FACULTY OF SCIENCE AND TECHNOLOGY

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SUMMARY

Pressure control is one of, if not the, most critical component of any drilling operation. Keeping the pressure inside the well within the constraints of the formation around is crucial in ensuring safe operations. As wells are reaching their lifetime of production, and since new prospects become more challenging, new technology can be used to turn a profit on difficult wells. Managed Pressure Drilling represents an established technology that is increasingly being employed by the exploration industry worldwide. Making HPHT wells and partially depleted reservoirs drillable, the technology is ideal for the maturing Norwegian Continental Shelf.

The use of MPD technology is increasingly prevalent in the drilling industry and a major opportunity lies in automating the control of the processes. Using the capable PI controller in parallel with drilling simulations makes it possible to fine-tune the drilling process. Transient drilling simulators make it possible to emulate the conditions downhole and create tuning parameters for use with the PI controller. The ability to create controllers with quick response times, minimal overshoot, and strong stability is showcased during simulations. Furthermore, an approach for easily creating a stable controller based on the most popular model-based tuning method is presented. Simulations point towards the PI controller as a powerful tool when paired with MPD technology.

SAMMENDRAG

Trykkontroll er en av de viktigste faktorene under enhver boreoperasjon. Å holde trykket i brønnen innenfor grensene til formasjonen rundt er kritisk for å sikre tryggheten under operasjoner. Felt på sokkelen begynner å modnes og nye prospekter har mer utfordrende forhold, men teknologi kan brukes for å utvinne lønnsomt også fra disse. Managed Pressure Drilling er en etablert teknologi som stadig oftere benyttes av den globale leteindustrien. Ved å gjøre HPHT-formasjoner og vanskelige brønner utvinnbare er teknologien ideell for den modne norske kontinentalsokkelen.

Bruk av MPD-teknologi er stadig mer utbredt i boreindustrien og store muligheter ligger i automatisering av prosesskontrollen. Ved å anvende den allsidige PI-kontrolleren i parallell med brønnsimuleringer er det mulig å fin-justere boreprosessen. Transiente modeller i boresimulatorer gjør det mulig å etterlikne forholdene i brønnen og finne tuning-parametere for bruk med PI-kontrolleren. Muligheten til å lage kontrollere med rask respons, minimalt overskyt, og stabil oppførsel vises gjennom simuleringene. Videre presenteres en fremgangsmåte for å skape en stabil kontroller basert på den mest populære modell-baserte tuning-metoden. Simuleringene fremhever PI-kontrolleren som et kraftig verktøy som kompliment til MPD-teknologien.

PREFACE

This Bachelor's thesis was written in the 3rd year of my BSc. Degree in Petroleum Technology at the University of Stavanger. The work with this thesis has allowed me to gain further insights into the field of process technology. I have also been able to put my knowledge of drilling and the petroleum industry into words.

I would like to thank my supervisor at the University of Stavanger, Jan Einar Gravdal, for his help in writing this thesis. Being guided through the process of running simulations and extracting information from them has been very helpful.

I would also like to thank NORCE for providing the software and licenses needed to run the simulations and the University of Stavanger for the opportunity to write this thesis.

CONTENTS

LIST OF FIGURES

LIST OF TABLES

ABBREVIATIONS

List of all abbreviations in alphabetic order:

- **BHP** Bottom Hole Pressure
- **CC** Cohen-Coon
- **CCS** Continous Circulation System
- **CML** Controlled Mud Level
- **CBHP** Constant Bottomhole Pressure
- **IOR** Improved Oil Recovery
- **MPD** Managed Pressure Drilling
- **NPT** Non-Productive Time
- **NCS** Norwegian Continental Shelf
- **OBM** Oil Based Mud
- **PSA** Petroleum Safety Authority Norway
- **PMCD** Pressurized Mud Cap Drilling
- **PI** Proportional Integral
- **PID** Proportional Integral Derivative
- **RPM** Rotations per Minute
- **UiS** University of Stavanger
- **WBM** Water Based Mud
- **ZN** Ziegler-Nichols

CHAPTER

ONE

INTRODUCTION

Drilling for oil and gas has presented challenges for more than 50 years on the Norwegian Continental Shelf (NCS). Drilling offshore in some of the roughest waters in the world all year long takes a toll on both crew and equipment and the desolate locations increase the risks. A high focus on HSE rules in Norway has aimed to continuously improve the safety of the NCS. The challenge is keeping that level of safety intact, both for the crew and the environment, in the near future of the industry. With an increasing number of installations being decommissioned due to low production, the hunt for new hydrocarbons has made difficult, albeit promising, reservoirs relevant once again. Depleted reservoirs, HPHT wells, and wells with narrow pressure windows are increasingly being planned for due to the scarcity of new, easily drillable, reservoirs (Birkeland 2009). An old technology that already has been delivering promising results for decades is MPD. Managed Pressure Drilling is not a new invention but has found great popularity as increasingly more difficult reservoirs are being drilled. Making difficult wells drillable, MPD technology can potentially save the industry enormous amounts of time as well as make the well deck safer (Quoc et al. 2021). Although the technology is steadily gaining traction in the oil and gas industry, some challenges still remain present and stop this from being a 'no-brainer'. Rigorous planning of new wells, extensive training of crews, as well as increased initial costs of advanced equipment all add up and may leave a sour taste for many operators. An ever-present danger when using certain MPD methods involving under-balanced drilling fluid is the lack of barriers to prevent kicks and subsequent blowouts. Already a highly automated operation area, the use of such technology on the NCS would most likely be automated and controlled by computers and controllers. Such automation brings benefits but also challenges. Understanding the basis of automated controllers and how these function in different roles is key to making offshore MPD operations safer.

Thesis Outline

The thesis can be categorized into seven sections. In section 1, information about the oil and gas industry is presented and some important terms are introduced. Section 2 introduces the concept of Managed Pressure Drilling, or MPD, which is a key component in the thesis. Finishing off the main theory, section 3 introduces key concepts of the PID controller and how these relate to the automation of MPD operations. In section 4 simulations are performed and the results of them are shown. Section 6 contains a discussion of the results found in the previous section. Finally, the conclusion and recommendations for further research on this topic can be found in section 7. The Appendix contains technical overviews and pictures of the well setups used in the simulations in section 5. This is also where scripts required to recreate the simulations in the thesis are found, as well as technical data.

CHAPTER

TWO

DRILLING

The drilling phase is perhaps the most challenging and critical part of oil and gas production. Before extraction of oil and gas from a well can start, it is necessary to first drill a path to the underground resources. Mistakes made in this phase will affect the production and eventual plugging operations of the well. Modern wells often reach several kilometers in length and are drilled in inhospitable and desolate locations and through challenging conditions underground. The goal of every drilling operation is to reach the target depth safely and according to, or better than, the drilling operational plan, which means drilling as fast as possible without inducing excessive downtime.

Modern drilling technique consists of using sections of steel tubes, known as drill pipes, which are attached to a drilling bit and then used to drill into the ground beneath an installation. As many of the easily available oil fields are already produced, finding new oil and gas reserves means drilling deep and in increasingly challenging formations. Due to the compacting of sediments over millions of years, the temperatures and pressures in these exploration areas increase with depth and can become a hassle to deal with. A great deal of attention should be made to the pore and fracture pressure of any formation being drilled in. Drilling operations will be performed with the goal of staying between or in the vicinity of these pressures. Keeping the pressure in the well too high or too low would mean disregarding safety and inviting problems.

2.1 Pressures

The pore and fracture pressure are arguably the most important pressures in drilling and exploration underground. The pore pressure can, according to Møgster (2013), be described as the fluid or gas pressure in the pores in the formation. Keeping the pressure in a well below this would mean fluids and gas from the formation could join the drilling fluid up the annulus and induce what is known as a kick. The fracture pressure could subsequently be described as the upper pressure limit of the formation. A well with a pressure above the fracture pressure

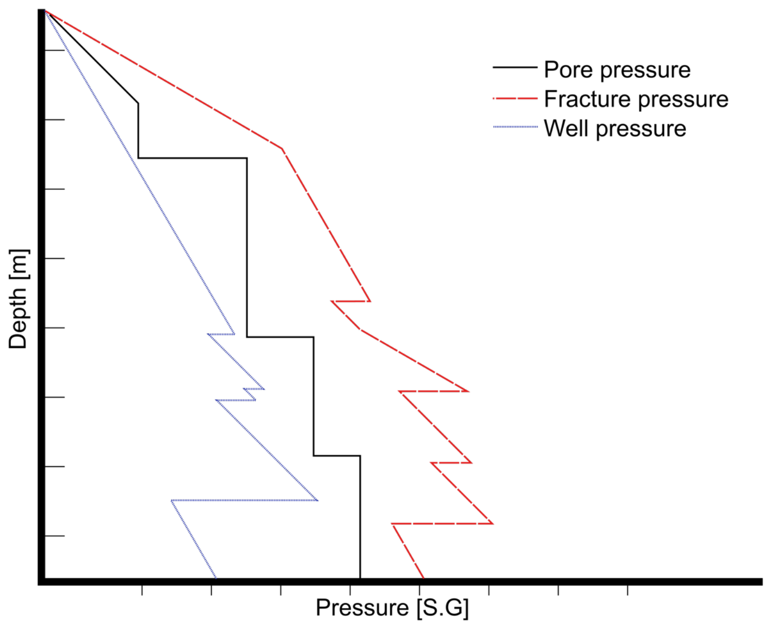


Figure 2.1.1: Plot showing a simplified illustration of the pressure gradient in a well including the pore and fracture pressures, as well as the pressure inside the well.

could “crack” the formation around, inducing cracks and crevices in the formation. This would mean opening up space in the formation for the drilling fluid to escape, as seen in Figure 2.2.1. Losing the drilling fluid to the reservoir is known as lost circulation and would lower the pressure in the well and risk leading to the same problems as when drilling below the pore pressure (Møgster 2013, p. 5). The ideal, then, would be to keep the pressure in the well between these two pressures. This is illustrated in the formula below, Equation 2.1, where the drilling pressure is shown between the pore and fracture pressures.

$$\rho_{pore} < \rho_{drill} < \rho_{frac} \tag{2.1}$$

$$\rho_{collapse} < \rho_{pore} < \rho_{drill} < \rho_{frac} < \rho_{overburden} \tag{2.2}$$

In addition to the previously mentioned pore and fracture pressures, there are also the collapse and overburden pressures present, shown in Equation 2.2. Keeping pressure in the well below that of the collapse pressure could lead to a collapse of the formation and well, preventing the equipment from being tripped out. Staying above the overburden pressure, defined as "the combined weight of formation materials and fluids in the formation" (Møgster 2013, p. 5), could lift the whole formation up, destroying it in the process. Keeping the pressure of the well between these limits could be easier said than done. Known as the pressure window, keeping the well in this golden zone should greatly limit the risk of going on a loss or inducing a kick. Keeping the well balanced does require extensive testing and planning of the well before even getting the rig or installation in place. As the

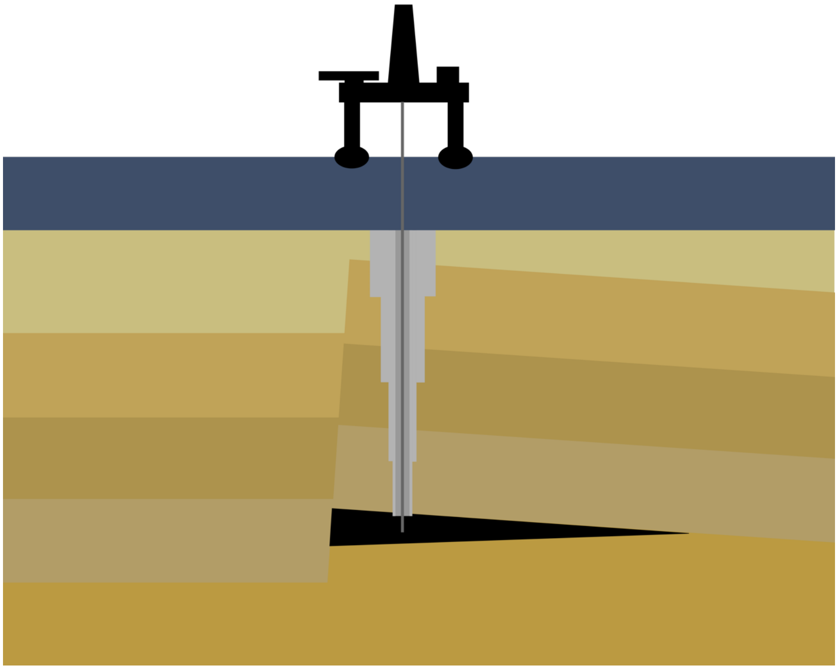


Figure 2.1.2: Simple illustration showing the outline of a vertical well drilled using a range of casings

pressure underground generally increases with depth, a system of casings is put in place to isolate parts of the drill string. These casings consist of steel pipes with larger diameters which are then cemented off, effectively closing off these sections so the pressure gradient in these sections can be disregarded. Still, casings can only be set at certain intervals to avoid running out of room, so the risk of influxes or losses will continuously have to be weighed against the risk of running out of viable pipe sizes. Longer wells require better planning and carry a greater risk of running out of pipe sizes as the formation may differ from the geological surveys done beforehand. Where casings are not present, called the open-hole section, pressure is balanced using drilling fluid.

