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Method for Optimal Placement of Sensors in a Wired Pipe Drillstring

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Abstract

This paper introduces a method for selecting the best sensor layout when using wired pipe for drilling operations. The introduction of wired pipe in drilling operations increases the data rate significantly compared to standard telemetry systems.

Various sensors systems are available, measuring parameters such as drillstring vibration, drillstring torque, downhole fluid temperature and downhole annulus pressure. Also available are measurements from various logging tools placed as a part of the bottomhole assembly.

The data from the sensors can contain important information that can be used for preventing various operational problems, such as high vibrations, insufficient hole cleaning, kick incidents, and loss of circulation.

The method described in this paper can be used for designing a sensor layout for a wired pipe drillstring. The method analyzes data available from the sensors to yield the information required to detect operational problems.

The paper presents two different cases where the method is applied, one from a kick incident and the other from a loss of circulation incident. The results show that by optimizing the sensor layout for a wired pipe drillstring, cost efficient performance can be ensured with regards to potential drilling problems.

Introduction

During drilling it is important to avoid non-productive time. To avoid such situations, data can be gathered and used for extracting information about the well and the formation. Various types of sensors are being used during drilling operations, measuring different physical properties of the formation and the well.

One of the challenges during drilling operation has been to transfer data from downhole sensors to surface. The wired pipe drillstring has been used to provide large amounts of drilling data during the operation. In a wired pipe drillstring, a data cable is integrated into each pipe joint and has the possibility of transferring data from the sensors at the drill bit. In addition, data can also be transmitted from sensors mounted along the drillstring. The data cable gives the possibility of sending large amount of data from the sensors along the drillstring while the drilling process is in progress[1,2].

Various methods for automatic analyzing, presenting and evaluating the data has been examined, to be able to transform the data into information[3]. A further evaluation of existing sensors and suggestion of new sensors and their placement should be performed. In production wells, an evaluation method for sensor selection and sensor placement with regards to predicting reservoir production rates has been developed[4,5].

The current paper focus on ranking the usefulness of various sensors when performing a drilling operation. The sensors selected in this paper are sensors that gives information about the fluid flow in the well, and the focus has been on pressure sensors and flow sensors. The temperature gradient between the well and the reservoir fluids are not included in the model, so the importance of temperature sensors should be further examined in a future study.

The paper is divided into five sections. In the next section a description of the theory regarding modelling and ranking methods is presented. Section three briefly presents two cases where the ranking method is applied. In section four the main results using the method are presented and discussed, and conclusions are given in section five.

Theoretical background

The method for evaluation and ranking of sensors is performed based on a detailed dynamic model of both the well properties and the reservoir properties. In addition,

the sensitivity and measurement errors obtained from the sensors in question are evaluated. This section is divided into two subsections, one presenting the dynamic model and the second presenting the method for ranking the sensors.

Dynamic model The model used in the sensor evaluation method is a dynamic, multi-phase fluid flow model[6,7,8,9]. The Navier-Stokes equations are used as a basis for the description, and the well model is discretized into small boxes of about 50 m, both in the drillstring and in the annulus.

In this analysis, only the liquid phase and gas phase are included in the calculations. In the conservation equations for the mass balances for gas and liquid, the mass transfer between the phases are neglected. The mass balances for the gas and liquid phases are,

$$\frac{\partial}{\partial t}\left(\rho_g \alpha_g\right) + \frac{\partial}{\partial z}\left(\rho_g \alpha_g v_g\right) = 0 \quad (1)$$

$$\frac{\partial}{\partial t}\left(\rho_l \alpha_l\right) + \frac{\partial}{\partial z}\left(\rho_l \alpha_l v_l\right) = 0 \quad (2)$$

where $\rho_\star$ is the fluid density, $v_\star$ is the phase velocity and $\alpha_\star$ is the void fraction.

The momentum equations for each phase are added together, which results in the drift-flux formulation. The drift-flux formulation is a simplified momentum balance equation for the mixture, given by

$$\frac{\partial}{\partial t}\left(\rho_l \alpha_l v_l + \rho_g \alpha_g v_g\right) + \frac{\partial}{\partial z}\left(\rho_l \alpha_l v_l^2 + \rho_g \alpha_g v_g^2 + p\right) = -\frac{d}{dz} p_f - \left(\rho_l \alpha_l + \rho_g \alpha_g\right) g \sin\theta \quad (3)$$

where p is the pressure, p_f is the frictional pressure component caused by both the viscous effects of the fluid and the wall shear stress factor and θ is the angle between the horisontal direction and the well trajectory direction. The closure relations are further described in[10].

