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Supervisory control for underbalanced drilling operations

Torbjørn Pedersen * **John-Morten Godhavn** ** **Jerome Schubert** ***

* *Norwegian University of Science and Technology, Trondheim, N-7491, Norway (e-mail: torbjorn.pedersen@ntnu.no)*
** *Norwegian University of Science and Technology and Statoil ASA, Trondheim, N-7491, Norway (e-mail: jmgo@statoil.com)*
*** *Texas A&M University, College Station, TX-77843, USA (e-mail: jerome.schubert@pe.tamu.edu)*

Abstract: Good flow and pressure control is essential for successful Underbalanced Drilling (UBD) operations. This work evaluates the use of Model Predictive Control (MPC) for integrated control of well conditions and the topside separation system during UBD. The downhole well pressure, separator liquid levels, and the separator pressure are controlled by manipulation of the rig pump, the choke, and the separator valves. The control system adheres to downhole and topside constraints. These constraints include pore and collapse pressures, minimum flow rate for hole cleaning, maximum choke pressure, separator pressure, and separator liquid levels. The proposed MPC solution uses simple Hammerstein-Wiener models, where parameters are determined by system identification incorporated into standard drilling procedures. The control system is tested using a high-fidelity multi-phase flow simulator (OLGA) for some common drilling scenarios, including drilling into a producing formation and performing connections. We show that the MPC solution is able to take proactive action to ensure safe and efficient operation without having to enter well control mode or shutting down the separator system. By limiting the amount and variation in influx from the reservoir, we get less Non-Productive Time (NPT), we improve safety, and we may to some extent be able to reduce the footprint of the equipment.

Keywords: Process control, model predictive control, simulation, drilling automation, multi-phase flow, underbalanced drilling

1. INTRODUCTION

Drilling is one of the oldest engineering activities in the world, yet the current degree of automation is still surprisingly low. The authors have been involved in many discussions about why this is so, and the commonly stated reasons include: the companies do not see the added benefits; the safety requirements are too stringent; the available sensors are not good enough; retro-fitting of rigs is too expensive; and the all too common, it is too hard to change the existing practices.

However, due to ever rising drilling costs and new safety concerns, we see renewed interest in improved automation solutions for drilling. We are still a long way from commonly accepted industry standards and easily implementable systems (Saeed et al., 2012), but we now see a more systematic discussion of how the process can be automated, and which levels of control are most suitable for drilling (Godhavn, 2009; Breyholtz and Nikolaou, 2012; Macpherson et al., 2013).

There are several interesting control challenges within the field of drilling, such as: vibration management, directional drilling (geo-steering), automatic fluid mixing, and automatic pipe handling. However, we limit this article to the area of flow and pressure control. Flow and pressure control are instrumental to the stability, safety, and successful drilling of a well. The nightmare scenario during any drilling operation is that a severe gas kick, an uncontrolled influx of gas, evolves into a full blow-out and potentially another Macondo accident. This is a possible scenario if a kick is not detected early enough, or if insufficient actions are taken. Secondary concerns are: having to abandon a two-hundred million dollar well because the reservoir was badly damaged or the well collapsed; or having to perform expensive side-track operations.

The normal mode of operation in most drilling operations is to be statically overbalanced. By overbalanced, we mean that we always have a higher pressure in the part of the well exposed to the reservoir, than exerted by the reservoir. By static, we here mean when not circulating any fluid. If this is achieved we have no influx of reservoir fluids (including gas) when drilling. Drilling rigs are generally not equipped to process large amounts of reservoir fluids.

We can be overbalanced by adjusting the density of the mud; or if the well is sealed with a Rotating Control Device (RCD) a backpressure can be enforced at the surface by manipulation of the choke. Note that we need some flow through the choke to be able to control the pressure.

Operations where we use a controlled backpressure is one type of Managed Pressure Drilling (MPD). The flow rate will affect the pressure in the well due to the frictional pressure drop in the annulus. We have a steady state, fundamental equation for the bottomhole pressure (Rehm et al., 2008):

$$p_{\mathrm{bh}} = p_{\mathrm{hydr}} + p_{\mathrm{afp}} + p_{\mathrm{bp}}, \tag{1}$$

where p_{hydr} is the hydrostatic pressure exerted by the drilling fluid and the cuttings load, p_{afp} is the annulus friction pressure loss, and p_{bp} is the applied back-pressure.

The International Association of Drilling Contractors (IADC) has defined Underbalanced Drilling (UBD) as: "A drilling activity employing appropriate equipment and controls where the pressure exerted in the wellbore is intentionally less than the pore pressure in any part of the exposed formations with the intention of bringing formation fluids to the surface" (IADC, 2011).

