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Control Requirements for High-End Automatic MPD Operations

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Abstract

Automatic control solutions for drilling are expected to become widely used in the future. Both basic and more advanced control tools are well established in other communities like offshore processing facilities and oil refineries. Drilling systems, however, have traditionally been operated manually. There is a great economic potential for the introduction of automatic control providing reduced drilling time, increased regularity and improved performance, especially for wells with very narrow pressure margins. One example of automated drilling is automatic control of the downhole pressure by topside choking in managed pressure drilling (MPD) operations. Narrow drilling margins, especially in depleted reservoirs, ask for highly accurate pressure control.

StatoilHydro applied automatic MPD operations successfully offshore at the Kvitebjørn field in the North Sea in 2007, and several new MPD projects are currently being prepared. This paper presents some results from Kvitebjørn and discusses automatic control requirements for drilling operations. These requirements include a specified accuracy for a set of normal operations, such as rate changes and set point ramping during connections, surge and swab, and some failure operations, such as power loss, gas kicks and blocked choke. The paper also includes some ideas for the future of intelligent drilling operations with increasing automation.

Nomenclature

APC = Advanced Process Control
BHA = Bottom Hole Assembly
CCS = Continuous Circulation System
DCSS = Distributed Control and Safety System
FPWD = Formation Pressure While Drilling
GUI = Graphical User Interface
HP = High Pressure
HPHT = High Pressure High Temperature
HSE = Health, Safety and Environment
IMS = Information Management System
KF = Kalman Filter
MPC = Model Predicitive Control
MPD = Managed Pressure Drilling
MWD = Measurements While Drilling
NPT = Non-Productive Time
OPC = OLE for Process Control
PID = Proportional, Integral and Derivative
PWD = Pressure While Drilling
RPM = Rotations Per Minute
SG = Specific Gravity
SPM = Strokes Per Minute
TVD = *True Vertical Depth*

Introduction

Finally it seems like the drilling industry has opened their eyes for the potential of automatic control. Automatic control is a very mature technology that has been widely used in most industries for several decades. The main motivation factors for the introduction of automatic control are reduced costs and improved efficiency, e.g. in mass production of cars, food, etc, where expensive manual labour has been replaced by machines. Another motivation factor is improved accuracy and safety, e.g. in air planes and nuclear plants. In the oil and gas industry, process control is widely used at refineries, onshore plants and offshore rigs. Here hundreds or thousands of variables like pressure, temperature, level and flow, are controlled automatically by feedback control loops consisting of controllers and remotely actuated valves, pumps, etc. Typically two operators supervise all control loops in a plant from a control room. The process is so complex that it is not possible for them to operate without automatic control. In drilling however, the driller runs the drilling process almost 100% manually, i.e. with no or very little help from automatic control. From a well-equipped chair he operates the rig pump, the draw works, and much more. The goal is to drill the well into the reservoir in a safe way as fast as possible. The downhole pressure must be kept sufficiently high to avoid hydrocarbons flowing into the well and below the fracture pressure to avoid mud loss or damages to the reservoir near the well-bore. The drilling performance or success is therefore very dependent on individual interpretation, attention and skill. Mistakes will take place as long as we depend on manual operation. However, reduced pressure margins in difficult wells like in depleted and high pressure (HP) reservoirs, give very little room for mistakes. Another aspect is the limitation on response time in a manual system. Detection and reaction times for human operators are slow compared to what is achievable with an automatic system. Even more important is repeatability, as the majority of operations are performed well below the technical limitations. Today's manual control of the drilling process is mainly based on surface data, since only limited and indirect knowledge about the downhole condition is available online during drilling. With manual control the focus on sensors and accuracy has been low, since the need for high accuracy is limited during manual operations.

The operations on the drill floor have been partly mechanized with special robots remotely operated by the driller. This is a result from increased focus on HSE and working conditions. During connections the driller also operates mechanical equipment to add or remove a pipe section. Manual labour at the drill floor is hazardious. Therefore, at least in the North Sea, government regulations have lead to increased mechanization with special robots operated by the driller and less manual work and the drill floor. The result is a significant improvement in HSE, but the efficiency has not been improved as much, since we still need to have people on the drill floor for some operations.

Currently there is a great demand for rigs, the rig prices have increased and therefore it has become even more important to drill in a fast and precise way. Many wells are drilled in depleted reservoirs with very narrow drilling windows. All this together with the availability of new equipment have increased the complexity for the driller. Fortunately, automatic control can offer solutions that can improve many parts of the drilling process. We believe that automization is necessary to obtain a significant step change in efficiency of the well construction process. Automization is also required for well constructions under marginal conditions. Improved HSE is a third effect of automization by moving people away from the drill floor and into a safe working environment. In our company we have collected all these efforts under the heading "Intelligent Drilling".

Automated Drilling

The term automatic control or industrial IT covers a large range of tools suitable for drilling operations, some of these are already in use, some are being tested right now, but a large part of them has not been utlised yet.

Robotics. The drilling process involves a lot of mechanical operations and handling of large and heavy equipment. Some of these have been mechanized, so that the driller can do many operations by remote control from the drill chair. Examples of such operations are

- Tripping from open- or cased hole, pipe handling, bottom hole assembly (BHA) handling
- Off bottom operations: vonnection, virculation, reaming and friction testing
- On bottom drilling: optimize drilling efficiency; ROP and equipment lifetime. Here the critical factors are: hole cleaning, drill string dynamics, well bore stability, drill string stress state and directional control

The efficiency for all this mechanized but still manual operations depends on the skills of the driller. A step change in efficiency can only be achieved if these operations are fully automized with no people on the drill floor and where the machines are controlled by a computer, e.g. a completely automated connection with coordinated control of pumps, draw works and pipe handling robots.

Instrumentation. High quality measurements are required to provide accurate information during marginal drilling operations. The average non-productive-time (NPT) is 20-25%, see Fig. 1. A significant part of this is related to well instabilities and circulation. Another significant part is related to the reliability of the equipment including pumps, valves, sensors, communication, logging tools, etc. These numbers are huge compared to related industries like offshore processing, onshore refining, chemical plants, manufacturing, etc, and the other businesses cannot live with this bad regularity. Drilling has survived with such numbers as long as the well potentials have been so great. Now, however, the trend is going towards marginal drilling for smaller volumes, and this motivates for more efficient, more accurate, more robust and less expensive solutions. The sensor quality must be significantly improved if drilling automation shall have a chance to succeed.

Control Methodology. Feedback control is the basic mechanism by which systems, whether mechanical, electrical, chemical, physical, biological, or others, maintain their equilibrium. For example, the equilibrium of the body temperature is maintained through the use of feedback control (Wiener). Automatic control has been applied since ancient times, but a significant boost in the development came in the 1940's and the following decades. Kalman published a major contribution in estimation theory in 1960, while Zames published significant results within nonlinear control later in the 1960's. Since then a large number of control tools have been developed and applied in a wide range of industrial processes, and today automatic control is an absolute necessity in almost all industries. The simplest form for feedback, or reactive control, is, for example, the temperature control in a building. The measured temperature is compared to a desired set point and the feedback error between the two is used to control the temperature, by turning the heat or air condition on and off (Åstrøm and Murray). More sophisticated model based control is, for example, used in robots painting cars or in autopilots landing aircrafts.

