NTNU
Norwegian University of
Science and Technology

TTK4551 - Specialization Project

# An Overview of Managed Pressure Drilling Systems with Implications of Incorporating HeaveLock

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Trondheim, January 9, 2019

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## Abstract

Controlling the downhole pressure conditions while drilling wells for oil and gas production is essential for both safety and efficiency. Some wells demand more precise control than others, and drilling can become a challenge for many wells. If for example the pressure becomes too low, the well might collapse or, in the worst case, start producing oil and gas uncontrollably. Automatic control systems have been developed to obtain control over the downhole conditions during drilling, e.g. Managed Pressure Drilling (MPD) and Continuous Circulation Systems (CCSs).

This report presents some of the challenges that the oil and gas industry faces within drilling operations, how conventional drilling is performed, and goes into detail on how modern MPD and CCS systems work to help solve some of the faced challenges. The report also introduce problems that these systems cannot solve, and show how HeaveLock™, a downhole tool under development, may be the solution to said problems.

The first part of the report present several aspects of drilling operations that is necessary to understand the challenges that drilling operations is facing. It also provides some basic knowledge on how modern drilling is performed. In the second part, the models and control systems of a MPD system is developed, before being implemented in a simulator. Then, the report presents simulation results comparing conventional drilling with the use of MPD and CCS, before ending with suggestions of future work.

## Sammendrag

Det å regulere trykket i en brønn under boreoperasjoner i olje- og gassindustrien er essensielt for både sikkerhet og effektivitet. Noen brønner krever mer nøyaktig regulering enn andre, og boring av slike kan ende opp å være en stor utfordring. Hvis for eksempel trykket i brønnen blir for lavt, kan brønnen kollapse og i værste fall starte ukontrollerbar olje- og gassproduksjon. Automatiske kontrollsystemer har blitt utviklet for å kunne regulere tilstandene i brønnen, for eksempel Managed Pressure Drilling (MPD) og Continuous Circulation System (CCS) systemer.

Denne rapporten presenterer noen av utfordringene olje- og gassindustrien møter når det kommer til boreoperasjoner, hvordan konvensjonell boring foregår, og går inn i detaljene rundt hvordan moderne MPD og CCS systemer fungerer for å løse disse utfordringene. Rapporten introduserer også problemer som disse systemene ikke kan løse, og viser hvordan HeaveLock™, et nedihullsverktøy under utvikling, kan ha løsningen på nevnte problemer.

Første del av rapporten presenterer flere aspekter om boreprosessen som er nødvendig for å forstå utfordringene boring kan møte på. Denne delen gir også basiskunnskap om hvordan moderne boring foregår. I den andre delen blir det utviklet modeller og reguleringssystemer for et MPD system, før disse blir implementert i en simulator. Deretter presenterer rapporten simuleringsresultater som sammenligner konvensjonell boring med boring hvor MPD og CCS benyttes, før den ender i forslag om videre arbeid.

# Preface

This report is the result of a 7.5 credits specialization project carried out in the second to last semester for those studying for a Master's degree in Cybernetics and Robotics, at the Norwegian University of Science and Technology (NTNU) in Trondheim. The report presents necessary background information needed to understand the later discussions on the subject at hand. The project assignment was given by a startup called Heavelock, and the underlying tasks were prepared by my supervisor, the co-inventor of Heavelock, Professor Ole Morten Aamo.

I would like to thank my supervisor Professor Ole Morten Aamo for his guidance on this project. I would also like to thank Heavelock for the opportunity and their continuous support throughout the project.

Readers are assumed to have some knowledge of control theory.

Torkil Sekse Mollan

Place and Date

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# Abbreviations

**BHA** Bottom Hole Assembly.

**BHP** Bottom Hole Pressure.

**BP** Back-pressure.

**CCS** Continuous Circulation System.

**ECD** Equivalent Circulating Density.

**EMW** Equivalent Mud Weight.

**MD** Measured Depth.

**MPD** Managed Pressure Drilling.

**MW** Mud Weight.

**TVD** True Vertical Depth.

**WOB** Weight on Bit.

# 1 Introduction

Some oil and gas wells can be more troublesome to drill than others, facing both efficiency and safety challenges. For some of these wells, today's technology is just not good enough to solve these challenges, and the wells may be classified as *non-drillable*. In later years, automatic control systems have become huge success factors in allowing earlier non-drillable wells to be drilled. They have the ability to control well conditions more precisely, reducing risks and increasing efficiency. Modern Managed Pressure Drilling (MPD) and Continuous Circulation Systems (CCSs) are among these successes, making drilling of wells become less of a challenge [1][2]. A new tool called HeaveLock™ is currently being developed to solve one of the few remaining challenges, allowing wells to be drilled from floating drilling rigs in open seas and rough weather.

Up until the date of this project, it is known that HeaveLock™ relies on having CCS systems implemented. However, it is unknown if there are any implications with existing MPD and CCS systems when HeaveLock™ is incorporated, or if HeaveLock™ needs knowledge about how these systems work to function properly. This is the main motivation behind this project. The objective is therefore to gain insight and understanding of existing systems, present a detailed overview on how they work, and use this information to recommend ways to incorporate HeaveLock™.

## 1.1 Tasks

The project was divided into the following tasks

1. Find out how automatic MPD systems work today and how they are used. This step includes both technology and procedures.
2. Get an overview of, in as much detail as possible, the control systems used in MPD. How is the control structure? How does the pump ramping work together with the choke control? How are desired values for pressure and pump rates calculated?
3. Implement a MPD control system in HeaveSim and simulate connections with the automatic MPD system active (without HeaveLock).
4. How does the procedures change for automatic MPD control when CCS systems are used (still without HeaveLock)? Implement any found changes relative to step 3 in HeaveSim.
5. How should HeaveLock operate to minimize changes needed relative to step 4? It would be beneficial if MPD systems with CCS could operate more or less the same way regardless of HeaveLock. What does HeaveLock have to know, and what can it manage without or learn by itself in form of smart algorithms (machine learning)? This step is primarily a discussion based on step 4, but could include implementation or testing in the simulator if time allows it.

# 2 Theory

In the following sections, several aspects and concepts of drilling operations are presented to provide the necessary knowledge and theory needed for what is to come. Feel free to skip to the parts you do not already know, or return to this chapter if you need a refreshment of memory as you read on.

## 2.1 Connection Procedures

A drill string is made up of multiple lengths (or joints) of drill pipe. A connection is the act of adding such a length to the drill string to be able to drill even further [3]. The specific procedure for a connection is slightly different depending on which drilling control systems that are used. Most procedures have common elements though, and these are

1. Hoist drill string by some amount
2. Detach top drive (the device that rotates the drill string during drilling)
3. Attach top drive to a new joint
4. Connect new joint to drill string
5. Lower drill string back down and resume drilling

## 2.2 Drilling Window

The *drilling window* is defined as the difference between fracture pressure and pore pressure, see Fig. 1. Pore pressure is the pressure within pores of trapped formation fluids in the reservoir. Fracture pressure is the pressure needed to fracture the subsurface formations, causing pores to connect and thus enhance the formation's ability to transmit fluids, i.e. the formation's *permeability*. Both pore and fracture pressures are usually given in equivalent mud weight (EMW) as a function of true vertical depth (TVD). EMW is the mud weight (MW) (or density) needed to withstand a certain pressure. TVD is the vertical depth of the well, and only for a vertical well is TVD equal to the measured depth (MD), which is measured along the wellbore [3].

$$\text{EMW}\,[ppg] = \frac{p_{dh}\,[psi]}{0.052 \cdot \text{TVD}\,[ft]} \tag{2.1}$$

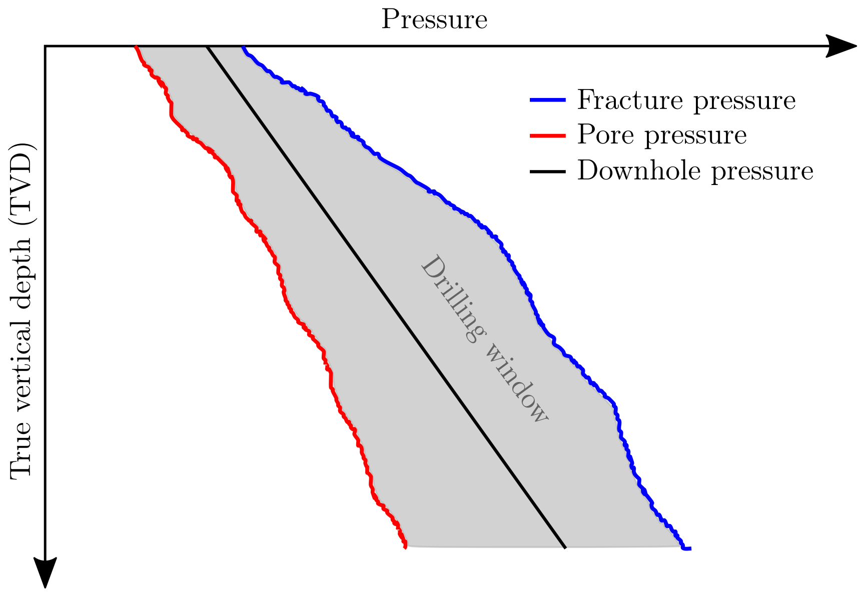



Figure 1: Drilling window

During drilling operations it is important that downhole pressures are kept within the drilling window [4]. Downhole pressures $p_{dh}$ are calculated as follows

$$p_{dh} = p_b + p_h + p_f, \tag{2.2}$$

where $p_b$ is any applied back-pressure (BP) in the surface end of the annulus, $p_h$ is the hydrostatic pressure at a given TVD and $p_f$ is the pressure loss due to friction between the annulus walls and a circulating fluid. In dynamic conditions, i.e. during circulation, one may use the equivalent circulating density (ECD) as the mud's density when calculating $p_h$ and thus remove $p_f$ from (2.2), but this is just a matter of taste.

$$\text{ECD}\,[ppg] = \text{MW}\,[ppg] + \frac{p_f\,[psi]}{0.052 \cdot \text{TVD}\,[ft]} \tag{2.3}$$

If downhole pressures falls below the pore pressure, formation fluids may enter the wellbore and cause dangerous situations. A flow of formation fluids into the wellbore is commonly known as a *kick*. A kick is especially dangerous if the fluids contain gas, which expands as it climbs towards the surface because of the lower surrounding pressure. If not controlled, a kick can evolve into a *blowout*, i.e. formation fluids reaching the surface. This is an extremely dangerous situation that may cause major catastrophic events, the Deepwater Horizon disaster in the Gulf of Mexico being one of the latest [5].

Dangerous situations may also occur when the downhole pressures climbs above the fracture pressure. As mentioned earlier, fractures increase the formation's permeability. If nothing more severe happens before the pressure returns to the drilling window, the increased permeability may still increase the probability and severity of a kick if the downhole pressure drops below the pore pressure at a later time. Another risk with the downhole pressures being too high is loss of circulation, i.e. drilling fluid (mud) is lost due to filling of pores in the formation, decreasing or even eliminating the amount of returned fluid. Because of the friction loss $p_f$, downhole pressures are always higher during circulation. Therefore, unexpectedly losing circulation could cause pressure drops and thus initiate kicks.

Due to the dangers that follows with violating the drilling window, it is important to control the downhole pressures to stay within the window during drilling operations. Different pressure control strategies have been developed for this. MPD systems are one of the more modern strategies, but essentially they all manipulate the right hand side of (2.2) in some way.

