Universitetet
i Stavanger

**Faculty of Science and Technology**

# MASTER'S THESIS

| | |
|---|---|
| Study program/ Specialization:<br>Msc Petroleum/Drilling & Well Technology | Spring semester, 2013<br><br>Open access |
| Writer::<br>Stian S. Borgersen | ………………………………………… (Writer's signature) |
| Faculty supervisor:<br>Gerhard Nygaard<br><br>External supervisor(s): | |
| Title of thesis:<br><br>*Influx Attenuation During MPD Operations* | |
| Credits (ECTS):<br>30 | |
| Key words:<br>*Influx attenuation* | Pages: 58<br><br>+ enclosure: 22<br><br>Stavanger, 16/6/2013<br>Date/year |

## 1.1 Introduction

### Introduction

Automation in the drilling industry is the background for this thesis. More preciously, it is to find new automatic methods for controlling and circulating out reservoir influxes in a wellbore. *Influx Attenuation* is a term that relates to an automated well control procedure for a kick or influx.

This thesis presents a method for automatically attenuating a kick taken during drilling. This method is referred to as "*Influx Attenuation*". An influx attenuation controller is tested and run in MatLab for various scenarios involving a well taking a kick. The influx attenuation approach was finally tested at a small scale laboratory test rig at the University of Stavanger. These tests proved the *influx attenuation* approach successful of attenuating influxes coming into the experimental test rig.

A litterateur study of proposed new automatic well control procedures has also been performed. The main focus of the literature study was on automatic well control, and more specifically the term "*Influx attenuation*" was looked into.

## 1.2 Acknowledgements

Thanks to:

I would like to thank my fellow students for five excellent years at the University of Stavanger. A good working environment with room for humor and discussion was much appreciated both during this thesis and the previous years at UiS.

A big thank to Sivert B. Drangeid for his help with various technical and practical problems encountered at the laboratory during the thesis work.

I would also like to address my gratitude to Professor Gerhard Nygaard for providing me with this thesis and for his help with Matlab and technical assistance on the test rig during the thesis.

## 1.3 Abstract

When a kick incident occurs on an offshore drilling rig today, the conventional well control procedures involves and relies on human skills and experience. Everything is done manually and the risk of human errors is always present.

In the world of drilling, automation will become more and more common over the next years to come. Other industries such as the aviation industry have implemented automation with great success and used it for many decades already. Automation can prove very useful in the field of well control. E.g., small influxes can be automatically controlled and circulated out of the wellbore without the interference of humans.

Such new automatic procedures come with benefits in form of e.g. decrease in the non productive time, and can provide a higher level of safety on a drilling rig. Automation can thus prove positive in both economical and HMS matters. To be able to get automation into the world of drilling and well control, it will require changing the whole mindset of the industry. Such a reform will challenge the already established well control strategies. The first step towards being able to start such a transformation towards automation, will be to prove successful test results from serious and promising automation research projects.

This thesis presents an automatic well control procedure tested on a small scale well model at UiS.

# Table of Contents

## 1.4 Nomenclature

| | |
|---|---|
| MPD | Managed Pressure Drilling |
| RCD | Rotating Control Device |
| BHP | Bottomhole Pressure |
| ROP | Rate Of Penetration |
| PID Controller | Proportional Integral Derivative Controller |
| MPC | Model Predictive Controller |
| NPT | Non Productive Time |
| BOP | Blowout Preventer |
| WCV | Well Control Valve |
| SIDDP | Shut In Drill Pipe Pressure |
| SICP | Shut In Casing Pressure |

# 2 THEORY

## 2.1 MPD – Managed Pressure Drilling

The IADC (2011) [1] defines MPD as; "*Managed Pressure Drilling (MPD) - an adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore. The objectives are to ascertain the downhole pressure environment limits and to manage the annular hydraulic pressure profile accordingly. It is the intention of MPD to avoid continuous influx of formation fluids to the surface. Any influx incidental to the operation will be safely contained using an appropriate process.*"

The managed pressure drilling technology is a closed wellbore circulation system. (A conventional drilling system can be thought of as an open loop circulation system.) The annulus is closed off with a piece of equipment called RCD – rotating control device. The RCD is the key to making a closed loop circulation system possible. MPD technology allows for quick changes of the bottomhole pressure in a wellbore and can therefore provide very good pressure integrity in the well. The technology of managed pressure drilling has thus opened up for drilling targets that have been unavailable with conventional drilling technology. This can be targets with a very narrow pressure window, e.g. a depleted reservoir. A narrow pressure window means very small differences between the pore pressure and the fracture pressure of the surrounding formation. In such cases there will be a great need for accurate control of the bottomhole pressure to avoid serious well control incidents. This quick and precise control of pressures in the well is one of the advantages with MPD. [2]

In conventional drilling operations the downhole pressure is mainly controlled through the rate of circulation and by manipulating the mud weight, but in MPD this can be done by applying additional pressure to the system. A common way of doing this is with the use of a choke manifold connected to a back pressure pump system. This back pressure system will help maintaining the flow through the choke, and thus pressure can be applied to the well both when circulating and when the well is in static conditions. Full pressure integrity can therefore be ensured during e.g. connections when the main pumps are shut off. A MPD system with a back pressure pump can be seen below in figure 1. [2]

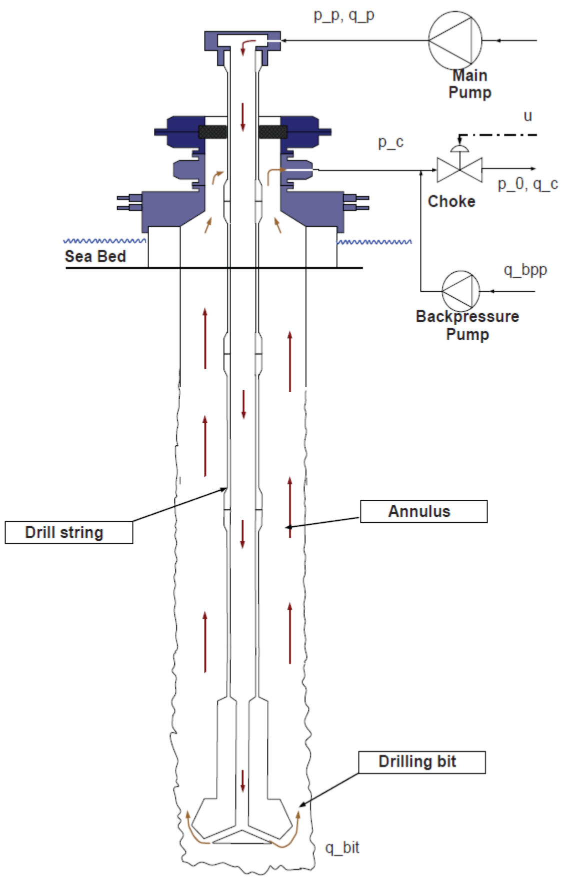


Figure 1: Sketch of a MPD system [3]

A MPD system with a back pressure pump installed, gives the following equation for the bottomhole pressure during circulation:

$$\text{MPD BHP} = P_{HS} + P_{AF} + P_{BPP} \tag{2.1}$$

$P_{HS}$ = Hydrostatic pressure in the well

$P_{AF}$ = Pressure in the well due to annular friction when circulating

$P_{BPP}$ = Pressure applied from a back pressure pump

$$\text{Conventional BHP} = P_{HS} + P_{AF} \tag{2.2}$$

The bottomhole pressure during static conditions in the well is given by the following equation. During static conditions like e.g. connections, there will be no frictional pressure in the well, but the back pressure system can compensate for this:

$$\text{MPD BHP} = P_{HS} + P_{BPP} \tag{2.3}$$

$$\text{Conventional BHP} = P_{HS} \tag{2.4}$$

With MPD there are also other advantages, such as less differential pressure in the well. (Not so much overbalance when drilling) This is something that can result in higher ROP (rate of penetration) because the cutting transport will be easier from around the bit.

One of the biggest advantages with the MPD technology is the better accuracy in pressure and flow rate monitoring. This makes it possible to get real time monitoring of well conditions. Now the driller has the ability to better control deviation from expected behavior of flow and pressure. MPD technology therefore makes it possible for more rapid reaction that can avoid normal drilling problems from escalating. This can thus reduce the non productive time, NPT, on a drilling rig significantly. [2]

There are several different methods of MPD. Some are listed below;

Returns Flow Control

Constant BHP (CBHP)

Dual Gradient (DG)

Backpressure system

Pressurized Mudcap Drilling (PMCD)

## 2.2 Kick or Influx

A kick is an unwanted influx of formation fluid into the wellbore. If such an influx is not acted upon and attenuated in a controlled manner, a kick can develop into a blowout which can lead to severe damage to equipment, environment and people. A kick can occur when the pressure in the wellbore is lower than the pressure of the surrounding formation. If this scenario takes place in a porous and permeable formation that contains fluids, it can lead to a situation where the pressure in the wellbore no longer can withstand the pressure from the fluids in the surrounding formations and eventually the formation fluids will flow uncontrolled into the wellbore. [4] [5]

### 2.2.1 Reasons for kicks/influx

There are several reasons for a kick to occur, (some are listed below.) [4], [5]

- Insufficient mud weight
- Refill of mud during tripping
- Swabbing
- Lost Circulation
- Abnormal pressures

- Insufficient mud weight
  A kick taken because of insufficient mud weight – is called an underbalanced kick. That means that the hydrostatic pressure of the fluid column in the well is lower than the formation pressure of the surrounding formation and thus the formation fluid can flow out into the well.

- Refill of mud during tripping

  While tripping out of the well the wellbore must be refilled with mud to compensate for the steel (volume) that is being removed. If this for some reason is not done, it could lead to a scenario where there is not enough mud in the well to withstand the formation pressure and in turn lead to a reservoir influx/ kick.

- Swabbing

  While tripping out of the well the drill string will act as a piston. Due to this piston effect a pressure drop will take place in the well. This pressure drop is affected by the tripping speed. The pressure drop may therefore become large enough to result in a kick scenario if the tripping speed is too large.

  There are several parameters that affect the swabbing:

  The two main important factors concerning swabbing is the well bore geometry and the tripping speed (the speed of the pipe moving out of the hole). Well bore geometry is here thought of as annular clearance – difference between outside diameter of pipe being pulled and inside diameter of well bore. The smaller the annular clearance is, the bigger the risk of swabbing will be. (Due to a larger piston effect) Rheological properties such as fluid density, viscosity and gel strength will also affect the swabbing.

- Lost Circulation

  A lost circulation situation can occur due to several reasons. Large pressures due to too high mud weight or too high ECD can simply fracture the formation and result in losses. Drilling into a formation with very low pressures can also give the same result. Too fast tripping in speed can cause surge pressure exceeding the formation pressure resulting in losses. But regardless of the reason, a lost circulation event will result in a situation where the fluid level in the well along with the hydrostatic pressure will drop. The bottomhole pressure will therefore also drop, and should it drop below the formation/pore pressure the well can possibly kick.

The same factors regarding the swabbing effect will also be valid for the effects of surge pressures in the well bore. The annular clearance along with the tripping in speed will have great effect on the surge pressure.

- Abnormal Pressures

  When drilling, one tries to keep the downhole pressure in the well between the formation/pore pressure and the fracture pressure. But sometimes one can drill into a high – or low pressurized formation zone. If drilling into an over-pressured zone, the well might kick if the pore pressure exceeds the pressure in the well. For the case of drilling into a under pressured zone, it can as mentioned above, lead to a lost circulation situation which may induce a reservoir influx.

### 2.2.2 Detection of reservoir influx

There are several indications of a possible kick, reservoir influx during drilling, such as:

- Increase in flow rate
- Increase in mud pit volume
- Change in Pump Pressure
- Positive drill break/Increase in ROP
- Decrease in standpipe pressure
- Delta flow change
- Decrease in mud weight
- Well flow with pumps shut off

**Warning signs of kicks** [4],[5]

Increase in flow rate out of the well can be the result of an influx of formation fluids helping the mud up the annulus and out the well. This is a primary kick indicator.

Increase in mud/ pit volume can be the result of an influx displacing some mud volume in a flowline. If there is not any surface controlled operations that could lead to the pit volume increase, this is a primary kick indication.

A change in the pump pressure is a primary kick indicator. Due to influx of formation fluids, the mud can flocculate and cause an increase in the pump pressure. With time the influx will displace the mud and the pump pressure may therefore decrease.

A positive drill break or a sudden increase in "rate of penetration", ROP, is a secondary kick indicator. Gradually increases in ROP are often seen if abnormal pressure should occur and is therefore not a kick indicator. Such a sudden increase in ROP is interpreted as a change in the geological formation when drilling. The new type of formation is assumed to be a potential kick zone. A positive drill break is in other words merely an indication that the new formation has the potential to cause an influx situation.

Delta flow change – if the volume going out of the well is larger than the volume being pumped into the well, it could mean that a possible influx situation is occurring.

Decrease in mud weight can sometimes lead to a kick. The decrease in mud weight is often caused by cuttings containing gas. Such gas cuttings fortunately have little effect on the bottomhole pressure, but can as mentioned sometimes lead to a kick situation.

Well flow with rig pumps shutdown: When the mud in the well bore continuous to flow out of the well even though the rig pumps are off, it is a clear indication of a kick. (Exception: when mud in the drill pipe is considerably heavier than in the annulus)

## 2.3 Well Control

Well control involves the different procedures/techniques applied to prevent influx of formation fluids into the wellbore. The term well control can be divided into two main groups; Primary, and secondary well control.

**Primary well control**

This is the process which involves keeping the hydrostatic pressure in the wellbore between the pore pressure and the fracture pressure. The correct pressure is achieved by manipulating the density of the mud column. [6] [7]

**Secondary well control**

If primary well control should fail, secondary well control is activated. This is done by closing the BOP – blow out preventer, sealing of the well to prevent the fluids in the well from escaping. [6] [7]

### 2.3.1 MPD and Well Control

MPD can offer different improvements to conventional drilling when it comes to well control:

- Earlier kick detection [10], [11]
- Improved kick management [9], [14]
- Better BHP control [2]
  - Quick reduction of BHP in case of losses
  - Quick increase with backpressure system

The BHP control related to MPD comes from the ability to manipulate the topside choke and pumps. This will more easily give control of the annular pressure during drilling operations. Earlier kick detection and better BHP control means that it is possible to react quicker in case of a kick incident than for conventional drilling. This will reduce the risk of serious well control incidents developing. [2]

### 2.3.2 Shut-in Procedures

If a kick is detected, the conventional procedure is to shut down the main pumps and then perform a "flow check" on the well. This is done to see if any gas or other reservoir fluids have entered the well. If a kick is confirmed, the BOP will be closed and the well will be shut in. (Now the SIDPP and SICP is recorded, which is later used for determining the weight of kill mud).This conventional well control method will remove the frictional pressure drop in the well due to the shutdown of the pumps. The removal of the frictional pressure drop will decrease the pressure downhole and in turn lead to increased influx of reservoir fluids. Due to the closed BOP the increased influx will lead the downhole pressure to rise until it has balanced out the reservoir pressure and the influx will then stop. When the well now is balanced out, the new "kill" mud will be pumped into the well to displace the reservoir influx fluid and to keep the bottomhole pressure at a desired level preventing further influx. [4]

### Hard vs. soft shut down

Grace 2003 [8] describes two methods for shutting in a well; a hard shut-in and a soft shut-in procedure.

In the hard shut in procedure the pumps are shut down and a flow check is performed. (For maximum 15 minutes) If the flow check is positive, the annular preventers are closed with the choke line closed. This hard shut down may lead to pressure waves travelling down the well. This can be a problem in wells with narrow pressure margins, leading to influx or loss situations. On the other hand the hard shut in procedure is faster and will thus result in a smaller influx volume than for the soft shut in procedure. [8] [4]

The soft shut in procedure will as for the hard shut in procedure start by shutting down the pumps and check for flow out of the well. But before closing the annular preventers, the choke is first opened and then after the annular preventers are closed, the choke is closed. This soft shut in procedure will not create the pressure peaks down the wellbore as the hard shut in procedure does, but may lead to higher amount of reservoir fluid to enter the well. [8] [4]

The conventional method of performing a shut-in of the well takes time and allows a lot of reservoir fluid to enter the well. There is room for improvement when it comes to these shut-in procedures. A MPD method opens up for another and more effective way of shutting in a well. It is called the “Dynamic Shut-in Procedure”;

### 2.3.3 Dynamic Shut-in Procedure

This method is presented by Liv A. Carlsen et al. 2008 [9] and is designed for detecting an influx, isolating the wellbore and keeping the BHP constant. This dynamic shut-in procedure will stop an influx by reducing the opening of the choke without having to stop the main pumps. By using an automated coordinated control method, the influx will be displaced while the bottomhole pressure is kept higher than the pore pressure of the leaking formation.

A more detailed look into the procedure: In case of an influx situation the flow out of the well will increase. This means the flow rate through the choke will also increase, and thus the frictional pressure across the choke will now increase. Due to this the bottomhole pressure will increase, and to reduce this effect the choke will be opened by the control system. When a kick is confirmed, the bottomhole pressure will be increased by setting the choke to its original position prior to the influx situation. As a result of this the influx will be reduced. If needed the bottomhole pressure can be further increased by manipulating the choke manifold even more. [9]

The study concludes that by performing the dynamic shut-in procedure, the reservoir influx can be considerably reduced compared to the conventional shut-in procedures.
This is mainly due to that fact that in this shut-in procedure the pumps are not stopped and thus there is no loss of annular friction in the well and a more constant bottomhole pressure can be achieved. [9]

### 2.3.4 Circulation methods

There are two main methods for circulating out a kick from a well. They are listed and explained shortly below. [4]

#### 2.3.4.1 W&W – Wait and Weight method

This method is a *one circulation method*. That means that the influx is pumped out of the well using the kill mud in only one circulation.

First the SIDPP – shut in drill pipe pressure, is recorded. The SIDPP is now used for determining the weight of the kill mud. The mud weight is increased to the needed kill mud weight, and then the influx will be circulated out the well using the kill mud. [4]

#### 2.3.4.2 DM – Drillers Method

The driller's method is a *two circulation method*, which means that the kick influx is first pumped out of the well before the mud weight is increased to kill density.

In the driller's method there is no waiting to weigh up the kill mud. A circulation process starts immediately, with the purpose of displacing the kick influx in the well. When this is done, a second circulation starts. Now the kill mud will be pumped down in the well to stabilize the pressure. [4]

## 2.4 Automation in drilling

The drilling industry is an industry where much of the techniques and procedures still used are old ways of doing things. Things are still done manually by the rig personnel, e.g., well control procedures which are strongly based on experience and interpretation of every situation that may arise. There is nothing wrong in this as long as it works, and it does. But there is room for much improvement. In many aspects of the handling of well control scenarios, from kick detection to shut-in procedures to circulating influxes out of the well bore, there can be time and money saved. But not just time and money is a concern in this matter, also risk during operations and safety of the whole rig and its personnel can be increased with automation.

Take kick detection as an example. Detecting an influx situation can be difficult and often depends on the drillers experience and awareness alone. Such a crucial event should not be left for human interpretation alone to determine. With automated drilling one could reduce the risk of serious influx situations to occur. If a kick can be detected earlier, the influx volume can be reduced, and HSE matters will be increased. There will be less chance of small kicks escalating into more severe incidents, and possibly causing damage or injury to the rig, environment or the rig personnel.

