Managed Pressure Cementing: Control System Design & Simulation

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Abstract — Oil and gas extraction have always been a dangerous process, starting with the hole drilling. When it starts, to avoid walls collapse, casings are inserted and cemented. This process not only guarantees a solid well structure but also avoids losses of any fluid to the formation, where cement works as isolator, preventing environmental problems.

Managed Pressure Cementing (MPC) is a method to cement deep offshore wells in a safer, more controlled and more efficient way. It is a relatively new process therefore companies are very conservative with releasing information to the outside world. Oil platforms normally belong to companies that hire subcontractors, i.e. smaller companies, to perform different specialized works, but the rig owner always assigns his own staff to supervise the different operations. Statoil commissioned this project thesis with the objective of providing a complement to the training given to supervisors who will follow future cementing processes.

A model for predicting fluids behaviour inside the well was implemented using MATLAB software. The objective of such approach is to develop simulations in a controlled computational environment and draw relevant conclusions e.g. to characterize the pressure profiles inside the well. In order to fulfil the main objective of managing the Bottom Hole Pressure (BHP), a Proportional and Integral (PI) controller is integrated on the model. It actuates on an automatic choke at the rig that regulates the flow out of the well, opening/closing it and consequently changing Surface Back Pressure (SBP). The pressure reference at the bottom is 898 Bar, which has an error window of $\pm 6,9$ Bar.

The results obtained from computational simulations validate proposed control objectives, since the BHP evolved inside defined boundaries, except during one critical moment.

***Index Terms* — Managed Pressure Cementing; Bottom Hole Pressure; Modelling Well Structure & Fluid Flow; Proportional and Integral Controller; Automatic Choke.**

I. Introduction

A. Motivation

This project thesis was developed in cooperation with Statoil, which is appointed as one of the world's biggest oil companies in 2015 [1]. Statoil owns a large number of offshore rigs, therefore it is a normal procedure to hire specialized contractors, which are smaller companies with competencies and capacities to execute specific operations.

MPC is a technique already being implemented by small companies, but as it is a new method they are normally conservative about sharing specific information and details regarding the process. This project aims at becoming the beginning of a guide to complement the supervisor's training on the cementation process.

In terms of technological progress, MPC technique mainly brings more safety by improving zonal isolation without inducing losses to the formation and avoiding formation fluids flowing to the annulus during cementing process [2].

In terms of the technique itself, its main goal is to keep the annular BHP between the pore pressure and fracture pressure which define the pressure window, but as the project implements a PI controller, the expected BHP is compared to a reference value to minimize the difference between them. It is of utmost significance the controller works properly and BHP stays inside the desired Mud Weight Window (MWW).

B. Previous Work

The first reference case is exposed by Mashaal *et al.* [3] and it is about utilizing MPD technique not only to drill but also to case and cement the Harding PNE2a well in the North Sea. This well is an extended reach well in order to access the remaining oil, but "A combination of reservoir depletion and weak interbedded sands and shales" [3] and equipment failure has result in 10 days of non productive time but still the extended reach well achieved the reservoir, maintaining its BHP.

Bjørkevoll *et al.* [4] refers to utilizing MPD technique to cement an offshore depleted reservoir (Kvitebjørn Field) in the North Sea. This was, "to the author's knowledge, the first time running and cementing a liner has been done with an automatic choke system controlled in real time by an online dynamic flow model" [4]. During drilling operations on the first wells, while the reservoir was full, the conventional method worked, but when the pressure started to increase "depletion caused severe losses". An MPD method had to be developed and tried out. The main concern while planning it was to maintain the down hole pressure constant and focus on the pressure on the entire well. During this operation pressure was being monitored and the choke was actuating to balance the pressure at the bottom, especially at the end, when it was necessary to achieve a certain SBP that would be "equal to the necessary pressure in static well conditions" [4].

Rajabi *et al.* [5], witnessed in Caspian Sea, in 2010, the first time MPC method was used successfully under sea. The technique consisted in RMR using a "closed loop circulation system […] facilitating an excellent level of control over the wellbore pressure". MPC was implemented in a top-hole, so the MWW was tight and the cementing job was difficult due to “loss of cement slurry and shallow water and gas flow” [5]. After placing the cement it was recorded some losses to the formation. Even after a few hours it was possible to notice with the acquired data that pressure would change from zone to zone. Some fluid was still being lost to the formation, but not enough to go beyond the limits of formation and fracture pressures. Also “no gas invasion or leakage” had been detected until the paper publishing [5].