During drilling, the interaction between the well and the reservoir is transient. The well inflow from the reservoir is defined using the equations from the well pressure test at constant rate[11],

$$q_{res} = \frac{4\pi K h \left(p_{res} - p_{well}\right)}{\mu\left(2S + \ln\left(\frac{4Kt}{e^{\gamma}\phi\mu c r_w^2}\right)\right)}, \quad (4)$$

where K is the permeability of the reservoir, S is the skin factor, h is the height of the well section that has contact with the reservoir, t is the time since the reservoir section were influenced by the well pressure, ϕ is the porosity of the reservoir, μ is the viscosity, c is the compressibility of the reservoir fluid and r_w is the well radius.

The reservoir model and the well model are combined by dividing the reservoir into several small segments, each having contact with the well[12]. When drilling into a reservoir, some of the parameters in the formation are known from geophysical surveys and from the exploration drilling phase. Information such as the layer orientation and porosity of the formation might be known from seismic data.

Sensitivity and measurement errors of model parameters The simulated measurement values of the sensors in our model are a function of the parameters defined in the model. The flow-model parameters in the annulus/drillstring system (pump rates, choke openings, temperature, mud-densities,...) and the reservoir-model parameters (porosity, permeability, pore pressure,....) are known at each given time t. Letting $\boldsymbol{c}_t := (c_{1,t}, ..., c_{k,t})^T$ denote the vector of K model parameters of interest at time t and $\boldsymbol{s}_t := (s_{1,t}, ..., s_{M,t})^T$ denote the set of values of the M available model sensors in the annulus/drillstring system at time t arranged as a vector. We may then define the *sensitivity matrix* J_t of the model sensors at time t by:

$$J_t := \left(\frac{\partial s_{i,t}(\boldsymbol{c}_t)}{\partial c_{j,t}}\right)_{i=1,j=1}^{M,K}. \quad (5)$$

The (i,j)-entry of J may be thought of as a quantitative measure of how sensitive sensor s_i is to perturbations of parameter c_j. Since the sensors are physical devices they have finite precision. We will assume the measurement errors of the sensors s_i are time-independent, uncorrelated and normal distributed with variance σ_i^2. The covariance matrix $\Sigma := E(\boldsymbol{s} - E\boldsymbol{s})(\boldsymbol{s} - E\boldsymbol{s})^T$ of the sensors is then diagonal:

$$\Sigma = \mathrm{diag}(\sigma_i^2). \quad (6)$$

As initial values of the model parameters are fed into the well-flow simulator and time is advanced it computes the simulated (estimated) sensor values $\hat{s}_{i,t}(\boldsymbol{c}_t)$ for each time t as a function of the model parameters $\boldsymbol{c}_t$. Let $s_{i,t}$ denote a set of measurement values provided by a corresponding set of realized (physical) sensors, then we may define a total weighted error measure of the sensors as:

$$Err_t := \sum_{i=1}^{K}\left(\frac{s_{i,t} - \hat{s}_{i,t}(\boldsymbol{c}_t)}{\sigma_i}\right)^2. \quad (7)$$

Let $\hat{c}_t$ define the parameter estimate that results from minimizing expression (7). Under some (reasonable) set of conditions on the vector-valued function $\boldsymbol{s}_t(\boldsymbol{c}_t)$, the $\hat{c}_t$ are approximately normally distributed with covariance matrix P_t where:

$$P_t = J_t^T \Sigma^{-1} J_t. \quad (8)$$

We emphasize that P_t may be estimated through estimating J_t in (5) without any access to real measurements s_i

from the sensors if we have a simulator providing the sensor values, given that we know or provide a guess of the sensor covariance matrix Σ in (6). However, we have found in our simulation experiments that the ranking of sensors is highly sensitive to the choice of Σ.

The sensor ranking criterion We have freedom in choosing the location of the sensors s_i as well as their type and their number M. This gives a lot of different possible instrumentations of the drillstring/annulus system. We will use the error covariance matrix P_t from (8) for the estimated parameters to discriminate quantitatively between different instrumentations[13]. The parameters $\boldsymbol{c}_t$ are located in a K-dimensional space and $\det P_t$ is the volume of the confidence region of the parameter estimate $\hat{\boldsymbol{c}}_t$ in the space. The smaller the volume, the less is the uncertainty in the estimate $\hat{\boldsymbol{c}}_t$. For P_t as in (8) and a given set of M sensors $\boldsymbol{s}_t$ we may rank their relevance according to their dependency on model parameters $\boldsymbol{c}_t$ using the following greedy algorithm [13]: Let $S_t := \{s_{j,t}\}_{j=1}^{M}$ denote the full set of sensors under consideration.

