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# Managed Pressure Cementing

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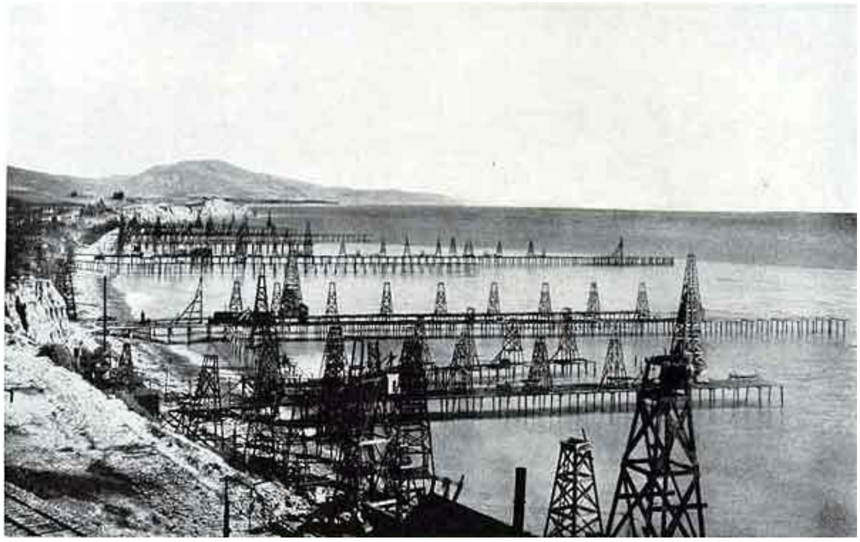

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by

**João Francisco da Cunha Meneses Pereira da Silva**

Thesis to obtain the Master of Science Degree in

## Cybernetics and Robotics

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## Abstract

Managed Pressure Cementing (MPC) is a method to cement deep offshore wells in a safer, more controlled and more efficient way. It will end up being less costly because by applying managed pressure drilling (MPD) first the sections drilled are less so there is less cement to spend which ends up being cheaper. As it is a relative new process the companies do not want to release the information about it to the outside world.

Oil platforms normally belong to a company which hires several smaller companies to do different tasks but the rig owner always has someone of their staff to supervise the different operations. Statoil asked for this project thesis which can become a complement to the formation given to a supervisor who will follow future cementing processes. Through similar methods better known like MPD it is shown a simple model for the fluid movement inside the well during the process and a controller is applied to maintain the annular bottom hole pressure (BHP) constant. The model is implemented with MatLab code in order to retrieve simulations of estimates of the fluids behaviour and also of different pressures along the well.

As an imperative component to fulfil the proposed objectives the controller is a proportional and integral one (PI) and it controls the BHP by actuating on an automatic choke at the rig that regulates the flow out of the well. The pressure reference at the bottom is $890\, Bar$ which is a huge value that became a problem as the controller gains had to be really small. Despite having a slow response and the targeted value sometimes would not even be reached an approximated value was quickly overtaken and that can be enough as the most important thing is to maintain the BHP between pore and fracture pressures.

## Key Words

Managed pressure cementing

Bottom hole pressure

Automatic choke

Proportional and integral controller

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# Nomenclature

**List of Acronyms**

MPC – Managed Pressure Cementing

MPD – Managed Pressure Drilling

BHP – Bottom Hole Pressure

PI – Proportional and Integral

SPE – Society of Petroleum Engineers

SBP – Surface Back Pressure

MWW – Mud Weight Window

**List of Variables**

$A$ – Cross sectional area

$a$ – Acceleration

$d$ – Diameter

$E$ – Energy

$F$ – Force

$g$ – Acceleration of gravity

$k_c$ – Choke constant

$k_i$ – Controller integral gain

$k_p$ – Controller proportional gain

$l$ – Length

$m$ – Mass

$p$ – Linear momentum

$q$ – Fluid flow

$t$ – Time

$u$ – Choke opening

$V$ – Volume

$v$ – Velocity

$x$ – Position

$y$ – Position

$z$ – Position

$\beta$ – Isothermal Bulk Modulus

$\rho$ – Fluid density

# CHAPTER 1

# INTRODUCTION

## 1.1. Statoil

Petroleum industry is one of the largest industries in Norway for the past years. In 2013, state revenues from this industry were NOK 401 billion meaning 29% of state revenues of that year. The company that most contributed and still contributes to this value is Norwegian State Oil Company, or Statoil, which is one of the most well succeeded oil and gas companies all over the world. It was firstly founded in 1972, in Norway and after seven years it started the extraction of resources. Eight years ago Statoil merged with Norsk Hydro's oil and gas department. This joint made the company stronger which allowed its internationalization. Since then Statoil has been playing a huge roll on Norwegian economy by entering on Norway's stock exchange [1, 2].

As an international company Statoil has operations in 36 different countries around the world. They explore gas and oil mainly but their worries regarding environment and their interested in joining clean energy market made them start capturing and storing carbon during fossil fuels extraction processes. Oil and gas stations offshore are also being improved in order to produce clean energy from renewable resources like wind power stations. Statoil's biggest activities are in Norway on its continental shelf as it has plentiful oil and gas resources. It is divided in 3 ocean areas, the North Sea, the Norwegian Sea and the Barents Sea covering an area greater than two million square kilometres with almost 80 production fields where the North Sea plays the major part (60 fields). Statoil is currently the leading operator on the continental shelf being presented in 52 fields [1, 2].

To such a big company as Statoil innovation and development must be presented all the time and this project is a proof of it. MPC is an improvement to the way wells are cemented after drilled. According to the Society of Petroleum Engineers (SPE) it was already successfully implemented in fields where specific conditions were verified though the final objective is to use this method in every well regardless its conditions [3].

## 1.2. Objectives

As a company that owns a lot of offshore rigs it is normal to big companies like Statoil to hire smaller and specialized companies to execute different operations. As oil industry is a very expensive market a company can be specialized only in drilling wells or cementing them while other is responsible for extracting the resources and still making a huge profit. However it is necessary for Statoil to have someone to supervise on field all and each operation. MPC is a technique already being implemented by the small companies but as it is a new technique they do not want to give specific information and details regarding the method. This project can become the beginning of a guide to complement the supervisor's training on the cementation process.

In order to start the extraction of oil/gas from a well the hole has to be made but it cannot be all drilled at once as the pressure at the bottom changes with depth and with the type of rock encountered while drilling. This pressure must be in between two values – fracture and collapse values – otherwise the well might fracture or collapse which could lead to the closing of the well. When the pressure value gets too close of one of these values the drilling process stops and casings are inserted in order to be cemented so the drilling can continue without fracture/collapsing the well. This project will allow the observation and control of the BHP during the cementation process by using a PI controller on the referred pressure. The pump pressure at the entrance of the well will be the input, the BHP will be the variable to control and the choke at the top of the annulus will be the actuator of the controller.

## 1.3. Thesis Structure

This thesis is divided into seven chapters including the present one describing its main reasons and objectives. The next chapter describes the methods that influence the MPC model projected.

Chapter three presents the theory behind the model to be implemented in MatLab code and how it is structured while chapter four specifies how the PI controller was projected.

The fifth chapter illustrates the simulation of the model projected in chapter three and four and in chapter six the results provided by the simulation are shown and discussed. The last chapter presents the final conclusions on the project and possible future work or improvements to this thesis.