## 2.3 Conventional Control

In conventional control, bottom hole pressure (BHP) is controlled by manipulating ECD to match the desired EMW given by the drilling window. This is done by changing the MW and thus the hydrostatic term $p_f$ in (2.2). Manipulation of hydrostatic pressure is just one of the functions of drilling mud. Mud is also used to carry out cuttings as well as keeping drilling equipment cool, clean and lubricated. Because of constant exposure to cuttings and more, the mud's properties might change over time. Mud engineers regularly have to examine samples of returned mud to consider changing it, adding weight materials or other additives, to keep the mud's properties as desired for it to function as intended. The MW is just one of these properties, but it is the main property for keeping BHP within the drilling window using conventional control.

There is no surface back-pressure in conventional control, meaning that the annulus pressure at the surface is equal to atmospheric pressure, which implies that (2.2) reduces to

$$p_{dh} = p_h + p_f, \tag{2.4}$$

but we see from the equation that changes in hydrostatic pressure $p_h$ directly affects the downhole pressure $p_{dh}$, and thus it makes sense to manipulate MW to achieve control over BHP.

There are drawbacks to this strategy, however, and one of these is the time it takes to change the mud weight. In other words, conventional control of downhole pressures is relatively slow compared to e.g. MPD systems. If the drilling window does not allow considerable fluctuations in downhole pressure, i.e. a *narrow* drilling window, conventional control may not be the solution and other strategies should be considered.

## 2.4 Managed Pressure Drilling

MPD systems aim to control BHP by implementing and controlling surface back-pressure $p_b$ in the surface side of the annulus. By controlling the back-pressure, there is no need to continuously manipulate the mud weight anymore. We see from (2.2) that controlling $p_b$ directly affects $p_{dh}$, just like $p_h$ does in conventional control. There is a difference, however. Manipulation of mud weight changes the *slope* of the downhole pressure as a function of TVD, while manipulation of back-pressure acts as a constant term moving the downhole pressure function from side to side with respect to Fig. 1.

Surface back-pressure control is achieved by having a controllable choke valve in the return side after the annulus, see Fig. 2. There is no applied back-pressure when the choke valve is fully open, as the valve outlet is exposed to atmospheric pressure. By closing the valve, a pressure drop is created over it, and back-pressure is applied. The back-pressure $p_b$ in (2.2) is substituted with it's equivalent choke pressure $p_c$

$$p_{dh} = p_c + p_h + p_f. \tag{2.5}$$

The back-pressure pump is needed to maintain flow though the valve if there is no flow through the annulus, e.g. when the main pump is stopped during connections. This ensures that the valve does not saturate and thus maintains full control of the applied back-pressure [1]. There is a non-return valve in the bottom hole assembly (BHA) that makes sure that no fluids enters the drill string when the main pump is shut down and the back-pressure pump is on.

A more detailed look at the control systems in a specific MPD system is given in Section 4.

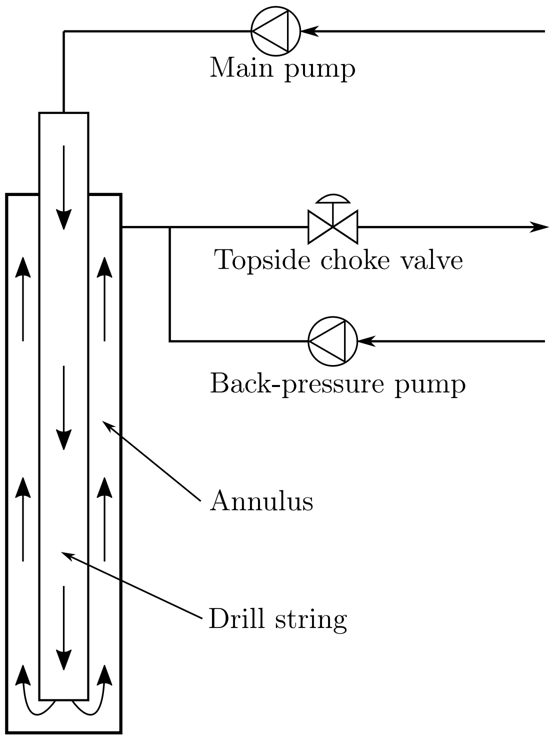
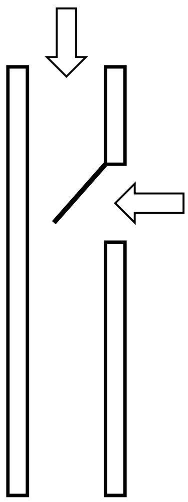



Figure 2: MPD overview

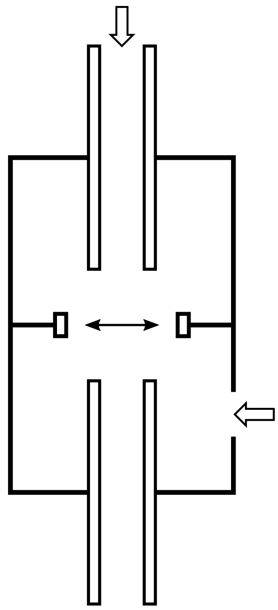
## 2.5 Continuous Circulation System

CCS is a system developed to ensure continuous circulation during connections while drilling. There exists different systems that ensures this, but the main function of them all is to keep a continuous flow through the mud loop during all drilling operations, i.e. the main pump is not stopped at any time. Some systems use special drill pipes that has built-in flapper valves for this purpose, see Fig. 3a. During drilling, mud is pumped through the pipe from the top, and the flapper valve is closed (aligned with the pipe). During a connection, a hose is connected to the valve and mud is pumped from the side instead, allowing unscrewing of the top to attach or detach joints of drill string without spilling mud. This is a simple system, but is rather costly since every stand of drill string needs a flapper valve.

There exists another system that allows arbitrary types of drill pipe. This is a rather complex system, using two chambers that can be filled with mud and pressurized independently of each other, see Fig. 3b. The main idea is that the chambers can be separated, so that mud can flow through just the lower chamber and into the drill string while another joint is added or removed from the top chamber. Then, the upper chamber is filled and pressurized, before joining the chambers and performing the connection.



(a) Pipe with flapper valve



(b) Pressure chambers

Figure 3: CCS systems

Continuous circulation has multiple positive effects, maybe the most important one being maintaining ECD. Without CCS implemented, the main pump is stopped during connections and circulation is lost. This causes a pressure drop due to the friction loss $p_f$ in (2.2) that is non-present in static conditions. After the connection is done and the main pump is turned back on, the downhole pressure increases again. Pressure fluctuations like these are unwanted, and in the case of a narrow drilling window, the pressure might even exceed the pore and fracture pressure limits. Since CCS systems ensures continuous circulation, the ECD is maintained and this problem is eliminated. CCS could even allow drilling of wells that earlier were classified as non-drillable because of their narrow drilling windows. Continuous circulation also ensures that cuttings are transported to the surface nonstop, meaning that no cuttings get the chance to sink and collect in the wellbore. Collections of cuttings may result in very expensive problems like stuck pipe [6].

Even though CCS systems eliminate pressure fluctuations due to transitions between static and dynamic conditions, pressure fluctuations still arise from axial motion of the drill string, e.g. during *tripping*, the act of hoisting the drill string out of the hole or lowering it back down [3].

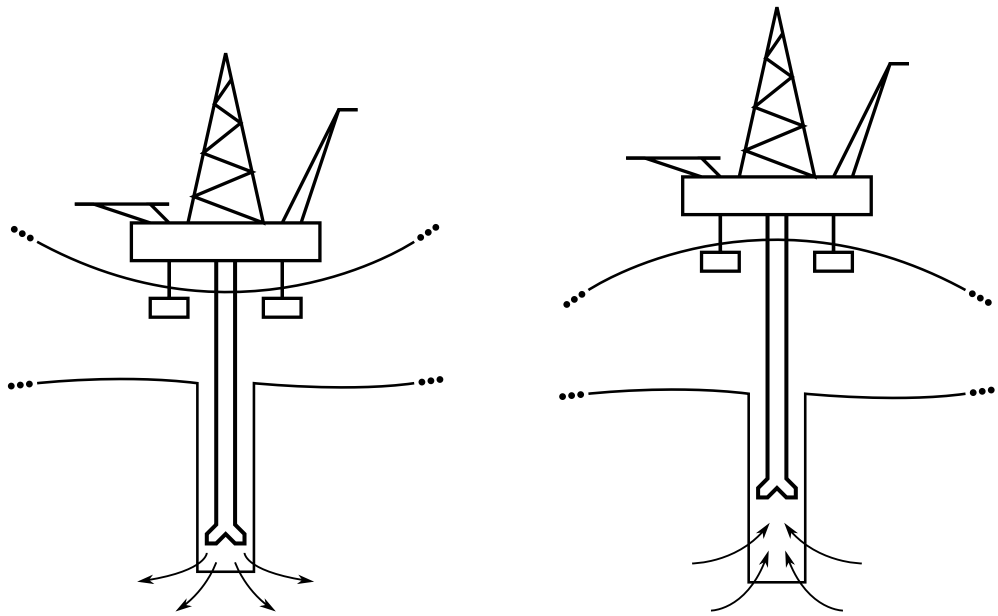
## 2.6 Surge and Swab

The axial motion of the drill bit from hoisting and lowering the drill string create bottom hole *surge* and *swab* pressures, respectively. Movement of the drill bit in a wellbore can be compared to the movement of a piston in a sealed cylinder. Pushing on the piston will try to compress the volume below it, thus increasing the pressure inside that reduced volume. Retracting the piston will do the opposite, expand the volume and decrease the pressure. The same applies to drill bit movements, where the amount of increase and decrease in pressure is called surge and swab pressures, respectively. However, to allow circulation of mud from the drill string to the annulus, the drill bit is not hermetically sealed to the wellbore wall as a piston would be. This allows the displaced volume of mud to exit into the annulus when the drill string is lowered. When the drill string is hoisted, mud from both inside the drill string and annulus may fill the increasing volume beneath it, depending on if there is flow or not, i.e. the main pump is on or off.

Dangerous situations may occur if the surge and swab pressures are not controlled. If the instantaneous surge and swab pressures are too high, the BHP could exceed the drilling window limits. High surge pressures might fracture the well and/or cause loss of circulation. If this happens, or if the swab pressures are too high, kicks could occur, which in the worst case scenario may result in a blowout. By giving the mud enough time to pass by the drill bit as it moves, the instantaneous surge and swab pressures are reduced. This effect can be experienced when you try to fill or empty a syringe with some kind of liquid. The nozzle allows liquid to enter or exit the syringe, just like mud can pass by the drill bit to enter or exit the volume below the bit. It is rather easy to fill or empty the syringe if you take your time moving the piston slowly, but it gets tougher as you pull/push the piston harder. This is because a greater pressure (and thus force) is needed to increase the flow through the nozzle. The greater the bit velocity, the greater the mudflow is due to the volume change, and thus the surge and swab pressures are higher. This means that drilling operators can control surge and swab pressures to some extent by controlling the hoisting and lowering velocities.

## 2.7 Heave Problem

Floating offshore drilling rigs introduce another problem. Even though drilling operators can control surge and swab pressures due to hoisting and lowering of the drill string by controlling the velocity, surge and swab pressures due to vertical motion of the drilling rig is not controlled. The vertical motion of a floating rig is called *heaving* and is mainly caused by waves, see Fig. 4. Note the vertical position of the drilling rig relative to the wave it floats on. The drilling rig is at it's highest at the crest of the wave, and lowest at the trough. Also note the surge and swab effects of the heaving motion that Fig. 4 illustrates.



