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Model Predictive Control of Flow and Pressure in Underbalanced Drilling

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Abstract: This paper presents a novel application of linear model predictive control (MPC) for pressure and flow control in underbalanced drilling operations. Coordinated control of pump flow and choke pressure is used to control the return flow rate, and the well pressure profile. The control system is verified using a high fidelity drilling simulator for some common drilling operations. The proposed solution shows promising results for operations close to the selected set-points, but the simple models employed have distinct limitations. The control solution is easily extendable to larger control problems, and can be augmented with better models.

Keywords: Process control, model predictive control, MPC, drilling, underbalanced, UBD, constraints, simulation

1. INTRODUCTION

During the last decade, the focus on safety and efficiency in drilling operations has increased. One of the main enablers for better safety solutions is better automation and instrumentation technology. Control solutions must be stable, robust, and offer reasonable tracking performance (Godhavn, 2009).

Even though there has been performed substantial work in the field of drilling automation, and there are some existing commercial automation solutions, we are far from good holistic control systems (Saeed et al., 2012). This work aims at improving the automation alternatives for underbalanced drilling (UBD).

If the pressure in the part of the well which is open to the formation exactly balances the formation pressure, the well is said to be at balance. In conventional and managed pressure drilling (MPD) we enforce a higher pressure in the open-hole region than in the formation to hinder influx from entering the well. In UBD we intentionally keep the well pressure below the formation pressure. Both in MPD and UBD tight control is the key for successful operations.

The main control inputs for MPD and UBD are normally the choke manifold, the rig pump, and the drilling fluid density. The well is sealed with a rotating control device (RCD), such that a backpressure can be enforced at the surface by e.g. closing the choke. Higher density or higher flow rates (frictional pressure loss) will increase the bottom-hole pressure.

Underbalanced drilling is different from conventional drilling, because in large parts of the operation the well is flowing. The return flow, often a combination of gas, different fluids, and rock cuttings, is processed at the surface. The return flow is the combination of the injected fluid and the influx from the reservoir. The amount of inflow depends on the difference between the open-hole pressure and the formation pressure, and the well production index (productivity). Several phenomena related to high pressure, compressibility, varying flow regimes, large differences in time-scales, poor measurements, and uncertain parameters make the process difficult to understand, model, and control.

Underbalanced drilling requires more personnel, more training and more equipment than conventional drilling. This includes a full-scale surface separation facility. The main reasons for employing underbalanced drilling may include (Finley et al., 2006):

- Fewer drilling breaks (no differential sticking or lost circulation).
- Limited near wellbore damage (better productivity).
- Reduced time-to-production.
- Detect hydrocarbons while drilling.
- Increased rate of penetration.
- Increased bit life.
- Formation not drillable in overbalance.

The actual benefits will vary depending on formation and well properties. It is not always feasible to use underbalanced drilling due to e.g. well stability issues, or too high production rates (due to limited capacity at the surface), while in some cases it is not the most economical alternative (Finley et al., 2006).

This paper tries to determine if we can get a sufficiently robust control solution with constrained linear model-based predictive control and simple step response models. The control solution is evaluated by employing a high fidelity drilling simulator, the IRIS Drilling Simulator (WeMod), to validate the performance of the control system during some common drilling operations. The well simulator is developed by the International Research Institute of Stavanger (IRIS) (previously Rogalandsforskning / Rogaland Research). The selected well case is shown in Fig. 1. The influx from the reservoir is pure gas. Note that we do not have any online measurements of the reservoir inflow or pressure, but these may be estimated from well testing. We assume that the bottom-hole pressure (p_{bh}) is available with no delay. Although this is not realistic, we may get a low delay with a wired drill pipe transmission system (Reeves et al., 2005).