## CHAPTER 2

## BACKGROUND

In 1894 Henry L. Williams was the first to drill a well offshore on a beach. The results obtained were so good that two years later he and his associates developed the first offshore field in Pacific Ocean on a Californian beach. Despite being offshore it required a connection to shore. This connection was dropped in 1911 when first independent platforms were built in Caddo Lake. However, the first offshore sketch goes back to 1869, a platform designed by Thomas Fitch Rowland but never built. Soon (1938) offshore techniques reached Gulf of Mexico and in 1947 the Kerr-McGee drilling platform was out of sight of land. It was the first offshore rig being in such condition.

Since 1960s petroleum industry suffered a tremendous evolution with new processes being discovered and with the introduction of computer technology. Techniques like steam injection (figure 2.1) allowed producing oil crude faster not only while retrieving it but also by avoiding having one well per rig if we think on horizontal drilling technique (figure 2.2) where an horizontal well can replace up to 6 vertical wells [4].

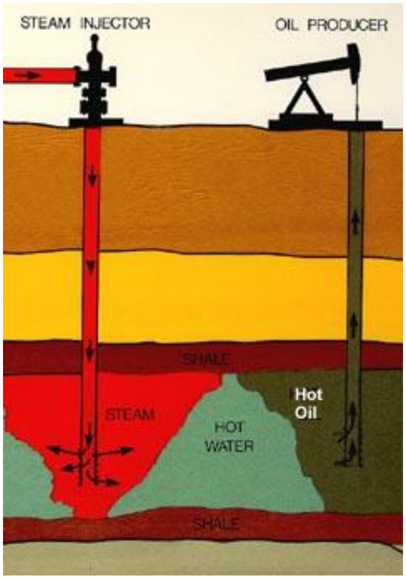


Figure 2.1: Steam injection on the left side that reduces viscosity of the oil through heat on the right side [5].

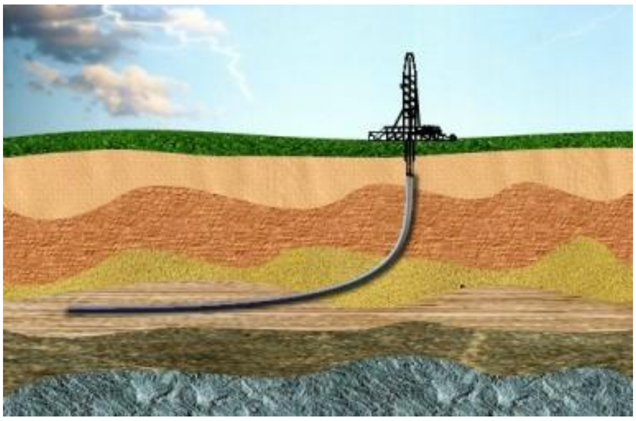

Figure 2.2: Horizontal drilling technique [6].

## 2.1. Managed Pressure Drilling

Since offshore drilling started several records are constantly being overcome such as the height of a platform, the height of the water column between the seafloor and the rig or even the depth of a well. The last one is naturally the most important, not because it is a record to break but because it is needed to go further down. The first resources to be retrieved from the wells are the ones closer to the surface but as soon as those reservoirs are depleted, if there are more resources deeper and if it is possible to drill further, then the cheapest move is to continue instead of looking for a new reservoir and drill it [3]. But drilling deeper has its difficulties too.

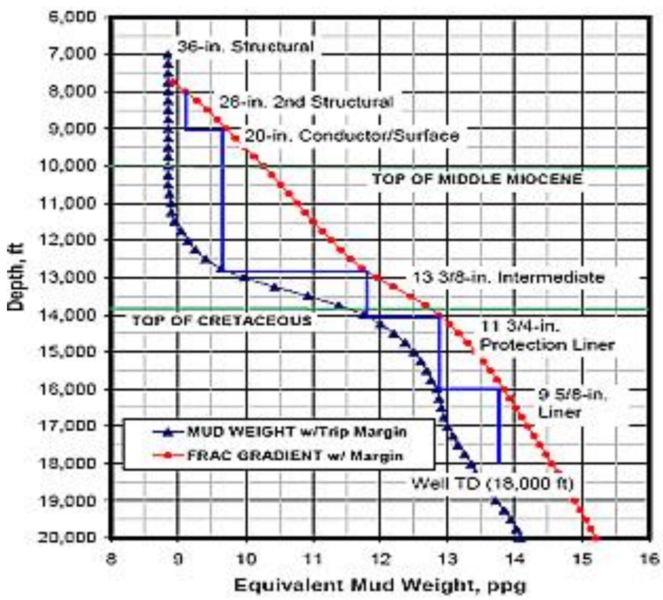


Figure 2.3: Mud weight window [7].

Since the beginning of the drilling process until the extraction of oil and gas from the reservoirs that pressure is one of the most important variables requiring a constant vigilance. If it is not controlled the well might fracture if the pressure is too high, which leads to fluid losses, or collapse if the pressure is too low. This two limit values define the pressure window or mud weight window (MWW) and they change with depth and with soil properties (figure 2.3). The reduction of this window is often encountered offshore due to marine sediments. MPD is a compilation of drilling techniques developed to be used when conventional drilling is not possible to be used due to the MWW being too tight to accurately control BHP [3]. We can see in figure 2.3 that every time mud density gets closer to one of the limits drilling stops and cementing process starts. MPD goal is to minimize the amount of times drilling has to stop to cement as with MPD the blue line representing the real mud density changes to a continuous line.

During drilling process mud is pumped down through the drill string and up through the wellbore annulus. This circulation leads to an annular friction pressure variation which changes equivalent circulating mud density. In order to counter this oscillations mud flow must be controlled. According to Mohamed A. Mashaal et al. [8] “The basic principle of this form of MPD is to apply annular surface back pressure (SBP) to control the BHP and compensate for annular pressure fluctuations that result from switching mud pumps on and off. [...] a rotating control device (RCD) seals the top of the annulus and the flow of mud from the well is controlled by a choke manifold to apply a desired SBP.”

MPD technique was applied in 2012 on the Harding Field [8]. The goal at the time was to assure a constant BHP while drilling. An automated system would allow a set-point for that pressure to be established so the choke at the exit point would open/close automatically if pressure variations were verified. Naturally there is always an error associated to it which might result from the MPD system itself as estimations and calibrations are made at first, from the variation of drilling parameters in transient situations or even from unexpected events like equipment failures. The BHP window and the respective mud weight to be used during the process are also estimated to secure the safety of the process. Despite having some problems with the equipment (resulting in 10 days of non productive time), the two different sections drilled on the Harding Field were successfully drilled with MPD technique showing that it is possible to reach distant reservoirs when they are not conventionally reachable.

### 2.2. Managed Pressure Cementing

MPC technique came up right after good and regular results with MPD techniques as it consists on controlling the BHP by applying SBP through an automatic choke. The pressure along the well is kept as steady as possible and inside the MWW referred before. The expected mud density (in this case fluid density as there is cement inside as well) behaviour is expected to be approximately equal to the one obtained when MPD is applied.

By maintaining a constant pressure along the well it will be possible to assure a better isolation by cementing the well without losing any fluid to the formation or get formation fluids inside the annulus. Before MPC technique the cementation process was based in estimates and predictions from data about soil properties and information on possible gas chambers. According to Youssef Elmarsafawi and Amor Beggah [3] “The conventional method consists in the natural tendency to increase slurry density to avoid well kicks and trip gas” while MPC will “maintain the well-bore pressure between the pore pressure and fracture pressure.”