2.2 Drilling fluid

The drilling fluid is the blood of the drill string. Often referred to as drilling mud or simply ‘mud’, the drilling fluid is the liquid being pumped into the well to keep it in balance and perform vital tasks. The journey of the mud goes from the mud tanks, through the mud pumps, down the well inside the drill string, through the nozzles of the drill bit at high speed, up the well again in the annulus, on to the installation, through the shakers and back into the mud tank. During this journey it performs many tasks, like cleaning the borehole, cooling the bit, transporting out loose debris and cuttings, and giving the personnel onboard the installation important information on the health of the well. One of its most important tasks is keeping the pressure inside the drill string within the pressure window. This is done by adding heavy weighing materials to the mud to increase the pressure inside the drill string, or by diluting the mud to lower the pressure. Due to the length of wells, mud is mixed up beforehand and stored in tanks until it is pumped

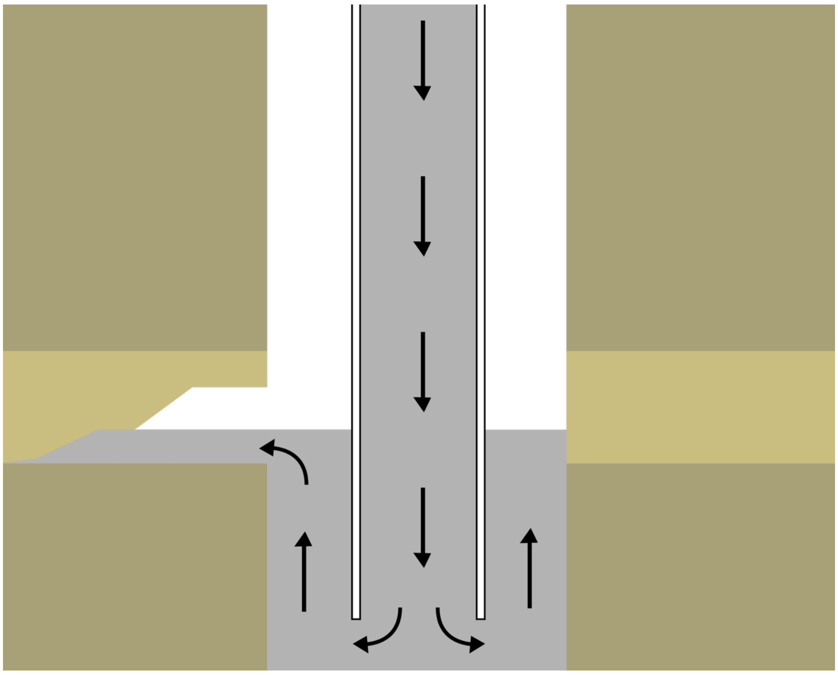


Figure 2.2.1: Illustration showcasing an example of loss of drilling fluid in a well. This is due to cracks and crevices in the formation and could be made worse by improper drilling techniques.

down. The volume of mud means mixing it up and pumping it down the drill string takes time and results in non-productive time, known as NPT, during incidents like kicks and losses. There are three main categories of mud or drilling fluid: oil-based mud, OBM, water-based mud, WBM, and synthetic-based mud, SBM. In addition, there is seawater which is used offshore in the first stage of drilling and in some other operations. There are benefits and weaknesses of each type, and they are used in different formations and wells.

Drilling requires detailed knowledge about the formation being drilled through and is planned thoroughly to avoid NPT. The challenges can be many when running steel pipes from the installation and several kilometers into the ground. By keeping the pressure in the well in balance with the outside formation through drilling fluid, the safety of the installation and environment is prioritized. By actively controlling the most critical aspect of the drilling process, the well pressure, the process could be improved with less downtime. The main principles of a drilling process are to a large extent kept unchanged for a century. However, Managed Pressure Drilling when used actively constitutes a major enhancement in the ability to control the well pressure.

CHAPTER

THREE

MANAGED PRESSURE DRILLING

Managed pressure drilling, or MPD, is an umbrella term for a range of methods and associated tools. It was developed to ease the extraction of oil and gas from reservoirs by manipulating the pressure in the well. Initially experimented with in the first half of the 20th century, the MPD options being offered to the industry today bring cost-saving promises. Reduced downtime, greater extraction rates, and the possibility of drilling in the most unhospitable formations are the results. In an industry slow to implement new technology, the use of MPD methods is quickly rising and an ever-increasing amount of wells are being drilled with active use of such methods (Rehm et al. 2009). Figuring out the basics of MPD technology makes it easier to employ it in real-life operations. It can also give an idea of the opportunities and risks associated with its use.

3.1 Basics of MPD technology

MPD is a collective term for several methods and technologies developed for drilling operations. Drilling with MPD can mainly be done in two different ways, either in an active or in a reactive way. Reactive MPD usage means to use MPD methods in response to events during drilling. The well is then drilled conventionally but with MPD equipment on board in case of kicks or similar incidents. This means kicks can be circulated out without needing to mix up new, heavier mud, thereby saving time and costs. The alternative method is using MPD actively while drilling. This can be done by constantly drilling at balance, or slightly above, and using the MPD tools to keep pressure in the well within the pressure window. This enables drilling in challenging reservoirs, such as HPHT or depleted reservoirs for exploration and possible production. Active use of MPD requires extensive planning of the well and coursing of personnel to mitigate the increased risk that its use brings. The risks involved when actively employing MPD methods while drilling will be discussed in later sections.

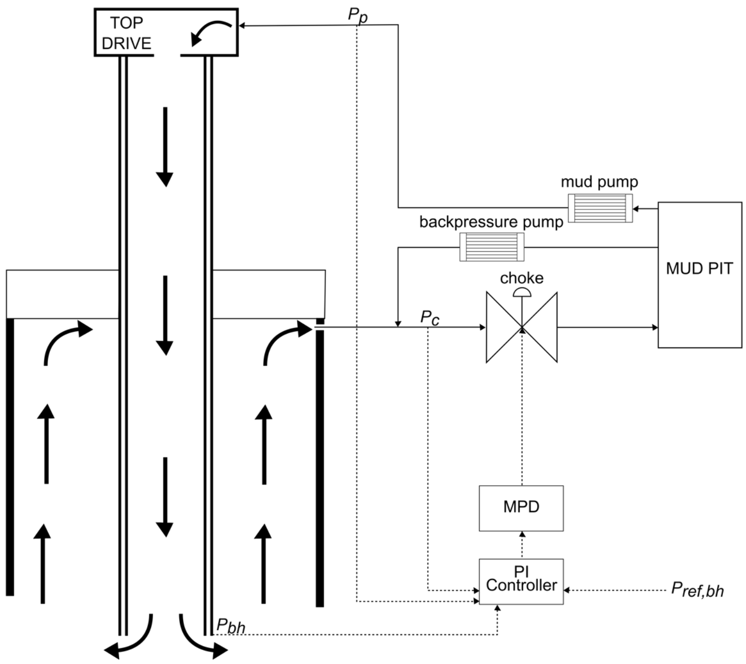


Figure 3.1.1: Schematic showing how an automated MPD system using a PI controller works, whereP_{bh} is the bottom hole pressure, $P_{ref,bh}$ is the reference bottom hole pressure, P_p is the pump pressure, and P_c is the pressure measured before the choke.

3.1.1 Constant Bottom Hole Pressure

Constant bottom hole pressure method, known as CBHP, may be the best-known of the main MPD methods applied in the industry. The principle behind the method is quite intuitive and comparable to conventional drilling. The basic concept behind CBHP is using a choke mounted at the top of the annulus to limit the return flow of mud onto the installation. This creates back pressure, thereby increasing the pressure in the well to reach the target pressure. The choke can be opened and closed manually or by automated control. In addition to the choke, some other equipment like backup pumps are installed. Drilling using CBHP can help avoid problems such as loss of circulation, influx of reservoir fluids, differential sticking, and fracturing of the formation. All these problems are, at least to a large extent, caused by drilling outside the pressure window of the formation. The non-productive time induced by such problems is in most cases extensive. In addition, fewer casings are required, and they can be set deeper, thanks to the choke manipulating the pressure in the well. These factors greatly reduce the expected amount of NPT on installations. The resulting potential for significant cost-saving makes this technology attractive for new wells being drilled today (Rehm et al. 2009).

3.1.2 Controlled Mud Level

Using the hydrostatic head actively can also make drilling wells easier. Controlled mud level drilling (CML) makes use of the principle of hydrostatic pressure by "lowering" the mud level in the riser from the drilling floor towards the sea floor.

Doing this reduces the hydrostatic pressure from the drilling floor to the seabed. This in turn creates a pressure gradient that is more adapted to the in-situ gradient down in the formation, for example at deep water depths. The principle behind CML is to displace the pressure gradients by using mud weights. This makes it possible to drill deeper down. Setups for dual gradient drilling use differ from a conventional drilling setup as there needs to be a system for making the mud in the riser above the sea floor lighter than that of the well. This can be done in different ways. One way of doing it is injecting a lighter gas into the riser at the seabed. Another possibility is by redirecting cuttings into a separate return line. It's also possible to use a mud return pump or through riserless technology (Drilling Contractor 2011).

3.1.3 Pressurized Mud Cap Drilling

A third method of MPD drilling worth examining is pressurized mud cap drilling, PMCD, which is, according to Sommernes and Vik (2018), a variation of mud cap drilling (MCD). This method is mainly used for limiting losses in formations with large cavities and spaces, such as carbonate structures. The principle behind PMCD is to fill the annulus space with a weighted mud cap and then use sacrificial drilling fluid in the drill string, keeping the bottom hole pressure constant in the process. There are no returns using this method and the drilling fluid used is absorbed into the crevices of the formation. The drilling is done underbalanced to avoid too high losses of drilling fluid to the formation. While certainly interesting, PMCD is limited in use and mainly used on carbonate fields and has not yet seen use on the NCS (Sommernes and Vik 2018, p. 99-102). Greater focus is therefore in this thesis devoted to the CBHP method.

3.2 Opportunities

The use of MPD methods in drilling of wells represents great opportunities for the industry. As many fields being produced today on the NCS are nearing maturity, the industry has to turn every stone in the hunt for new, profitable, prospects. Most of the "easy" wells are already being produced from or plugged and abandoned. That means that difficult wells, such as those that are partially depleted or with HP/HT characteristics, are being considered when searching for new oil and gas. Producing from these wells becomes possible by actively using MPD methods while drilling. Although active MPD usage is ideal for difficult formations, MPD methods can also be used in a more reactive fashion when drilling. Using conventional drilling methods, the addition of reactive MPD tools can be used to circle out kicks and reduce NPT.

