Drilling Hydraulics Monitoring and Problem Detection

Master Thesis

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This work is dedicated to Ingrid and Rainer Lüftenegger.

ACKNOWLEDGMENT

The author would like to thank the following:

Univ.-Prof. Dipl.-Ing. Dr.mont. Gerhard Thonhauser for advising and supporting this thesis

OMV for the support and the provided sensor data

Dipl. -Ing. Philipp Zöllner for his help, ideas and technical assistance during the whole project

EIDESSTATTLICHE ERKLÄRUNG

Ich erkläre an Eides statt, dass ich die vorliegende Arbeit selbständig und ohne fremde Hilfe verfasst, andere als die angegebenen Quellen und Hilfsmittel nicht benutzt und mich auch sonst keiner unerlaubten Hilfsmittel bedient habe.

AFFIDAVIT

I declare in lieu of oath, that I wrote this thesis and performed the associated research myself, using only literature citied in this volume.

(Date) (Markus Rainer Lüftenegger)

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Abstract

One essential element of real-time drilling monitoring is wellbore hydraulics reflected by fluid flow and pressure response. Issues such as equipment failures, kicks and wellbore instability create a significant source of drilling related problems and consequentially increase lost time and associated “red money”. In addition to lost time incidents, the optimum processes to clean and condition the hole in relation to hydraulics have a significant potential in avoiding hidden lost time.

The first part of this work focuses on the analysis of prevalent problems impacting drilling hydraulics. Causes and implications, as well as the distinct patterns of real-time measurements during and prior to a particular problem are discussed. Several months of operational data and related morning reports have been studied to support the analysis and to provide example cases. A detection and verification tree (DVT) at the end of each section summarizes the main monitoring observations and suggested verification steps to diagnose selected hydraulics related drilling problems. Further, recently developed problem detection systems are reviewed. Generally these systems can be divided into three generations. They mainly dealt with the automatic detection of drillstring washouts, kicks and losses.

The second part of this work outlines a concept to monitor the response of the standpipe pressure during pump start-up operations. Main objective of the concept is to avoid operational problems caused by pressure surges resulting from gelation effects and cuttings settling. Analysis of data at a high degree of operational detail generated using automated operations recognition showed that pressure surges can be minimized if the pump is started in an optimal fashion. The concept is implemented by a monitoring screen depicting the magnitude of the pressure surge in relation to the pump start-up procedure and other important parameters thus enabling the drilling personnel to act on the information generated. In this way, hidden lost time resulting from overcautious pump start up can be avoided.

The third part of this work describes the conceptual development of a kick detection system based on real-time flowrate and return flowrate measurements. Main objective of the system is to provide automatic detection and verification of an imminent kick situation during drilling. The number of false alarms could be reduced by implementing flow transients encountered during pump start-up and axial pipe movement in the detection routine. Initial tests carried out on historical real-time data showed that the system is capable to detect kicks with the required sensitivity whereas the false alarm rate was in the range of 2 to 10 false alarms per day.

Kurzfassung

Die Überwachung von hydraulischen Parametern reflektiert durch Druck und Durchfluss ist ein essentieller Bestandteil der Echt-Zeit Überwachung des Bohrprozesses. Gestängeleckagen, unkontrollierte Zuflüsse von Formationsflüssigkeiten und Bohrlochinstabilität repräsentieren einen Großteil der Probleme die während des Bohrprozesses auftreten und folglich zu einer Steigerung der unproduktiven Zeit und damit verbundenen Kosten führen. Weiters entsteht ein gewisser Anteil an unproduktiver Zeit durch schlechte Bohrlochreinigung. Daraus resultiert ein mögliches Einsparungspotential durch die Echt-Zeit Überwachung der Bohrlochhydraulik.

Der erste Teil dieser Arbeit beschäftigt sich mit der Analyse von Problemen die das hydraulische System bzw. Druck und Durchfluss beeinflussen. Gründe und Konsequenzen sowie die speziellen Muster von Echt-Zeit Sensormessungen der einzelnen Probleme werden diskutiert. Ein sogenannter „Detection and Verfication Tree“ am Ende jedes Kapitels fasst signifikante Erkenntnisse zusammen und liefert eine Möglichkeit einzelne Problem zu diagnostizieren. Weiters werden aktuelle hydraulische Überwachungs- und Frühwarnsysteme besprochen. Generell lassen sich diese Systeme in drei Generation unterteilen, sie beschäftigen sich hauptsächlich mit der automatischen Erkennung von Leckagen, Zuflüssen und Spülungsverlusten.

Der zweite Teil dieser Arbeit beschreibt ein Konzept zur Überwachung des Drucks während des Hochfahrens der Spülungspumpen. Ziel ist es, operative Probleme die durch Druckstöße während des Hochfahrens hervorgerufen werden, zu vermeiden. Drückstöße resultieren hauptsächlich durch Gelbildung und Ansammlungen von Cuttings. Die Analyse von Daten unter Verwendung von „Automated Operations Recogniton“ zeigte das Druckstöße zu Begin des Hochfahrens minimiert werden können wenn die Pumpe entsprechend hochgefahren wird. Das Konzept wird durch die Darstellung der Magnitude der Druckstöße in Bezug auf weitere wichtige Parameter grafisch implementiert. Der Bohrmannschaft wird damit ermöglich auf die gezeigten Daten zu reagieren und dadurch unproduktive Zeit durch übervorsichtiges Pumpen Hochfahren zu vermeiden.

Der dritte Teil dieser Arbeit beschreibt die konzeptionelle Entwicklung eines Zufluss Früh-Warn Systems basierend auf Echtzeitdurchfluss und -rückfluss Messungen. Das vorgestellte System ermöglicht eine automatische Erkennung und Verifikation eines vorherrschenden Kicks während des Bohrens. Durch die Berücksichtigung von Routineoperationen wie axiales Bewegen des Bohrstranges und Pumpen Hochfahren konnte die Anzahl der Falsch Alarme reduziert werden. Tests mit historischen Echt-Zeit Daten zeigten das das System im Stande ist Kicks frühzeitig zu erkennen wobei die Rate der Fehlalarme im Bereich von 2 bis 10 Fehlalarme per Tag lag.

1 Introduction

1.1 Components of the Circulation System

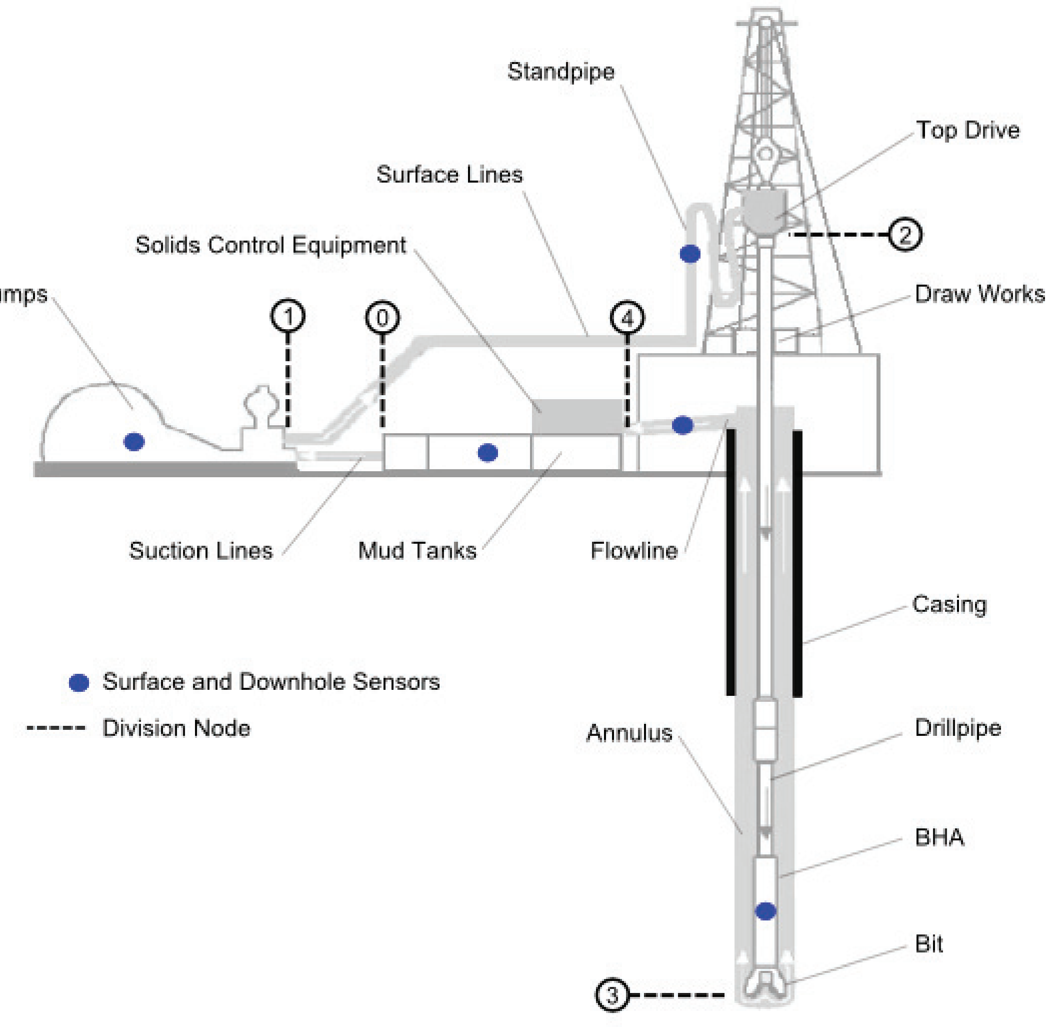

Figure 1: Schematic circulation system of a drilling rig

With reference to Figure 1, the general flowpath of drilling fluid through the circulation system of a drilling rig can be described by the following main components:

- **Division Node 0 to 1 – Pumping Equipment**

Large high pressure reciprocating pumps are utilized to circulate drilling fluid through the circulation system. Typically two to three pumps are necessary to produce the required hydraulic horsepower. The mud pumps are fed by centrifugal pre-charge pumps. The pre-charge pump is connected to the mud tanks via a suction line.

- **Division Node 1 to 2 – Surface Lines**

A surface piping system connects the high pressure discharge lines of the mud pumps with the standpipe. The standpipe extends approximately one third into the derrick, where it connects to the flexible high pressure hose of the top drive.

- **Division Node 2 to 3 – Drillstring**

Drilling fluid is being circulated through a drillstring which extends from the surface to the bottom of the hole. The drillstring typically consists of several different types of tubular goods. The very last part of the drillstring is called bottom hole assembly (BHA). A bit is mounted onto the BHA. To replace worn out bits it is necessary to pull the string out of the hole. This and the consecutive reinsertion is called tripping.

- **Division Node 3 to 4 – Annulus**

At the bottom of the hole, drilling fluid leaves the bit to the annulus, there it (a) assists in generating new hole by the jetting action of the bit nozzles, (b) exerts a certain pressure on to the formation, (c) cools and lubricates the bit and drillsting and (d) lifts the cuttings up the annulus. Protective casing strings are run at particular depths to support the wall of the wellbore resulting in various annular geometries of the open-hole and casings strings.

- **Division Node 4 to 0 – Solids Control System**

At the surface, the cuttings laden drilling fluid leaves the annulus via the flowline which leads to the solids control equipment. There the cuttings will be removed through several cleaning steps. Conditioned mud is stored in several mud tanks and re-enters the circulation cycle via the suction line of the mud pumps.

1.2 Drilling Hydraulics Monitoring Parameters

1.2.1 Standpipe Pressure

The standpipe pressure can be described as the sum of all pressure losses of the circulation system. Generally, the system pressure is dependent upon:

- Flowrate
- Hole depth
- String and wellbore geometry
- Individual components of the drillstring e.g. DHM, bit nozzles etc.
- Density and rheology of the drilling fluid
- Drilling problems

The standpipe pressure is measured via an analogue pressure sensor located at the standpipe manifold (refer to Figure 1). Older sensors consist of a diaphragm, hydraulic line and a pressure transducer. The mud in the standpipe is separated from the hydraulic fluid by the diaphragm which acts as force-summing element. Increased pressure on the diaphragm increases the pressure of the hydraulic fluid. The transducer detects the hydraulic fluid pressure and produces a continuous current or continuous voltage signal (typically 4 to 20 mA) which varies in direct proportion to the stand pipe pressure. Measurement uncertainties result from mud cake building up at the diaphragm and the manually adjusted pre-charge pressure of the hydraulic fluid.