With new technology and automatic procedures there is possible to detect kicks faster than with manual conventional procedures like pit gain etc. [10], [11], [12], [13] Several studies have shown promising results for new and better kick detection procedures. [10], [11], [12], [13] E.g. Don Reitsma 2011, [11], describes a successfully tested method for faster detection of kicks with the use of standpipe pressure and annular discharge pressure.

There is much talk about possible drilling operations in areas with very fragile nature, such as arctic areas. A blowout would have catastrophic consequences in areas like this. With an automated controller comes faster response to a possible influx situation and tighter control of downhole pressure. Godhavn et al. 2011, [3], describers exactly this; how automated control methods can be applied to improve pressure control during MPD operations. With such a controller, drilling in vulnerable areas might be more realistic in near future.

The motivation for automation in drilling can be different from company to company. The potential for improved HSE is absolutely present, and can as mentioned be achieved with earlier kick detection and safer handling of influx situations. But automation will also be able to benefit the economical sides of the drilling industry. By implementing different automated operations or procedures such as earlier kick detection, the NPT on a drilling rig can be reduced, [10]. Reducing the NPT on a drilling rig will result in significant cost savings. In these days with sky high daily rates on the drilling rigs, the economical potential is great. [3]

Thorogood, 2012, describes how automation in aviation has developed and how the drilling industry may learn and benefit from this development. It is described how the drilling industry can learn valuable lessons from mistakes done in aviation, and thus apply this in the development of potential automatic procedures. Several important factors that the drilling industry must bear in mind are listed and discussed in this paper. Such as the risk of degradation of skills of the rig personnel on the account of automation; Thorogood describes that there is a possibility that an increased reliance in automation will result in a degradation of practical and intellectual skills required in emergency situations. A way to prevent such a situation, Thorogood has the following solution: This possible degradation should be counteracted by an increased focus on education, training and recurrent proficiency testing to ensure that the driller retains his or hers “raw skills”. [23]

Over the last years, extensive research involving MPD and automation has been carried out. Especially when it comes to kick detection, downhole pressure control and kick handling [10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, 21, 22] This research (among many other) has proven very promising and can thus open up for new ways for operating and thinking within the field of well control.

### 2.4.1 Influx Attenuation

As mentioned, the conventional procedure when a kick is detected is to stop the main pumps and shut in the well with the BOP. When the pressure in the well is in balance, the influx is circulated out. New heavier mud is pumped down to kill the well, and now the drilling can resume. This is time consuming and a lot of reservoir influx volume is unnecessarily allowed to enter the wellbore. It should therefore be possible to improve current well control procedures related to kick handling.

Another and perhaps safer way to handle an influx situation would be to let an automated system take care of it. No human interaction in form of e.g.; interpretation of different parameters etc during drilling, or manual regulation of the topside choke is needed, and thus eliminating the risk of human errors. The rig personnel would not need to perform regular procedures in case of any small influx situation should occur, because an automated system would detect it, circulate it out and balance the well before it could develop into something more serious.

Several studies have shown interesting results in attempts to improve the conventional methods of well control. [9, 15, 20, 21, 22] The term influx attenuation is a relatively new term used in the field of well control. Basically it means a way to control and circulate out any influx detected in the wellbore. This is to be done automatically by an automated *influx attenuation* control system.

In three papers by Jing Zhou et al., 2009, 2010 and 2011, a method that automatically will attenuate an influx without shutting down the main rig pumps is presented. The paper from 2011 [22] called ”*Switched control for Pressure Regulation and Kick Attenuation in MPD systems”*, utilizes a controller that uses the choke valve and a backpressure pump to control the BHP and reservoir influxes. The control algorithm is a switched control scheme which will switch between two different controllers depending on the situation in the wellbore. During normal operations, a pressure controller will be active. This particular mode will control the annular pressure in the well and thus keeping the BHP around a desired pressure, $p_{ref}$. Whereas if a situation with pressures in the wellbore exceeding the $p_{ref}$ and a reservoir influx should be detected, a kick handling mode will be activated. This mode is a pure flow controller, which will provide a way to attenuate the kick so that the influx from the reservoir stops. [22]

This automated influx attenuation method was tested on “WeMod” - a drilling simulator developed by the International Research Institute of Stavanger (IRIS). Simulations with conventional well control response, (shut down rig pumps etc), were also performed. When comparing the results for these two methods, the automated influx attenuation approach showed significantly lower gas influx than for the conventional well control procedure. This can be seen in figure 2 and 3 below. (Notice the different scale of the y-axis in the two plots.) This new procedure is also able to keep a more constant BHP than conventional procedures are. [22]

With conventional procedures, it takes more time to control an influx than with the proposed influx attenuation procedure. This is due to the mud pumps being shut down and a delay before closing the choke.  The time the new influx attenuation procedure saves is contributing to the reduced amount of reservoir influx volume entering the well. [22]

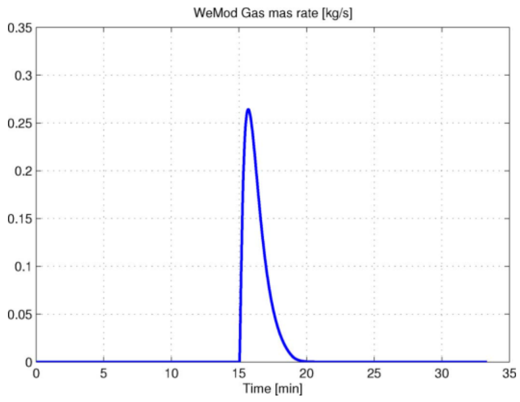


**Figure 2. Graph showing the gas influx for the proposed *influx attenuation* procedure [22]**

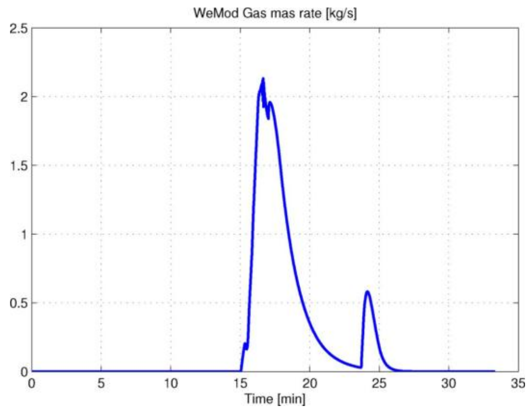


**Figure 3. Graph showing the gas influx for the conventional procedure. [22]**

## 2.5 Control Theory

Control theory is a way to represent dynamical systems with inputs. To be able to control and get the wanted reactions on the output of a system, a controller can manipulate the inputs to the system. These inputs are called *reference*. [24]

The purpose of a control theory is to create stability in the system. That means that the system is able to stay at a desired set point, and not drift away from it. [24]

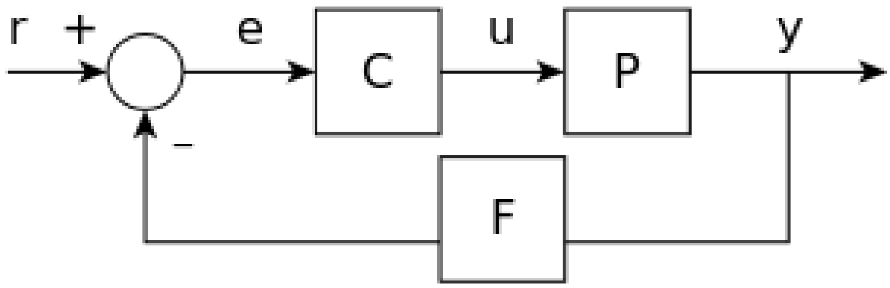


Figure 4. A feedback controller[24]

where *r* is reference, *e* is error – the difference between the reference and the measurement, *C* is the controller, *u* is controller output or manipulated variable (MV), *P* is the process, *y* is the controlled variable (CV) and *F* is the feedback. [24]

### 2.5.1 PID – Proportional, integral and derivative controller.

"A proportional – integral – derivative controller, PID controller, is a generic loop feedback mechanism widely used in industrial control systems." [25] Such a PID controller will calculate the difference between the desired setpoint (SP) and a measured process variable (PV). This difference is called the "error". By adjusting the process control input, the controller can minimize this error. [25]

The PID controller consists of three parameters; the proportional *P*, the integral *I*, and the derivate *D*. The three different parameters are related to different errors; *P* is related to the present error, *I* to the sum (accumulation) of past errors, and *D* to future errors. [25]

To compute the output of the PID controller, all of the controller terms, (*P*, *I* and *D*), are summed to form the following algorithm: (eq. 2.5)

$$u = u_0 + K_p e + \frac{K_p}{T_i}\int_0^t e d\tau + K_p T_d \dot{e} \qquad (2.5)$$

where $u_0$ is the actuator bias, $K_p$ is the proportional gain, $T_i$ is the integral time and $T_d$ is the derivative time.

The following algorithm is an alternative form of eq. 2.5:

$$u = u_0 + K_p e + K_i \int_0^t e d\tau + K_d \dot{e} \qquad (2.6)$$

where $K_p$ is the proportional gain, $K_i$ is the integral gain and $K_d$ is the derivative gain. [25, 26]

### 2.5.2 PI – controller

Not all of the three terms in the PID controller are always needed to achieve proper system control. The PID controller can now be called a PD, PI, P or I controller depending on the terms not present. To create such a controller, the other terms are set equal to zero. A PI – controller as used on the test rig at UiS, is a "PID controller" where the derivative (D) of the error is not used. This is a common controller due to the fact that the derivative parameter is sensitive to measurement noise. [25]

The controller used on the test rig at UiS is as mentioned a PI controller. There is one PI – controller with fixed parameters, and another which uses "gain scheduling" to estimate the regulation parameters. The gain scheduling regulator was used during experiments on the rig due to the fact that the process is nonlinear and a PID controller is a linear controller.

The controller output is given by, [25]

$$K_P\Delta + K_i \int \Delta \, dt \tag{2.7}$$

where Δ is the error or deviation of actual measured value (PV) from the setpoint (SP).

$$\Delta = SP - PV \tag{2.8}$$

### 2.5.3 Feed Forward Control

Due to the fact that the PID controller is a feedback controller using constant parameters and that it has no direct knowledge of the given process, will affect the performance of the controller. [25] So, to achieve improved control properties and performance, model knowledge will be needed. To attain this, a “feed forward” control can be applied. A feed forward controller is used whenever a known disturbance or a change in the reference value is the case. Preferably a feed forward term should comprise a model of the process. [26]

There are typically two main forms of feed forward control; feed forward from disturbance and feed forward from the reference. Below is eq. 2.9, the PI – controller with a feed forward term:

$$u = u_0 + K_p e + \frac{K_p}{T_i}\int_0^t e d\tau + K_{fd}\, d + K_{fr}\, \dot{r} \tag{2.9}$$

where $K_{fd}$ and $K_{fr}$ is the feed forward terms from the disturbance and the reference respectively. [25]

### 2.5.4 MPC – Model Predictive Control

MPC, short for Model Predictive Control, is a more sophisticated method of process control. (MPC has been used in the process industries such as chemical plants and oil refineries since the 1980s, [27].) MPC is commonly used for representing complex dynamic systems. Where simple PID controllers are not sufficient, the more compound nature of the MPC controllers can be required to give satisfactory control of a system. Such systems that may require a MPC controller can include large time delays and high-order dynamics. [27]

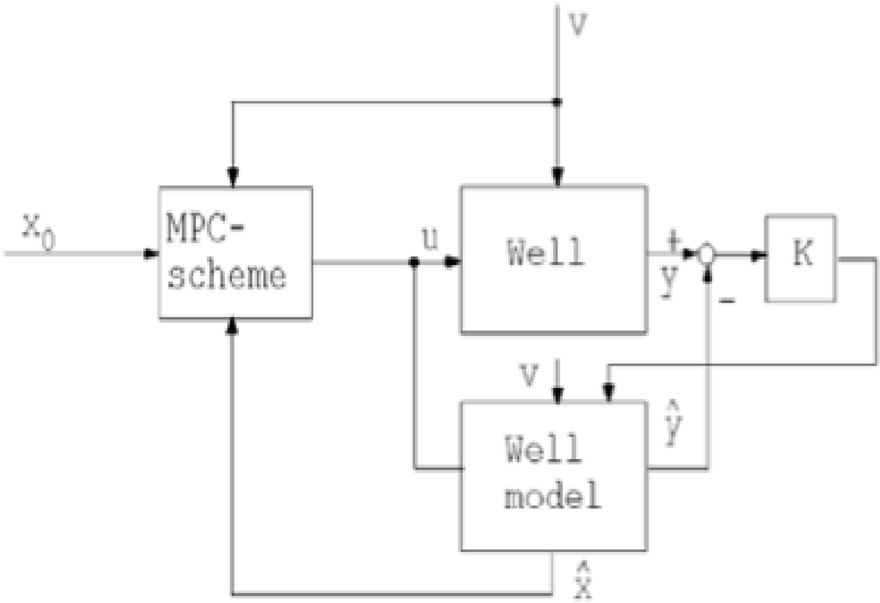


Figure 5. Non linear MPC scheme. [19]

The MPC will use a model to predict the future behavior of a system. The prediction will be based on adjustments of the input variables and how these adjustments or changes will affect the output variables of the system. [27]

MPC models can be linear or non linear depending on the exact purpose they are designed for. When the process is non linear, there can often be a mismatch between a linear model and the process. This results in a situation where the model no longer can represent the process effectively. In such a situation, the MPC can use a non linear model to more precisely control the system. [27]

Several studies have shown that Model Predictive Control efficiently can be used for automation purposes in well control, [16], [17], [19], [28]. These studies have proved MPC to be successful in achieving better control of the bottomhole pressure in the wellbore.

E.g. Nygaard et al. 2007 used a dynamic control model that incorporates MPC to control the BHP during drilling operations. Control of the BHP was achieved by controlling the choke settings during both drilling and pipe connections. Controlling the choke setting during pipe connections can be of great significance. A choke set with too much opening might cause a reservoir influx situation, where a choke setting with too low opening can lead to an unwanted overpressure in the well. The tight control was made possible by the dynamic model's opportunity to predict the future behavior of the well, providing an optimal choke setting that could be selected in advance. The paper gave positive results for the proposed MPC control methodology. [16]

Breyholtz et al. [28] also describes successful use of an MPC application. The study concludes the following: "The ability of MPC to control both hook position and BHP through coordinated manipulation of mud-pump flow rate, sub-sea-pump flow rate, and drillstring velocity, while satisfying various important constraints, was demonstrated on computer simulations." [28]

## 2.6 The Kaasa model

The Kaasa model is a simplified dynamic wellbore model which is based on the assumption that there is uniform flowrate and density throughout the drillstring, and that the flow in annulus is uniform along the whole length of the annulus. This gives the possibility of dividing the wellbore into two separate compartments with different dynamics; the drillstring and the annulus. [26]

The Kaasa model uses the pump pressure to regulate the BHP. Using the pump pressure instead of the choke pressure can be beneficial. This is due to the difficulty related to estimating the density and the friction factor in the annulus. The annulus contains mud, reservoir fluid and cuttings which all affect the density of the fluid there. The annulus can vary from open hole solutions to cased and perforated, and it can therefore be difficult to estimate a friction factor for the annulus. When using the pump pressure one does only need to think about what is inside the drill pipe, which is drilling mud with known rheological properties. However, the bottom hole assembly will introduce challenges when estimating friction pressure, but this can be recorded prior to drilling. [26], [29]

The Kaasa model is composed of the following equations: [26]

$$\dot{p}_p = \frac{\beta_d}{V_d}\left(q_p - q_b\right) \tag{2.10}$$

$$\dot{p}_p = \frac{\beta_a}{V_a}\left(q_b + q_{res} + q_{bpp} - q_c - \dot{V}_a\right) \tag{2.11}$$

$$\dot{q}_b = \frac{1}{M}\left(\left(p_p - p_c\right) - \left(F_d + F_b + F_a\right) {q_b}^2 + \left(\rho_d - \rho_a\right) gh\right) \tag{2.12}$$

$p_p$ = pump pressure

$p_c$ = choke pressure

$q_p$ = pump flowrate

$q_b$ = flowrate through the bit

$q_{res}$ = flowrate from the reservoir

$q_{bpp}$ = flowrate from the back pressure pump

$q_c$ = flowrate through the choke, $q_c$ is given by equation 2.13:

$$q_c = z_c k_c \sqrt{\frac{p_c}{\rho_a}} \quad (2.13)$$

where

$z_z$ = choke opening

$k_c$ = choke parameter (constant)

$p_c$ = choke pressure

$\rho_a$ = density of the fluid contained in the annulus

Wellbore parameters;

$\beta_d$ = bulk modulus of the drill string

$V_d$ = volume of the drill string

$\beta_a$ = bulk modulus of the annulus

$V_d$ = volume of the annulus

$F_d$ = friction coefficient for the drill string

$F_b$ = friction coefficient for the bit

$F_a$ = friction coefficient for the annulus

$\rho_d$ = density of the fluid contained in the drill string

$\rho_a$ = density of the fluid contained in the annulus

"$\rho_d$ and $F_d$ are considered known, $\rho_a$ and $F_a$ are unknown due to the complex nature of the fluid properties in the annulus caused by unknown reservoir influx, $q_{res}$, as well as unknown properties of cuttings and the well wall." [20]

The Kaasa model is based on dividing the wellbore system into two control volumes: one for the drill string and one for the annulus. Figure 6 below shows a schematic drawing of the two control volumes considered.