Saving time is a major factor when considering MPD methods, both used actively and reactively. Drilling operations usually involve a great deal of downtime, known as non-productive time or NPT. This downtime is necessary due to a variety of reasons, such as when adding length to the drill string, during cementing operations, and to combat well problems. Even a small reduction in NPT is worth looking into for operators due to the high cost of keeping drilling operations running. MPD promises time savings in several ways:

Increased length of casings: Because it is possible to manipulate the pressure using chokes and other equipment, the space between each change of casing size increases. This reduces the time used for cementing operations. Because the drill string does not need to be tripped out and in again as often, NPT can be substantially reduced (Birkeland 2009, p. 2).

Fewer well problems: Drilling using MPD allows for greater control of the pressure in the drill string and makes it easier to avoid exceeding the pore and fracture pressures of the formation. This in turn can reduce the frequency of well problems, such as stuck pipe, influxes, kicks, and lost circulation. This saves time used to stabilize the well in addition to costs for replacement parts (Nas et al. 2010).

3.3 Challenges

Although a game-changer in many areas, implementation of MPD methods still faces challenges. A challenge faced across the different methods occurs when using oil-based mud, OBM instead of water-based mud (WBM). According to Gravdal et al. (2018), a well filled with WBM will respond faster and more predictably than a well drilled using OBM. This comes down to compressibility. Due to the inherent incompressibility of water, the reaction to the choke's adjustments quickly travels through the fluid column in the well and the pressure changes accordingly. The long, often deviated, wells being drilled today changes this aspect. This is because increased length results in longer reaction times, and because these are often drilled using OBM to reduce torque and drag. The performance of OBM in the lubrication of the drill string makes it more likely than WBM to be used in long wells with deviating paths. Unlike the Newtonian properties of water, oil is non-Newtonian and more compressible, and as a result, gives a different reaction to choke adjustments (Gravdal et al. 2018, p. 117). Both the unreliable response to choke adjustments, as well as the long response times that follow in long wells, represent a challenge when using MPD methods and PI controllers.

A challenge especially dire when using the back-pressure method in MPD operations is the reliance on instrumentation in the well. The CBHP method relies on information sent from the bottom of the drill string, as seen in Figure 3.1.1. Accurate and fast transmission of signals from the well is essential. In conventional wells, information to and from tools deep in the wellbore is sent through mud pulses. This method is not the most accurate but does the job in most wells (Gravdal et al. 2018, p. 118). A method of sending and receiving accurate and fast information downhole is using wired pipe. This technology consists of drill pipes with a high-speed cable integrated and running along the length of the pipes. High speeds and real-time information are the benefits, while a steep price tag represents the downside of utilizing such technology (Møgster 2013, p. 16). Due to the high price of using wired pipe, assessments should be performed to see if it makes sense for a given well. Cheaper methods exist, such as using choke pressure instead of the bottom hole pressure, and could be employed instead of the costlier bottom hole sensors.

Connections are made more difficult when using MPD due to the nature of the technology. During connections, mud flow into the well from the pumps must traditionally be halted. According to Birkeland (2009), wells are often drilled underbalanced when using MPD methods, with the MPD choke accounting for the difference and making sure the well stays balanced. During connections, the mud pump is not running and the well may therefore be at risk of influx from the formation. This represents a challenge in keeping the pressure in the well within the pressure margins of the formation when the pressure margins are slim. However, technology has been developed to solve the challenge that this represents. The Continuous Circulation System, CCS, makes it possible to make connections without stopping flow into the well. Continuing circulation during connections makes it possible to keep the pressure balanced with ECD plus hydrostatic pressure. This improves hole cleaning in comparison to keeping the mud static, in addition to reducing the possibility of connection gas. However helpful the tool is, its use is often prevented due to the high cost of renting units (Birkeland 2009, p. 17). Therefore, like wired pipe, it becomes essential to make sure employing it in operations would be profitable.

After connections are made and the pumps started up again, a new problem might present itself. One factor important in calculating the suitable MPD response is the rate at which mud is being pumped into the well, known as the pump rate. Gravdal et al. (2018) writes that this can be calculated from the stroke rate of the pumps, that is, the number of times the pistons in the pump perform a rotation. This is, however, difficult to base adjustments on when the pumps are operating at low pump rates, for example during start-up. Pump rate latency is likely to be introduced during such operations and would mean that the choke is adjusted much later than desirable. A fix to this problem exists in using the rotational speed of the engine in the pump rather than basing adjustments on the stroke count. Knowing about this potential problem beforehand and reading off the engine speed instead of the pump rate is required to avoid this potential issue (Gravdal et al. 2018, p. 117).

These challenges are mostly solvable given enough planning and money but do require rigorous assessments beforehand to make sure the drilling operation is profitable. Ignoring these challenges, however, could prove dangerous as drilling using MPD carries heightened risks when compared to conventional drilling.

3.4 Risks

The consequences of improper use of MPD methods can be severe. The dangers were showcased during an incident involving loss of well control at the Statoil (now Equinor) operated Gullfaks field in 2010. According to the Statoil report cited in Aftenposten, the specific well being drilled, known as the C-06A, was a challenging one. It was defined by a narrow pressure window and damaged formation due to previous drilling operations. To mitigate the constraints of the well it was decided to drill using MPD methods. Drilling was performed using a mud with weight lower than that of the pore pressure but balanced by back pressure produced by the choke. This essentially meant that a major barrier against influxes, kicks, and other dangerous events was removed. According to Statoil's own investigation, a

Figure 3.4.1: Picture of the Gullfaks A platform in the North Sea, along with the headline of an article in Aftenposten that implies the possibility of a major incident on the field. Photo: Øyvind Hagen, Statoil

hole in a 13 3/8" casing led to the cement shoe at the 20" casing cracking. This in turn resulted in a loss of fluid to the formation. As a result of this, hydrocarbons from the well started flowing up the annulus, resulting in a kick. Immediately following the incident, crew both on the installation and on land were baffled about what had happened and how to respond. In a strike of luck, cuttings and material from the well helped block and reduce the stream up to the platform and thereby lowering the risk of serious harm to the crew onboard. The well was finally blocked after 2 months, but findings in the investigation following the incident led to the entire field being shut down for a period of time. According to the Norwegian PSA, only luck prevented a major incident from happening (Bjørheim 2011). The danger posed to the crew onboard and the environment during the incident was severe and highlighted the need for proper risk assessments. The stalled response of personnel tasked with controlling the well also shows that training in MPD usage is needed. This is especially important as many wells planned with MPD in mind are drilled through challenging formations. HP/HT wells and wells with narrow pressure windows have less margin of error and are more frequently being considered.

3.5 Automation

Manually controlling the MPD operations leads to an increased risk of human error and overworked drillers according to Gravdal et al. (2018). The tasks performed by the drillers onboard installations are crucial in maintaining a safe and effective drilling operation. Although process control is overwhelmingly automated in oil refineries and other onshore or offshore facilities, drillers are often left to control many processes. Monitoring well parameters, looking for signs of influx or losses, operating remote equipment on the drill floor during connections, and more. Adding MPD options gives the driller more tools to easier manage the well, but not without added complexity and more parameters to monitor. A CBHP setup, for example, leads to the need for risk assessments due to being an underbalanced drilling method and requires monitoring of choke opening and bottom hole pressure. Furthermore, the operation of the MPD choke will be reliant on often inaccurate measurements and lag in signal transmission, leading to an increased possibility of human error. Automated systems can take such factors into account and make adjustments accordingly. A human MPD operator will rely on skill, experience, and focus to avoid mishaps and incidents. Automated drillers, on the other hand, can be programmed to meet efficiency and safety measures and have far quicker reactions than a human operator (Gravdal et al. 2018, p. 121). Due to health, safety, and environmental concerns, many traditionally manual tasks have been mechanized or automated in recent years. Connections are no longer made by roughnecks covered in oil but by mechanized, remotely operated machines, with hydraulic oil running through their veins. As safety is a major concern on the NCS, automation of MPD systems should be highly prioritized to mitigate the chances of error when utilizing the technology.

CHAPTER

FOUR

PI CONTROLLER

Proportional Integral Derivative controllers, or PID controllers, make up the backbone of industrial processes and everyday technology. According to Incatools (2023), "99 percent of all automation control loops are PIDs". Based on mathematical concepts and developed in the early 20th century, PID controllers are making modern society possible. Both a multimillion-dollar chemical processing plant and the heating cables in a modern bathroom rely on this controller (Incatools 2023). A technology not meaningfully improved upon since its inception could be used to automate the extraction of oil and gas resources in some of the most challenging formations ever drilled through. The logic behind this can be found by studying the build-up of the PID controller and how it can be applied in different applications.

4.1 Fundamentals of PI Controllers

Originally developed in 1911 by Elman Sperry, PID controllers were popularized in the 1940s as a result of tuning methods developed by Ziegler and Nichols (Omega 2023). The task of a PID controller is to keep track of and adjust a process by comparing it to a target value and making adjustments as needed. A typical application in the industry is monitoring the fluid level of a container. If the fluid level is too high, a gate is opened. If the level is too low more fluid is directed into the container. Although quite a trivial task, replacing the human operator with a PID controller frees up manpower, reduces the chance of human error, and reduces costs substantially. A plant with hundreds of such processes happening simultaneously, such as an oil refinery, is the perfect application of the technology. Instead of having people running around and adjusting processes manually, a few operators can monitor hundreds of processes in a control room. In industrialized countries with high wages, automation of processes is essential for maintaining profitable operations. Unlike human operators, PID controllers don't have bad days or shifting focus and reduce the chance of miscalculations on the production line. Today PID controllers are the brains of bathroom fans, heated

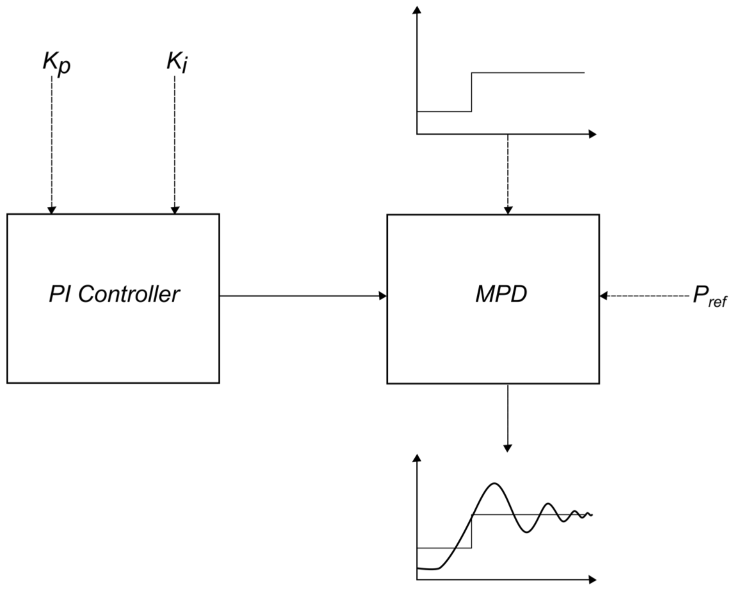


Figure 4.1.1: Illustration showing how a PI controller can be used in cooperation with an MPD choke during drilling operations

floors, cruise control, and much more. Although old technology, the usefulness of these controllers lies in their rock-solid construction.