When MPC started to be used at first the pressure was controlled by a manual choke but soon the automatic one was implemented. The Kvitebjørn Field was one of the platforms from the North Sea that tried MPC by having as basis MPD technique and equipment. Acording to Knut Steinar Bjørkevoll et al. [5] this platform was the first to run and cement a liner with an automatic choke to control the flow inside the well. As they had to project the model they ran several simulations to try to approximate it to reality as much as possible stating that the challenging part was precisely to do the transition from the estimates and simulations of the projected model to the real time calculations as there was always some noisy data and the computer response had to be really fast to give reliability to the model.

# CHAPTER 3

# CASE STUDY

This chapter presents the simplified model to simulate the automated control of the bottom hole pressure while cementing a well offshore.

Firstly, assumptions made regarding fluids properties in order to simplify the model are justified. Then the well structure is detailed and the equations for the variables ruling the fluid movement are explained.

## 3.1. Cement & Mud Properties/Behaviours

As a fluid dynamics problem there are several fluid properties that must be taken into account such as pressure, velocity, density and temperature as function of time and space. In terms of space variable it will be only considered the vertical displacement. The first assumption in order to simplify the problem is to consider cement incompressible in comparison with mud. As a fluid, cement is naturally compressible but if we take into account its isothermal bulk modulus (inverse of compressibility) we see that it is around $40\,GPa$ (Portland cement is the most common) [9] while mud bulk value is within the same value as water bulk modulus ($\cong 2\,GPa$). So if both fluids are submitted to a certain pressure pushing them against each other mud will be more compressed than cement. In order to simplify the problem temperature variations will be neglected so the density will not change in time (isothermal flow). Regarding the flow, it can be laminar inside the casings but inside the annulus it can be turbulent. As the type of flow and its behaviour is not a major problem at this stage it will be considered laminar everywhere inside the well for simplicity of the problem. Table 1 shows some fluid properties that will be considered while simulating the model.

| | Density $(kg/m^3)$ | Isothermal Bulk Modulus $(GPa)$ |
|---|---|---|
| Mud | $1500$ | $1{,}5$ |
| Cement | $2000$ | $40$ |

Table 1: Mud and cement properties.

There are three conservation laws which rule fluid dynamics: conservation of mass (Eq. 1), conservation of energy (Eq. 2) and conservation of momentum (Eq. 3).

$$\frac{\partial}{\partial t}\iiint_V \rho \, dV + \iint_A \rho(\vec{v}.\vec{n}) \, dA = 0 \qquad \text{(Eq. 1)}$$

$$\frac{\partial}{\partial t}\iiint_V E\rho \, dV + \iint_A E\rho(\vec{v}.\vec{n}) \, dA = 0 \qquad \text{(Eq. 2)}$$

$$\sum_i \vec{F_i} = \frac{d\vec{p}}{dt} = \frac{d}{dt}\iiint_V \vec{v}\rho \, dV + \iint_A \vec{v}\rho(\vec{v}.\vec{n}) \, dA \qquad \text{(Eq. 3)}$$

The referred laws are applied to steady state systems where the first two equations state that the variations of mass/energy per unit time are equal to the difference between the mass flowing in and out of the system (Eq. 1) and the energy transferred to and from the system (Eq. 2) as energy can neither be created nor destroyed only transformed. The last equation above is also known as Newton's Second Law of Motion which says that the sum of the forces on a system is equal to the variation of linear momentum per unit time, where the system is represented by its momentum $\vec{p}$ which is equal to $(m\vec{v})$, its mass $m$ and its velocity $\vec{v}$. $\vec{F_i}$ is the $i-th$ force acting on the system, $V$ is its volume, $\rho$ is its density and $A$ is the system area that the flow through where $\vec{n}$ is area's normal. The variable $E$ is the system total energy (intern, kinetic and potential).

As it was said before, unlike the cement, mud will be considered as a compressible fluid which means balance from Eq. 1 will be different from zero. Considering the equation referred and knowing the process is isothermal

$$\frac{\partial}{\partial t}\iiint_V \rho \, dV + \iint_A \rho(\vec{v}.\vec{n}) \, dA = \frac{V}{\beta}\frac{dP}{dt} \qquad \text{(Eq. 4)}$$

where P denotes pressure and $\beta$ is the mud isothermal bulk modulus [10].

### 3.2. Well Structure

A wellbore has different dimensions along the process (length increases and outside diameter decreases with depth for example) but the structures used are similar on all wells. At the top a riser (in offshore cases) is used to connect the rig to the sea floor. The drilling starts at this level and several casings are cemented after each other one at a time. The next casing must be narrower than the previous one as it has to be moved through it. The drill pipe moves inside the riser and casings and the drill bit (end of the drill pipe) moves downwards inside the open hole that it drills which will be cemented next. Before the cementing process of a section normally a malleable liner is attached to the end of the previous casing before inserting the next casing in order to save steel and therefore reduce costs.

The fluid circulation during cementing starts at the top by pumping the fluid inside the drill pipe. After reaching the open hole the fluid starts moving up through the annular cavity created by the previous casings and the drill pipe ending expelled through a choke placed at the rig level.

The model for this project presents the structure referred before and for simplicity it will be considered that the section/casing to be cemented is the first one so we have the riser and an open hole where the first casing is inserted with a liner after the riser and the drill pipe steady inside the structure.

### 3.3. Variables

There are several variables important to track during simulation. Some of them are state variables and others are calculated through previous equations and other basic equations.

#### 3.3.1. State Variables

State variables (represented by $\gamma$ in the next equation) are the ones used to describe the dynamic system and are represented by differential equations

$$\dot{\gamma} = f(\gamma, w) \qquad \text{(Eq. 5)}$$

Physically they are continuous but in order to be able to represent them in programming language a discrete algorithm has to be used. By definition, the derivative is given by

$$\dot{\gamma} = \frac{\gamma(k+\Delta t) - \gamma(k)}{\Delta t} \qquad \text{(Eq. 6)}$$

and by manipulation we get to Euler Integration (Eq. 7) where $\gamma$ is the state variable, $k$ represents the current iteration, $f(.)$ is a function that gives the increment to be added to $\gamma$ which depends on other variables ($w$) and on the state variable itself and $\Delta t$ is the time step which has to be small enough to give plausible results according to what would be expected if a continuous system was considered (it will be $0{,}1$ seconds while executing the simulation).

$$\gamma_{k+1} = \gamma_k + \Delta t\, f(\gamma_k, u_k) \qquad \text{(Eq. 7)}$$

The position $(x)$ of the cement inside the well, its average velocity $(v_{av})$ and its volume $(V_c)$ are three of the state variables. Mud volume $(V_m)$ pumped inside the well over the cement is also a state variable while the other two are the pressures at the top near the pump (input), $P_p$ and choke (output), $P_c$.

### 3.3.2. Other Variables & Respective Equations

There are other variables important to refer as they are used in (Eq. 7). The position $x$ referred before is the cement front (or head) which grows with depth (like any other length variable). There are two other positions traced: the cement back (or tail), $y$, and the mud tail (mud being pumped after cement), $z$ (figure 3.1). The first one allows understanding if the cement is in one or more different casings and also indicates the front of the mud over the cement while the second gives us the length of the gap created at the top due the cement being denser than the mud bellow it. As the front of the cement is a state variable the other two are designed according to

$$y = x - \frac{V_c}{A_{avy}} \quad \text{(Eq. 8)}$$

$$z = x - \frac{V_c + V_m}{A_{avz}} \quad \text{(Eq. 9)}$$

where $A_{avy}/A_{avz}$ are the average cross sectional areas of the casings where the fluids are. This is approximated by dividing the known volume of cement inside the casings by its length disregarding the diameter of each casing.