C. Outline

In section II the techniques which serve as basis to MPC are presented while in section III the theoretical foundations are synthesized. Section IV has the obtained results from MatLab model simulation and their discussion. The last section shows the conclusions and possible future work.

II. Background Techniques

This model is built up based on techniques like MPD, Underbalanced Drilling (UD) and/or Riserless Mud Recovery (RMR) techniques, which are used to drill wellbore sections and were already adapted and tried out on the cementing and drilling process successfully.

The conventional cementing process does not control the pressure. Calculations are made to understand the necessary cement and its density but the MWW associated to this has to be larger than when MPC is used.

A. Overbalanced and Underbalanced Drilling

These two techniques are based on hydrostatic pressure of the well column and reservoir’s. While in overbalanced drilling hydrostatic column pressure is higher than reservoir’s, pushing the fluid downwards, underbalanced drilling (UD) works on the opposite direction, meaning the fluid flows to the top, used mainly in production phase. UD is normally achieved by reducing fluids density, injecting an inert gas [6]. It has its cons, being easier to lose control of hydrocarbons production, which can lead to a blowout. Having a low hydrostatic pressure also means an increasing risk of well collapsing [6].

B. Riserless Mud Recovery (RMR)

RMR technique incorporates a dual gradient technology which allows returning the marine sediments with the flow to the rig with the help of a subsea pump connected to a suction module. As the drilling fluid returns to the rig it is possible to reuse it, so one of the advantages is that there are no worries it may run out. The fact of having a closed loop enables to control the volume of the fluid and consequently its flow, in order to follow the pressure variations and compensate them earlier [7]. It ensures improved hole conditions and wellbore quality. With the decreasing of shallow gas kicks and flow loss risks, in addition to the increasing of the mud weight window it also extends the casing set point depth.

C. Managed Pressure Drilling

The method described by Mashaal *et al.* [3] states that the basic principle “of MPD is to apply annular SBP to control the BHP and compensate for annular pressure fluctuations that result from switching mud pumps on and off”. Its main characteristic is the use of an automated choke which mechanically reacts to any pressure oscillation by applying SBP through its opening/closing, in order to keep the BHP steady, around its estimated value for the set-point to the feedback loop. Drilling cost reduction and safety increasing are the main advantages of using MPD [2]. The first one is achieved mainly by reducing the drilling time while the second one is by keeping the BHP away from the pore and fracture limits (avoiding fluids flowing to the formation).

D. Balanced Pressure Cementing by Air Injection in Annuli

Air injection is a method based on both UD and MPD techniques. Considering air injection occurs in annuli, wellbore annular pressure drops until it is lower than reservoir’s. The pressure difference will make the fluid flow from the bottom to the top through the annulus. SBP is then used to keep annular pressure inside MWW [8]. Reducing drilling fluid density allows using the desired density cement slurry guaranteeing its strength during cementing process.

E. Managed Pressure Cementing Technique

MPC process is a conjugation of the techniques enunciated before, mainly MPD and RMR. It uses the dual gradient technique while the BHP is maintained by controlling SBP through an automated choke at the top. This system causes a faster reaction to pressure oscillations, by setting a target BHP value to maintain during the entire process. This is the main advantage as it improves the safety of the well and its “zonal isolation by cementing the annulus without inducing losses to the formation or result in formation fluids flowing to the annulus in a narrow down hole pressure margins.” [2]. One of the biggest challenges is to keep the pressure bellow fracture limit. As cement is denser than mud there is a natural increasing of fluid’s Equivalent Circulating Density, meaning the annular pressure also increases, especially when cement reaches the annulus.

III. Theoretical Foundations

A. Physical Laws

According to Welty *et al.* [9] there are three main physical laws (disregarding “relativistic and nuclear phenomena”) which rule fluid dynamics regardless their nature:

(1) The law of conservation of mass (continuity equation), that states that the difference of mass efflux from and flow into control volume, plus the accumulation of mass within that same control volume during a certain period of time, has to be null.

$$\iint_A \rho(\boldsymbol{v}\cdot\boldsymbol{n})dA + \frac{\partial}{\partial t}\iiint_V \rho dV = 0 \qquad (1)$$

where ρ is fluid density, $\boldsymbol{v}$ is its velocity and V its volume. A is the casing cross sectional area.