A PID controller is constructed from the concepts of proportionality, integration, and derivation. There are several variations of PID controllers, such as the simple P controller and the popular PI controller. The goal of any PID controller is to adjust a process variable in accordance with a target value. This is achieved through mathematical formulas built from these concepts. The formula for the PID controller is as provided by (Wikipedia 2023) in Equation 4.1:

$$u(t) = K_p e(t) + K_i \int_0^{\tau} e(\tau) d\tau + K_d \frac{de(t)}{dt} \tag{4.1}$$

Here, $u(t)$ is the controller output, K_p represents the proportional gain, K_i represents the integral gain and K_d represents the derivative gain. The error is represented through $e(t)$, t is the time component, and τ is the variable of integration. The controller used in this thesis is the PI controller and the formula can therefore be rewritten without the derivative term, as in the edited Equation 4.2:

$$u(t) = K_p e(t) + K_i \int_0^{\tau} e(\tau) d\tau \tag{4.2}$$

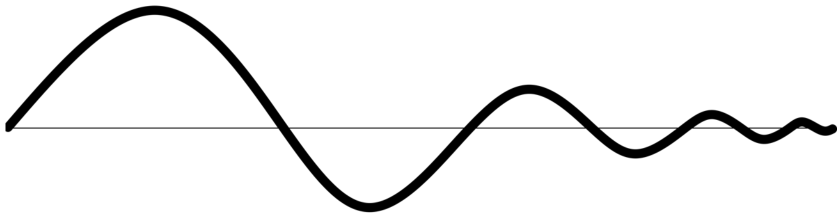
The rate of adjustment to the process is known as gains. The magnitude of these gains decides how quickly and by how much the process variable is changed. According to Incatools (2023), the P-, I-, and D-parts of the controller affect different aspects of the response, such as speed, overshoot, and risk of oscillations. Although certain traits of the controller response can be improved by adjusting one parameter, such changes will often also affect the other parameters to some degree. Tuning of such controllers is therefore not as straightforward as it may seem (Incatools 2023). A rough overview of how adjustments made in the different parts of the controller could affect the response is as follows:

Proportional term: Gives an overall signal to change proportional to the error present

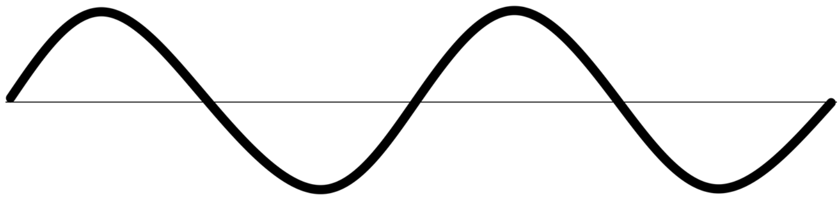
Integral term: Reduces the error through low-frequency compensation by integration.

Derivative term: Improves response through high-frequency compensation using the derivative of the error present.

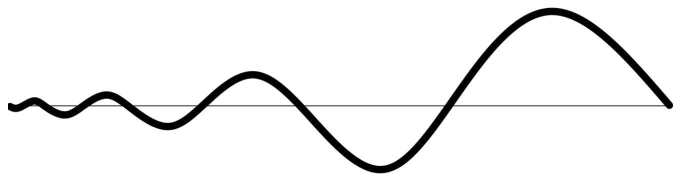
The whole premise of the PID controller falls through without correct tuning. If the controller meant to automate a process instead creates instability and errors, then the whole purpose of it is lost. While easy in theory, PID controllers require careful tuning to avoid overshooting of target values and oscillating motions. Different objectives require different tuning and considerations must be balanced. According to Incatools (2023), fast adjustments often lead to overshooting the target value, while adjusting without overshoot may take awfully long. While manual adjustments can be made on the basis of the previously discussed gains, many prefer to use established tuning methods. The tuning method that laid the groundwork for the later popularity of PID controllers was first published in 1942 by the duo Ziegler and Nichols and would be known as the Ziegler-Nichols method. In their paper, titled "Optimum settings for automatic controllers", naming and measurement conventions were proposed and most importantly, the effects of tuning on controller response were studied. They included formulas for tuning and their method quickly became the go-to method for easy implementation of PID controllers in various industries. The Ziegler-Nichols method, or ZN method, is defined by fast, aggressive tuning with substantial overshoot. Although not suitable for all processes, the ZN method is quick and simple to implement and yields reasonable performance in most applications. In addition, the method can be used as a benchmark or as starting values for manual tuning. Although still the most popular, other tuning methods have been established for purposes where the ZN method falls short. An example of this is the Cohen-Coon method, published in the early 1950s and built on the ZN method. Kappa-Tau is yet another tuning method built on the ZN method, while the Lambda method paves its own path and does not build on Ziegler and Nichols' work (Incatools 2023).



(a) Convergent trend



(b) Oscillating trend



(c) Divergent trend

Figure 4.1.2: Figure (a) shows an example of convergence in a signal, figure (b) shows an oscillating signal, where the signal switches between equal positive and negative values, while figure (c) shows a divergent trend in a signal. The last two trends should be avoided.

The last thing needed when drilling in deep reservoirs with slim pressure margins is overshooting the fracture pressure of the formation and cracking it. Thus, avoiding responses that ruin the well and incur significant NPT is crucial in tuning PID controllers for use with MPD. Controller response should ideally be quick without too much overshoot in areas with low fracture pressure. Avoiding oscillations or divergence in the process is also important. Additionally, the controller should act in a predictable and reliable way to avoid the risk of incidents and harm to the environment and crew onboard. Knowledge about MPD operations and how to handle MPD-related incidents is still not sufficient on the NCS. This was showcased by the Gullfaks incident when crews both onboard and onshore struggled with understanding the extent of the MPD-related kick during the 24 hours after the incident. Midtun (2015) conducted interviews with personnel onboard an installation regarding their knowledge of MPD routines and risks. The conclusion was that planning, information, and training on MPD operations was insufficient and that crew onboard generally had little to no knowledge about the technology (Midtun 2015, p. 82). Making the controller as stable as possible is therefore a priority.

There are three main tuning methods used when tuning a PID controller:

Hedonistic

Rule-based

Model-based

Which method is the most suited depends on factors such as how the process behaves, which considerations need to be made, and the capability of the people performing the tuning. A small, inexperienced team working on a limited budget may easily reach for the Ziegler-Nichols method and be done with it, while a high-volume factory with larger budgets could use advanced model-based tuning methods to make the process more efficient. Every method has advantages and challenges which in turn determines how well it fits different use cases.

4.2 Hedonistic Tuning

The perhaps most intuitive method of tuning is the hedonistic method, often referred to as the trial-and-error or guess-and-check method. Starting out with some standard values for the P-, I-, and D-gains, either based on intuition or using the results of methods such as Ziegler-Nichols, the controller is then tuned for better speed and stability. Tuning this way does not require much experience but that it can be quite time-consuming. A benefit of tuning done this way is that the controller is likely to respond to the process in a manner the operator would want it to. By running the process or simulation repeatedly, small fixes and tweaks can perfect the controller response. A major challenge using this method however is a lack of predictability of how the controller responds to abnormal process values. While the response of a controller tuned using rule-based methods can be worked out mathematically, responses of hedonistically tuned controllers are unpredictable in nature. Incidents like leaks or other malfunction of equipment related to the process could give values outside of the scope used for tuning the controller and in turn result in oscillation or overshoot (Incatools 2023).

4.3 Rule-based Tuning

Based on mathematical formulas and equations, rule-based tuning can act as a diving board for further tuning and more predictable controller responses. Starting with the duo of Ziegler and Nichols, rule-based tuning still remains popular due to its ease of use and reasonable results in process applications. Ziegler and Nichols may have been the first but today there exist several other rule-tuning methods that may be more fitting to different applications. The most well-known alternatives are Cohen-Coon, Lambda, and Kappa-Tau. The Kappa-Tau method of tuning is a later release, having been published in 1991 by Hagstrøm and Algård. Improving upon the ZN method, the Kappa-Tau method aims to fix some of the most prominent flaws of its predecessor, including its high proportional gains and poor results in systems with long dead time. This is done by collecting more information and using it in a different way. The benefits of tuning using the KT method are less oscillatory response, optimal disturbance rejection with no overshoot, and the ability to choose between a slower or faster response. The Lambda method is the only one mentioned that is not based on the work of Ziegler and Nichols. Using lambda as its tuning parameter, this method has the potential for creating very stable loops. In addition to a very stable performance, it works well for systems with a large time delay and features the ability to choose how fast the controller responds. As with the other methods, the Lambda method also comes with some challenges, such as a slow rejection of disturbances and only working with PI controllers (Incatools 2023).

4.3.1 Ziegler-Nichols Method

The Ziegler-Nichols method of tuning, or the ZN method, is the most popular way of tuning PID controllers. It was published in a 1942 paper and laid the basis for many later models, such as the Cohen-Coon method. Owing to its simplicity of use, the method became popular amongst industries seeking automation options. Although the PID controller had been released more than 20 years prior, Ziegler and Nichols' new tuning method made for much easier tuning, opening the technology to more people. The method developed by the duo allowed for a quick tuning process and relatively good results without the need for costly and complicated tuning processes. The Ziegler-Nichols method is a step-gain tuning method and the gain values are determined by creating oscillation in the process and then taking measures of values at this instability point. The values noted are the critical P-value K_{cr} and the period of the oscillations T_u. These are then put into formulas to determine the correct values for the process. The formula used in further testing is borrowed from (Ziegler and Nichols 1942) and is shown in Equation 4.3.1, where K_u represents the critical P-value and T_u represents the critical period.

Control Type	K_p	K_i	K_d
P	$0.50K_u$	-	-
PI	$0.45K_u$	$0.54K_u/T_u$	-
PID	$0.60K_u$	$1.2K_u/T_u$	$3K_uT_u/40$

Table 4.3.1: Table used for finding controller parameters by using critical values. To be used with Ziegler-Nichols' second method of tuning. Inspired by (Wikipedia 2023).

Having been in the public for about 80 years, the method has seen countless derivatives and variations developed. The Cohen-Coon method, for example, is based on the Ziegler-Nichols method. The ZN method used in later simulation and tuning is referred to as Ziegler and Nichols' second method. This method was specifically designed for use with proportional integral controllers. Needing only two values, the setup is very simple and quick. This makes it ideal as a baseline for further testing and as a simple way to obtain relatively good process values. There are however some severe drawbacks associated with the tuning method. The method is designed with a high overshoot in mind and with an aim for about 25

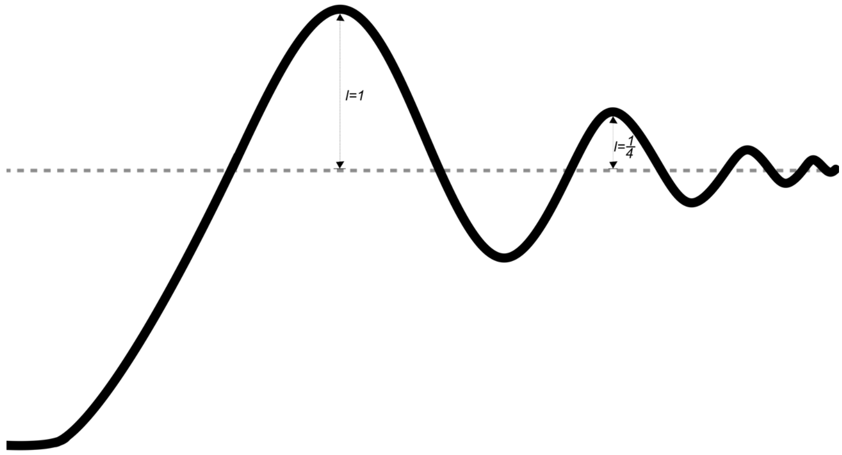


Figure 4.3.1: Illustration showing a typical signal reaction based on Ziegler-Nichols tuning, characterized by a large overshoot

percent overshoot. Although this level of overshoot is rare in practice, the general level of overshoot is larger than many other methods (Incatools 2023).