1. For $1 \leq i \leq M$, compute $d_{i,t} := \det P_t$ for the set of sensors $S_t \setminus s_{i,t}$.

2. Set the rank $R_{j,t}$ of the sensor j with the lowest value of $d_{j,t}$ to $R_{j,t} := M$. (This sensor is the least important sensor in the sense that it carries the least information about the parameters $\boldsymbol{c}_t$.) Set $S_t := S_t \setminus s_{j,t}$ and set: $M = M - 1$.

3. Repeat all the steps from the first step above until S_t has only one member, that member will be the top-ranked sensor.

In this way we end up with a ranking of the sensors where the higher ranked sensor provides more reliable information about the model parameters than any lower ranked sensor, that is the higher ranked sensors depend more robustly on the model parameters and their values are therefore more trustworthy than values from lower ranked sensors.

Case descriptions

To evaluate how the described method can be used to select the best sensor layout for the drilling operation, two different drilling cases are described. The first case represents an underbalanced situation where the downhole pressure in the well is lower than the reservoir pressure, causing influx of reservoir fluids.

The second case represents a managed pressure drilling operation, where a loss of circulation situation occur. The loss of circulation is due to a reservoir fracture. Both drilling operations are simulated using the dynamic well-reservoir model.

The model calculates a set of observables: Pressure, temperature, phase velocities, mass fluxes at each discretized time step in a set of dicretized boxes of the well geometry. We define a set of sensors and locate these throughout different zones in the well. The temperature of the reservoir fluid are however not modelled.

Well design The geometry of the well used in the two cases is based on a North Sea well, where the measured depth of the well is 3600 m. The vertical depth is 2000 m and the last part of the well is a horisontal section of 1300 m. The well geometry details are given in Table 1.

The fluid system of the well consists of a main fluid pump, a choke fluid pump and a choke valve. The main fluid pump is connected to the top of drillstring. The choke pump is connected to the top of annulus, providing extra fluid flow through the choke valve. This setup is typically used in a drilling operation with a narrow pressure window. The drilling fluid used in both simulations is water mixed with baryte to obtain a specific gravity of 1.6 sg.

The well model is set up with different types of sensors measuring fluid mass flow rates and pressure. Some of the sensors used are sensors typically used in standard drilling operations today, such as pump rate, pump pressure and choke valve pressure loss. In addition, several sensors are becoming available when using a wired pipe for data transfer such as pressure sensors along the drillstring. Other sensors that currently are available, but seldom used in drilling operations are also included, such as casing shoe pressure sensors. Finally, sensors that are currently not available such as downhole annulus flow sensors are included in the analysis to evaluate the need for additional future sensor development.

A total of nine different sensor locations are basis for the analysis. At each of these sensor locations, a pressure sensor and a flow sensor system measuring total mass flow and fluid component mass flow can be placed. Fig. 1 shows some sensor locations along the drillstring. The sensors are of four basic types:

- Pressure sensors.
- Mass flow meter for total mass flow.
- Mass flow meter for gas mass flow.
- Mass flow meter for drilling fluid mixture flow.

The sensors are placed at the following positions, ordered from the from the pump to the choke:

1. At the pump: Sensors at this location are typically included for a standard drilling operation, measuring pump strokes per minute. Pressure is also typically measured.

2. Inside the drill bit: A pressure sensor could be located at this position. Flow sensors at this position

are typically not included in a standard drilling operation.

3. At the bottomhole assembly measuring annulus properties at a drill bit depth of 3600 m: A pressure sensor are typically located at this position as a part of a standard Measurement-While-Drilling system. Flow sensors at this position are not currently available.

4. Within the drillstring measuring annulus properties at a depth of 3200 m: A pressure sensor could be located at this position using the wired pipe technology. Flow sensors at this position are not currently available.

5. Within the drillstring measuring annulus properties at a depth of 2800 m: A pressure sensor could be located at this position using the wired pipe technology. Flow sensors at this position are not currently available.

6. Within the drillstring measuring annulus properties at a depth of 2400 m: A pressure sensor could be located at this position using the wired pipe technology. Flow sensors at this position are not currently available.

7. At the casing shoe: A pressure sensor could be located at this position, but are mainly used when the well is being set into production. Flow sensors at this position are not currently available during drilling.

8. At the seabed BOP: A pressure sensor could be located at this position. Flow sensors at this position are mainly used when the well is being set into production.