(2) Newton's second law of motion (momentum theorem), that affirms "The time rate of change of momentum of a system is equal to the net force acting on the system and takes place in the direction of the net force" [10].

$$\sum \boldsymbol{F} = \iint_A \boldsymbol{v}\rho(\boldsymbol{v}\cdot\boldsymbol{n})\, dA + \frac{d}{dt}\iiint_V \boldsymbol{v}\rho\, dV \qquad (2)$$

(3) The first law of thermodynamics (energy equation), which declares the total variation of energy is due to the exchange of heat between the system and its surroundings and the work done by the system [11], where e is the energy per unit mass.

$$\frac{\partial Q}{dt} - \frac{\partial W}{dt} = \iint_A e\rho(\boldsymbol{v}\cdot\boldsymbol{n})\, dA + \frac{d}{dt}\iiint_V e\rho\, dV \qquad (3)$$

B. Model

This is the section where a quick overview on the equations that rule the model, based on the previous laws, is done.

Taking into consideration that the model is to be applied on MATLAB software and that the previous laws refer to continuity as a "must", the program has to run enough iterations so that the discontinuity is unnoticeable. Its goal is to displace cement over mud along a well, helping pushing it down by pumping mud in afterwards, while a PI controller adjusts SBP at the exit of the well to maintain the BHP steady, until cement is all placed inside the annulus.

Cement head, x, is a state variable and changes with velocity at that same position, which from equation (1) results in

$$q_x = q_{av} \Leftrightarrow v_x\, A_x = v_{av}\, A_{av} \Leftrightarrow v_x = \frac{A_{av}}{A_x}\, v_{av} \qquad (4)$$

where q represents flow, while v_{av} corresponds to average velocity of the cement inside the well (5). An average casing cross sectional area, A_{av}, was created, being the current cement volume inside the well divided by the length of its column.

$$v_{av_{k+1}} = v_{av_k} + \Delta t \cdot a \qquad (5)$$

Acceleration is calculated based on (2), obtaining (6), where the net force over the cement is equal to what is pushing it upwards (x position) plus what is pushing down (y position) plus gravitational and frictional [12] forces.

$$\begin{gathered}\frac{d}{dt}(m_{cem}v_{av}) = (P_y - P_x)\cdot A_{av} + m_{cem}\cdot g + F_f \\ \Leftrightarrow a = \frac{(P_y - P_x)\cdot A_{av} + m_{cem}\cdot g + F_f}{m_{cem}}\end{gathered} \qquad (6)$$

Forces were replaced by pressures, P, over the casings cross sectional areas, in what is considered, equal at the bottom and at the top. Cement mass, m_{cem}, is the amount already inside the well.

Moving forward to pressures equations[13], the top ones change manipulating (1),

$$(q_{out} - q_{in}) + \frac{V}{\beta}\dot{P} = 0 \qquad (7)$$

While pressure at the entrance (pump, P_p, (8)), while pumping cement, is set by the engineer, the one at the exit (choke, P_c, (9)) is automatically adjusted by the controller during the entire simulation.

$$\dot{P_p} = (q_p - \dot{V})\frac{\beta}{V} \qquad (8)$$

$$\dot{P_c} = (-q_c + \dot{V})\frac{\beta}{V} \qquad (9)$$

Pressure variations are dependent on flows in and out of the system (in this case, the columns of mud beneath their positions) and on fluid (mud) compressibility, represented by the variation of volume, $\dot{V}$, where β is isothermal bulk modulus of mud [14].

About the most important pressure, BHP, it is calculated based on the annular pressure as what matters is to avoid well collapse/fracture over the annulus. To the P_c it is just needed to add annular hydrostatic pressure and frictional pressure terms to get annular BHP (10).

$$P_{BH} = P_c + P_h + P_f \qquad (10)$$

To end model equations, flows in and out are set. The flow in is indicated by the engineer and is constant except during the transition moments from one value to the other. The flow out is given by choke flow equation (11), where k_c is an intrinsic choke parameter regarding its physical characteristics, u is the choke opening, that can go from zero (totally closed) to one (totally opened), and P_{atm} which is atmospheric pressure.

$$q_c = k_c u\sqrt{P_c - P_{atm}} \qquad (11)$$

C. PI Controller Model

The controller is a crucial piece in this project. An automatic controller compares the real value from its output with the desired value, determining its deviation and producing a control signal which reduces the error to zero (or close to zero) [15].