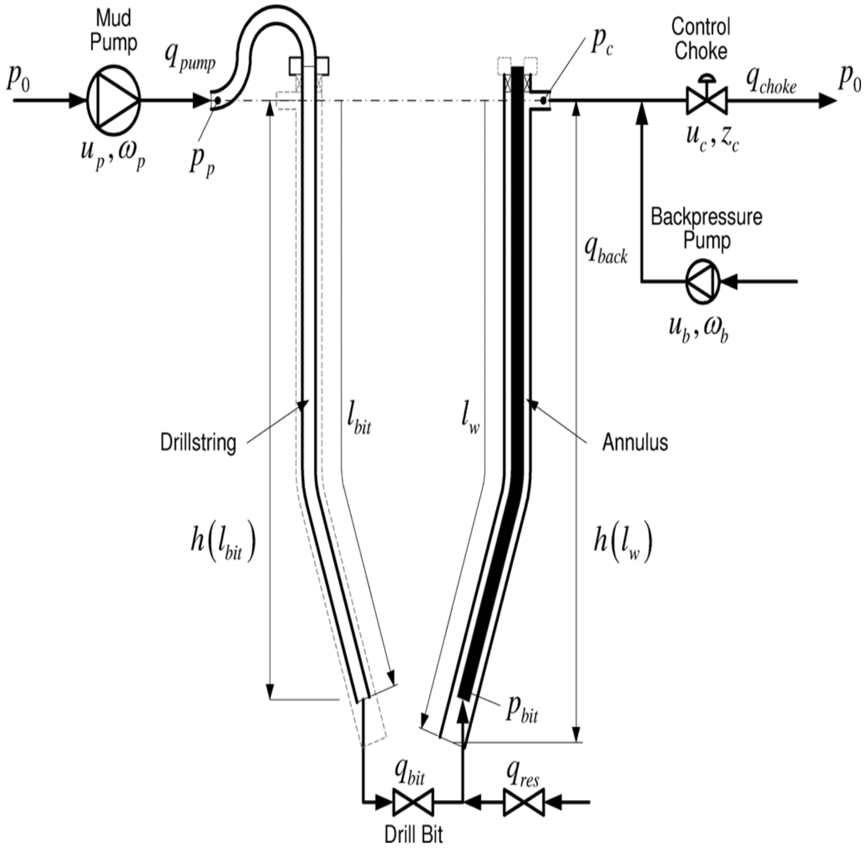


Figure 6. "A simplified schematic drawing of the drilling system" [22]

# 3 Influx attenuation model in Matlab

A model intended to automatically control and attenuate influxes in a wellbore was created in MatLab. This model is called *influx attenuation.* It is a simple mathematical model based on the Kaasa model mentioned in the previous section. The model simulates a MPD operation with a back pressure system installed. It uses the choke pressure as reference for regulating the process and has two main features; a controller used for regulating the downhole pressure during drilling and an additional influx attenuation control. The following differential equations are used in the model:

Pump pressure:

$$\dot{p}_p = \frac{\beta_d}{V_d} (q_p - q_b) \qquad \text{(eq. 3.1)}$$

Flowrate through bit:

$$\dot{q}_b = \frac{1}{M} \left( \left(p_p - p_c\right) - \left(F_d + F_b + F_a\right) {q_b}^2 + (\rho_d - \rho_a)\, gh \right) \qquad \text{(eq. 3.2)}$$

Choke pressure:

$$\dot{p}_c = \frac{\beta_a}{V_a} (q_b + q_{res} + q_{bpp} - q_c) \qquad \text{(eq. 3.3)}$$

Flowrate through choke: $q_c = z_c k_c \sqrt{\frac{p_c}{\rho_a}}$ (eq. 3.4)

The model is a PI feedback controller with a feed forward term; feed forward from disturbance. This controller incorporates an Euler integration loop to solve the differential equations. (The controller code can be found in the Appendix A.1 and A.2)

A time delay is added to the pump flow rate to compensate for the time it takes for the mud to go through the whole well. This delay is estimated to about 6 seconds. The added delay gives a more correct and realistic picture of the downhole situation.

An estimate of the reservoir influx is calculated by taking the flowrate through the choke and subtracting the delayed rig pump flowrate together with the back pressure pump flowrate. This gives the equation:

$$q_{res}(estimated) = q_{choke} - q_{pump(delay\ 6s)} - q_{back\ presure\ pump} \quad \text{(eq. 3.5)}$$

The influx attenuation controller is activated when this estimated reservoir influx exceeds a certain value. This value is set to 50 l/min. When the influx is detected the regulator will start manipulating the MPD choke to regulate the choke pressure up to a point where reservoir influx is no longer detected. A safety margin of 5 bars is added to the choke reference pressure after an influx is detected the first time. That means after the influx attenuation controller has been activated the first time, there will be added 5 bar to BHP to prevent further influx situations.

**Scenario 1**

In this scenario a kick is taken during drilling due to a reduction in the rig pump rate. The pump rate will be reduced down to a rate of 1,000 l/hr after t = 300 seconds, which will generate an influx. The pump is never shut completely down during the scenario, but keeps the rate of 1,000 l/hr constant through the rest of the simulation. The controller will successfully control and circulate the influx of the well in approximately 180 seconds after detection, at t ≈ 480 s. This can be seen in figure 8 below.

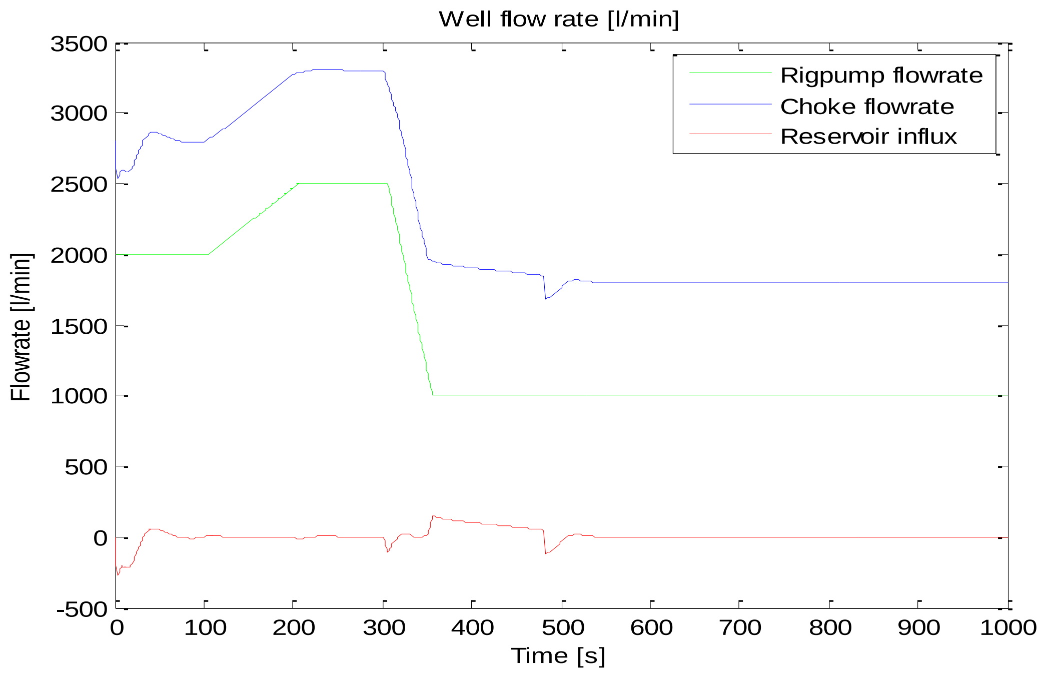


Figure 7. Well flow rates during scenario 1.

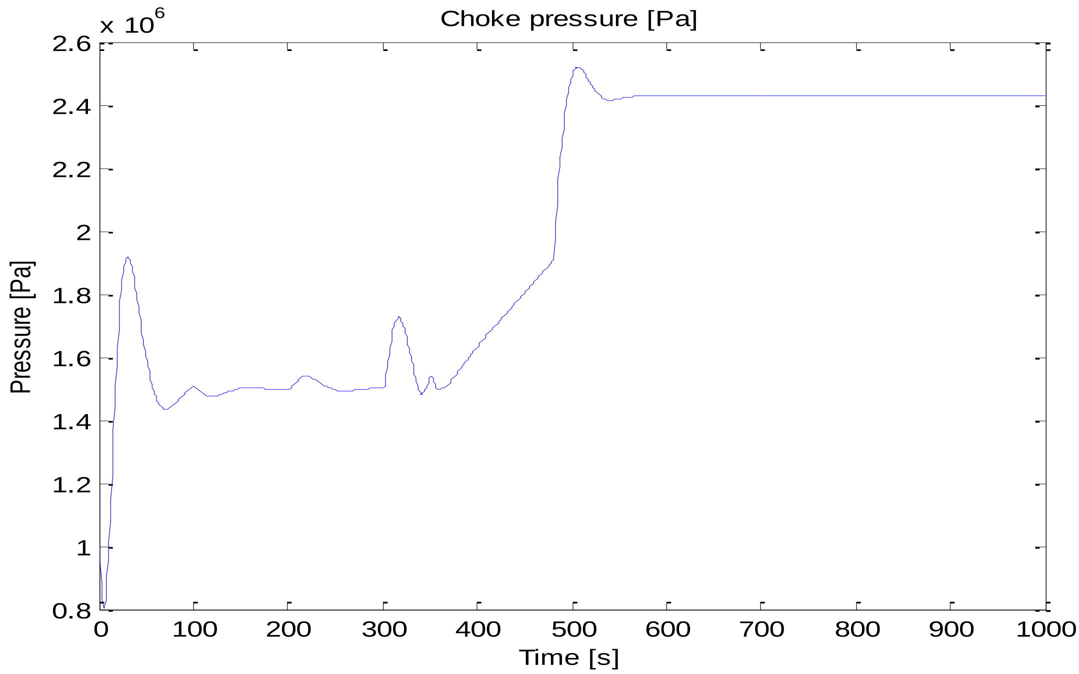


**Figure 8. Choke pressure plot scenario 1.**

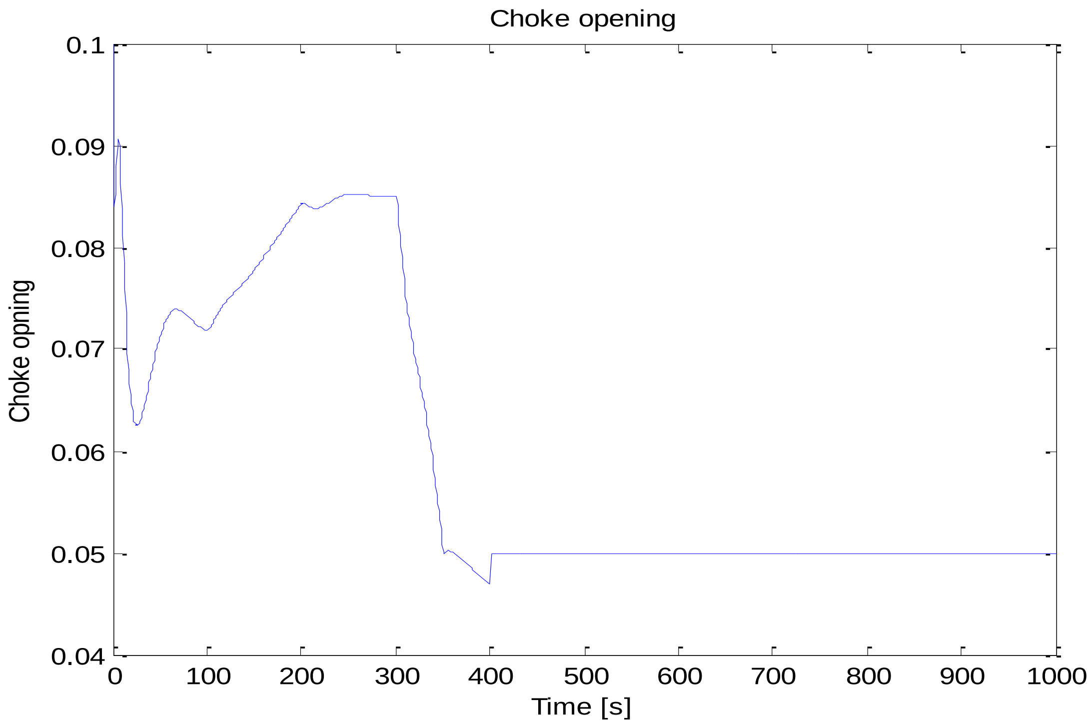


**Figure 9. Choke opening scenario 1.**

From figure 8 and 9 one can see that after the influx is detected at $t = 300$ s the controller is successfully increasing the choke pressure rapidly by closing the choke. The controller increases the choke pressure until the influx is properly attenuated at $t \approx 480$ s. The choke pressure is added 5 bar as a safety margin to prevent the well from further influx situations.

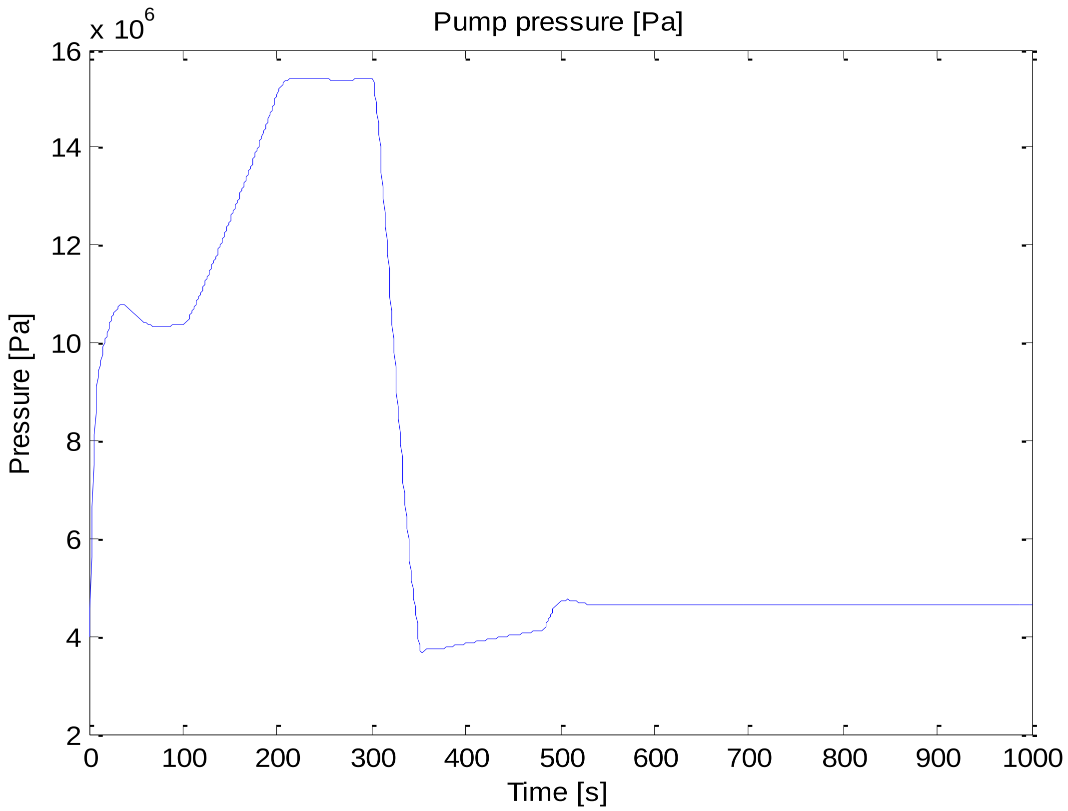


Figure 10. Pump pressure plot – Scenario 1

Figure 10 shows that the pump pressure throughout the simulation, and as one can see, the pump is never shut down during the influx situation. After the pump rate is decreased leading to an influx at $t = 300$ s, the pump pressure is constant due to the constant pump flow rate. This is a contributing factor to the influx being attenuated so quickly. A conventional procedure would have shut down the pump and the BHP would decrease and allowed more reservoir influx into the well. This is prevented with the use of this influx attenuation model.

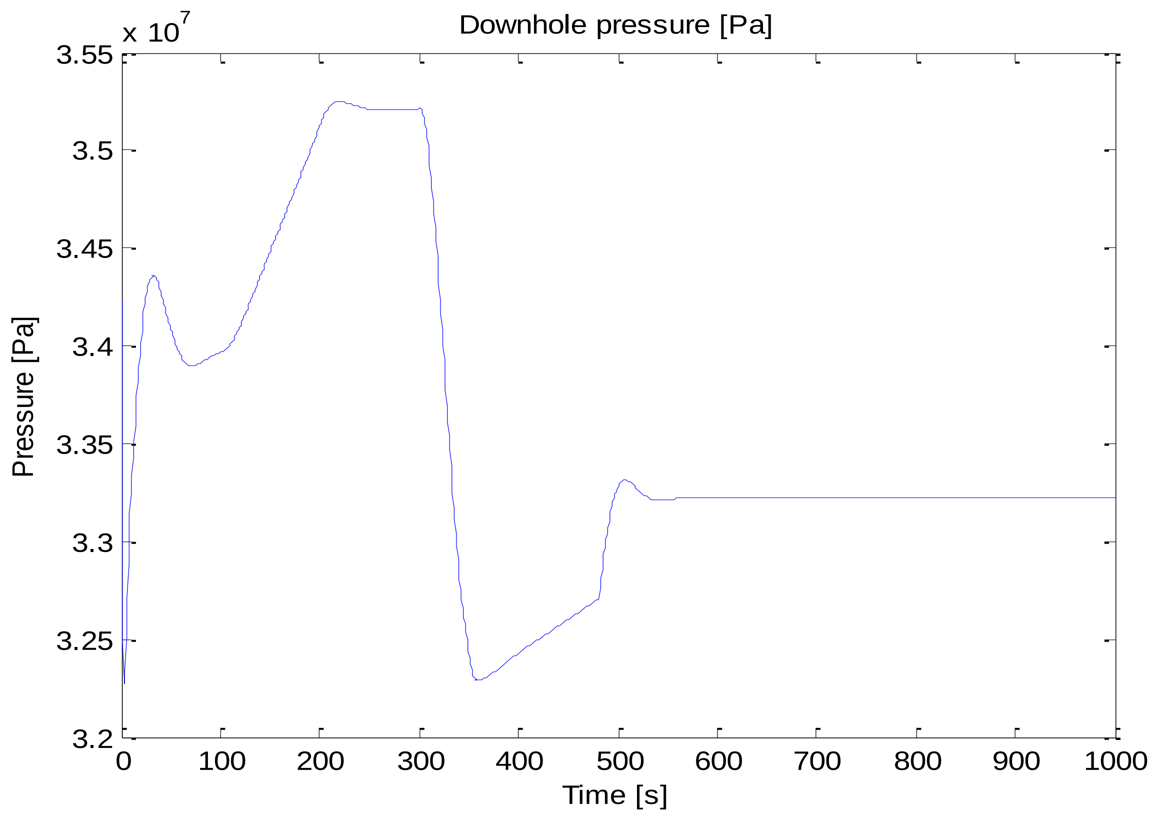


**Figure 11. Downnhole presssure/BHP - Scenario 1**

Figure 11 shows the BHP during scenario 1. The BHP is greatly reduced at t = 300 seconds due to the decrease in the pump rate. The regulator manages to restore the pressure balance in the well with the use of the choke. After the influx is circulated out, after t = 480 s, the BHP is held constant for a while before resuming drilling.

The influx attenuation model generated in MatLab proved successful in attenuating the influx generated from the decrease in pump flow rate.