Control. More than 95% (Åstrøm and Murray) of all industrial control loops are based on the simple linear proportional, integral and derivative (PID) controllers, see equation (5) in the Appendix. This is an example of a linear controller containing only linear terms. In some cases extra functionality is added to PID solutions, such as feedforward control and minimum select logic. Feedforward control is proactive and can take proactive action before the disturbance results in an error. The main reasons for the huge success for PID control is the simplicity with few tuning parameters, limited need for process knowledge and, of course, that in most cases PID provides a sufficient solution to the problem. Other more sophisticated examples of linear controllers, where process knowledge is used in the design, are H-infinity and model predictive control (MPC). In the process industry MPC, introduced by Cutler and Ramaker in 1979, dominates the field of advanced process control (APC). An MPC uses a model of the process and solves an optimisation problem for a given object function. It is possible to solve multivariable control problems with constraints on both inputs and outputs. Most processes are nonlinear and in some cases linear control solutions are not sufficient. Nonlinear control has therefore been a major focus area within the control community the last couple of decades and several nonlinear controllers have been applied successfully in industrial applications. Robotics, flight control and acoustic noise cancellation are three well known examples. Some examples of nonlinear control methods, see overview in Khalil, are feedback linearization, sliding surface, passivity- and Lyapunov-based, backstepping, and nonlinear MPC. A nonlinear controller combined with state and model parameter estimation is developed in Zhou et. al.

The most important concept in control is stability. An equilibrium of a dynamical system is said to be stable if there exists a set of initial conditions so that you always will remain within some desired domain around this equilibrium. The stronger notion of asymptotic stability requires that you will converge to the equilibrium in addition to stability. The second most important term is robustness, which is a measure for the controller's ability to handle errors and upsets and to remain stable, such as disturbances, model errors, process noise and measurement noise. Another import term is of course performance, which can be defined by bandwidth or the maximum deviation from the set point for a given disturbance.

Estimation. Another important area within control research is estimation of unknown states and parameters. Here typically a model of the system is used along with inputs and outputs to compute estimates of unmeasured states and unknown or uncertain parameters. The most known method is the Kalman filter (KF), based on the early work by Kalman. The Kalman Filter will provide an optimal estimate of the states in a linear system driven by white Gaussian noise with known covariance. Several modified versions of the KF have been developed for nonlinear and large scale systems (Extended, Ensemble and Unscented KF). More sophisticated nonlinear observers have also been developed; e.g. Luenberger-type and high gain observers. An observer developed for MPD is presented in Stamnes et. al.

Dynamic Simulator for Engineering and Operator Training. Dynamic simulation is a widely used technology both in process design, redesign, trouble-shooting, and operator training. Many problems have been identified and solved prior to start-up by simulations. The general experience is that the start-up of new systems goes faster with fewer problems when a thorough preparation has been done using a simulator. Even more important is operator training. In offshore operations in the North Sea there are 6 crew shifts working on a 2 weeks on - 4 weeks off schedule including both day and night shifts. For drilling, this means that a large number of drillers are involved in each operation, and that there might be a long time between each time a driller is exposed to, e.g. a well control situation. Process operators on some installations have mandatory training several times a year. This takes place at an on-shore training center. The training simulator has the same graphical user interface (GUI) as in the real operations offshore, and the real process is replaced by software in a simulation model. An instructor runs scenarios on the simulator and gives specific tasks to the operators. For an MPD operation, such tasks could be connections, well control situations and mud loss to the reservoir resulting in lost circulation. Currently there exist training facilities and they are used in the preparations for MPD operations for drilling supervisors, drillers and MPD operators. Even more realistic training simulators are planned with extended use of high fidelity hydraulic models integrated with MPD equipment.

Control System Specifications for High-End Automatic MPD

Standardization and modulization are two major issues for integration of systems. For example, when a pump is installed at an offshore oil rig, it should have a standard interface with the other systems on-board, both the mechanical, the electrical and the control system. In this way the pump can be replaced easily with a pump from another vendor with minimal changes to the interface. All system data should be integrated into the same distributed control and safety system (DCSS) and all pumps, chokes etc should be controlled from this same system. This means that e.g. in MPD, the MPD functionality should be implemented in the same system as the driller use for conventional drilling and not on its own control system, and that the MPD operation also should run on the same DCSS. All real time data should be logged on the same information management system (IMS) with a high update frequency (1-5 Hz). And as we are working towards integrated operations with improved collaboration between the offshore drilling crew and on-shore support centers, real time data should also be made available on-shore. If necessary, then external systems should be interfaced by standard protocols such as OPC for real time data and Witz-ml for low frequency data. As mentioned, higher data accuracy and reliability are required when used in an automatic control system. Robustness can be improved by redundant measurements and fault detection algorithms (e.g. 2 of 3 voting). A safety system independent of the control system for emergency shut downs is also necessary.

Hydraulic Model. Mathematical dynamical models of the well hydraulics have been developed and applied both for design and planning of the drilling. In automatic MPD such models have been used also in real time in closed loop with the control system. Well geometry and equipment such as pumps, drill string, drill bit, annulus and choke are modeled. The well volumes are partitioned in a large number of control volumes and rates, pressure and temperatures at different locations in the well are computed by a set of first principles equations, in some cases combined with some simplifications and empirical relations. Important real time parameters are then mud density and rheology. The mud is often a Non-Newtonian fluid and the Herschel-Bulkley fluid model is often used for friction estimation. Flow rates into and out of the well along with ambient temperature give the boundary conditions. The simplest use of such models is a plot showing the typical nonlinear relation between mud rate and pressure drop due to friction in the annulus. In automatic MPD a hydraulic model can, for example as at Kvitebjørn, be used in real time to provide a choke pressure set point that will result in the desired downhole pressure. When used in real time, the hydraulic model accuracy can be improved by automatic updates of state and parameters, adaptation, based on real time measurements, see e.g Lohne et.al., Gravdal et.al. and Iversen et.al.

Managed Pressure Drilling. In traditional drilling with open mud return (not MPD), the driller's actions are based on real time measurements of the stand pipe pressure, the mud pump rate, typically given in strokes pr minute (SPM) or rotations pr minute (RPM), rate of penetration (ROP) and tripping rate. In addition the driller has low frequent readings from downhole (MWD) and manual analysis of the returned mud including cuttings. In MPD the driller will also look at the well head pressure (choke pressure) and maybe the return flow rate, if a flow meter is installed up- or downstream the choke. This primary data set must then be analysed with respect to pressure barriers and margins to adjust the operation by changing the pump rates and choke position (in MPD). In high-end automatic MPD operations with small pressure margins, this analysis must be automated. In our company we have decided that, if we are going to drill hydrostatically under-balanced, then we want to drill with automatic control of the downhole pressure. Automation requires increased instrumentation, i.e. more sensors and more accurate and reliable sensors. Instrumentation is expensive downhole, but improved or extra instrumentation topside will not contribute much to the total costs in drilling. Regarding control, the focus so far has been on using the choke to control the downhole pressure (see e.g. Zhou et.al, Fredericks et.al. and Santos et.al.), but multivariable control using the pumps, chokes and drawworks will give a better solution and some attempts have been tried in this direction (Nygaard et.al., Carlsen et.al., and Rommetveit et.al.).