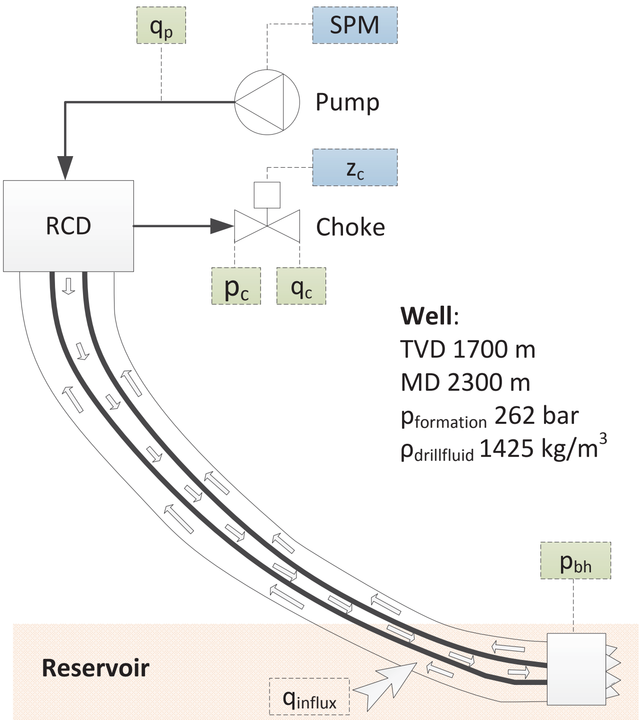

Fig. 1. Illustration of the well.

WeMod use a dynamic model which describes one-dimensional two-phase flow in pipelines with nonlinear partial differential equations (PDEs). The PDEs describe mass, momentum and energy balances for each phase. The momentum equations are lumped together, giving a drift-flux formulation. Models of friction, velocity, temperature, gelling, and flow regime are used to close the system (Tennøy et al., 2012).

An MPC software, SEPTIC, is used to configure and run the predictive control solution. SEPTIC is an in-house control software developed by Statoil ASA. The basic control problem is expressed in equations (1-5).

$$\min_{\Delta u} y_{dev}^T Q_y y_{dev} + u_{dev}^T Q_u u_{dev} + \Delta u^T P \Delta u \tag{1}$$

$$u_{min} < u < u_{max} \tag{2}$$

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

$$y_{min} < y < y_{max} \tag{4}$$

$$y = M(y, u, d, v) \tag{5}$$

The quadratic objective function (1) 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 constraints on the range of the controlled variables (y). The dynamic model (5) predicts the response in controlled variables, by considering past and future states (y), inputs (u), measured disturbances (d) and predicted unmeasured disturbances (v). The constraints on the controlled values can be softened (Strand and Sagli, 2004).

Previous work on model-predictive control of drilling includes e.g. Breyholtz et al. (2011) on dual-gradient drilling, Breyholtz et al. (2009) on MPD drilling, and Nygaard and Nævdal (2006) on non-linear MPC for well stabilisation using only a choke. This paper extends the field, with new results on multi-variable control and return flow control in underbalanced drilling operations.

2. DRILLING MODEL AND CONTROL SYSTEM

A four level control structure is used. If we model this in a similar fashion to Maciejowski (2002), we get the structure in Fig. 2. At the bottom level (I) we have the actuators consisting of the control choke and the pump motor. At the next level (II) we have local control loops, with PI controllers stabilizing pump flow and choke pressure. At level three (III) we have the predictive control solution, which controls bottom-hole pressure and return flow; while the top level (IV) will only make some set-point and constraint adjustments when we have a change of operation. Level II runs each second, and level III every 10 seconds. Since the process is quite slow, and the models are quite simple, we do not have any issues with computational time even for large horizons with many evaluation points.

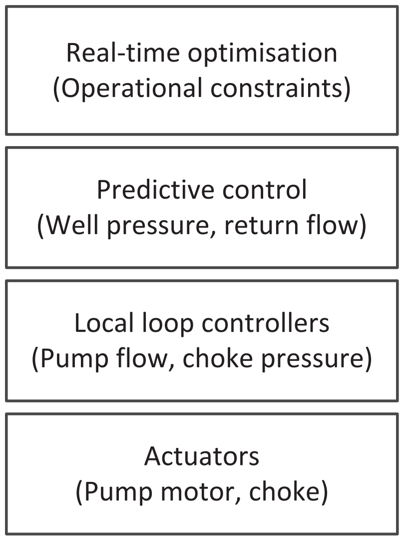

Fig. 2. Illustration of the different control levels.