UBD is often considered more complex than conventional drilling or MPD due to the presence of multi-phase fluids, the need for additional equipment and procedures, the lack of customized rigs, and the additional crew and training required during the drilling operations; and sometimes it is simply not technically feasible. However, we know that in some cases the economic gains are high enough that UBD is the preferred choice, and in some cases it is the only choice (Finley et al., 2006). Note that in MPD the pressure window is between the pore pressure and the fracture pressure, while in UBD it is between the collapse pressure and the pore pressure. In some situations the size of the windows will determine the appropriate technique. We limit the discussion in this article to UBD systems where we have injection of a lightened fluid, and disregard e.g. foam, air and mist systems.

If we examine Eq. 1, we can see that the term p_{hydr}, which in overbalanced drilling is determined by the combined density of the drilling fluid and the cuttings load, and the height of the fluid column, now will depend on the amount of reservoir fluid and injected lighter fluid in the annulus. The pressure loss, p_{afp}, will also depend on the reservoir influx, as the influx will change the friction parameters and the magnitude of the flow in the annulus. The reservoir influx depends on the pressure differential in the openhole region (i.e. the pressure differential between the reservoir pressure and the bottomhole pressure) and the reservoir productivity index. We therefore have a natural feedback loop with several steady-state solutions. See Aarsnes et al. (2014a) for a treatment of the problem.

It should be noted that in the case of MPD we only have relatively fast dynamics, as changes in choke openings and pump flow travel with the speed of sound, meaning that changes will be seen at the bottom in seconds or tens of seconds. In UBD we also have the much slower gas transport dynamics, which may take a very long time to converge, typically tens of minutes.

Fig. 1 shows a simplified schematic of the system. The well is shown as a u to illustrate the coupling of pressures at the bottom. It should be noted that the drill-pipe is duplicated on the right-hand side to illustrate that the return path is not a simple pipe, but modelled as concentric annuli. This is of course a drastic simplification, since the drill-pipe will be moving, we have several eccentricities in the annulus, the wellbore wall is uneven (and unknown), and the well geometry will cause the pipe to move away from the centre. There is a Non-Return Valve (NRV) in the drillstring which means that there will be no backflow into the string. The drill-bit is shown as a valve, to indicate that we have a large pressure loss over the nozzles. Note that the figure does not show the location of measurements.

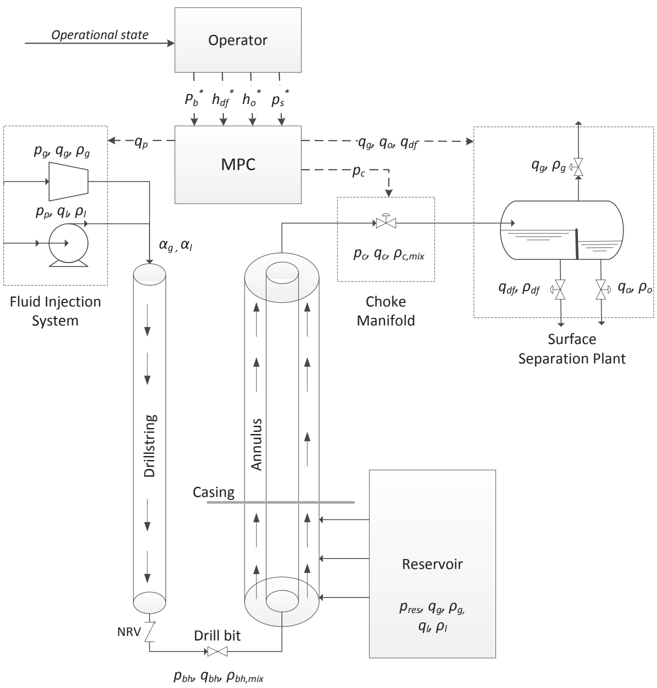

Fig. 1. Simple schematic of the well and the topside equipment.

We already mentioned measurements as an issue of concern. In drilling we have a strong separation between downhole measurements and topside measurements. Topside measurements are usually available, or could be made available. They are (compared to the process dynamics) frequent, and usually of decent quality. However, for bottomhole measurements the most common method for sending data to surface is referred to as mud-pulse telemetry. This is a technique where pressure pulses are modulated through the drilling mud. The process is slow, a bit-rate of 5-10 bits per second is not uncommon, it has long delays and is noisy (Downton, 2012). We will also lose all downhole measurements during connections (and other scenarios with no or low circulation) or if we have too much gas in the drillstring. It is, however, possible to send the data to the surface after circulation is restored. Better systems, such as wired drill pipe (WDP), are available. WDP offers communication delays of as little as 2-4 seconds with high-speed data transmissions. However these systems have only been used in maybe a few hundred wells, and many of these were pilot projects (Pixton et al., 2014). This number is vanishingly small, as the estimated number of active oil and gas wells in the US alone are more than one million (Note that this is also true for MPD wells and to some extent UBD wells). WDP is still perceived as an immature technology and as a costly investment by the general petroleum industry. For a general discussion about measurements related to automation in drilling, see Cayeux et al. (2014).