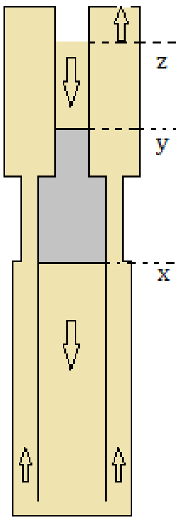


Figure 3.1: Intermediary state with cement between mud. $\boldsymbol{x}$ – cement head; $\boldsymbol{y}$ – cement tail; $\boldsymbol{z}$ – mud tail.

In order to get the displacement of cement at the front the velocity $v$ is calculated via the average velocity value. From equation of mass balance as what goes inside a system is equal to what comes out of it its flow across the entire system must remain the same

$$q = q_{av} \Leftrightarrow v\,A = v_{av}\,A_{av} \Leftrightarrow v = \frac{A_{av}}{A}\,v_{av} \qquad \text{(Eq. 10)}$$

At first the velocity of the front of the cement was being used instead of the average one as a state variable but as soon as the mud would reach a casing with a different area the oscillations in acceleration were too big to use with the discrete algorithm. This was happening because the cross sectional area was abruptly changing from one iteration to the next. Applying Eq. 3 at the front of the cement in order to know its acceleration we get Eq. 11.

$$\sum_i \overrightarrow{F_i} = \overrightarrow{F_y} + \overrightarrow{F_x} + \overrightarrow{F_g} + \overrightarrow{F_f} = \frac{d}{dt}\iiint_V \vec{v}\rho\,dV + \iint_A \vec{v}\rho(\vec{v}.\vec{n})\,dA \qquad \text{(Eq. 11)}$$

where the first two forces on the left side of the equation are due to the pressure applied over and under the cement at positions $y$ and $x$ respectively, the third force is caused by gravity applied on the cement column and the last comes from friction caused by the casings in contact with the cement. If two different areas would have been considered for the first two terms in a casing transition situation, as force is the pressure applied on a surface and as the pressures do not change abruptly between iterations, the second term would increase too much and would make the fluid to run back. Also if we look at the right side of the equation, if different areas were considered along the well, the velocity would change and it would make the problem much more difficult therefore it was decided to use average values for both velocity and cross sectional areas.

Simplifying Eq. 11

$$\sum_i \vec{F_i} \equiv (P_y - P_x)A_{av} + m_c g(x - y) - F_f = m_c \frac{dv_{av}}{dt} \equiv m_c a \Leftrightarrow$$

$$\Leftrightarrow a = \left[(P_y - P_x)A_{av} + m_c g(x - y) - v_{av} f\right]/m_c \qquad \text{(Eq. 12)}$$

cement acceleration is retrieved by dividing both sides by cement mass, where $P$ denotes pressure and $g$ the acceleration of gravity ($9{,}8\, m/s^2$). When the previous equation is used to calculate de acceleration $F_f$ is the average velocity $v_{av}$ of the cement times a constant $f$ determined by trial and error (the obtained value for simulation is $0{,}4\, Kg/s$[1]). As the frictional term is suppose to change with velocity it was decided not to set it as a constant value.

In order to obtain most of the pressure values along the well two physical phenomena were considered: the hydrostatic pressure $P_h$ which is the pressure due to forces applied on the fluid when it is at rest, like gravity applied by the column of fluid above the point where it is wanted the pressure value, and the frictional pressure term $P_f$ which in this case is associated to the energy loss due to fluid viscosity and pipe roughness. Both pressures at the top (at the pump and at the choke) are not calculated through Eq. 13 as they are state variables but the other pressures of interest considered at $x$, $y$ and $z$ points in depth have the next formula as basis

$$P = P_0 + P_h + P_f \qquad \text{(Eq. 13)}$$

where $P_0$ denotes the pressure over the column that contributes to the hydrostatic parameter [3, 10].

Finally, as it was referred before, pressures at the top are state variables so they are obtained through Euler Integration but its variations ($f$ function) are retrieved from Eq. 4 where the first term is represented by the variation of

[1] Variable $f$ has as unit $kg/s$ because it is being multiplied by velocity and its result must be a force which has Newton ($N$) as unit ($N = kg.m/s^2$).

volume of mud beneath it and the second is the flow in or out depending on if it is being calculated the pump or choke pressure respectively.

Pump pressure variation:

$$-\dot{V}_{mp} + q_p = \frac{V_{mp}}{\beta}\dot{P}_p \Leftrightarrow \dot{P}_p = \left(-\dot{V}_{mp} + q_p\right)\frac{\beta}{V_{mp}} \qquad \text{(Eq. 14)}$$

Choke pressure variation:

$$\dot{V}_{mc} - q_c = \frac{V_{mc}}{\beta}\dot{P}_c \Leftrightarrow \dot{P}_p = \left(\dot{V}_{mc} - q_c\right)\frac{\beta}{V_{mc}} \qquad \text{(Eq. 15)}$$

The volumes indicated in the previous equations are the volume of mud pumped after cement (Eq. 14) and volume of mud already inside the well before pumping the cement (Eq. 15) which decreases with time. Their derivatives are calculated based on the cement flow rate given by its average velocity times the average casing cross sectional area enunciated before. The flow in $q_p$ is a constant defined by the engineer while the flow out $q_c$ is obtained through the choke equation

$$q_c = k_c u\sqrt{P_c - P_{atm}} \qquad \text{(Eq. 16)}$$

where $P_{atm}$ is the atmospheric pressure while $k_c$ is the choke constant which represents its physical properties designed by its manufacturer but that in this case was calculated based on reference values applied on Eq. 16. The $u$ variable simulates the choke opening and it can take a value between zero (totally closed) and one (totally opened). On the next chapter it will be explained the influence of this variable on the PI controller.

# CHAPTER 4

# CONTROLLER MODEL

The controller is a central piece in this project. It will allow constraining the annular bottom hole pressure between pore and fracture pressures through an automatic choke at the top which will work as an actuator to the controller. However this is not exactly how a controller works. Instead of defining boundary values the purpose of having a controller is to set a reference value which in this case is the annular bottom hole pressure and keep the real value around it. Then by adjusting the controller gains it is possible to reject values outside the defined margins.

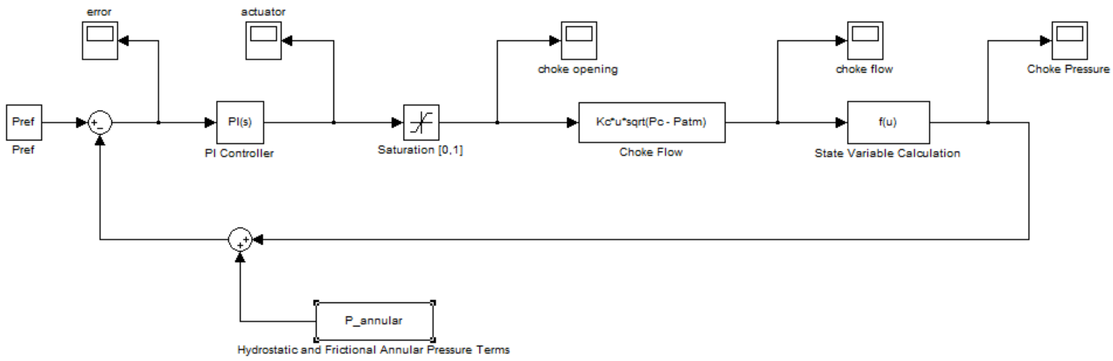


Figure 4.1: Intermediary Block diagram regarding PI controller.