State of the art pressure sensors utilize a strain gauge attached to the force summing element (typically a steel plate) in order to measure the pressure at the standpipe. A hydraulic fluid is no longer necessary. Once calibrated, the measured pressure is proportional to a certain strain. The analogue signal can be converted by To convert the analogue signal into digital bits an analogue-to-digital (A/D) converter is typically utilized. The typical accuracy is in the range of 0.25 % of full scale.

1.2.2 Flowrate

On almost every rig the nominal pump output is not measured directly. As stated in equation 1 nominal pump output (Q_{Pump}) is calculated based on the number of pump strokes per minute (SPM) and the pump output per stroke. Pump output per stroke is calculated based on the size (A) and the number of pistons (n), the stroke length (l) and an assumed pump efficiency (ξ).

$$Q_{Pump} = SPM * n * A * l * \xi \quad \text{Eq. 1}$$

To count the number of strokes per minute, a proximity switch sensor is installed near the piston of each pump. The sensor applies a logical signal (+0 or +12 VDC/A) on two wires with a series of switch closings every time the piston rod travels past the sensor.

Short comings of this type of flow meter are (1) the relatively slow response due to the relatively long time period (typical 1 to 2 seconds) between strokes and (2) inaccuracies resulting from the uncertain pump efficiency, which changes with pump pressure and wear of internal parts (D.M Schafer et al, 1992). The accuracy of the sensor highly depends on how good the efficiency of the pump can be estimated..

1.2.3 Return Flowrate

1.2.3.1 Paddle Meter

The most common means of measuring outflow is the paddle meter or flow show located at the flow line (refer to Figure 1). A spring mounted paddle extends into the flow and is deflected by the fluid impinging on it. The deflection angle is proportional to the fluid height and velocity of the drilling mud and thus the return flow rate. Calibration of the paddle deflection provides a means of measuring the flow rate.

Short comings of this type of flow meter are (1) the high inaccuracy (can be up to 30% of full scale), and (2) repeatability (D.M Schafer et al, 1992). Because of the high inaccuracy this type of sensor is typically used only as a qualitative measure of return flow rate (e.g. high/low flow) with the return flow represented by a fraction of maximum paddle deflection specified in percent rather than lpm.

1.2.3.2 Sophisticated Measurements

Magnetic, sonic or coriolis flow meters provide a much better accuracy and are typically deployed in high pressure and high temperature (HPHT) or managed pressure drilling (MPD) applications. For an introduction to the working principle of magnetic and sonic flow meters we refer to (D.M Schafer et al, 1992).

A coriolis flow meter as depicted in figure 2, utilizes the Coriolis Effect to measure the amount of mass moving through a u-shaped tube that is caused to vibrate at a certain frequency in a perpendicular direction to the flow. Coriolis forces created by the fluid running through the tube interact with the vibration frequency and causing the tube to twist. Generally, the larger the angle of the twist the larger the flow through the sensor will be.

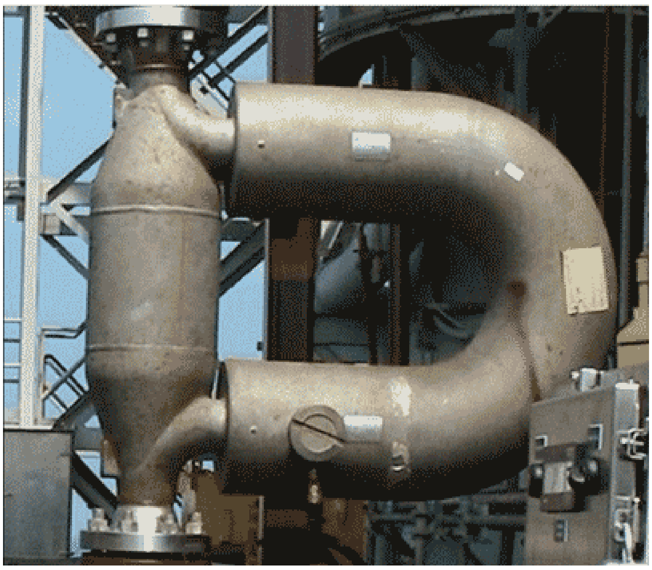

Figure 2: Coriolis flow meter (www.atbalance.com)

Short comings of magnetic flow meters are the restriction to water based drilling fluids. The typical accuracy is in the range of 0.5 % of full scale. Acoustic level meters typically require certain computational corrections to maintain a high accuracy as the acoustic velocity utilized by acoustic level meters is significantly affected by the temperature and composition of the air in the return flow line and must be corrected accordingly. In addition, they require a rather long straight section (min. 1 meter) of the flow line in order to achieve laminar flow which might be a problem on smaller rigs.

Coriolis flow meters require a rather large flow line (12in) which takes more space and thus might be a problem for smaller rigs. In addition, they are quite expensive compared to other sensors. The accuracy is in the range of 0.1 % of full scale.

1.2.4 Active Mud Pit Volume

The active volume of the surface tank system is typically measured by ultrasonic level meters located at the tank system (refer to Figure 1). Changes in the height of the liquid level can be converted to volume changes via the geometry of the tanks.

The accuracy of commercial available sensor is in the range of 0.25 % of full scale and it can resolve changes in liquid level up to 3 mm. However this has to be seen in context of liquid motion and might be significantly higher for drilling applications where agitation will induce a random motion of the liquid. The motion of the drilling mud due to agitation or swell on offshore rigs can be compensated by installing two sensors. The pit volume totalizer averages the measured liquid levels and provides the total volume of the active tank systems which in turn leads to a certain inaccuracy.

1.2.5 Annular Pressure while Drilling

Measurement of the annular pressure can be included in the real-time transmission sequence of some MWD/LWD tools provided by different service companies. Drilling fluid enters a conduit of the pressure sensor attached to the tool and its pressure acts on the conduits walls elastically deforming them. A strain gauge pressure transducer picks up the deformation and gives the sensors readings. Calibration is performed at different pressures and temperatures to determine certain pressure and temperature coefficients.

2 Problems impacting Drilling Hydraulics

The main objective of this chapter is to analyse drilling problems impacting the pressure and fluid flow of the circulation system, two parameters essentially linked to hydraulics monitoring. Causes and implications of common hydraulics related drilling problems, as well as the distinct patterns of real-time measurements during and prior to a particular drilling problem, are discussed within this chapter. Generally, all available measurements need to be considered to allow an effective diagnosis. Several months of operational data and related morning reports have been studied, to support the analysis with real-time examples. At the end of each section a detection and verification tree (DVT) summarizes the monitoring observations and suggested verification steps to detect selected hydraulics related drilling problems.

Four problem groups have been introduced to classify problems impacting drilling hydraulics. According to figure 1, the different problem groups can be related to particular components of the circulation system with the intention to create a common basis of discussion:

- **Change of Pumping Equipment Efficiency (Division Node 0 to 1)**

The mud pumps represent the main component of the circulation system and directly impact drilling hydraulics. Problems related to this piece of equipment are generally caused by changes in the volumetric efficiency of the pump due to wear of internal parts. Wear can be largely attributed to the abrasive nature of the drilling fluid and the high operating pressures.

- **Change of the Tubular Flowpath (Division Node 2 to 3)**

Drilling tubulars are especially prone to leaks. Enlargement due to erosion of existing leaks preferably located at tool joints or mechanical fatigue cracks within the pipe body are generally described as drillstring washouts. As a consequence the flowpath of the drilling fluid is changed as a certain portion of flow will enter the annulus through the leak i.e. the flow is diverted. In addition to flowpath changes resulting from flow diversion, drilling fluid can also become blocked or restricted in case the nozzles of the bit or BHA components are plugged.

- **Change of the Annular Flowpath (Division Node 3 to 4)**

Similar to a change of the tubular flowpath, also the annular flowpath might undergo modifications during the drilling process. Here, restrictions created by cuttings bed build up and excess caving production resulting from inappropriate drilling practices are the main reasons for trouble. In addition, inclinations above 30° can lead to cuttings slumping down towards the BHA and causing it to become stuck.

- **Change of the Material Balance (Division Node 3 to 4)**

Changes of the material balance i.e. changes in volume and mass of the drilling fluid can result from an influx of formation fluid into the annulus, a loss of drilling fluid to the formation and contaminants continuously added to the drilling fluid during the drilling process. Contaminants are generally any material e.g. solids, salt water etc. causing an undesired change of drilling fluid properties i.e. rheology and density.

2.1 Change of Pumping Equipment Efficiency

According to Figure 3, a change in the efficiency of the pumping equipment can be encountered within division nodes 0 and 1.

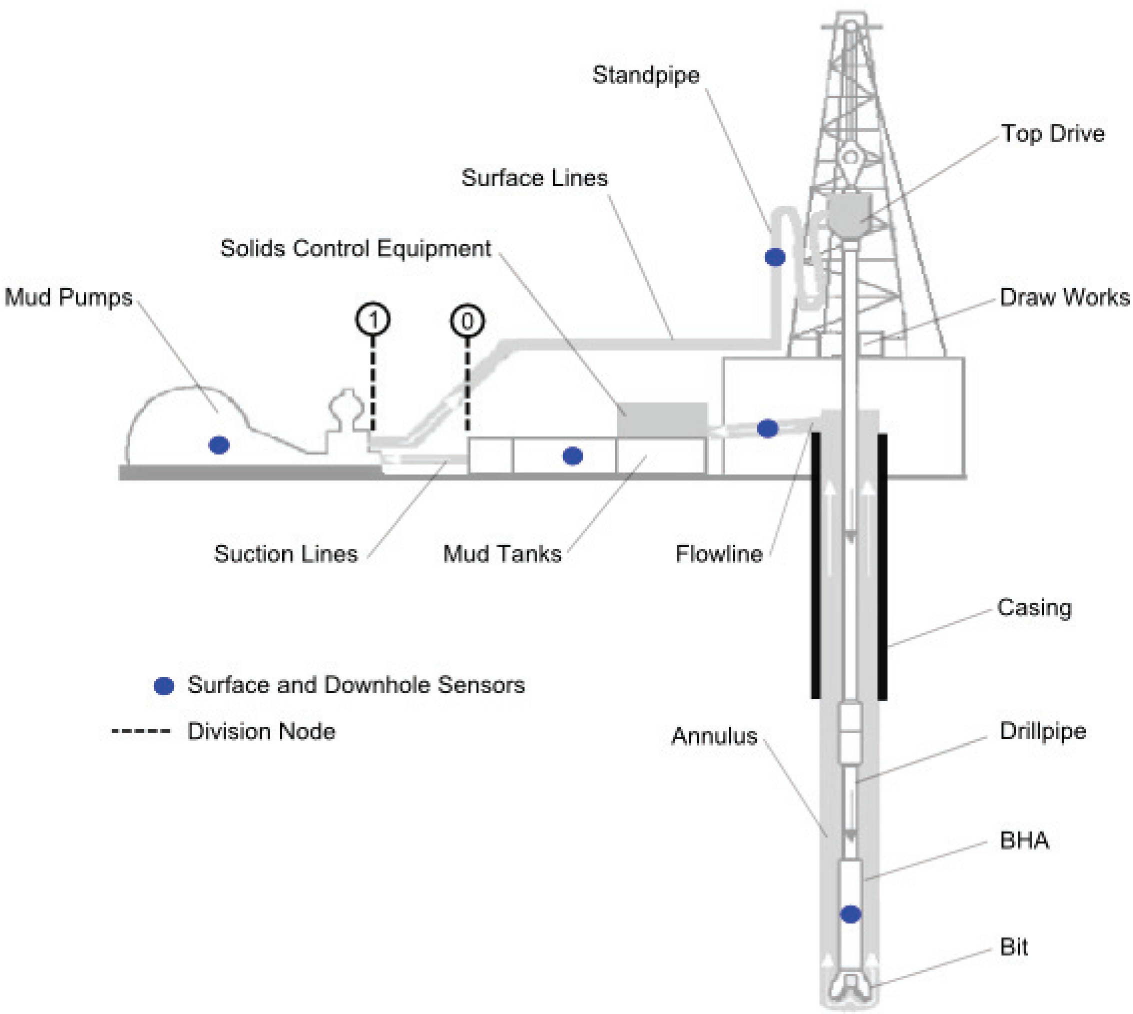

Figure 3: Pumping equipment efficiency change

2.1.1 Loss of Mud Pump Efficiency

A properly designed, pressure-fed piston or plunger pump generally has a 96 to 97 percent volumetric efficiency. During an ongoing drilling operation the mud pumps generally lose operating efficiency. This loss is however not quantified nor checked by the drilling crew.