During a drilling operation, the main consideration is to ensure that we have proper well control. Too low pressure in the well may lead to a kick situation. In underbalanced drilling we have a kick if we have higher flow from the well than the surface systems can handle. Too low pressure may also cause problems with well stability. If the pressure rises above the pore pressure, we will lose some of the main benefits from underbalanced drilling, as even short periods of overbalance may lead to great damage to the reservoir (Salimi et al., 2010). We state the well stability constraints as a maximum and minimum limit on pressure in the open-hole region, including some safety margins. For simplification we assume this region to be one point (i.e. one set-point).

A secondary consideration is to ensure that we do not exceed the operating conditions of the surface equipment. Focusing on flow and pressure control, we pose the constraints given in Table 1. The constraints on the controlled variables can be softened, while the constraints on the manipulated variables are hard. During underbalanced drilling a large underbalance will normally improve penetration rates, but will also give more inflow from the reservoir and thus more return flow at the surface. We will pose an ideal value for the return flow, set at a value which allows us to handle transient increases in flow due to for example slugs.

Table 1. System constraints.

Max and min well pressure	$p_{bh,min} < p_{bh} < p_{bh,max}$
Max and min return flow	$q_{c,min} < q_c < q_{c,max}$
Max and min choke pressure	$p_{c,min} < p_c < p_{c,max}$
Max and min pump flow	$q_{p,min} < q_p < q_{p,max}$
Max and min Δpump flow	$\Delta q_{p,min} < \Delta q_p < \Delta q_{p,max}$
Max and min Δchoke pressure	$\Delta p_{c,min} < \Delta p_c < \Delta p_{c,max}$

To model the process we employ simple first order step response models with delay, given by (6).

$$g(s) = \frac{k}{\tau s + 1} e^{-\theta s}, \tag{6}$$

where k is the process gain, τ is the dominant time lag constant, and θ is the time delay.

We have a [2x2] system where we have two controlled variables (CVs), the down-hole pressure and the return flow (q_c). The CVs can be controlled by adjusting either of two manipulated variables (MVs), the choke pressure (p_c) or the pump flow (q_p). The flow rate will influence the friction in the system, creating increased frictional pressure drop, while the difference between the formation pressure and the down-hole pressure will control the formation inflow. There are large differences in how fast the different inputs will affect the output, and in some cases we may not be allowed to manipulate the pump (for example during a connection). We calculate the ideal value for bottom-hole pressure based on a steady state solution of the relation between bottom-hole differential pressure and the choke flow. We thus have controlled and manipulated variables:

$$y = [p_{bh}, q_c] \tag{7}$$
$$u = [p_c, q_p] \tag{8}$$

Where y_{dev} is calculated based on the deviation from the set-point given by the relation between the ideal flow and the bottom-hole pressure.

To identify the reservoir influx, the well is initialized near balance, i.e. we have little inflow from the reservoir. We perform a series of steps, where we reduce the bottom-hole pressure, to evaluate the size of the inflow, the change in the well friction drop, and the travel time to the surface.

By the use of closed-loop identification, models were identified for the relations between p_{bh}, q_c, p_c and q_p. The relationships are summarised in Table (2).

Table 2. CV-MV relationships

CV/MV	p_c	q_p
p_{bh}	+	+
q_c	−	+

Where (+) indicates a positive relationship, while (−) indicates a negative relationship. It should be noted that the relationship between q_c and p_{bh} is used to identify the parameters for the calculation of the ideal bottom-hole pressure based on the requested return flow, and not directly in the MPC solution.

Some of the major disturbances are changes in fluid density, variations in reservoir influx, changes in reservoir pressures, drill-string motion, gas rising through the system, and changes in flow regime.

Penalty matrices Q_y, Q_u, and P are selected to prioritize 1) well pressure limits, 2) equipment limitations, and 3) bottom-hole pressure set-point; and to ensure few changes in the manipulated variables.

3. SCENARIO

During drilling we need to add more drill pipe at fixed intervals. In most systems, this also means that we must shut down the main pump. In underbalanced drilling we can continue to let the well flow during the connection procedure. The reservoir will then serve as a backpressure pump during the connection. When the system changes between normal drilling and the connection procedure, we get a new set of constraints from the top level control system. We could also get changes in constraints due to e.g. variations in pore or collapse pressure, at increasing depths.