Our list for desired instrumentation in a high end MPD operation includes:

1. Downhole: The available solution in most operations is low frequent measurements while drilling (MWD) communicated by mud pulse telemetry. Typically these measurements are updated every 20-30 seconds and their value is reduced by having a significant time delay and sometimes also low accuracy and reliability. Typically these measurements are not available at low and zero mud rates. The preferred solution for downhole measurements is therefore wirep pipe or broadband pipe. The main measurement is the downhole pressure in the annulus. But the pressure upstream the bit, temperature up- and downstream the bit and the flow through the bit are also of great interest. Distributed pressure and temperature measurements in the annulus can be used to improve kick detection and well control. If high frequency measurements are not available, then the second best solution is to use a hydraulic model and update this with low frequency downhole pressure readings communicated by mud pulse telemetry. Accurate pressure control relies on accurate measurements. E.g. if the drilling window is 5 bars (± 2.5 bars), then the measurement accuracy should be 1 bar or better. For high pressure wells, e.g. up to 1000 bar, this asks for a pressure measurement with accuracy of 0.1% of the range. If a hydraulic model is used, then the model errors must be smaller than the drilling window, e.g. ± 2.5 bars.
2. Standpipe: usually both pressure and temperature readings are available. The flow is usually given by SPM or RPM from the pump. This is sufficient in most cases, but can be inaccurate at low rates, so an accurate flow meter is a better solution, e.g. located upstream the rig pumps. If a hydraulic model is used, then it needs online updates of the mud properties, such as density and rheology. Online measurements of these are therefore preferable. The density is a very important parameter in the hydraulic model as, e.g., a density error of 0.01 SG means 1 bar pressure error per 1000 meters TVD. A reliable trip signal when the pump stops will be useful for pressure control during pump stops.
3. Choke: in MPD both pressure up- and downstream the choke and temperature readings are available. An accurate flow meter, e.g. downstram the choke, is strongly advised for improved pressure control and kick detection. The density of the returned mud is a very important parameter for kick detection and analysis of solids from the well.

A fast (10-30 seconds closing time), accurate (0.1% or better) and reliable choke is indeed required for high pressure control performance. The choke should have position feedback and a redundant choke in parallel should be available for cases when the primary choke is blocked or fail. A backpressure pump is advised to maintain flow through the choke when the circulation is stopped. Both this and the main rig pumps should have fine variable flow rate control and low minimum flow to allow precise pressure control.

Heave. In the North Sea we drill a lot of subsea wells from floating rigs. In this case we have the extra challenging factor of severe vertical motion (heave) of the rig in harsh weather, typically more than 3 meters up and down with 10-20 seconds period. This is a great challenge both mechanically and with respect to accurate control of the downhole pressure (Solvang et.al.), as the heave motion results in large pressure variations in the well. Currently we are not aware of any qualified solutions for MPD in such conditions, but this is something both we and other companies are working on. There is an urgent need for a solution as the reservoirs, especially HPHT, deplete rapidly and will close the available drilling window. This means that we need to be able to drill accurately with MPD at floaters in harsh weather in the near future to avoid losing large volumes of oil and gas.

Control Performance. As mentioned, the most important issue for an automatic control system is to be stable and robust with respect to relevant disturbances and possible errors. This is however easy to achieve in MPD by using a sufficient low controller gain, since the MPD system is what we call open loop stable. The controller must be designed to provide some desired performance for a set of tasks in a given operation window. The controller shall adjust the choke to provide a desired pressure, either downhole or upstream the choke topside. And even though the MPD system is open loop stable, it can become closed loop unstable if the controller is too aggressive. The performance requirements will vary from case to case depending on the available drilling window.

Normal Drilling Operations. The main function for the control system is to control the downhole pressure close to the set point and within a given window, e.g. ± 5 bar, during normal drilling. Normal drilling operations include:

- Pump rate changes. The control performance will limit how fast the pump rate can be changed and still stay within the given pressure window.
- Stop and start of pumps
- Connections, where the rig pump is ramped down to no flow and the choke pressure is ramped up to compensate for lost friction pressure drop. The control performance will limit how fast the pump can be stopped and started and still stay within the given pressure window. This is easier to achieve if a continuous circulation system is installed.
- Changes in drillpipe rotation
- Drillstring movements, such as tripping, surge and swab. The control performance will limit how fast the drillstring can be moved and accelerated, and still stay within the given pressure window.
- Down-linking: the pressure should be kept within the pressure window while pulses are sent to the BHA using mud pulse telemetry. An example of such pulses can be 200 lpm up and down with appr. 30 seconds time steps.

In general an MPD control system requires high bandwidth to handle fast rate changes, set point changes and large disturbances. Typically the closed loop response time should be better than 30 seconds, but this will be case dependent.

Failure operations. The control system should also be able to handle unexpected events and failure situations, preferably within the same pressure window. Failure operations include:

- Influx from the well, e.g. a gas kick: The control system should be able to detect this as soon as possible. A well control procedure, either manual or automatic, should then be inititated to stop the influx.
- Mud loss to the formation: This is similar to influx, it should be detected and initiate a manual or automatic procedure.
- Blocked choke: if cuttings block the choke, or the choke malfunctions, e.g. mechanically or electrically, then this should be detected as soon as possible, and handled, e.g. by switching the control to a parallel choke.
- Power loss: if all pumps stop, then the downhole pressure will drop quickly loosing both the friction and the choke backpressure. The choke should then be closed quickly to trap pressure.

Commercial solutions for kick detection and control exist (Santos et.al.). Carlsen et.al. present an automatic coordinated control solution, where the choke control is coordinated with pump control. It is shown by simulations to give much better results than conventional procedures (Driller's Method and Wait and Weight Method).

Lessons learned from previous automatic MPD operations. Experiences from Kvitebjørn (Syltøy et.al. and Bjørkeveoll et.al.) and other MPD operations (Fredericks et.al and Santos et.al.) include the following learnings:

- Data logging: time-tag and collect all data relevant for control on the same log file including MPD skid data, rig pump flow rate and downhole pressure (PWD). This is important with respect to analyzis both in real time and post processing.
- Kick- and mud loss detection: Display flow in (rig pump rate and backpressure pump rate) and out (measured choke rate) on driller's and MPD operator's screens and alarm on large deviations. Also display density of mud in and

return mud to detect gas influx (low density) or cuttings (high density).

- Check time delays on external signals used by hydraulic model and control system, including rig pump rate, bit depth, drill string RPM, ROP, weight on bit, and downhole pressure. Such delays should be small (preferably < 1 sec). Large delays will result in pressure spikes downhole. This is especially important for the rig pump rate (this is the most dynamic variable and it will change quikly and often)
- Rig pump rate: The best solution is to have a mass flow meter. If not, then it is better to use RPM than SPM. SPM is too inaccurate at low rates.
- Pump rate changes: The drillers should be trained to start and stop the pumps carefully to avoid pressure spikes during connections. Even better is to change the pump rates with preprogrammed automatic ramping functions.
- Pulling pipe without pumping downhole must be performed very carefully, as it can give pressure spikes downhole.
- The PWD pressure sensor might drift significantly (more than 10 bar at Kvitebjørn). High accuracy is required if this measurement shall be used to calibrate the hydraulic model.