UBD uses a full-scale separation system. The main objective of the separator is to separate the drilling fluid and the produced reservoir fluids. The drilling fluid is reused, while produced fluids are deposited, flared, or sent to production lines. Both horizontal and vertical separators are used. The separator design, size, number of processing stages and orientation are determined by the amount of available space and the expected operational envelope (Laleh et al., 2012). In this work we will use a horizontal separator with one internal weir plate. For simplicity we assume that we have three-phase separation, and that cuttings will follow the heavy liquid (drilling fluid).

Several authors have provided substantial work on modelling of well pressure and flow dynamics with multi-phase fluids (Rommetveit et al., 1995; Lage, 2000; Perez-Tellez, 2003; Petersen et al., 2008; Fan et al., 2009), as well as simpler models aimed at control or parameter identification purposes (Nygaard, 2006; Hauge et al., 2012; Aarsnes et al., 2014a,b).

In this work we look at integrated control of topside and bottomhole objectives. We want to evaluate the performance we can get with very simple models, as simplicity and ease of use will be key factors for gaining acceptance on drilling rigs. The personnel operating the equipment are much more likely to have a two-day course in single-input single-output (SISO) proportional-integral-derivative (PID) controller tuning, than a comprehensive background in control theory. We also want the operation of the control system to tie into existing procedures, and not to add additional steps (and time) to the operation.

We make some simplifications in the current work. We ignore the drillstring dynamics and movement, which in reality will induce complex and significant pressure surges and volume changes (Mitchell, 1988). We also use a simple well geometry, a pure vertical well with concentric annuli. We assume the existence of good downhole measurements from WDP, and good topside multi-phase flow measurements. In reality we would probably need at least some kind of observer or simulator, which can account for fusion of topside measurements and stochastically delayed bottomhole measurements.

Other work on Model Predictive Control (MPC) for drilling includes e.g. Breyholtz et al. (2011) on dual-gradient drilling, Breyholtz et al. (2009) and Pixton et al. (2014) on MPD, and Nygaard and Nævdal (2006) on non-linear MPC for well stabilisation using the choke, and Pedersen and Godhavn (2013) on MPC for UBD which uses both the pump and the choke to control downhole pressure.

2. DRILLING OBJECTIVES AND CONSTRAINTS

In UBD the main pressure control objectives are: to keep the pressure in the openhole region above the collapse pressure, or more rarely, to limit the amount of produced fluid below the processing capacity (indirectly controlled by the pressure differential); to keep the pressure below the reservoir pressure, as even short periods of overbalance can severely damage your assets (Salimi et al., 2010); and to keep the surface and casing pressures within the equipment and well limitations. Note that well pressure limits are not for one given point, but for the whole openhole region. As we drill deeper we will impose new pressure set points, possibly with very different values. In the same manner, if the wellbore is isolated from the reservoir through e.g. a cementing and casing job, we are no longer concerned with pressure control in these sections. We can also enforce simultaneous (dependent) pressure set points at multiple locations in the well, if for example the size of the pressure window (constraints) varies along the length of the well.

The main tasks of the fluid flowing through the well are to lift the cuttings from the bottom and out of the well, to supply energy to the bottomhole motor, and to supply cooling to the bit. Our control objective will be reformulated to satisfy a minimum rate which satisfies all these constraints, as well as a maximum rate to not produce more fluid than the separation system can handle. As already mentioned, the flowing fluid will also strongly affect the well pressure.

The main control objective for the separation system is to properly separate the returned fluids, which includes meeting the required degree of separation quality for the next levels of processing or export. This is indirectly achieved by controlling the separator pressure, and the level of the heavy (drilling fluid) and light fluid (produced light oil). This gives constraints on minimum and maximum liquid levels, and separator pressure. We do not want too tight level control, as the separator also plays a role as a buffering device.

We also enforce equipment constraints on the maximum rate of change for the rig pump and the chokes. We do this to limit wear, and to limit the imposed pressure transients.

Our controlled variables will be the bottomhole pressure (p_{bh}), the choke pressure (p_c), the separator pressure (p_s), the choke opening (z_c), the flow (drilling fluid, oil, and gas) through the choke (q_{df}, q_o, and q_g), and the level of the drilling fluid (h_{df}) and the oil (h_o) in the separator. We can manipulate set points for the rig pump volumetric flowrate ($q_{\mathrm{p,\,sp}}$), the choke pressure ($p_{\mathrm{c,\,sp}}$), and the separator pressure ($p_{\mathrm{s,\,sp}}$) and liquid levels ($h_{\mathrm{df,\,sp}}$ and $h_{\mathrm{o,\,sp}}$). Inner control loops will reach the set points by adjusting the pump speed (ω_p), the opening of the choke (z_c), and the opening of the separator valves (z_{g}, z_{df}, and z_{o}). This will help linearise underlying non-linearities. Due to the much slower dynamics when adjusting the mud density, we will not consider this as a variable for making short term adjustments. However, it will play a very important role in pressure control over longer time-windows.