During a connection the drilling stops, the bit is removed from the bottom, and the main pump is ramped down to zero. We still have the same pressure window, but we only require enough return flow from the well to have sufficient control capabilities over the bottom-hole pressure. We thus adjust the choke pressure to obtain the new ideal flow rate and to compensate for the loss of frictional pressure. The operation is illustrated in Fig. 3. After the connection is finished, the pump is ramped back up, the bit is lowered, and the drilling is resumed.

4. SIMULATION RESULTS

A simulation framework was constructed using Matlab, WeMod, an OPC server (required for communication with SEPTIC), 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 with all control levels.

A selection of situations, including a connection scenario and some model identification simulations were tested to evaluate the control system and the simulation framework.

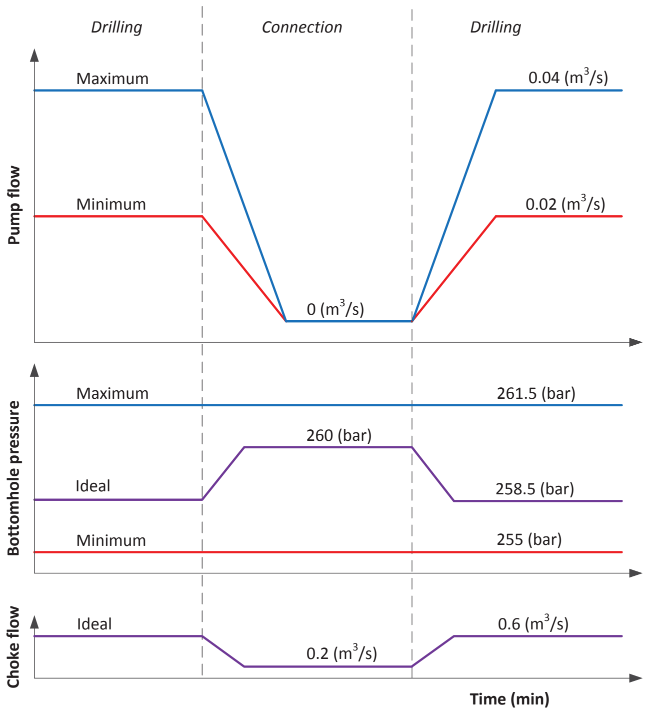

Fig. 3. Connection procedure.

The well simulator is initiated, and after 120 seconds we get influx from the reservoir. A few things should be noted: We see from Fig. 4 that the gas front will use about 1100 seconds (18 minutes) to reach the surface. We will then get a large increase in return flow. We also see that quite small changes in bottom-hole pressure will give large variations in flow (compared to the pump influx), since a pressure differential of 1.5 bars (reservoir at 262 bar) gives an inflow of 0.3 m^3/s. Adjusting pressure to control the return flow will have a very long output delay.

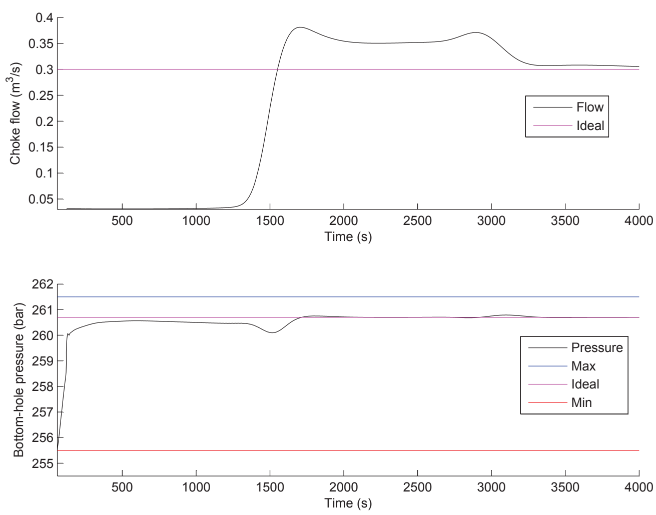

Fig. 4. Gas to surface delay.