Kvitebjørn Results

Kvitebjørn is a high pressure high temperature (HPHT) gas condensate field located in the Northern North Sea on the Norwegian Continetal Shelf. The initial pore pressure was 775 bar (1.93 SG) and the fracture pressure was 975 bar (2.19 SG). The reservoir temperature is 155 degrees C and the water depth is 190 meters. Nine wells were already drilled before MPD was introduced. However, after experiencing great losses during drilling due to depletion (140-170 bar) on the last conventional well, it was decided to drill with MPD for the remaining wells. Due to the introduction of MPD and other measures, more depletion can be tolerated. This allowed for safe drilling of wells that otherwise could not have been drilled. Since 2006, production from the Kvitebjørn field has been adjusted so as to keep the pressure within specific depletion criteria at all locations, where future wells will be drilled. The setup of the MPD system included a rotary control head, use of Cs/K formate designer mud, a dual choke system on return flow, a mass flowmeter for improved kick detection, an auxiliary pump for maintaining flow during stops of circulation, use of balanced mud pills both to be able to kill the well in a cautious way and to minimse pressure surges during pulling of drillstring and running in liner, a continuous circulation system (CCS) to allow for connections without stopping the circulation, and an advanced online dynamic flow and temperature model to calculate a choke presseure set point in real time. For more details, see Syltøy et.al and Bjørkevoll et.al.

Control System. A simple schematic for control is given in Fig. 2. Pump rates are set manually by the driller along with drillstring rotation and movement. A hydraulic model (SINTEF model) calculates a new set point every 2 seconds for the choke pressure in order to hold a desired downhole pressure. The desired downhole pressure was set to maximize the drilling window without risking underbalance. It was set 0.02 SG above the anticipated maximum pressure for reservoir still to be drilled and also 0.02 SG above the measured pore pressure. A formation pressure while drilling (FPWD) tool was included in the bottom hole assembly (BHA), and made it possible to measure formation pressure at any time without tripping or stopping circulation. The hydraulic model relies on information about the mud like density and rheology. For details see Syltøy et.al, Bjørkevoll et.al., Iversen et.al. and Petersen et.al. The PAMPS control system adjusts the choke so that the measured choke pressure tracks the choke pressure set point provided by the SINTEF model.

Hydraulic Model. The hydraulic model (SINTEF and similar others) have a very high number of states and is not appropriate for controller design. Typically a model based controller (MPC and others) has the same order as the model of the process it shall control. For control purposes it is therefore desired to work with a simpler model including the dynamics that are important for control. In order to investigate this, an open loop step response test was performed. This is shown in Fig. 3. Here the choke was stepped by 10% and the response in the choke pressure was analysed. In this period the pump rates were held constant and the well was closed (cemented). The results show that both what we call the process gain, i.e. how much the pressure change relative to a change in the choke opening, and the time constant, i.e. how long time it takes before a new equlibrium is reached after a change, increase with increasing pressure. The responses are smooth and without oscillations. This is promising with respect to getting a good match with a simple model fit for control. A simple model for the mass balance in the annulus including mud compressibility and choke characteristics is given in Appendix A. This model describes the pressure-flow dynamics, i.e. how the pressure responds to changes in pump flows and choke openings. The only state in the model is the annulus pressure represented by the choke pressure. The purpose of the model is controller development.

PID Controller Performance. A PID controller, see equation (5), was used to control the choke pressure. It was tuned to give satisfactory performance for relevant choke pressures between 20 and 60 bar and relevant rates between 600 and 1800 lpm. The reservoir was drilled with automatic MPD and the reported performance of the PID controller was very good. A number of tests were run during commissioning in closed hole for well A-13, i.e. before starting drilling into the reservoir. In the Appendix it is shown how a linearization of the model in closed loop with the PID controller was used to analyze the closed loop performance and stability.

Fig. 5 shows how well the controller tracks steps in the choke pressure set point between 10 and 70 bar. This is a good example on how the controller shall react to set point changes. The choke position should overshoot to get a rapid pressure response on both low and high pressures. The controller shall then provide smooth convergence to the desired pressure without a large overshoot and oscillations.

Fig. 6 shows how the controller adjusts the choke to track the pressure set point from the SINTEF model during an experiment similar to a connection without the CCS running. The rig pump rate is ramped down from 1000 lpm to zero during 6 minutes. The SINTEF model increases the pressure set point from 28 to 42 barg to compensate for lost friction pressure. The controller chokes to compensate both for reduced flow and to increase the backpressure. It is seen that there is a small steady deviation (1-2 bars) between the set point and the measured pressure during the connection. This complies well with the explanation in the Appendix, see equation (8)(15).

Fig. 7 shows a swab and surge experiment. The drill string is moved up and down at different rates. The SINTEF model compensates by changing the choke pressure set point and the controller tracks the set point quite well and within the given window by adjusting the choke position accordingly.

Conclusion

In this paper automated drilling is discussed in general with an overview of what automatic control tools can offer in future drilling operations. Some requirements necessary for high performance MPD are presented. Details regarding pressure control for the MPD operations at the Kvitebjørn field are given. A simple nonlinear hydraulic model capturing only the main pressure and flow dynamics was developed. This model was applied for controller development, tuning and analysis.

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Appendix

Notation

ρ_{ann} = average mud density in annulus
V_{ann} = annulus volume
ρ_{in} = mud density for flow into annulus
Q_{in} = mud volume flow rate into annulus
ρ_{aux} = mud density for flow from backpressure pump
Q_{aux} = mud volume flow rate from backpressure pump
ρ_{out} = mud density for flow through choke
Q_{out} = mud volume flow rate through choke
β = mud compressibility
p = annulus pressure upstream choke
z = choke position
$C_v(z)$ = choke characteristics
K_p = controller gain
T_i = controller integral time
T_d = controller derivative time
r = controller set point (desired choke pressure)
e = controller deviation between desired and actual choke pressure
Q_{in0} = nominal mud volume flow rate into annulus
Q_{aux0} = nominal mud volume flow rate from backpressure pump
ρ_{out0} = nominal mud density for flow through choke
Q_{out0} = nominal mud volume flow rate through choke
p_0 = nominal annulus pressure upstream choke
z_0 = nominal choke position
Δq = change in mud volume flow rate through choke from nominal
Δp = change in annulus pressure upstream choke from nominal
Δz = change in choke position from nominal
a = process gain: response in choke pressure to change in choke position
c = disturbance gain: response in choke pressure to change in mud flow rate from pump
T_p = time constant: response time for choke pressure to changes in choke position or pump flow rates
s = Laplace parameter
Δz_{ff} = possible feedforward control term to compensate for pump flow rates
ζ = damping factor for closed loop linearized dynamics
T_c = time constant for closed loop linearized dynamics
T_r = ramping time for connection experiment
D_r = pressure set point change for connection experiment
D_q = mud pump flow rate change for connection experiment
e_{ss} = theoretical steady state pressure offset during connection experiment

A Simplified model for control. A mass-balance model was developed including only the choke characteristics and the compressibility in the well to relate the choke position, the choke pressure and the flow rates from the pump and through the choke.

$$(1)\quad \frac{d}{dt}\left(\rho_{ann}V_{ann}\right) = \rho_{in}Q_{in} + \rho_{aux}Q_{aux} - \rho_{out}Q_{out}$$

Here ρ_{ann} is the average mud density in the annulus volume, V_{ann} is the annulus volume, ρ_{in} is the mud density for the flow Q_{in} from the rig pump, ρ_{aux} is the mud density for the flow Q_{aux} from the auxiliary pump, and ρ_{out} is the mud density for the flow Q_{out} through the choke. Here the drillstring volume has been neglected (assumed incompressible). Differentiation of the left hand side and the introduction of the compressibility factor $\beta = \frac{1}{\rho}\frac{\partial \rho}{\partial p}$ and the choke pressure p give

$$\begin{aligned} &\dot{\rho}_{ann} V_{ann} + \rho_{ann} \dot{V}_{ann} = \rho_{in} Q_{in} + \rho_{aux} Q_{aux} - \rho_{out} Q_{out} \\ (2) \quad &\dot{\rho}_{ann} = \frac{\partial \rho_{ann}}{\partial p} \dot{p} = \beta \rho_{ann} \dot{p} \\ &\dot{p} = \frac{\rho_{in} Q_{in} + \rho_{aux} Q_{aux} - \rho_{out} Q_{out} - \rho_{ann} \dot{V}_{ann}}{V_{ann} \beta \rho_{ann}} \end{aligned}$$