The main actuator for controlling the well pressure is the choke. However, if we are not pushing against a constraint, we may also use the rig pump to help control large pressure changes. The main role of the rig pump will be to ensure the minimum required flow rate at the bit, and thus proper hole cleaning. The controlled variables in the separator are considered independent, and are controlled by their corresponding valves. This is of course a simplification, and we will have strong coupling between e.g. the liquid levels and the separator pressure, and the drilling fluid level and the oil level. If we do not have too large fluctuations from the ideal values, these interactions should be manageable. However, they could also be included as separate models.

If the separator reaches the maximum instantaneous production rate, we can temporarily close the choke to reduce the flow, while we reduce the pump rate to keep the same pressure; or we can select to increase the bottomhole pressure to also reduce the long-term reservoir influx.

A low wellbore pressure is usually very beneficial for the Rate of Penetration (ROP) as it can eliminate the chip-hold down force (McLennan et al., 1997). That is, we want as low pressure as possible in a safe manner. If we expect to reach the maximum production capacity, we can therefore increase the bottomhole pressure in steps as we expose more reservoir. However, if the pressure gets too low, we might risk that parts of the wellbore collapse, we might get a stuck drillstring, or even a full well collapse. Another variable to consider is the cost of removing produced fluids (or the gain for selling them).

We prioritize 1) the well pressure limits; 2) the equipment limitations; 3) the bottomhole pressure ideal value; and 4) few changes in the manipulated variables. Note that since we want to limit the divergence from the ideal values in the separator, reaching these values also have a quite high priority. This is not in accordance with limiting the variance in the separator output, and there is a trade-off for this tuning.

Some of the major disturbances are variations in reservoir influx, density changes in drilling fluid, changes in reservoir pressures, drill-string motion, slugs, and changes in flow regime.

An overview of important interactions is found in Tab. 1, showing manipulated variables (MVs), controlled variables (CVs), and disturbance variables (DVs). Where (+) indicates a positive relationship, while (−) indicates a negative relationship, sp is short for set point. Note that we have a complex relationship between the choke pressure and bottomhole pressure. Depending on if the well pressure is hydrostatically dominated or friction dominated, we can get either a rise or a fall in choke pressure as the bottomhole pressure rises. This means that we need to know in which region we are operating. Normally an UBD operation with high gas production is friction dominated, and we will have a (+) relation. Note that the interactions are for steady-state changes and not for temporary transients where we will have many more connections.

Table 1. Map of modelled system interactions.

CVs		p_{bh}	p_c	z_c	h_{df}	h_o	p_s	q_{df}	q_o	q_g
MVs	$p_{\mathrm{c,\,sp}}$	+/-	+	-					-	-
	$q_{\mathrm{p,\,sp}}$	+						+	-	-
	$h_{\mathrm{df,\,sp}}$				+					
	$h_{\mathrm{o,\,sp}}$					+				
	$p_{\mathrm{s,\,sp}}$						+			
DVs	p_{res}	+/-							-	-
	ρ_{df}	+							-	-

3. DRILLING MODEL AND CONTROL SYSTEM

The control hierarchy is illustrated in Fig. 2. At the bottom level (I) we have the actuators consisting of the choke, the pump motor, and the separator valves. At the next level (II) we have local control loops, with e.g. proportional-integral (PI) controllers stabilizing pump flow, choke pressure, and separator flows. At level three (III) we have the predictive control solution, which controls bottomhole pressure and return flow; while (IV) the operator will adjust the ideal resting values, and constraint sets when we have a change of operation, or reach a new stage of the well plan. Level (II) runs each second, and level (III) every 5 seconds. Since the process is quite slow, and the models are quite simple, we do not have issues with the computational time, even for large horizons with a significant amount of evaluation points.