4.3.2 Cohen-Coon Method

The Cohen-Coon method, or CC-method, is a twist on the Ziegler-Nichols method from 1942, released eleven years after its predecessor entered the public. According to Control Notes (2011), the Cohen-Coon method uses more information from the process than the ZN method, leading to an increased range of use cases. In some industrial applications, the CC method may be more suited than the ZN method. This could be owed to the Cohen-Coon method's increased flexibility in regard to process dead time. The method consists of three parameters: The steady-state gain a, the time delay L, and the time constant T. Being built upon the ZN method, most benefits of this method are carried over in the Cohen-Coon method (Control Notes 2011)(Incatools 2023).

4.3.3 Lambda Method

The Lambda method is designed to give the operator greater control of the response time. Unlike the previous method, the Lambda method is not based on the work of Ziegler and Nichols but instead follows its own path. The advantage of using the Lambda method is, according to Vandoren (2013), its ability to "move a process to a new setpoint in a specified amount of time without overshoot. The ability to be able to "time" the response is of great value in many applications and eliminating overshoot can also be valuable. When drilling for oil and gas, an overshoot of the pressure window could mean fracturing the formation and causing irreversible damage to the well. As with the other methods, these benefits come at a cost. In particular, the complete elimination of overshoot makes slow processes even slower and means the process value remains below the target value for a considerable amount of time. That means a controller tuned using the Lambda method takes much longer to reach the target value than say a Ziegler-Nichols-tuned controller (Vandoren 2013). The question is then if the challenges of such a slow response time are weighed up by its lack of overshoot and how much this would mean in a drilling scenario.

4.4 Model-based Tuning

Model-based tuning offers a permanent solution for controller needs in specific applications. According to Incatools (2023), emphasis is placed on a strict workflow to enable the best possible tuning results. This ensures process behavior is considered while also making room for control needs. On the flip side, this strict path is necessary and not something that can be skipped through. It also requires that the objectives are clear from the start, for example, if the emphasis is to be placed on response time, overshoot reduction, or better stability. This approach enables a balance between the performance and robustness of the controller, whereas, with model-based tuning, one or the other often has to be prioritized. This could prove helpful in MPD operations, where performance is important for effective drilling, while stable operations are necessary from a safety point of view. A drawback of this sort of tuning is the amount of time required to achieve good results. It is time-consuming but the possible benefits over using rule-based or hedonistic tuning methods can be substantial (Incatools 2023). Once the parameters are found they seldom need readjustments. Although favorable in many industries, this does not necessarily make much sense for drilling operations. Every well is different, with different sediments and casing depths. This means the PI controller for the MPD used must be set up individually for each well in order to reflect the different drilling environments. This "future-proof" part of the method could potentially be worth little for use in drilling but rather sow doubt about the suitability of the method in this use.

CHAPTER

FIVE

SIMULATION

5.1 Simulation setup

5.1.1 Openlab Drilling

In order to test the various tuning methods in a realistic scenario, a commercial drilling simulator is used. The web-based software Openlab Drilling makes it possible to start multiple test runs with varying pressures and drilling fluids while altering the conditions of the well and formation. As pointed out by Ewald et al. (2018), the software is developed by NORCE and is based on their computer models of well-flow and drill string mechanics. The flow model in particular is developed by Lorentzen et al. (2014). Parameters such as length of the well, deviation, rig type, drilling fluid, and the possibility of well incidents can be changed or enabled in the simulator (Ewald et al. 2018). The parameters changed in the testing of tuning methods following are the length of the well and the various pressures. The configuration used in the testing is similar to that of an offshore drilling rig used on the NCS and is demonstrated in the Abstract.

To ensure a fair and objective comparison of the different tuning methods, a Python script is in some testing used to initiate simulations in Openlab. The script run through Python simulates a change in pump rate which in turn creates a pressure change used to test the properties of the PI-controller of the MPD. Due to the controllers present in the Openlab simulator, it is not necessary to run simulations through programs such as Python or Matlab but it is used to accurately report on and compare the tuning methods. To run simulations through Python, an extension is first downloaded from the Openlab website and run through the Command Prompt of Windows. After installing the extension, various Python scripts, including for use in MPD control, are available on the Openlab resource page. The simulations are started through Python and can not be altered underway, ensuring there is no interference in the process.

5.1.2 Simulation Approach

To obtain the most precise results, different methods are used throughout the testing phase of the tuning methods. The testing is done by changing the Kp- and Ki-values of a PI controller. The PI controller in turn controls the MPD choke used while drilling. The effects of the tuning method can therefore be directly read off of the Bottom Hole Pressure (BHP) plot in the Openlab application.

Before the testing can begin, values for the different tuning methods are found. This is in most cases done by provoking a response in the process and then noting various parameters of the mentioned response. The Ziegler-Nichols method, for example, requires tuning the Kp-value until the process oscillates and then using the same Kp-value as well as the frequency to determine the values for further testing.

After the values are found, initial testing is performed. Using only the Openlab simulator and the values found, initial testing can give a quick check on how well the tuning methods are expected to work. This gives a pointer to whether further testing of the method is favorable or not. This initial testing is done by changing the PI parameters and then provoking an MPD response. This can be done by for example dramatically increasing or decreasing the pump rate in the well. The resulting pressure change makes the MPD choke kick in and its response can then be studied for response time, overshoot, oscillation, and convergence.

After initial testing is done, more rigorous and comparative testing is performed using the aforementioned Python script. This approach ensures fair testing and results that can be compared to each other. When using this method, the Openlab web software acts as a viewing station and displays various well-parameters, the BHP being the most important for evaluating the responses. As with the initial testing, the results are evaluated for response time and other parameters. The tuning method best fit for the well is chosen for further tuning and testing.

For the last part of the testing, manual adjustments are made to the PI controller in an effort to further improve the response of the MPD choke. The goal is to see if the tuning method can be further improved for a specific well.

5.1.3 Well Description

The simulations used during tuning are similar to those found on the NCS. They are simulated without the possibility of influx or losses to the formation to simplify them as the focus is on the MPD part of the well. The wells are slightly deviated in order to better represent their real-life counterparts. The lengths of the wells are 2500 meters and 5000 meters in different simulations. This is done to showcase how different operating environments can affect the tuning process. Technical data about the well, along with casing depth and more, is described in the Abstract part. A 3D illustration of the well path can be seen in Figure B.2 in the Abstract.

5.2 Simulations

5.2.1 Initial Tuning

To tune the PI controller, the Ziegler-Nichols method of tuning is used. This implies a step-gain response that relies on first provoking instability in the process and then using values extracted from the results to set up the PI controller. To find the ZN values, a simulation is started with an MPD set to be controlled using the bottom hole pressure in the well. The K_i and K_d parameters are then set to 0 as only the K_p value is to be used to find the critical values. The K_p is set to a low value and then slowly increased to find the limit of instability. Once instability in the process is introduced in the form of oscillations, the critical K_p value, known as K_u, is noted, and the period of the signal is measured and noted as T_u. An example of how this may look is presented in Figure 5.2.1. These are then put through Equation 5.1 and 5.2 to find the values to put into the PI controller. A more complete overview is provided in Table 4.3.1.

$$K_p = 0.45 * K_u \tag{5.1}$$

$$K_i = 0.54 * K_u/T_u \tag{5.2}$$

5.2.2 Comparative Tuning

Comparative tuning is used to show how the MPD reacts to a change in the wellbore. By using the same scenario with each simulation case, a fair comparison is achieved. This is done by running the simulation through a Python script with a planned change in well parameters. The same method is used for finding the ZN values in each simulation case and is described in the Initial Tuning section. The PI controller is set up using these ZN values.

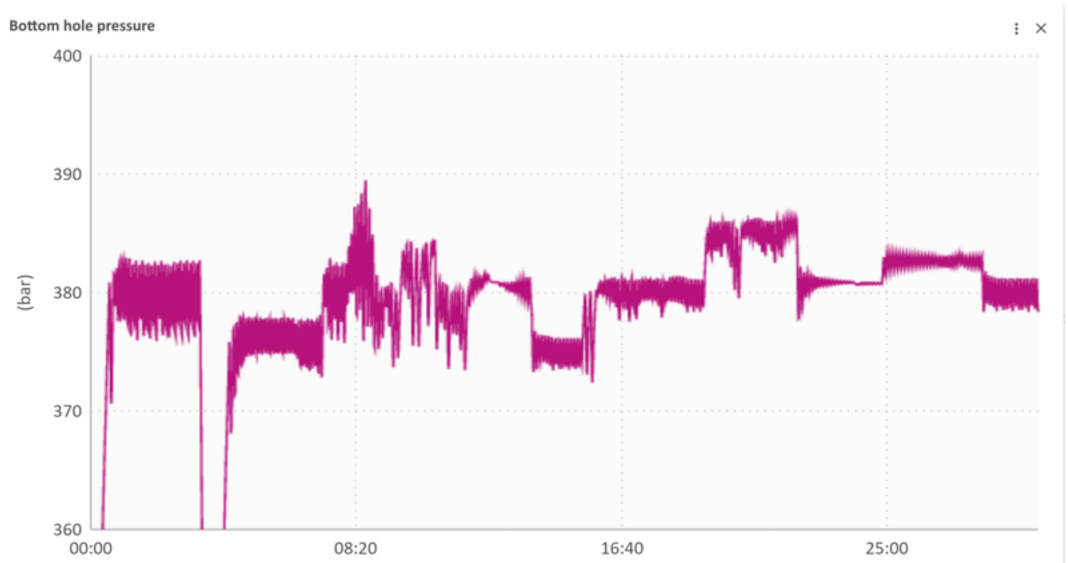


Figure 5.2.1: Screenshot from the Openlab simulator showing how the initial ZN values are found. Divergent, convergent and oscillating trends in the signal can be seen in the plot.

5.2.3 Additional Tuning

After comparing the different tuning methods and making some adjustments, it is clear that some methods suit the task of managing MPD operations better than others. This can be seen in the amount of overshoot and the response times as well as the robustness of the models. Using these selected few methods, further tuning is performed manually in the hopes of achieving better properties of the PI controller.

5.3 Simulation Cases

5.3.1 2500-meter Deviated Well

The 2500-meter well is a slightly deviated well drilled using oil-based mud. The exact layout and technical data can be viewed in Appendix B4-5. The length of 2500 meters is chosen as sort of a standard length as most modern production wells will reach at least this depth. Although modern technology enables horizontal wells to be drilled, an inclined well is selected to keep the focus on the tuning process. Drilling horizontal wells would make the system more susceptible to external influence. Horizontal drilling can lead to worsened hole cleaning, a higher risk of stuck pipe, and affect the pressure in the system, as ECD is replaced by increasing friction pressure.

The Ziegler-Nichols values found in the initial tuning and used in the simulations can be found in Table 5.3.1. As seen in Figure 5.3.1, the tuning seems to give a good adjustment of the process. There is no meaningful overshoot, and the process is adjusted quite quickly.

5.3.2 5000-meter Deviated Well

The 5000-meter well is built as an extension of the previous 2500-meter well, as if the previous well has been continued for another 2500 meters. This means the first 2500 meters consists of casings, while the open hole section lasts 2500 meters. The total length of the well is then about 5000 meters. As with the previous well, this well is also slightly deviated and drilled using an OBM. The purpose of using such a deep well is to see how tuning parameters change with depth and if one set of parameters can last an entire well. This well setup also represents a challenge when drilling. Both the length, which increases travel time for signals, and the oil-based mud, which is compressible, pose challenges for the MPD and PI controller. It remains relevant for the industry, as many wells are drilled to this depth.

The response seen in the process is not very fast, as shown in Figure 5.3.2. The process is adjusted quite slowly and does not reach the target pressure before the simulation ends. This is in contrast to the fast adjustments in the previous case and shows the impact that doubling the length of the well has on the process. The Ziegler-Nichols values used in the simulation can be seen in Table 5.3.2. They show how the period recorded during initial testing is 12 seconds, more than double the 5 seconds for the 2500-meter well.