9. At the choke valve: A pressure sensor are typically measured at this position. Flow sensors at this position are typically used as a part of a kick detection system.

For convenience, all the four basic sensor types are used at all the nine locations, giving a total of 36 sensor values.

Case 1: Reservoir influx due to a kick incident Prior to the kick incident the main drilling fluid pump is running at a rate of 1000 liters/min. The choke pump is running at a rate of 225 liters/min. This results in a bottomhole pressure of 342 bar. At $t_0 = 0$ seconds a kick incident occurs, resulting in gas influx from the reservoir into the well, and the influx lasts for 200 seconds.

The pressure values of the drilling fluid main pump, the choke valve pressure loss and the flow mass rates at the choke are all shown in Fig. 2.

During the kick incident, all the sensors are evaluated and ranked according to the sensitivity to the incident. The rankings are shown in Table 2 and Table 3.

Case 2: Loss of circulation due to a reservoir fracturing incident Prior to the fracturing incident the main drilling fluid pump is running at a rate of 1000 liters/min. This results in a bottomhole pressure of 342 bar. At $t_0 = 0$ seconds a fracturing incident occurs, resulting in loss of circulation at a rate of 500.0 liters/min. The annulus is not refilled with mud, and the drilling fluid main pumps continues pumping for 400 seconds.

The pressure values of the drilling fluid main pump, the pressure values of the choke pump and the flow mass rates at the choke are all shown in Fig. 3. During the loss of circulation incident, all the sensor are evaluated and ranked according to the sensitivity to the incident. The ranking is shown in Table 4 and Table 5.

Discussion of results

Case 1: Kick incident. In this model experiment, we consider all model parameters apriori fixed, except one: The reservoir permeablity K which is used to model the influx rate of reservoir gas into the well-system. The parameter K is considered known to within 10% of a prescribed value. When generating the results presented here, two different runs of the model were performed with the difference being the value of the accuracy of the flow sensor as given by σ_F.

- Run 1: $\sigma_P = 0.10$ bar and $\sigma_F = 0.10$ kg/s and model parameter relative uncertainty $\Delta_c = 10\%$. Results presented in Table 2.

- Run 2: $\sigma_P = 0.10$ bar and $\sigma_F = 0.50$ kg/s and model parameter relative uncertainty $\Delta_c = 10\%$. Results presented in Table 3.

The results show that the ranking of instruments is sensitive to the accuracy of measurement values in the sensors: In Run 1 the flow sensors are ranked highest at the beginning of the kick (10 seconds after start of influx of reservoir gas) with the pressure sensors getting higher ranks as model runtime progresses and ominating the best sensors at about 180 seconds after start of influx of reservoir gas. In Run 2, the pressure sensors are the highest ranked sensors throughout the model runtime. These results suggest that a case by case study is necessary in order to assess the best instrumentation of the well in question.

Case 2: Loss of circulation incident. In this model experiment, all model parameters are kept fixed except the rate of loss R of drilling fluid into the reservoir. This parameter is used to model the dependency of sensors to the rate of loss of drilling fluid. The parameter R varies within 10% of a prescribed value. When generating the re-

sults presented here, two different runs of the model were performed with the difference between the two runs being the value of the accuracy of the flow sensor as given by σ_F.

- Run 1: $\sigma_P = 0.10$ bar and $\sigma_F = 0.10$ kg/s and model parameter relative uncertainty $\Delta_c = 10\%$. Results presented in Table 4.

- Run 2: $\sigma_P = 0.10$ bar and $\sigma_F = 0.50$ kg/s and model parameter relative uncertainty $\Delta_c = 10\%$. Results presented in Table 5.

Similar to the Case 1 described above, the results reported here show that the ranking of instruments is sensitive to the accuracy of measurement values in the sensors: In Run 1 the flow sensors are the highest ranked sensors throughout the model runtime while in Run 2 the pressure sensors are the highest ranked sensors throughout the model runtime. As for case 1 above, these results suggest that a detailed case by case study is necessary in order to assess the best instrumentation of the well in question using the method proposed in this paper.

Conclusions

The increase of sensors available for use during drilling operations introduces a challenge for selecting the optimal sensor layout. The sensor data can be transferred into useful information for the driller. The method described in this paper show how the various sensors are sensitive to various scenarios during drilling, such as kicks and circulation losses.