It was decided to apply only the PI terms because the derivative one amplifies the noise, saturating the actuator [15], obtaining equation (12) for the controller output, which is the choke opening, where K_p is the proportional gain, e_r is the BHP deviation and T_i is the integral time.

$$u(t) = K_p e_r(t) + K_i \int_0^t e_r(t)\, dt \tag{12}$$

$$K_i = \frac{K_p}{T_i} \tag{13}$$

The controller provides the closed loop to maintain the BHP steady, by adjusting the SBP. BHP will be the reference value of the system while the pressure at the exit of the annulus at the top will be the output of the loop, summing up with the hydrostatic and frictional terms to obtain the simulated BHP (10).

With a limited value at the exit of the controller it is necessary to avoid windup so that the error does not keep accumulating (figure 1).

```
if u > 1
    u = 1;
    u_integral = previous_u_integral;
elseif u < 0
    u = 0;
    u_integral = previous_u_integral;
end
```

Figure 1: Windup and saturation elimination.

The controller was dimensioned by trial and error. Proportional gain was the first to be tried out, considering the integral gain zero. Bearing in mind that the BHP highest deviation is of the order of the units of Bars and that all the estimates on MATLAB are done according to the International System of units (SI), the order of the error (PI controller input) is 10^6 Pa. For that reason, as the goal on the exit of the controller is to have a value between 0 and 1 (choke opening), the desired gain should be inversely proportional to the error, meaning less than $10^{-6}\,\mathrm{Pa}^{-1}$. Considering small changes down to the thousandth per iteration, the proportional gain has to go down to 10^{-9} order. The chosen value for K_p ended up being $8 \times 10^{-9}\,\mathrm{Pa}^{-1}$ (absolute value). If this value was decreased, the BHP deviation would become greater as the response would be slower. If it was increased, the response would be faster and consequently the error would be lesser, but on the other side, as the pressure variation would be greater at the bottom, it would also be greater at the top, meaning more oscillations on the position of the fluid on a way that it could move backwards.

Another issue that must be taken into account is that the proportional term can be either positive or negative. If the real BHP is lower than the reference one it means that the pressure error is positive and, e.g. with K_p positive, the increment on the choke opening would also be positive, opening even more the valve. Its pressure would decrease and so would the BHP, increasing the error. To invert this situation K_p must be negative.

The integral term is calculated based on the proportional one (13), where T_i represents the period of time that the controller needs to double the proportional contribution, which in this case is 6 seconds. Both final gain values were adjusted at the same time in order to get the best possible results.

IV. Simulation & Results Discussion

A. Well Dimensioning

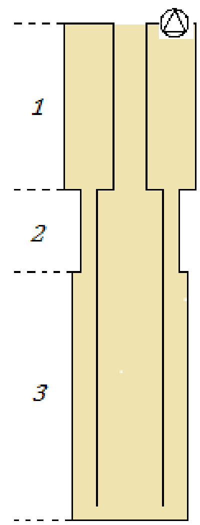

Figure 2: Longitudinal cut of the well that shows different sections of the well structure.

Table 1: Lengths and diameters of different well's sections (provided by Statoil). Numbers between parentheses are making reference to the different sections on figure 2.

Section	Depth (m)	Inner Diameter ($Inch$[1])	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

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

The well structure approached for the simulation is considered to be a common well, where a drill pipe and a casing are the inner pipes. The casing is the pipe to cement to the open hole, which is connected to the top riser through a liner. The riser corresponds to the part that connects the sea floor to the rig (in this case the water column is not considered). Table 1 summarizes the dimensions of the well sections respecting to the sketch from figure 2.

B. Initial State

The process begins by pumping the cement at a constant rate, equals to 500 l/min (60 thousand litres during 2 hours). In order to try to keep the steady state it is assumed that the initial flow out, q_{c_i}, is the same as the initial flow in, which is equal to the cement flow rate stated before. Manipulating equation (11) and disregarding atmospheric pressure comparing to choke pressure, its initial value is obtained:

$$P_{c_i} = \left(\frac{q_{c_i}}{u_i k_c}\right)^2 = \left(\frac{0{,}5/60}{0{,}11 k_c}\right)^2 = 42{,}69\ Bar^2 \qquad (14)$$

$$k_c = \frac{q_{mud}}{u_h \sqrt{P_{c\_ref}}} = 3{,}6667 \times 10^{-5} \qquad (15)$$

where u_i is the initial valve opening (equals to 0,11), adjusted in order to get the less oscillations possible. The constant k_c is considered to be inherent to the choke physical characteristics (15), where q_{mud} is the most used value of mud flow (1100 l/min) during the simulation. u_h is the value for the choke half opened and $P_{c\_ref} = 10\ Bar$ is an acceptable value for choke pressure reference. These values were the chosen ones because they are references during the simulation, so they represent the most common/desired values.

