [20]

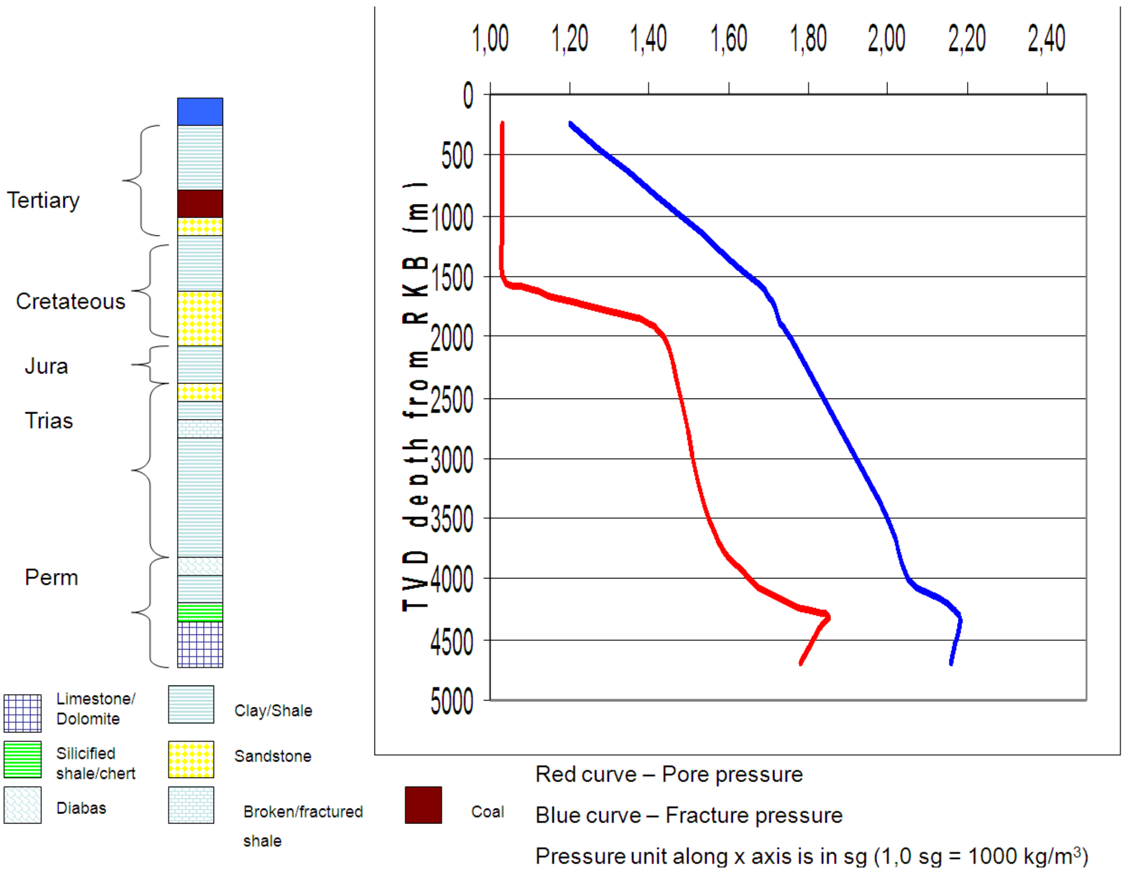


Figure 3: Pore pressure and fracture pressure prognosis [21].

The figure above shows a pore pressure and fracture pressure prognosis for a well. Here is the red curve pore pressure, and blue curve for fracture pressure. This data tells us which mud weight one should use at what depth. In addition, it shows a stratigraphic column for what types of rock one may encounter in the vertical area in the well. This is important for selection of drill bits, as different bits are used for different formations, and may forecast which kind of troubles you can encounter in the different formations. It will also be decisive to how the casings should be position in the well.

2.3 Casing Program

A well also needs a casing program, and a casing program is part of the drilling program. The casing program consists of different sections, and each section is drilled to a certain depth, and then cased and cemented. As stated previously, the casing protects the well from the outside formations, and the outside formations from the well. They are needed to avoid both unwanted influxes and fracturing in the well. When there is a need to weigh up mud due to increasing pore pressure, a casing is often run and cemented in advance.

For the given prognosis in Figure 2, there is the following hole and casing sizes planned for the well. In addition, I have set values that may fit for both setting depth from the rotary kelly bushing (RKB) in meters, and mud weight, based on the pressure prognosis. The mud weight is in specific gravity (s.g.), and 1 s.g. is equivalent to 1000 kg/m^3.

Table 1: Hole and casing sizes for a well [21].

Hole section	Casing size	Setting depth from RKB	Mud weight (s.g.)
36”	30”	400 m	1.03 s.g.
26”	18 5/8”	1450 m	1.17 s.g.
Run BOP (Blow out preventor on riser)			
17 ½”	13 3/8”	3000 m	1.58 s.g.
12 ¼”	9 5/8”	4200 m	1.84 s.g.
8 ½”	7” liner	TVD	2.01 s.g.

For each section there would be used different bottomhole assemblies (BHA).

The different sections will be drilled with different types of drilling fluid like seawater/water based mud and oil based mud. One need to use sufficient high flowrate for each section to ensure proper cuttings transport. The expected pump pressure and dynamic bottomhole pressure (ECD) has to be evaluated to ensure that one stays inside the allowed pressure margins.
One also need to evaluate Torque and Drag (T&D) of the drillstring during static and dynamic conditions (tripping in and out) to ensure that the string is not damaged beyond its yield point but also to ensure that one is able to reach the target.

2.4 Directional Wells

Before the 20th century, a percussion drilling was primarily used for drillings wells [5]. Percussion drilling is a method of drilling whereby the bit, or another impact tool, suspended from a steel cable into the well, is repeatedly dropped to the bottom of the hole. By dropping the bit or the impact tool repeatedly the formation or rock at the bottom is crushed. The most used technology of percussion drilling is the cable-tool drilling technique. This kind of technology were primarily used for vertical wells.

The cable-tool drilling technique was the predominant technique used for drilling for a long time. This was because most wells were drilled vertically, but during the late 20th century new technology accelerated the use and development of rotary drilling. Rotary drilling uses a rotating drill bit with nozzles to shoot out drilling mud when penetrating into the earth [22].

For directional drilling, rotary drilling set up big advancements in the development of these wells. Especially the rotary steerable system (RSS), a tool which allows the operator directional control while rotating the drill pipe, helped advance the development. RSS are located at the very bottom of the drilling assembly. They work by continuously rotating at desired rate from surface, and constantly pointing the drill bit in the desired direction. Newer RSS have minimal interaction with the borehole, thus preserving borehole quality. The RSS technology allowed for more access in previously inaccessible formations from the same rig [23].

As the first well paths were vertical, or was meant to be vertical, meant that some reservoirs were in fact inaccessible. In many cases, a drilling platform could not be directly placed vertically above the location of the reservoir. For example, the reservoir may be underneath a town, harbor, or the reservoir is shallow and difficult to extract everything from a vertical entry. These reservoirs had to be accessed using directional drilling. In these cases, the surface equipment is often offset, and the wellbore includes an angle which builds up so that the wellbore can reach the desired target. One may then end up with a longer reach well, or a horizontal reach well, illustrated in Figure 4. These are some area of use for directional drilling.

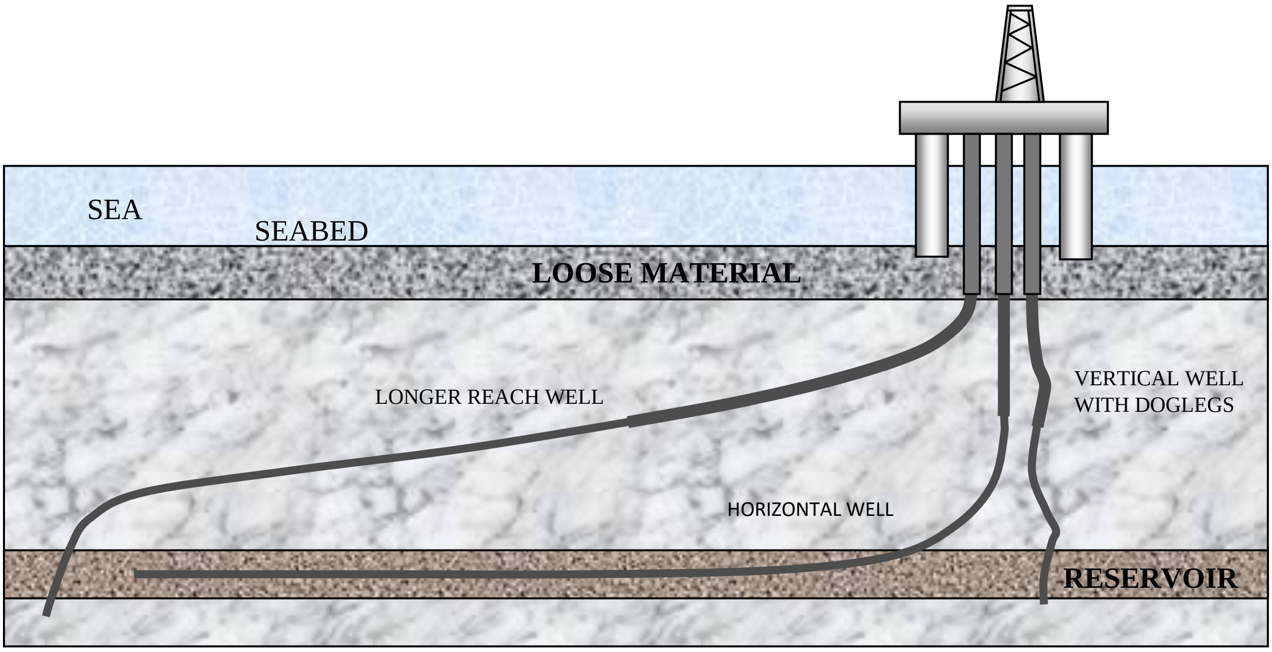


Figure 4: Different well paths [24].

2.4.1 Doglegs and Tortuosity

A reoccurring problem in the past for planned vertical wells, was that the wellbore could change its direction slightly when there was a significant variation in density/hardness of the formation it drilled through. It would then follow the edge between the hard and soft formation. This was obviously not the desired well path, as they often wanted to drill completely vertically, and a tool that could fix this was the whipstock. This tool remedied the deviation the well might have taken, but it would not completely take away all the smaller bends the well might have obtained [24]. The well would essentially become vertical, but there would be several small deviations from the, as seen in Figure 4. These rapid changes of the trajectory of the wellbore are called doglegs and is usually expressed as dogleg severity. Dogleg severity (DLS) is measured in degrees per 30 meters. I.e., a large dogleg severity at a location would indicate a kink in the well path. Such kinks in the well path will lead to additional friction when running tubulars in and out of the well. It becomes more difficult to get the tubular into the hole and it requires more force to trip the tubular out of the hole.

A high dogleg severity may lead to weakened drillstring where the dogleg is, problems with running casing, and the repeated abrasion by the drillstring in the location of the dogleg could

results in a worn spot, called a keyseat. Here the BHA could get stuck as they are pulled through this section. In addition, if the well gets cased, the casing could wear unusually quick due to the friction between the casing and formation. Furthermore, if the well were to go through a higher density formation, you would need a harder, stiffer BHA. This BHA may in turn have problems going through the where dogleg section is located if that section was previously drilled with a more limber BHA. Lastly, excessive doglegs create overall increased friction on the drillstring, further increasing the chance of a stuck pipe [25].
Even though there are multiple reasons doglegs could damage the well, they are often utilized by engineers in directional drilling intentionally, to reach a desired target, or change trajectory rapidly [25].