(a) Heaving down creates surge pressure and mud could be lost to the formation

(b) Heaving up creates swab pressure and formation fluids could enter the wellbore

Figure 4: Heaving motion and its downhole effects

These effects could lead to dangerous situations and are of course unwanted. Unfortunately, pressure fluctuations due to heave motion are not as easy to control as those from hoisting and lowering of the drill string. The waves themselves account for the surge and swab pressures in this case and waves cannot be controlled. They can, however, be compensated for.

Waves acting like perfect sine waves are rare in open sea, and they usually come as a combination of waves with different amplitudes and frequencies, i.e. a *wave spectrum* [7]. This makes heaving due to waves very difficult to anticipate or estimate, if not impossible. Therefore, trying to actively control the axial motion of the drill string relative to the rig, to compensate for heave, might just be impossible. However, dynamic mechanical systems that store and use external energy can be designed to compensate for heave.

Different mechanical systems have been developed to compensate for the heave motion caused by waves, allowing the drill string to move more or less independently of the floating rig. By implementing heave compensation systems, the drill string does not move relative to the seabed, even though the floating rig moves vertically with the waves. In simplified terms, heave compensation systems can be compared to the suspension systems on road vehicles, simple mass-spring-damper systems. The suspension allows the wheels to move independently of the vehicle chassis. On bumpy roads the wheels will follow the road surface, while the suspension tries to eliminate any vertical motion of the chassis, resulting in a smooth and comfortable ride. In comparison with heave compensation, the bumps in the road are the waves, the wheel is the floating rig and the chassis is the drill string.

Without heave compensation systems, the floating drilling rig will not be able to drill in rough waters. The surge and swab pressures that are created is just one of the issues. The fact that the drill bit will repeatedly impact the bottom of the wellbore is another issue, and can damage both the well and drilling equipment. Heave compensation can eliminate these issues altogether, as well as provide the ability to control weight on bit (WOB), i.e. the amount of force applied to the bit from above. WOB control is important to drill more efficiently.

Even though floating drilling rigs have some kind of heave compensation system implemented to enable drilling, many systems are not active during connections. This is because most systems are connected to the drill string only, allowing just the drill string to move independently of the rig heave. To make a connection, i.e. to add another joint of drill pipe, the top drive must be unscrewed and screwed onto the new joint. This means that the drill string must be secured to the drill floor temporarily, physically disabling most heave compensation systems. There are solutions to this, e.g. heave compensated platforms that allows the entire drill floor to move independently of the rig itself.

The fact that some heave compensation systems are not active during connections is not necessarily a problem in calm conditions, but it can become problematic in rough seas, as the surge and swab pressures may exceed the drilling window limits.

## 2.8 HeaveLock™

Even though a heave compensated platform can eliminate the heave problem for floating drilling rigs, it is a large and expensive system to implement. Of course, such a system could be considered when constructing new drilling rigs, but it might not be a viable option for existing rigs as it requires major modifications, which results in even greater expenses. To enable existing floating drilling rigs to drill in rough seas, a cheaper system would be preferable. This is the main motivation behind the development of HeaveLock™, an autonomous downhole tool that aims to eliminate surge and swab during connections.

The idea behind HeaveLock™ is to maintain a constant BHP by compensating for the surge and swab pressures that are created, rather than eliminating the root cause for surge and swab, i.e. drill string axial motion. If the drill bit is pulled up, creating a pressure drop in the volume below it, one could compensate for this by somehow increasing the pressure by the same amount. A topside choke valve, like the one used in MPD systems (see 2.4), can accomplish this by increasing the back-pressure and thus downhole pressure according to (2.2). Increasing the flow by controlling the main pump is another option. This will increase the friction loss through the mud loop, and again the downhole pressure as seen in (2.2). This is not as easy as it seems though; studies have shown that trying to compensate for heave-induced surge and swab pressures with topside equipment is very difficult, especially in deep wells [8].

It is common to assume incompressible liquids in hydraulic systems, resulting in instantaneous responses. In reality, however, liquids are compressible. This, in fact, can become a limiting factor in hydraulic systems of a certain size, like it does in deep wells. Due to compressibility, pressure waves (such as sound waves) will travel through a medium at the speed of sound in that medium [9]. This means that it takes time for topside pressure changes to reach the bottom of the well, and this delay increases with well depth. The delay can actually approach and exceed half the time period of the heaving motion, resulting in pressure changes reaching the bottom way too late, i.e. the drill bit is already moving the other way, effectively amplifying the surge and swab pressures. Consequently, to fully compensate for surge and swab, topside changes has to be made *ahead* of the drill bit motion. This implies that the heaving motion has to be estimated ahead of time, which already is known to be difficult from Section 2.7.

Since using topside equipment has proven to be difficult, equipment should be placed downhole to easier manage to compensate for surge and swab. This is why HeaveLock™ is a downhole tool to be placed at the bottom of the drill string, somewhere close to or as a part of the BHA.

However, this revelation give rise to another challenge; how should HeaveLock™ be controlled, considering that it is a long distance from the drilling rig?

Mud-pulse telemetry, a much used communication technology in drilling operations, transmits information through the drill string by sending pressure pulses in the mud [10]. Unfortunately, this technology is also limited to the speed of pressure waves, and is mostly used to log measured downhole data. This means that mud-pulse telemetry cannot be used to control HeaveLock™, as the problem with delays still stand. However, modern wired drill pipe technology makes it possible to transmit information with electric signals through the pipe itself, more or less eliminating the delay [11]. The drawback is that this type of drill pipe is more expensive than regular drill pipes. HeaveLock™ is designed to be fully autonomous, meaning that it should be able to operate without external inputs. What kind of communication system that is used is thus irrelevant.

HeaveLock™ aims to compensate for surge and swab with a downhole controllable choke valve building up a pressure above it, and practically using the drill string as an accumulator. Closing the valve will increase the pressure drop over the valve, increasing the pressure in the drill string, and thus compressing the fluid inside it. The compressed fluid is basically stored energy that can be released by opening the valve. When the valve is opened, the pressure inside the drill string decreases and the fluid expands. The expanding fluid will temporarily increase the flow through the valve, until the pressure is equalized. This is the effect that HeaveLock™ wish to utilize to compensate for surge and swab pressures.

When the drill string is moving down, the valve should close, restricting the flow and building up pressure upstream. When the drill string is moving back up again, the valve should open, letting the expanding fluid in the drill string fill the void created beneath the bit. HeaveLock™ relies on having built-up pressure to do this, i.e. to maintain controllability. HeaveLock™ has nothing more to give as soon as this pressure is equalized. Some kind of strategy needs to be in place to ensure that there is built-up pressure to work with at all times, at least during connections. Also, for all this to be possible, HeaveLock™ relies on having continuous flow, making CCS systems a necessity.

## 2.9 HeaveSim

HeaveSim is a simulator developed for studying the effects that heave can have in drilling operations like tripping and connections, and for analyzing the performance of HeaveLock™.

# 3 Modeling

The purpose of MPD systems is to control the BHP subject to slowly varying conditions. Typical slowly varying conditions are the desired pressure as a function of depth (see Fig. 1), temperature changes downhole and so on. In the following sections, simple models that are used in the development of a MPD control system in Section 4 are derived. Some assumptions that should not affect the purpose of a MPD system have been made to derive these.

## 3.1 Conventional Well

A conventional well can be described as two separate volumes, i.e. the volume inside the drill string and annulus, separated by a single restriction, the drill bit. The mass balance of a hydraulic volume $V$ is [12]

$$\frac{V}{\beta}\dot{p} + \dot{V} = q_{in} - q_{out}, \tag{3.1}$$

where $\beta$ is the fluid's bulk modulus, $\dot{p}$ and $\dot{V}$ is the rate of change of pressure and volume, respectively, and $q_{in}$ and $q_{out}$ is the volumetric flow into and out of the volume, respectively. For non-restricted or non-pressurized open volumes, $\dot{p}$ is assumed to be zero and (3.1) becomes just a volume balance. For the drill string volume and the non-restricted annulus volume this gives us the differential equations

$$\frac{V_d}{\beta_d}\dot{p}_p + \dot{V}_d = q_p - q_b \tag{3.2a}$$

$$\dot{V}_a = q_b + q_f - q_{out}, \tag{3.2b}$$

where $q_p$ is the flow delivered by the main pump, $q_b$ is the flow through the bit, $q_f$ is any flow between annulus and formation, $q_{out}$ is the flow out of the annulus topside, and the subscripts $d$ and $a$ stand for drill string and annulus, respectively. For slowly varying systems it is safe to assume that the pressure delay from top to bottom is negligible, and the rate of change of pressure is the same at the top and bottom of the drill string, even though the pressures differ with hydrostatic pressure and friction loss. Therefore, we can choose to use the pump pressure $p_p$ to describe the pressure dynamics in the drill string, which is preferable because it is available as a measurement. Mud pumps are usually positive displacement pumps, and $q_p$ is therefore assumed constant [13]. A positive flow $q_f$ from the formation is classed as influx, while a negative flow is classed as mud loss. $\dot{V}_d$ can be assumed to be zero if drill string elasticity is assumed negligible, which it is for MPD purposes. The rate of change of the annulus volume $\dot{V}_a$ is described by

$$\dot{V}_a = A_d v_d, \tag{3.3}$$

where $A_d$ is the cross-sectional area and $v_d$ is the axial velocity of the drill string relative to the well. Because the drill string is elastic, one could argue that a more exact measure is obtained by using the bit velocity, but for MPD purposes it should be safe to assume that these velocities are equal. Positive velocity is here defined as upwards along the well. The outflow is then

$$q_{out} = q_b + q_f - A_d v_d. \tag{3.4}$$

The flow through the bit can be described by a momentum balance

$$\frac{d}{dt}(mv) = \sum F, \tag{3.5}$$

where $m$ and $v$ is the mass and velocity of the fluid in the control volume, respectively, and $F$ is any force acting on the control volume. Using that $m = \rho A h$ and $q = Av$ we have that

$$\rho h \dot{q} = \sum F, \tag{3.6}$$

where $\rho$ is the density of the fluid inside the control volume, $h$ is the length or height of the control volume and $\dot{q}$ is the rate of change of flow through the control volume. For the bit we have the following, assuming that the friction and gravity forces are negligible compared to the pressure forces in such a small control volume

$$\frac{\rho h}{A}\dot{q}_b = p_b - p_{dh}, \tag{3.7}$$

where $A$ is the area of the orifice, $p_b$ is the pressure on the bit inlet and $p_{dh}$ is the pressure on the outlet, i.e. the downhole pressure given by (2.2). The pressure on the bit is thus

$$p_b = \frac{\rho h}{A}\dot{q}_b + p_{dh}, \tag{3.8}$$

The pump pressure $p_p$ is then given as

$$p_p = p_b - p_{h,d} + p_{f,d}, \tag{3.9}$$

where $p_{h,d} = \rho_d g h$ is the hydrostatic pressure and $p_{f,d}$ is the friction loss in the drill string.