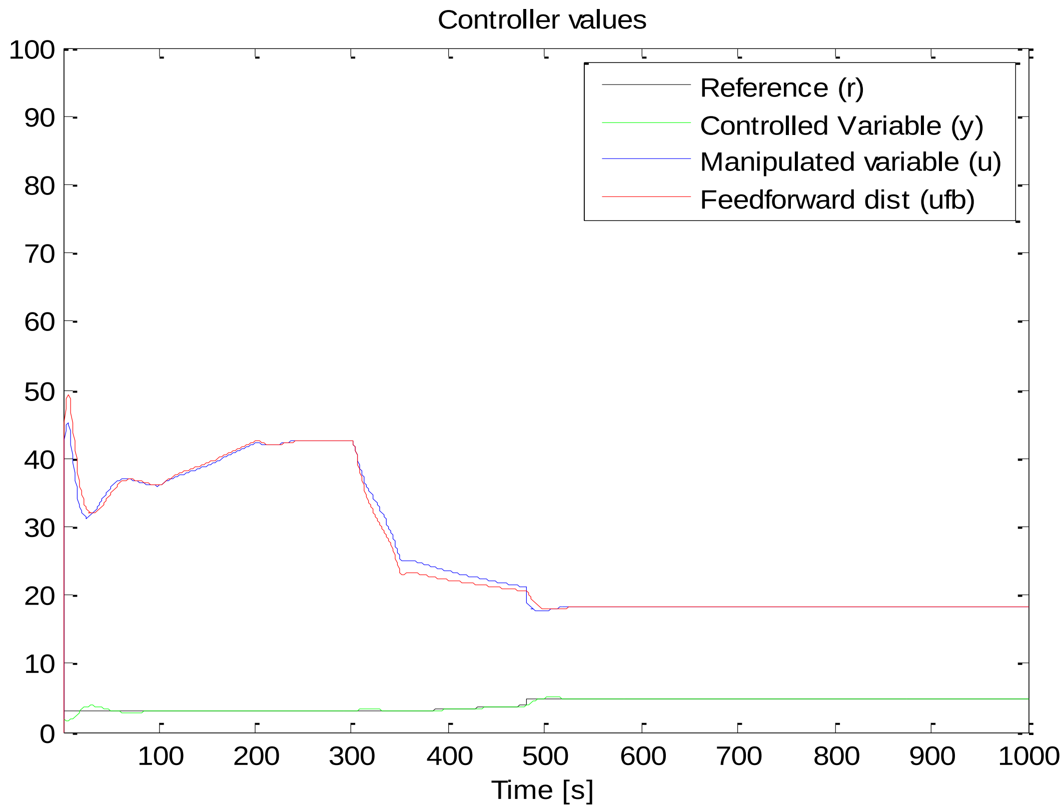


**Figure 12. Controller values scenario 1.**

Figure 12 shows that the controller is quite accurate. The controller is successfully capable of regulating the choke pressure towards the reference pressure. Also one can see that the feed forward and the manipulated variable are fairly accurate. This clearly shows that the controller used in the influx attenuation model is capable of providing good and accurate system control.

**Scenario 2**

In scenario 2 the rig pump flow rate is not reduced, but another incident occurs that induces an influx situation. During drilling, a high pressurized gas zone is hit after t = 320 seconds. This will result in a severe influx situation. Controlling this situation takes a little longer than the previous one in Scenario 1. Approximately 520 seconds (8min 40 seconds) after the influx is detected, the influx is properly attenuated and the well is under control. This is can be seen from figure 13 below.

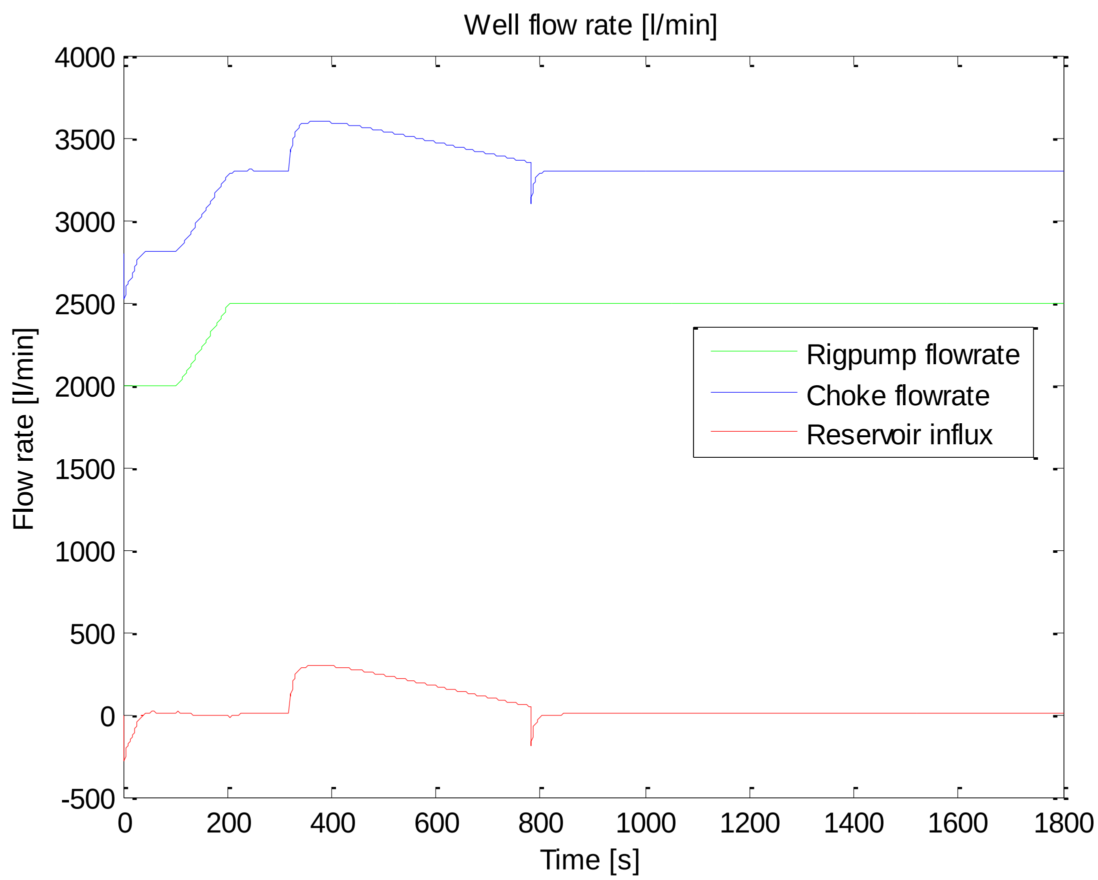


Figure 13. Well flow rate scenario 2.

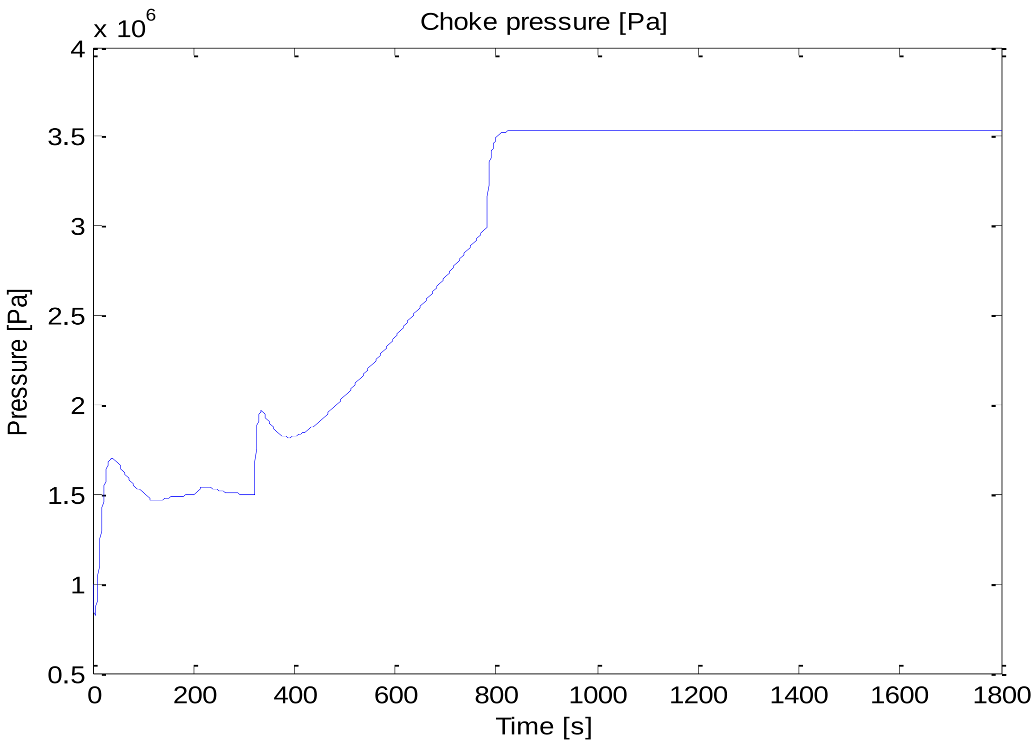


Figure 14. Choke pressure scenario 2.

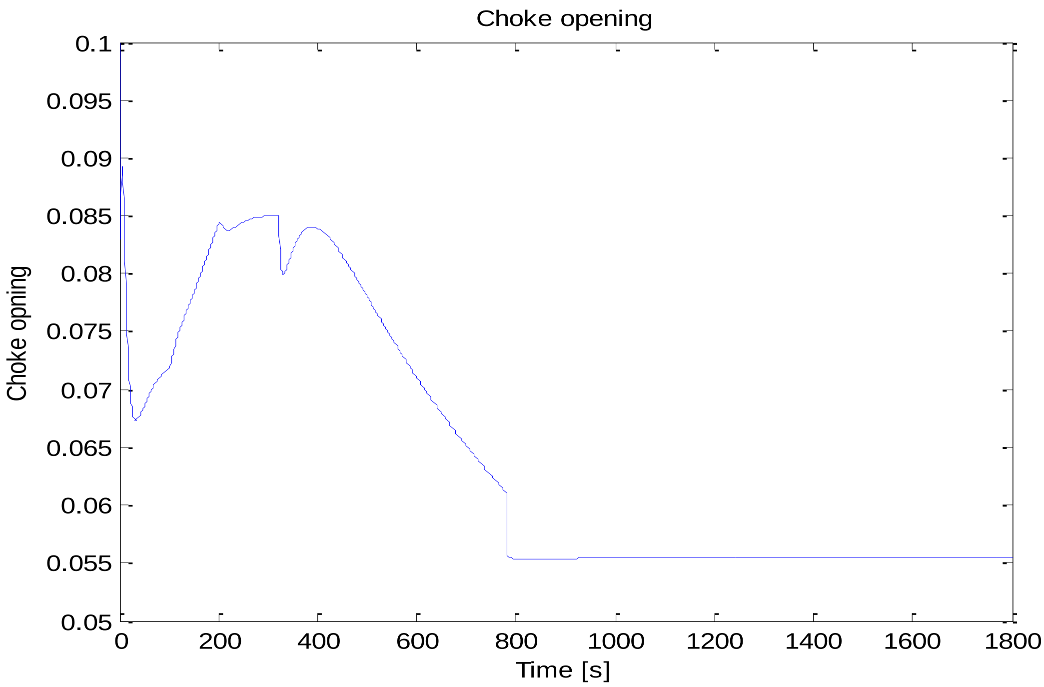


Figure 15. Choke opening scenario 2.

Figure 14 and 15 shows how the influx attenuation controller manages to increase the choke pressure by adjusting the choke opening. The choke is closing until the influx is properly controlled after t ≈ 800 s.

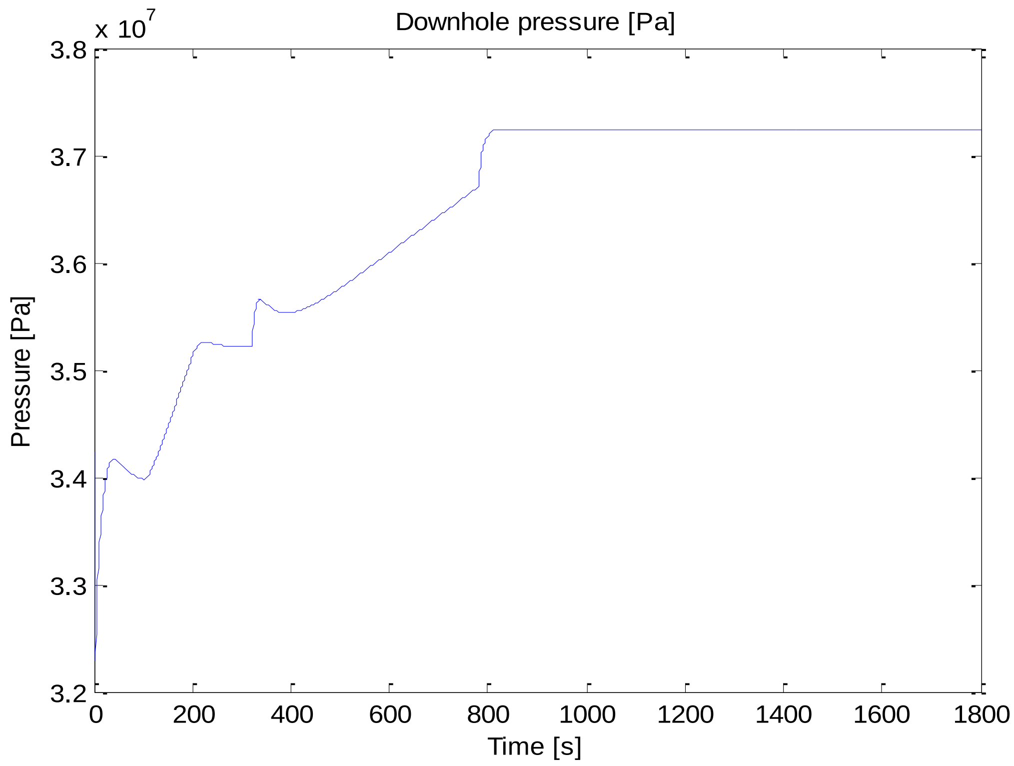


Figure 16. Downnhole presssure/BHP – Scenario 2.

Figure 16 shows an increase in the BHP after t = 100 seconds. This is due to an increase in the pump flow rate up to a rate of 2,500 l/min. Another increase can be seen after approximate 300 seconds. This is a direct result of the kick taken when hitting the high pressure gas zone after t = 320 s. The next increase is trigged by the controller closing the choke to attenuate the influx. After the influx is controlled, a 5 bar safety margin is added to prevent further influx situations.

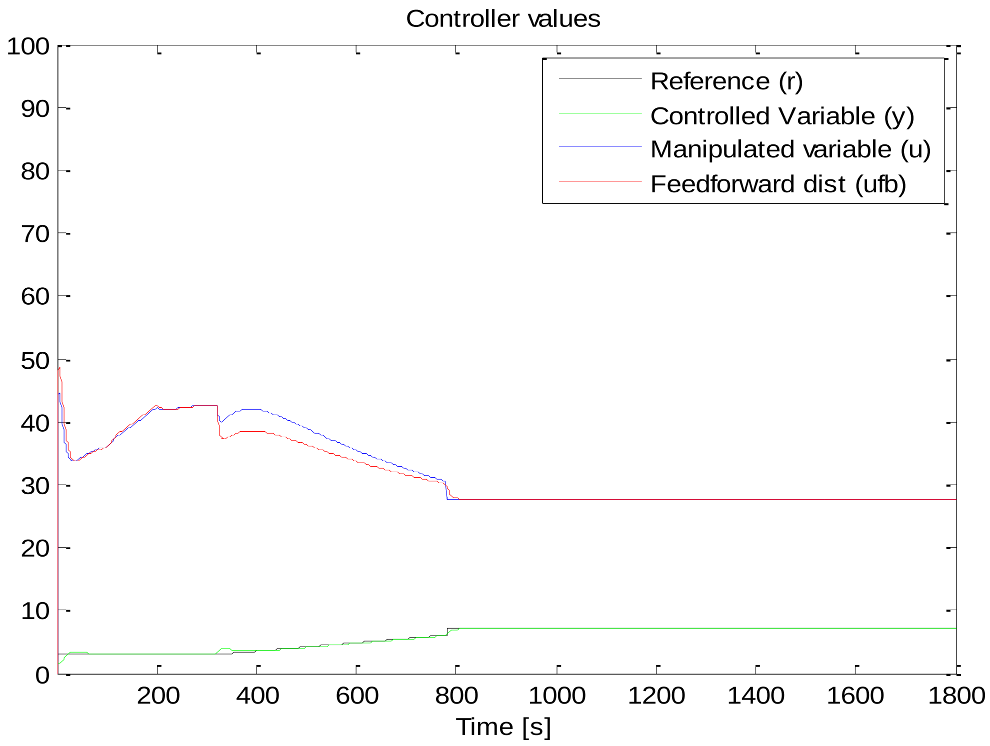


**Figure 17. Controller values scenario 2.**

The controller values are presented in figure 17. Here we can see that the controller and the reference are very accurate. The feed forward from the disturbance and the manipulated variable also shows fairly good correlation. The controller provides good control of the system in scenario 2 as well.

The influx attenuation model also proved successful in attenuating the influx induced by drilling into a high pressure gas zone.

# 4 The test rig facility

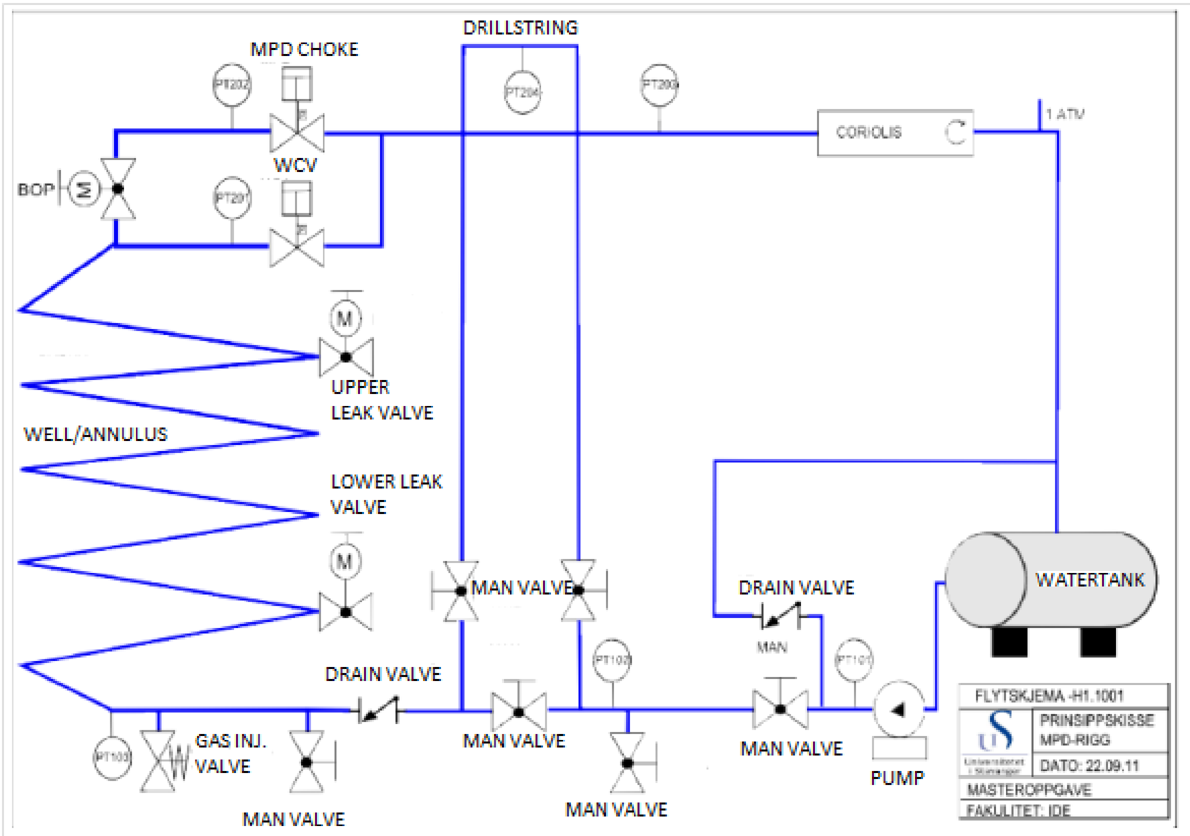


Figure 18 - P&ID of the test rig at UiS. A. Wang [30]

The test rig facility used in this thesis is a small scale well model which is designed to act as a MPD system. The well model provides a way to test different MPD well control procedures. (E.g. influx detection, influx attenuation etc.)