With an initial pressure at the exit already defined, the pressure at the entrance should not only balance it but also push the cement downwards. The fluid can move up but not too much so it will not hit the top, therefore it must be higher than P_{c_i}. The achieved value which does not allow the fluid to go up and beyond pump position is 65 Bar.

Using initial conditions on equation (10), initial real BHP is 895,3 Bar.

C. Pumping Cement

The first two hours of simulation are to pump the cement. As its density is higher than the mud already inside the well, cement weight will play a major role pushing the mud downwards, creating a gap at the top.

The pump pressure also suffers changes while pumping the cement. Instead of considering it as a state variable, when the height of the gap created at the top is higher than 10 meters, the pump pressure decreases at a rate of 0.18 Bar/min until it reaches zero[3], whereas if it is smaller, the value increases at the same rate, to a maximum of 65 Bar (figure 3).

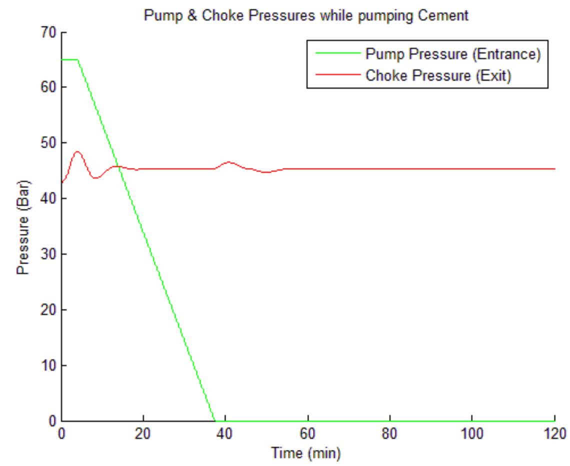

Figure 3: Top pressures during the stage of pumping the cement.

Considering the oscillations of first half hour of simulation on figure 4, they occur because BHP has to be adjusted. As choke pressure has to increase, to increase BHP, the choke starts closing, reducing flow rate through it. When BHP surpasses the reference pressure, the controller adjusts the choke, opening it and increasing flow out. In the mean time, as soon as it is safe to reduce pump pressure, fluid acceleration decreases, and consequently its velocity too, decreasing choke pressure and opening the valve even more, leading to an amplitude oscillation (first maximum of figure 4) greater than the deviation started with.

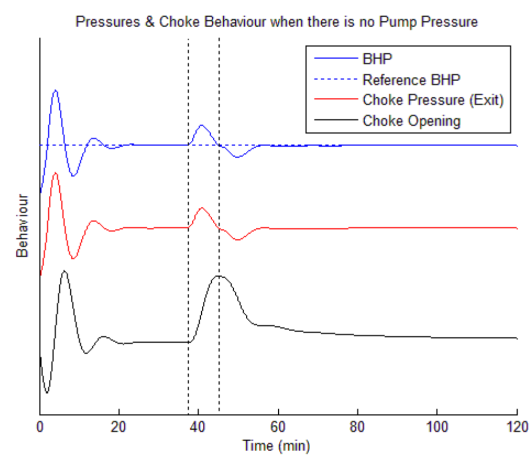

Figure 4: Influence of pump pressure when it gets down to zero Bar. BHP has the same behavior as choke pressure while choke reacts when BHP oscillates above or below its reference.

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

[3] 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.

The other oscillations are just from the controller feedback loop, until pump pressure reaches zero Bar. The perturbation begins at the dashed lines on figure 4, where it is possible to see that the controller reacts by opening the choke to release pressure over it. When BHP is re-established the choke opening is maintained but not for long as pressure goes below its reference, so the valve starts closing to raise its pressure and consequently BHP.

D. Pumping Mud until Cement hits the Bottom

Mud starts being pumped, increasing its rate until it reaches $2200\ l/min$. The controller tries to equalize the flow out with the flow in, but the second one is always higher than the first, which makes the space at the top to disappear after a few minutes. When the well is filled, the flow rate is decreased down to $1100\ l/min$ until cement hits the bottom (figure 5).