## 3.2 Managed Pressure Drilling

The flow $q$ through a restriction can be described by [12]

$$q = C_d A \sqrt{\frac{2}{\rho}\Delta p}, \tag{3.10}$$

where $C_d$ is a constant discharge coefficient, $A$ is the cross-sectional area of the orifice, $\rho$ is the density of the fluid flowing through the restriction and $\Delta p$ is the pressure drop over the restriction. The discharge coefficient is related to any energy loss and that the cross-sectional area of the flow will be somewhat smaller than that of the orifice. For a controllable choke valve we say that the flow $q_c$ is

$$q_c = C_c A(u_c)\sqrt{p_c - p_{c0}}, \tag{3.11}$$

where $C_c = C_d\sqrt{\frac{2}{\rho_a}}$ is the valve constant, $A(u_c)$ is the valve characteristic function and $p_c$ and $p_{c0}$ are the pressures at the inlet and outlet of the valve, respectively. For MPD systems the outflow from the annulus is restricted, i.e. both volumes are now hydraulic, and (3.1) gives us the differential equations

$$\frac{V_d}{\beta_d}\dot{p}_p + \dot{V}_d = q_p - q_b \tag{3.12a}$$
$$\frac{V_a}{\beta_a}\dot{p}_c + \dot{V}_a = q_b + q_f + q_{bpp} - q_c, \tag{3.12b}$$

where $q_{bpp}$ is the flow delivered by the back pressure pump. With the same reasoning used in Section 3.1, we choose to use the pump pressure $p_p$ and choke pressure $p_c$ to describe the pressure dynamics in the drill string and annulus, respectively. Rearranging the equations gives the differential equations that describes the pressure dynamics

$$\dot{p}_p = \frac{\beta_d}{V_d}(q_p - q_b - \dot{V}_d) \tag{3.13a}$$
$$\dot{p}_c = \frac{\beta_a}{V_a}(q_b + q_f + q_{bpp} - q_c - A_d v_d), \tag{3.13b}$$

where $\dot{V}_d$ again can be assumed to be zero if the drill string elasticity is assumed negligible.

## 3.3 HeaveLock™

The model defined above can be extended to include HeaveLock™ by following the same procedure as in the previous sections. Another hydraulic volume is introduced when HeaveLock™ is implemented, basically dividing the drill string into two separate hydraulic volumes, separated by HeaveLock™. All three hydraulic volumes are now described by three differential equations, i.e.

$$\frac{V_{d1}}{\beta_d}\dot{p}_p + \dot{V}_{d1} = q_p - q_{hl} \tag{3.14a}$$

$$\frac{V_{d2}}{\beta_d}\dot{p}_{hl0} + \dot{V}_{d2} = q_{hl} - q_b \tag{3.14b}$$

$$\frac{V_a}{\beta_a}\dot{p}_a + \dot{V}_a = q_b + q_f + q_{bpp} - q_c, \tag{3.14c}$$

where $V_{d1}$ and $V_{d2}$ are the volumes for the two drill string volumes, $p_{hl0}$ is the HeaveLock™'s outlet pressure and $q_{hl}$ is the flow rate through HeaveLock™ itself, which is described by a controlled valve equation, i.e.

$$q_{hl} = C_{hl}A(u_{hl})\sqrt{p_{hl} - p_{hl0}}, \tag{3.15}$$

where $C_{hl}$ is a valve constant, $A(u_{hl})$ is the characteristic function of the valve, and $p_{hl}$ and $p_{hl0}$ are the pressures at the valve's inlet and outlet, respectively.

# 4 MPD Control System

As mentioned in 2.4, MPD systems achieve control over BHP with use of a topside choke valve and a back pressure pump, but how these are controlled is yet to be discussed. There are no measurements downhole, so how can a topside choke valve achieve control over the downhole pressure?

[redacted] MPD control system consist of two main components, namely a downhole estimator and a choke pressure controller [1]. The downhole estimator use topside measurements to estimate the friction loss $\hat{p}_{f,a}$ and mud density $\hat{\rho}_a$ in the annulus, in addition to several other unknown states. With these estimates, a downhole pressure estimate and the desired choke pressure for the choke pressure controller can be determined with (2.5), i.e.

$$\hat{p}_{dh} = p_c + \hat{p}_{h,a} + \hat{p}_{f,a} \tag{4.1}$$

$$p_c^d = p_{dh}^d - \hat{p}_{h,a} - \hat{p}_{f,a}, \tag{4.2}$$

where $\hat{p}_{h,a} = \hat{\rho}_a g h$ is the hydrostatic pressure at a given TVD $h$ within the annulus.

## 4.1 Choke Pressure Controller

From (3.13b) we have the equation describing the annulus pressure dynamics

$$\dot{p}_c = \frac{\beta_a}{V_a}(q_b + q_f + q_{bpp} - q_c - A_d v_d), \tag{4.3}$$

where $q_b$ and $q_f$ are not known and cannot be measured. We want a controller that makes the choke pressure $p_c$ track a given desired value $p_c^d$, and define the tracking error

$$e_c = p_c - p_c^d. \tag{4.4}$$

Differentiation of (4.4) and insertion of (3.13b) yields

$$\dot{e}_c = \dot{p}_c - \dot{p}_c^d = \frac{\beta_a}{V_a}(q_b + q_f + q_{bpp} - q_c - A_d v_d) - \dot{p}_c^d. \tag{4.5}$$

We consider $q_c$ as the control input as it's the only controllable variable. Using feedback linearization methods we choose a desired input that cancels the other terms

$$q_c^d = q_b + q_f + q_{bpp} - A_d v_d - \frac{V_a}{\beta_a}(\dot{p}_c^d + v), \tag{4.6}$$

where $v$ is considered a new input and chosen as $v = -k_p e_c$, making (4.5) become

$$\dot{e}_c = v = -k_p e_c, \tag{4.7}$$

which indicates a stable system for all positive $k_p$, as the only pole $\lambda = -k_p$ then is negative.

Since we do not have $q_b$ and $q_f$ in (4.6) available as measurements, they must be estimated, and by inserting (4.4) in (4.6) we have an equation for calculating the desired choke flow

$$q_c^d = \hat{q}_b + \hat{q}_f + q_{bpp} - A_d v_d + \frac{V_a}{\beta_a}(k_p(p_c - p_c^d) - \dot{p}_c^d), \tag{4.8}$$

where $\dot{p}_c^d$ is assumed known, either from a reference model (see Appendix B) or by differentiating (4.2), i.e.

$$\dot{p}_c^d = \dot{p}_{dh}^d - \dot{\hat{p}}_{h,a} - \dot{\hat{p}}_{f,a} = -\dot{\hat{p}}_{f,a}, \tag{4.9}$$

where the desired downhole pressure $p_{dh}^d$ and hydrostatic pressure $\hat{p}_{h,a}$ is assumed to be slowly varying and $\dot{\hat{p}}_{f,a}$ is assumed given from the downhole estimator. By knowing the desired choke flow we can find the needed control input by rearranging the valve equation from (3.11), i.e.

$$u_c = A^{-1}\left(\frac{q_c^d}{C_c\sqrt{p_c - p_{c0}}}\right). \tag{4.10}$$

## 4.2 Downhole Estimator

As seen from (4.8) together with (4.2), several estimates are needed for the choke pressure controller, i.e. annulus mud density and friction loss, together with bit and formation flow.

### 4.2.1 Mud Density and Friction Loss

As the estimator for annulus mud density and friction loss is somewhat complicated, it is left as further work and will not be gone through in much detail. However, if we can obtain an accurate approximation of the friction loss for a given well through identification tests in HeaveSim, it should be possible to see the effects of implementing a MPD system from simulations anyway. It is worth noting though, that research has shown that estimates of the mud density can be approximately 10 $\frac{kg}{m^3}$ higher in the annulus than the drill string while drilling, most likely because of the amount of cuttings in the fluid [14]. This corresponds to a pressure difference of approximately 1 bar for every 1000 meters TVD, and could influence the results if left out.

### 4.2.2 Bit Flow

We can use (3.12a) to approximate the bit flow $q_b$, i.e.

$$q_b = q_p - \frac{V_d}{\beta_d}\dot{p}_p, \tag{4.11}$$

where the drill string elasticity is assumed to be negligible in the situations MPD is designed for, i.e. $\dot{V}_d = 0$. A simple low pass filter is applied to achieve a sufficient estimate

$$\begin{aligned} \hat{q}_b &= \frac{1}{\tau s + 1}\left(q_p - \frac{V_d}{\beta_d}p_p s\right) && \text{(4.12a)} \\ &= \frac{1}{\tau s + 1}\left(q_p + \frac{V_d}{\tau\beta_d}p_p\right) - \frac{V_d}{\tau\beta_d}p_p. && \text{(4.12b)} \end{aligned}$$

### 4.2.3 Formation Flow

The only missing estimate is now the estimate for the formation flow $q_f$. From (3.13b) we have the equation describing the annulus pressure dynamics

$$\dot{p}_c = \frac{\beta_a}{V_a}(q_b + q_f + q_{bpp} - q_c - A_d v_d), \tag{4.13}$$

and by assuming that the formation flow varies slowly we can say that

$$\dot{q}_f = 0. \tag{4.14}$$

These dynamics can be summarized in vector form

$$\frac{d}{dt}\begin{bmatrix} p_c \\ q_f \end{bmatrix} = \begin{bmatrix} \frac{\beta_a}{V_a}(q_b + q_f + q_{bpp} - q_c - A_d v_d) \\ 0 \end{bmatrix}. \tag{4.15}$$

A linear observer for this system is given by

$$\frac{d}{dt}\begin{bmatrix} \hat{p}_c \\ \hat{q}_f \end{bmatrix} = \begin{bmatrix} \frac{\beta_a}{V_a}(\hat{q}_b + \hat{q}_f + q_{bpp} - q_c - A_d v_d) \\ 0 \end{bmatrix} + L\left(C\begin{bmatrix} p_c \\ q_f \end{bmatrix} - C\begin{bmatrix} \hat{p}_c \\ \hat{q}_f \end{bmatrix}\right), \tag{4.16}$$

where $L = [l_1 \ l_2]^\top$ is the observer gain, and $C = [1 \ 0]$ is the output matrix since $p_c$ is the only state being measured. This gives the linear observer for $q_f$, assuming it varies slowly

$$\dot{\hat{p}}_c = \frac{\beta_a}{V_a}(\hat{q}_b + \hat{q}_f + q_{bpp} - q_c - A_d v_d) + l_1(p_c - \hat{p}_c) \tag{4.17a}$$

$$\dot{\hat{q}}_f = l_2(p_c - \hat{p}_c). \tag{4.17b}$$

## 4.3 Back-pressure Pump

The main objective of the back-pressure pump is to ensure minimum choke flow at all times. Different strategies are used to control the pump, but how it ensures minimum choke flow is really not that important, as long as its flow rate does not cause the choke valve to saturate. In some systems it is controlled manually, while other systems have some kind of logic controlling when it should start pumping. Another option is to let the pump stay on at all times.

# 5 Implementation in HeaveSim

## 5.1 Discretization

Since most modern controllers are digital, the MPD system's choke pressure controller and downhole estimator given in Sections 4.1 and 4.2 must be discretized before implementation. The same applies to implementing the MPD system in HeaveSim. With some assumptions, the controller equations can be discretized directly, i.e. they only depend on current measurements and estimates. The estimator consist of differential equations, i.e. numerical methods for differentiation must be applied when discretizing, which results in discrete equations evaluating values based on values from earlier time steps. The current time step is referred to with a subscript $k$, and $k+1$ and $k-1$ refers to the next and previous time step, respectively. See Appendix A for a closer look on how the controller and estimator was discretized.