The loss in volumetric efficiency can result from the following conditions:

- Wear of internal parts

The harsh operating conditions resulting from high pump pressures and the abrasive nature of the drilling fluid being pumped accelerate the wear of moving parts inside the pump. Wear generally decreases the piston and valve seal leading to incomplete filling and discharge of the cylinder.

- Chocked Suction Filter Screen

Solids, debris, chunks of mud etc. can cause the filter screen on the suction side of the pump to become choked or blocked leading to a reduced pump feed and incomplete filling of the cylinders.

- Insufficient pre-charge

Similar to a chocked suction filter screen, an insufficiently working centrifugal pre-charge pump also reduces the feed to the mud pump leading to incomplete filling of the cylinders.

- Entrapped Air in the Mud

Entrapped air may decrease the volumetric efficiency to 50 percent or less. Air can become entrained in the mud by the very nature of cleaning mud i.e. agitation occurs which mixes air into the mud. Higher viscosity mud makes air entrapment worse.

In any case, the nominal output of the mud pump is reduced thus leading to a reduction in standpipe pressure at a constant flowrate. The flowrate measurement remains constant because the assumed pump efficiency is not changed in the actual calculation of flowrate (refer to chapter 1).

2.1.1.1 Detecting and Verifying a Mud Pump Efficiency Change

The condition and efficiency of the pumping equipment is usually identified by visual and vibration checks. Distinct sensors e.g. accelerometers, high frequency pressure transducers etc. to monitor the equipment are not part of any standard rig instrumentation system.

An attempt to perform predictive pump maintenance in real-time has been made by Litzlbauer et. al. (C.H. Litzlbauer et. al, 2002). By sampling the pump pressure at a high frequency and analysing related patterns, it was possible to identify emerging pump failures, thus timely maintenance work could be planed and performed, avoiding pump break downs in critical situations. However this approach required the installation of high frequency pressure transducers.

2.2 Change of the Tubular Flowpath

According to Figure 4, a change of the tubular flowpath can be encountered within division nodes 2 and 3.

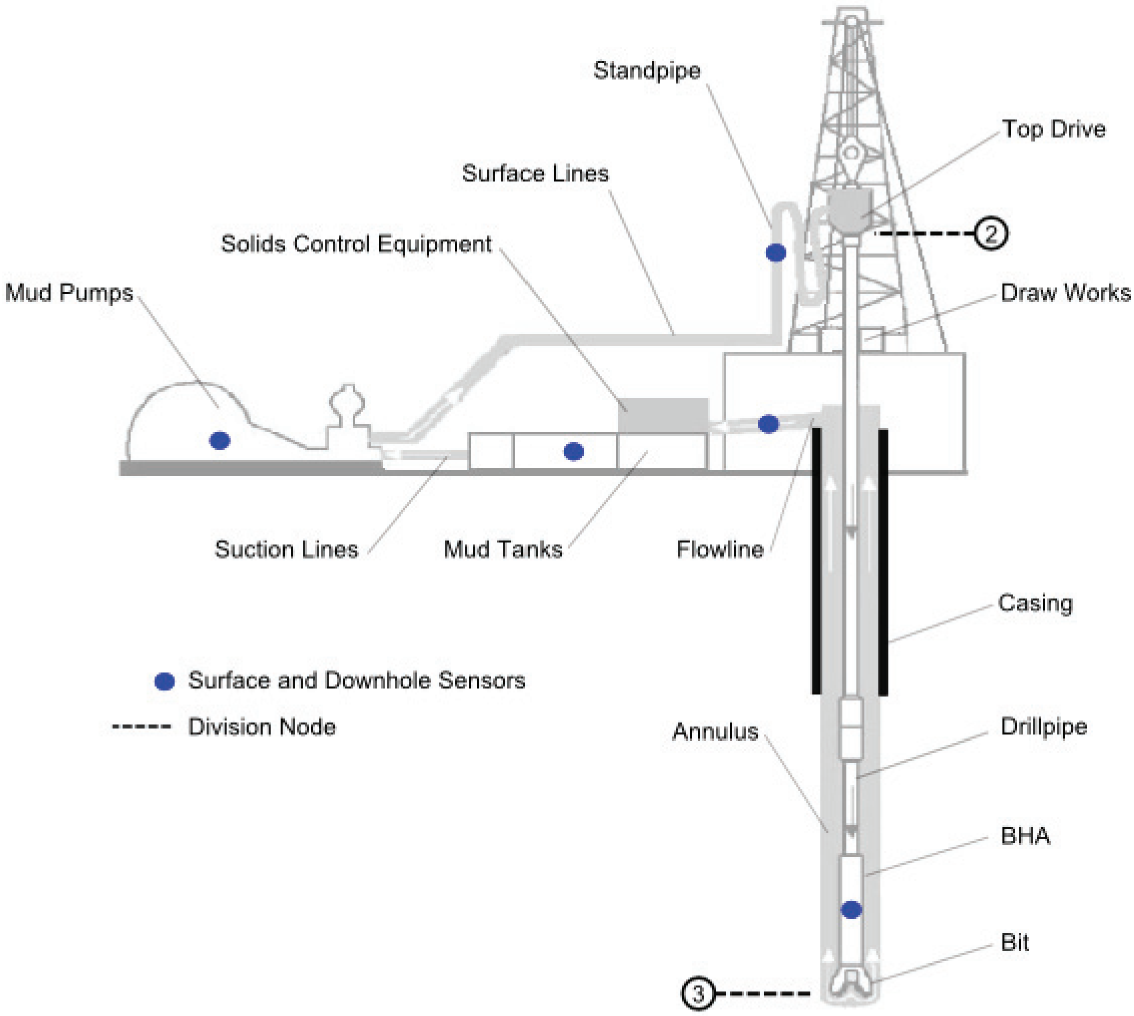

Figure 4: Change of the tubular flowpath

2.2.1 Washouts and Equipment Failure

Today's extended reach and highly deviated wells create a very harsh environment for the drillstring. High torque and drag situations, corrosive formation fluids, high temperatures and high pressures represent an additional challenge. On the economic side, limited supply capacities and high steel prices also worsen the situation by forcing the operator to rely on older drillpipes for critical applications (P. A. Daison, 2008). Cracks, leaks and consecutive washouts are the consequence often leading to complete failure of the drillstring and significant lost time for fishing operations or in worst case loss of an entire well section are encountered.

Washout i.e. enlargement of the leak or crack can be mainly related to the highly abrasive drilling fluid and the high flow velocity through the leak. As washout progresses the mechanical integrity of the affected region is further decreased. At some point in time and under certain downhole load conditions such as excessive torque or overpull the string will most likely rupture.

Figure 5 shows a picture of washouts detected at an earlier and later stage (P. A. Daison, 2008). On the right picture the conical shape of the hole indicates the later detection whereas the crack shown on the left picture remained longish indicating little wash out.

Figure 5: Washouts detected at an earlier and later stage (P. A. Daison, 2008)

Drillstring washouts typically originate at cracks created by mechanical fatigue (J. Abdollahi et al., 2003). Mechanical fatigue is originated at highly stressed locations for instance internal upsets, slips cuts or thread roots etc. when subjected to cyclic stress reversal. The high forces acting on the slip area of the drillpipe during a connection and the consecutive slip cuts might be identified as the main reasons for cracks in that area (J. Abdollahi et al., 2003).

Other reasons for leaks include improper make-up, damaged threads and shoulders or defective materials.

2.2.1.1 Detecting and Verifying Equipment Failure and Drillstring Washouts

Continuous monitoring of the standpipe pressure at a know flowrate has proofed to be the most successful way to identify a possible washout (P. A. Daison, 2008).

Generally, a decrease in standpipe pressure at a constant flowrate may indicate the presence of a possible drillstring washout. The decrease in standpipe pressure can be related to the changed flowpath of the drilling fluid i.e. depending on the size of the leak a certain volume rate will bypass parts of the drillstring through the leak. Due to the reduced volume rate below the leak the frictional pressure loss will also decrease. Consequentially the standpipe pressure is reduced.

Depending on the size and location of the initial leak two scenarios may be identified:

1. A gradual decrease in standpipe pressure resulting from progressive washout of a small crack. This might be considered as the “classical” washout scenario.

2. A sudden decrease in standpipe pressure resulting from a major crack or immediate twist-off and consecutive washout. This is generally referred as equipment failure.

Figure 6 illustrates a major crack scenario during a logging operation conducted on drillpipe.

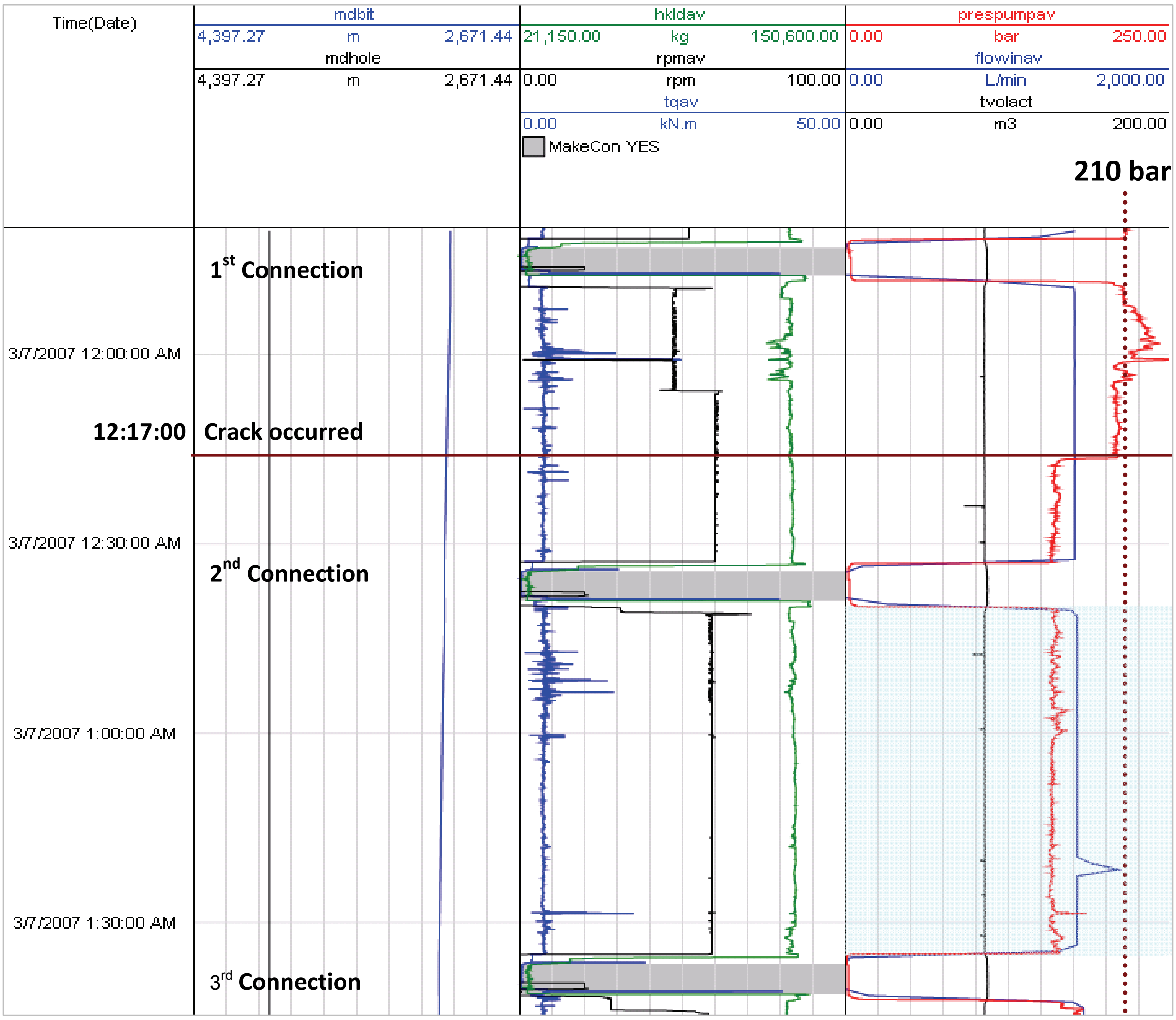

Figure 6: Drilling data time-series illustrating a crack and consecutive washout

After a connection at around 12:15, the pressure fluctuations coming from the logging tools are apparent on the stand pipe pressure log (red line). These fluctuations ceased short after and the SPP (red line) remained relatively constant at around 210 bar until 12:17. At this time, a sudden pressure drop of around 50 bar, while the flowrate (right blue line) remained constant at around 1400 lpm indicates a major crack or leak in the drillstring. Between the second and third connection a gradual decrease of around 2 bars per hour can be observed, indicating that the crack is eventually starting to wash out. No pressure fluctuations after pump start-up can be observed. The declining trend becomes even more apparent after the third connection (not shown on the picture). Increasing the flowrate did not result in a stabilisation of the pressure level, while it dropped short after. The string was finally pulled out off hole and the drilling crew reported a crack in the box connection of a drillpipe.