Many doglegs, or other deviations of the wellbore trajectory, can increase the tortuosity of the well. Tortuosity is a measure of deviation from a straight line. It can be calculated as the ratio between the actual distance traveled between two points, including deviations, divided by the straight line distance. It is often used by drillers to describe the wellbore trajectory. [26]

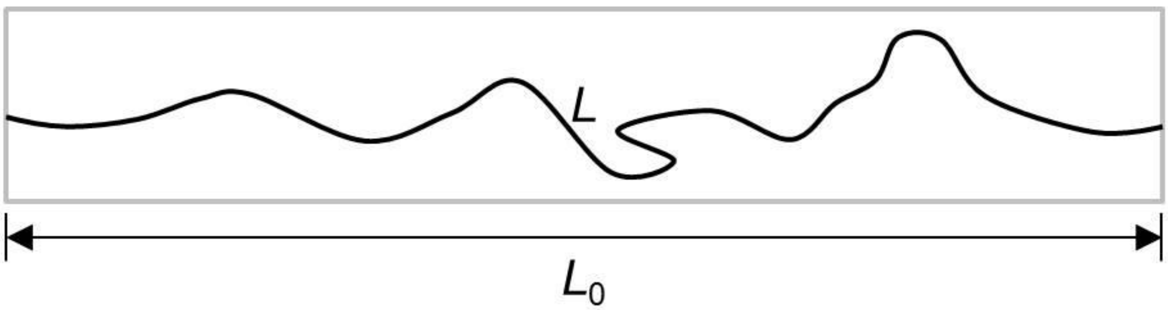


Figure 5: Illustration of tortuosity definition [26].

$$Tortuosity = \frac{L}{L_0} \tag{1}$$

where

- L is the actual distance traveled (m)
- L_0 is the straight line distance (m)

High tortuosity and many doglegs often increase the friction between the drillstring and wellbore, as mentioned earlier. As the wellbore is drilled, the operator must be aware of the DLS and tortuosity, because if the friction becomes too great, it can cause torque and drag problems.

There might not be sufficient weight of the string to reach the target, and the required torque to rotate the string will exceed the strength of the pipe and couplings. When pulling out, the axial force needed on top can exceed the strength of the pipe causing the drillstring to deform and perhaps be teared off.

2.4.2 Well Trajectory Design

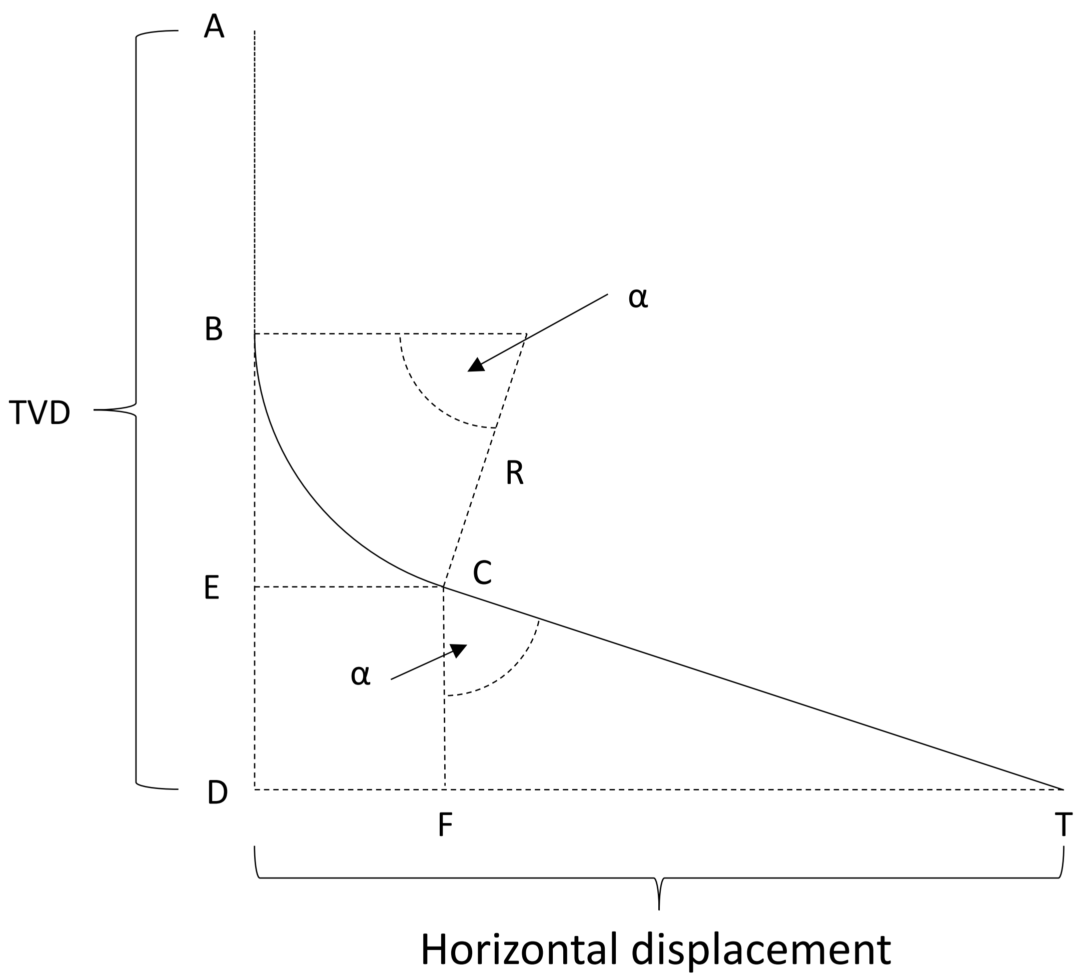


Figure 6: Example of well path/well trajectory design. Typical build and hold (B&H) well path. Made in Microsoft PowerPoint.

Directional drilling has become a must in offshore drilling. Larger fixed rigs are not so easily moveable, so to access different parts of the reservoir, you must utilize directional drilling in some way. Some of these wells are called horizontal wells. These wells are important to ensure maximum drainage of the reservoir.

Definitions of some important abbreviations and terms for the well path in directional wells:

- KOP (kick off point) is the depth where the well is deviated from the vertical trajectory in a given direction (B in Figure 6)
- The build section comes after the KOP, where the inclination angle increases. (curve from B to C in Figure 6). Because the drill pipe often is made entirely of steel, and is nearly inflexible, the angle of the wellbore can only be changed by a few degrees per tens of meters, also called the buildup rate, which also accounts for dogleg severity in this section.
- Inclination angle is the angle of the inclined section of the well. The angle is defined in relation to the vertical (angle α in Figure 6)
- TVD (true vertical depth) is the length from the rotary table to the vertical depth of the target (from A to D in Figure 6)
- MD (measured depth) is the entire length of the wellbore from the rotary table to the target (from A to T in Figure 6)
- Azimuth is the compass direction of the wellbore, and is often specified in degrees with respect to the geographic or magnetic north pole, measured clockwise (see Figure 7)
- Horizontal displacement (HD) is, as the name suggests, the horizontal displacement of the wellbore. It is the distance of the straight line that is parallel to the surface between the target and the start of the wellbore (D to F in Figure 6)
- Step out ratio is the relation between HD and TVD

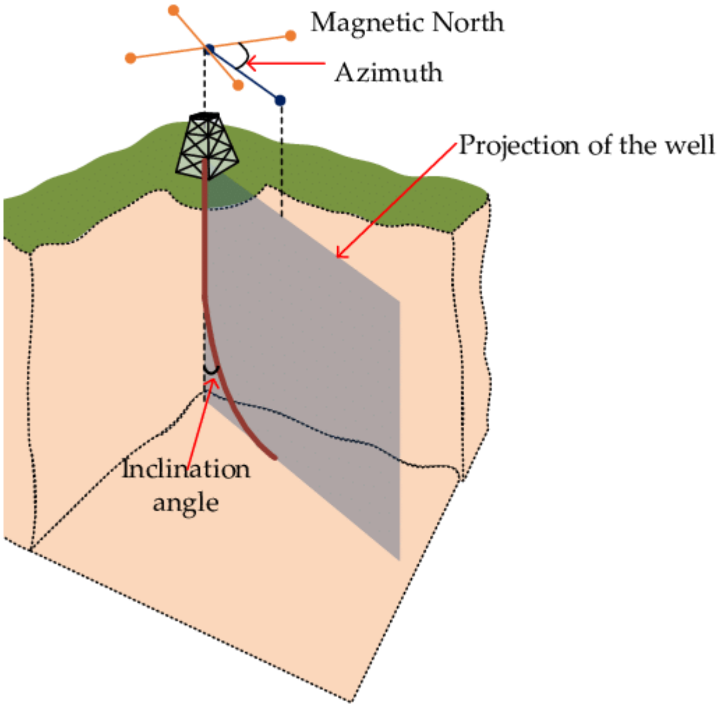


Figure 7: Illustration of azimuth [27]

2.4.2.1 Collision Avoidance

In general, in drilling it is important to avoid any scenarios where either the environment is exposed to danger or human lives are at risk. At rigs where it is planned to have multiple directional wells, it is then important to avoid these wells intersecting. If wells were to intersect or collide, it may even result in an underground blowout [28]. Therefore, it is important to have some sort of a collision avoidance system in place. With these systems, the operator would like to know how close an offset well is to any point along the well being planned. These calculations must also include uncertainties, as the deeper the well, the larger the uncertainties may become. If the anti-collision survey has been done to a higher level of accuracy, the operator may safely proceed with the drilling operation with regards to the collision risk [20].

2.4.2.2 Survey Measurements & Position Calculations

Every 30 meter, the inclination and azimuth will be measured. There will be some uncertainty in these measurements. Based on measured depth (MD), inclination and azimuth measurement, it is possible to use different survey calculation methods to calculate the wellbore position in terms of true vertical depth and changes in horizontal orientation (E-W, S-N).

One example of such method is the minimum curvature method. The uncertainty in wellbore position will be accumulated since more and more uncertain measurements are used while drilling ahead [29].

2.5 Cuttings Transport and Hole Cleaning

An ERD well often consist of a large part where the drill pipe is not in the center of the well, in either high deviations or in the horizontal part of the well. This unconventional placement of the pipe leads to two different velocity of cuttings transport in the well. In the lower part of the well, the velocity of the cuttings is lower, and at the upper part the velocity is higher. Furthermore, the cuttings are transported better at higher velocities, but because ERD wells have a near horizontal section, cuttings tend to fall to the lower part of the wellbore due to gravity. To further agitate the cuttings at the lower part, the operator must start to move and rotate the pipe to move cuttings to the upper part, thus improving hole cleaning. [30]

Other procedures than rotating the drillstring to solve hole cleaning issues is higher mud viscosity and higher flow rate. These procedures may not always be the remedy of hole cleaning, as it can increase the annular pressure loss, leading to an excessive ECD.

ECD stands for equivalent circulating density, and is related to many factors, such as annular pressure loss, and is an important parameter in avoiding kicks and losses. [31]

As hole cleaning is more complex in ERD wells, cuttings may slide down bends to create a bed, or at the near horizontal sections the cuttings may gather in dunes below the drillstring and BHA. This scenario in not ideal, as the cuttings may cause stuck pipe. [30]

3 Torque & Drag

3.1 Drag

Drag is an axial force where higher contact between the hole and pipe increases overall axia force and is one of the major limiting factors when it comes to directional drilling. Drag is caused by friction between the wellbore and the drillstring, and always work in the opposite direction as the pipe movement. This friction depends on the contact force (Normal force) between the string and the wellbore. Both weight of the string and string tension in curvatures will have impact on the contact force and hence impact the drag [32].