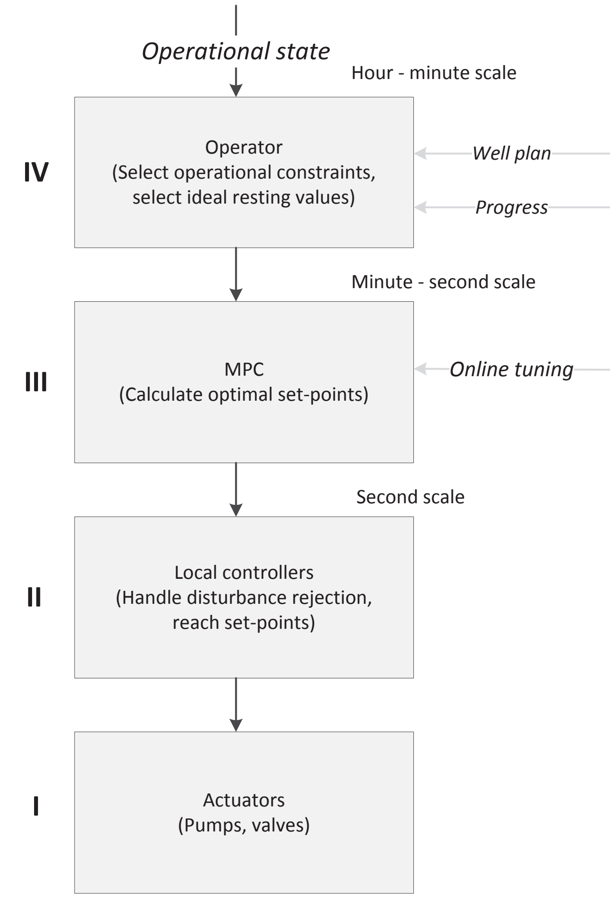

Fig. 2. Overview of the control hierarchy.

An MPC software package, SEPTIC, is used to configure and solve the predictive control problem. SEPTIC is an in-house control software developed by Statoil ASA, and has been successfully used in many process control applications. The basic control problem is formulated in equations (2-6).

$$\min_{\Delta u} y_{\mathrm{dev}}^T Q_y y_{\mathrm{dev}} + u_{\mathrm{dev}}^T Q_u u_{\mathrm{dev}} + \Delta u^T P \Delta u, \tag{2}$$

$$u_{\min} < u < u_{\max}, \tag{3}$$

$$\Delta u_{\min} < \Delta u < \Delta u_{\max}, \tag{4}$$

$$y_{\min} < y < y_{\max}, \tag{5}$$

$$y = M(y, u, d, v). \tag{6}$$

The quadratic objective function (2) penalizes deviation from the desired set points for the controlled variables (y_{dev}), deviations from ideal values for manipulated variables (u_{dev}), and value changes for the manipulated values (Δu). We have constraints on the range of the manipulated variables (u), in the rate of change in the manipulated variables (Δu), as well as on the range of the controlled variables (y). The dynamic model (6) predicts the response in controlled variables, by considering past and future states (y), inputs (u), measured disturbances (d) and predicted unmeasured disturbances (v) (Strand and Sagli, 2004). All state constraints in this problem are considered to be soft constraints; however, any state outside of the valid range is heavily penalized by a growing error term. The rate of growth (penalty) is set by the user and is high for critical parameters, and low for some parameters where it is not that important to stay inside the given envelope, these constraints are marked by (soft) in figures.

The matrices Q_y, Q_u, and P are tuning parameters in the system, and will be used to achieve the desired response and to set the priority of manipulators.

Our modelling approach will be data driven, and based on system identification. We employ simple first order step response models with time delay, given by

$$g(s) = \frac{k}{\tau s + 1} e^{-\theta s}, \tag{7}$$

where k is the process gain, τ is the dominant time lag constant, and θ is the time delay. We also use slightly more complex Hammerstein-Wiener models, where we account for input and measurement saturation, giving us quasi-linear models if we have saturated parameters. The approach is similar to traditional dynamic matrix control (DMC) and will require quite long time-horizons and storage of a large amount of previous inputs (Maciejowski, 2002). We may also introduce too many tuning parameters for the intended users.

We want to identify the relationships between controlled and manipulated variables during standard drilling procedures. The relationship between pump flow and bottomhole pressure will be identified during standard friction testing operations. The reservoir influx can be identified during connections, where we (sometimes) also can choose to increase the pressure reference in several steps. The model can be identified and updated, as we observe the resulting flow at the surface. An average model can be built based on the different readings, or we can switch model based on the selected operational values. The separator models are assumed to be identified a priori, based on initial testing at several flow conditions.

Since we are continuously extending the well, our models will almost always be out-of-date. We will therefore need to update the models regularly as the well is getting deeper.

The control loops at level (II) are simple PI controllers, or in some cased gain-scheduled PI controllers. Amplitude anti-windup is enforced on this level and then signalled to the MPC, while rate limitations are handled directly by the MPC.

The choke characteristics are often non-linear, with optimal performance in a banded region (e.g. 20-70 percent opening), we model this directly in the MPC and enforce soft constraints with increasing penalties outside of the wanted operating range. We also do this to limit the time the choke spends in an almost closed position while drilling, as we have a higher chance of choke plugging and a higher rate of wear during this mode of operation.

4. SCENARIO AND SIMULATION SET-UP

The main challenges in pressure and flow control arise during transients in the system, or because of sudden unexpected changes in the reservoir formation. Transients are usually related to connections. During drilling we need to add more drillpipe at fixed intervals, a procedure referred to as a connection. In most systems, this also means that we must shut down the main pump. During a connection the drilling (and rotation) stops, the bit is lifted from the bottom, and the main pump is ramped down to zero. After the connection is finished, the pump is ramped back up, the bit is lowered, and the drilling is resumed.