The results show that the various sensor input can be ranked according to their sensitivity to the scenario in question. The results from in the two presented cases, indicate a typical ranking of sensors given either a kick incident or a loss of circulation incident. However, it must be mentioned that the accuracy of the sensors plays a major role when ranking the sensors. It should be noted that a sensor ranking procedure should be performed for a specific set of sensors related to a specific incident, possibly as a part of a risk analysis of the drilling operation.

The temperature gradient between the well and the reservoir are not modelled. Further work should be performed for evaluation of the temperature sensors before further conclusions regarding the temperature sensors can be made.

The result from the paper indicate that flow sensors could be essential in improving an early detection of both kick incidents and incidents resulting in loss of circulation, provided these sensors have sufficient accuracy.

The paper also shows that our proposed method depends on detailed information of the well and the accuracy of sensors to be available in order to make assessments on optimal instrumentation of the well.

Nomenclature

sg	=	specific gravity, relative to water.
t	=	time.
K	=	permeability.
g	=	constant of gravity.
α	=	void fraction.
ρ_{star}	=	density for gas and liquid phase.
$\alpha_\star$	=	void fraction for the gas and liquid phase.
p	=	total pressure.
p_f	=	frictional pressure.
p_{well}	=	well pressure.
p_{res}	=	reservoir pressure.
ϕ	=	reservoir porosity.
S	=	skin factor.
μ	=	viscosity.
c	=	compressibility of reservoir fluid.
r_w	=	well radius.
h	=	height of well section in contact with reservoir.
$v_\star$	=	phase velocity for the gas and liquid phase.
θ	=	angle of inclination with the horizontal.
q_{res}	=	rate of influx of reservoir fluid.
$\boldsymbol{s}_t(\boldsymbol{c}_t)$	=	vector of sensor values at time t.
$\boldsymbol{c}_t$	=	vector of model parameters at time t used to model the sensor values $\boldsymbol{s}_t$.
J_t	=	sensitivity matrix of sensor values at time t.
$\sigma_\star$	=	uncertainty in sensor values for gas mass flow, total mass flow, drilling fluid mass flow and pressure sensors.
Σ	=	covariance matrix of sensor values.
Err_t	=	error measure of sensor values at time t.
$\hat{\boldsymbol{c}}_t$	=	vector of estimated model parameters at time t obtained by minimizing Err_t.
P_t	=	covariance matrix of model parameters $\boldsymbol{c}_t$ at time t.
$R_{j,t}$	=	the rank of sensor j at time t.
Δ_c	=	Relative uncertainty in model parameter c.

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Tables

Table 1: Well Geometry

Well parameter	**Well values**
Measured depth	3600 m
True vertical depth	2000 m
Casing shoe depth	2300 m
Horisontal section	1300 m
Casing diameter	$9\frac{5}{8}$ inch
Open hole diameter	$8\frac{1}{2}$ inch
Drillpipe diameter	$4\frac{1}{2}$ inch

Figures

	The rank of sensors at time t_{10} and t_{175} after kick at time t_0	
Rank	$t_{10} = 10$: Time in seconds passed after t_0	$t_{175} = 175$: Time in seconds passed after t_0
1	Total mass flow: Annulus at 3200 m	Pressure: Inside bit
2	Drilling fluid mass flow: Annulus 3200 m	Pressure: Annulus at bit
3	Total mass flow: Annulus at 2800 m	Pressure: Drilling main pump
4	Drilling fluid mass flow: Annulus at 2800 m	Pressure: Annulus at 3200 m
5	Total mass flow: Annulus at 2400 m	Pressure: Annulus at 2800 m
6	Drilling fluid mass flow: Annulus at 2400 m	Pressure: Annulus at 2400 m
7	Total mass flow: Annulus at casing shoe 2300 m	Pressure: Annulus at casing shoe 2300 m
8	Drilling fluid mass flow: Annulus at casing shoe 2300 m	Total mass flow: Annulus at seabed BOP
9	Pressure: Annulus at bit	Drilling fluid mass flow: Annulus at seabed BOP
10	Pressure: Annulus at 3200 m	Total mass flow: Annulus at casing shoe 2300 m
11	Pressure: Inside bit	Drilling fluid mass flow: Annulus at casing shoe 2300 m
12	Total mass flow: Annulus at seabed BOP	Total mass flow: Annulus at 2400 m
13	Drilling fluid mass flow: Annulus at seabed BOP	Drilling fluid mass flow: Annulus at 2400 m
14	Pressure: Annulus at 2800 m	Total mass flow: Annulus at 2800 m
15	Pressure: Annulus at 2400 m	Drilling fluid mass flow: Annulus at 2800 m
16	Pressure: Annulus at casing shoe 2300 m	Total mass flow: At choke valve
17	Total mass flow: At choke valve	Drilling fluid mass flow: At choke valve
18	Drilling fluid mass flow: At choke valve	Total mass flow: Annulus at 3200 m
19	Pressure: Drilling main pump	Drilling fluid mass flow: Annulus at 3200 m
20	Pressure: Annulus at seabed BOP	Pressure: Annulus at seabed BOP