The simple model is given by an approximation, neglecting density changes and slow variations in the annular volume:

$$(3) \quad \dot{p} \approx \frac{1}{V_{ann} \beta} \left(Q_{in} + Q_{aux} - Q_{out} \right)$$

The flow through the choke is given by a choke characteristics $C_v(z)$ and a simple valve equation for liquids:

$$(4) \quad Q_{out} = C_v(z) \sqrt{\frac{p}{\rho_{out}}} \, .$$

Here z is the choke position. Following industrial practice on control, a linear PID controller was applied. The simplified model given by equations (3) and (4) include nonlinearities in the choke characteristics and the square root of the choke pressure. The dynamics depends also on the slowly time-varying annulus volume and mud compressibility. It is possible to compensate for these nonlinearities by e.g. gain scheduling, cascaded master-slave pressure-flow control or feedback linearization, but in this case it was not necessary, as it was possible to tune the PID controller to give satisfactory performance and robustness for the relevant operation window (pressure, flow, volume) for MPD operations. A PID controller is given by:

$$(5) \quad z = K_p e + \frac{K_p}{T_i} \int e + K_p T_d \dot{e} \, ,$$

Here z is the control input equal to the desired choke position, $e=r-p$ is the deviation between the set point r and the measured pressure p. The tuning parameters in a PID controller are the gain K_p, the integral time T_i, and the derivative time T_d. In this, as in most other cases, derivative action was not used ($T_d=0$).

Linearization. A common method to simplify the analysis is to linearize the dynamics given by equation (3) and (4) around given nominal rates, pressure and choke position (Q_{in0}, Q_{aux0} , $Q_{out0} = Q_{in0} + Q_{aux0}$, p_0 , z_0) and consider small changes in rates (Δq), choke position (Δz) and pressure (Δp) around this. We assume for the simplicity of presentation that the auxiliary pump is not running ($Q_{aux}=0$), so that Q_{in0} is equal to Q_{out0}:

$$\begin{aligned} &Q_{in} = Q_{in0} + \Delta q \\ (6) \quad &z = z_0 + \Delta z \\ &p = p_0 + \Delta p \end{aligned}$$

The nominal choke position and pressure are given by these equations:

$$\begin{aligned} &Q_{out0} = C_v(z_0) \sqrt{\frac{p_0}{\rho_{out0}}} \\ (7) \quad & \\ &p_0 = \rho_{out0} \left[\frac{Q_{out0}}{C_v(z_0)} \right]^2 \end{aligned}$$

The linearized system can be written as a first order system

$$(8) \quad \Delta p = \frac{a \Delta z + c \Delta q}{1 + T_p s}$$

Here s is the Laplace parameter and the linearization constants are given by

$$a = \left.\frac{\partial p}{\partial z}\right|_0 = \frac{\partial}{\partial z}\left(\rho_{out}\left[\frac{Q_{out}}{C_v(z)}\right]^2\right)\Bigg|_0 = \frac{-2\rho_{out}Q_{out}^{\ 2}}{[C_v(z)]^3}\frac{\partial C_v}{\partial z}(z)\Bigg|_0 = -2\frac{p_0}{C_v(z_0)}\frac{\partial C_v}{\partial z}(z_0)$$

$$(9)\quad c = \left.\frac{\partial p}{\partial Q_{out}}\right|_0 = \frac{\partial}{\partial Q_{out}}\left(\left[\frac{Q_{out0}}{C_v(z_0)}\right]^2\right)\Bigg|_0 = \frac{2Q_{out0}}{[C_v(z_0)]^2}\Bigg|_0 = 2\frac{p_0}{Q_{out0}}$$

$$T_p = \left.\frac{-1}{\frac{\partial \dot{p}}{\partial p}}\right|_0 = \frac{-1}{\frac{\partial}{\partial p}\left[\frac{1}{V_{ann}\beta}\left(Q_{in} - C_v(z)\sqrt{\frac{p}{\rho_{out}}}\right)\right]}\Bigg|_0 = \frac{2V_{ann}\beta\sqrt{p\rho_{out}}}{C_v(z)}\Bigg|_0 = 2V_{ann}\beta\frac{p_0}{Q_{out0}}$$

This verifies the findings from the open loop step response in the well (Fig. 3) that the time constant (T_p) increases with pressure. The relation between the process gain a with pressure and choke position indicates how gain scheduling can be used. The disturbance gain c indicates how rate variations can be compensated for by feedforward control

$$(10)\quad \Delta z_{ff} = -\frac{c}{a}\Delta q = \frac{2p_0}{Q_{out0}}\frac{C_v(z_0)}{2p_0\frac{\partial C_v}{\partial z}(z_0)}\Delta q = \frac{C_v(z_0)}{Q_{out0}}\frac{1}{\frac{\partial C_v}{\partial z}(z_0)}\Delta q = \sqrt{\frac{\rho_{out0}}{p_0}}\frac{1}{\frac{\partial C_v}{\partial z}(z_0)}\Delta q$$

The closed loop dynamics is found by including the PID pressure controller (no derivative or feedforward terms):

$$\Delta p = \frac{a\Delta z + c\Delta q}{1 + T_p s}$$

$$\Delta z = K_p\left(1 + \frac{1}{T_i s}\right)e$$

$$(11)\quad e = \Delta r - \Delta p$$

$$e = \Delta r - \frac{aK_p\left(1 + \frac{1}{T_i s}\right)e + c\Delta q}{1 + T_p s}$$

$$e = \frac{T_i s(1 + T_p s)\Delta r - cT_i s\Delta q}{T_i T_p s^2 + (1 + aK_p)T_i s + aK_p}$$

This is a second order system, where the controller parameters K_p and T_i occur. The expression above can be used to tune the controller by, e.g., pole placement. The closed loop time constant and damping can be computed by entering realistic numbers for the Kvitebjørn process:

$$a = 5\,{}^{\%}\!/_{bar},\ c = 0.05\,{}^{bar}\!/_{lpm},\ T_p = 50\sec$$
$$T_i = 20\sec, K_p = 0.5\,{}^{\%}\!/_{bar}$$

(12) $$\begin{aligned} T_iT_ps^2 + (1 + aK_p)T_is + aK_p &= aK_p\left(1 + \left(1 + \frac{1}{aK_p}\right)T_is + \frac{T_iT_p}{aK_p}s^2\right) \\ &= aK_p\left(1 + 2\zeta T_cs + T_c^{\,2}s^2\right) \\ T_c = \sqrt{\frac{T_iT_p}{aK_p}} = 20\sec, \zeta &= \left(1 + \frac{1}{aK_p}\right)\frac{T_i}{2T_c} = 0.7 \end{aligned}$$

This can be characterized as a quite tight tuning with damping $\zeta=0.7$ and time constant $T_c=20$ seconds in closed loop. Controller parameter tuning can be based on this equation, but then it also necessary to consider bandwidth limiting effects like choke dynamics (travel time and deadband) and other unmodelled effects (pressure wave resonance in the annulus, etc).