As it is shown on the diagram of figure 4.1 the difference between the reference pressure value and the real one gives the pressure error $e$ which when combined with proportional and integral terms results in the new choke opening value $u$ so that a new choke pressure value is calculated. In order to keep this value as realistic as possible it is defined that if the valve opening goes out of the defined range $[0,1]$ it must keep the limit value as a choke cannot be physically closed or opened more than its maximum.

### 4.1. Proportional and Integral (PI) Controller

About the PI Controller block on the previous image it represents the influence of the gains that will contribute to adjust the pressure. It was decided to have only the proportional and integral terms because they depend on the present error and on the accumulation of past errors respectively [11]. The proportional term is defined by its gain $k_p$ times the error so the response will be faster the higher the proportional gain is. As the integral term is an accumulation of the previous errors it will depend on them so it is calculated by the integral gain $k_i$ times the integral of the error since the initial moment until the present time and the higher it gets the bigger the amplitude of oscillations becomes. The next equation represents the PI controller adopted.

$$u = k_p e + k_i \int e dt \qquad \text{Eq. 17}$$

A differential term regarding prediction errors could have been added but the choice was not including it because despite bringing more stability to the system it easily brings extra noise due to high frequencies which would require a low pass filter to remove them. This would complicate the model instead of simplifying it so it was decided not to deepen this situation.

It is also important to understand how the choke should behave according to pressure oscillations at the bottom hole. So if the pressure increases reaching a higher value than the reference one it means that the error will be negative and so if we consider both constants in equation Eq. 17 higher than zero it will mean that the choke will start closing. This will lead to an increasing of pressure which is not what is desired (the choke should open when pressure increases) so instead of having positive constants $k_p$ and $k_i$ they are set and adjusted with negative values to get the opposite response. They were both found by trial and error method (see table 2).

| | |
|---|---|
| $k_p$ | $-8 \times 10^{-10}$ |
| $k_i$ | $-8 \times 10^{-11}$ |

Table 2: Proportional and Integral values obtained by trial and error to use on the simulation.

As the controller is dealing with very high pressures (the error can reach a few Bar after a perturbation) and as the model is implemented with units according to the International System (SI) the value for the pressure error easily reaches a few hundreds of thousands Pascal. This means that the first constant to adjust ($k_p$) has to be really small so the system do not become unstable. If the proportional gain is too large the system will never be able to achieve the desired value and amplitude oscillations will tend to grow. The integral constant is adjusted afterwards and it should be even smaller than $k_p$ as it accumulates past errors. The main goal while trying to adjust both terms was to keep the choke opening in between the desired limits without reaching them so that it is assured that the controller is working during the maximum simulation time.

### 4.2. Annular Bottom Hole Pressure

As soon as the new valve opening value is calculated Eq. 16 is used to get the flow through it. As the choke pressure is a state variable the flow obtained previously through Eq. 16 will be inserted in Eq. 15 which gives the pressure variation at the valve. Adding to the new choke pressure the hydrostatic and frictional pressure terms due to the annular fluid column we get annular bottom hole pressure from Eq. 13. This new value will be the next one to calculate the new error and so on.

# CHAPTER 5

# SIMULATION

After explaining the whole generalized model with its equations it is important to take into account that models are not that linear and there are always some special cases or situations where equations suffer some changes especially during transition moments. This model is not an exception so before showing the obtained results it will be particularized and explained special cases and transition moments.

## 5.1. Dimensioning & Initial State

Before approaching the simulation itself the well dimensioning had to be made. In order to have a more realistic case Statoil provided the physical dimensions like casing sections length and different well diameters. Some of the initial conditions were also provided by them and others were assumed.

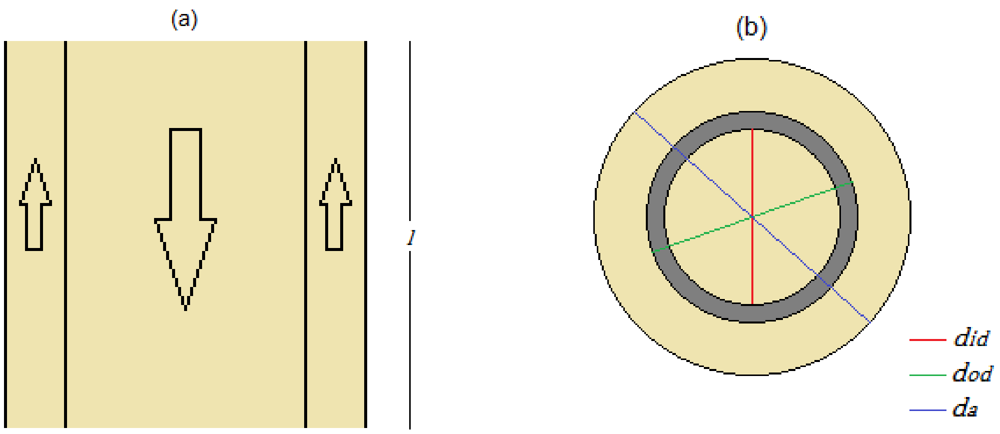


Figure 5.1: Longitudinal (a) and cross sectional (b) views of a well section.

Figure 3 shows the variables needed for the model: from image (a) we can see the length provided in depth and from image (b) the different diameters considered for the same section. The variable $l$ stands for a uniform casing section length, while $d_{id}$ and $d_{od}$ correspond to the inner and outer diameters of a casing section respectively, and $d_a$ to the annular diameter of that same segment. So for the different sections along the well presented in figure 5.1 we have the sizes form table 3.

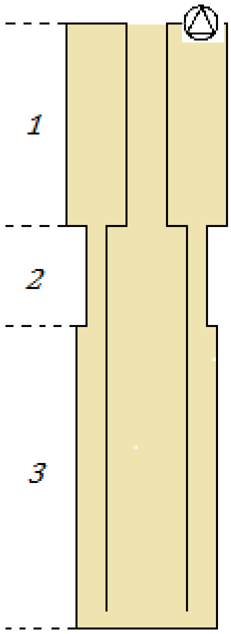


Figure 5.2: Longitudinal Different sections of the well structure.

| | Depth $(m)$ | Inner Diameter $(Inch)$[2] | Outer Diameter $(Inch)$ |
|---|---|---|---|
| Drill Pipe (1) | $0 - 2000$ | $5{,}000$ | $6{,}625$ |
| Casing (2 & 3) | $2000 - 6000$ | $12{,}409$ | $14{,}000$ |
| Open Hole (3) | $3000 - 6000$ | $19{,}000$ | – |
| Liner (2) | $2000 - 3000$ | $16{,}750$ | $18{,}000$ |
| Riser (1) | $0 - 2000$ | $19{,}000$ | $21{,}000$ |

Table 3: Lengths and diameters of different well's sections given by Statoil. Numbers between parentheses are making reference to the different sections on figure 5.2.

[2] Diameters are in Inch instead of Meter (SI unit) to avoid the usage of small numbers and because it is the common unit inside petroleum engineering community ($1\ Inch = 0{,}0254\ m$).