### 5.1.1 Choke Pressure Controller

If the time derivative of the desired choke pressure $\dot{p}_c^d$ is assumed known, the desired choke flow in (4.2) is discretized directly as

$$q_{c,k}^d = \hat{q}_{b,k} + \hat{q}_{f,k} + q_{bpp,k} - A_d v_{d,k} + \frac{V_a}{\beta_a}\left(k_p(p_{c,k} - p_{c,k}^d) - \dot{p}_{c,k}^d\right), \tag{5.1}$$

where the estimates $\hat{q}_{b,k}$ and $\hat{q}_{f,k}$ are given by the downhole estimator, and the desired choke pressure is given by (4.2) and discretized directly as

$$p_{c,k}^d = p_{dh,k}^d - \hat{p}_{h,a,k} - \hat{p}_{f,a,k}. \tag{5.2}$$

The needed control input given in (4.10) is also discretized directly, i.e.

$$u_{c,k} = A^{-1}\left(\frac{q_{c,k}^d}{C_c\sqrt{p_{c,k} - p_{c0,k}}}\right). \tag{5.3}$$

### 5.1.2 Downhole Estimator

#### Bit Flow

The bit flow estimate (4.12) is discretized as

$$\hat{q}_{b,k} = (1-\alpha)\hat{q}_{b,k-1} + \alpha\left(q_{p,k} - \frac{V_d}{\beta_d h}(p_{p,k} - p_{p,k-1})\right), \tag{5.4}$$

where $\alpha = \frac{h}{\tau+h}$, $h$ is the sampling period and $\tau$ is the time constant of the filter.

#### Formation Flow

The formation flow observer given in (4.17) is discretized as

$$\hat{p}_{c,k+1} = \hat{p}_{c,k} + h\left(\frac{\beta_a}{V_a}(\hat{q}_{b,k} + \hat{q}_{f,k} + q_{bpp,k} - q_{c,k} - A_d v_{d,k}) + l_1(p_{c,k} - \hat{p}_{c,k})\right) \tag{5.5}$$

$$\hat{q}_{f,k+1} = \hat{q}_{f,k} + hl_2(p_{c,k} - \hat{p}_{c,k}), \tag{5.6}$$

and estimates the formation flow in the next iteration based on known estimates and measurements in the current time step.

## 5.2 Findings and Deviations

HeaveSim is still a simulator under development and is not perfect. E.g. the fact that cuttings may change the mud density and bulk modulus in the annulus is not considered yet, and neither is mud loss or formation fluids entering the wellbore. This means that the mud density and bulk modulus is the same in both drill string and annulus in HeaveSim, i.e. $\rho = \rho_d = \rho_a$ and $\beta = \beta_d = \beta_a$. This must be taken into consideration when implementing the MPD system in the simulator and might give rise to deviations from how the MPD system is defined above.

### 5.2.1 Choke Valve

There is a slight difference between how controllable restrictions (or valves) are implemented in HeaveSim and how they have been defined in (3.11). The following equation shows how they are implemented in HeaveSim, i.e.

$$q = Cf_c(u)\sqrt{\frac{\Delta p}{\rho}}, \tag{5.7}$$

where $C = C_d A_{max}\sqrt{2}$ is the valve constant, $A_{max}$ is a constant scaling factor such that the choke characteristics $f_c(u)$ is a function from 0 to 1, rather than from 0 to the maximum valve area $A_{max}$, and $u$ is a control input (or valve opening) from 0 to 100%. This means that (5.3) must be changed to

$$u_{c,k} = f_c^{-1}\left(\frac{q^d_{c,k}}{C\sqrt{\frac{p_{c,k}-p_{c0,k}}{\rho}}}\right). \tag{5.8}$$

### 5.2.2 Downhole Estimator

#### Friction Loss

Since HeaveSim does not consider change in mud density and bulk modulus in annulus, we can use the same values for the whole system, and there is no need to estimate these values. The only unknown variable in (5.2) is thus the friction loss $\hat{p}_{f,a,k}$. Due to complexity, the estimator for the friction loss has not been defined, and the value must be found by other means. The friction loss depends on the flow in the annulus, and by logging the downhole and choke pressures in simulations with different flow values, we can calculate the friction loss for the different flow values with (4.2). The results from such an identification test is shown in Tab. 1 and Fig. 5.

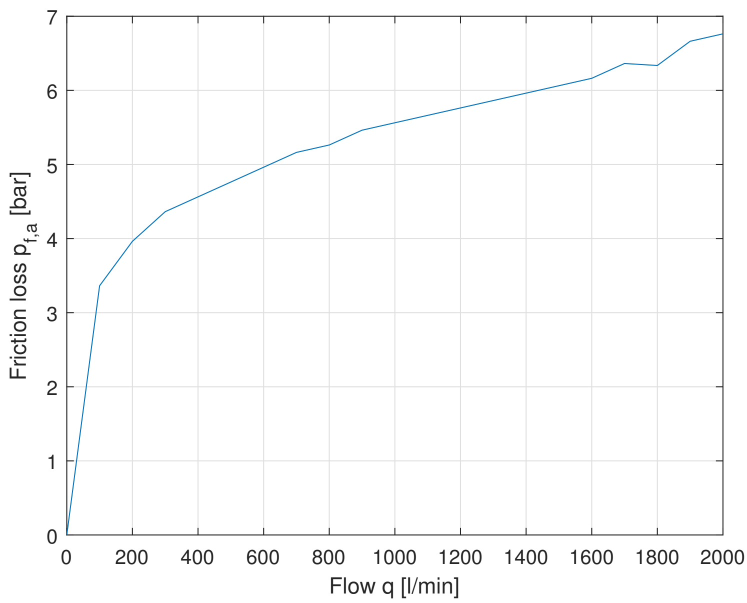



Figure 5: Annular friction loss

Table 1: Friction loss identification test results

| $q$ [$l/min$] | $p_{dh}$ [$bar$] | $p_c$ [$bar$] | $p_h$ [$bar$] | $p_{f,a}$ [$bar$] |
|---|---|---|---|---|
| 100 | 170.0 | 1.0 | 165.64 | 3.363 |
| 200 | 170.6 | 1.0 | 165.64 | 3.963 |
| 300 | 171.0 | 1.0 | 165.64 | 4.363 |
| 400 | 171.3 | 1.1 | 165.64 | 4.563 |
| 500 | 171.5 | 1.1 | 165.64 | 4.763 |
| 600 | 171.7 | 1.1 | 165.64 | 4.963 |
| 700 | 172.0 | 1.2 | 165.64 | 5.163 |
| 800 | 172.2 | 1.3 | 165.64 | 5.263 |
| 900 | 172.4 | 1.3 | 165.64 | 5.463 |
| 1000 | 172.6 | 1.4 | 165.64 | 5.563 |
| 1100 | 172.8 | 1.5 | 165.64 | 5.663 |
| 1200 | 173.0 | 1.6 | 165.64 | 5.763 |
| 1300 | 173.2 | 1.7 | 165.64 | 5.863 |
| 1400 | 173.4 | 1.8 | 165.64 | 5.963 |
| 1500 | 173.6 | 1.9 | 165.64 | 6.063 |
| 1600 | 173.8 | 2.0 | 165.64 | 6.163 |
| 1700 | 174.1 | 2.1 | 165.64 | 6.363 |
| 1800 | 174.3 | 2.3 | 165.64 | 6.363 |
| 1900 | 174.7 | 2.4 | 165.64 | 6.663 |
| 2000 | 175.0 | 2.6 | 165.64 | 6.763 |

This data is then put into a look-up table in HeaveSim, which is used to look up the friction loss for a given annulus flow during simulations. This way we can achieve proper estimates of the friction loss for a given case, without implementing the complex estimator. The drawback, however, is that this procedure must be done for every case that you want to simulate, and a proper estimator will be more efficient in the long run.

**Formation Flow**

Since mud loss and formation fluids is not implemented in HeaveSim, these values are non-existent or equal to zero for any simulations done. By setting the formation flow observer parameter $l_2 = 0$, we achieve perfect estimates for the formation flow, i.e. $\hat{q}_f = q_f = 0$.

# 6 Simulations and Results

During connections in conventional drilling, the main pump is shut down after the drill string is fully hoisted. Then the connection is performed when there is no flow from the main pump, and once the connection is done, the main pump is started again. With MPD, the back-pressure pump must ensure minimum choke flow before the main pump can be shut down. The opposite applies before the back-pressure pump can be shut down; the main pump must ensure minimum choke flow. When using CCS systems, the back-pressure pump is no longer needed, and the main pump maintains flow during connections.

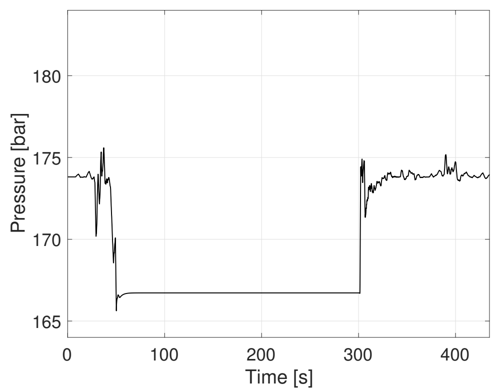
In the following simulations, the drill string is hoisted up 2.6 meters for 10 seconds from $t = 25s$, and slowly lowered back down from $t = 375s$ to $t = 405s$. The main pump is shut down at $t = 40s$ and started back up at $t = 299s$. In the MPD cases, the back-pressure pump is started at $t = 35s$ and reaches full capacity before the main pump is turned off. Once the main pump reaches full capacity at $t = 330s$, the back-pressure pump is shut down. This may not be the optimal back-pressure pump control, but at least the minimum choke flow is always ensured. In the CCS case, the back-pressure pump stays off at all times and the main pump is kept on.

Real well data [redacted] has been used for the simulations, including well path, main pump flow rate and heaving motion. The flow rates has been fabricated for more realistic simulations in the time interval $40 \leq t \leq 330$ for both the MPD and CCS cases, as the real data is from conventional drilling, i.e. the main pump was deactivated during this interval. The connection that is simulated is a connection at 2910 meters MD and about 1586 meters TVD.

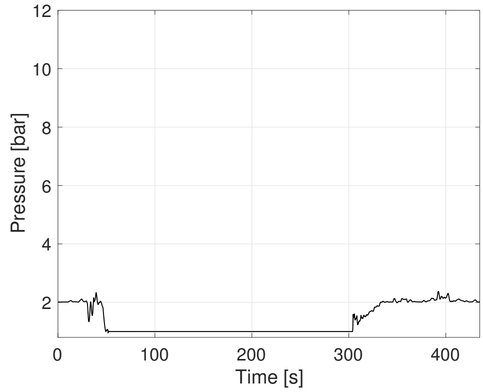
## 6.1 Calm Conditions

To simulate calm conditions, the heaving motion was set to zero for the first set of simulations. Simulations from a floating drilling rig with no heaving motion will also resemble the behaviour of an onshore drilling rig.