3.1.1 Friction

The coefficient of friction, or the friction factor, is a nondimensional factor that accounts for several elements impacting pipe movement. These factors include mud system lubricity, pipe stiffness, cuttings beds, stabilizer and centralizer interaction, differential sticking, hydraulic piston effects and keyseats. [33]

Minor changes in the coefficient of friction may have major impacts on the torque and drag calculations. It is therefore crucial for the drilling operator to consider a variety of friction factors in the planning phase, as in for example a sensitivity analysis. [33]

3.1.2 Bouyancy – Weight of Drillstring

While the string is in the hole, the hole is filled with drilling fluid. This means that when the string is in the hole, there is a buoyancy effect on the string, leading to that the unit mass for the string must be corrected for buoyancy. Buoyancy force is an upward force which opposes the submergence of an object in drilling fluid. The buoyancy factor is [34]:

$$\beta = 1 - \frac{\rho_{mud}}{\rho_{drill\ pipe}} \tag{2}$$

where

- β is the buoyancy factor

-ρ_{mud} is the density of the drilling fluid (kg/m^3)

-ρ_{steel} is the density of the drill pipe or steel (kg/m^3)

and the buoyed unit mass is [34]:

$$w = \beta g w_{drillstring} \tag{3}$$

where

-w is the weight of drillstring in drilling fluid [*kg/m*]

-$w_{drillstring}$ is the weight of the drillstring in air [*kg/m*]

-g is the gravity constant [*m/s*^{2}]

3.1.3 Axial Forces for Different Sections of the Wellbore Without Pipe Rotation

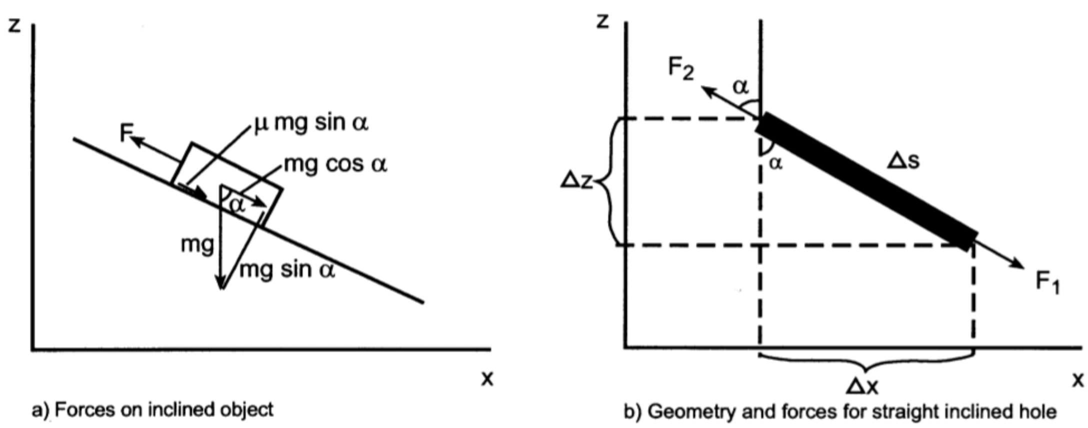


Figure 8: Forces and geometry in straight hole sections [34]

For the straight sections of a wellbore, the primary aspect is that pipe tension does not add to the normal pipe force, hence not affecting the friction. Straight sections are dominated by weight, since just the normal weight component causes friction (see Figure 8).

The top force F2 is given by:

$$F_2 = F_1 + \beta g \Delta s w(cos\alpha \pm \mu sin\alpha) \quad (4)$$

where:

-α is the angle of inclination

-g is the gravity constant [*m/s*^{2}]

-Δs is the relevant distance of the drillstring section

-signs + means tripping out of hole and – means tripping into hole

-μ is the coefficient of friction

It is observed that the change in axial force is caused by an axial weight component and the friction (drag). The axial weight is found using the projected height principle [34]. Only the vertical displacement matters.

To simplify the calculations of drag for curved sections of the wellbore, we make an assumption that the tension in the drillstring is greater than the weight of the pipe in the curved section [24], and further assuming this is a tension dominated process. So, we will assume that the pipe is weightless when calculating friction in the following formula for axial force on top of a curved section. The friction is assumed to be caused by only tension (Capstan effect). This approach is adopted from [34].

To illustrate see Figure 6. Figure 6 will also be the example for the derivation. F_2 is set at C, and F_3 is set at B.

The force F_3 is given by:

$$F_3 = \beta wgRsin\alpha + F_2 e^{\pm\mu\alpha} \quad (5)$$

where

-R is the radius of the curve [m]

-μ is the friction coefficient

-e is Euler's number

-α is the angle of curve in radians

-signs + means tripping out of hole and – means tripping into hole

Note that the term $F_2 e^{\pm\mu\alpha}$ both contains the axial forces at the bottom of the bend and the friction in the bend itself.

Lastly, there is the straight vertical section, which can be calculated using formula (4), where (cosα+μsinα)=1, because inclination is 0 degrees:

$$F_4 = F3 + wg\Delta s \tag{6}$$

In the vertical section, there is no friction.
Using these formulas, one can start at the bottom of the well assuming a value for the contact force between the bit and the formation. For tripping in and tripping out, this boundary force is set to zero. Then one can calculate section by section reaching the surface where the axial force on top at the string is determined. This can then e.g. be compared with what the string can handle before it yields. This would be a typical load case that has to be checked when tripping out. Hookload is defined as the axial force on just above the top drive, which again is located above the string.

For tripping in or running casing, the friction will work against the movement so it is important that the combined weight of the string and the top drive can overcome the frictional forces [35].

3.1.4 Hook load plot

Hookload is the measured load at the top of the top drive and includes the weight of the top drive itself, the buoyed string weight and mechanical friction. It will vary depending on if the operator is drilling, tripping in, tripping out and when the pipe is in slips. The next figure shows the hookload for increasing bit depth for three operational conditions.

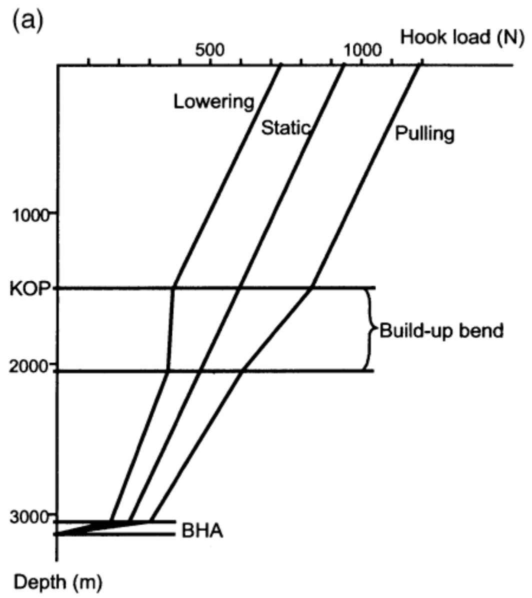


Figure 9: Axial forces vs depth for a string. Note that when there is no movement in the drillstring, when it is static, the hook load is always equal to the unit buoyed weight multiplied with the projected height, regardless of any borehole inclination [34].

As seen in Figure 9, during running into hole/slacking off (RIH), friction has a decreasing effect on the hook load, whilst it has an increasing effect during pulling out of hole/picking-up (POOH). This is evident in the two following equations:

$$Hook\ load_{RIH} = weight - friction \tag{7}$$

$$Hook\ load_{POOH} = weight + friction \tag{8}$$

What can be observed from equation 5 is that friction due to tension will increase when tripping out if the angle of the bend is increased. Note that $F_2 e^{+\mu\alpha} = F_2(e^{+\mu\alpha} - 1) + F_2$. It is the first term in the last expression that represent the drag in the bend.

From the exponential term, the friction due to Capstan effect (tension) increases when the angle of the bend increases.

For the tripping in case, the friction $F_2(e^{-\mu\alpha} - 1)$ will become negative and lead to a reduction in hookload. This is contrary to the tripping out case.

3.2 Torque

Torque is the rotational force between the drillstring and the formation and is the rotational equivalent of the linear force. It can also be thought of as a twist to an object. It is given by the cross product of the force and position vectors, and the power requirements of the rotary table can be determined from [36]:

$$P_{rt} = \frac{\omega T}{2\pi} \tag{9}$$

where:

- P_{rt} is the Power output from the rotary table [*Watt*]

- ω is the rotary speed [*RPM*]

- T is the torque [*Nm*]

In a perfectly vertical well, the torque is negligible, and only tension and compression are forces working on the drillstring. On the other hand, in directional wells torque can be significant, and in horizontal or extended reach wells, torque is crucial.
Torque is the force used to turn the drillstring. Some systems used to create the rotation are the rotary table and the top drive [36].

3.2.1 Top Drive

A top drive is the most used system for extended reach drilling. It is a mechanical device that provides clockwise torque to the drillstring. It usually hangs from the travelling block in the rig tower and is mounted on a frame called a guide dolly to avoid lateral movements in the drill. The top drive slides up and down on the guide dolly on a vertical steel beam system called a guide beam in the tower. By using the top drive, you can raise and lower the drillstring in the wellbore. The top drive can also rotate the string and move drilling fluid into the drill pipe [37].
The largest top drives can lift close to 1500 tons, and the motors to run it are available in

almost any sizes, either if it is a hydraulic motor, AC- or DC-motor. In addition, some of these motors can deliver over 30 kNm. [36]

Some of the advantages of a top drive is [38]:

- Top drive rotation per minute can reach up to 300 RPM
- Two internal blow out preventors (IPOB)
- Capable of drilling with three joint stands
- More often decreases chances of stuck pipe, which in turn decreases overall costs
- Reducing risk and increasing safety by removing much of the previously needed manual labor to operate the drill.
- Offering more control of the rotation and weight on bit
- Providing constantly maximum torque

Some of the disadvantages of a top drive is:

- Weight of the top drive can be over 40 tons
- Troubles with heaving effect in harsh conditions, such as offshore

As the benefits of a top drive far outweighs the disadvantages of using another system, top drive systems now represent “the industry standard” method of drilling for oil and gas.