Table 2: The ranking of the 20 best sensors for Case 1: Reservoir influx, $\sigma_F = 0.10$ kg/s: The model parameter $c = 0.10$ darcy is in this case the reservoir permeability, $\Delta_c = 0.10$ denotes its relative uncertainty, $\Delta_t = 1.0$ s is the temporal resolution of the model, and the deviances of the pressure (P) and flow (F) sensors are: $\sigma_P = 0.10$ bar, and $\sigma_F = 0.10$ kg/s.

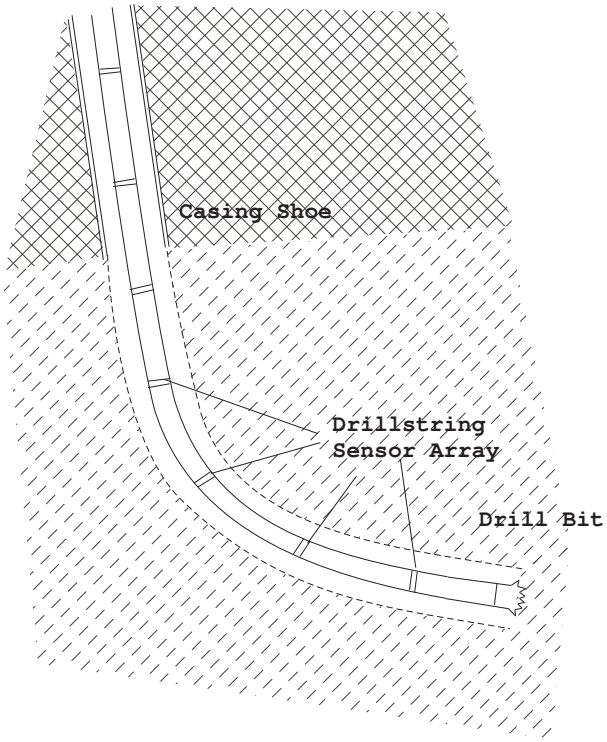


Figure 1: Sensor layout

Rank	The rank of sensors at time t_{10} and t_{175} after kick at time t_0	
	$t_{10} = 10$: Time in seconds passed after t_0	$t_{175} = 175$: Time in seconds passed after t_0
1	Pressure: Annulus at bit	Pressure: Inside bit
2	Pressure: Annulus at 3200 m	Pressure: Annulus at bit
3	Pressure: Inside bit	Pressure: Drilling main pump
4	Pressure: Annulus at 2800 m	Pressure: Annulus at 3200 m
5	Pressure: Annulus at 2400 m	Pressure: Annulus at 2800 m
6	Pressure: Annulus at casing shoe 2300 m	Pressure: Annulus at 2400 m
7	Pressure: Drilling main pump	Pressure: Annulus at casing shoe 2300 m
8	Pressure: Annulus at seabed BOP	Pressure: Annulus at seabed BOP
9	Pressure: At choke valve	Pressure: At choke valve
10	Total mass flow: Annulus at 3200 m	Total mass flow: Annulus at seabed BOP
11	Drilling fluid mass flow: Annulus at 3200 m	Drilling fluid mass flow: Annulus at seabed BOP
12	Total mass flow: Annulus at 2800 m	Total mass flow: Annulus at casing shoe 2300 m
13	Drilling fluid mass flow: Annulus at 2800 m	Drilling fluid mass flow: Annulus at casing shoe 2300 m
14	Total mass flow: Annulus at 2400 m	Total mass flow annulus at 2400 m
15	Drilling fluid mass flow: Annulus at 2400 m	Drilling fluid mass flow: Annulus at 2400 m
16	Total mass flow: Annulus at casing shoe 2300 m	Total mass flow: Annulus at 2800 m
17	Drilling fluid mass flow: Annulus at casing shoe 2300 m	Drilling fluid mass flow: Annulus at 2800 m
18	Total mass flow: Annulus at seabed BOP	Total mass flow: At choke valve
19	Drilling fluid mass flow: Annulus at seabed BOP	Drilling fluid mass flow: At choke valve
20	Total mass flow: At choke valve	Total mass flow: Annulus at 3200 m

Table 3: The ranking of the 20 best sensors for Case 1: Reservoir influx, $\sigma_F = 0.50$ kg/s: The model parameter $c = 0.10$ darcy is in this case the reservoir permeability, $\Delta_c = 0.10$ denotes its relative uncertainty, $\Delta_t = 1.0$ s is the temporal resolution of the model, and the deviances of the pressure (P) and flow (F) sensors are: $\sigma_P = 0.10$ bar and $\sigma_F = 0.50$ kg/s.