In underbalanced drilling, if we do not go to a balanced state during a connection or have a downhole isolation valve, the well will continue to flow during the procedure. The reservoir will then serve as a backpressure pump during the connection. We still have the same pressure window, but we require enough return flow from the well (or due to expansion) to have sufficient control capabilities over the bottomhole pressure. We can also select to keep a constant bottomhole pressure.

We thus adjust the choke pressure to obtain the new ideal bottomhole pressure (and flow rate) and to compensate for loss of frictional pressure. The operations are illustrated in Fig. 3. Note that in this case we circulate out cuttings before performing the connection. UBD uses less viscous drilling fluids than normal drilling operations, and it may be necessary to circulate some of the cuttings out of the bottom of the well to avoid problems with too much cuttings settling at the bottom.

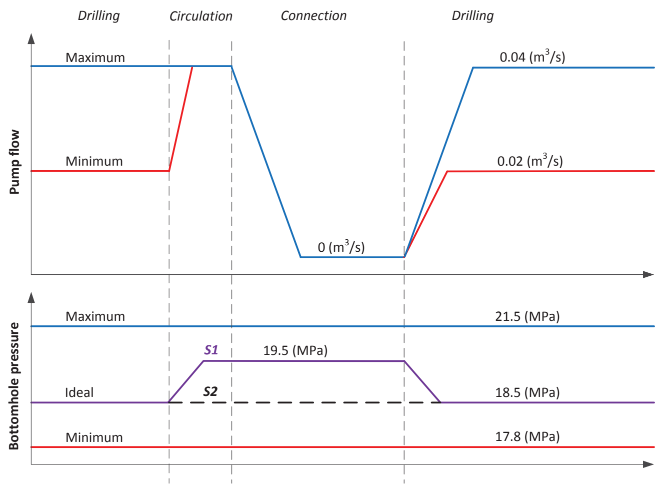

Fig. 3. Illustration of operation. First stippled line is start of circulation, second is start of pump ramp down, and third is start of pump ramp up.

We evaluate four scenarios. 1) A connection where we increase the bottomhole pressure during the connection to limit the reservoir flow; 2) A connection where the goal is to keep a constant bottomhole pressure; 3) Drilling into a productive reservoir zone, and receiving a large influx of reservoir fluids; and 4) A significant change in the reservoir pressure during drilling. Well, equipment, and reservoir parameters are given in Tab. 2.

Table 2. Well, equipment, and reservoir parameters used in simulation.

Variable	Value
True vertical depth	1800 m (5906 ft.)
Inclination	90 degrees
Inner pipe diameter	0.127 m (5.0 in.)
Outer pipe diameter	0.145 m (5.7 in.)
Wellbore diameter	0.2159 m (8.5 in.)
Reservoir pressure	21.5 MPa (3120 psi)
Production index	0.035-0.1 $\frac{m^3/s}{\text{MPa}^2}$ (5-15 $\frac{\text{SCFD}}{\text{psi}^2}$)
Reservoir temperature	345 K (161 F)
Oil to gas ratio	1:1500
Gas density	7 kg/m^3 (0.06 ppg)
Oil density	900 kg/m^3 (7.51 ppg)
Drilling fluid density	1025 kg/m^3 (8.55 ppg)
Surface temperature	295 K (71 F)
Max production rate	16.39 m^3/s (50 MMSCFD) gas
Max choke pressure	20.6 MPa (5000 psi)
Separator radius	1 m (3.3 ft.)
Separator length	6 m (19.7 ft.)
Choke diameter	0.076 m (3 in.)
Chokeline inner diameter	0.102 m (4 in.)
Chokeline length	20 m (65.6 ft.)

A simulation framework was constructed in Pedersen and Godhavn (2013) using Matlab, OPC servers, and the SEPTIC software. OPC is OLE (object linking and embedding) for process control, a standard for transferral of real-time plant data. The framework is event driven and simulates the well, separator, and all control levels. The well is simulated using the Oil and Gas Simulator (OLGA), while a reduced order separator is implemented in Matlab. OLGA is a commercial multi-phase simulator developed to simulate oil and gas flow in pipelines (Bendiksen et al., 1991). Since its beginning as a pipeline simulator, OLGA has seen substantial revisions, and now also supports transient simulation of wellbore dynamics.

5. RESULTS

For all figures, max and min indicates upper and lower limits, set point is the operator selected target value, while ref(erence) is the calculated input value from the MPC system. The main control goal is to not break any important constraints, however a secondary goal is to stay within a performance window of plus-minus 5 bars from the bottomhole pressure set point.