The fairly large crack extension, which was around 50% of the length of the tool joint (as mentioned in the report) resulted in a sudden pressure drop of around 50bar, which was pretty obvious to identify on the standpipe pressure reading.

In general, the detection and verification of washouts resulting from smaller cracks, damaged threads etc. can be a difficult task as the standpipe pressure typically exhibits a less obvious signature. Here, the pressure decreases gradually over several hours. However a data example for a “classic” wash out scenario which more often encountered than the equipment failure scenario wasn’t available at times.

Distinguishing between a sudden and gradual decrease in standpipe pressure is hence important to identify the root cause of the pressure change.

In addition, standpipe pressure is affected by a variety of other uncertainty factors which should be considered to proof or contradict a possible washout:

- **Pump Efficiency**

As discussed, significant variations in standpipe pressure can also be the result of a decrease in pump efficiency. A visual check of the mud pumps will be required to verify a washout.

- **Mud Rheology and Density**

Changes of the drilling fluid properties e.g. viscosity, gel strength, density etc. will have a direct impact on the standpipe pressure. Also pumping low vis pills will momentarily reduce the system pressure. In general, it is difficult to verify if a pressure change can be related to rheological changes of the drilling fluid, as these parameters are not measured in real-time.

- **Down-hole Tools**

The operation of down-hole motors, MWD and LWD tools also produces fluctuations in standpipe pressure measurement (on/off bottom pressure etc.). Running MWD tools in high mud weight and high solid content mud environments can lead to erosion of internal flow parts leading to a gradual decrease of the standpipe pressure reading. Erosion can be contradicted if the MWD signal strength does not change.

- **Pipe Rotational Speed**

A sudden decrease in standpipe pressure can be observed if the pipe rotational speed is decreased in narrow annular geometries.

- **Lost Nozzles**

In case a nozzle detaches from the bit during drilling, a sudden reduction in standpipe pressure can be observed as the pressure drop across the bit is reduced.

The variety of uncertainty factors can make the detection and verification of an imminent washout a very difficult task.

To allow a more distinct verification, additional parameters need to be considered in conjunction with the standpipe pressure reading:

- **MWD Turbine RPM**

By monitoring the rotary speed of a MWD downhole turbine in real time and integrating those data with flow rate and surface pressure data, washouts deeper in the drillstring can be detected (P. A. Daison, 2008). Similar to standpipe pressure the turbine rpm measurement directly depends on flow rate. For a given turbine geometry a reduction in flowrate due to drilling fluid bypassing part of the drillstring will result in a reduction of turbine rpm. Simply speaking the turbine measurement can be understood as an additional flowmeter inside the BHA. A gradual decrease in turbine rpm while the flowrate remains constant may then be interpreted as a washout, subject to the condition that the washout is above the MWD turbine.

The approach seems to have produced good results for gradual washout scenarios not so much for major cracks. This may be related to the generally low transmission rate of MWD measurements (around 20 seconds). Other constraints of this approach might be that the transmission bandwidth often doesn't allow the addition of turbine RPM measurement in the real-time transmission sequence.

- **Annular Pressure while Drilling**

Annular pressure data may also be used for washout detection (P. A. Daison, 2008). A decrease in annular pressure while drilling may indicate that drilling fluid is bypassing part of the annulus. Constraints of this approach are the availability of annular pressure while drilling and the low real-time transmission rate.

- **Rate of Penetration**

Loss of drilling fluid trough the leak can affect the performance of the down-hole motor and bit, eventually leading to a reduction of ROP.

2.2.2 Blockage

Common problems associated with drillstring blockage are plugged nozzles or plugged BHA components. The blockage can be the result of debris, hand tools, lost circulation material etc. In severe cases circulation can be completely lost. Lost time results from unscheduled roundtrips to change or clean the affected components.

2.2.2.1 Detecting and Verifying a Drillstring Blockage

In general, an obstruction within the drillstring or bit accompanies a sudden increase in standpipe pressure measurement while the flowrate remains constant. The SPP will be higher than expected at a particular flowrate and depth, flow is restricted and the string can be moved without high over-pulls.

Other monitoring observations may include rubber pieces over the shakers, low MWD signal strength, reduced ROP and drillstring vibration. The study of operational data and morning reports carried out in this thesis showed that all reported plugged nozzle incidents were caused by prior downhole motor (DHM) stalling events. For every motor there is a maximum recommended value of motor differential pressure, which should be maintained by the driller or directional driller. At this point, the optimum torque is produced by the motor. If the effective weight on bit (WOB) is increased beyond this point, pump pressure increases further. Also the differential pressure across the motor is increased to a point where the rubber lining of the stator is deformed i.e. the rotor/stator seal is broken and drilling mud flows straight through without turning the bit. A stalling condition is indicated by a sharp jump in standpipe pressure and torque reading. If this condition is maintained the motor will most likely fail and must be replaced.

Figure 7 presents a time data series of several DHM stalling events which consecutively caused a plugging incident.

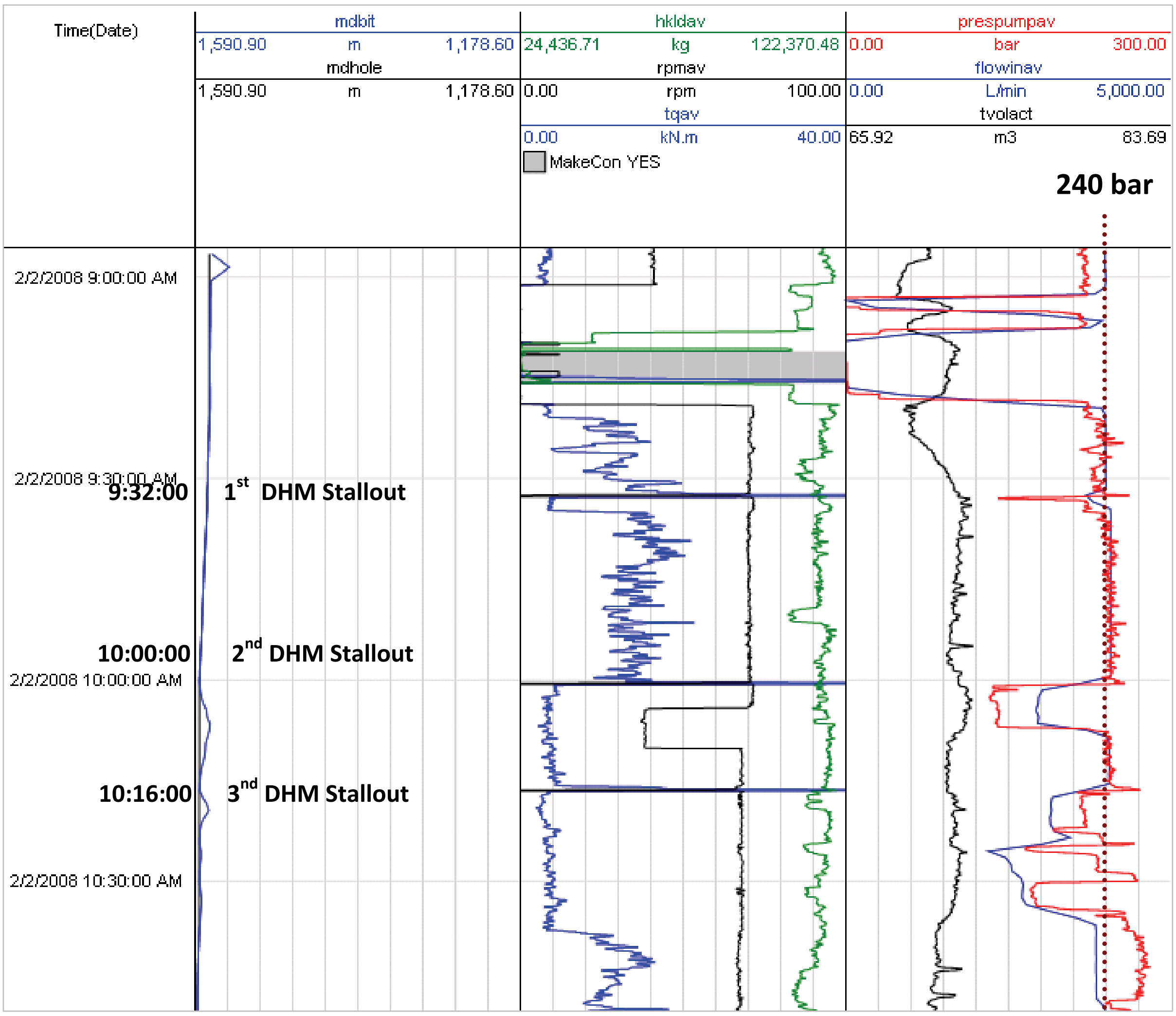

Figure 7: Drilling data time-series indicating a plugged nozzle

After a connection at 09:15 drilling is continued in rotary mode. A flowrate (right blue line) of 4000 l/min was established resulting in a SPP (red line) of around 240 bar. The first stalling event occurred at 09:32 indicated by sharp increase in SPP to 260 bar and torque to 55KNm. Consecutive stalling events occurred at 10:00 and 10:16. The flowrate was changed several times after the third pressure peak to eventually de-plug the nozzles, however the SPP remained at a very high level (260 to 280 bar) while no excessive torque was observed. The string was finally pulled out of hole at 12:22 and the drilling crew reported seven nozzles plugged with rubber pieces.

2.2.3 Detection and Verification Tree (DVT)

As discussed, detecting and verifying the presence of a drillstring washout can be a very difficult task, as a variety of other influencing parameters sometimes mask the problem. Figure 8 is an attempt to summarize the various monitoring observations typically encountered during a drillstring washout (W. Aldred et al., 2008).