Steady state deviation during connections. Equation (11) can also be used to estimate the steady state deviation during connections, when the pump rate is ramped down and the pressure set point is ramped up. Assume that the pump is ramped down linearly from a rate D_q to zero during a time T_r and that the set point simultaneously is increased by D_r, then the Laplace-transform of these signals are given by

(13) $$\begin{aligned} \Delta r(t) &= \frac{D_r}{T_r}t \Rightarrow \Delta r(s) = \frac{D_r}{T_rs^2} \\ \Delta q(t) &= -\frac{D_q}{T_r}t \Rightarrow \Delta q(s) = -\frac{D_q}{T_rs^2} \end{aligned}$$

The final value theorem can then be used to compute the steady state deviation e_{ss} during the ramping by

(14) $$\begin{aligned} e_{ss} &= \lim_{t\to\infty} e(t) \\ &= \lim_{s\to 0} se(s) \\ &= \lim_{s\to 0} s\frac{T_is(1 + T_ps)\dfrac{D_r}{T_rs^2} + cT_is\dfrac{D_q}{T_rs^2}}{T_iT_ps^2 + (1 + aK_p)T_is + aK_p} \\ &= \frac{T_i(D_r + cD_q)}{aK_pT_r} \end{aligned}$$

This shows that the steady state deviation can be reduced by increasing the controller gain or by reducing the controller integral time. The deviation will also decrease if the ramping time is increased. It also shows that the deviation does not depend directly on the compressibility of the fluid or the annulus volume, since T_p does not appear in this term. To compare with the results in Fig. 6 the deviation is calculated by

(15) $$\begin{aligned} & D_r = 13bar, D_q = 1000lpm, T_r = 360\sec \\ & a = 5\,{}^{\%}\!/_{bar}, c = 0.05\,{}^{bar}\!/_{lpm} \\ & T_i = 20\sec, K_p = 0.5\,{}^{\%}\!/_{bar} \\ e_{ss} &= \frac{20(13 + 0.05\cdot 1000)}{5\cdot 0.5\cdot 360} \\ &= 0.3bar + 1.1bar \\ &= 1.4bar \end{aligned}$$

In this example the greatest contribution comes from the pump rate change. A feedforward control signal to the controller from the pump rate as in equation (10), would reduce the steady state error. This is an example of tracking control, where it is common to have a controller term to compensate for a varying pressure set point.

Figures

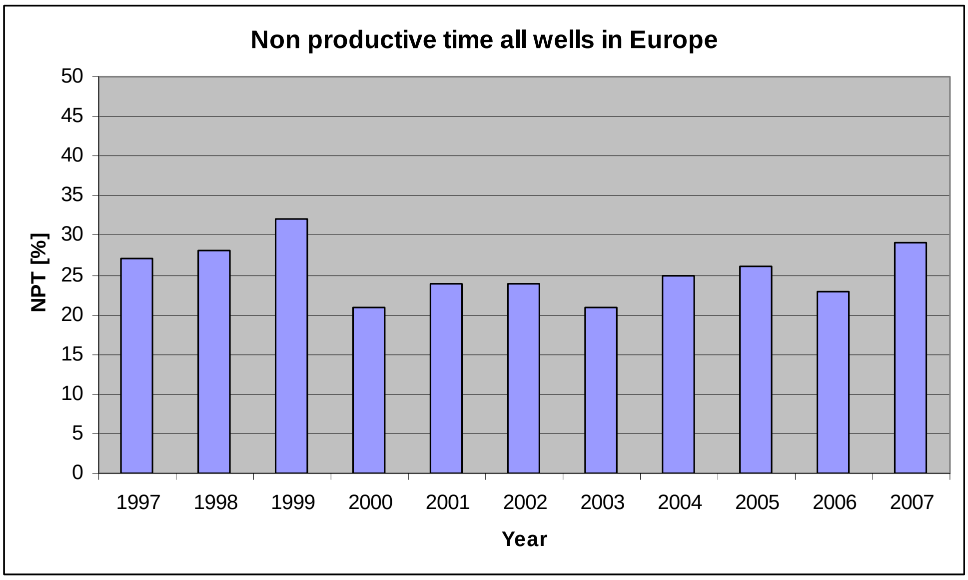

Fig. 1 - Non-productive drilling time for European wells. The numbers have been retrieved from the Rushmore database (http://www.rushmorereviews.com/rushmore.htm)

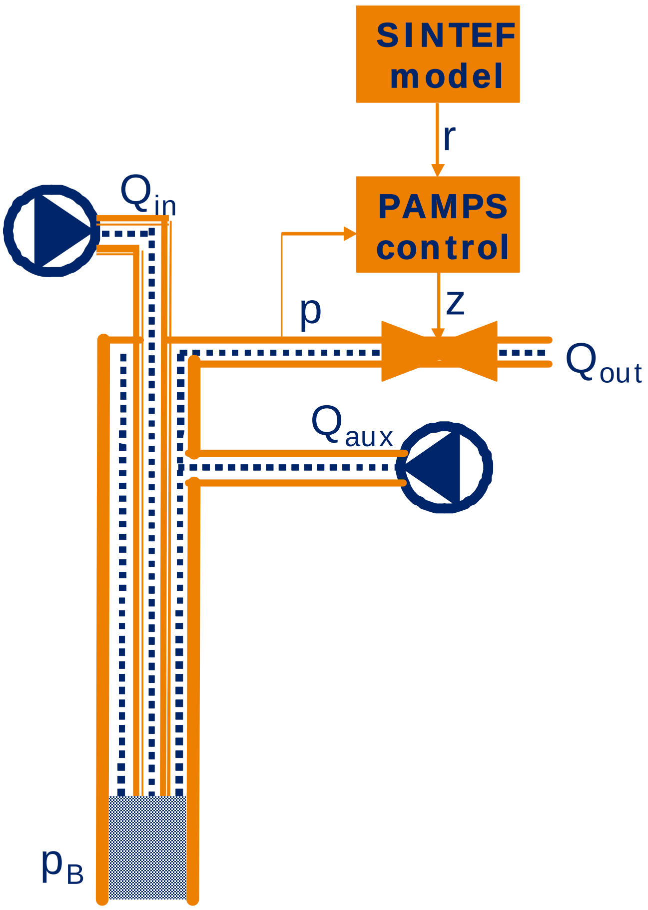

Fig. 2 - Left: Simple schematic drawing of MPD setup at Kvitebjørn including rig pump, auxiliary pump, choke, control system (PAMPS) and SINTEF hydraulic model.