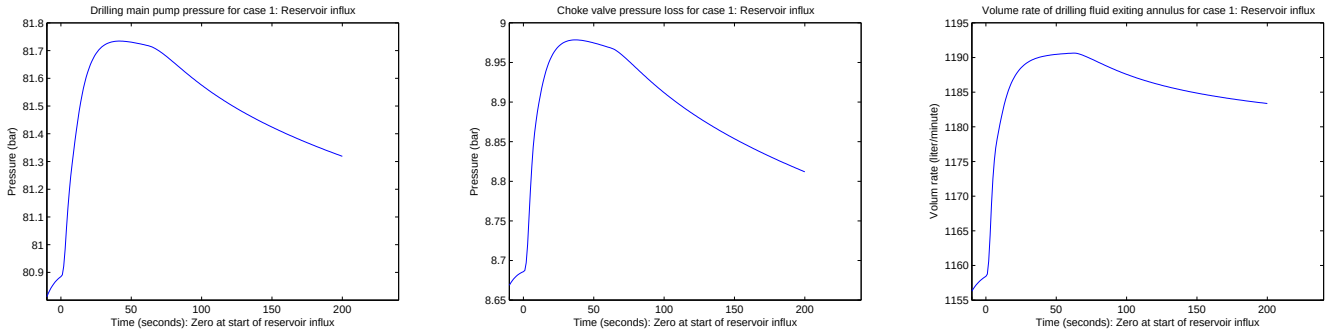


Figure 2: Drilling main pump pressure, choke valve pressure loss and volume rate at choke for case 1: Influx of reservoir fluids due to gas kick

	The rank of sensors at time t_{10} and t_{180} after fracturing at time t_0	
Rank	$t_{10} = 10$: Time in seconds passed after t_0	$t_{180} = 180$: Time in seconds passed after t_0
1	Drilling fluid mass flow: Annulus at 3200 m	Total mass flow: Annulus at seabed BOP
2	Total mass flow: Annulus at 3200 m	Drilling fluid mass flow: Annulus at seabed BOP
3	Total mass flow: Annulus at 2800 m	Total mass flow: Annulus at casing shoe 2300 m
4	Drilling fluid mass flow: Annulus at 2800 m	Drilling fluid mass flow: Annulus at casing shoe 2300 m
5	Total mass flow: Annulus at 2400 m	Total mass flow: Annulus at 2800 m
6	Drilling fluid mass flow: Annulus at 2400 m	Drilling fluid mass flow: Annulus at 2800 m
7	Total mass flow: Annulus at casing shoe 2300 m	Total mass flow: Annulus at 2400 m
8	Drilling fluid mass flow: Annulus at casing shoe 2300 m	Drilling fluid mass flow: Annulus at 2400 m
9	Total mass flow: Annulus at seabed BOP	Drilling fluid mass flow: Annulus at 3200 m
10	Drilling fluid mass flow: Annulus at seabed BOP	Total mass flow: Annulus at 3200 m
11	Total mass flow: At choke valve	Total mass flow: At choke valve
12	Drilling fluid mass flow: At choke valve	Drilling fluid mass flow: At choke valve
13	Pressure: Annulus at bit	Pressure: Annulus at bit
14	Pressure: Inside bit	Pressure: Inside bit
15	Pressure: Annulus at 3200 m	Pressure: Drilling main pump
16	Pressure: Annulus at 2800 m	Pressure: Annulus at 3200 m
17	Pressure: Annulus at 2400 m	Pressure: Annulus at 2800 m
18	Pressure: Annulus at casing shoe 2300 m	Pressure: Annulus at 2400 m
19	Pressure: Drilling main pump	Pressure: Annulus at casing shoe 2300 m
20	Pressure: Annulus at seabed BOP	Pressure: Annulus at seabed BOP

Table 4: The ranking of the 20 best sensors for Case 2: Loss of circulation, $\sigma_F = 0.10$ kg/s: The model parameter $c = 0.00833$ m^3/s is in this case the volume rate of loss of drilling fluid, $\Delta_c = 0.10$ denotes its relative uncertainty, $\Delta_t = 1.0$ s is the temporal resolution of the model, and the deviances of the pressure (P) and flow (F) sensors are: are defined to be: $\sigma_P = 0.10$ bar and $\sigma_F = 0.10$ kg/s.