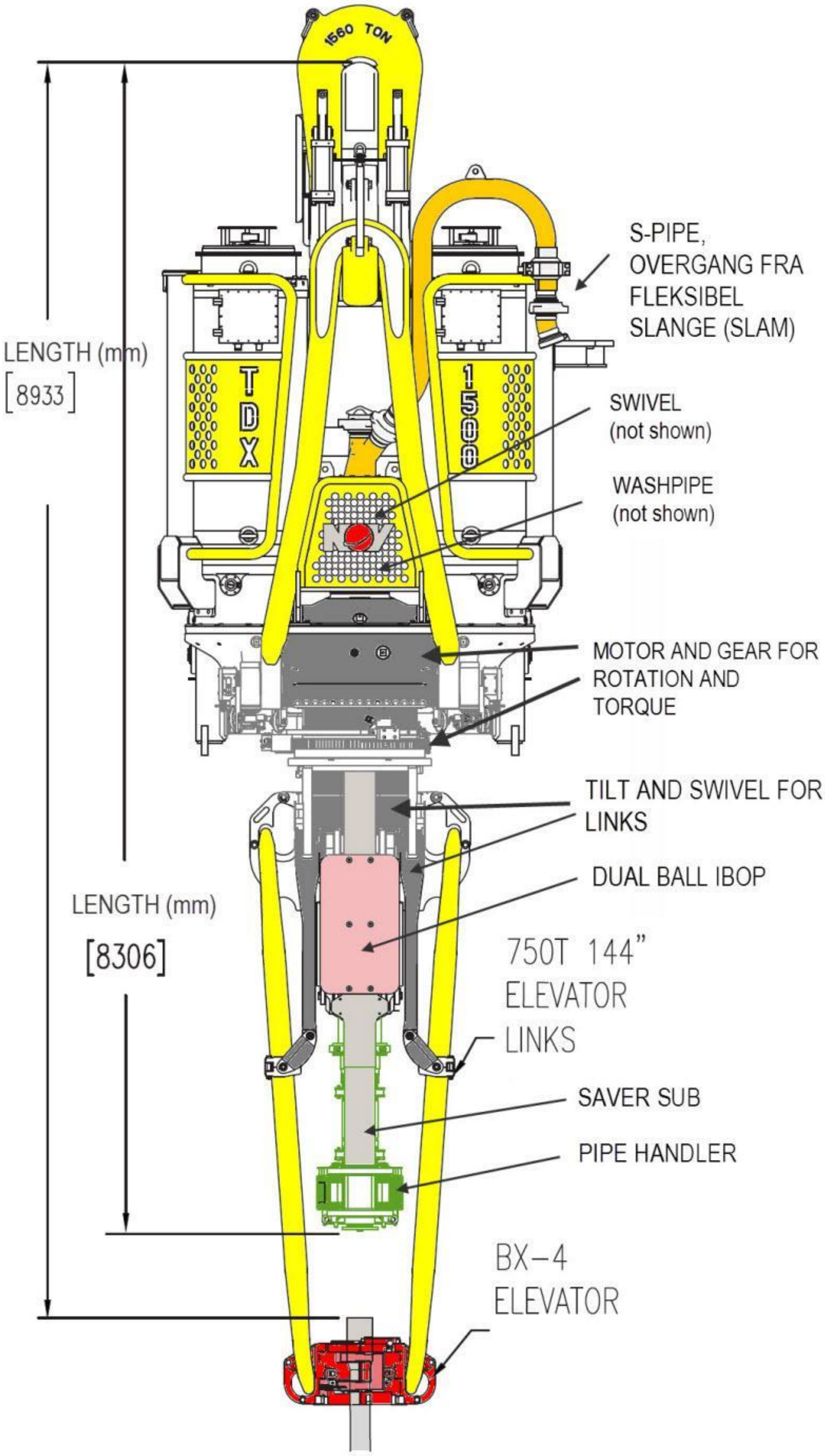


Figure 10: Top drive sketch from NOV – National Oilwell Varco [37]

3.3 Buckling

Buckling is often referred to as an unwanted occurrence of bending, deforming or maybe fracturing of the drillstring. It is caused by the drilling operator applying too much force or weight on top of the drillstring. Because of buckling requires some room between the drillstring and hole, the bigger the hole the higher the tendency of buckling. This means that a 12¼" hole has a lower buckling tendency than a 15" hole [39].

Buckling often occurs while the drilling operator is unaware of it happening. The operator might be stressed, not observant enough or have not done his calculations properly. This in turn leads to the operator spending time and money to figure out what's wrong by changing several different factors, while the real problem was buckling the whole time [39] [40].

In the paper Aadnøy et. al. [41] the authors states that the following conditions are observed on a long horizontal well.

- *"Buckling may occur at the start of the horizontal section. Use large diameter thinwalled 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 further be divided into helical and sinusoidal buckling. Sinusoidal buckling is the first phase of buckling, as it occurs at a lower compressional load than helical, resulting in some sort of a snake-like bend in the string. If sinusoidal buckling occurs, the pipe will start to deform, but only in a 2D plan [41]. Helical buckling is then the next phase, where higher compressional loads act. It is a more extreme form of buckling and causes contact between the string and wellbore. This in turn leads to the string exerting a force on the hole itself, leading to interference with weight transfer to the bit and drillstring fatigue [42].

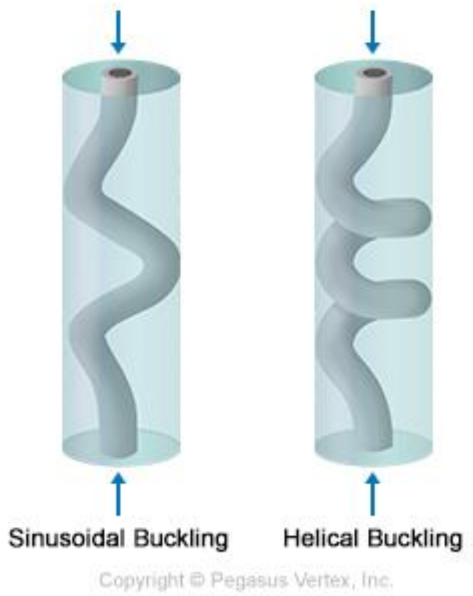


Figure 11: Illustration demonstrating sinusoidal and helical buckling [42].

3.4 Limitations

When pulling out, there will be large axial tension on the top of the string. It is important to ensure that the tensile yield point of the pipe is not exceeded, so that the drill pipe is not deformed. When running pipe into the while it is important that the string weight is sufficient to overcome friction forces to be able to reach the desired target.

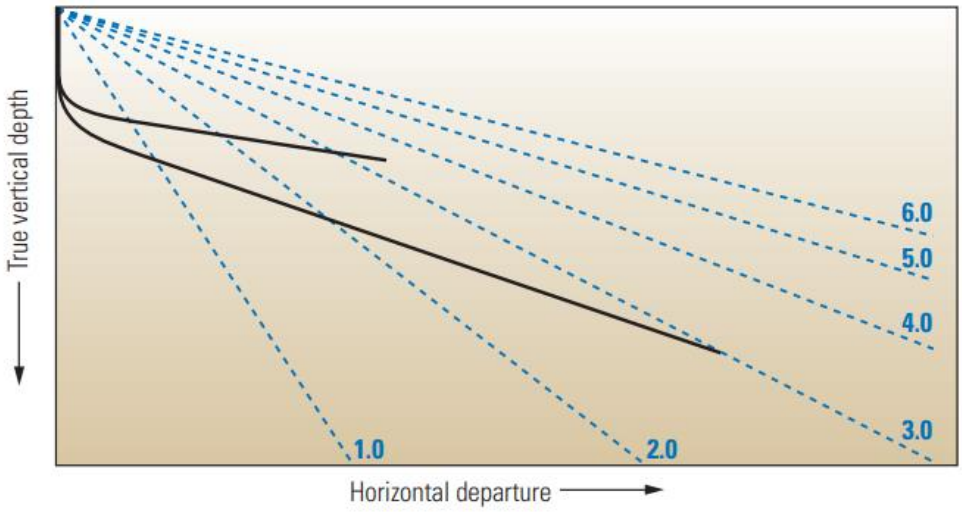
4 Extended reach wells

As mentioned previously, a well is categorized as an extended reach well (ERW) when the step out ratio surpasses 2.0, which was the limit going back 40 years. Today, wells may be drilled with a step out ratio more than 10.0, but this progress in step out ratio has slowed down in the last years [43].

The step out ratio may be a basic indicator of the complexity of the well, so the higher the step out ratio, the more complex the well. A typical feature of an ERW is that the target often is located at a far horizontal distance from the drilling rig.

The current world record for the longest well in the world is in the Sakhalin-1 field, which has 9 of the 10 longest wells in the world. The record is held by production well O-14, with a length of 15000 meters with horizontal completion [44].

4.1 Extended Reach Well Types



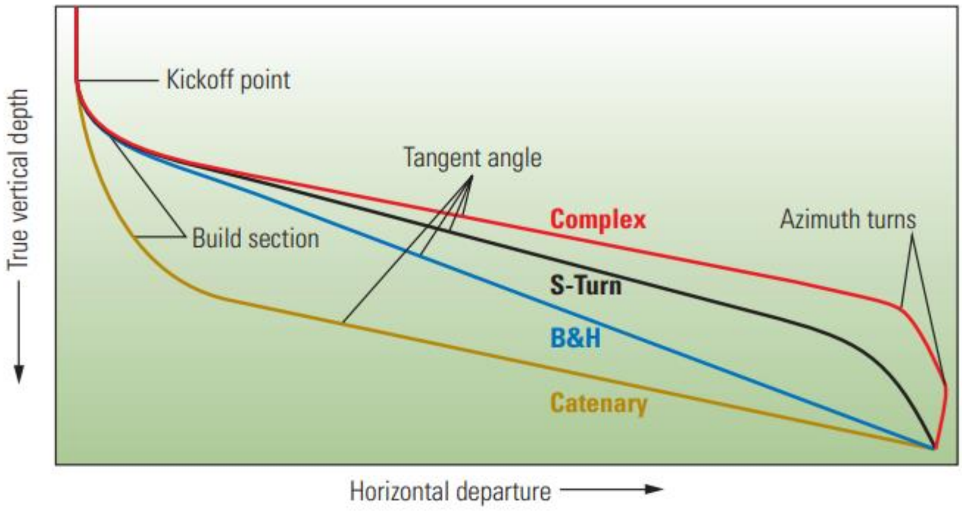


Figure 12: Blue numbers in the upper figure represent the step out ratio [33].

There are two main categories when it comes to extended reach wells: very shallow or very long wells (Figure 12, upper figure, the black curves). Each has unique challenges, and neither has higher HD/TVD ratio than the other. In Figure 12, the blue numbers in the upper illustration represent the step out ratio. The different classifications of extended reach well profiles are build and hold (B&H), S-turn, Catenary or Complex. These are illustrated in Figure 12.

In the case of the B&H profile, after the tangent angle is achieved, the drill continues at a constant angle. B&H wells require very little directional and drilling control.

The S-turn design often has a higher-angle tangent section than the typical B&H design, before dropping to a more vertical angle as it nears the target. The benefit of this design is that it might reduce uncertainty when matching TVD with the survey data. Additionally, it may shorten drilling time in abrasive target zones whose stability is time-dependent.
The catenary profile is a slight variation of the B&H profile. It starts with a lower build rate, that accelerates when the angle of the wellbore increases. The catenary design is predominantly chosen to reduce torque problems. The overall length of the well (MD) is longer and there is a higher tangent angle in catenary designs than in B&H designs.
Complex well paths are often characterized by a third dimension, also including variations in the azimuth, i.e. compass direction. While complex designs are more difficult to execute than the others, they enable the operator to access more targets with a single well [33].

4.2 Critical Design Challenges When Planning Extended Reach Wells

The following section is taken in its entirety from [45]:

"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"*

In this thesis we will show calculation examples for 1. and 3. in the list above.

5 ERD Calculation Example

To demonstrate some of the theory discussed in this paper there will be made a calculation example of an ERD well which calculates axial load for the drillstring at different positions in the wellbore. Two main scenarios well be considered. One is tripping out where one wants to check that the axial load on top of the string does not exceed the strength of the pipe. The other critical scenario is when one shall run a liner into the well, and one want to check that there is enough weight to overcome frictional forces working against the movement. A liner is "*a casing string that does not extend to the top of the wellbore, but instead s anchored or suspended from inside the bottom of the previous casing string.*" [46]. A 2D well profile will be used that is exemplifying a typical ERD well profile. First some calculation related to the geometry will be shown before showing the axial load calculations for the two scenarios. Then an Excel sheet was developed for performing sensitivity analysis when varying parameters. Snapshots of the Excel spreadsheet can be found in Appendix. For simplicity, during writing of the calculations, rounding of numbers have been done, but not while calculating the final answers. The formulas for geometrical calculations are from [21].