Basically the test rig consists of the following parts: a pump with a maximum effect of 50 Hz, different types of valves – a BOP, MPD choke, Well Control Valve (WCV), electrical and manual valves. The rig model has about 50 m of PVC pipe with a diameter of 40 - 75mm. A coriolis flow meter is installed to monitor the flowrate out of the well. The rig is connected to a PC with Simulink installed. A controller in Simulink is used to control the rig model during experiments and to process data.

To simulate an influx situation, a gas injection valve is installed. This allows pressurized air to enter the bottom of the annulus. An electrical valve as well as a manually operated valve is installed for the gas injection purpose.

The model is set up with seven pressure transmitters located various places on the rig. The locations are: one in front of the pump giving the pump pressure – one in front of standpipe – one in the top of the rig – one in the bottom of annulus giving the BHP – one in front of both the MPD choke and the WCV – the last can be found in front of the coriolis meter. These pressure sensors give the possibility of monitoring the pressures along flow direction of the well from pump to flowing out the well.

Figure 19: Picture from the laboratory hall at UiS showing the test rig facility – the computer plus two monitors used to control the rig can be seen to the left.

# 5 Experiments

The intention of the experiments done in this thesis was to find a way to automatically attenuate any influx coming into the system. This was done by modifying an existing Simulink model to fit the purpose of this thesis. A PI regulator with gain scheduling was used in the model and the pump pressure was used as a reference for the regulator.

First the Simulink model and the rig was connected and the real time data logging started. Now the pump was started at the desired pump rate. In most of the experiments performed in this thesis work, the pump rate was set at 0.30 (30% of maximum effect), giving a flow rate through the Coriolis of about 4500 l/hr, equal to 75 l/min. The pump rate was held constant throughout the experiments.

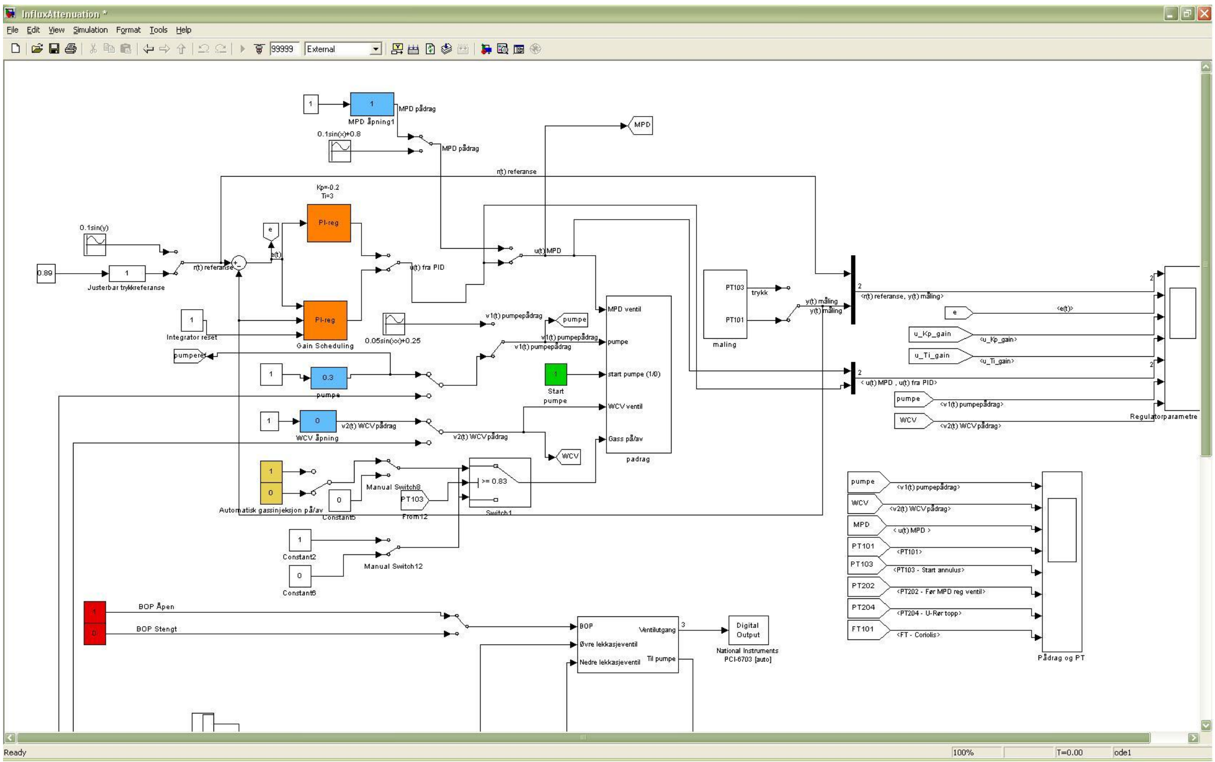

Figure 20. A screenshot of the Simulink control window.

After a short while the pump pressure would reach a constant value. This pressure was recorded and set as a reference pressure for the regulator. When the reference was set equal to the pump pressure, giving an error of approximately zero, the PI regulator was activated. The PI regulator used the MPD choke to control the pump pressure toward the desired reference pressure.

After activating the PI regulator, the pressure limit for allowing influxes into the well was set. This can be seen as the pore pressure of a formation.  To allow gas to enter the well model, an “automatic gas injection valve” had to be switched on. If now the pressure in the annulus, BHP, was to sink below this certain value, an electrical valve would open to allow gas to enter the annulus as long as the pressure stayed below the pre determined pore pressure.

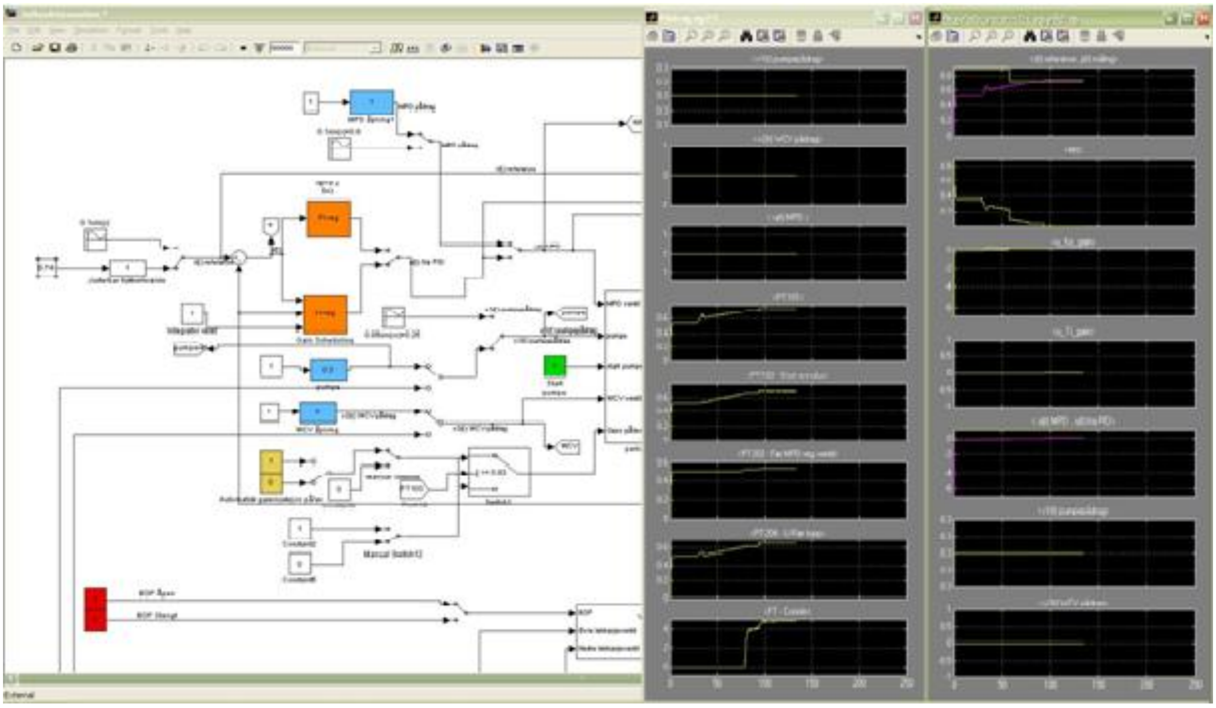

Figure 21. Screenshot showing the model running, and to the right, real time data measurements from the rig can be seen.

Whenever an influx situation occurred this would be visible through clearly distorted measurements from the coriolis meter. When a kick was taken, the real test for the PI regulator began. It was now the regulator had to prove its functionality by controlling the process. To increase the downhole pressure, the reference was now stepwise increased and the regulator closed the MPD choke gradually to follow the reference. This was done until the regulator had increased the pump pressure enough for the BHP to be higher than the pore pressure, and thus controlled the influx. When the coriolis meter showed no signs of gas in the system, the test was considered finished and the model was turned off.

# 6 Results

The results obtained from the experiments shows that the automatic influx attenuation procedure was successful in attenuating influxes taken during the experiments. The PI regulator was successful in following the reference and thus the controller could easily increase the pressures in the well leading to a controlled influx attenuation procedure.

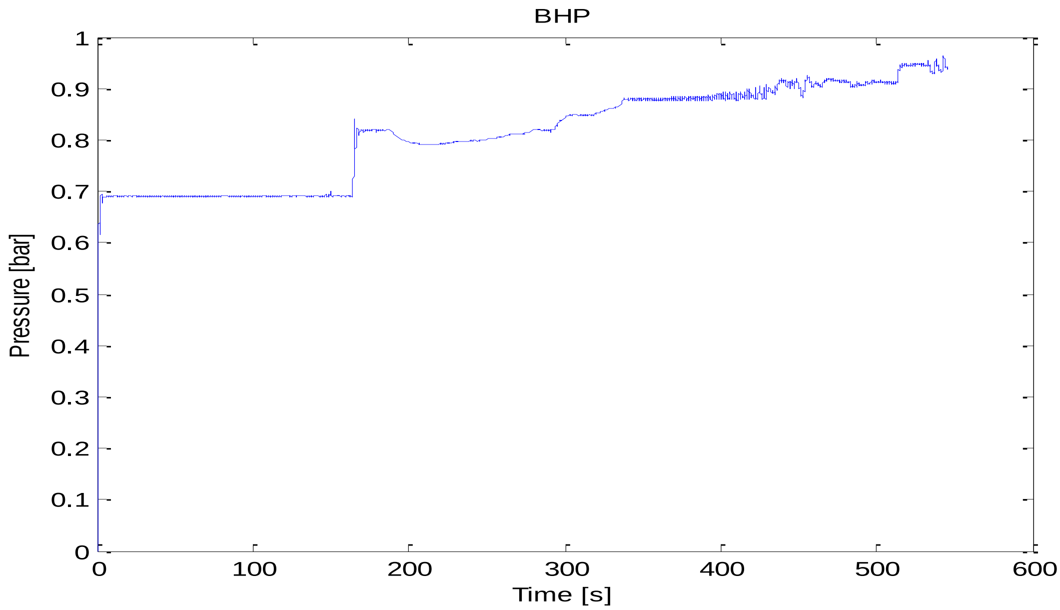


Figure 22. BHP pressure in the rig model during the experiment

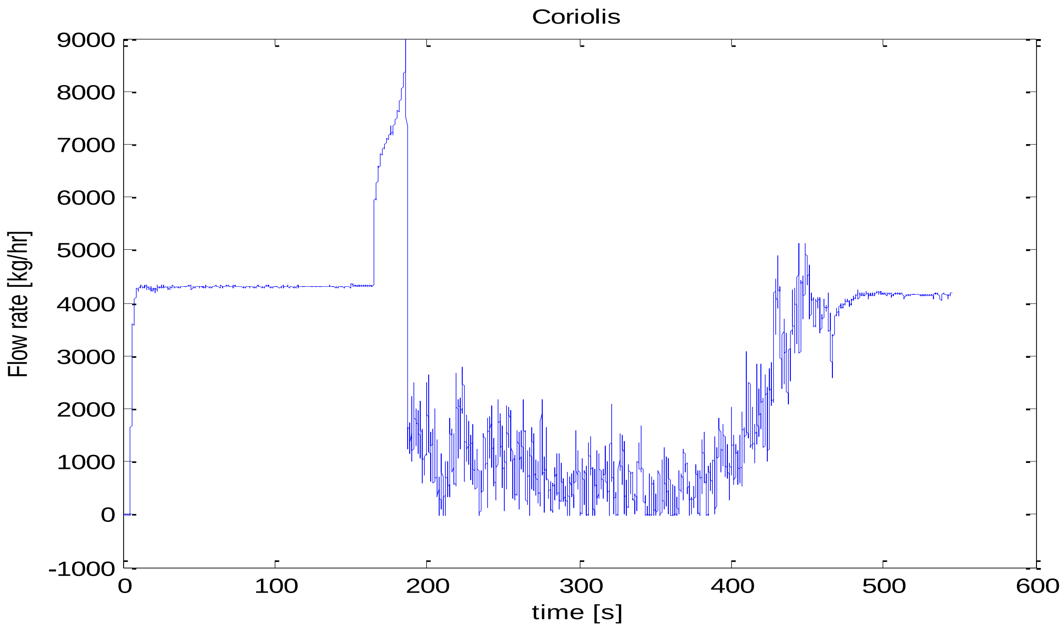


Figure 23. Corioilis flow meter showing the flow out of the well

From figure 22, one can see that the bottomhole pressure is held constant at 0.69 bar until it suddenly increases up to 0.81 bar at t ≈ 170 s. This sudden jump in the bottomhole pressure is due to a gas influx entering the well and thus increasing the pressure in the system. The intention was to simulate a situation where a high pressurized gas zone was hit during drilling, resulting in a kick.

The gas injection pressure limit, or the pore pressure, was set to 0.89 bar. If the pressure sensor in the annulus recorded a BHP under the value of 0.89 bar, an electric valve would open and gas would be allowed into the well.

After the BHP increases due to the influx, it takes some time for the pressure in the system to stabilize. The coriolis flow meter shows signs of something happening at t ≈ 165 s where the flow rate out of the well suddenly increases. After t ≈ 180 seconds the influx is more visible from the coriolis flow meter. This can be seen in the distorted areas of the graph. Approximately 100 seconds after obvious signs of a kick, at t ≈ 280 s, the regulator starts to close the MPD choke. This results in the BHP increasing in an attempt to attenuate the influx.

After approximately 340 seconds the controller has managed to increase the BHP to 0.88 bar. The reference is increased yet again and after t ≈ 470 s the BHP has reached and stabilized itself at a pressure of 0.90 bar. The BHP is now above the pore pressure and the gas influx should now stop.

After t ≈ 480 s in figure 23, the coriolis graph is clearly showing a more straight line, implying that the influx is controlled and is out of the wellbore. It takes the influx attenuation procedure about 300 seconds (5 minutes) from detection of the influx to fully regained pressure control of the well.

After the influx is successfully attenuated, an extra safety margin of about 0.05 bar is added in order to prevent further influx situations from occurring. This can be seen in figure 22 and 24 after t ≈ 515s.

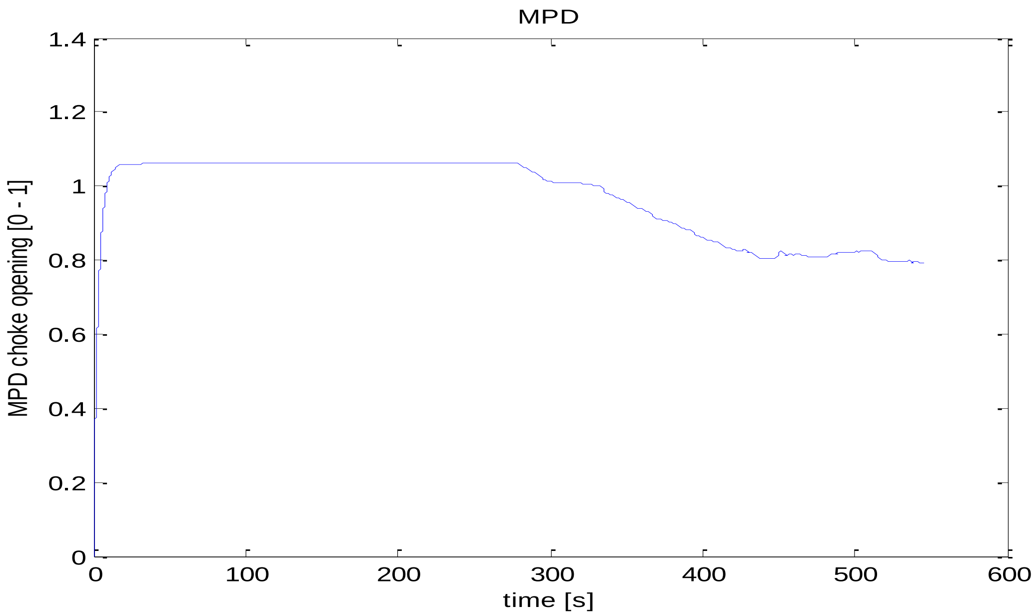


Figure 24. Graph showing the MPD choke opening during the experiment

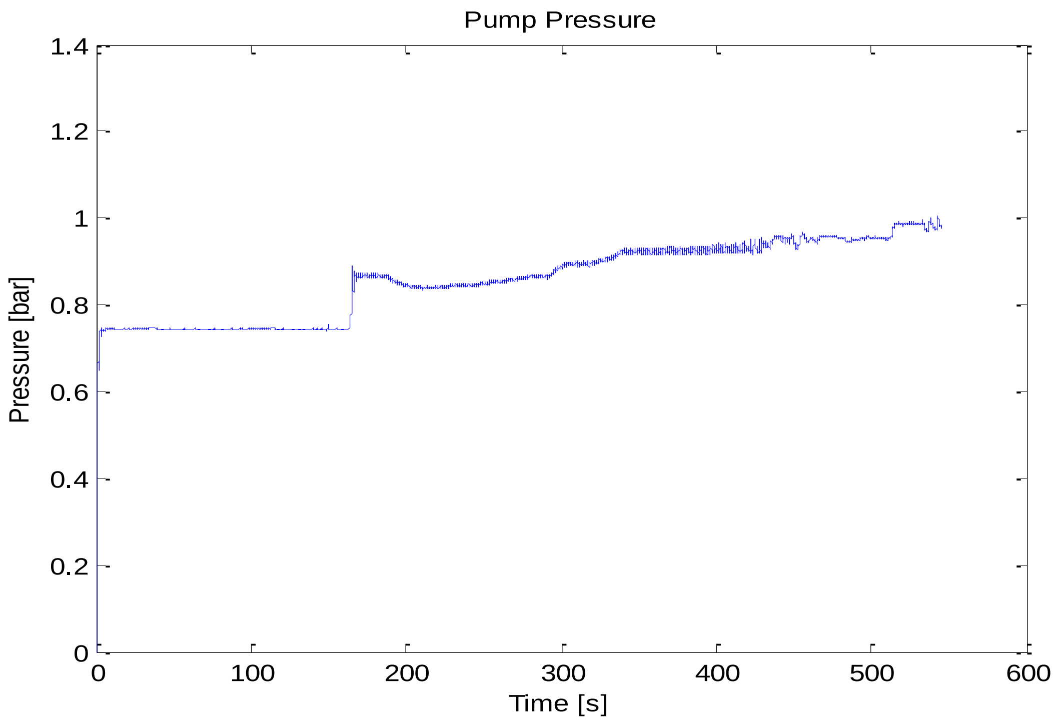


Figure 25. Graph showing the pump pressure throughout the experiments

In figure 24 and 25 the MPD choke position and the pump pressure can be seen. This is displayed to show how the PI controller can regulate the pump pressure by manipulating the choke opening.