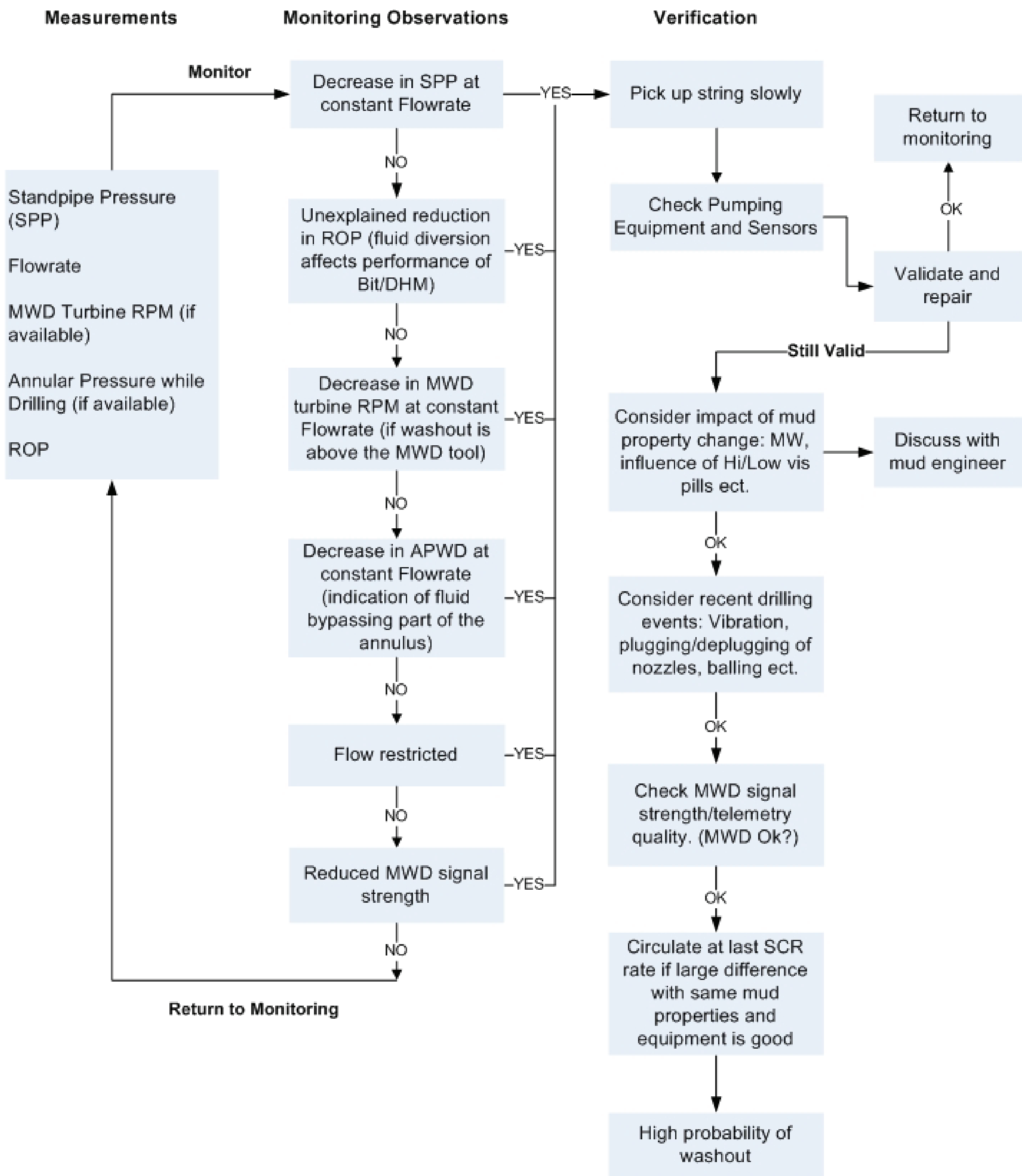

Figure 8: Drillstring washout detection and verification tree (adapted from W. Aldred et.al, 2008)

Figure 9 represent a summary of common monitoring observation and possible verification steps to proof or contradict a possible drillstring blockage.

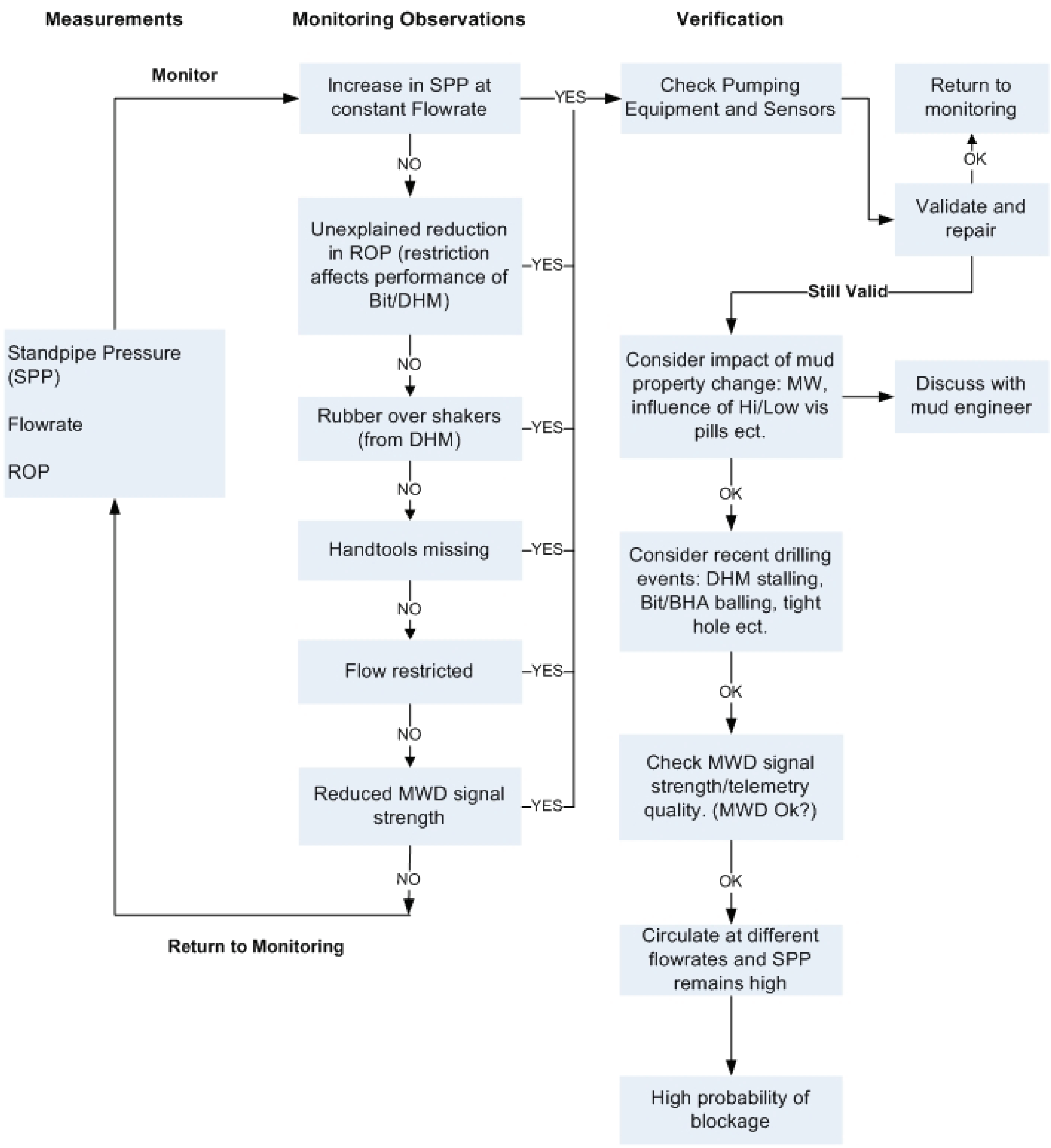

Figure 9: Drillstring blockage detection and verification tree

2.3 Change of the Annular Flowpath

According to Figure 10, a change of the annular flowpath can be encountered within division nodes 3 to 4.

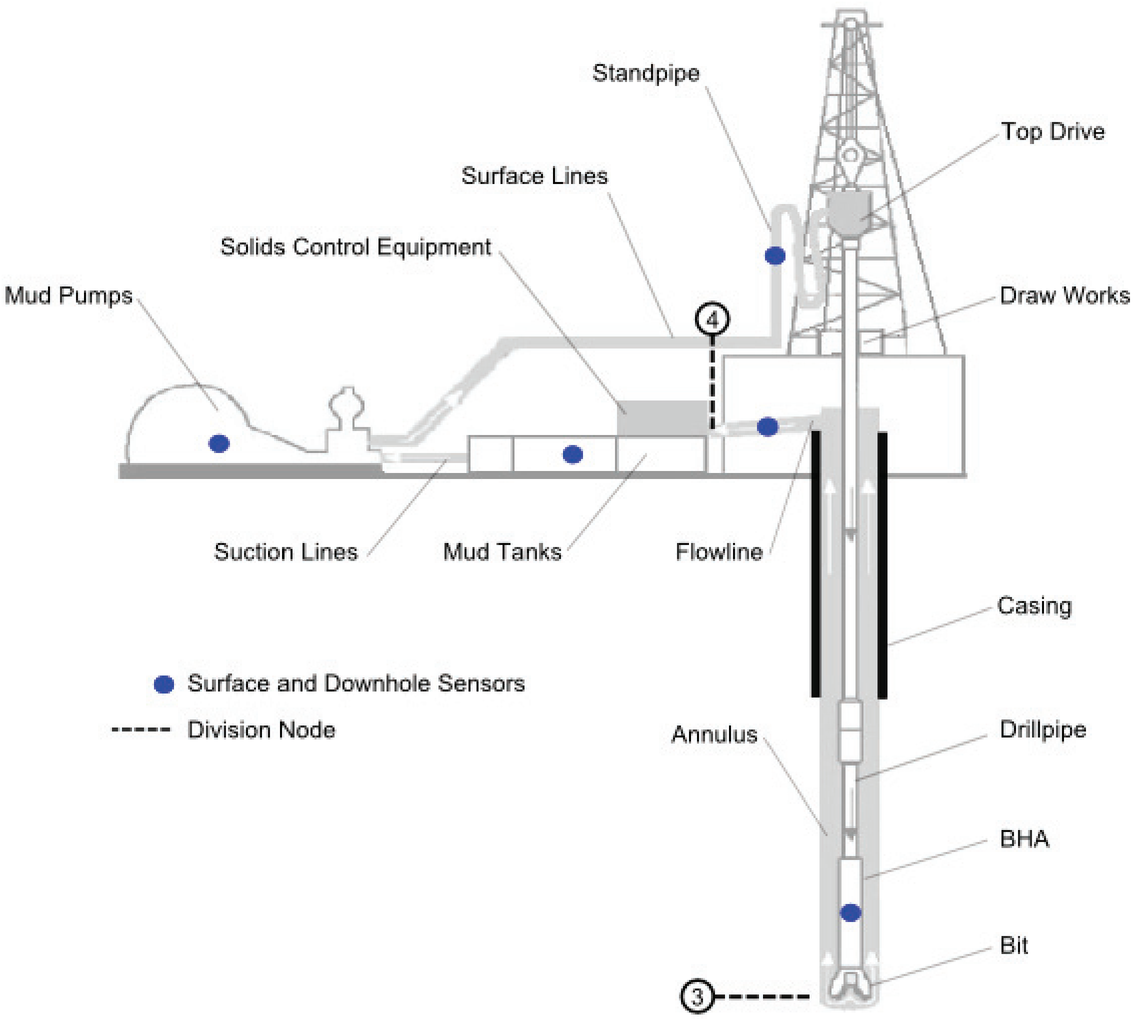

Figure 10: Change of the annular flowpath

2.3.1 Annular Cuttings Loading

For a given set of operational parameters the hole cleaning might be insufficient to remove cuttings from the annulus properly. Thus cuttings will settle in undesired quantities around the drillstring and BHA, eventually leading to operational problems such as stuck pipe.

Especially in deviated wellbores, the additional restrictions created by cuttings accumulating on the low side of the wellbore give rise to high over-pulls and pack offs.

2.3.1.1 Detecting and Verifying Annular Cuttings Loading

Circulation is typically restricted as a result from cuttings loading the annulus. Hence higher pump pressures than expected for a particular flowrate and depth can be observed. In addition, the SPP reading can be erratic and sharp pressure peaks may result from cuttings or cavings sliding down towards the BHA momentarily packing off the wellbore.

Other monitoring observations include an erratic torque as the drillstring is wind up and spun free in the solids accumulations. This is often referred as stick slip. For a given hole cleaning efficiency the volume of cuttings over shakers may decrease. An increased over-pull at connections can be observed. Annular pressure will increase due to a higher ECD resulting from the restrictions in the annulus. This however requires a real-time measurement of annular pressure while drilling.

Figure 11 presents the common behaviour of real-time measurements during insufficient hole cleaning:

An erratic torque (centre blue line) and standpipe pressure (red line) can be identified on the log highlighted by the green bar. Also an increase in standpipe pressure of around 3 bar from 4:00 to 4:50 can be observed, which might indicate that cuttings start to load and restrict the annular space.

The ream and wash sequence conducted at around 4:50 may proof an imminent hole cleaning problem.