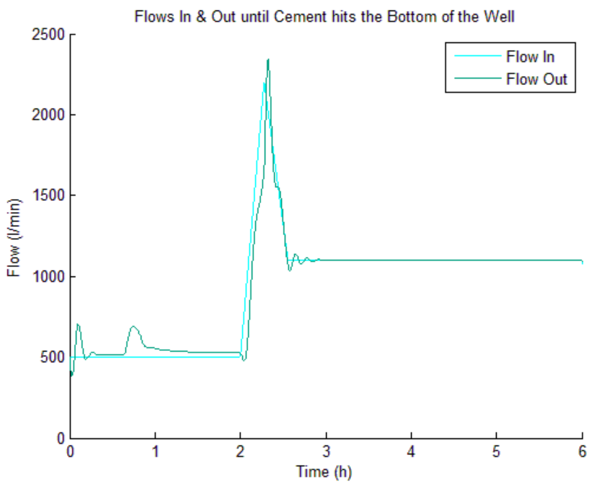

Figure 5: Flows in and out until cement hits the bottom of the well.

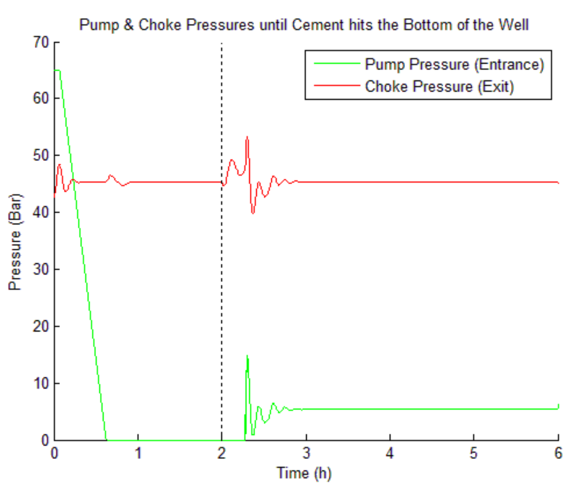

Figure 6: Top pressures until cement hits the bottom. Vertical dashed line marks the instant flow changes, changing choke pressure. Pump pressure increases as soon as mud hits the top.

When the space at the top is filled with mud, pump is under pressure again (figure 6), and its abrupt oscillation causes changes at the choke and consequently at the bottom hole. Flow out must be equal to flow in and pressures at the top must behave according to each other. In this case, as both are measured at the same depth, they should be equal if the fluid inside the well were homogeneous. As there are two fluids with different densities, and as the denser is still only inside the drill string and casing, the hydrostatic pressure of the inside column is higher than the annular one. Then, pump pressure has to be lower than choke pressure so that BHP gives the same result both ways, by adding the corresponding hydrostatic pressure. Despite pressures at the top being different from each other, they still must behave in the same way: if, in this situation, pump pressure rises, choke pressure also increases (figure 6).

E. Cementing the Annulus

After 6 hours of simulation pushing cement downwards, it finally hits the bottom and goes into the annular cavity. This is the most critical moment during the entire process. Hydrostatic pressure inside the annulus changes while cement moves upwards it. To help balancing the BHP, the flow in is decreased once again until a third of $2200\ l/min$ is reached. During the last 50 meters casing with cement inside it, the pump flow rate decreases even more, until approximately $23\ l/min$.

As hydrostatic pressures from the inner casings and the annulus are evolving in opposite directions, their pressures at the top are also growing in opposite ways (figure 7).

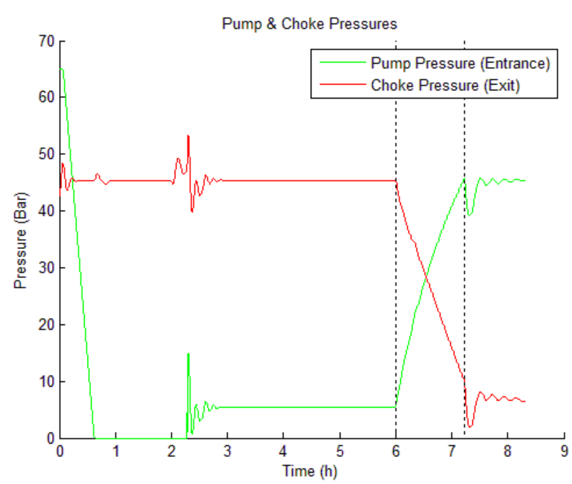

Figure 7: Top pressures during the entire simulation. First vertical dashed line marks the moment cement reaches the bottom well while the second indicates that there are missing 50 meters casing with cement inside.