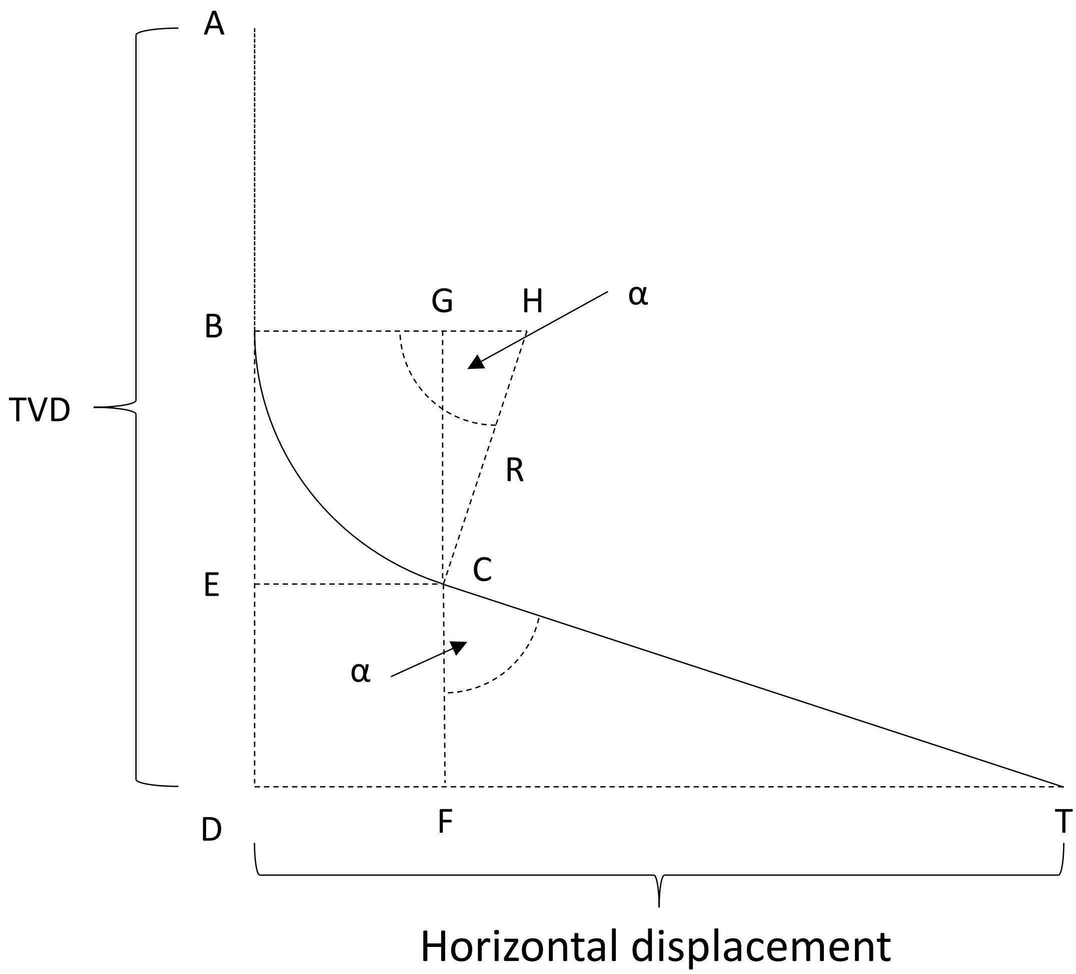


Figure 13: Same figure as Figure 6, but with some minor adjustments. Made in PowerPoint.

5.1 Geometrical Calculations

We will use Figure 13 as illustration for the 2D well profile. Firstly, we will start to calculate the different geometrical sizes and distances for the sections, so that we can use the sizes and distances when calculating the forces later. We will be dividing the sections into AB, BC, the buildup bend, and CT, the sail section. This is a typical B&H well profile.

To start, distances of section AB, CT, buildup rate and inclination is already set. This is so we can find horizontal displacement (HD), measured depth (MD) and true vertical depth (TVD) for desired target, as the target should not change if we change any of the starting variables later on in a sensitivity analysis. The vertical section is set to 1000 meters, buildup rate in bend is 1.5 degrees per 30 meters and stops when the inclination is 80 degrees. The sail section is 7000 meters long before finally reaching target. Azimuth is held constant at 0 degrees, so we are drilling directly north.

As mentioned in the last paragraph, we need to find TVD, HD, and MD for the desired target. To start, we find TVD by adding the sections AB, BE and ED from Figure 13 together. AB is already set to be 1000 meters. Further, we'll need to use some geometrical formulas to find the length of BE and ED.

Because this well profile includes a bend with a constant buildup rate, this bend is a curve, a slice of a circle. This means that it has a radius R, which is an important variable for the following calculations. To find the radius R you need to use that the buildup rate is defined by change in angle (Δi) divided by change in length (Δl). The following relation expresses relationship that is fulfilled:

$$\frac{\alpha}{BC} = \frac{\Delta i}{\Delta l}$$

which can also be written as:

$$BC = \frac{\Delta l}{\Delta i}\alpha \qquad (9)$$

In addition, we have:

$$\frac{BC}{2\pi R} = \frac{\alpha}{360°}$$

which can also be written as:

$$R = \frac{BC}{2\pi}\frac{360°}{\alpha} \qquad (10)$$

Furthermore, by putting BC from formula (9) into formula (10) we get:

$$R = \frac{360°}{2\pi}\frac{\Delta l}{\Delta i}$$

Since the buildup rate, change in angle divided by change in length, is 1.5 degrees per 30 meters, $\frac{\Delta l}{\Delta i}$ will then be 30 meters per 1.5 degrees.

$$R = \frac{360°}{2\pi}\frac{30\ m}{1.5°} \cong 1145.92\ m$$

5.1.1 TVD Calculations

To calculate BE we can use trigonometry:

$$\sin\alpha = \frac{opposite}{hypotenuse}$$

And by using the triangle formed by CGH, the opposite is CG, which is the same length as BE, and the hypotenuse is R. Further this formula can then be written as:

$$BE = R\sin\alpha$$

$$BE = 1145.92\ m \times \sin(80°) \cong 1128.51\ m$$

And lastly for TVD, to find ED we will use trigonometry again:

$$\cos\alpha = \frac{ED}{CT}$$

which can be written as:

$$ED = CT\cos\alpha$$

$$ED = 7000\ m \times \cos(80°) \cong 1215.54\ m$$

To sum up TVD:

$$TVD = AB + BE + ED$$

$$TVD = 1000\ m + 1128.51\ m + 1215.54\ m = 3344.05\ m$$

TVD, from A to D, is 3344.05 m.

5.1.2 HD Calculations

The only two horizontal distances for the well is DF and FT. To find the length of both these distances, we will use trigonometry. We will use EC to calculate DF, as EC = DF. At EC, we will take advantage of the CGH triangle:

$$\cos\alpha = \frac{GH}{R}$$

which can be written as:

$$GH = R \times \cos\alpha$$

Then we have:

$$EC = R - GH = R - R \times \cos\alpha = R(1 - \cos\alpha)$$

$$EC = 1145.92\ m \times (1 - \cos(80°)) \cong 946.93\ m$$

For the distance FT we will only need trigonometry.

$$\sin\alpha = \frac{FT}{CT}$$

which can be written as:

$$FT = CT \times \sin\alpha$$

$$FT = 7000\ m\ \times \sin(80°) = 6893.65\ m$$

To sum up HD:

$$HD = EC + FT$$

$$HD = 946.93\ m + 6893.65\ m = 7840.58\ m$$

HD, from D to F, is 7840.58 m.

5.1.3 MD Calculations

As MD is the total length of the wellbore, we will need to add the vertical, bend, and sail sections together. We already have the vertical and sail section, so we will need to calculate the length of the bend section. The bend section is from B to C in Figure 13. We have already found the formula for BC in formula X. In this formula α is in degrees.

$$BC = \frac{\Delta l}{\Delta i}\alpha$$

$$BC = \frac{30\ m}{1.5°} \times 80° = 1600\ m$$

$$MD = AB + BC + CT$$

$$MD = 1000\ m + 1600\ m + 7000\ m = 9600\ m.$$

MD, from A to T through B and C, is 9600 m.

Thus, the target or reservoir is located at a TVD of 3344.05 m, HD of 7840.58 m, and with a MD of 9600 m. This is important to have in mind for future force calculations, since the target or reservoir never changes TVD or HD. If the sail angle is changed, the kickoff point will change. These changes in calculations were incorporated into the Excel sheet calculations as one can find in Appendix A.

5.2 Hookload Calculations

To demonstrate the axial load calculations, we will use the formulas from the Torque & Drag chapter. We will continue the example set in the geometrical calculations.
To start, there will be a condition for F_1 to be set to zero which is relevant for both cases. It is because there is no contact between the string and the bottom of the wellbore during tripping, thus there cannot be any contact forces. This assumption is from [35] where it states "*At the very bottom of the string tension is small and the weight dominates friction also for curved bends. … During tripping in and out of the well F_1 = 0 is used as an end condition.*"
Furthermore, mud weight is set to 1600 kg/m^3, density of steel is set to 7850 kg/m^3, and the coefficient of friction is set to 0.3.

Table 2: Drill pipe geometric characteristics:

Nominal weight	Nominal weight	Grade	Type of tool joint	Appr. weight incl. tool joint
(in)	(lb/ft)			kg/m
5	19.50	S	NC50 (XH	33.57

Also, this drill pipe has a tensile yield strength of 316.5×10^3 da N, meaning that if the force on top of the drillstring exceeds this number, the pipe might deform, or in worst case tear.

The BHA is set to be 100 meters long and weigh 80 kg/m in dry air.

To start, one would calculate the buoyancy factor. Using formula (2):

$$\beta = 1 - \frac{\rho_{mud}}{\rho_{drill\ pipe}}$$

$$\beta = 1 - \frac{1600\ kg/m^3}{7850\ kg/m^3}$$

$$\beta \cong 0.80$$

Now one would like to know the weight of drill pipe and BHA in mud. To calculate this, one should multiply the buoyancy factor with the weight of drill pipe or BHA in dry air, from formula (3):

$$w = \beta w_{drillstring}$$

Since we have two section with different weight in dry air, drill pipe and BHA, one should calculate buoyed mass for both sections:

$$w_{drill\ pipe} = 0.80 \times 33.57 kg/m^3 \cong 26.73\ kg/m^3$$

$$w_{BHA} = 0.80 \times 80\ kg/m^3 \cong 63.69\ kg/m^3$$

With the different parameters set, we are ready to calculate the forces for the different sections of the drillstring.

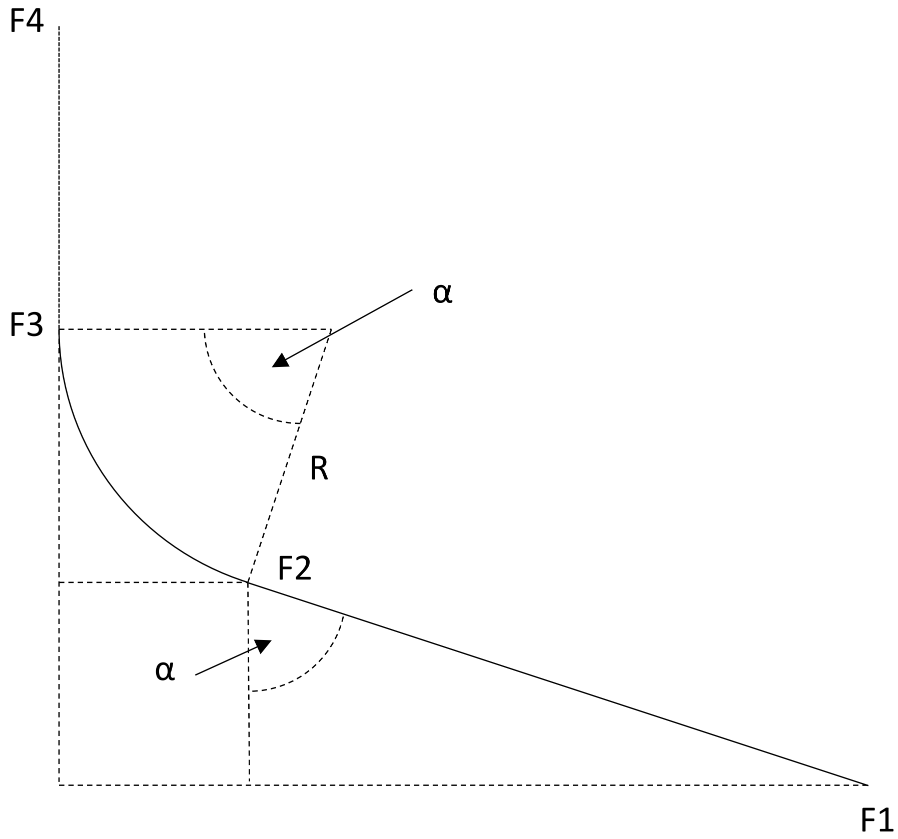


Figure 14: 2D well profile. Made in PowerPoint.