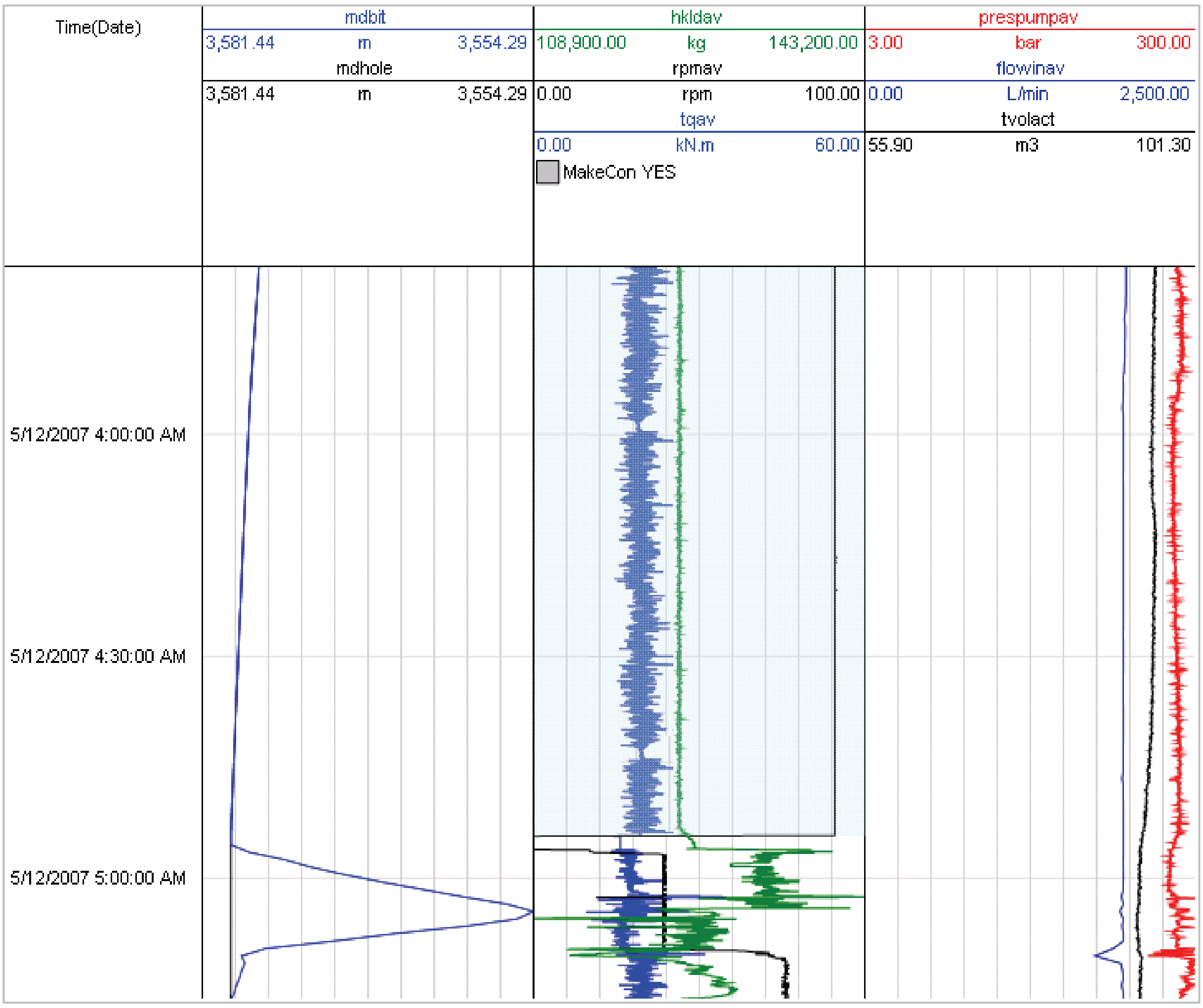

Figure 11: Drilling data time-series indicating poor hole cleaning

2.3.2 Wellbore Instability

Wellbore instability i.e. rock failure occurs when earth stresses or interactions between the formation and the drilling fluid act to squeeze, stretch, constrict or otherwise deform the borehole (W. Aldred et.al, 1999). When a wellbore is drilled, the process may be thought of as one replacing the rock which was originally in the hole with drilling fluid. This causes disturbance to the in-situ stress state local to the wellbore because a column of rock which supported three, probably different principal stresses (three axes, i.e. two horizontal and one vertical) is replaced by drilling fluid in which the three principal stresses are equal and, typically, lower than any of the stresses in the original rock column. As a result the rock surrounding the wellbore fails.

For a given hole cleaning efficiency, the excess cavings rates produced by wellbore failure may cause restrictions of the annulus leading to operational problems such as pack offs and stuck pipe. In general, the higher the cavings rate the more severe the failure for a given hole cleaning efficiency.

Some common indications for a failing wellbore are related to changes of cuttings shapes, losses, an erratic torque and pressure spikes. Control mechanisms include changing mud chemistry, mud weight and flowrate (i.e. ECD) to exert more or less pressure on the formation or changing rate of penetration or drillstring revolutions per minute to facilitate hole cleaning (W. Aldred et.al, 1999).

2.3.2.1 Detecting and Verifying Wellbore Instability

Generally, wellbore instability can be classified as either mechanical or chemical. Mechanical wellbore instability is related to failure of rock around the wellbore because of high ECD, low rock strength or inappropriate drilling practice. Common mechanical wellbore failures are breakouts, induced fractures and natural fracture enlargement and invasion. Chemical wellbore instability is the result of damaging interactions between the drilling fluid and the formation. This type of wellbore instability is commonly associated with shale swelling.

The most common mechanical and chemical wellbore instability mechanisms are discussed below:

- **Wellbore Breakouts**

Breakouts can result from insufficient mud pressure supporting the formation, generally low rock strength and a high mean stress (W. Aldred et.al, 1999). The rock fails under compressive shear stress perpendicular to the maximum wellbore stress leading to large cavings. Depending on the hole cleaning efficiency, restriction due to cavings loading the annulus may result in pressure spikes and an erratic torque. The observed pattern might be similar to the one presented in figure 12. The dominant cavings observed at the shakers are generally of angular shape, as indicated in Figure 14 (W. Aldred et.al, 1999). Generally, wellbore breakout can be controlled by good hole cleaning practices or by increasing the mud weight.

Figure 12: Angular caving shape from wellbore breakouts (W. Aldred et.al, 1999)

- **Drilling Induced Fractures**

Drilling induced fractures are created whenever the load imposed on the formation is larger than the fracture resistance of the formation. This condition is generally encountered if the mud weight is too large resulting in an excessive ECD for a given flowrate. As a consequence the portion of the rock surrounding the wellbore is fractured and mud leaks off through the fractures leading to so called induced losses. In severe case the destabilisation of the surrounding rock resulting from mud invasion can lead to wellbore instability, high cavings rates and consequentially stuck pipe.

Generally, any mechanical condition which causes an abnormal pressure surge can cause wellbore instability, and may cause lost circulation. Examples of this condition are pressure surges during pump start-up operations resulting from gelation effects, or pressure surges resulting from rapid down-ward movement of the drillstring. These type of problems are of special concern in case very narrow operational windows are available i.e. there is only a small difference between the formation pressure.

- **Chemical Activity**

Chemical wellbore instability arises from damaging interactions between the rock, generally shale, and the drilling mud. When drilling with water based mud, the water is absorbed into the shales, causing them to swell and weaken. As a result, chunks of shale will break-off and fall into the borehole. The hydrated shale tends to stick to the drillstring and BHA components eventually causing a stuck pipe.

In general, the pump pressure and torque will increase due to the restriction; also the drilling rate might be slower as less weight gets to the bit.

- **Naturally Fractured Formations and Weak planes**

In case of a naturally fractured formation is drilled, the fluid pressure in the annulus exceeds the minimum horizontal stress, resulting in mud invasion of fracture networks surrounding the wellbore. This can result in severe destabilization of the near wellbore region, due to the movement of blocks of rock, leading rapidly to high cavings rates, lost returns and stuck pipe. The blocks of rock are bounded by natural fracture planes and therefore, have flat, parallel faces. As presented in Figure 13, cavings are typically of tabular shape and bedding, if any, will not be parallel to the faces of the caving (W. Aldred et.al, 1999).

Figure 13: Tabular caving shape form natural fractures (W. Aldred et.al, 1999)

2.3.3 Detection and Verification Tree (DVT)

Figure 14 describes how to diagnose the 4 most important wellbore instability mechanisms. Three of these are mechanical and one of these is of chemical origin. Detecting problems related to annular cuttings loading have not been included in the diagram since the general monitoring observations are similar to the one observed during wellbore breakout (except from large cavings visible at the shakers).

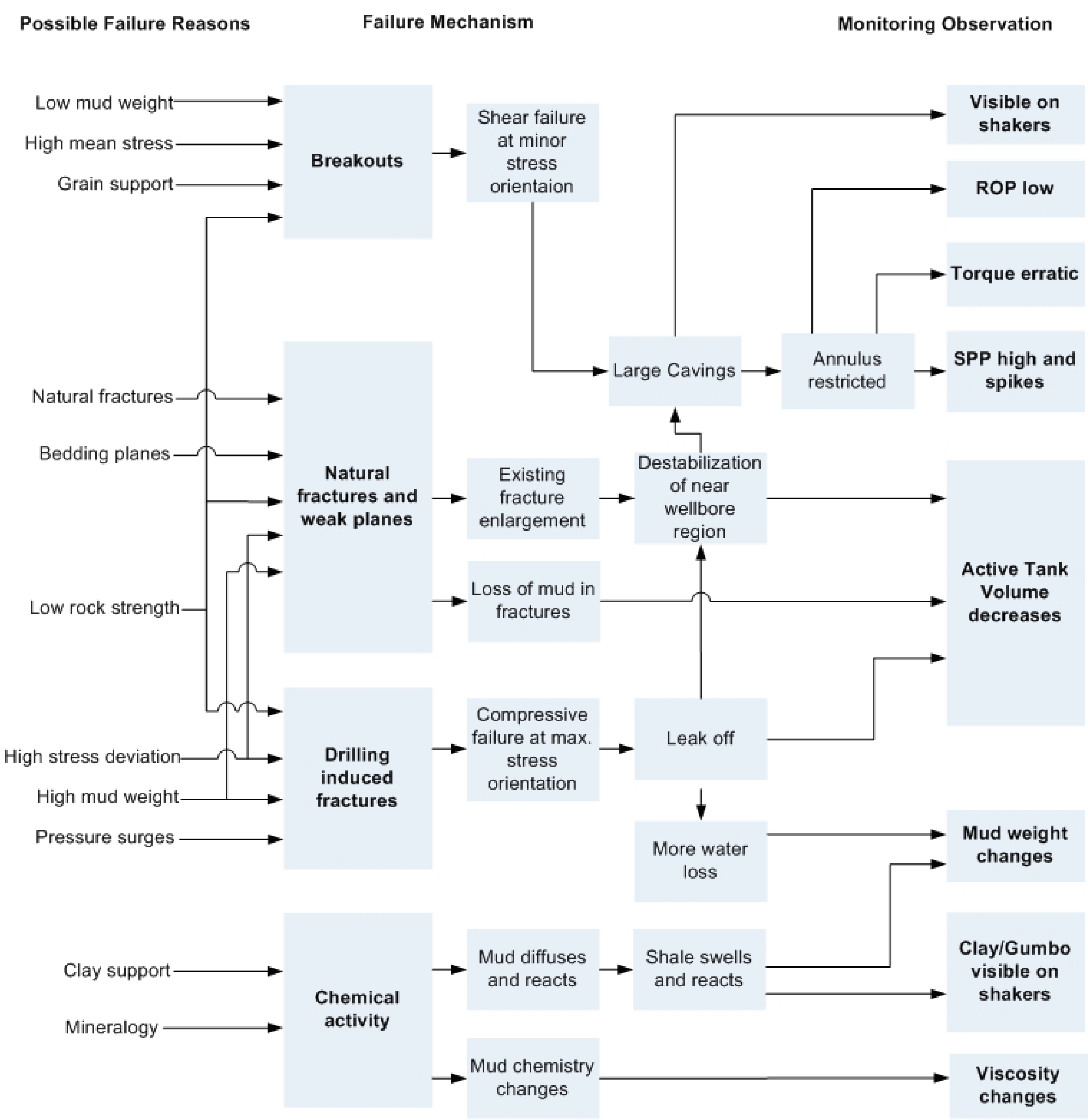

Figure 14: Wellbore instability detection and verification

2.4 Change of the Material Balance

According to Figure 15, a modification of the material balance of the drilling fluid can be encountered within division node 3 and 4.