Figures 5 and 6 show the control performance during a connection with low return flow (ideal value of 0.3 m^3/s) and a connection with high return flow (ideal value of 1.5 m^3/s). At 2000 seconds we initiate a connection operation, and get a change in constraints and set-points. At 4000 seconds, we change back to drilling.

We note from the figures that there are some differences between the two cases, as is expected based on the selection of models. The low flow case has a set-point very close to the formation pressure (upper limit), and we see that we get problems when the pump stops completely (just before 3000 seconds). At this point, the return flow from the well consists of only small amounts of pure gas. The system starts to oscillate, and we break the upper limit. We believe that only small amounts of fluid influx from the reservoir would limit this behaviour, and if there is no such flow naturally, we could use a backpressure pump. During the high flow case, we have larger margins and the pure gas flow is less problematic. The performance is well within the acceptable limits. Note that the scenario is slightly different, with a lower bottom-hole pressure limit.

From Figures 5 and 6 we can also see a spike in pressure and flow at 6000 seconds for the low flow case, and at 5500 seconds for the high flow case. The difference in travel time is explained by the total fluid velocity in the system, which is higher for the second case.

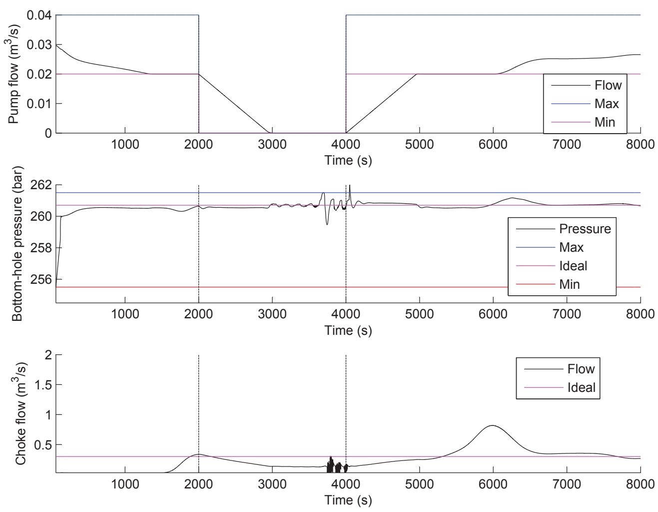

Fig. 5. Connection scenario with low ideal return flow.

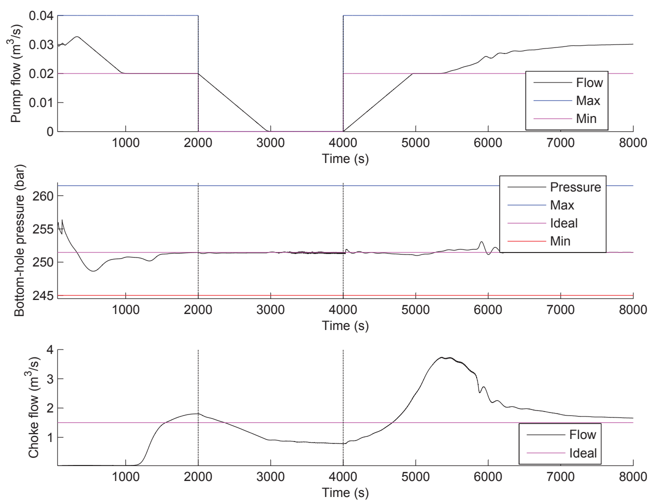

Fig. 6. Connection scenario with high ideal return flow.

Fig. 7 highlights the control behaviour when a large gas bubble reaches the surface. We have a high increase in pressure, as the main bulk of the bubble reaches the surface, followed by a steep decline in pressure, when the gas leaves the well. We see from the use of the manipulated variables that the choke is handling most of the adjustments, but that the pump flow is used when needed. This is how it should be, since using the pump as a control input is both slower and more expensive than adjusting the choke (drilling fluid is expensive). Note that as the gas displaces fluid from the annulus, the density is decreasing, so we do not see the same change in bottom-hole pressure as we see in the choke pressure.