As stated previously, $F_1 = 0$, and the next force to calculate is F_2. Since we have the BHA in this section, the drill pipe in this section is the length of sail section ($\Delta s_{sail\ section}$) minus the BHA length (Δs_{BHA}). F_3 is the force on top on the bend, or at the KOP. Finally, F_4 is the force on top of the vertical section, the total hookload.

5.2.1 Hookload Calculations for a Pickup Scenario

We will start by calculating for a pickup scenario.

When having two different buoyed weights in the sail section, one must remember to differentiate the different buoyed weights of drill pipe and BHA. From formula (4), F_2 can then be written as:

$$F_2 = F_1 + ((w_{drill\,pipe}(\Delta s_{sail\,section} - \Delta s_{BHA}) + w_{BHA}\Delta s_{BHA})g(\cos\alpha + \mu\sin\alpha))$$

$$F_2 = 0 + \left(26.73\frac{kg}{m^3} \times (7000\,m - 100\,m) + 63.69\frac{kg}{m^3} \times 100\,m\right) \times 9.81\frac{m}{s^2} \times (\cos(80°) + 0.3 \times \sin(80°))$$

$$F_2 \cong 878046.82\,N$$

Note that $F_1 = 0$

Next, one shall calculate the force in the buildup bend, F_3, using formula (5):

$$F_3 = w_{drill\,pipe} gRsin\alpha + F_2 e^{\mu\alpha}$$

$$F_3 = 26.73\frac{kg}{m^3} \times 9.81\frac{m}{s^2} \times 1145.92\,m \times \sin(80°) + 878046.82\,N \times e^{0.3\times(80°\times\frac{\pi}{180°})}$$

$$F_3 \cong 1630775.91\,N$$

Lastly, F_4, on top of the vertical section ($\Delta s_{vertical\,section}$), should be calculated using formula (6):

$$F_4 = F_3 + w_{drill\,pipe} g\Delta s_{vertical\,section}$$

$$F_4 = 1630775.91\,N + 26.73\frac{kg}{m^3} \times 9.81\frac{m}{s^2} \times 1000\,m$$

$$F_4 = 1892997.21\,N$$

The final force F_4, the hookload, is 1892997.21 N with the current parameters set. This can be shortened to:

Table 3: Calculated hookload at 80 degrees inclination and 0.3 friction coefficient.

Newton	kilo Newton	10^3 deca Newton	Ton force
1892997.21	1893.00	189.30	193.03

Where 1 ton force is equal to 9806.65 N.

To be sure that one is sufficiently below the tensile limit of the pipe, it is important to calculate the safety factor. In the safety factor, there is incorporated a safety margin as well, which states that the axial load should not exceed 90% of the drill pipe tensile yield limit. This is calculated by:

$$Ta = 0.9 \times Te \tag{11}$$

where:

- Ta is the force the pipe can handle with the safety margin

- 0.9 is the safety margin

- Te is the tensile yield limit of the pipe (N)

Furthermore, the safety factor, which should be higher than 1.5, is calculated by:

$$SF = \frac{Ta}{T} \tag{12}$$

where:

- SF is the safety factor

- T is the hookload calculated on top of the drillstring, F_4

To ensure oneself that the pipe is strong enough, one should calculate the safety factor using formulas (11) and (12):

$$Ta = 0.9 \times Te$$

$$Ta = 0.9 \times 316.5 \times 10^3 \ da\ N = 284.5 \times 10^3 \ da\ N$$

$$SF = \frac{Ta}{T}$$

$$SF = \frac{284.5 \times 10^3 \ da\ N}{189.3 \ \times 10^3 \ da\ N} \cong 1.505$$

1.505>1.5, thus meaning that the safet factor criteria is satisfied and the pipe can be used in the operation.

In some cases, the pipe might get stuck as mentioned previously, which requires the driller to pull with extra force on top to get the stuck pipe loose. This is called margin of overpull

(MOP). The MOP should be some tons, such that the operator has some extra force if needed in a stuck pipe situation.

MOP is calculated by:

$$T + MOP = 0.9 \times Te$$

$$MOP = Ta - T$$

$$MOP = 284.5 \times 10^3 \; da\; N \; - 189.30 \times 10^3 \; da\; N = 95.2 \times 10^3 \; da\; N$$

To calculate this in ton force:

$$MOP = \frac{95.2 \times 10^3 \; da\; N}{0.980665} = 97.14 \; ton\; force$$

In this example of drilling operation, the operator has met all required limitations, and has enough MOP to counter a stuck pipe situation.

5.2.2 Sensitivity Analysis – Pickup

A sensitivity analysis is an analysis that determines how target parameters are affected by changes in other input parameters [47].

In this sensitivity analysis, we will change the parameters inclination and coefficient of friction to see how these parameters affect the different forces in the different sections. These are all calculated with Excel using the formulas in the 2D well profile example. The target of the well is kept fixed for all three inclinations hence the KOP and length of the different sections had to be recalculated. This was done by implementing the formulas in an Excel sheet. In Appendix A a snapshot of the Excel sheet developed is shown.

First, starting with an inclination of 80° and varying the coefficient of friction (μ) from 0.2 to 0.4:

Table 4: Table of force F_1 with different coefficient of friction at all inclinations.

μ		
0.3	F_1	0
0.4	F_1	0
0.2	F_1	0

Of course, since the bottom end condition is that F_1 is kept at 0 N, it does not change whether one changes the coefficient of friction, which further applies for all inclinations.

The next section, the force F_2 at different inclinations:

Table 5: Table of force F_2 with different coefficient of friction with 80 degrees inclination.

μ		Force (N)	Force due to DP in sail section (N)	Force due to BHA in sail section (N)
0.3	F_2	877975.52	848664.83	29310.69
0.4	F_2	1062297.54	1026833.37	35464.17
0.2	F_2	693653.49	670496.29	23157.21

Table 6: Table of force F_2 with different coefficient of friction with 85 degrees inclination.

μ		Force (N)	Force due to DP in sail section (N)	Force due to BHA in sail section (N)
0.3	F2	704317.15	680197.41	24119.74
0.4	F2	886081.73	855737.37	30344.37
0.2	F2	522552.57	504657.46	17895.11

Table 7: Table of force F_2 with different coefficient of friction with 75 degrees inclination.

μ		Force (N)	Force due to DP in sail section (N)	Force due to BHA in sail section (N)
0.3	F2	1061000.49	1026721.93	34278.56
0.4	F2	1247813.06	1207499.00	40314.06
0.2	F2	874187.92	845944.85	28243.07

It is observed that the forces increase when the friction factor increases, which is correct. When the friction factor increases, the forces connected to the friction factor also increases. This is from formula (4), where μ before sin is positive.

In addition, the forces increase also when the inclination decreases. This is due to the drill pipe and BHA in the sail section is set closer to a vertical setting, increasing weight forces for the drillstring.

The following section, top of buildup bend, with the force F_3 with different inclinations:

Table 8: Table of force F_3 with different coefficient of friction with 80 degrees inclination.

μ		Force (N)	Force due to capstan effect (N)
0.3	F3	1630640.99	456772.40
0.4	F3	2152850.60	794659.99
0.2	F3	1213001.06	223454.49

Table 9: Table of force F_3 with different coefficient of friction with 85 degrees inclination.

μ		Force (N)	Force due to capstan effect (N)
0.3	F3	1398459.18	394827.66
0.4	F3	1903258.80	717862.70
0.2	F3	1002366.86	180499.93

Table 10: Table of force F_3 with different coefficient of friction with 75 degrees inclination.

μ		Force (N)	Force due to capstan effect (N)
0.3	F3	1861532.58	510312.24
0.4	F3	2396642.84	858609.93
0.2	F3	1426022.38	261614.61

As one may observe, the increase in forces when varying friction factor in F_3 is much higher than in varying the friction factor in F_2. This is because of the Capstan effect, making the friction factor make up most of the change in total force F_3, as explained previously. In addition, at 75 degrees F_3 is at its highest. This may be because from F_2, which one uses to calculate the Capstan effect in F_3, is also at its highest with 75 degrees inclination.

Finally, the top of the vertical section, with the force F_4 with different inclinations:

Table 11: Table of force F_4 with different coefficient of friction with 80 degrees inclination.

μ		Force (N)	kN	10^3 da N	Tonne force	SF	MOP
0.3	F4	1892838.97	1892.84	189.28	193.02	1.50	97.45
0.4	F4	2415048.58	2415.05	241.50	246.27	1.18	44.20
0.2	F4	1475199.04	1475.20	147.52	150.43	1.93	140.04

Table 12: Table of force F_4 with different coefficient of friction with 85 degrees inclination.

μ		Force (N)	kN	10^3 da N	Tonne force	SF	MOP
0.3	F4	1820085.38	1820.09	182.01	185.60	1.57	104.87
0.4	F4	2324884.95	2324.88	232.49	237.07	1.23	53.39
0.2	F4	1423993.02	1423.99	142.40	145.21	2.00	145.26

Table 13: Table of force F_4 with different coefficient of friction with 75 degrees inclination.

μ		Force (N)	kN	10^3 da N	Tonne force	SF	MOP
0.3	F4	1956939.11	1956.94	195.69	199.55	1.46	90.91
0.4	F4	2492049.37	2492.05	249.20	254.12	1.14	36.35
0.2	F4	1521428.91	1521.43	152.14	155.14	1.87	135.32

For a fixed inclination, we observe that the axial load on top of the string increases when the friction coefficient is increased.

When the friction coefficient is 0.4, the safety factor will be below 1.5 for all three sail inclinations considered, and the operator would have the least MOP. In these cases, the operator should consider using a stronger drill pipe with a higher tensile yield limit.

As for friction factor at 0.2, which has the highest SF, there is less overall friction in the well, decreasing the total tensile stress on the string.

If we look at 80 degrees and the force F_3 on top of the build section, we observe that the friction force caused by the Capstan effect increases by: 794659 N - 223454 N = 571205 N when the friction coefficient increases from 0.2 to 0.4.

If we look at F_2 for the same inclination and friction factor, we observe that the F_2 force increases by:

1062297 N – 693653 = 368644 N.

The sum of these two increases will be the same as the total increase in F_4 on top of the string:

571205 N + 368644 N = 939849 N

2415048 N – 1475199 N = 939849 N

From this we can see that the frictional increase in the bend is most dominating.

It is noticed that 75 degrees inclination gave worst axial load. This may be because F_2 became largest in this case and since the Capstan friction is calculated by $F2(e^{\mu\alpha} - 1)$, and will contribute to increased friction. But this must be investigated further.