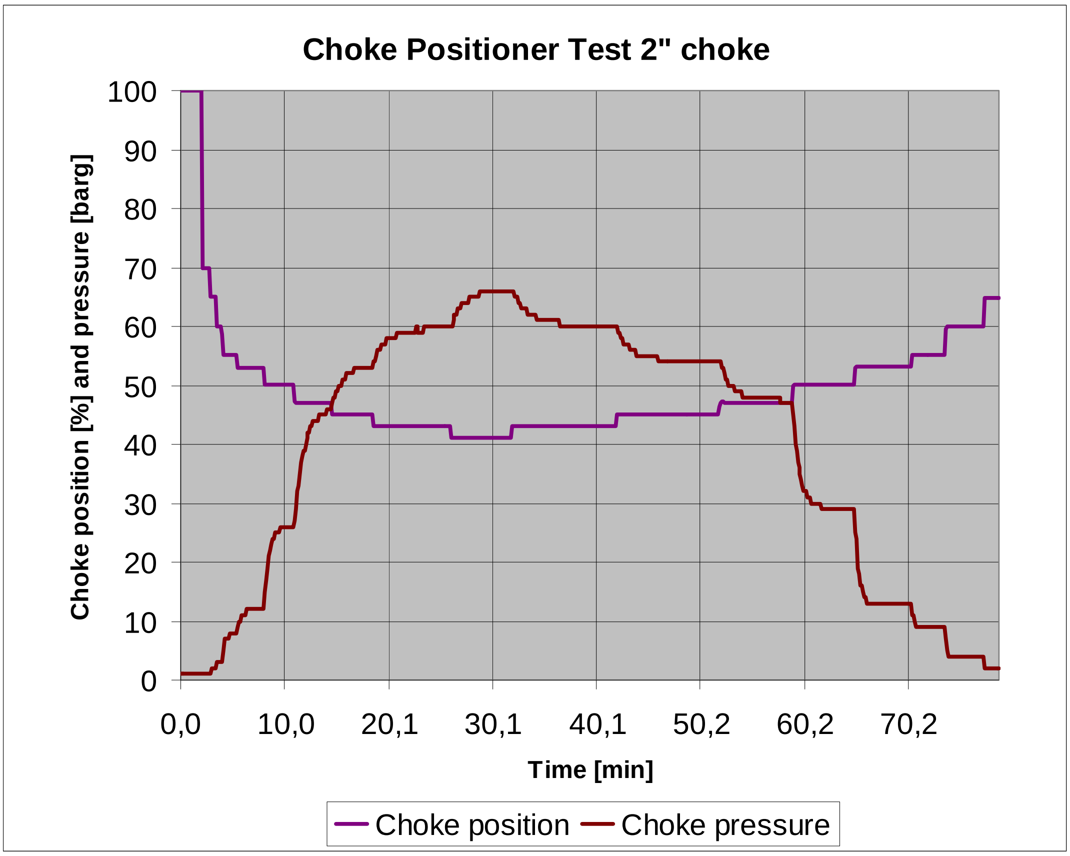

Fig. 3 - Open loop step response for identification of simplified well model.

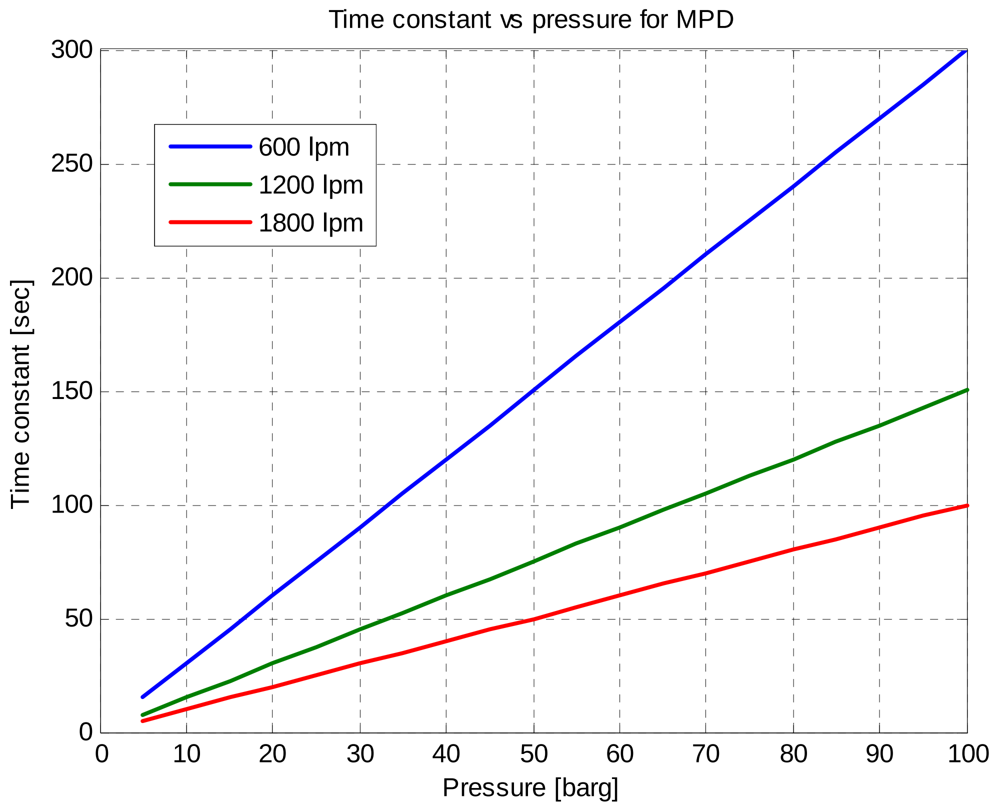

Fig. 4 - Calculated pressure dependency for hydraulic time constant T_p from equation (9) for Kvitebjørn for 3 different pump rates. E.g. for a pump rate 1200 lpm, the time constant will increase from 30 seconds with 20 bar pressure to 90 seconds with 60 bar pressure. This goes well with the results shown in Fig. 3.