The pump rate gives a pump pressure of 0.74 bar. This is held constant until $t \approx 170$s. Now the same sudden increase in pressure as seen with the BHP can be found in figure 25 with the pump pressure. This is also due to the gas influx flowing into the annulus.

After the influx is detected, the reference is increased and the PI regulator is switched on. From figure 24 and 25 one can see that after $t \approx 280$ s the regulator begins to close the MPD choke. This is done by stepwise increasing the reference with steps in the area of 0.05 bar.

The first increase of the reference is with a step of 0.02 bar. This increases the pump pressure to 0.9 bar. The next reference step is of 0.05 bar and takes place after approximately 330 seconds. The MPD choke is now closing more rapidly to reach the reference at 0.95 bar. The pump pressure reaches the value of 0.95 bar after approximately 100 seconds. This pump pressure leads to a BHP large enough to stop the influx, as seen from figure 22 and 23. After the influx is attenuated, a 0.05 bar safety margin is applied to ensure the rig from experiencing more influx situations.

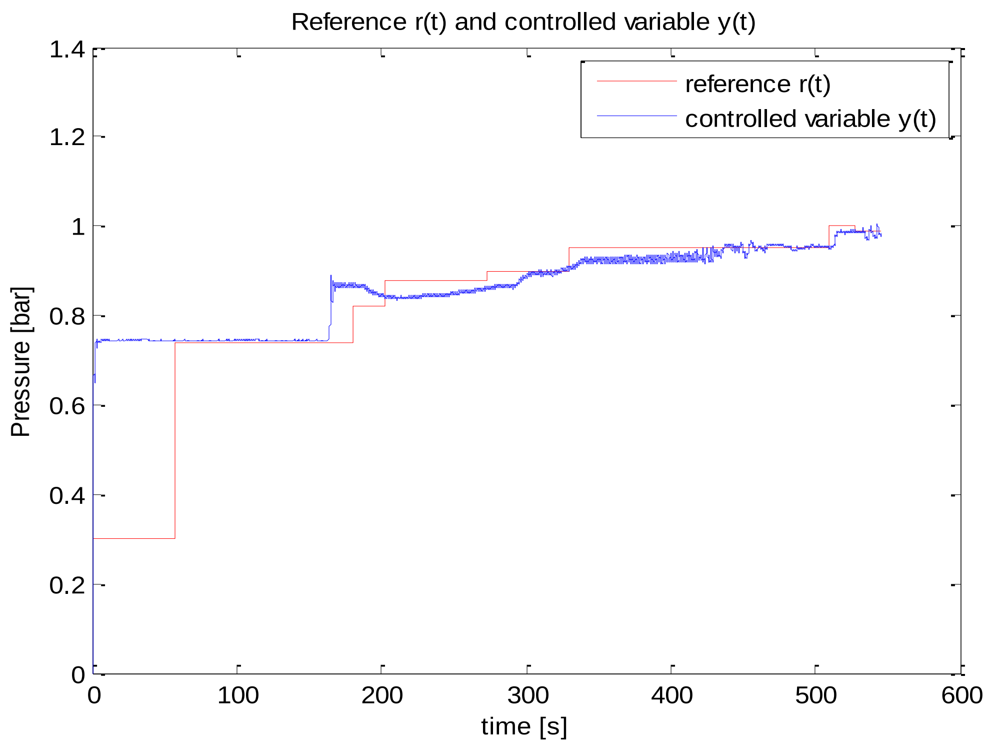


**Figure 26. A graph to illustrate the how the regulator worked in the experiment.**

As illustrated in figure 26, the regulator is successful in matching the reference in every step and thus increasing the pump pressure. The PI regulator proved to be able to increase the pump pressure in order to attenuate influxes in the rig model.

The pump rate was as mentioned held constant throughout the experiments and never shut completely down. This gives a huge advantage for this approach, because this means that no annular friction is lost and thus the BHP is not reduced. A pump shut down is something that would only lead to more time spent and more reservoir influx allowed into the well. A well control procedure like this, with the pumps running constantly, will give a more rapid attenuation and less influx volume.

# 7 Discussion and Conclusion

**Discussion & Conclusion**

The main objective of this thesis was to develop a model for *influx attenuation.* This model was to be based on a regulation of the pump pressure instead of the more common way with choke pressure regulation. A simple model was first created in Matlab and various simulations were performed to show the model's performance. A similar model based on pump pressure regulation was used to run different experiments on the small scale test rig located at UiS.

The PI controller used in the model was a bit slow in regulating the pressures. It took a little too long for the controller to match the reference value. The regulation parameters may not have been 100 percent in match with regulation of the pump pressure. A faster and more precise controller would perhaps have given an even better more rapid well control procedure. Even though the regulator was a bit slow, it still performed ok and did its purpose, and the experiments performed at the test rig showed positive results.

The automated influx attenuation procedure proved successful in controlling and circulating influxes out of the wellbore relatively fast. This rapid attenuation resulted in relatively small amounts of reservoir influx being allowed into the well. Due to this the influx attenuation procedure gave positive indications for possibly increasing the efficiency of well control and thus reducing the danger of HSE incidents. This can mean safer drilling operations, reducing the risk of spills to the environment, and most important of all, a more safe working environment for personnel offshore.

Even though these results are governed from a small scale test project, it shows that there is possible for new automatic well control methods to improve the conventional methods used today. In theory, the results indicate that such an automatic influx attenuation procedure might be able to increase the safety on a drilling rig. This is because the influx will be attenuated quickly without shutting down the pumps. This results in less influx volume and less chance for serious incidents occurring.

During this thesis, numerous scientific articles considering well control and automation were studied.  This gave an impression that automation really can contribute in the drilling industry. With methods for earlier kick detection and influx attenuation, the efficiency of well control can be significantly improved. This efficiency can lead to e.g. an influx being controlled and circulated out earlier than with conventional methods, and thus leading to higher degree of HSE.

# 8 Further Work

**Further work and improvements**

The test rig facility is currently using a coriolis meter as an indication of influx. This flow meter is a one phase liquid flow meter well suited for water flow measurements. During a gas influx situation the measurements from the coriolis meter will be distorted, going up and down, clearly showing that not only water is flowing in the system. For better evaluation of the influx volume taken with this procedure, a gas flow meter can be installed. This will help in determining the volumes of reservoir influx taken during kicks more accurately. Installing such a gas flow meter may also give more conclusive results in terms of the efficiency of the influx attenuation procedure.

The pump used at the laboratory should also be considered changed or modified. It is too powerful and must always run on very low gears and frequencies. This results in the motor overheating and turning off as a safety configuration after some time. To avoid this, another pump should be acquired to better fit the purpose of the experiments on the test rig. Optionally the current pump can be modified to be able to run more easily on low gears.

There were also some problems experienced with the pressure sensors used on the rig. They might have been exposed to more noise than what have been believed. The noise affecting sensor and etc have earlier been a problem in the laboratory hall. This noise has previously been cancelled out with the use of low pass filters for every sensor on the rig. These low pass filters seems not to always have been able to cancel out all the noise, and thus sometimes resulting in varying pressure measurements. There have been some building and expanding of other test facilities in the laboratory hall both during and before this thesis. Maybe some of the new equipment installed can be the reason for the experienced noise.

I suggest that both the regulation parameters and the low pass filters are looked into before performing any more experiments on the rig. A faster acting regulator can produce a better well control procedure. Combined with more accurate pressure measurements the rig facility at UiS will be more complete and ready for further testing and experimenting.

# 9 References

[1] IADC – UBO & MPD Committee 2011. *The UBO & MPD Glossary, Dec 2011* http://www.iadc.org/wp-content/uploads/2011/12/UBO-MPD-Glossary-Dec11.pdf

[2] Bernt S. Aadnøy, Iain Cooper, Stefan Z. Miska, Robert F. Mitchell, Michael L. Payne 2009 – SPE "*Advanced Drilling and Well Technology" - SPE 2009, Richardson, TX* ISBN: 978 - 1 - 55563 - 145 - 1

[3] Godhavn et al. 2011 – "*Drilling seeking automatic control solution" - 18$^{th}$ IFAC World Congress Milano (Italy) August 28 – September 2, 2011*

[4] Mitchell, Robert F. and Miska, Stefan Z. – "*Fundamental of Drilling Mechanics" – SPE vol. 12, 2011, Richardson, TX. p. 636 – 638.*

[5] Larry W. Lake – "*Petroleum Engineering Handbook"* – 2006 SPE. ISBN 978-1-55563-114-7

[6] http://en.wikipedia.org/wiki/Well_control

[7] Godhavn et al. 2013 – "*Automatic Well Control System"* - *2013 IADC/SPE MPD & UBO CONFERENCE 18.04.2013*

[8] Robert D. Grace – "*Blow Out and Well Control Handbook"* – Gulf Professional Publishing – ISBN: 978-0-7506-7708-0

[9] Liv A. Carlsen et al. 2008 – "*Performing the Dynamic Shut-In Procedure Because of a Kick Incident When Using Automatic Coordinated Control of Pump Rates and Choke-Valve opening" - SPE/IADC Managed Pressure Drilling and Underbalanced Operations Conference and Exhibition held in Abu Dhabi, UAE, 28-29 January 2008.*

[10] Don Reitsma 2010 – "*A simplified and highly effective method to identify influx and losses during Managed Pressure Drilling without the use of a Coriolis flow meter" - SPE/IADC Managed Pressure Drilling and Underbalanced Operations Conference and Exhibition held in Kuala Lumpur, Malaysia, 24-25 February 2010.*

[11] Don Reitsma 2011 – "*Development of an Automated System for the Rapid Detection of Drilling Anomalies using Standpipe and Discharge Pressure" – SPE/IADC Drilling Conference and Exhibition held in Amsterdam, The Netherlands, 1-3 March 2011.*

[12] David Hargreaves et al. 2001– "*Early Kick Detection for Deepwater Drilling: New Probabilistic Methods Applied in the Field." - SPE Annual Technical Conference and Exhibition held in New Orleans, Louisiana, 30 September–3 October 2001.*

[13] Ian Mills et al. 2012 - *"Simulator and the First Field Test Results of an Automated Early Kick Detection System That Uses Standpipe Pressure and Annular Discharge Pressure" - SPE/IADC Managed Pressure Drilling and Underbalanced Operations Conference and Exhibition held in Milan, Italy, 20-21 March 2012.*

[14] Gravdal et al. 2009 – "*Improved Kick Management During MPD by Real-Time Pore-Pressure Estimation" - SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, 4-7 October 2009*

[15] van Riet, E. J. and Reitsma D. 2003 – "*Development and Testing of a Fully Automated System to Accurately Control Downhole Pressure During Drilling Operations" - SPE/IADC Middle East Drilling Technology Conference and Exhibition held in Abu Dhabi, UAE, 20-22 October 2003.*

[16] Nygaard, Gerhard et al. 2007 SPE – *"Bottomhole Pressure Control During Drilling Operations in Gas-Dominant Wells" – SPE/IADC Underbalanced Technology Conference and Exhibition, Houston, USA, 11-12 October 2004.*

[17] Breyholtz, Øyvind et al. 2009 SPE – *"Advanced Automatic Control for Dual-Gradient Drilling" – SPE Annual Technical Conference and Exhibition, New Orleans, Lousiana, USA, 4-7 October 2009.*

[18] Fredericks, Paul et al. 2008 – "*Successful Implementation of First Closed Loop, Multiservice Control System for Automated Pressure Management in a Shallow Gas Well Offshore Myanmar" - IADC/SPE Drilling Conference held in Orlando, Florida, U.S.A, 4-6 March, 2008.*

[19] F. Iversen et al. 2006 – *"Feasibility Study of Managed – Pressure Drilling With Automatic Choke Control in Depleted HP/HT Field" - SPE Annual Technical Conference and Exhibition held in San Antonio, Texas, U.S.A., 24 – 27 September 2006.*

[20] Zhou, Jing et al. 2009 – "*Pressure Regulation with Kick Attenuation in a Managed Pressure Drilling System" - Joint 48th IEEE Conference on Decision and Control and 28th Chinese Control Conference, Shanghai, P.R. China, December 16-18, 2009*

[21] Zhou, Jing et al. 2010 – "*Adaptive Observer for Kick Detection and Switched Control for Bottomhole Pressure Regulation and Kick Attenuation during Managed Pressure Drilling" - 2010 American Control Conference, Marriott Waterfront, Baltimore, MD, USA June 30-July 02, 2010.*

[22] Zhou, Jing et al. 2011 – "*Switched Control for Pressure Regulation and Kick Attenuation in a Managed Pressure Drilling System" - IEEE TRANSACTIONS ON CONTROL SYSTEMS TECHNOLOGY, VOL. 19, NO. 2, MARCH 2011.*

[23] J.L. Thorogood, Drilling Global Consultant LLP 2012 - *"Automation in Drilling: Future Evolution and Lessons from Aviation" - IADC/SPE Drilling Conference and Exhibition held in San Diego, California, USA 6-8 March 2012*

[24] http://en.wikipedia.org/wiki/Control_theory

[25] http://en.wikipedia.org/wiki/PID_controller

[26] Gerhard Nygaard and John-Morten Godhavn, 2013 – *"Automated Drilling Operations"*. UiS and NTNU 2013

[27] http://en.wikipedia.org/wiki/Model_predictive_control

[28] Breyholtz et al. 2011 SPE – *"Managed - Pressure Drilling: Using Model Predictive Control To Improve Pressure Control During Dual Gradient Drilling" - SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, USA, 4 – 7 October 2009.*

[29] G. O. Kaasa, E. N. Stamnes, L. Imsland, and O. M. Aamo. "*Simplified hydraulics model used for intelligent estimation of downhole pressure for a managed-pressure-drilling control system." SPE Drilling & Completion*, (SPE 143097) 127-138, March 2012.

[30] Alexander Wang 2012 – *"MPD og automatisk brønnsparkhåndtering anvendt på boreriggmodell"* 2012

# APPENDIX

## A MatLab code – Influx attenuation

### A.1 Influx attenuation – Decrease rig pump flowrate

```
%% Influx attenuation model - based on the Kaasa model using Euler
integration
%
%  Remping down rig pump flowrate
%
% These are the differential equations used in the model:
% p_pdot = (beta_d/V_d)*(q_p-q_c)
% q_bdot = 1/M((p_p-p_c)-(Fd+Fb+Fa)*q_b*q_b+(rho_d-rho_a)*g*h)
% p_cdot = (beta_a/V_a)*(q_b+q_res+q_bpp-q_c)
% q_c = z_c*k_c*sqrt(p_c/rho_a)
%
% Parameters and initial values
clear all; % deletes all variables
close all; % removes all plot windows

%In this controller, the choke is the regulator for MPD

% Constants
maxtime = 1000; % seconds
dt = 0.001; % euler step time
Ts = 1;% loop time step

%Operator parameters
q_p = 2000/60000; % rig pump rate 2000 l/min
q_bpp = 800/60000; % back pressure pump rate 800 l/min
q_c = q_p + q_bpp; % choke flow rate p2800 l/min
z_c = 0.1; % choke opening

% Wellbore parameters
h = 1951;         %Height/Length of well
beta_d =2e9;      %Bulk modulus drill string
beta_a =1e9;      %Bulk modulus annulus
V_d =17;          %Volume drill stringm3
V_a = 48;         %Volume annulus m3
M = 4.3e8;
Fd = 5e9;         %Friction factor drillstring
Fb = 1e9;         %Friction factor
Fa = 2e9;         %Friction factor annulus
rho_d = 1580;     %Density of fluid in the drill string
rho_a = 1580;     %Density of fluid in the annulus
g = 9.81;         %Gravity constant
k_c = 0.021;


influx_attenuation = 0;

% Define range

p_min=0*10^7; % p_p_m
p_max=5.0*10^7; % p_bhp_m
```

```
z_min=0;
z_max=0.20;

% Reservoir parameters
p_pore = 3.30e7;     %Pore pressure
p_frac = 3.75e7;     %Fracture pressure
ProdIndex = (100/60000)/5e5; % 100 l/min at delta p of 5 bar %
'permeability'


%Array initialization
p_p_ar = zeros(maxtime,1);
p_c_ar = zeros(maxtime,1);
p_b_ar = zeros(maxtime,1);
q_b_ar = zeros(maxtime,1);
q_c_ar = zeros(maxtime,1);
q_p_ar = zeros(maxtime,1);
q_bpp_ar = zeros(maxtime,1);
q_res_ar = zeros(maxtime,1);
r_ar = zeros(maxtime,1);
u_ar = zeros(maxtime,1);
y_ar = zeros(maxtime,1);
ufd_ar = zeros(maxtime,1);
z_c_ar = zeros(maxtime,1);

% Initial values
p_p = 40e5;               %Pump pressure
p_c = 10e5;               %Choke pressure
q_b = 2000/60000;         %Flowrate through bit
p_b = p_p + rho_d*g*h;    %Bottomhole pressure

%reference value
p_c_r = 15e5;             %Choke reference pressure

%Initialize controller
e = 0;
u = 0;
ufd = 0;
ufb = 0;
y = 0;
r = 0;
Kp = 2;
Ki = 0.2;



% main iteration loop
for time = 1:maxtime

    % change mud pump rate
    if (time > 100) && (time <= 200)
        q_p = q_p + 5/60000; % ramp up to 2500 l/min
    end
    if (time > 200) && (time <= 300)
        q_p = 2500/60000; % fixed at 2500 l/min
    end

    if (time > 300) && (time <= 350)
%         q_p = 1000/60000; % fixed at 2500 l/min
```

```
    q_p = q_p - 30/60000; % ramp up to 2500 l/min
end

if (time > 400)
    z_c = 0.05; % reduce choke to 5%
end

%Pore pressure
q_res = ProdIndex*(p_pore - p_b);
if q_res < 0
    q_res = 0;
end

% Frac pressure
q_loss = ProdIndex*(p_frac -p_b);
if q_loss > 0
    q_loss = 0;
end



%store parameters
p_p_ar(time) = p_p;
p_c_ar(time) = p_c;
p_b_ar(time) = p_b;
q_b_ar(time) = q_b;
q_p_ar(time) = q_p;
q_c_ar(time) = q_c;
q_bpp_ar(time) = q_bpp;
q_res_ar(time) = q_res;
u_ar(time) = u;
y_ar(time) = y;
r_ar(time) = r;
ufd_ar(time) = ufd;
z_c_ar(time) = z_c;

%store delayed q_p verdi (6s)
if time > 6
    q_p_6 = q_p_ar(time - 6);
else q_p_6 = q_p;
end

q_p_6_ar(time) = q_p_6;

%Influx attenuation
last_kick_atten = influx_attenuation;
influx_attenuation = 0;
if time > 100
    if (q_c - q_p_6 - q_bpp > 50/60000)
   p_c_r = p_c_r + 1e5/30;
   influx_attenuation = 1;

end
end

%Add higher safetymargin - 5bar
if last_kick_atten == 1 && influx_attenuation == 0
    p_c_r = p_c_r + 5e5;
end
```

```
    %% Controller code

    % Feed forward from disturbance
    zfd = (q_p + q_bpp)/(k_c*sqrt(p_c/rho_a));


    % scale to percentace
    r = ((p_c_r-p_min)/p_max)*100.0; % reference is p_c
    y = ((p_c-p_min)/p_max)*100.0; % controlled variable
    u = ((z_c-z_min)/z_max)*100.0; % manipulated variable
 %   ufd_last = ufd;
    ufd = ((zfd-z_min)/z_max)*100.0; % feed forward disturbance
    %ufb = u ;

    % controller code
    last_e = e;
    e=y-r;
%    delta_u=Kp*(e-last_e)+((Kp*Ts)/Ti)*e; % using Kp and Ti
    delta_u=Kp*(e-last_e)+(Ki*Ts)*e; % using Kp and Ki


    ufb=ufb+delta_u; % feedback


%    u = ufb; % +ufd+ufr;
%    u = ufb+ufd_last; % +ufd+ufr; with time delay
    u = ufb+ufd; % +ufd+ufr;

    % limit u
    if u<=0
       u=0;
    end
    if u>100
        u=100;
    end


    %scale to physical values (only z are needed)
    z_c_old = z_c;
    z_c = z_min + z_max*(u/100.0);
    %




    % Euler integration loop
    for eulerstep = 1:(1/dt)
        p_pdot = (beta_d/V_d)*(q_p-q_b);
        q_bdot = 1/M*((p_p-p_c)-(Fd+Fb+Fa)*q_b*q_b+(rho_d-rho_a)*g*h);
        p_cdot = (beta_a/V_a)*(q_b+q_res+q_bpp+q_loss-q_c);
        p_p = p_p + p_pdot*dt;
        q_b = q_b + q_bdot*dt;
        p_c = p_c + p_cdot*dt;


        q_c = z_c*k_c*sqrt(p_c/rho_a);
        p_b1  = p_p+rho_d*g*h-(Fd+Fb)*q_b*q_b; % pump pressure
        p_b = p_c+rho_a*g*h+Fa*q_b*q_b; % using choke pressure
```

```
    end
end

figure;
plot(1:maxtime,p_b_ar,'b');
xlabel('Time [s]');
ylabel('Pressure [Pa]');
title('Downhole pressure [Pa]');

figure;
plot(1:maxtime,p_p_ar,'b');
xlabel('Time [s]');
ylabel('Pressure [Pa]');
title('Pump pressure [Pa]');

figure;
plot(1:maxtime,p_c_ar,'b');
xlabel('Time [s]');
ylabel('Pressure [Pa]');
title('Choke pressure [Pa]');

figure;
plot(1:maxtime,q_b_ar*60000,'b',1:maxtime,q_p_ar*60000,'g',...
    1:maxtime,q_bpp_ar*60000,'k',1:maxtime,q_c_ar*60000,'r',...
    1:maxtime,(q_p_ar + q_bpp_ar)*60000,'y',1:maxtime,q_res_ar*60000,'b--
',...
    1:maxtime,(-q_p_ar - q_bpp_ar + q_c_ar)*60000,'c--',...
    1:maxtime,(q_c_ar - q_p_6_ar' - q_bpp_ar)*60000,'r--');
xlabel('Time [s]');
ylabel('Flow rate [l/min]');
title('Well flow rate [l/min]');
legend('bit','rigpump','backpp','choke','est choke', 'res', 'est
res','est(6) res');



figure;
plot(1:maxtime,r_ar,'k',1:maxtime,y_ar,'g',1:maxtime,u_ar,'b',1:maxtime,ufd
_ar,'r');
legend('Reference (r)','Controlled Variable (y)','Manipulated variable
(u)',...
    'Feedforward dist (ufb)');
xlabel('Time [s]');
axis([1 maxtime 0 100]);
title('Controller values');


figure;
plot(1:maxtime,q_p_6_ar*60000,'g',...
     1:maxtime,q_c_ar*60000,'b',...
     1:maxtime,(q_c_ar - q_p_6_ar' - q_bpp_ar)*60000,'r');
xlabel('Time [s]');
ylabel('Flowrate [l/min]');
title('Well flow rate [l/min]');
legend('Rigpump flowrate','Choke flowrate','Reservoir influx');
```

```
figure;
plot(1:maxtime,p_b_ar,'r',1:maxtime,p_p_ar,'b',1:maxtime,p_c_ar,'g');
xlabel('Time [s]');
ylabel('Pressure [Pa]');
title('Pressure plot [Pa]');
legend('Downhole Pressure','Pump Pressure','Choke Pressure');

figure;
plot(1:maxtime,z_c_ar,'b');
legend('Choke opening');
xlabel('Time [s]');
ylabel('Choke opning');
title('Choke opening');
```