In order to keep BHP as steady as possible, the controller starts by closing the choke when cement hits the bottom, to accompany the flow in decrease. When it stabilizes again the choke has to start opening, as annular hydrostatic pressure continues to increase, obliging the choke pressure to decrease. At the end, as the flow is becoming really low, the controller closes again (not totally) the choke so that its pressure do not decreases too much (figure 8).

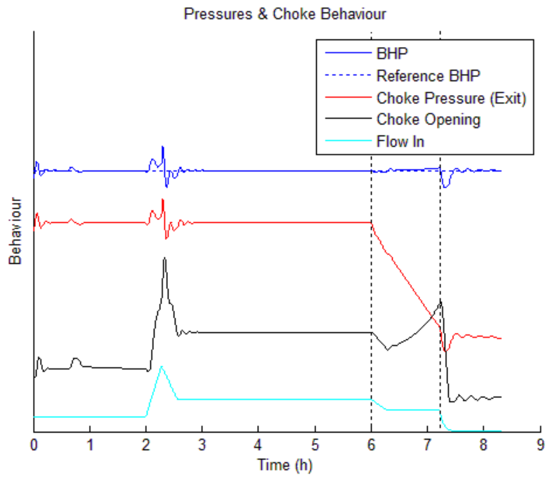

Figure 8: Controller reaction through choke opening/closing to flow in change and annular hydrostatic pressure increase.

Making reference to the main goal of the simulation, in figure 9 is represented the BHP along the simulation, where the dashed lines represent the limits imposed on the projected model by Mohamed A. Mashaal *et al.* [3], (±6,90 Bar from reference pressure). It is possible to see that, during the 8,23 hours of simulation, the boundaries are exceeded only once. Comparing with BHP curve from the previous figure, this small time interval corresponds to the moments after the gap at the top disappears. From all perturbations during the model this is possibly the most abrupt situation the model has to react to. When flow in changes, it does it smoothly. Even when cement moves into the annulus, it goes gradually.

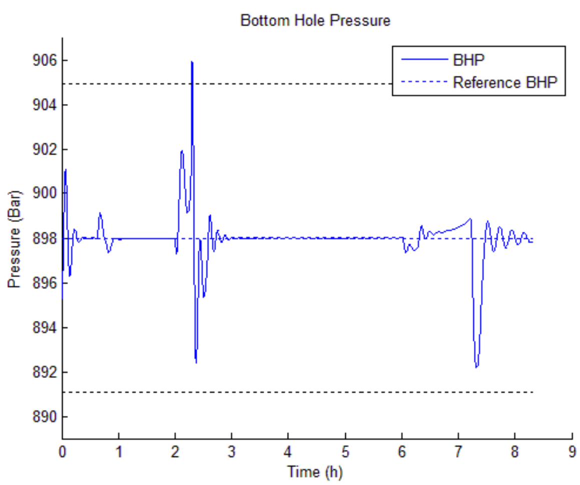

Figure 9: Bottom hole pressure during the entire simulation. Horizontal dashed lines represent the boundaries that should not be exceeded (±6,90 Bar).

Figure Figure 1010 shows one of the best obtained results. Despite not being able to maintain the pressure inside the boundaries for a few moments, the choke does not have abrupt variations and never go from one extreme to another. It never reaches them either, except at the end when the simulation is almost finished and the flow out is really low, implying choke's closure.

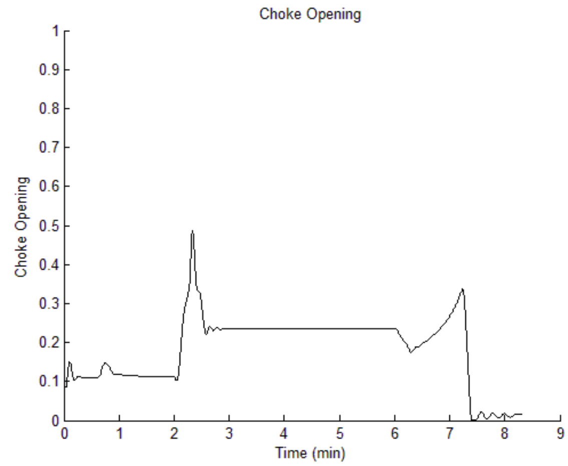

Figure 10: Choke opening for the entire simulation time. It is possible to see that it never reaches the extremes.