Fig. 4 shows simulation scenario (S1) with increased bottomhole pressure (and reduced reservoir influx) during connections. The well is initially underbalanced at the given drilling fluid density. We enter a producing part of the formation, and get influx from the reservoir. The flow stabilizes around the one hour mark (first stippled line). Drilling continues for two hours, and we get steadily increasing influx from the reservoir as new parts of the formation are uncovered. At the three hour mark we start circulation and perform the connection procedure. As seen from the figure, we only have small oscillations around the ideal value, and are not close to pushing the well or equipment constraints. We stay within the performance window (except for the start, where we are initialized in a state already outside of the window). We see some oscillations in the choke flow, as we adjust the choke opening to achieve the desired bottomhole pressures. At the five hour mark we drill into a region in the reservoir with higher pressure, and get a large sudden increase in influx; however this does not lead to large deviations from the requested well pressure.

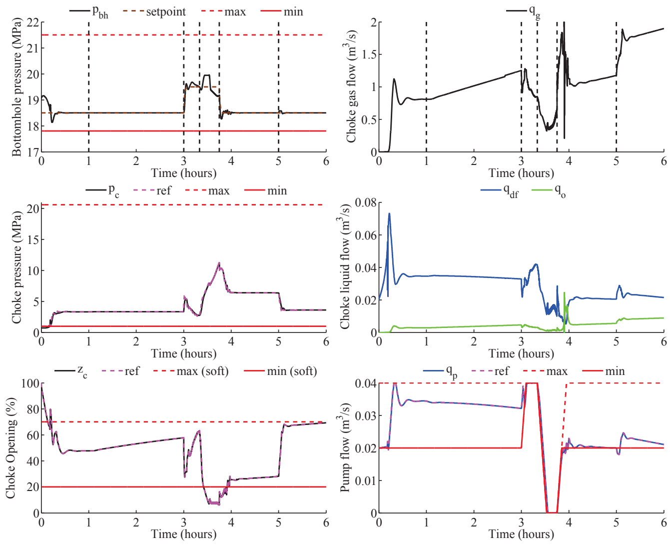

Fig. 4. Connection with increased bottomhole pressure. First stippled line shows when we have reached a stable state after influx from the reservoir starts. The final line shows the location of a large influx from the reservoir.

If we look closer at the separator during (S1), we see from Fig. 5 that we generally have acceptable oscillations in the system. However, at the first large liquid outflow, we are not able to keep the drilling fluid level within the constraints, and this would severely impact the quality of the produced oil. The subscripts for flows s and c, indicates separator outflow and choke flow. We also see that the output closely follows the input, and that most oscillations are sent straight through to the production line. The buffering objective of the separator is therefore not fulfilled, and a new tuning or a secondary buffering device should be used. Note that during the first part of the scenario, we have no influx of gas or oil to the separator. As mentioned earlier we want to couple the well and the separator, and a feed-forward from the choke opening (and flow) should be employed. For larger disturbances from the well, we want to adjust the set point values for the separator in the MPC solution in a matter similar to Godhavn et al. (2005).

Fig. 6 shows scenario (S2), where the goal is to keep a constant bottomhole pressure. We are able to keep the well within the limits during the connection and to stay inside the performance window, however the choke saturates at fully open during the circulation phase, and if this was to continue for a longer time we would see significant

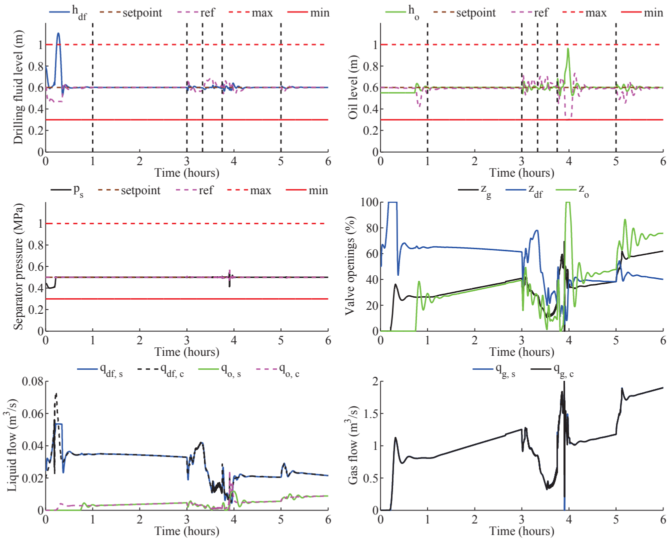

Fig. 5. Separator measurements and inputs during connection with increased bottomhole pressure.