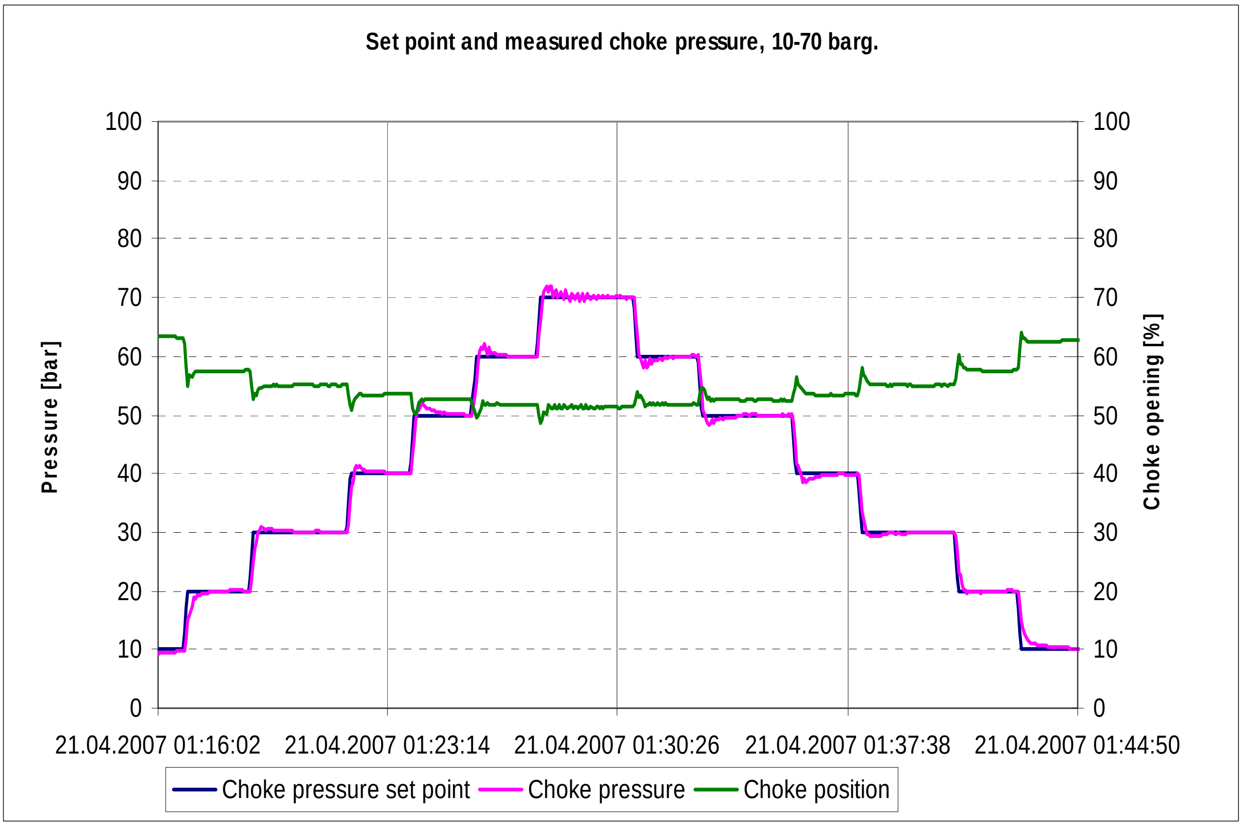

Fig. 5 - Closed loop test of PID controller with step responses to changes in the choke pressure set point.

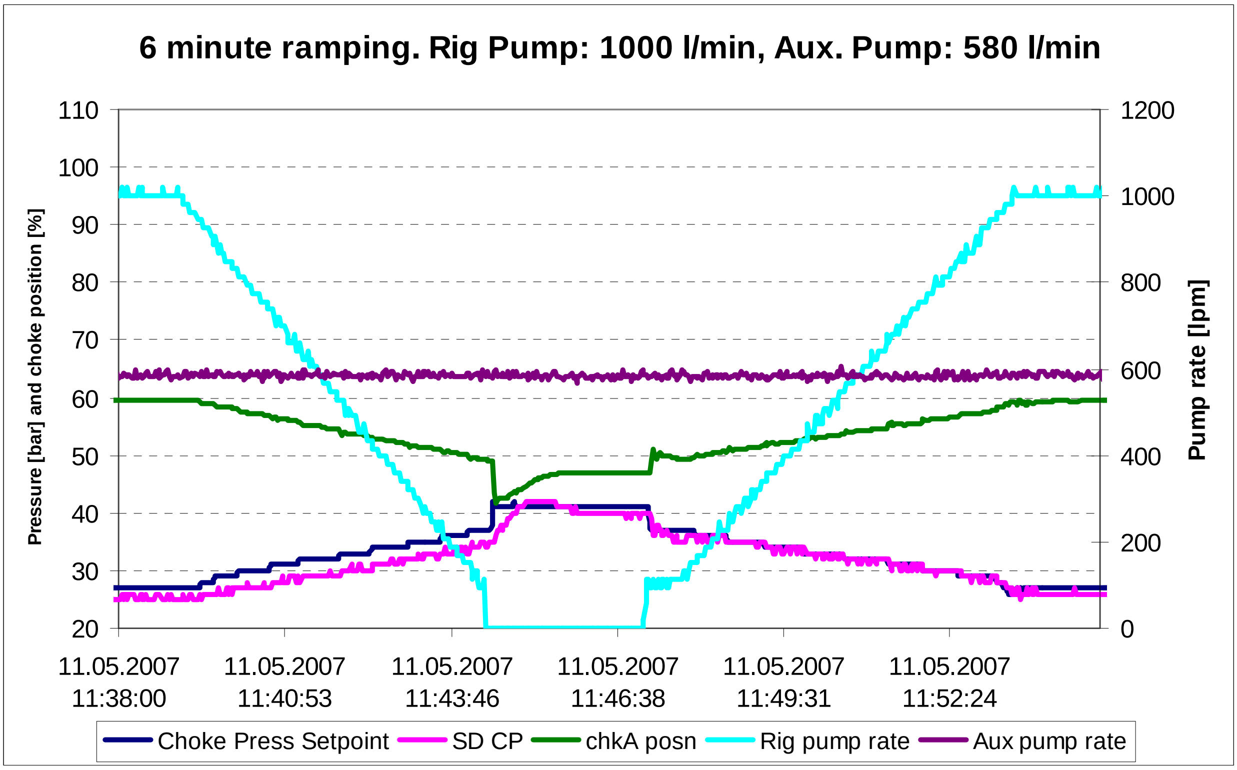

Fig. 6. Test of PID controller with varying choke pressureset point from SINTEF model during a connection.

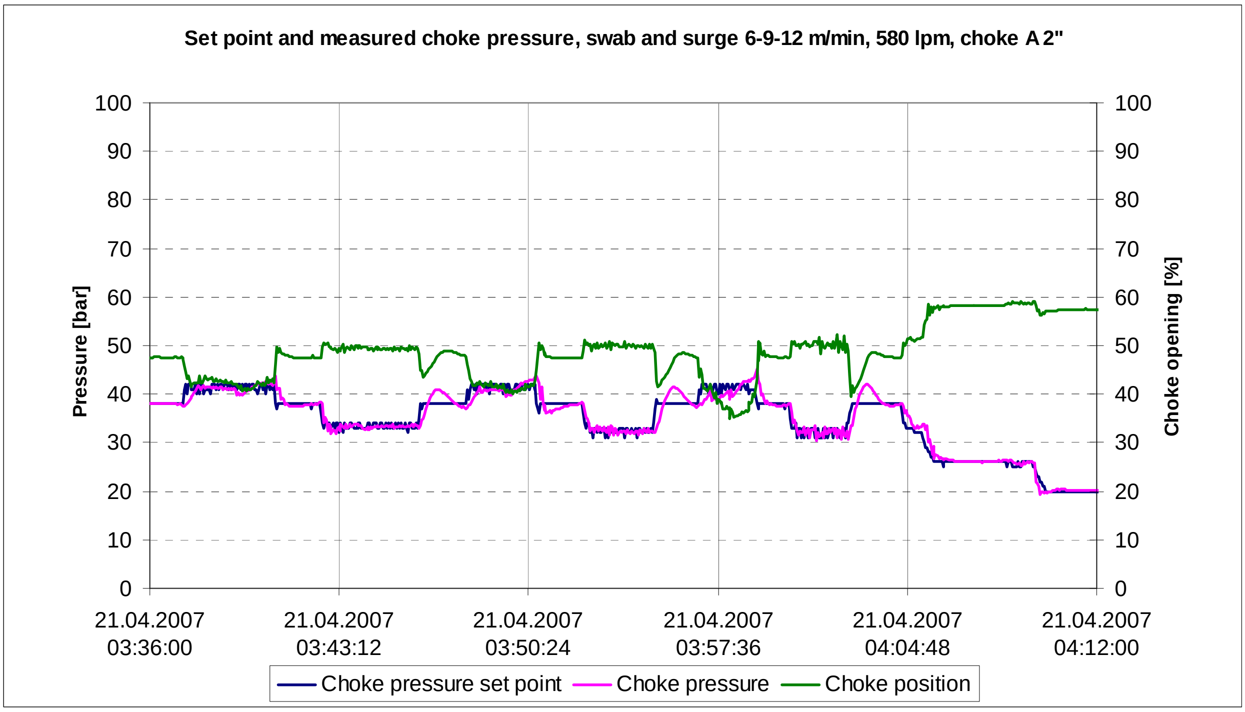

Fig. 7 - Surge and swab experiment.