5.2.3 Hookload Calculations for a Slack Off Scenario

In the second scenario, we have a RIH operation. For this operation, the operator would like to find out if there is enough force to overcome the friction forces, so that the drillstring will reach its target. The operator must then keep in mind that the force on top of the drillstring, including weight of top drive, must be more than 0 N. The higher the force, the easier the trip in process is. If the force is a negative number, a result of the frictional forces is higher than the weight forces, then it is impossible to trip into the well.

In this scenario, we would like to run a liner into the wellbore, which is 2000 meters long and placed at the bottom of the well. The liner has a weight of 43.12 kg/m in dry air. Over the liner will be the same drill pipe used in the tripping out scenario. The inclination is fixed at 75 degrees, and we will use the same mud weight and steel/pipe density as in the tripping out scenario, hence the buoyed weight of the liner in mud will be:

$$w_{liner\_buoyed} = \beta g w_{liner}$$

$$w_{liner\_buoyed} = 0.80 \times 43.12\ kg/m^3 \cong 34.33\ kg/m^3$$

There will be a coefficient of friction of 0.35 at the liner section, and 0.2 for the rest of the drillstring. The desired target will still be the same, at TVD = 3344.05 m, and HD = 7840.58 m, so with a different inclination, the KOP will no longer be 1000 meters beneath the rig. With a 75 degrees inclination, the KOP is at a depth of 363.87 meters, and this is found using the Excel sheet in Appendix A. In addition, we will also use the top drive weight, which in this case weighs 25 tons. Using the theory discussed previously we start calculating from the bottom of the wellbore upwards, where we use the same bottom end condition as previously, resulting in F_1=0.

Then, start calculating F_2, force on top of sail section:

$$F_2 = F_1 + g\left(w_{drill\ pipe}(\Delta s_{sail\ section} - \Delta s_{liner})(\cos\alpha - \mu_{drill\ pipe}\sin\alpha) + (w_{liner_{buoyed}}\Delta s_{liner}(\cos\alpha - \mu_{liner}\sin\alpha)\right)$$

$$F_2 = 0 + 9.81\frac{m}{s^2}\left(26.73\frac{kg}{m^3} \times (7237.87\ m - 2000\ m)(\cos(75°) - 0.2 \times \sin(75°)) + 34.33\frac{kg}{m^3} \times 2000\ m \times (\cos(75°) - 0.35 \times \sin(75°))\right)$$

$$F_2 \cong 36764.33\ N$$

Note that the friction calculated is negative, as is correct for this tripping in scenario. The formula is modified from formula (4) to fit this scenario.

Next, one shall calculate the force in the buildup bend, F_3, using formula (5):

$$F_3 = w_{drill\ pipe} gRsin\alpha + F_2 e^{-\mu\alpha}$$

$$F_3 = 26.73\frac{kg}{m^3} \times 9.81\frac{m}{s^2} \times 1145.92\ m \times \sin(75°) + 36764.33\ N \times e^{-0.2\times(75°\frac{\pi}{180°})}$$

$$F_3 \cong 318542.10\ N$$

Note that here, since we are tripping in, the exponent of Euler's number has a negative value.

Lastly, F_4, on top of the vertical section ($\Delta s_{vertical\ section}$), should be calculated using formula (6):

$$F_4 = F_3 + w_{drill\ pipe} g\Delta s_{vertical\ section}$$

$$F_4 = 318542.10\ N + 26.73\frac{kg}{m^3} \times 9.81\frac{m}{s^2} \times 363.87\ m$$

$$F_4 = 413956.56\ N$$

The force F_4, is 413956.56 N with the current parameters set. This can be shortened to:

Table 14: Table of force F_4 at liner length 2000 m, and inclination of 75 degrees.

Newton	kilo Newton	10^3 deca Newton	Ton force
413956.56	413.96	41.40	42.21

In addition, we have a top drive in this scenario, which need to be included as a weight force as well, since it has a mass of 25 tons. The resulting force including weight from top drive is then:

$$F_5 = F_4 + g w_{top\ drive}$$

$$F_5 = 413956.56\ N + 9.81 \frac{m}{s^2} \times 25000\ kg$$

$$F_5 = 659206.56\ N$$

The force F_5 can be shortened to:

Table 15: Table of force F_5 at liner length 2000 m, and inclination of 75 degrees.

Newton	kilo Newton	10^3 deca Newton	Ton force
659206.56	659.21	65.92	67.22

As one may see, there is enough force on surface to trip in the drillstring to desired target.

5.2.4 Sensitivity Analysis – Slacking Off

In the slacking off scenario, we will instead have a fixed inclination at 75 degrees and vary the parameters of liner length and coefficients of friction. These are all also calculated with Excel using the formulas in the 2D well profile example. As mentioned previously, we will be using a different depth of KOP since we have a fixed inclination of 75 degrees. The depth is now 363.87 meters. This analysis was calculated by implementing the formulas in an Excel sheet. In Appendix A, a snapshot of the Excel sheet developed is shown.

We will use liner length of 1000 meters, 2000 meters and 4000 meters, coefficients of friction in openhole (liner section) 0.25, 0.35, 0.45, and coefficients of friction for drill pipe section 0.1, 0.2 and 0.3.

First, we will start off with a liner length of 2000 meters, and vary the coefficients of friction:

Table 16: Table of force F_1.

Coefficient openhole	Coefficient drill pipe		
0.35	0.2	F1	0
0.45	0.3	F1	0
0.25	0.1	F1	0

Since we still have the same bottom hole condition of no contact between the drillstring and bottom of the wellbore, there is no contact force. Then F_1=0 for all conditions.

The next section, the force F_2, is calculated in three steps, first for the liner section, then for the drillpipe in the sail section, and lastly the total force on top of sail section:

Table 17: Table of forces in sail section with a liner length of 2000 meters and different coefficients of friction.

Coefficient openhole	Coefficient drill pipe		Force (N)	Force due to weight of liner	Force due to friction
0.35	0.2	F2 liner	-53384.45	174334.90	-227719.35
0.45	0.3	F2 liner	-118447.12	174334.90	-292782.02
0.25	0.1	F2 liner	11678.22	174334.90	-162656.68
Coefficient openhole	Coefficient drill pipe		Force (N)	Force due to weight of drill pipe	Force due to friction of drill pipe
0.35	0.2	F2 drill pipe	90139.22	355452.82	-265313.60
0.45	0.3	F2 drill pipe	-42517.58	355452.82	-397970.40
0.25	0.1	F2 drill pipe	222796.02	355452.82	-132656.80
Coefficient openhole	Coefficient drill pipe		Force (N)	Force due to weight	Force due to friction
0.35	0.2	F2 total	36754.78	529787.73	-493032.95
0.45	0.3	F2 total	-160964.69	529787.73	-690752.42
0.25	0.1	F2 total	234474.25	529787.73	-295313.48

Table 18: Table of forces in sail section with a liner length of 4000 meters and different coefficients of friction.

Coefficient openhole	Coefficient drill pipe		Force (N)	Force due to weight of liner	Force due to friction
0.35	0.2	F2 liner	-106768.90	348669.81	-455438.70
0.45	0.3	F2 liner	-236894.24	348669.81	-585564.05
0.25	0.1	F2 liner	23356.45	348669.81	-325313.36
Coefficient openhole	Coefficient drill pipe		Force (N)	Force due to weight of drill pipe	Force due to friction of drill pipe
0.35	0.2	F2 drill pipe	55720.97	219728.73	-164007.76
0.45	0.3	F2 drill pipe	-26282.91	219728.73	-246011.64
0.25	0.1	F2 drill pipe	137724.85	219728.73	-82003.88
Coefficient openhole	Coefficient drill pipe		Force (N)	Force due to weight	Force due to friction
0.35	0.2	F2 total	-51047.92	568398.54	-619446.46
0.45	0.3	F2 total	-263177.14	568398.54	-831575.69
0.25	0.1	F2 total	161081.30	568398.54	-407317.24

Table 19: Table of forces in sail section with a liner length of 1000 meters and different coefficients of friction.

Coefficient openhole	Coefficient drill pipe		Force (N)	Force due to weight of liner	Force due to friction
0.35	0.2	F2 liner	-26692.22	87167.45	-113859.68
0.45	0.3	F2 liner	-59223.56	87167.45	-146391.01
0.25	0.1	F2 liner	5839.11	87167.45	-81328.34
Coefficient openhole	Coefficient drill pipe		Force (N)	Force due to weight of drill pipe	Force due to friction of drill pipe
0.35	0.2	F2 drill pipe	107348.35	423314.87	-315966.52
0.45	0.3	F2 drill pipe	-50634.91	423314.87	-473949.78
0.25	0.1	F2 drill pipe	265331.61	423314.87	-157983.26
Coefficient openhole	Coefficient drill pipe		Force (N)	Force due to weight	Force due to friction
0.35	0.2	F2 total	80656.12	510482.32	-429826.19
0.45	0.3	F2 total	-109858.47	510482.32	-620340.79
0.25	0.1	F2 total	271170.72	510482.32	-239311.60

It is observed that with a longer liner, weight force increases, which is correct as liner weight is heavier than drill pipe weight. In addition, it is observed that the friction forces are also largest with the longest liner. In total F_2 becomes largest for the longest liner.

The next section, at the top of buildup bend, the force F_3 with different liner length:

Table 20: Table of forces in buildup section with a liner length of 2000 meters and different coefficients of friction.

Coefficient openhole	Coefficient drill pipe		Force (N)	Force due to weight of drill pipe	Force due to Capstan friction (N)
0.35	0.2	F3	318508.73	290219.85	-8465.90
0.45	0.3	F3	181531.35	290219.85	52276.20
0.25	0.1	F3	495925.46	290219.85	-28768.64

Table 21: Table of forces in buildup section with a liner length of 4000 meters and different coefficients of friction.

Coefficient openhole	Coefficient drill pipe		Force (N)	Force due to weight of drill pipe	Force due to Capstan friction (N)
0,35	0,2	F3	250930.03	290219.85	11758.10
0,45	0,3	F3	112514.25	290219.85	85471.54
0,25	0,1	F3	431537.41	290219.85	-19763.75

Table 22: Table of forces in buildup section with a liner length of 1000 meters and different coefficients of friction.

Coefficient openhole	Coefficient drill pipe		Force (N)	Force due to weight of drill pipe	Force due to Capstan friction (N)
0.35	0.2	F3	352298.08	290219.85	-18577.90
0.45	0.3	F3	216039.91	290219.85	5678.53
0.25	0.1	F3	528119.49	290219.85	-33271.08

The Capstan effect is highest for the largest friction coefficients and longest liner. This checks out with the previous theory explained, as the Capstan effect affects the friction forces. In addition, the Capstan effect friction is largest with the longest liner because it provides a larger force at the top of the sail section, further demonstrating the Capstan effect is dependent of the force acting at F_2. Because drill pipe weight does not change in the bend, the force due to weight of drill pipe stays the same for all liner lengths and friction factors.

Next section, the top of the vertical section, with the force F_4 with different liner lengths and coefficients of friction:

Table 23: Table of forces on top of vertical section with a liner length of 2000 meters and different coefficients of friction.

Coefficient openhole	Coefficient drill pipe		Force (N)	kN	10^3 da N	Tonne force
0.35	0.2	F4	413915.26	413.92	41.39	42.21
0.45	0.3	F4	276937.89	276.94	27.69	28.24
0.25	0.1	F4	591331.99	591.33	59.13	60.30

Table 24: Table of forces on top of vertical section with a liner length of 4000 meters and different coefficients of friction.

Coefficient openhole	Coefficient drill pipe		Force (N)	kN	10^3 da N	Tonne force
0.35	0.2	F4	346336.56	346.34	34.63	35.32
0.45	0.3	F4	207920.78	207.92	20.79	21.20
0.25	0.1	F4	526943.94	526.94	52.69	53.73

Table 25: Table of forces on top of vertical section with a liner length of 1000 meters and different coefficients of friction.