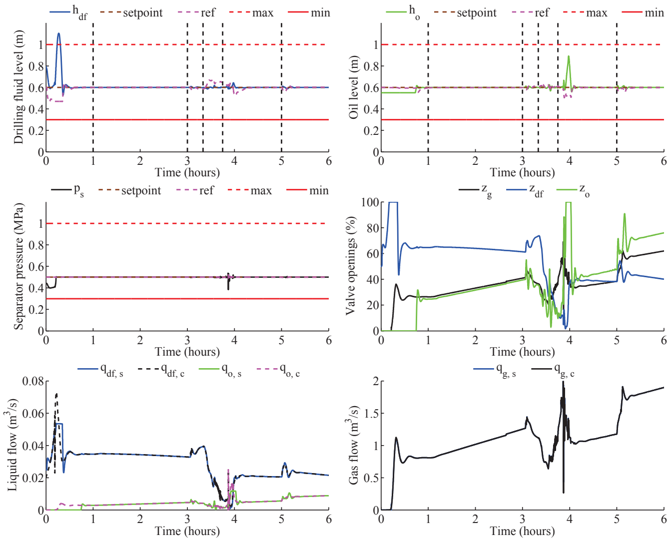

Fig. 7. Separator measurements during connection with constant bottomhole pressure.

deviations from the ideal pressure. We could account for this by circulating at a lower rate, at the expense of a longer operation. In this scenario we are not exploiting the natural pressure decrease and increase due to the changing pump flow, and the choke must remove/provide all the pressure to compensate for the frictional pressure changes. The travel time for the selected choke is 15 seconds.

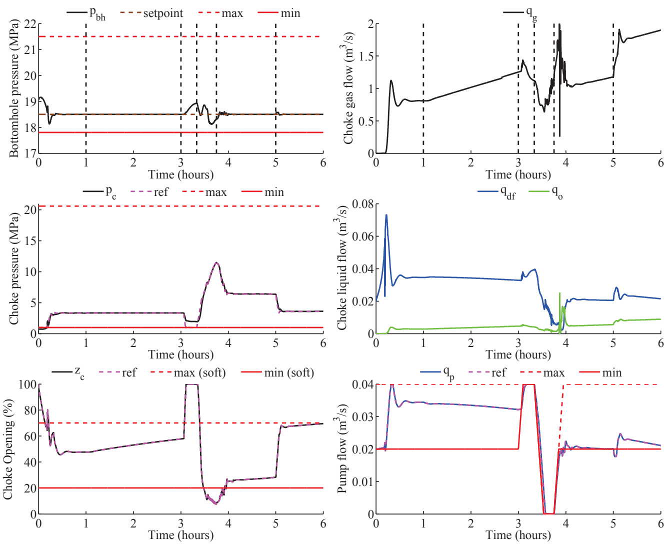

Fig. 6. Connection with constant bottomhole pressure.

From Fig. 7 we see that the there are only small differences from the scenario with higher connection pressure, but we do get some more gas influx during the connection.

If we adjust the separator level set points based on measured topside flow, we can make room for more fluid in the separator to handle large liquid slugs. Fig. 8 shows the results when we actively change set points based on measured flow. We see that we get better performance, but it is a marginal scenario and we cannot really tell if this measure alone would allow usage of this separator capacity. However, good control always helps avoiding unnecessary shutdowns due to separator flooding.

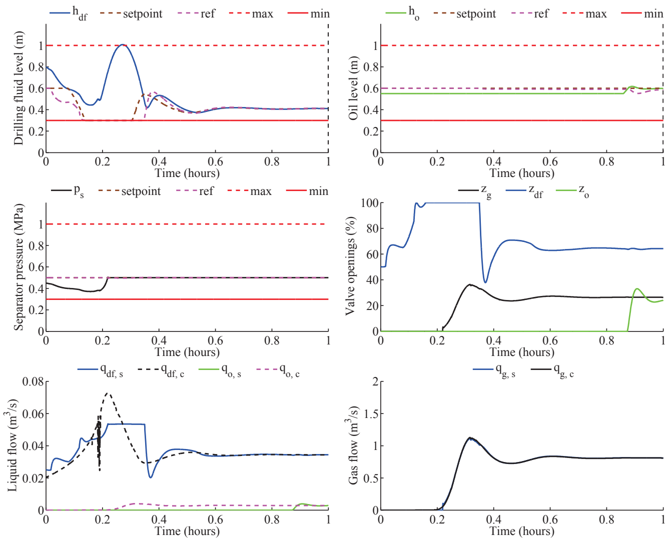

Fig. 8. Separator measurements when we actively change the set points of the separator based on measured flow.

6. CONCLUSION

We have presented a MPC solution for integrated control of well conditions and the topside separation system during UBD using simple data driven models. The performance has been evaluated during the most common drilling operation, as well as for a major disturbance. System identification is performed during normal drilling procedures, and does not impose additional steps during the operation. The simple models have limited validity, and require knowledge of the current operating region. However, due to the slow time constants of the operation, it is possible to keep the models up to date. For both scenarios, increased and constant bottomhole pressure during a connection, we can keep the pressure within a plus-minus 5 bar window, given that the conditions have not changed too much since the identification procedure. We expect that the performance would be worse in field applications where the disturbances are larger.

In future work we want to look closer at the handover between manual and automatic control. We also want to make sure that the control system does not hide severe well problems from the operators, and that the cause of the problems and the actions which the control system takes to correct these are transparent for the operator.

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