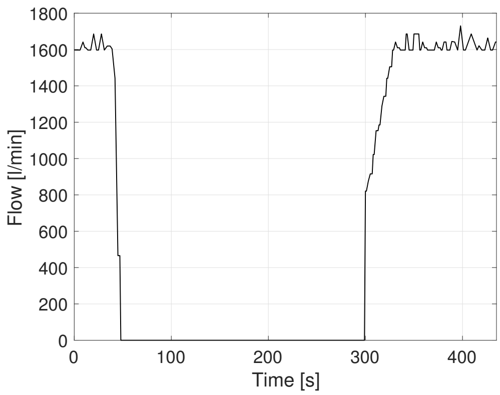
### 6.1.1 Conventional Drilling



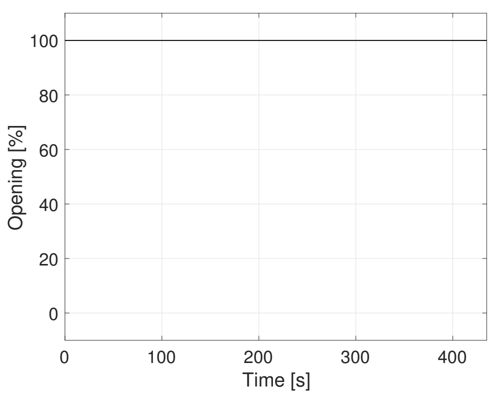

(a) Downhole pressure




(b) Choke pressure




(c) Main pump flow

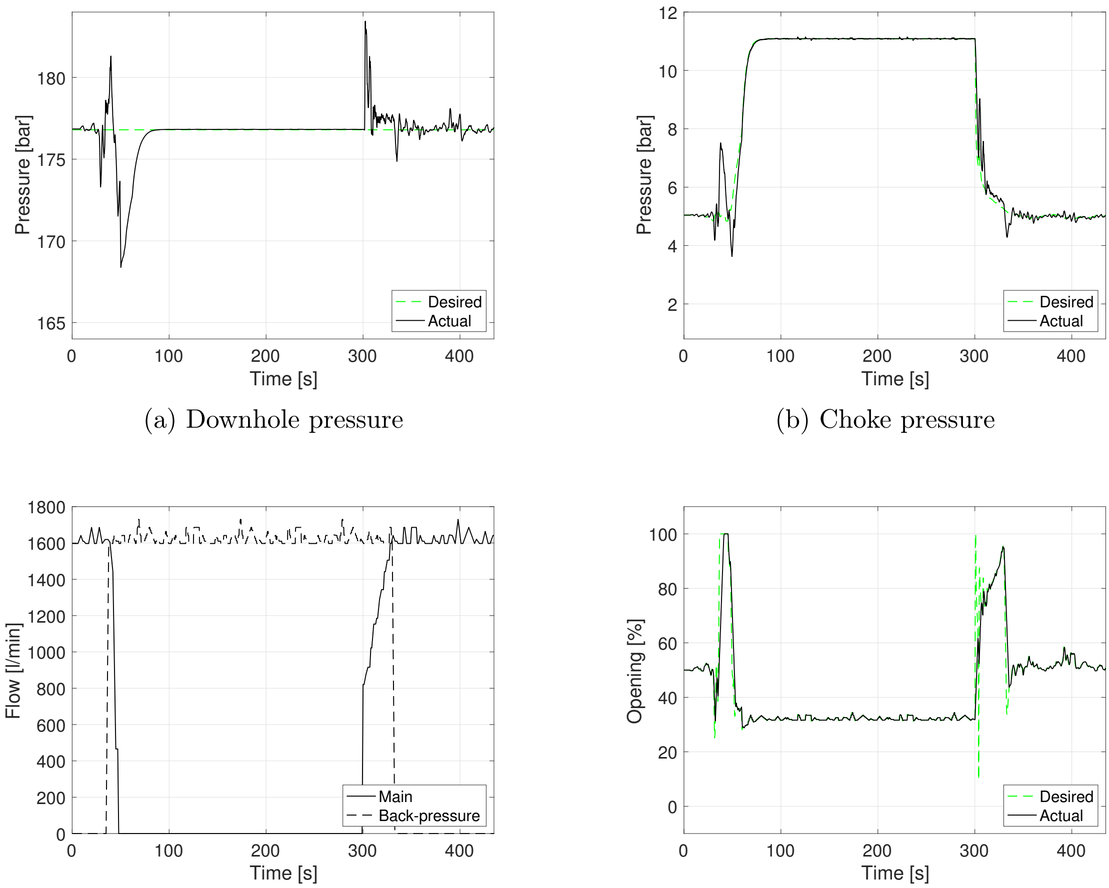



(d) Choke opening

Figure 6: Conventional drilling connection in calm conditions

Fig. 6 shows the simulation results of a connection made with conventional drilling in calm conditions. In Fig. 6d we see that the choke is fully open at all times. From Fig. 6a and 6c we see that the downhole pressure drops when the main pump is shut down. This pressure drop is equal to the friction loss that no longer exist when circulation is lost.

### 6.1.2 MPD




(a) Downhole pressure (b) Choke pressure

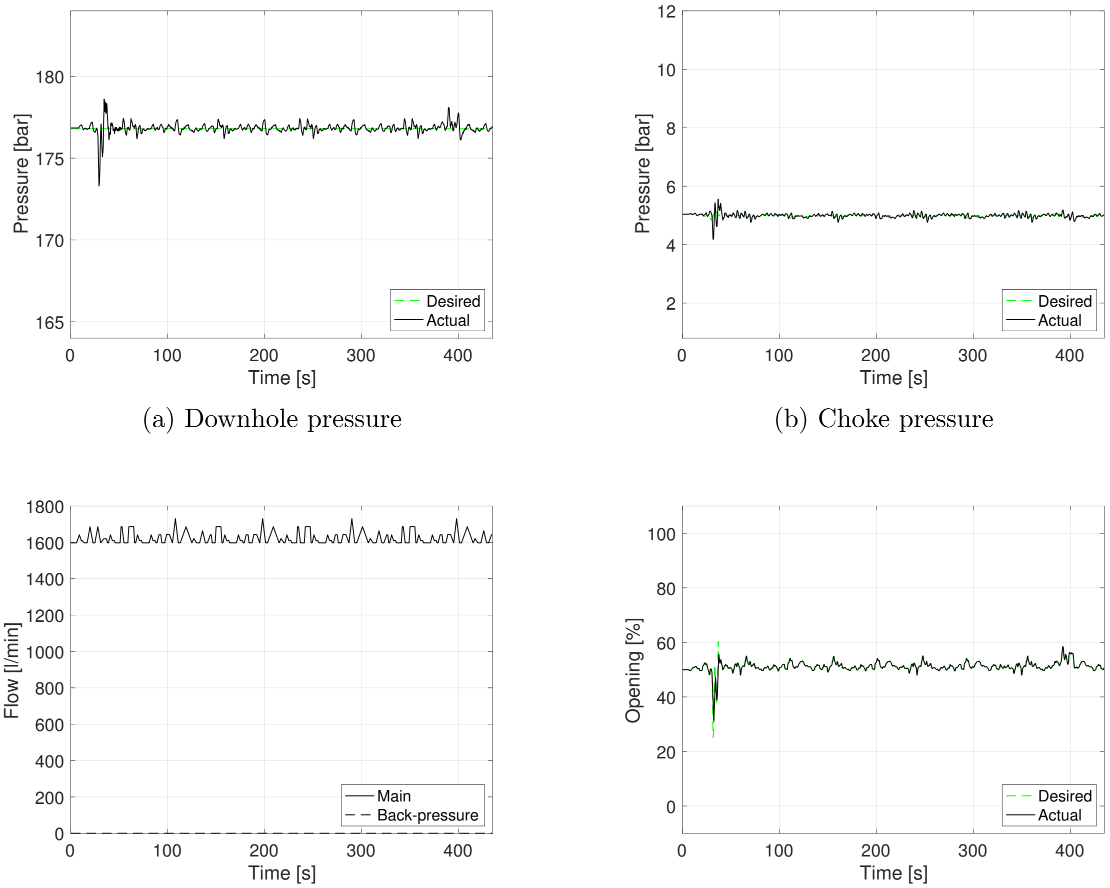
(c) Main pump flow (d) Choke opening

Figure 7: MPD connection in calm conditions

Fig. 7 shows the simulation results of a connection made with MPD in calm conditions. From Fig. 7c we see that the back-pressure pump is active when the main pump is shut down, ensuring minimum flow through the choke valve. Circulation is still lost through the main loop, but we see from Fig. 7b that the MPD system manages to build up a surface back-pressure to account for the no longer existing friction loss, returning the downhole pressure to its desired value as shown in Fig. 7a. Because the back-pressure pump delivers the same amount of flow as the main pump in this case, the choke must have a smaller opening to build up the needed surface back-pressure, as is apparent from Fig. 7d. If the back-pressure pump was able to deliver a higher flow rate, and this flow rate was adjustable, one could achieve a choke valve operating in the same range at all times.

Also notice how stable the downhole pressure is during the connection, even though the back-pressure pump flow rate varies by the same amount as the main pump does.

### 6.1.3 MPD+CCS




(a) Downhole pressure

(b) Choke pressure

(c) Main pump flow

(d) Choke opening

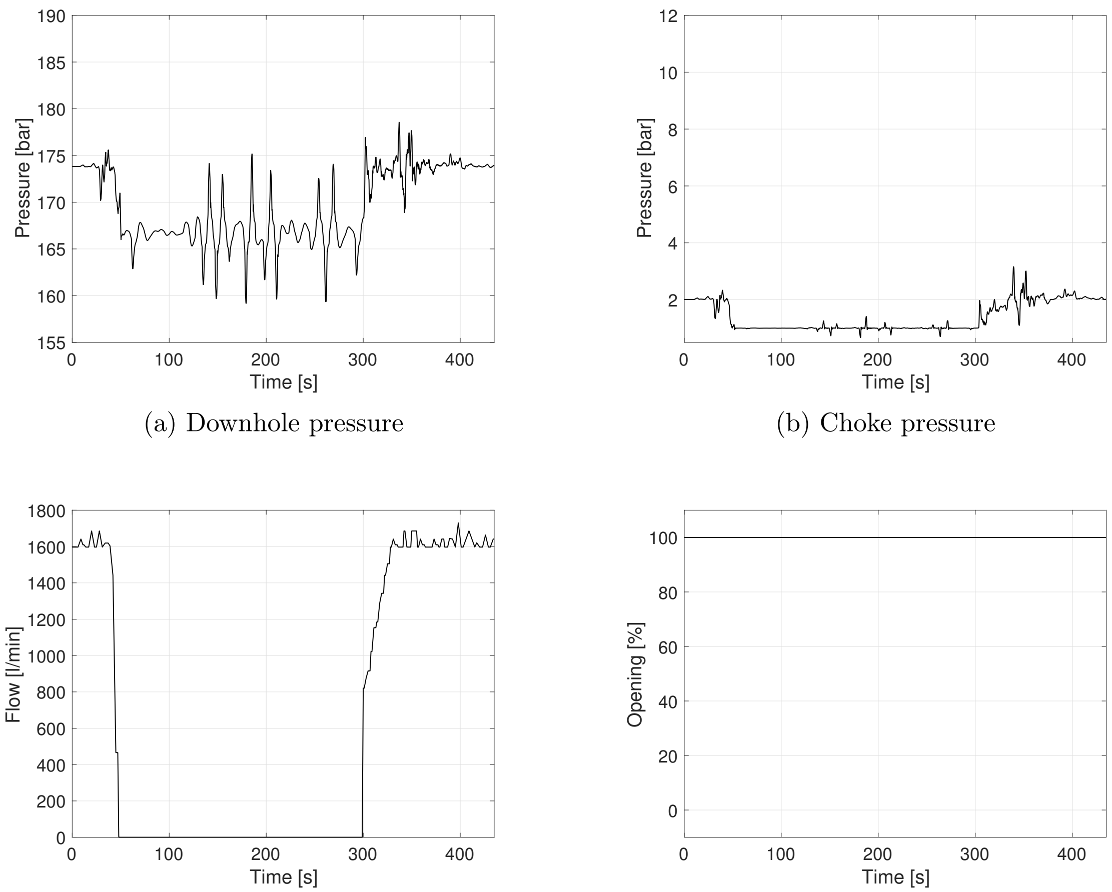
Figure 8: MPD+CCS connection in calm conditions

Fig. 8 shows the simulation results of a connection made with both MPD and CCS systems in calm conditions. From Fig. 8c we can see that the back-pressure pump is no longer active during the connection, but the main pump flow rate is kept constant and circulation is maintained. Since there is no loss of circulation, the friction loss is also maintained, and the MPD system no longer has to account for this. This is also seen from Fig. 8b, where there no longer is any added surface back-pressure during the connection. Fig. 8d shows that the choke operates within the same range at all times, i.e. around 50%, and will not lose its controllability due to saturation. The CCS system seem to eliminate any pressure drop during connections, and the MPD system can focus solely on slower varying conditions.