Considering now the initial conditions that will trigger the beginning of the simulation it is important to understand that despite not simulating the circulation of only mud inside the well before pumping the cement it is considered that when the simulation starts the fluid inside the well is in a steady state. Consequently there is a flow inside the well and there are pressures applied at the top. During the simulation the pump rate will differ from cement to mud and from stage to stage but in any case it will remain constant as it is a variable controlled by the engineer.

The cement is always pumped at the same rate which is $500\ l/min$ and there are $60$ thousand litres to pump so it must take $2$ hours to be pumped in. So in order to keep the steady state from the previous situation it is assumed that the initial flow in is the same as the initial flow out which is equal to the cement flow rate. In order to push the cement a pressure of $100\ Bar$[3] is applied at the pump at the beginning and the choke pressure is considered equal to $20\ Bar$ while it is considered that the choke is exactly half opened ($u_i = 0{,}5$).

Finally as the pressure reference ($\boldsymbol{P_{ref}}$) at the bottom of the well is $890\ Bar$ it was decided to start with a different value so that it would be possible to understand if the controller was working properly. From some of the previous values the choke constant $k_c$ is calculated by manipulating Eq. 16 [12]

$$k_c = \frac{q_m}{u_i\sqrt{P_{ref}-P_{atm}}} = 5{,}1854 \times 10^{-5} \qquad \text{Eq. 18}$$

where $\boldsymbol{q_m}$ is the mud flow after cement. These values were the chosen ones because they are references during the simulation so they represent the most common/desired values.

[3] For pressure values the adopted unit is Bar instead of Pascal (SI unit) to avoid large numbers and because it is the common unit inside petroleum engineering community ($1\ Bar = 1 \times 10^5\ Pa$).

## 5.2. Cement Displacement

With the general model and equations defined the focus is now on the simplifications and or obstacles that appeared after implementing it. As the well of the case study has different dimensions in depth it was necessary to define different stages for different physical dimensions which led to transition situations that required special attention.

The simulation starts with the casing ready to be cemented (figure 5.3 (a)) and with the cement being pumped in. As its density is higher than the mud already inside the well cement weight will play a major role pushing the mud downwards and creating a gap at the top due to gravity force (figure 5 (b)). During the first cubic meter of cement pumped it is assumed that its acceleration is zero so it has a constant velocity. This situation occurs because if we try to calculate the acceleration with Eq. 12 it would be too big because cement mass would be too small.

The pump pressure is other variable that suffers changes while pumping the cement. Instead of considering it as a state variable during that period it is a constant and equal to the initial value ($100\ Bar$) while the gap created is not big enough ($2$ meters). As soon as the space exceeds that value the pressure is dropped to zero[4].

When cement reaches the casing (figure 5.3 (c)) the changing in area makes the difference. Physically in order to keep the flow constant if the area increases the velocity across it should decrease proportionally. As this change is abrupt the velocity would also change suddenly so the average area and velocity variables referred on chapter 4 are introduced in Eq. 12 ($F_f$ is the force due to friction which depends on the fluid velocity which in this case would be the average value). This change also smoothes the acceleration variations and avoids oscillations on the cement position.

[4] In reality the pressure drops to atmospheric pressure but as in all calculations made this value was much smaller than other pressure values at stake the value for it is $0\ Bar$ instead of $1\ Bar$.

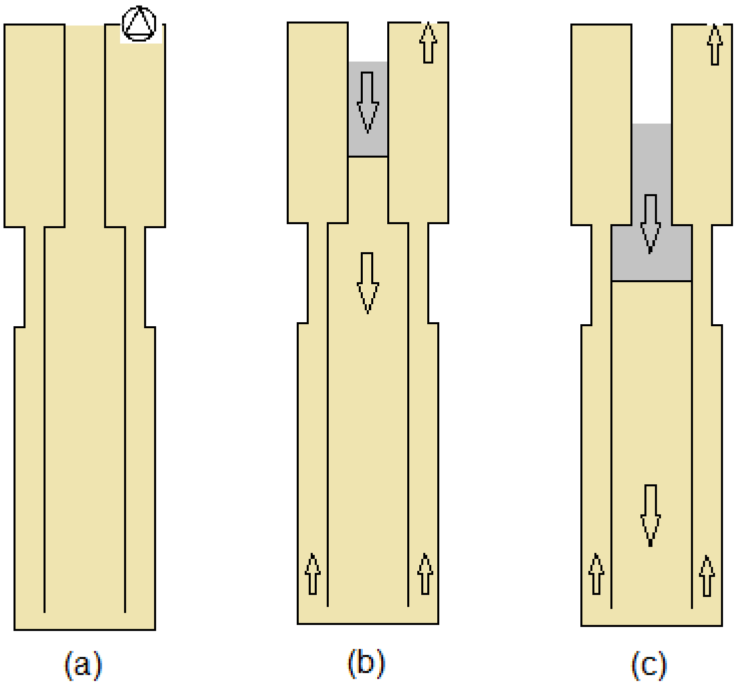


Figure 5.3: Ciment displacement while pumping it. (a) Initial state with no cement; (b) Cement inside drill pipe section; (c) Cement inside both drill pipe and casing sections.

After pumping the $60\ m^3$ of cement it is time to keep pushing it down so mud is pumped in with a higher rate. Until the gap created at the top does not disappear mud is pumped at $2200\ l/min$ (figure 5.4 (a)). At the moment mud reaches the top (figure 5.4 (b)) the pump pressure becomes a state variable like described in chapter 4 and according to Statoil the flow rate is decreased so that the pressure does not increase too much at the top and consequently at the bottom. The flow rate is halved and as soon as cement hits the bottom of the well it is changed to a third of the starting mud rate value. At this final stage (figure 5.4 (c)) cement starts going inside the annulus and going up so the pressure at the bottom is expected to increase as until now was calculated based on the mud column of the annulus while from this moment on it is calculated on that same column but with cement volume increasing inside it which is heavier than mud. In order to reduce the pressure at the bottom it is expected that the controller fully opens the choke at the top. The simulation ends when all the cement leaves the casing to the annular cavity (Figure 5.4 (d)).

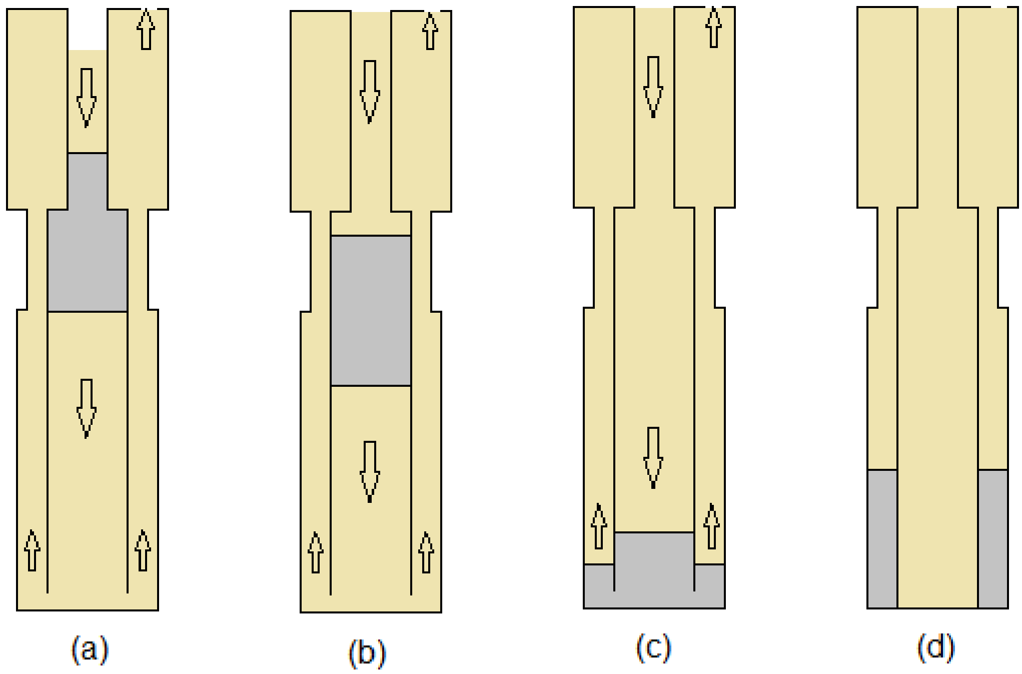


Figure 5.4: Ciment displacement while pumping mud. (a) Cement still inside drill pipe and casing sections; (b) Cement only inside casing section; (c) Cement reaches the bottom and goes to the annulus; (d) Final state with cement inside of the bottom part of the annulus.