In the next graphic it is possible to see the position of the cement and mud during the entire simulation. The table summarizes the main transition points that the cement goes through.

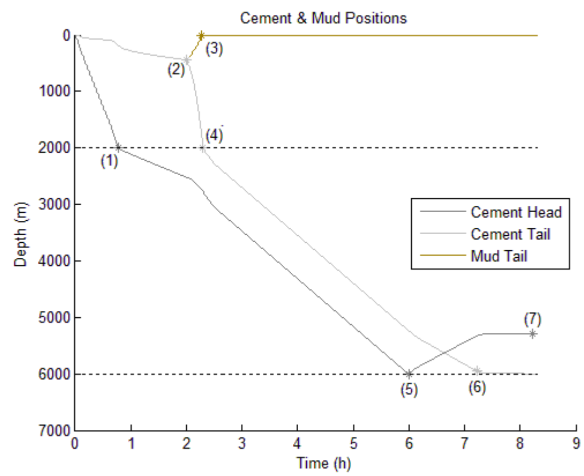

Figure 11: Simulation of the behaviour of the fluids inside the well. After 8,23 hours cement is all in place. Numbered coordinates are on table 2Table.

Table 2 – Coordinates of the sequence of transition moments pinpointed in figure 11.

Point	Time (h)	Cement Head Depth (m)	Cement Tail Depth (m)	Mud Tail Depth (m)	Description
(0)	0,00	0,0	0,0	-	Beginning of simulation by pumping cement
(1)	0,77	2000,0	178,1	-	Cement head reaches the casing
(2)	2,00	2516,0	438,7	438,7	Mud started to be pumped
(3)	2,28	2736,0	1798,0	0,0	Gap at the top of the well disappears
(4)	2,30	2769,0	2000,0	0,0	Mud head reaches the casing
(5)	6,00	6000,0	5231,0	0,0	Cement head hits the bottom of the well
(6)	7,23	5326.0	5950,0	0,0	Last 50 meters casing of cement
(7)	8,23	5283,0	6000,0	0,0	End of simulation

V. Conclusions

The work developed provides an early stage contribution towards understanding the use of systems control theory and practice to enhance the managed pressure cementing process. Several assumptions and simplifications were considered, as there was no support and previous work on the model, at least to the best of the author's knowledge. There were some obstacles, such as the type of fluids considered in this work (e.g. mud and cement) with complex structures and exhibit different behaviours in similar situations, therefore experimental work and testing is needed in the future.

Regarding the simulation results, they are within prescribed expectations as the pressure at the bottom of the well, and along it, was inside the interval imposed during the entire simulation, except for a few moments when the gap at the top disappeared, which could have been avoided decreasing the flow rate when the gap at the top approaches small values. It is likely that it would have smoothed the pump pressure variation, avoiding BHP variation and containing it in between limits.

The model that was developed in this thesis for predicting fluids behaviour does not completely capture the reality of phenomena of fluid interactions inside the well, but it showed to be valuable to provide early understanding of the processes. 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 necessarily the same velocity as the other points along the cement column, especially they are in different diameter sections at the same instant time) and it also varies from a central position to a position near a wall due to friction losses.

Given the scope and the time limitations imposed by the project, it was decided from the outset to resort, it all possible, to a simple linear fixed controller structure. In accordance, a simple proportional plus integral controller structure was exploited, whereby the gains were essentially tuned using a combination of first physical principles and trial and error methods. The final results obtained proved satisfactory for an initial study of this challenging area of research.

There are some aspects in this work that can be improved with further work and experimentation. Starting with the model itself, fluids properties applied on the model could be more realistic. This project was not approached through the point of view of fluid mechanics, which would be interesting, not only in terms of flow regime and flow type but also in its compressibility, changing its density in time. This change is also influenced by temperature, as it may vary with e.g. depth and friction. An analysis to the influence of each pressure term that contributes to BHP would also complement this project. That way it would be possible to understand which flow rate at the entrance of the well would be ideal to each stage.

Taking a look at the controller, the non-linearity of the choke equation brought difficulties to the project, where a linear controller may not be the best choice. An alternative to this adversity could be, instead of having one controller, to apply gain scheduled linear controllers to each state enunciated on the previous chapter, computing a number of gains for a selected number of frozen-time operating points and interpolating them afterwards to obtain a controller that changes naturally with time. The possible use of more advanced nonlinear control laws is also worth exploiting.

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