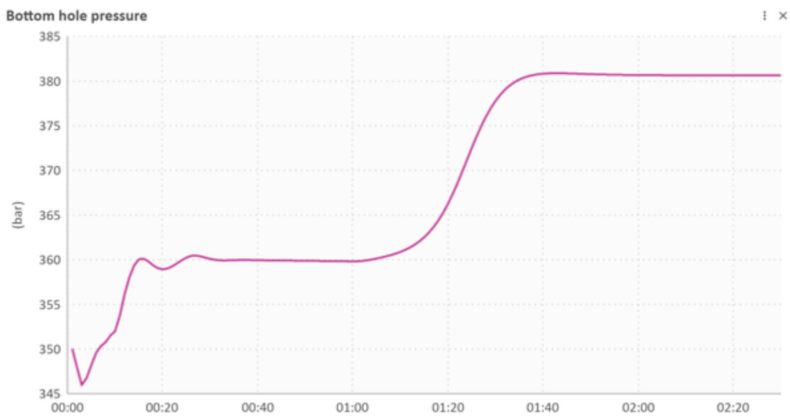


Figure 5.3.1: Plot showing the reaction of the process to the controllers' input in the 2500-meter well.

Control Type	K_p	K_i
Critical values	0.018	5 s
ZN values	0.008	0.002

Table 5.3.1: Critical and ZN values used for the 2500-meter well.

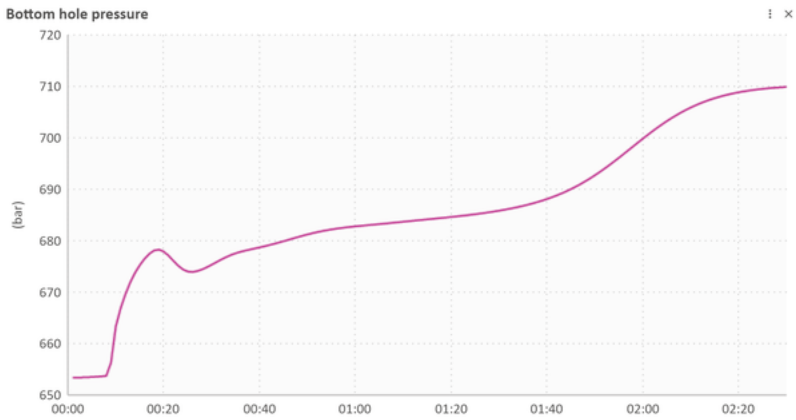


Figure 5.3.2: Plot showing the reaction of the process to the controllers' input in the 5000-meter well.

Control Type	K_p	K_i
Critical values	0.01	12 s
ZN values	0.005	0.0005

Table 5.3.2: Table showing the critical and Ziegler-Nichols values used for the 2500-meter well.

5.3.3 Further Tuning

Further tuning was done by manually adjusting the controller parameters. The aim was to see if the overshoot or response time of the process could be improved. The 2500-meter well was used in the simulations and the Ziegler-Nichols values from Table 5.3.1 formed a starting point. Several simulations were run with slightly adjusted values each time. Python was used to launch the simulations since that made it possible to compare them accurately. Through continuous testing, a set of parameters were found.

Applied to the 2500-meter well, a faster reaction is achieved. The bottom hole pressure can be found in Figure 5.3.3 and the values used in Table 5.3.3. The downside of the quick response is the considerable overshoot present in the signal. Reaching nearly 390 bars, the pressure overshoots the target value of 380 bars by nearly 10 bars. This could cause problems when operating within narrow pressure margins. The tuning parameters used do however not seem to affect stability, with flow sweep tests showing good resilience when faced with varying flow rates. The plots showing flow rate and bottom hole pressure can be seen in Figure C.4 in Appendix C4.

5.3.4 Continuous Drilling

Simulations were also performed to test if the same values as in the 2500-meter well could be used when continuing down to 5000 meters. The results can be viewed in Figure 5.3.4 and the flow sweep tests can be found in Appendix C3.

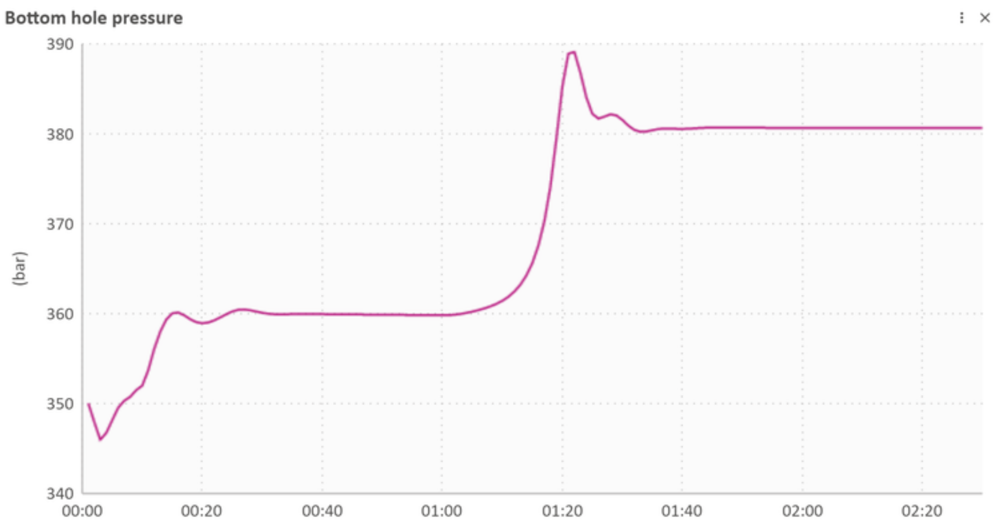


Figure 5.3.3: Plot showing the process response to the adjusted controller in the 2500-meter well.

Control Type	K_p	K_i
Values	0.005	0.0017

Table 5.3.3: Table showing the adjusted values used in the 2500-meter well

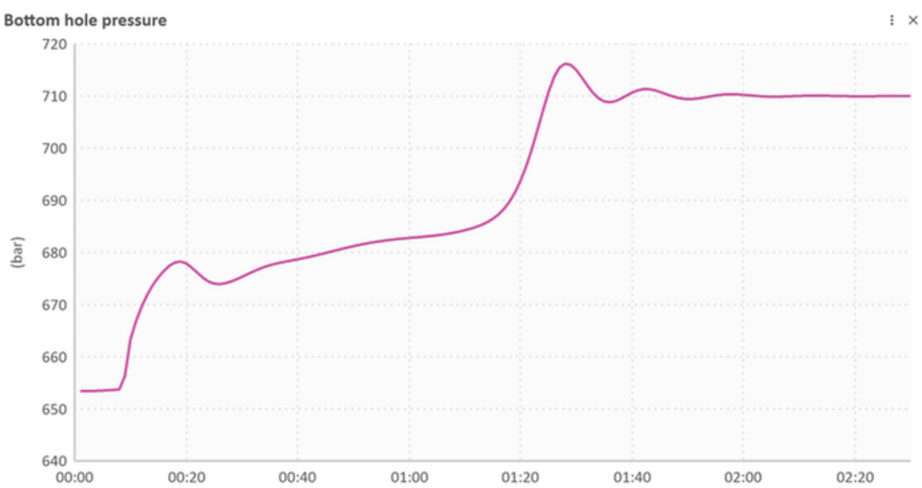


Figure 5.3.4: Plot showing the ZN-values found for the 2500-meter well applied in the 5000-meter well. There is some degree of overshoot present. Illustration from Openlab.

CHAPTER

SIX

DISCUSSION

The simulations performed demonstrate how the process reacts to the controller inputs. The simulated wells are 2500 and 5000 meters long and drilled in the same environment. A tuning method is used to test its suitability and to serve as a baseline for further tuning and experimenting. Studying how the process reacts to the controller inputs can help determine which method to use when tuning the controllers. Favorable characteristics of the controllers are quick response time, minimal overshoot, and solid stability. Adhering to these qualities should in theory make drilling more efficient without affecting the safety onboard. Whether the tuning process is successful or not is judged by comparing it to other simulations and by checking it against the favorable traits already laid out.

It is important to note that simulations only represent our best assumptions of real-life conditions. Although the flow models and simulator setup are carefully crafted and based on conditions in the field, they are still only assumptions. In addition, the simulations do not show the entire process while drilling, such as ramping up and down during connections. The possibility of influxes and losses is also turned off to simplify simulations. The focus should therefore be directed to trends and phenomena showcased during simulations, rather than the specific values achieved.

The Ziegler-Nichols method of tuning is used in the simulations for the 2500- and 5000-meter wells. The method is very popular in the process industry and is possible to use in cooperation with the Openlab simulator. First, the 2500-meter well was simulated with a Kp of 0.008 and a Ki of 0.002, both found from the initial tuning in the well. These are obtained from Table 5.3.1. When simulated using these values, the process responds in a controlled fashion. The process quickly changes and there if no visible overshoot. It also settles around the target value of 380 bars, albeit a little over, at 380,7 bars. This could point to some weakness in the Ki-value although such a small pressure difference most likely would fall within tolerances. Flow sweep tests performed on the well, as shown in Figure C.1a in section C1 of the Appendix, show good stability.

Further tuning was done to the 5000-meter well. The values used for this well can be found in Table 5.3.2 and is a Kp of 0.005 and a Ki of 0.0005. Although the Kp-value is close to that of the 2500-meter well, the Ki-value is far lower than for the previous well. This is based on a period of 12 seconds, far longer than the 5 seconds seen in the 2500-meter well. A large part of this comes down to the length difference between the two wells. The length between the bottom hole pressure sensor and MPD choke at the top of the annulus has doubled in the 5000-meter well. In addition, factors such as mud compressibility, which is explained in Chapter 6, affect the pressure delivery down the well. The oil-based mud present in the simulated well amplifies this effect. As seen in Figure 5.3.2, a slower response is the result of these considerations. At the two-and-a-half-minute mark, the process still has not reached the target pressure of 710 bars. Although the response is quite slow, the controller parameters make sure the process remains stable. As seen in the flow sweep simulations in Figure C.2a, the process remains stable throughout the flow changes.

Comparing the 2500- and 5000-meter well makes it clear that well length, drilling fluid, and other factors affect the potential reaction time of an MPD choke setup. This must then also be reflected in controller design to ensure stability in operations. The long reaction time of the 5000-meter well might seem excessive compared to the 2500-meter well but it provides a stable process without instability and oscillations. This can be crucial when dealing with more recent technology that workers on installations are not familiar with. From the simulations performed, the Ziegler-Nichols method has dealt with the process well and without instability in either of the wells. It can be interesting to compare these findings to the further simulations done in the wells.

Further simulations focused on the possibility of fine-tuning the controller used in the 2500-meter well. In addition, testing was performed to see if a single set of tuning parameters could be used throughout the entire 5000-meter well. In the first case, tuning was done by changing the Ziegler-Nichols values initially found for the 2500-meter well. The parameters were changed with an emphasis on response time, while also keeping the overshoot as low as possible. Through several test runs, the most successful parameters can be seen in Table 5.3.3. The Kp is at 0.005, while the Ki is shown as 0.0017. The resulting response can be seen in Figure 5.3.3. The response time is low, but it struggles with overshoot. The result is a pressure spike reaching almost 390 bars, close to 10 bars above the target pressure of 380 bars. It is clear that this could induce problems in a formation with a narrow pressure window. Fracturing the formation would definitely lead to problems and the time-saving compared to the Ziegler-Nichols-tuned simulation is not that great. The risk associated with such an aggressive tuning setting would in many wells be too serious.