## 6.2 Rough Conditions

In the next set of simulations, heaving motion is applied to simulate rough conditions. Real recorded heave data [redacted] is used. The results will no longer resemble the behaviour of any onshore drilling rig.

### 6.2.1 Conventional Drilling




(a) Downhole pressure

(b) Choke pressure

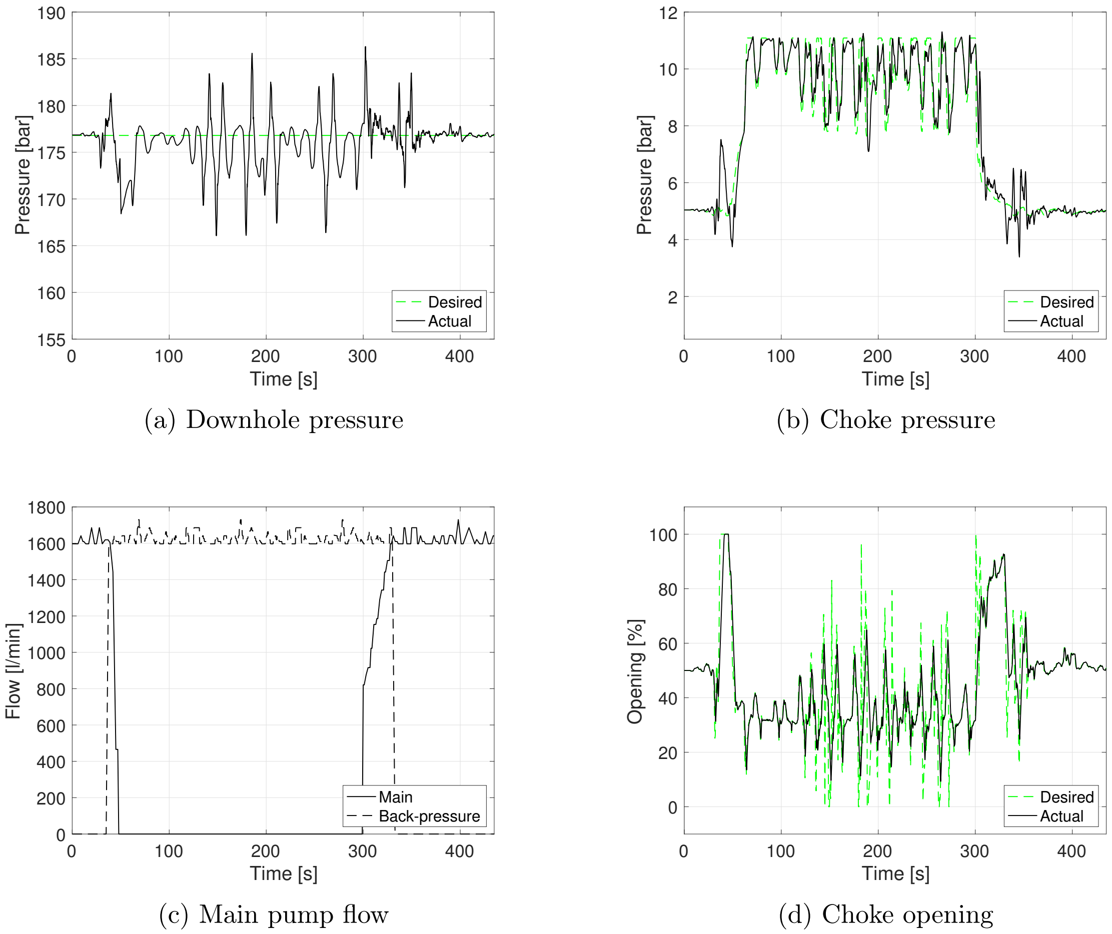
(c) Main pump flow

(d) Choke opening

Figure 9: Conventional drilling connection in rough conditions

Fig. 9 shows the simulation results of a connection made with conventional drilling in rough conditions. By comparing the results with those from conventional drilling in calm conditions (Fig. 6), we now see major downhole pressure fluctuations during the connection. This shows the effect of heave-induced surge and swab pressures, and in this case it varies with more than 15 bar.

### 6.2.2 MPD




(a) Downhole pressure

(b) Choke pressure

(c) Main pump flow

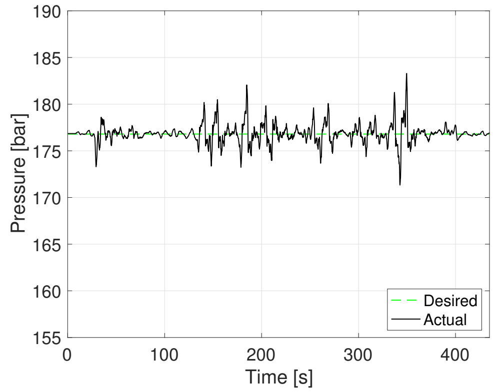
(d) Choke opening

Figure 10: MPD connection in rough conditions

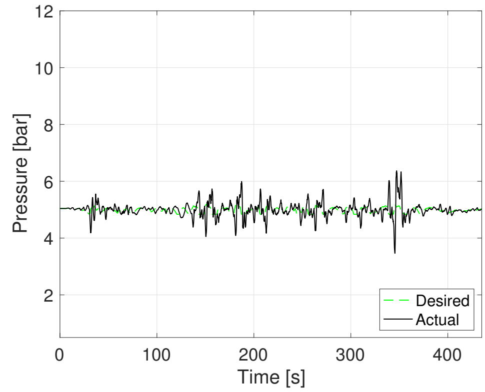
Fig. 10 shows the simulation results of a connection made with MPD in rough conditions. Just like in calm conditions (see Fig. 7), the MPD system manages to build up a surface back-pressure to account for lost circulation, and we see from Fig. 10a that there is no longer a constant drop in downhole pressure. However, it seems like the fluctuations are even greater than in the conventional case, now varying with up to 20 bar, even though Fig. 10b and 10d shows that the choke is working hard trying to achieve the desired downhole pressure.

As mentioned in Section 2.8, topside control may amplify the surge and swab pressures at certain depths due to the delay of pressure waves through the well. MPD systems are not designed to control surge and swab, but rather slowly varying conditions. One could argue that frequencies of heave-induced pressure fluctuations should be filtered out, and they most probably are in real cases, such that the MPD system does not act on them. The system should then no longer amplify the heave-induced surge and swab pressures.

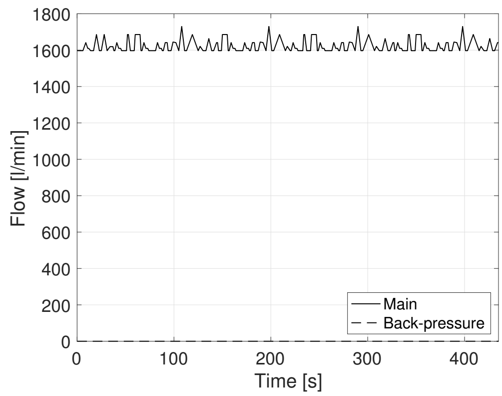
### 6.2.3 MPD+CCS



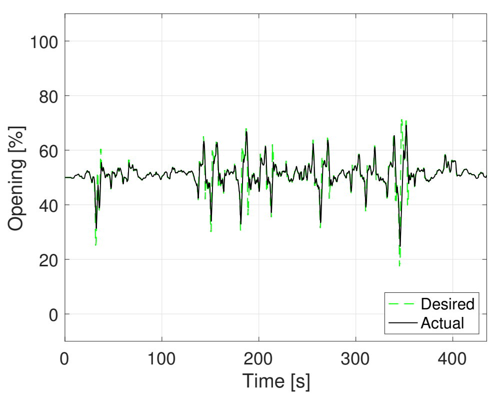

(a) Downhole pressure




(b) Choke pressure




(c) Main pump flow




(d) Choke opening

Figure 11: MPD+CCS connection in rough conditions

Fig. 11 shows the simulation result of a connection made with both MPD and CCS systems in rough conditions. Again, just like in calm conditions (see Fig. 8), we see that with continuous circulation the choke can keep operating within the same range at all times, ensuring controllability (see Fig. 11b and 11d). In Fig. 11a we see that the heave-induced surge and swab pressures are actually reduced with both MPD and CCS systems active. We do, however, still see a choke valve working hard to eliminate any surge and swab pressures.

# 7 Conclusion

Drilling of wells for oil and gas production is not always as easy as it seems. Some wells are more complicated than others, and demand careful planning to ensure that the well can be drilled safely. Wells can have narrow margins for failure that require accurate control of downhole conditions, to prevent what may become major accidents. Different control systems have been developed to make it easier to drill challenging wells, and help prevent such accidents. In this project we have taken a closer look at two of these systems, Managed Pressure Drilling (MPD) and Continuous Circulation System (CCS), and compared them with conventional drilling.

MPD systems can control the bottom hole pressure (BHP) by employing a choke valve controlling a back-pressure topside. However, in deep wells, MPD systems can only control BHP subject to slowly varying downhole conditions, and sudden short-lived conditions may go untouched or even get amplified.

CCS systems ensure continuous flow through the mud loop to prevent pressure drops that arise with flow interruptions. Such systems can stabilize the downhole conditions, rather than control them.

Both systems have been implemented in a simulator to study their performance, when drilling from both onshore and offshore drilling rigs. Simulations show that challenging wells can become even more challenging in open seas, as floating drilling rigs introduce another problem. The heaving motion of the drill string due to waves produce downhole pressure fluctuations that MPD and CCS systems cannot compensate for.

HeaveLock™, a downhole tool under development, may have the solution to this problem. HeaveLock™ relies on having a CCS system implemented, but if there are any implications with existing MPD and CCS systems when HeaveLock™ is implemented is yet to be discovered.

## 7.1 Future Work

Simple identification tests on the simulator was used to produce estimates of annular friction loss used in the simulations. Real MPD systems use an estimator for this, but this was not implemented in this project, and at this point, it is unclear whether or not this will have an effect on the results.

HeaveSim does not consider that the mud density may be different in drill string and annulus. If this were to be implemented in HeaveSim, one would also need to implement an estimator for the annular mud density. How big of a difference this makes is unknown.