## A.2 Influx attenuation – Drilling into a high pressure gas pocket

```
%% Influx attenuation model - based on the Kaasa model using Euler
integration
%
%  Drilling into a high pressure gas pocket
%
% These are the differential equations used in the model:
% p_pdot = (beta_d/V_d)*(q_p-q_c)
% q_bdot = 1/M((p_p-p_c)-(Fd+Fb+Fa)*q_b*q_b+(rho_d-rho_a)*g*h)
% p_cdot = (beta_a/V_a)*(q_b+q_res+q_bpp-q_c)
% q_c = z_c*k_c*sqrt(p_c/rho_a)
%
% Parameters and initial values
clear all; % deletes all variables
close all; % removes all plot windows

%In this controller, the choke is the regulator for MPD

% Constants
maxtime = 1800; % seconds
dt = 0.001; % euler step time
Ts = 1;% loop time step

%Operator parameters
q_p = 2000/60000; % rig pump rate 2000 l/min
q_bpp = 800/60000; % back pressure pump rate 800 l/min
q_c = q_p + q_bpp; % choke flow rate p2800 l/min
z_c = 0.1; % choke opening

% Wellbore parameters
h = 1951;          %Height/Length of well
beta_d =2e9;       %Bulk modulus drill string
beta_a =1e9;       %Bulk modulus annulus
V_d =17;           %Volume drill stringm3
V_a = 48;          %Volume annulus m3
M = 4.3e8;
Fd = 5e9;          %Friction factor drillstring
Fb = 1e9;          %Friction factor
Fa = 2e9;          %Friction factor annulus
rho_d = 1580;      %Density of fluid in the drill string
rho_a = 1580;      %Density of fluid in the annulus
g = 9.81;          %Gravity constant
k_c = 0.021;

influx_attenuation = 0;

% Define range

p_min=0*10^7; % p_p_m
p_max=5.0*10^7; % p_bhp_m
z_min=0;
z_max=0.20;

% Reservoir parameters
p_pore = 3.30e7;     %Pore pressure
p_frac = 3.75e7;     %Fracture pressure
ProdIndex = (100/60000)/5e5; % 100 l/min at delta p of 5 bar %
'permeability'
```

```
%Array initialization
p_p_ar = zeros(maxtime,1);
p_c_ar = zeros(maxtime,1);
p_b_ar = zeros(maxtime,1);
q_b_ar = zeros(maxtime,1);
q_c_ar = zeros(maxtime,1);
q_p_ar = zeros(maxtime,1);
q_bpp_ar = zeros(maxtime,1);
q_res_ar = zeros(maxtime,1);
r_ar = zeros(maxtime,1);
u_ar = zeros(maxtime,1);
y_ar = zeros(maxtime,1);
ufd_ar = zeros(maxtime,1);
z_c_ar = zeros(maxtime,1);

% Initial values
p_p = 40e5;             %Pump pressure
p_c = 10e5;             %Choke pressure
q_b = 2000/60000;       %Flowrate through bit
p_b = p_p + rho_d*g*h;  %Bottomhole pressure

%reference value
p_c_r = 15e5;           %Choke reerence pressure

%Initialize controller
e = 0;
u = 0;
ufd = 0;
ufb = 0;
y = 0;
r = 0;
Kp = 2.6;
Ki = 0.085;



% main iteration loop
for time = 1:maxtime

    % change mud pump rate
    if (time > 100) && (time <= 200)
        q_p = q_p + 5/60000; % ramp up to 2500 l/min
    end
    if (time > 200) && (time <= 300)
        q_p = 2500/60000; % fixed at 2500 l/min
    end

    if (time > 320)%Drilling into a high pressure gas pocket
%         q_p = 1000/60000; % fixed at 2500 l/min
        p_pore = 370e5;
    end


    %Pore pressure
    q_res = ProdIndex*(p_pore - p_b);
```

```
if q_res < 0
    q_res = 0;
end

% Frac pressure
q_loss = ProdIndex*(p_frac -p_b);
if q_loss > 0
    q_loss = 0;
end



%store parameters
p_p_ar(time) = p_p;
p_c_ar(time) = p_c;
p_b_ar(time) = p_b;
q_b_ar(time) = q_b;
q_p_ar(time) = q_p;
q_c_ar(time) = q_c;
q_bpp_ar(time) = q_bpp;
q_res_ar(time) = q_res;
u_ar(time) = u;
y_ar(time) = y;
r_ar(time) = r;
ufd_ar(time) = ufd;
z_c_ar(time) = z_c;

%store delayed q_p verdi (6s)
if time > 6
    q_p_6 = q_p_ar(time - 6);
else q_p_6 = q_p;
end

q_p_6_ar(time) = q_p_6;

%Influx attenuation
last_kick_atten = influx_attenuation;
influx_attenuation = 0;
if time > 100
    if (q_c - q_p_6 - q_bpp > 50/60000)
   p_c_r = p_c_r + 1e5/30;
   influx_attenuation = 1;

end
end

%Add higher safetymargin - 5bar
if last_kick_atten == 1 && influx_attenuation == 0
    p_c_r = p_c_r + 5e5;
end
%% Controller code

% Feed forward from disturbance
zfd = (q_p + q_bpp)/(k_c*sqrt(p_c/rho_a));


% scale to percentage
r = ((p_c_r-p_min)/p_max)*100.0; % reference is p_c
```

```
    y = ((p_c-p_min)/p_max)*100.0; % controlled variable
    u = ((z_c-z_min)/z_max)*100.0; % manipulated variable
 %   ufd_last = ufd;
    ufd = ((zfd-z_min)/z_max)*100.0; % feed forward disturbance
    %ufb = u ;

    % controller code
    last_e = e;
    e=y-r;
%    delta_u=Kp*(e-last_e)+((Kp*Ts)/Ti)*e; % using Kp and Ti
    delta_u=Kp*(e-last_e)+(Ki*Ts)*e; % using Kp and Ki


    ufb=ufb+delta_u; % feedback


%    u = ufb; % +ufd+ufr;
%    u = ufb+ufd_last; % +ufd+ufr; with time delay
    u = ufb+ufd; % +ufd+ufr;

    % limit u
    if u<=0
       u=0;
    end
    if u>100
        u=100;
    end


    %scale to physical values (only z are needed
    z_c_old = z_c;
    z_c = z_min + z_max*(u/100.0);
    %



    % Euler integration loop
    for eulerstep = 1:(1/dt)
        p_pdot = (beta_d/V_d)*(q_p-q_b);
        q_bdot = 1/M*((p_p-p_c)-(Fd+Fb+Fa)*q_b*q_b+(rho_d-rho_a)*g*h);
        p_cdot = (beta_a/V_a)*(q_b+q_res+q_bpp+q_loss-q_c);
        p_p = p_p + p_pdot*dt;
        q_b = q_b + q_bdot*dt;
        p_c = p_c + p_cdot*dt;


        q_c = z_c*k_c*sqrt(p_c/rho_a);
        p_b1  = p_p+rho_d*g*h-(Fd+Fb)*q_b*q_b; % pump pressure
        p_b = p_c+rho_a*g*h+Fa*q_b*q_b; % using choke pressure

    end
end

figure;
plot(1:maxtime,p_b_ar,'b');
title('Downhole pressure [Pa]');
xlabel('Time [s]');
ylabel('Pressure [Pa]');
```

```
figure;
plot(1:maxtime,p_p_ar,'b');
title('Pump pressure [Pa]');
xlabel('Time [s]');
ylabel('Pressure [Pa]');

figure;
plot(1:maxtime,p_c_ar,'b');
title('Choke pressure [Pa]');
xlabel('Time [s]');
ylabel('Pressure [Pa]');

figure;
plot(1:maxtime,q_b_ar*60000,'b',1:maxtime,q_p_ar*60000,'g',...
    1:maxtime,q_bpp_ar*60000,'k',1:maxtime,q_c_ar*60000,'r',...
    1:maxtime,(q_p_6_ar' + q_bpp_ar)*60000,'r--
',1:maxtime,q_res_ar*60000,'c',...
    1:maxtime,(q_c_ar - q_p_ar - q_bpp_ar)*60000,'c--',...
    1:maxtime,(q_c_ar - q_p_6_ar' - q_bpp_ar)*60000,'r');
title('Well flow rate [l/min]');
legend('bit','rigpump','backpp','choke','est choke','res', 'est
res','est(6) res');
xlabel('Time [s]');
ylabel('Well flow rate [l/min]');


figure;
plot(1:maxtime,r_ar,'k',1:maxtime,y_ar,'g',1:maxtime,u_ar,'b',1:maxtime,ufd
_ar,'r');
legend('Reference (r)','Controlled Variable (y)','Manipulated variable
(u)',...
    'Feedforward dist (ufb)');
axis([1 maxtime 0 100]);
title('Controller values');
xlabel('Time [s]');

figure;
plot(1:maxtime,q_p_6_ar*60000,'g',...
     1:maxtime,q_c_ar*60000,'b',...
     1:maxtime,(q_c_ar - q_p_6_ar' - q_bpp_ar)*60000,'r');
title('Well flow rate [l/min]');
legend('Rigpump flowrate','Choke flowrate','Reservoir influx');
xlabel('Time [s]');
ylabel('Flow rate [l/min]');

 figure;
plot(1:maxtime,p_b_ar,'r',1:maxtime,p_p_ar,'b',1:maxtime,p_c_ar,'g');
title('Pressure plot [Pa]');
legend('Downhole Pressure','Pump Pressure','Choke Pressure');
xlabel('Time [s]');
ylabel('Pressure [Pa]');

figure;
plot(1:maxtime,z_c_ar,'b');
xlabel('Time [s]');
ylabel('Choke opning');
title('Choke opening');
```

## B Influx attenuation procedure

1. Start the Simulink model with manual choke control

2. Read pump pressure "PT101" from scope

3. Use this pressure as reference for the PI regulator

4. Make sure the u(t) MPD and the u(t) PI for MPD choke opening are equal – this will result in a "bumpless" startup of the regulator

5. Read the error from the scope and make sure it is equal to zero

6. If the error is equal to zero - now switch to "PI regulator - gain scheduling"

7. If high pressures should occur – switch off pump to avoid damage to the rig

8. If the regulator is up and running and the system is stabile - increase the reference and see that the regulator manipulates the choke opening to reach the reference

9. Now choose a "pore pressure" – a setpoint pressure for the automatic gas injection to start. Below this pressure the gas will be allowed into the well.

10. Switch on to automatic gas injection

11. To attenuate the influx the reference must be stepwise increased (in steps of 15 – 30 seconds)

12. Increase the reference until the gas influx stops

13. The influx situation is properly attenuated when the coriolis flow meter shows no indications of gas in the system

14. The influx attenuation procedure should now have successfully controlled the influx and the test is finished.

# C Additional plots from tests on the rig model

Test run with a pump rate of 0.30 – meaning a pump flow rate of about 75 l/min.

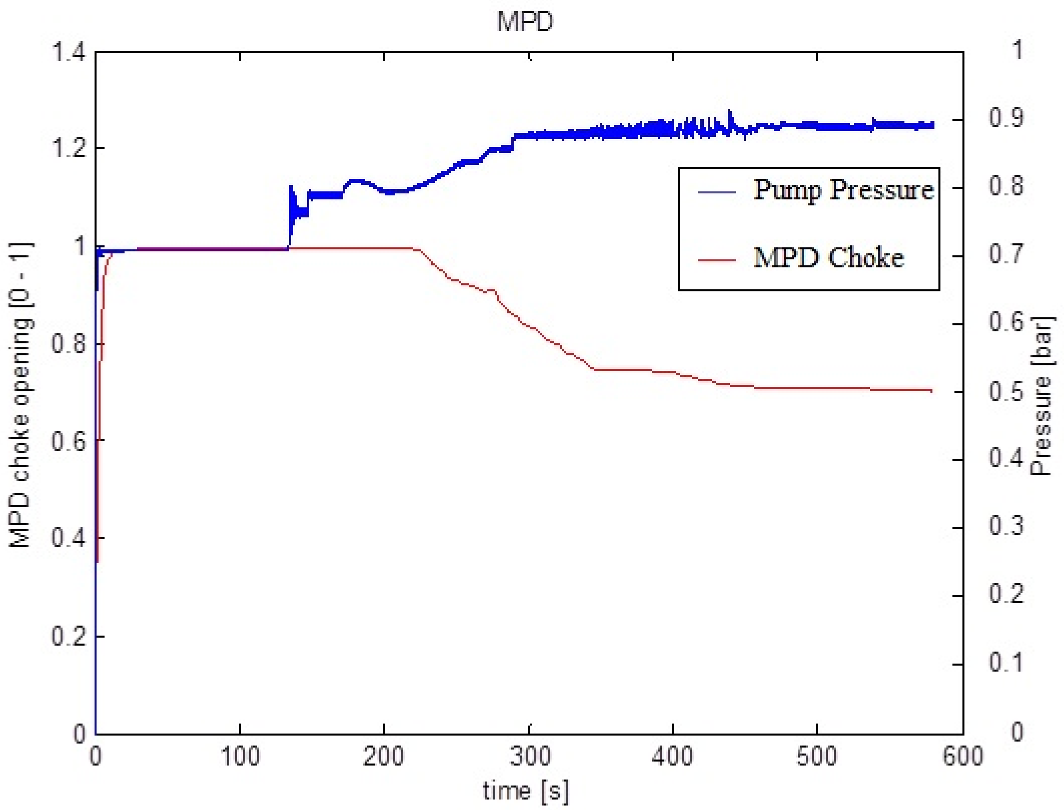


Figure 9.3.1. Plot showing the MPD Choke opening and the effect it has on the pump pressure