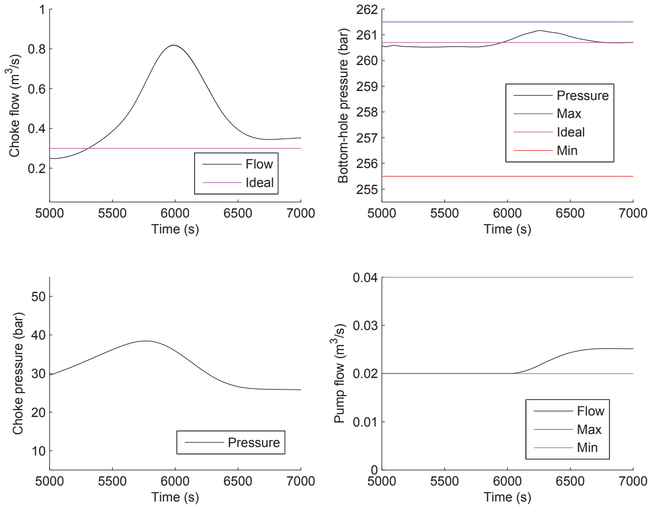

Fig. 7. Disturbance rejection of gas bubble.

5. CONCLUSION

A control problem is formulated for combined pressure and return flow control for underbalanced drilling using constrained model predictive control. The models used are simple step response models, but they still exhibit good control performance in certain limited areas. However, they also come with severe limitations. In addition we need to store a large history of inputs and outputs, and there is some work involved in identifying the models for all relevant operating points.

The MPC solution can easily be extended to control a larger set of variables, or to use a different set of models. The models should include the most important non-linearities of the system. We would like to extend the system to include control of drilling rate (and thus the amount of produced solids) and the surface separation facility. The surface separation facility is strongly linked to the well, as the return flow is directly fed to the separation system, and the pressures in the two systems are linked.

We would also like to compensate directly for measured disturbances, such as drill-string movement, and the inflow and return fluid density.

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Appendix A. NOMENCLATURE

Symbol	Description	Unit
p_{bh}	Bottom-hole pressure	$(Bar/10^5Pa)$
p_{res}	Reservoir pressure	$(Bar/10^5Pa)$
p_c	Choke pressure	$(Bar/10^5Pa)$
q_c	Return (choke) flow	(m^3/s)
q_p	Pump flow	(m^3/s)
z_c	Choke opening	(%)
q_{influx}	Reservoir influx	(m^3/s)
SPM	Pump strokes per minute	(SPM)

Appendix B. MODEL PARAMETERS

Parameter	k	τ	θ
$q_c : p_c$	$-1.3 \cdot 10^{-6}$	230	1100
$q_c : q_p$	1	1	1
$p_{bh} : p_c$	1	2.5	0.5
$p_{bh} : q_p$	$3.3 \cdot 10^7$	14.5	0.5

Appendix C. CONSTRAINTS

Constraints	Drilling	Connection
$p_{bh,min}$	$255.0 \cdot 10^5$	$255.0 \cdot 10^5$
$p_{bh,max}$	$261.5 \cdot 10^5$	$261.5 \cdot 10^5$
$p_{c,max}$	$100.0 \cdot 10^5$	$100.0 \cdot 10^5$
$p_{c,min}$	$1.0 \cdot 10^5$	$1.0 \cdot 10^5$
$q_{p,max}$	0.04	0.0
$q_{p,min}$	0.02	0.0
$\Delta q_{p,max}$	0.00073	0.00073
$\Delta q_{p,min}$	-0.00073	-0.00073
$\Delta p_{c,max}$	$5 \cdot 10^5$	$5 \cdot 10^5$
$\Delta p_{c,min}$	$-5 \cdot 10^5$	$-5 \cdot 10^5$

Appendix D. WELL PARAMETERS

Parameter	Value	Unit
Formation length	2	(m)
Formation permeability	50	(mD)
Formation porosity	0.0018	$(0-1)$
Formation pressure	262	(bar)
Skin factor	1	
Oil ratio	0	(%)
Gas ratio	100	(%)
Bit temperature	316	(K)
Surface temperature	283.15	(K)
True vertical depth (TVD)	1720	(m)
Measured depth (MD)	2300	(m)
Choke diameter	0.15	(m)
Drilling fluid density	1425	(kg/m^3)
Gas density	1	(kg/m^3)
Oil density	872	(kg/m^3)