Additional simulations were carried out to see if a single set of tuning parameters could be used at both the 2500- and 5000-meter length mark in the well. As the 5000-meter well builds upon the 2500-meter well, a single tuning setting would mean less time spent tuning the controller. The values used are sourced from Table 5.3.1. The simulation is shown in Figure 5.3.4 and shows quick tuning compared to the Ziegler-Nichols tuned simulation. There is a decent overshoot in the response, reaching a peak of about 715 bars, above the target value of

710 bars. It also uses some time to settle at the target pressure. This could be acceptable given a wider pressure window. Flow sweep simulations done for the well do however show severe weaknesses in the tuning settings. The plots for the choke opening and flow rate in the well can be seen in Figure C.3b and Figure C.3a in Appendix C3. As seen in the plots, disturbances start showing once the mud flow into the well drops below 2000 liters per minute. Once the rate drops below 1600 liters per minute, severe oscillations occur. These are not corrected until the flow rate reaches 2300 liters per minute. Ramping up and down the flow rate happens regularly while drilling due to connections and other operations. Such characteristics are therefore not wanted and would pose a serious risk in operations. It is clear that utilizing a single tuning parameter over large portions of wells is dangerous and should be avoided.

Reviewing the simulations reveals that tuning the controller is not as straightforward as it may seem. There are different considerations to keep in mind and wells represent a dynamic element. The Ziegler-Nichols method showed great potential with solid stability through changing flow rates and gave process responses without meaningful overshoot. Trying to improve the process response in the 2500-meter well gave a quicker response but also a substantial overshoot that would make it unfit for many wells. Testing of a single set of tuning parameters used throughout the well also gave disappointing results. Initial simulations showed reasonable results, with considerable overshoot but a fast process response. In-depth flow sweep simulations, however, showed weaknesses in dealing with lower flow rates in the well.

Overall, it becomes clear that a sort of mechanism for adjusting the tuning parameters as the well progresses should be implemented. The values found for the 2500-meter and the 5000-meter wells deviate substantially. Using the former values for the latter also introduced oscillations during flow sweeps and poses a great risk while drilling. This points to the need for some sort of step-gain scheduling. This can be explained as gradually changing the parameters as the well progresses. An implementation of this could be tables containing tuning parameters to be implemented at certain depths. Alternatively, a program to dynamically change the tuning parameters based on the well length and conditions could be used. Both alternatives point towards a method of changing the PI controller gradually while drilling.

CHAPTER

SEVEN

CONCLUSIONS

The purpose of this thesis has been to explore the use of PI controllers to manage pressure in cooperation with MPD methods, specifically the CBHP method. Through simulations using a commercial drilling simulator, various tuning parameters and methods have been tested on different wells. The conclusions reached from this are listed below:

- PI controllers are shown to work well when paired with an MPD choke method.
- The Ziegler-Nichols second tuning method gives reasonable tuning of the PI controller when used for drilling.
- Commercial drilling simulators can be used to find suitable tuning parameters for use in wells.
- Using static tuning parameters as the well progresses is not good practice and could easily lead to instability in the form of oscillations.

There exist many use cases for the technology presented. Similar processes as pressure control in wells include the transport of gases such as Co2 and hydrogen over long distances. These gases need to be pressurized but not exceeding certain limits. The use of stable PI controllers can automate this process safely.

Future work

As seen in simulations, using the same tuning parameters for the PI controller during long well segments does not work, but changing the Kp- and Ki-values regularly leads to better efficiency and lowers the risk of instability. Step-gain scheduling is a method that deals with this problem. An implementation suited for drilling use would be a dynamic program that adjusts the PI parameters along with the well. Using geological surveys, as well as bottom hole pressure, the controllers are constantly updated. This could lead to a much safer implementation of MPD technology. Keeping the safety offshore intact will prove crucial as the search for new fields narrows and the formations become more difficult.

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APPENDICES

A - GITHUB REPOSITORY

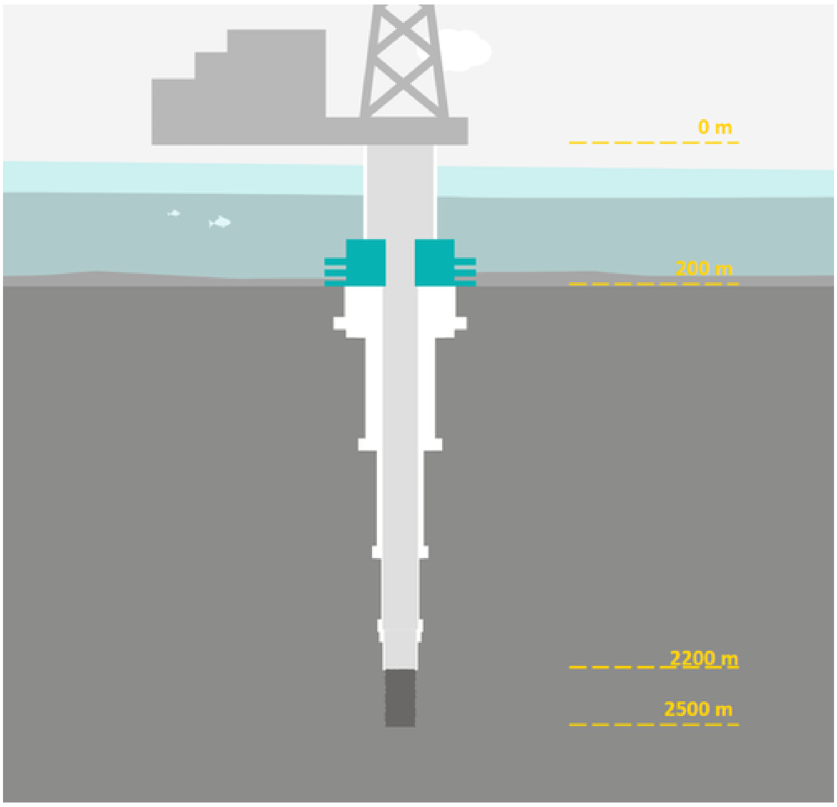
All code and Latex files used in this document are included in the Github repository linked below. Further explanations are given in the readme file.

Github repository link

- `https://github.com/Henrik-T-S/BAC23`

B - WELL INSIGHTS

B1 - Well Details



(a) Hole section of 2500-meter well

Figure B.1: Figure (a) shows the hole section and casings of the 2500-meter well, while Figure (b) shows a 3D graphic of the deviation of the well. Illustrations from the Openlab simulator.

B2 - Well Details

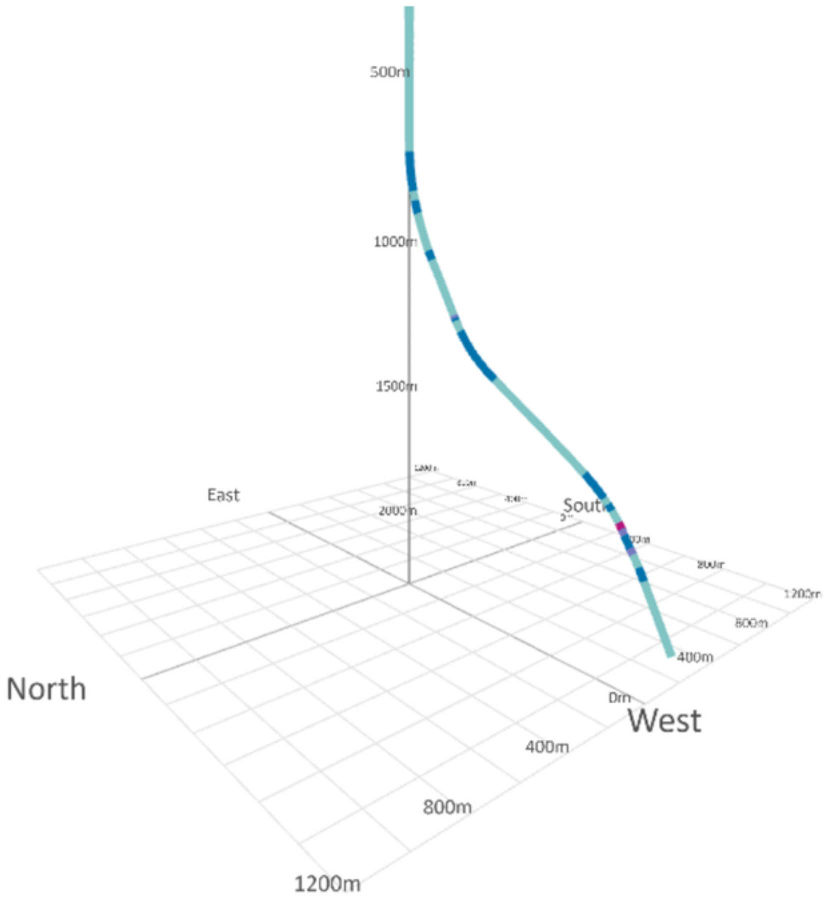
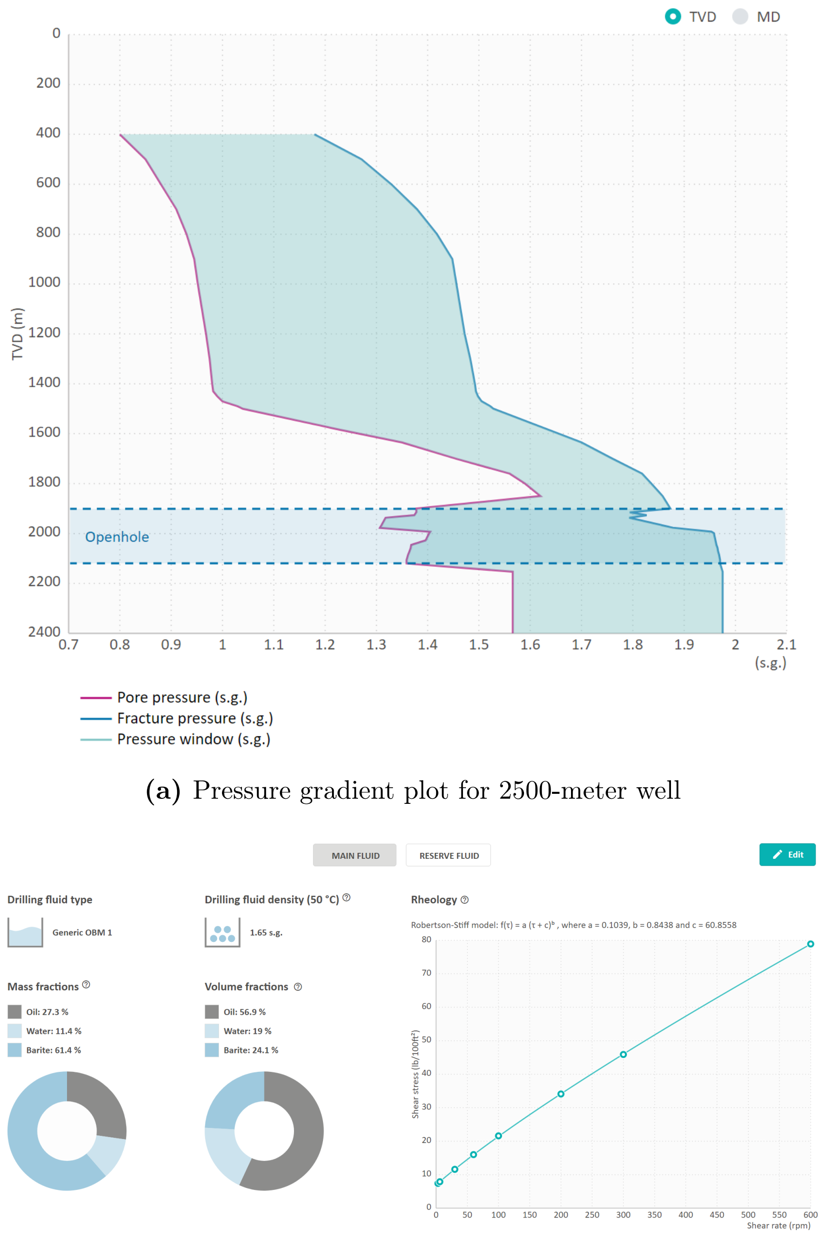


Figure B.2: 3D graphic showing the deviation of the 2500-meter well. Illustrations from the Openlab simulator.