Next figure shows the model described before implemented on MatLab software. It represents the continuous sequence of stages from the two previous figures. We can see that cement moves down and after a few minutes its weight it is enough to push it. When it reaches the casing at $2000\,m$ depth there is already a gap at the top and the velocity at the head decreases due to the larger pipe. It starts moving faster after $2$ hours of simulation as mud starts being pumped (at a higher rate than cement) and after a few minutes the gap is filled. As this period is really short the change in speed is not notable unlike when the cement hits the bottom where the red line slope decreases. After $7.5$ hours the simulation ends and the well is left at rest so the cement dries.

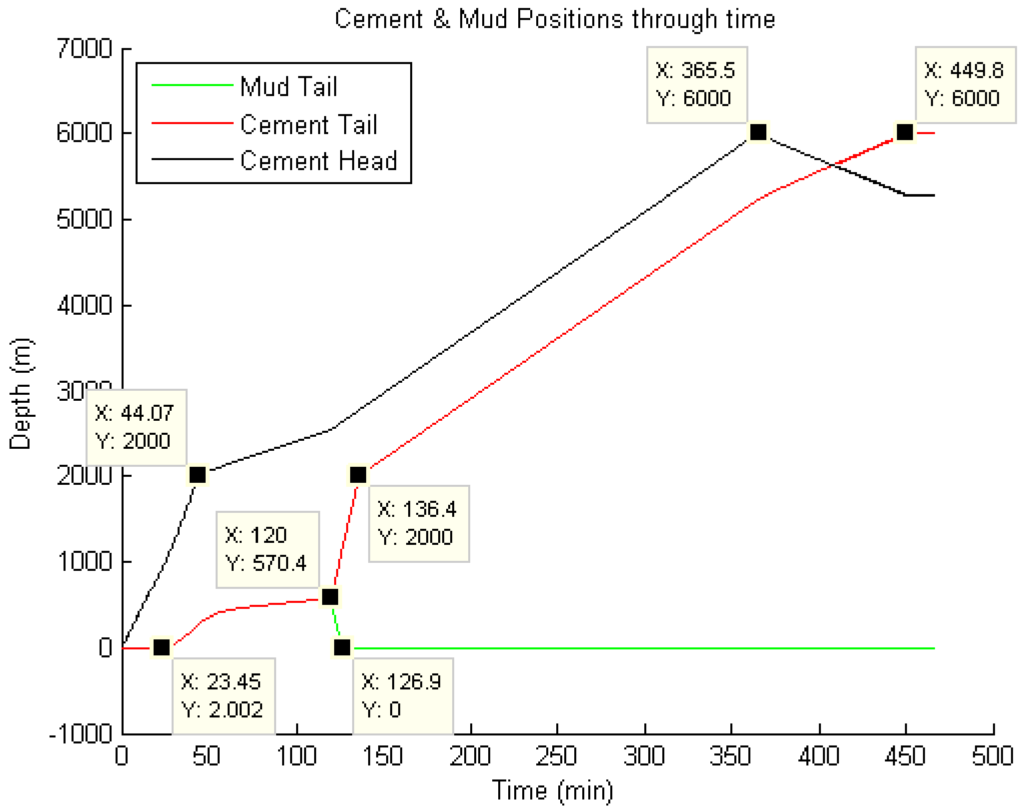


Figure 5.5: Simulation of the behaviour of the fluids inside the well. Pinpointed coordinates show transition states.

In the previous figure we can see some specific coordinates pinpointed. Moving from the beginning until the end on $x$-axis the first point marks the moment when cement weight is enough to push the mud down. The second shows when cement reaches the casing at $2000\ m$ depth. After $120$ minutes we see that mud starts being pumped in and after almost seven minutes mud reaches the top as the flow at the pump is higher than inside the well. The fifth point informs that mud as also reached the casing. The two last points point out the moments cement (black line) and mud (red line) reach the bottom of the well.

# CHAPTER 6

# RESULTS DISCUSSION

The main goal of this project besides projecting the model is to try to understand how the pressure at the bottom behaves as there are no sensors able to measure it. After implementing the model and following the simulation presented on the previous chapter the results obtained on pressures at the top and at the bottom and also the flows in and out will be presented in graphics, explained and discussed in this chapter.

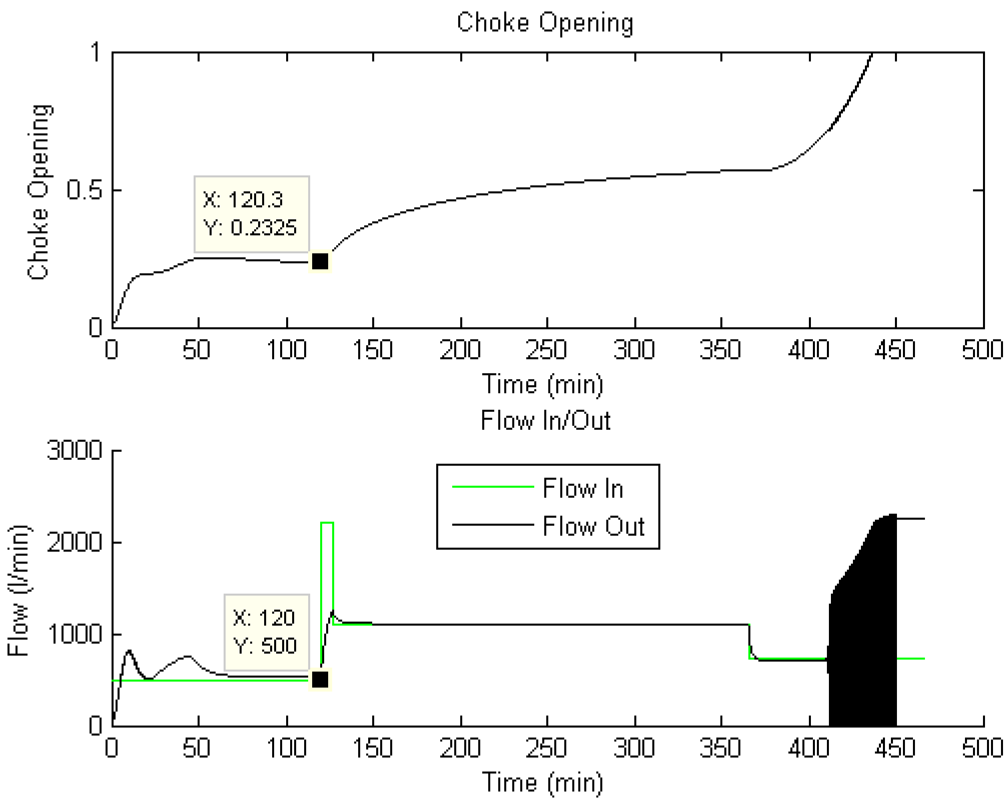


Figure 6.1: Simulation of choke behaviour (top graphic) and flow in and out of the well (bottom graphic). Coordenates pinpointed on both graphics show the transition moment when mud is pumped after cement.