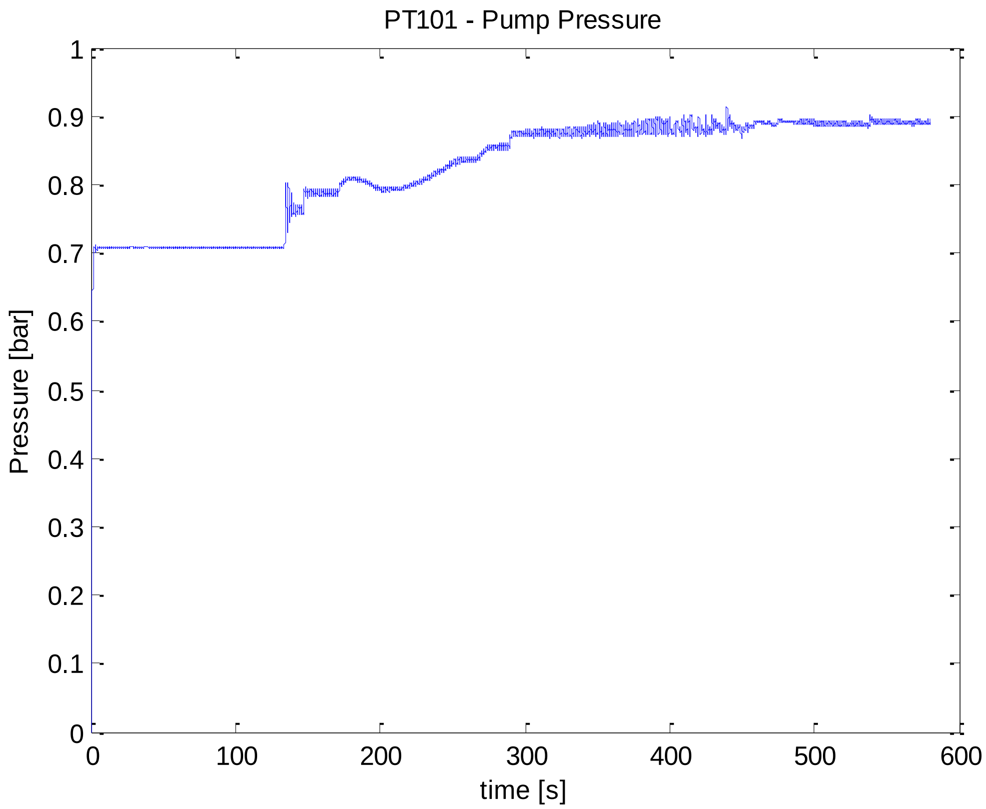


Figure 9.3.2. Graph showing the pump pressure during an experiment

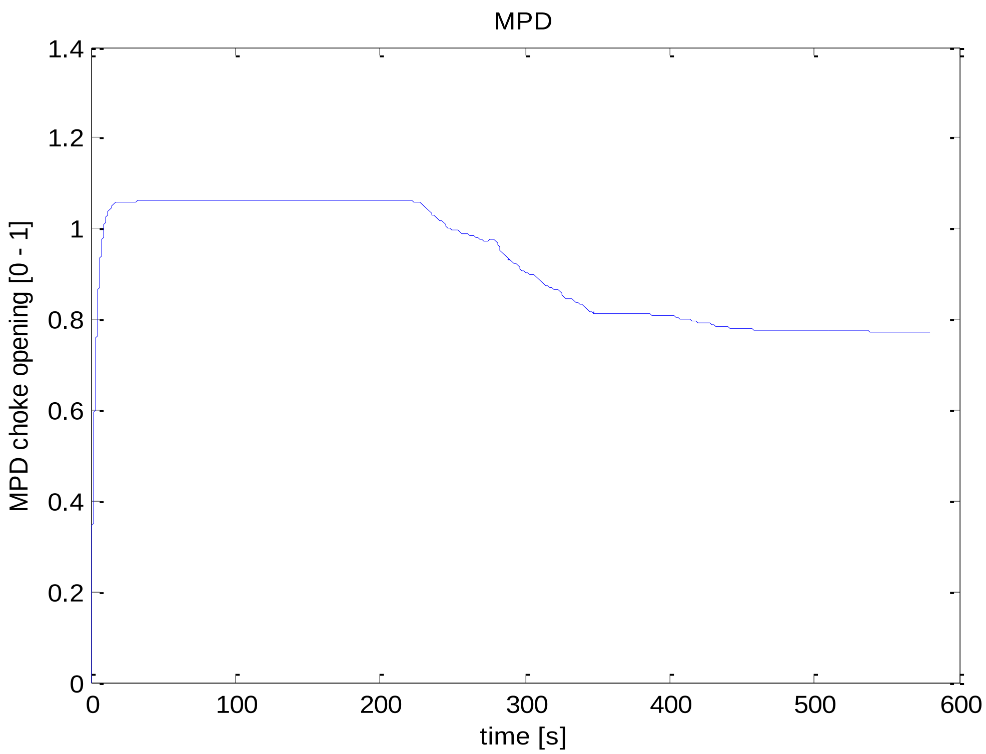


Figure 9.3.3. Graph showing the MPD Choke opening during an experiment

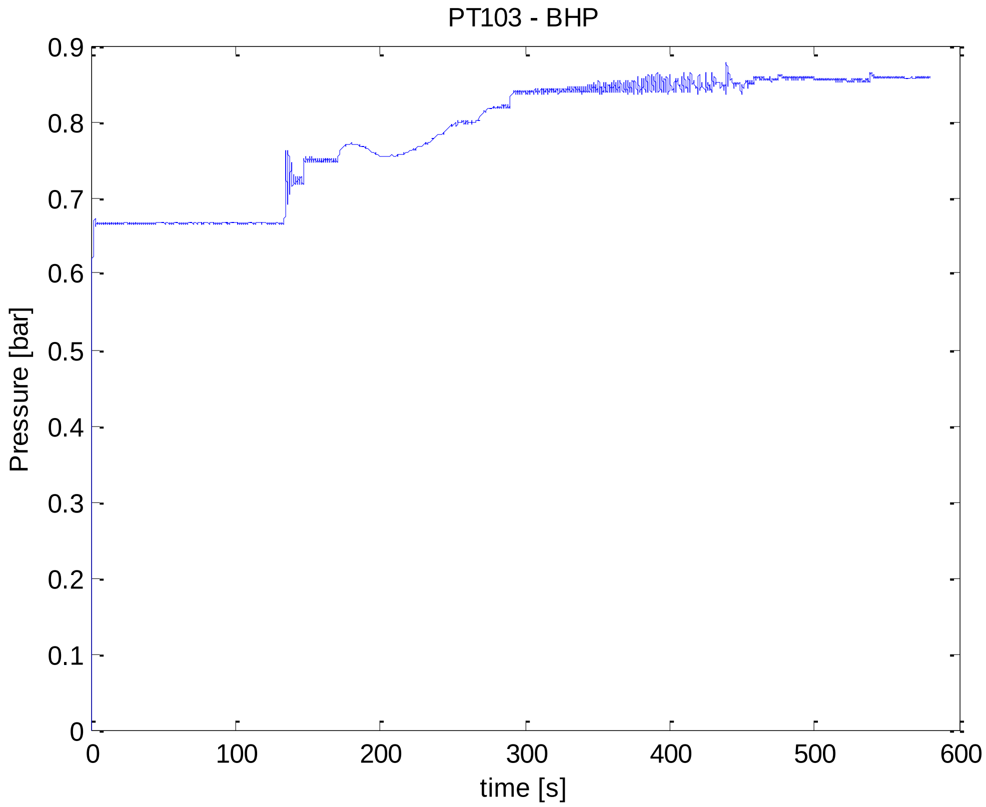


Figure 9.3.4. Graph displaying the BHP in the test rig during an experiment

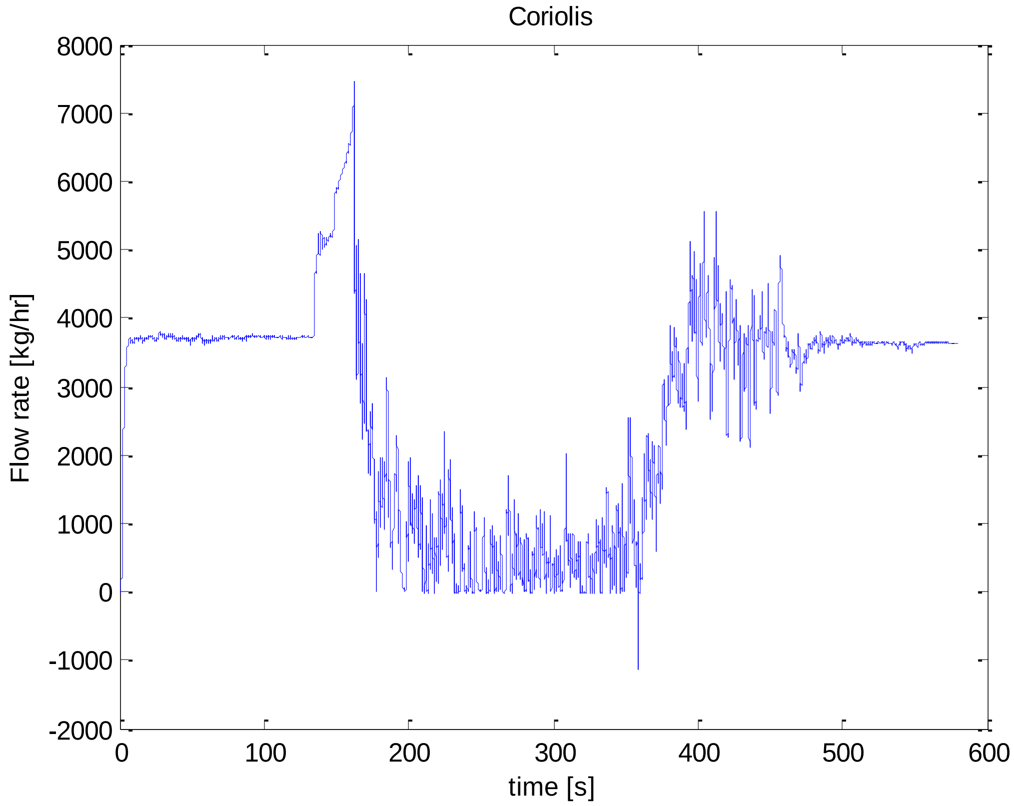


Figure 9.3.5. Data from the coriolis flow meter showing the flow out of the well bore during an experiment

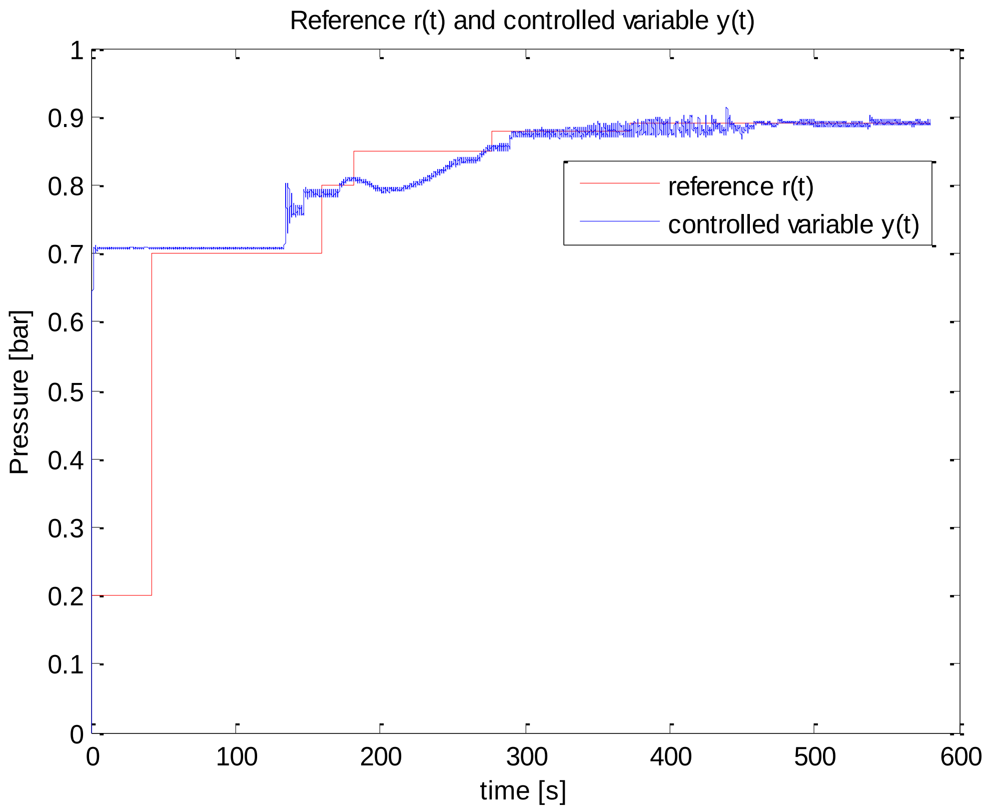


**Figure 9.3.6. This graph shows how the controlled variable matched the reference throughout an experiment**

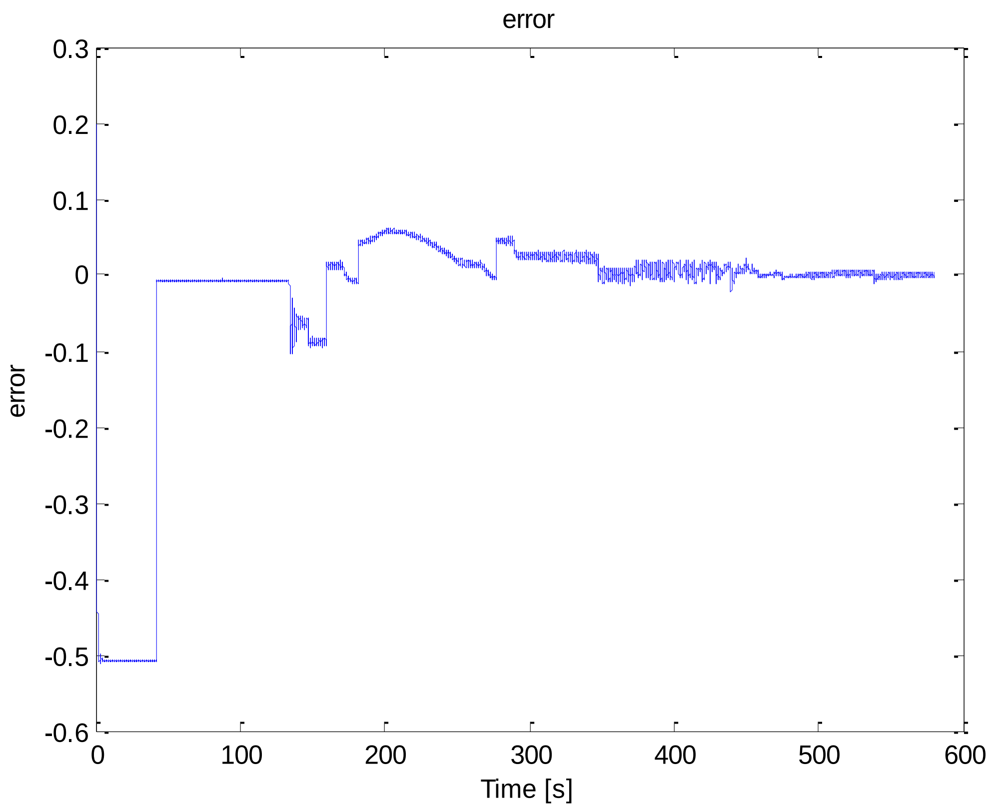


**Figure 9.3.7. Graph showing the error – the difference between the reference and the controlled variable**

# D “Plottescript” in Matlab used to generate plots and graphs

```
% %% Plottescript for generating plots and graphs %%
%
% close all;
% %clear all;
%
% % figure;
% % plot(inngang.time,inngang.signals(x).values);
% % title('motor');
% % print motor;
%
% figure;
% plot(inngang.time,inngang.signals(x).values);
% title('PT101 - Pump Pressure');
% print PT101;
% xlabel('Time [s]');
% ylabel('Pressure [bar]');
%
% % figure;
% % plot(inngang.time,inngang.signals(x).values);
% % title('PT102 - Pressure in front of annulus');
% % print PT102;
% % xlabel('Time [s]');
% % ylabel('Pressure [bar]');
%
% figure;
% plot(inngang.time,inngang.signals(x).values);
% title('PT103 - BHP');
% print PT103;
% xlabel('Time [s]');
% ylabel('Pressure [bar]');
%
%
%
% % figure;
% % plot(inngang.time,inngang.signals(x).values);
% %
% % figure;
% % plot(inngang.time,inngang.signals(x).values);
% % title('Pressure in front to MPD choke');
% % print PT202;
% % xlabel('time [s]');
% % ylabel('Pressure [bar]');
%
% % figure;
% % plot(inngang.time,inngang.signals(x).values);
% % title('Pressure in front of Coriolis');
% % print PT203;
% % xlabel('time [s]');
% % ylabel('Pressure [bar]');
% %
% % figure;
% % plot(inngang.time,inngang.signals(x).values);
%
% figure;
% plot(inngang.time,inngang.signals(x).values);
% title('MPD');
% print MPD;
% xlabel('Time [s]');
```

```
% ylabel('MPD choke opening [0 - 1]');
%
% % figure;
% % plot(inngang.time,inngang.signals(x).values);
%
% figure;
% plot(inngang.time,inngang.signals(x).values);
% title('Coriolis');
% print Coriolis;
% xlabel('Time [s]');
% ylabel('Flow rate [kg/hr]');
%
% % figure;
% % plot(inngang.time,inngang.signals(x).values,
'r',inngang.time,inngang.signals(x).values), 'b';
% % title('Pressureplot');
% % legend('MPD Choke', 'Pump pressure');
% % print PT103;
% % xlabel('time [s]');
% %
% % figure;
% % plot(inngang.time,inngang.signals(x).values,
'r',inngang.time,inngang.signals(x).values), 'b';
% % title('Pressureplot');
% % legend('BHP', 'coriolis');
% % print PT103;
% % xlabel('time [s]');
% % ylabel('Pressure [bar]');
%
%
%
%
% figure;
% plot(paadrag.time,paadrag.signals(x).values);
% title('Reference r(t) and controlled variable y(t)');
% print Reference r(t) and controlled variable y(t);
% xlabel('Time [s]');
%
% figure;
% plot(paadrag.time,paadrag.signals(x).values);
% title('error');
% print error;
% xlabel('Time [s]');
% ylabel('error');
%
% figure;
% plot(paadrag.time,paadrag.signals(x).values);
% title('u(t)MPD, u(t) from PID');
% print u(t)MPD - u(t) from PID;
% xlabel('Time [s]');
%
%
% %%
% % *BOLD TEXT*
%
% % figure;
% %
plot(inngang.time,inngang.signals(x).values,'r',inngang.time,inngang.signal
s(x).values,'b');
% % legend('ver','hor');
% % title('difftrykk');
```

```
% % xlabel('time');
% % ylabel('mBar');
% % grid on;
% % print -dtiff DP;
% %
% % figure;
% % plot(inngang.time,inngang.signals(x).values-
inngang.signals(x).values,'k');
% % legend('DPver - DPhor');
% % title('difftrykk');
% % xlabel('time');
% % ylabel('mBar');
% % print -dtiff DP-hv;
%
% % %% Friction factor coefficient
% % rho = 998.2;
% % DL = 0.855;
% % Di = 0.03325;
% % pi = 3.14;
% % %
% % % % Fanning friction factor
% % % f1 = (40500000*inngang.signals(13).values.*rho*Di^5*pi^2);
% % % f2 = (inngang.signals(11).values.^2*DL);
% % % ff = mrdivide(f1,f2);
% % %Darcy friction factor
% % f3 = (162000000*inngang.signals(13).values.*rho*Di^5*pi^2);
% % f4 = (inngang.signals(11).values.^2*DL);
% %
% % % figure
% % % plot(inngang.time,ff);
% % % legend('Fanning friction factor');
% % % xlabel('Time [s]');ylabel('Friction factor coefficient');
% %
% % figure
% % plot(inngang.time,f3/f4);
% % legend('Darcy friction factor');
% % xlabel('Time [s]');ylabel('Friction factor coefficient');
```