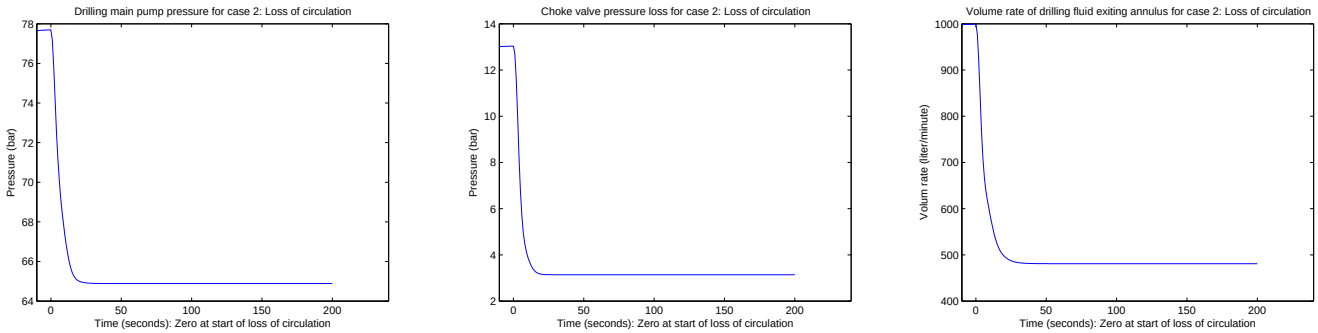


Figure 3: Drilling main pump pressure, choke valve pressure loss and volume rate at choke for case 2: Loss of circulation due to reservoir fracturing

	The rank of sensors at time t_{10} and t_{180} after fracturing at time t_0	
Rank	$t_{10} = 10$: Time in seconds passed after t_0	$t_{180} = 180$: Time in seconds passed after t_0
1	Pressure: Annulus at bit	Pressure: Annulus at bit
2	Pressure: Annulus at 3200 m	Pressure: Inside bit
3	Pressure: Inside bit	Pressure: Drilling main pump
4	Pressure: Annulus at 2800 m	Pressure: Annulus at 3200 m
5	Pressure: Annulus at 2400 m	Pressure: Annulus at 2800 m
6	Pressure: Annulus at casing shoe 2300 m	Pressure: Annulus at 2400 m
7	Pressure: Drilling main pump	Pressure: Annulus at casing shoe 2300 m
8	Pressure: Annulus at seabed BOP	Pressure: Annulus at seabed BOP
9	Pressure: At choke valve	Pressure: At choke valve
10	Total mass flow: Annulus at 3200 m	Total mass flow: Annulus at seabed BOP
11	Drilling fluid mass flow: Annulus at 3200 m	Drilling fluid mass flow: Annulus at seabed BOP
12	Drilling fluid mass flow: Annulus at 2800 m	Total mass flow: Annulus at casing shoe 2300 m
13	Total mass flow: Annulus at 2800 m	Drilling fluid mass flow: Annulus at casing shoe 2300 m
14	Total mass flow: Annulus at 2400 m	Total mass flow: Annulus at 2800 m
15	Drilling fluid mass flow: Annulus at 2400 m	Drilling fluid mass flow: Annulus at 2800 m
16	Total mass flow: Annulus at casing shoe 2300 m	Total mass flow: Annulus at 2400 m
17	Drilling fluid mass flow: Annulus at casing shoe 2300 m	Drilling fluid mass flow: Annulus at 2400 m
18	Total mass flow: Annulus at seabed BOP	Drilling fluid mass flow: Annulus at 3200 m
19	Drilling fluid mass flow: Annulus at seabed BOP	Total mass flow: Annulus at 3200 m
20	Total mass flow: At choke valve	Total mass flow: At choke valve

Table 5: The ranking of the 20 best sensors for Case 2: Loss of circulation, $\sigma_F = 0.50$ kg/s: The model parameter $c = 0.00833$ m^3/s is in this case the volume rate of loss of drilling fluid, $\Delta_c = 0.10$ denotes its relative uncertainty, $\Delta_t = 1.0$ s is the temporal resolution of the model, and the deviances of the pressure (P) and flow (F) sensors are: are defined to be: $\sigma_P = 0.10$ bar and $\sigma_F = 0.50$ kg/s.