Figure 6.1 projects what is happening at the top in terms of flow. The first graphic reports the adjustment that the choke is doing during the simulation in order to try to keep its pressure constant and regulate the flow out of the well while in the second graphic we can see the input flow set by the engineer. The first segment lasts until the cement is all inside the well while the second and very small segment is the transition moment when mud is being pumped while there is a gap at the top which quickly disappears and the flow in is decreased to avoid overpressure. The oscillations at the end can be better explained looking at figure 6.2. When the cement hits the bottom the pump rate is decreased because as soon as cement starts going into the annulus the hydrostatic pressure of its fluid column increases really fast so the flow decreasing is more a preventive measure. The pressure will tend to decrease as well and the controller starts closing the choke until the moment it starts increasing again due to the cement inside the annular cavity and so the choke opens and so on.

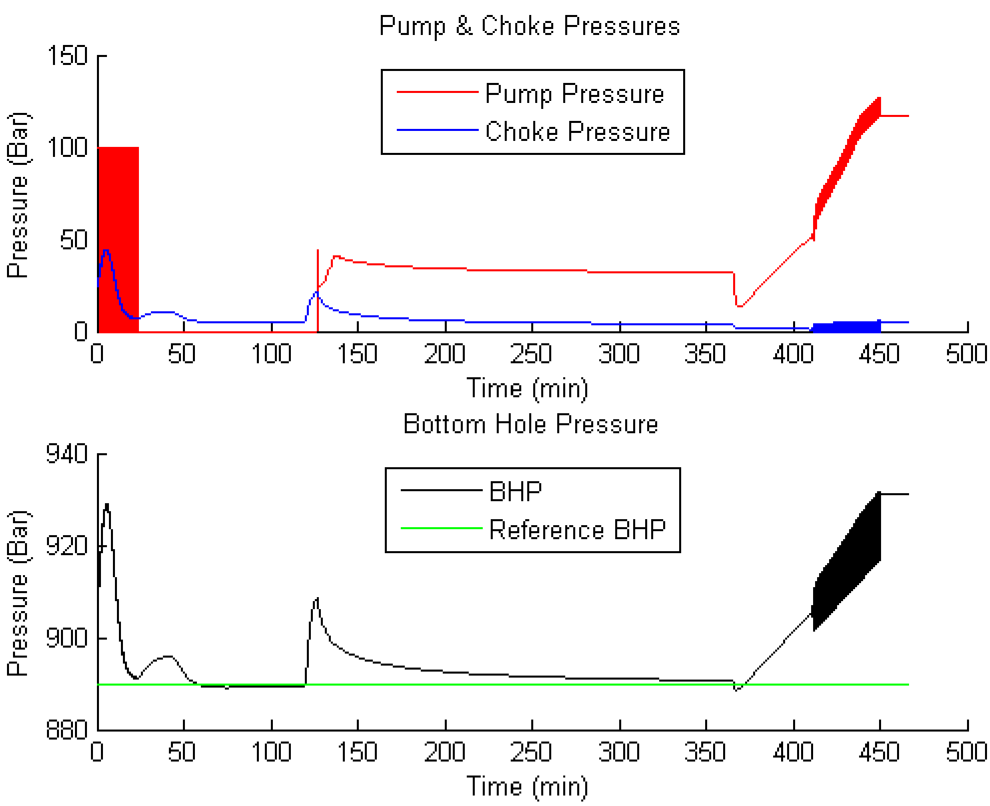


Figure 6.2: Simulation of the estimated pressures at the top and at the bottom (top and bottom graphics respectively).

Figure 6.2 also presents some oscillations at the beginning. They are due to the fact the pump pressure at the beginning is set to be $100\ Bar$ if the gap at the top is smaller than $2$ meters. The gap actually surpasses that length several times but in between those times the cement at the top is not enough to push the mud down with its weight so its velocity is still smaller than cement velocity at the pump so the gap decreases and $100\ Bar$ is applied again at the top. As the flow out is also disturbed by this oscillations we can see a high peak on BHP and choke pressure but then the controller adjusts and tries to stabilize them.

Last figure also confirms that the BHP follows the same behaviour as the choke pressure except when cement goes inside the annulus. The second highest peak (after $2$ hours) on pressure at the bottom occurs when the gap created by the cement is filled by the mud and consequently all the well is under pressure including the pump. The small perturbation between the two referred hills happens when pressure is no longer being applied at the pump. The controller smoothes the choke opening (opens slower) because the pressure at the bottom is not increasing and so the fluid near the choke is strangled when it should not as it is not taking into account the delay due to mud compressibility and the fact the actuator (choke) is quite far from the controlled variable.

Finally we can see that the controller is working as the BHP tends to the reference value and also the flow out tends to be equal to the flow in but not perfectly. The controller takes too much time to adjust and the proof is that BHP never reaches the desired value considering the interval with no perturbations from the minute $150$ to the $350$ for example. This fact can be explained by the really small values attributed to the controller gains but, as an example, if they were increased by a factor of two the choke would totally open in the middle of the interval referred before and the pressure would never reach the wanted value.

In a similar situation as the controller gains the other outputs like flow in and the pump pressure at the beginning are variables that must be adjusted as they are oscillating too much. Smoothing them instead of changing them abruptly can be a way to do it but in terms of MatLab code it would mean to have time dependencies which may not be a reliable thing as for example if the flow is increased the simulation will take less time to finish.

# CHAPTER 7

# CONCLUSION

This project was not an easy one as I had never had any contact with oil industry so almost everything was new to me and the starting point was difficult to find as I did not really know what to look for but it ended up being a project that I enjoyed a lot and that I could learn a lot with.

Firstly we can conclude that this project is still in an early stage. A lot of simplifications were considered as there was no support and previous work on the model. There were several obstacles like the fact that we are dealing with fluids that can have different behaviours in similar situations especially if a more realistic test is possible to do in the future.

About the results, they are within what was expected as the pressure inside the well was under control during the entire simulation except at the end when the cement would reach the bottom and pressure would start to increase and oscillate. That is not good for the choke as it will open and close really fast and can damage it. So as a future work on the PI controller maybe it should be consider calculating the gains through other known methods.

The model projected on this thesis is really simple and due to that it showed that it is a reliable one but it does not totally represent the reality. The fact that the velocity considered inside the well to make the calculations was an average value it is probably one of the biggest differences to reality as it changes when it is compressed (for example the head of the cement does not have the same velocity as the tail) and it also varies from a central position to a position near a wall due to friction losses.

To conclude, the pressure at the top revealed to be one of the most difficult variables to adjust. In real time there is always pressure at the pump as long as there is no gap at the top right after it but programming that became really difficult as there is no such thing as an infinitesimal value to define as a gap size. If the value was to small pressure would end up being no high enough and the fluids would flow in the opposite direction and if it was too large at a certain point it would not make sense to apply pressure at the pump if there was a space right next to it. Smoothing changes in constants can be an improvement to do in the future.

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