Coefficient openhole	Coefficient drill pipe		Force (N)	kN	10^3 da N	Tonne force
0.35	0.2	F4	447704.61	447.70	44.77	45.65
0.45	0.3	F4	311446.44	311.45	31.14	31.76
0.25	0.1	F4	623526.02	623.53	62.35	63.58

Lastly, we have the force on top with the top drive weight added, F_5:

Table 26: Table of force F_4 including top drive weight with a liner length of 2000 meters and different coefficients of friction.

Coefficient openhole	Coefficient drill pipe		Force (N)	kN	10^3 da N	Tonne force
0.35	0.2	F5	659165.26	659.17	65.92	67.22
0.45	0.3	F5	522187.89	522.19	52.22	53.25
0.25	0.1	F5	836581.99	836.58	83.66	85.31

Table 27: Table of force F_4 including top drive weight with a liner length of 4000 meters and different coefficients of friction.

Coefficient openhole	Coefficient drill pipe		Force (N)	kN	10^3 da N	Tonne force
0.35	0.2	F5	591586.56	591.59	59.16	60.33
0.45	0.3	F5	453170.78	453.17	45.32	46.21
0.25	0.1	F5	772193.94	772.19	77.22	78.74

Table 29: Table of force F_4 including top drive weight with a liner length of 1000 meters and different coefficients of friction.

Coefficient openhole	Coefficient drill pipe		Force (N)	kN	10^3 da N	Tonne force
0.35	0.2	F5	692954.61	692.95	69.30	70.66
0.45	0.3	F5	556696.44	556.70	55.67	56.77
0.25	0.1	F5	868776.02	868.78	86.88	88.59

It is observed that increased liner length and increased friction factor gives less axial force on surface, and represent the worst case with respect to tripping in. However, in all cases simulated, the operator would have been able to trip in and reach target, since a positive weight force is seen at surface.

6 Conclusion

Directional drilling, horizontal and high angle wells stands for more and more of oil and gas production. This drilling method and wells are called Extended Reach Drilling (ERD) and Extended Reach Wells. Usually, the definition of a well to be an ERD well is that it must have a step out ratio more or equal to 2.0. The higher this ratio gets, the more complex the well gets.

With what has been presented in this thesis, one can conclude that ERW are very complex directional wells, that need a lot of attention to detail during the planning phase, drilling phase, and during tripping. Tripping is a complex process for the operator, which has to always be aware of the forces acting on the string during tripping.

Moreover, this thesis focused on drag and corresponding limitations with regards to varying parameters during tripping, such as friction coefficient, inclination angle, and liner length. The objective of this analysis was to observe what would happen with the different forces acting at different positions in the well. The results from the sensitivity analysis presented that friction forces, and friction theory such as the Capstan effect, plays a large role during tripping operations. Thus, the sensitivity of the friction factor must therefore be calculated during the planning phase, such that the operator is aware of what forces they may operate with, and if they can safely proceed the tripping procedure.

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Appendix A

A-1: Geometrical calculations at 80 degrees inclination

Geometrical calulations				
Degrees/30m	1,50		R	1145,92
Vertical depth to KOP	1000,00		EC	946,93
Sail section	7000,00		FT	6893,65
Vertical depth in buildup bend	1128,51			
Curvelength of buildup bend	1600,00			
Vertical length of sail section	1215,54			
TVD	3344,04			
MD	9600,0			
Horisontal displacement	7840,58			

A-2: Geometrical calculations at 85 degrees inclination

Geometrical calulations				
Degrees/30m	1,50		R	1145,92
Vertical depth to KOP	1608,04		EC	1046,04
Sail section	6820,49		FT	6794,54
Vertical depth in buildup bend	1141,56			
Curvelength of buildup bend	1700,00			
Vertical length of sail section	594,45			
TVD	3344,04			
MD	10128,5			
Horisontal displacement	7840,58			

A-3: Geometrical calculations at 75 degrees inclination

Geometrical calulations				
Degrees/30m	1,50		R	1145,92
Vertical depth to KOP	363,87		EC	849,33
Sail section	7237,87		FT	6991,25
Vertical depth in buildup bend	1106,87			
Curvelength of buildup bend	1500,00			
Vertical length of sail section	1873,30			
TVD	3344,04			
MD	9101,7			
Horisontal displacement	7840,58			

Appendix B

B-1: Hookload calculations while tripping out at 80 degrees inclination and 0.3 friction factor

Tripping out scenario				
Varying parameters		Radians		
Mechanical friction coefficient	0,3			
Inclination (degrees)	80,00	1,3962634		
Characterisitcs of BHA and DP after varying parameters	Length (m)	Density, dry (kg/m)	Bouancy factor (kg/m)	
BHA	100	80	63,69426752	
Drillpipe	9500,0	33,57	26,72770701	
Te (steel strength) (Newton)	3165000			
Ta (Te*0,9) (Newton)	2848500			
Bouancy factor	0,796178344			
Results:				
F1 (Newton)	0	Force top of sailsection	Force top of BHA	
F2 (Newton)	877975,5156	848664,8287	29310,68688	
		Capstan		
F3 (Newton)	1630640,989	456772,4019		
		kN	10^3 da N	tonne-force
F4 (Newton)	1892838,97	1892,84	189,28	193,02
FS	1,504882373			
MOP (tonne-force)	97,45			

B-2: Hookload calculations while tripping out at 85 degrees inclination and 0.3 friction factor

Tripping out scenario				
Varying parameters		Radians		
Mechanical friction coefficient	0,3			
Inclination (degrees)	85,00	1,4835299		
Characterisitcs of BHA and DP after varying parameters	Length (m)	Density, dry (kg/m)	Bouancy factor (kg/m)	
BHA	100	80	63,69426752	
Drillpipe	10028,5	33,57	26,72770701	
Te (steel strength) (Newton)	3165000			
Ta (Te*0,9) (Newton)	2848500			
Bouancy factor	0,796178344			
Results:				
F1 (Newton)	0	Force top of sailsection	Force top of BHA	
F2 (Newton)	704317,1521	680197,4143	24119,73779	
		Capstan		
F3 (Newton)	1398459,18	394827,6614		
		kN	10^3 da N	tonne-force
F4 (Newton)	1820085,337	1820,09	182,01	185,60
FS	1,565036508			
MOP (tonne-force)	104,87			

B-3: Hookload calculations while tripping out at 75 degrees inclination and 0.3 friction factor

Tripping out scenario				
Varying parameters		Radians		
Mechanical friction coefficient	0,3			
Inclination (degrees)	75,00	1,3089969		
Characterisitcs of BHA and DP after varying parameters	Length (m)	Density, dry (kg/m)	Bouancy factor (kg/m)	
BHA	100	80	63,69426752	
Drillpipe	9001,7	33,57	26,72770701	
Te (steel strength) (Newton)	3165000			
Ta (Te*0,9) (Newton)	2848500			
Bouancy factor	0,796178344			
Results:				
F1 (Newton)	0	Force top of sailsection	Force top of BHA	
F2 (Newton)	1061000,489	1026721,925	34278,56394	
		Capstan		
F3 (Newton)	1861532,579	510312,2386		
		kN	10^3 da N	tonne-force
F4 (Newton)	1956939,111	1956,94	195,69	199,55
FS	1,455589489			
MOP (tonne-force)	90,91			

Appendix C

C-1: Total force including top drive calculations while tripping in with liner length 2000 and 0.35 and 0.2 friction factor

Tripping in scenario				
Inputs	Length (m)	Density, dry (kg/m^3)	Density in fluid (kg/m^3)	
Liner (m)	2000	43,12	34,33	
Mechanical friction coefficient open hole	0,35			
Mechanical friction coefficient	0,2			
	Length (m)	Density, dry (kg/m^3)	Density in fluid (kg/m^3)	
Drillstring in sailsection	5000,0	33,57	26,73	
Topdrive (kg)	25000			
Inclination (degrees)	75			
Inclination (radians)	1,308996939			
Results:				
F1 (Newton)	0	Force due to weight of liner	Force due to friction of liner section	
F2 liner (Newton)	-53384,45	174334,90	-227719,35	
		Force due to weight of dp top of sail section	Force due to friction of dp in sailsection	
F2 drill pipe (Newton)	86045,56	339309,9672	-253264,4074	
		Force top of sailsection due to weight	Force top of sailsection due to friction	
F2 total (Newton)	32661,11	513644,87	-480983,76	
		Force due to weigth of drill pipe	Capstanfriction	
F3 (Newton)	321031,20	295893,0717	-7957,92	
		kN	10^3 da N	tonne-force
F4 (Newton)	583229,18	583,23	58,32	59,47
		kN	10^3 da N	tonne-force
F5	828479,18	828,48	82,85	84,48

C-2: Total force including top drive calculations while tripping in with liner length 4000 and 0.35 and 0.2 friction factor

Tripping in scenario				
Inputs	Length (m)	Density, dry (kg/m^3)	Density in fluid (kg/m^3)	
Liner (m)	4000	43,12	34,33	
Mechanical friction coefficient open hole	0,35			
Mechanical friction coefficient	0,2			
	Length (m)	Density, dry (kg/m^3)	Density in fluid (kg/m^3)	
Drillstring in sailsection	3000,0	33,57	26,73	
Topdrive (kg)	25000			
Inclination (degrees)	75			
Inclination (radians)	1,308996939			
Results:				
F1 (Newton)	0	Force due to weight of liner	Force due to friction of liner section	
F2 liner (Newton)	-106768,90	348669,81	-455438,70	
		Force due to weight of dp top of sail section	Force due to friction of dp in sailsection	
F2 drill pipe (Newton)	51627,31	203585,8781	-151958,5682	
		Force top of sailsection due to weight	Force top of sailsection due to friction	
F2 total (Newton)	-55141,59	552255,69	-607397,27	
		Force due to weigth of drill pipe	Capstanfriction	
F3 (Newton)	253452,50	295893,0717	13435,32	
		kN	10^3 da N	tonne-force
F4 (Newton)	515650,48	515,65	51,57	52,58
		kN	10^3 da N	tonne-force
F5	760900,48	760,90	76,09	77,59

C-3: Total force including top drive calculations while tripping in with liner length 1000 and 0.35 and 0.2 friction factor

Tripping in scenario				
Inputs	Length (m)	Density, dry (kg/m^3)	Density in fluid (kg/m^3)	
Liner (m)	1000	43,12	34,33	
Mechanical friction coefficient open hole	0,35			
Mechanical friction coefficient	0,2			
	Length (m)	Density, dry (kg/m^3)	Density in fluid (kg/m^3)	
Drillstring in sailsection	6000,0	33,57	26,73	
Topdrive (kg)	25000			
Inclination (degrees)	75			
Inclination (radians)	1,308996939			
Results:				
F1 (Newton)	0	Force due to weight of liner	Force due to friction of liner section	
F2 liner (Newton)	-26692,22	87167,45	-113859,68	
		Force due to weight of dp top of sail section	Force due to friction of dp in sailsection	
F2 drill pipe (Newton)	103254,68	407172,0117	-303917,327	
		Force top of sailsection due to weight	Force top of sailsection due to friction	
F2 total (Newton)	76562,46	494339,46	-417777,00	
		Force due to weigth of drill pipe	Capstanfriction	
F3 (Newton)	354820,55	295893,0717	-18654,54	
		kN	10^3 da N	tonne-force
F4 (Newton)	617018,53	617,02	61,70	62,92
		kN	10^3 da N	tonne-force
F5	862268,53	862,27	86,23	87,93