B3 - Well Details



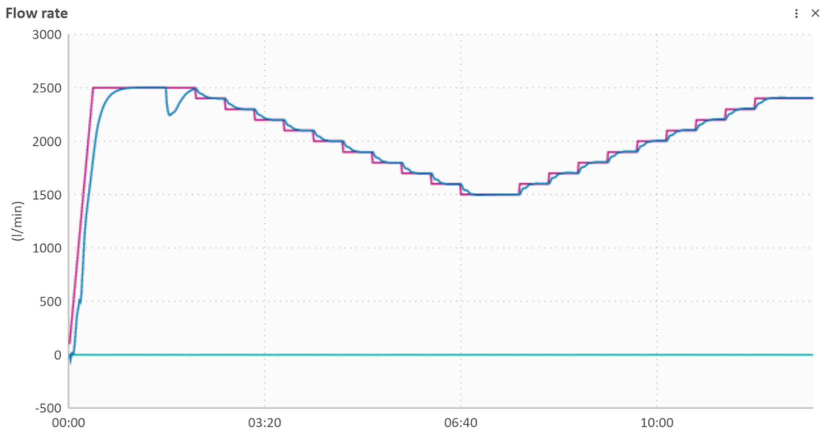
(a) Pressure gradient plot for 2500-meter well

(b) Fluid details for 2500-meter well

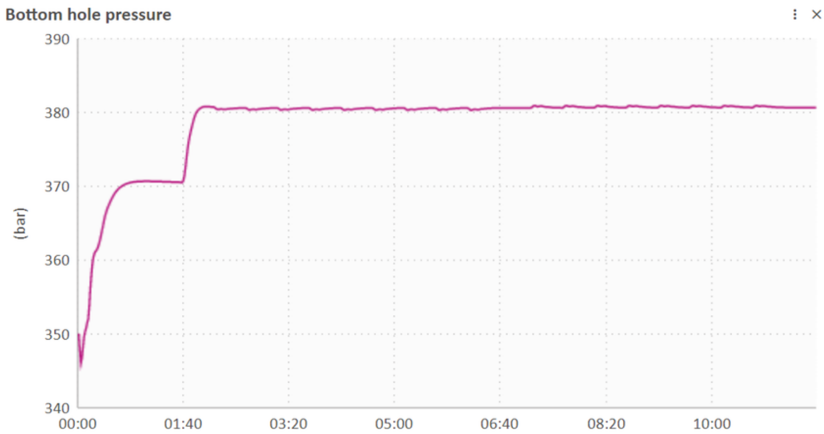
Figure B.3: Figure (a) illustrates the gradients for the pore and fracture pressures, as well as the pressure window, while Figure (b) provides details of the drilling fluid used in the simulation, in this case, an oil-based mud. Illustrations from the Openlab simulator.

C - FLOW SWEEPS

C1 - Flow sweep for 2500-meter well



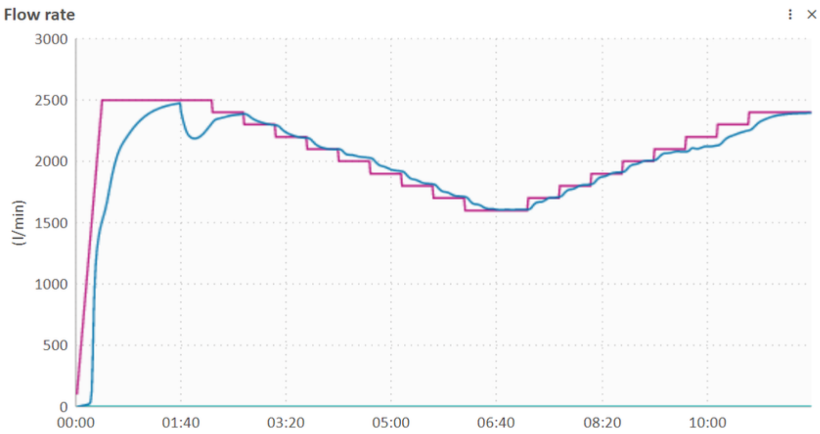
(a) Pump rate in the 2500-meter well being adjusted



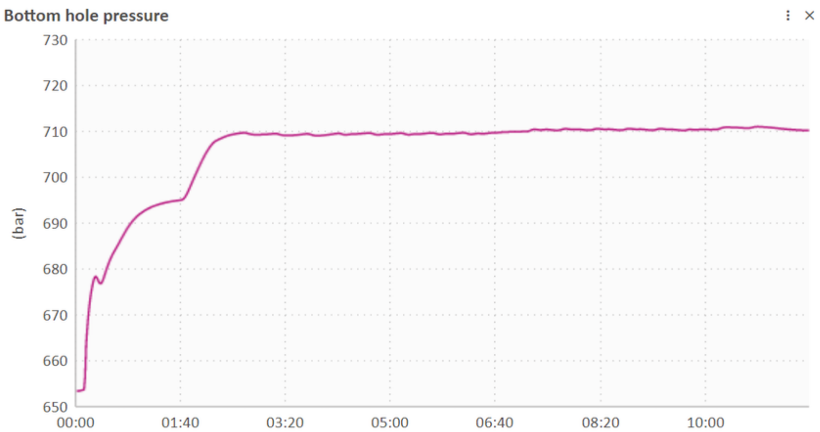
(b) Bottomhole pressure during the sweep

Figure C.1: Figure (a) shows the varying flow rate in the well, while Figure (b) shows how the bottom hole pressure changes as a result. As seen in Figure (b), the controller handles the changes fine and without large disruptions. Illustrations from the Openlab simulator.

C2 - Flow sweep for 5000-meter well



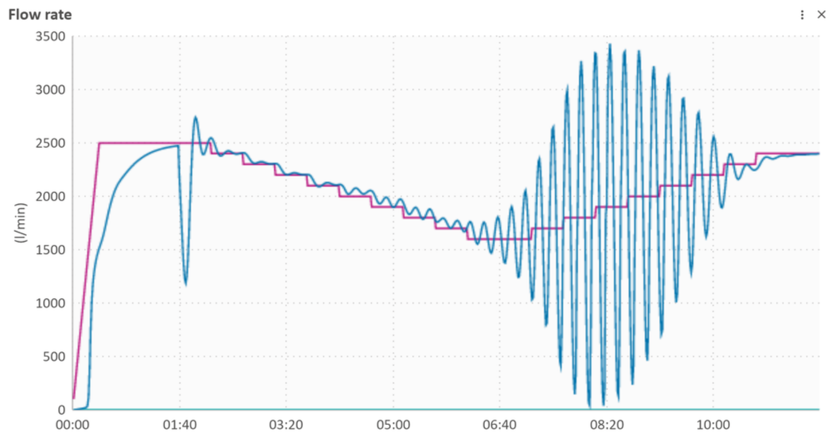
(a) Pump rate in the 5000-meter well being adjusted



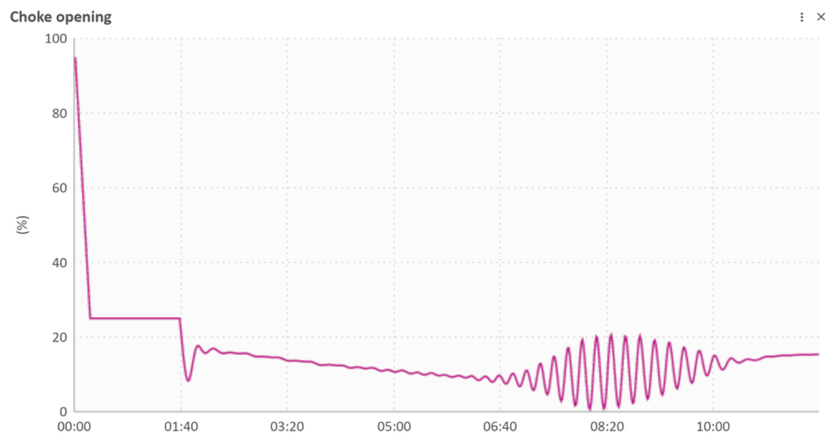
(b) Bottomhole pressure during the sweep

Figure C.2: Figure (a) shows the varying flow rate in the well, while Figure (b) shows how the bottom hole pressure changes as a result. The controller handles the difference in flow rates well but some disruptions can be seen. Illustrations from the Openlab simulator.

C3 - Flow sweep for 2500-meter-values in 5000-meter well



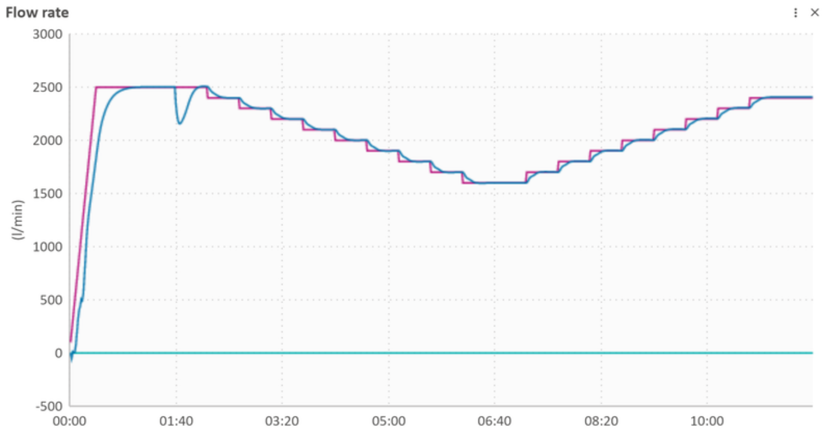
(a) Pump rate in the 5000-meter well being adjusted. Pump rate showing as the gradually adjusting purple line, while the unstable blue line shows the flow rate out of the well.



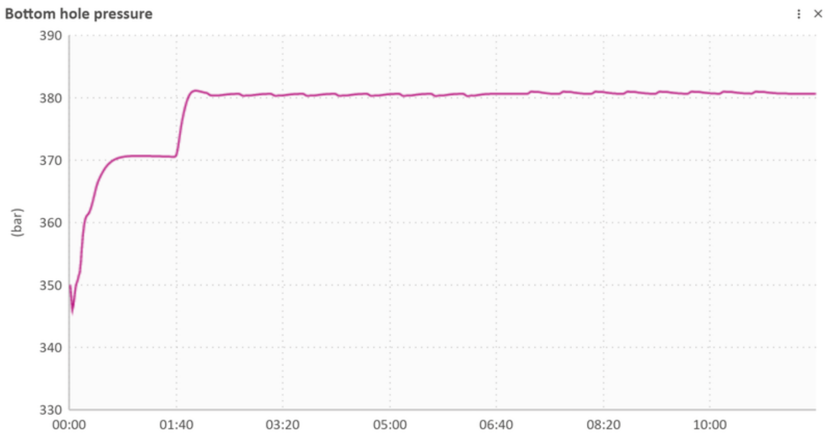
(b) Choke opening during the sweep expressed in percentages.

Figure C.3: Figure (a) shows the varying flow rate in the well, while Figure (b) shows the opening of the MPD choke in percent. There are noticeable disturbances below 2000 L/min pump rate. Illustrations from the Openlab simulator.

C4 - Flow sweep for adjusted 2500-meter well



(a) Pump rate in the 2500-meter well being adjusted



(b) Bottomhole pressure during the sweep

Figure C.4: Figure (a) shows the varying flow rate in the well, while Figure (b) shows how the bottom hole pressure changes as a result. The process is stable throughout the flow sweep simulation. Illustrations from the Openlab simulator.