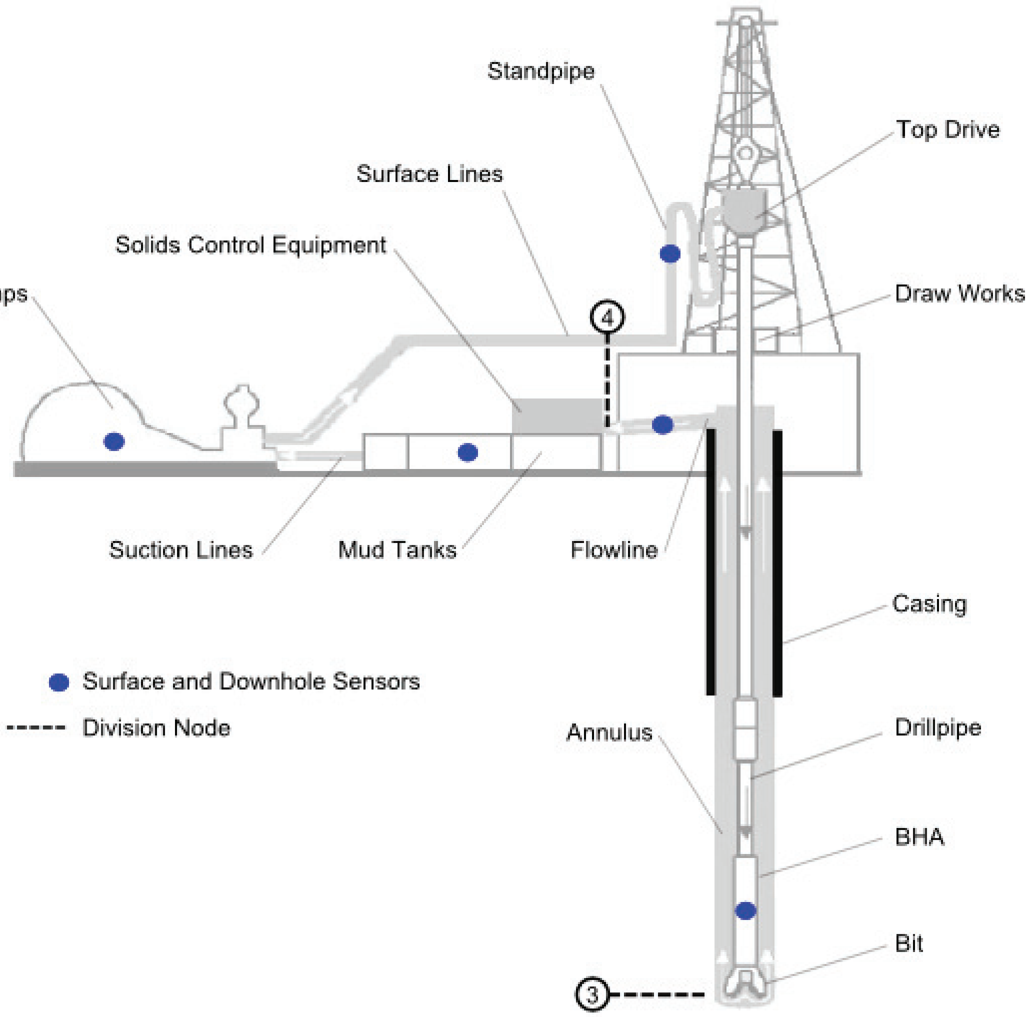

Figure 15: Change of the material balance

2.4.1 Influx of Formation Fluid

Well control has a major significance in the oil and gas industry. During drilling operations uncontrolled influxes into the well i.e. kicks are usually inevitable thus standard procedures exist, which enable the drilling crew to circulate out a kick in a safe and controlled way. In most cases, blowouts can be attributed to human error and misunderstanding of the prevailing situation. Generally, two different types of kick situations might be distinguished:

- **Underbalanced Kicks**

An underbalanced kick is encountered if the formation pressure is higher than the static or dynamic pressure of the mud column i.e. an underbalanced pressure situation exists at the bottom of the hole. Generally, this situation is the result of an insufficient mud weight e.g. if an overpressured horizon is drilled into unexpectedly.

- **Induced Kicks**

Induced kicks are typically the result of surge and swab effects encountered during axial pipe movement. Generally, swabbing occurs whenever the drilling fluid is not able to flow as fast around BHA components as the string is moved up i.e. a void space below the bit is created. This condition becomes imminent if (1) the pipe running speed is too large or (2) the viscosity respectively the gel strength of the mud is too high or (3) the clearance between BHA and borehole wall is too small. Vice versa, when running into the hole, a high pipe moving speed can cause pressure surges which can fracture the formation which in turn can lead to a kick situation if mud is lost through the created fractures. A real piston effect might become apparent if the bit or parts of the BHA are balled up with hydrated shale.

In general, the pipe moving speed is the only parameter which can be adjusted without a large effort to reduce surge and swab effects. By limiting the pipe moving speed in open hole, the mud has sufficient time to overcome the described friction effects and fill the borehole below the bit.

2.4.1.1 Detecting and Verifying a Kick Situation

There are two parameters directly related to changes of the volume balance which can be utilized to detect an influx into the wellbore during drilling:

- **Return Flowrate**

Generally, an increase in the rate of return while the flowrate into the well remains constant is indicative for an imminent kick situation. Rate of return is measured by a flow show or paddlemeter.

As mentioned, these sensors provide a very crude measurement of the return flowrate and require frequent calibration.

- **Active Tank Volume**

The most common method of detecting changes of the volume balance is by monitoring changes in active mud tank volume as measured by pit level meters. An increase in active tank volume is indicative for an imminent kick situation. HPHT wells require a kick to be detected at an influx of 5bbl.

Generally, active tank volume is not as responsive as the rate of return flow. This can be related to the large liquid surface area of the tanks so as for instance a level increase of 1cm might already correspond to a large influx volume. In HPHT wells the surface area of the tanks is thus limited to achieve the required sensitivity. Additionally, during high heave conditions the individual tank levels also show significant variations. To compensate the effects of heave on the measurement several level meters are utilized. A pit volume totalizer averages the tank levels of all active tanks which in turn incorporates a certain inaccuracy.

Faster detection of gains can be achieved by measuring the fluid level of the settling tanks below the shakers. In this way, delays resulting from the time required by the drilling fluid to flow into the active tanks can be eliminated. However this not frequently done.

Apart from the primary monitoring parameters directly related to volume changes, several other secondary parameters should be considered to detect a kick:

- **Rate of Penetration**

Drilling into a high porosity overpressured formation can result in an abrupt increase of penetration rate. The increase in rate of penetration can be largely attributed to the decreasing chip hold down effect. However rate of penetration is affected by numerous other factors such as weight on bit, bit rpm, mud rheology etc.

- **Standpipe Pressure**

A low density formation fluid entering the wellbore may cause the pump pressure to decrease. The lighter formation fluid in the annulus can cause mud to fall down the drillpipe consequently the pump rate increases (U-tube effect).

- **Hook Load**

A lighter fluid coming from the formation might reduce the buoyancy of the suspended drillstring thereby the indicated weight of the drillstring will also decrease, however hook load is influenced by a variety of other factors.

- **Mud Weight Out**

Although this may indicate a kick, low mud weights at the surface are usually the result of gas expansion, and reflect only the fact that a gas-containing horizon has been drilled (G. Schaumberg, 1998). Moreover, if the well did not kick as the gas was being circulated up the annulus, then there is only a small chance that it will kick once the gas has reached the surface.

Apart from kick indications during drilling, also several indications during routine operations such as pulling out of hole (POOH) and running in hole (RIH) need to be considered. They are of special importance because the predominate portion of kicks is typically encountered during tripping. During POOH, the volume of steel in each stand pulled should correspond to the volume of mud required to fill up the hole. If less volume of mud is required then fluid is most likely flowing from the formation.

Generally, the flowline must be connected to the trip tank and a measurement of trip tank volume must be available to compare the volume changes in real-time. When RIH, the well should flow an amount of mud equal to the volume of steel in each stand. Flow should cease short after the pipe has been lowered into the slips, if flow still continues then fluid is probably coming in from the formation. This will also require a volume measurement at the trip tank.

Figure 16 illustrates the behaviour of real-time measurements during a saltwater kick:

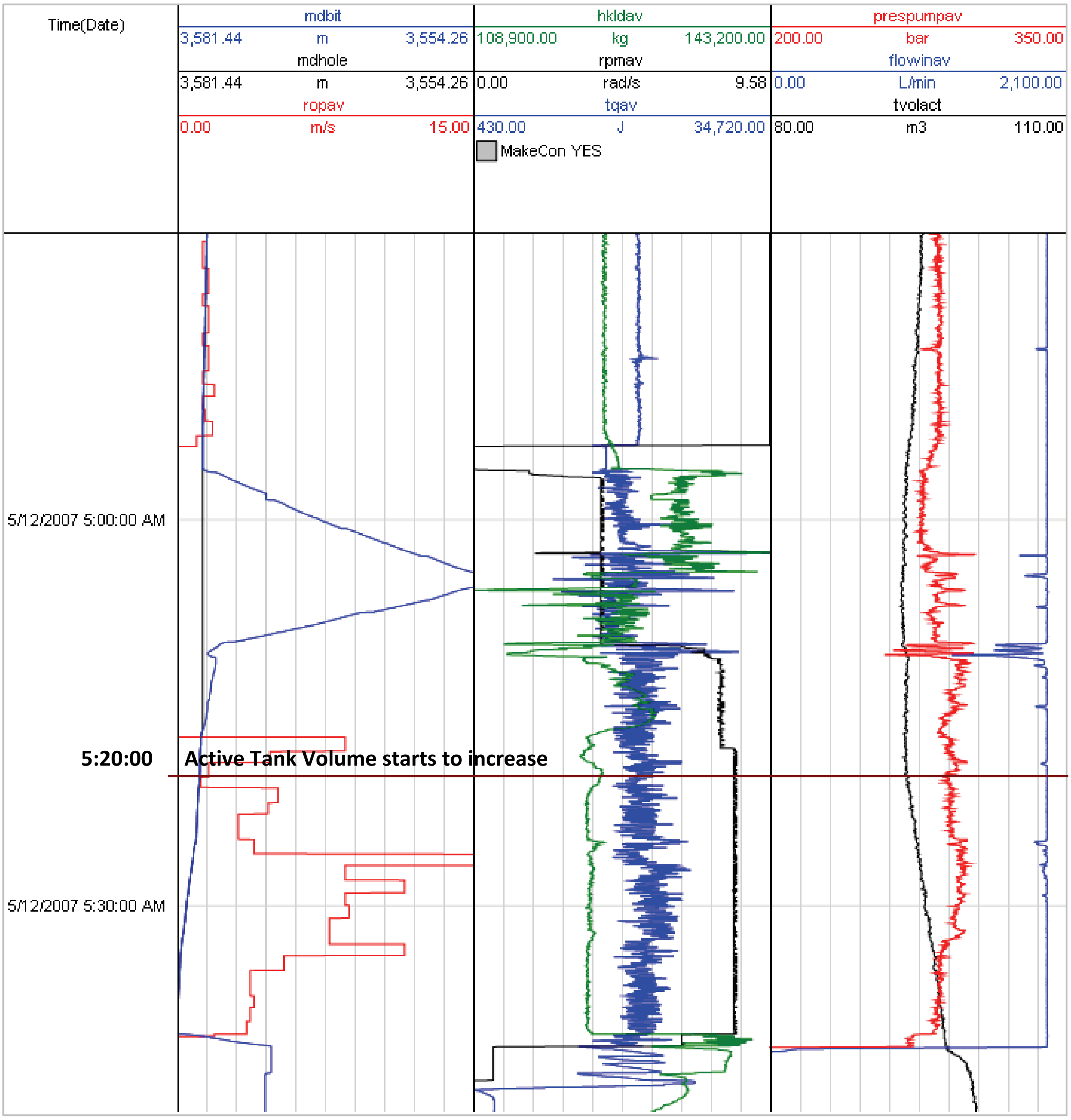

Figure 16: Drilling data time-series representing a kick situation

Rotary drilling was continued until 4:50 at a rate of penetration (left red line) of around 5m/s and a standpipe pressure (right red line) of 210 [bar]. At this time a ream and wash operation was conducted to condition the wellbore. Drilling was continued at around 5:15. An increase in active pit level (right black line) can be observed at around 5:20 indicating a possible influx of formation fluid. Also the ROP is generally higher after the ream and wash operation which might indicate that an overpressured high porosity formation is drilled. The decrease in SPP (right red line) starting at around 5:30 is another kick indication resulting from the lower density of the influx. Consecutively, the trend of increasing active pit volume becomes even more apparent and finally the well was shut in at around 5:40.

2.4.2 Loss of Drilling Fluid

Losses represent another serious and expensive well control problem facing the drilling industry. Conduits created by faults and fractures encountered during the drilling process lead to a loss of drilling mud to the formation. Apart from the additional well cost for drilling mud and remedial measures, losses also increase the potential for kicks, wellbore instability and stuck pipe.