A choke valve with perfect linear characteristics has been used for the simulations produced in this project. Simulating performance with a more realistic valve is a natural next step.

How the back-pressure pump is controlled has not been experimented with in this project. The only strategy has been to ensure minimum choke flow at all times, and nothing more. Studying the effects of different strategies like ramping or just letting it stay on at all times could be an interesting next approach.

The implemented MPD system tried to compensate for the heave-induced surge and swab pressures, but ended up amplifying them instead. One should consider options for filtering these pressure variations in such a way that MPD systems does not act on them. This should be looked into before implementing such a system on a floating drilling rig.

As mentioned above, any implications with MPD and CCS systems when HeaveLock™ is implemented is yet to be discovered, and is left as future work. This is also encouraged before developing a control strategy for HeaveLock™.

# Appendix A Discretization

## A.1 Methods

Both Euler's forward and backward differentiation methods are simple approximations of the time derivative of a time-varying function.

**Forward Euler**

Euler's forward differentiation method is defined as

$$\dot{x} \approx \frac{x_{k+1} - x_k}{h}, \tag{A.1}$$

where $h$ is the sampling period or step size equal to the time between steps $\Delta t = t_{k+1} - t_k$. It is mostly used for simulations, as it approximates the next state based on known information about the current state.

**Backward Euler**

Euler's backward differentiation method is defined as

$$\dot{x} \approx \frac{x_k - x_{k-1}}{h}, \tag{A.2}$$

where $h$ is the sampling period or step size equal to the time between steps $\Delta t = t_k - t_{k-1}$. It is mostly used for discretizing signal filters and controllers, as it gives a current state based on known information about the previous state.

## A.2 Choke Pressure Controller

The desired choke flow is calculated from (4.8), i.e.

$$q_c^d = \hat{q}_b + \hat{q}_f + q_{bpp} - A_d v_d + \frac{V_a}{\beta_a}(k_p(p_c - p_c^d) - \dot{p}_c^d). \tag{A.3}$$

If $\dot{p}_c^d$ is known, (A.3) can be discretized directly as

$$q_{c,k}^d = \hat{q}_{b,k} + \hat{q}_{f,k} + q_{bpp,k} - A_d v_{d,k} + \frac{V_a}{\beta_a}\left(k_p(p_{c,k} - p_{c,k}^d) - \dot{p}_{c,k}^d\right), \tag{A.4}$$

or otherwise by using backward Euler

$$q_{c,k}^d = \hat{q}_{b,k} + \hat{q}_{f,k} + q_{bpp,k} - A_d v_{d,k} + \frac{V_a}{\beta_a}\left(k_p(p_{c,k} - p_{c,k}^d) - \frac{p_{c,k}^d - p_{c,k-1}^d}{h}\right). \tag{A.5}$$

According to (4.10), the controller output or choke valve input for time step $k$ is then

$$u_{c,k} = A^{-1}\left(\frac{q_{c,k}^d}{C_c\sqrt{p_{c,k} - p_{c0,k}}}\right). \tag{A.6}$$

## A.3 Downhole Estimator

### A.3.1 Bit Flow

The bit flow estimate is given by (4.12), i.e.

$$\hat{q}_b = \frac{1}{\tau s + 1}\left(q_p - \frac{V_d}{\beta} p_p s\right) \tag{A.7a}$$

$$\implies \tau\dot{\hat{q}}_b + \hat{q}_b = q_p - \frac{V_d}{\beta}\dot{p}_p. \tag{A.7b}$$

Backward Euler

$$\tau \cdot \frac{\hat{q}_{b,k} - \hat{q}_{b,k-1}}{h} + \hat{q}_{b,k} = q_{p,k} - \frac{V_d}{\beta} \cdot \frac{p_{p,k} - p_{p,k-1}}{h} \tag{A.8a}$$

$$\tau\hat{q}_{b,k} - \tau\hat{q}_{b,k-1} + h\hat{q}_{b,k} = hq_{p,k} - \frac{V_d}{\beta}(p_{p,k} - p_{p,k-1}) \tag{A.8b}$$

$$(\tau + h)\hat{q}_{b,k} = \tau\hat{q}_{b,k-1} + hq_{p,k} - \frac{V_d}{\beta}(p_{p,k} - p_{p,k-1}) \tag{A.8c}$$

$$\hat{q}_{b,k} = \frac{1}{\tau + h}\left(\tau\hat{q}_{b,k-1} + hq_{p,k} - \frac{V_d}{\beta}(p_{p,k} - p_{p,k-1})\right) \tag{A.8d}$$

$$\hat{q}_{b,k} = (1 - \alpha)\hat{q}_{b,k-1} + \alpha\left(q_{p,k} - \frac{V_d}{\beta h}(p_{p,k} - p_{p,k-1})\right), \tag{A.8e}$$

where $\alpha = \frac{h}{\tau+h}$.

### A.3.2 Formation Flow

A linear observer for the formation flow is given by (4.17), i.e.

$$\begin{aligned}\dot{\hat{p}}_c &= \frac{\beta_a}{V_a}(\hat{q}_b + \hat{q}_f + q_{bpp} - q_c - A_d v_d) + l_1(p_c - \hat{p}_c) \\ \dot{\hat{q}}_f &= l_2(p_c - \hat{p}_c)\end{aligned} \tag{A.9}$$

Forward Euler

$$\begin{aligned}\frac{\hat{p}_{c,k+1} - \hat{p}_{c,k}}{h} &= \frac{\beta_a}{V_a}(\hat{q}_{b,k} + \hat{q}_{f,k} + q_{bpp,k} - q_{c,k} - A_d v_{d,k}) + l_1(p_{c,k} - \hat{p}_{c,k}) \\ \frac{\hat{q}_{f,k+1} - \hat{q}_{f,k}}{h} &= l_2(p_{c,k} - \hat{p}_{c,k})\end{aligned} \tag{A.10a}$$

$$\begin{aligned}\hat{p}_{c,k+1} &= \hat{p}_{c,k} + h\left(\frac{\beta_a}{V_a}(\hat{q}_{b,k} + \hat{q}_{f,k} + q_{bpp,k} - q_{c,k} - A_d v_{d,k}) + l_1(p_{c,k} - \hat{p}_{c,k})\right) \\ \hat{q}_{f,k+1} &= \hat{q}_{f,k} + hl_2(p_{c,k} - \hat{p}_{c,k})\end{aligned} \tag{A.10b}$$

## A.4 State-Space Models

A state-space representation of a model

$$\dot{\boldsymbol{x}} = \boldsymbol{A}\boldsymbol{x} + \boldsymbol{B}\boldsymbol{u} \tag{A.11a}$$

$$\boldsymbol{y} = \boldsymbol{C}\boldsymbol{x} \tag{A.11b}$$

where $\boldsymbol{A}$, $\boldsymbol{B}$ and $\boldsymbol{C}$ are matrices and $\boldsymbol{x}$, $\boldsymbol{u}$ and $\boldsymbol{y}$ are vectors. A state-space model is often used for simulations and discretized with forward Euler, i.e.

$$\frac{\boldsymbol{x}_{k+1} - \boldsymbol{x}_k}{h} = \boldsymbol{A}\boldsymbol{x}_k + \boldsymbol{B}\boldsymbol{u}_k \tag{A.12a}$$

$$\boldsymbol{x}_{k+1} = \boldsymbol{x}_k + h(\boldsymbol{A}\boldsymbol{x}_k + \boldsymbol{B}\boldsymbol{u}_k) \tag{A.12b}$$

$$\boldsymbol{x}_{k+1} = (1 + h\boldsymbol{A})\boldsymbol{x}_k + h\boldsymbol{B}\boldsymbol{u}_k, \tag{A.12c}$$

which gives the discrete state-space model

$$\boldsymbol{x}_{k+1} = \boldsymbol{A}_d\boldsymbol{x}_k + \boldsymbol{B}_d\boldsymbol{u}_k \tag{A.13a}$$

$$\boldsymbol{y}_k = \boldsymbol{C}_{\boldsymbol{d}}\boldsymbol{x}_k, \tag{A.13b}$$

where $\boldsymbol{A}_d = (1 + h\boldsymbol{A})$ and $\boldsymbol{B}_d = h\boldsymbol{B}$ are the discretized system and input matrices, respectively, and $\boldsymbol{C}_{\boldsymbol{d}} = \boldsymbol{C}$ is the output matrix.

# Appendix B Reference Models

Sometimes it is useful to generate trajectories for given reference signals, e.g. when reference signals are step functions typically given by a keyboard input. Step functions are sudden and can have extreme effects on a system, they may even destabilize systems in some cases. By using reference models, a smooth reference trajectory can be created of a step signal, which is easier to track in many cases. A simple low-pass filter can be used to generate such a trajectory of a reference signal [7], e.g.

$$x^d = h_{lp}(s) r^d, \tag{B.1}$$

where $x^d$ is the desired trajectory generated of the desired reference signal $r^d$, and $h_{lp}(s)$ is the transfer function of a low-pass filter.

## B.1 Time Derivative Knowledge

A bonus with using reference models is that we can gain knowledge of the time derivative of the reference trajectory. Consider using a second order low-pass filter as a reference model, i.e.

$$x^d = \frac{\omega_c^2}{s^2 + 2\zeta\omega_c s + \omega_c^2} r^d, \tag{B.2}$$

where $\omega_c$ is the *cutoff frequency* of the filter and $\zeta$ is the *relative damping ratio.* Rearranging and inverse Laplace of (B.2) yields

$$\ddot{x}^d + 2\zeta\omega_c \dot{x}^d + \omega_c^2 x^d = \omega_c^2 r^d. \tag{B.3}$$

We can convert this second order differential equation into a system of two first order differential equations by defining the two states

$$x_1 = x^d \qquad\qquad x_2 = \dot{x}^d, \tag{B.4}$$

and by differentiation we have

$$\dot{x}_1 = x_2 \tag{B.5a}$$

$$\dot{x}_2 = -\omega_c^2 x_1 - 2\zeta\omega_c x_2 + \omega_c^2 r^d, \tag{B.5b}$$

which can be represented by a state-space model as

$$\dot{\boldsymbol{x}} = \boldsymbol{A}\boldsymbol{x} + \boldsymbol{b}r^d, \tag{B.6}$$

where $x = [x_1 \ x_2]$ and the system and input matrices are given by

$$\boldsymbol{A} = \begin{bmatrix} 0 & 1 \\ -\omega_c^2 & -2\zeta\omega_c \end{bmatrix} \qquad \boldsymbol{b} = \begin{bmatrix} 0 \\ \omega_c^2 \end{bmatrix}. \tag{B.7}$$

With a measurement equation of the form

$$\boldsymbol{y} = \boldsymbol{C}\boldsymbol{x}, \tag{B.8}$$

where $C = [1 \quad 1]$, we gain knowledge of both the reference trajectory and its time derivative, $x^d$ and $\dot{x}^d$, respectively.

## B.2 Filter Design

To achieve good tracking performance, it is important that the bandwidth of the reference model (i.e. the cutoff frequency $\omega_c$ in the case of a low-pass filter) is chosen lower than that of the system being controlled, meaning that the reference model creates slow enough trajectory changes of which the system can handle.

Another bonus is that the filter can be designed to remove high frequency input signals. By properly tuning the filter design parameters $\zeta$ and $\omega_c$, one can achieve a reference trajectory that follows slowly varying signals, rather than high frequency inputs that can be seen as disturbances.

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