Generally two different types of losses might be encountered during the drilling process:

- Naturally Occurring Losses

In case a naturally fractured formation is drilled, the fluid pressure in the annulus exceeds the minimum horizontal stress, resulting in mud invasion of fracture networks surrounding the wellbore. This can result in severe destabilization of the near wellbore region, due to the movement of blocks of rock, leading rapidly to high cavings rates, lost returns and stuck pipe.

- Induced Losses

Induced losses can be largely attributed to an excessive overbalance condition, where the formation is unable to withstand the effective load imposed upon it by the drilling fluid. Excessive drilling fluid density is the most common cause of this condition. As a result, fractures will be induced at the wellbore wall and drilling fluid will be lost eventually leading to wellbore instability and stuck pipe.

Other reasons for induced losses are related to fractures resulting from pressure surges during pump start-up or fast axial string movement.

2.4.2.1 Detecting and Verifying Losses

Generally, the same measurements as for kick detection can be utilized in order to detect an imminent loss. A decrease in the rate of return at a constant flowrate into well or a decrease in active tank volume is indicative for losses.

A loss might be considered as a good indication for other apparent drilling problems for instance problems related to wellbore instability e.g. induced fractures. Detecting and verifying the root cause of the loss is hence a difficult task.

2.4.3 Contaminants

A contaminant is any material, generally small particles or fluids, which cause undesirable changes in the material balance and properties of the drilling fluid. Solids are by far the most prevalent and detrimental contaminants. Important fluid properties such as viscosity and density are deteriorated as result of highly dispersive clays, originating from shale and claystone, commercial solids added to the mud such as barite and chemically precipitated solids. Chemically precipitated solids are extremely small solids formed within the mud by chemically treating out contaminants, such as removing carbonate iones with lime or by treating out cement, gyp or anhydrite with soda ash or bicarbonate.

Excessive solids in the mud lead to operational problems directly related to high viscosity, high gel strength, thick filter cakes and high fluid loss etc. increasing the risk of differential pipe sticking and surging or swabbing pressures. Control of solids whether commercial or from the formation and hence rheological properties of the drilling fluid, is essential to ensure an optimal hydraulic performance and to avoid operational problems.

Another common contamination of drilling fluid is caused by saltwater resulting from salty make up water, drilling salt stringers or saltwater flows.

Generally salt contamination will be accompanied by an increase in the chlorides content of the filtrate. Rheological changes such as an increase in yield point and gel strength together with fluid loss and increased pH might also indicate salt contamination.

2.4.3.1 Detection and Verification of Contaminated Drilling Fluid

Detecting the point at which solids become excessive requires continuous and accurate monitoring of the drilling fluid. Common Indications include an increase in plastic viscosity, yield point, gel strength, fluid loss and solids content. However, all these parameters are still taken manually (typically twice a day) by individual testing equipment and measurement procedures e.g. viscosimeter, methylen blue test etc. described by certain standards (API 12B-1 2008; API RP 13B-2 2005). Hence it is not possible to react to changes in real-time.

An attempt to measure several drilling fluid properties automatically and in real-time has been performed by A. Saasen et. al, 2009 (A. Saasen et. al, 2009). The automatic drilling fluid analysis includes viscosity, fluid loss, electrical-stability measurements and chemical properties such as pH (A. Saasen et. al, 2009).

2.4.4 Detection and Verification Tree (DVT)

Figure 17 summarizes all the available measurements and monitoring observations and allows a verification of an imminent kick situation by following a certain procedure. Other mentioned problems related to a change in the material balance of the drilling are however not considered in the diagram.

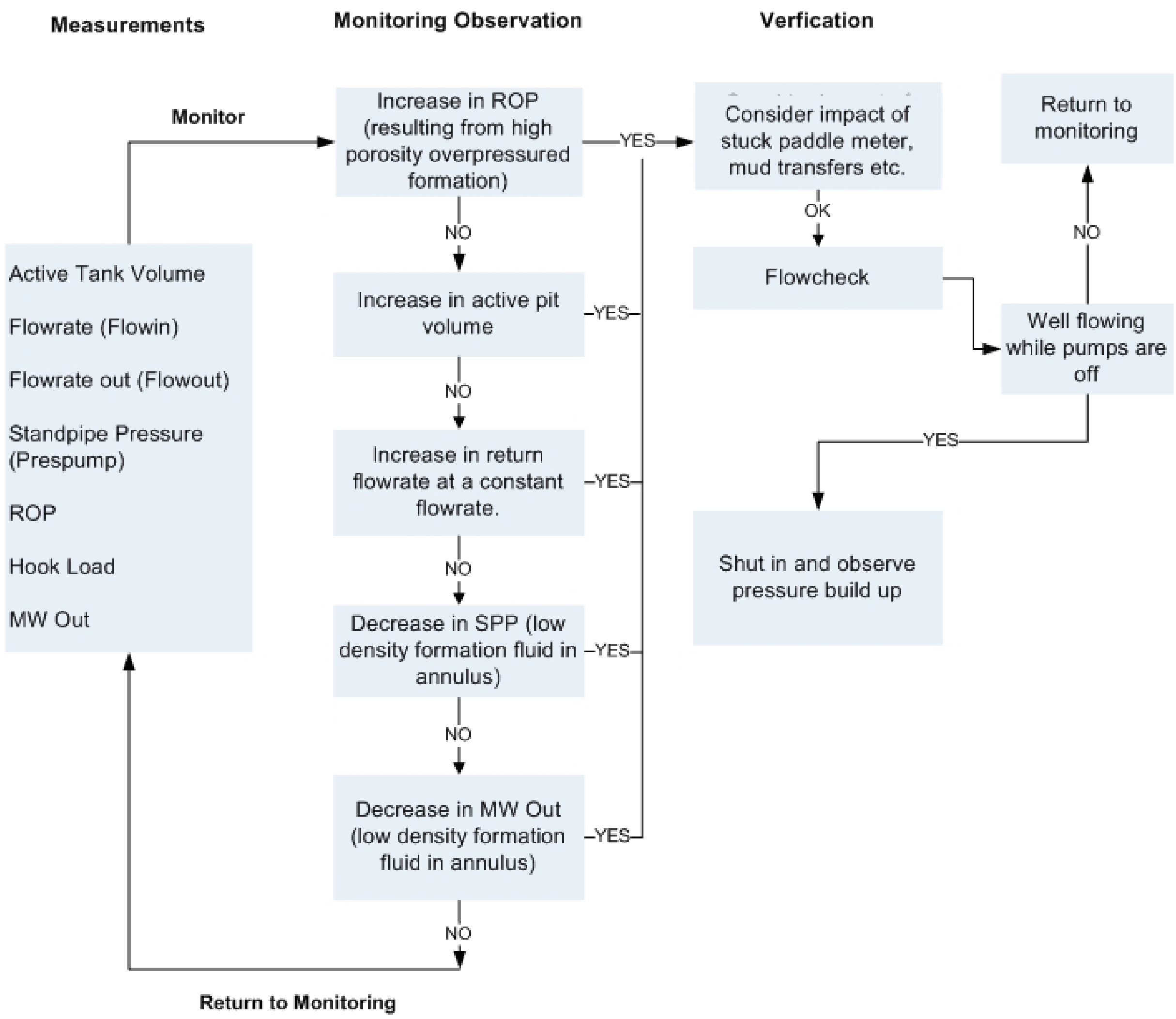

Figure 17: Kick detection and verification tree

3 Current Problem Detection Approaches

3.1 Human Supervision and Control

It can be stated that one of the most important components of early drilling problem detection and verification is, the driller. The driller monitors relevant parameters such as standpipe pressure, torque and drag, flow, active tank level increments etc. and thus continuously evaluates the current state of the circulation system. Certain features in the data i.e. deviations from normal drilling behaviour as discussed above, will allow him to identify a change in the systems state. Based on his acquired skills and knowledge of the system he will perform appropriate remedial measures to bring the system back to its original state. However, drilling a well is a complex task and the driller might not always be able to follow the huge amount of available real-time data at all times, thus he might overlook signs of a problem. In addition, experience and training of the individual person plays another important role in avoiding lost respectively hidden lost time resulting from wrong decisions or undetected faults. However software tools which help to evaluate the current condition of the wellbore are often too complex and sophisticated to be used by the driller.

There are numerous efforts made in producing monitoring tools that either concentrate the real-time data into a more ‘straightforward’ or manageable format or trigger an automatic alarm when the system is getting near a fault. The most sophisticated alarm systems in place model the entire circulation system and let the driller anticipate his actions providing automatic 24/7 screening of faults (R. NybØ, 2009). Still, most of the automatic alarm systems suffer from a high number of false alarms, whereas the frequent intermittence by false alarms was found to be a major problem for drilling personnel (Heber and Åsland, 2007).

3.2 Automatic Alarm Systems

Several problem detection and diagnosis systems have been developed in the past to automatically alert the driller when the circulation system is getting near a fault. The main focus laid on kick, lost circulation and washout detection. They may be classified into three generations:

3.2.1 First Generation

First generation alarm systems solely relied on thresholding to detect critical events i.e. in case a particular drilling parameter exceeds a certain predefined threshold value an audible alarm is sent to the driller. By setting high and low alarms for the return flowrate, kicks and losses can be detected.

In general this approach requires a calibrated measurement of the return flowrate and doesn't incorporate the intricacy of the observed process i.e. routine drilling operations such as tripping or reaming are not represented. Typically a series of alarms is trigger during the particular operations. A lot of human intervention is hence required to tune the thresholds and thus reduce the number of false alarms. To solve the sensitivity problem special sensors have been developed, to get an accurate measurement of flow (D.M Schafer et al, 1992).

3.2.2 Second Generation

Some improvement resulted from the deployment of cumulative sum methods using the Hinkley or Page algorithm (M.A. Weishaupt, 1991). Second generation alarm systems still utilize high and low alarms but now the threshold is windowed and noise is taken into account i.e. not only the very last measurement is utilized to set the threshold. The cumulative sum test is a well known statistical test used in quality control to detect processes that are out of control i.e. deviate from normal behaviour. If we consider a process that generates time ordered measurements m_1, m_2, m_3…. and suppose the measurement fluctuates around a mean value θ which is taken as the zero hypotheses. The cumulative sum for n measurements is given by Equation 2.

$$CuSum_{(n)} = \sum_{i=1}^{n} m_i - \theta \quad \text{Eq. 2}$$

If the process is in control the cumulative sum will be approximately zero since the measurements will tend to randomly vary around the mean value. A segment of the cumulative sum with an upward slope indicates a period where the values tend to be above the overall average. Likewise a segment with a downward slope indicates a period of time where the values tend to be below the overall average. Periods where the cumulative sum follows a relatively straight path indicate a period where the average did not change. If a threshold is applied on the cumulative sum a change point in the time series can be detect.

Although the cumulative sum test might be well suited to detect a step change in the mean of a constant variance Gaussian noise sequence, it might not be fully applicable to drilling problems (D. Hargreaves et al., 2001). As discussed in the previous chapter drilling problems typically exhibit a ramp shape trend rather than a sudden increase in the particular measurement. Several steps might be utilized to account for this problem. However it is difficult to determine the size and number of steps to approximate to a ramp. The choice of optimal parameters also varies widely for different rigs, flowrates and sensor types, so the performance of the system will heavily depend upon how well it is set up and tuned (D. Hargreaves et al., 2001). Further the underlying assumption that the noise is constant variance Gaussian might not be true (R. Nybø, 2009).

3.2.3 Third Generation

Third generation alarm systems employ a more sophisticated approach to detect changes from normal drilling behaviour. In general, the underlying assumptions and models have a clear physical meaning which incorporates that the behaviour of the system is understood and taken into account. They can be divided into deterministic, statistical and knowledge-based approaches.

3.2.3.1 Deterministic Approach

Deterministic systems model the entire circulation system to predict the effects of routine drilling operations for instance the effect of pipe movement on the flow out measurement. By comparing the actual measurement with the model prediction a residual is generated (refer to Figure 18). The residual is defined by equation 3.

$$r(t) = h(t) - y(t) \quad \text{Eq. 3}$$

Whereas $y_{(t)}$ is the actual measurement and $h_{(t)}$ is the predicted output of the model and $x_{(t)}$ can be an input to the model. If the model can be accurately constructed the residual should fluctuate around zero. A change in the residual towards a certain direction indicates an imminent problem.

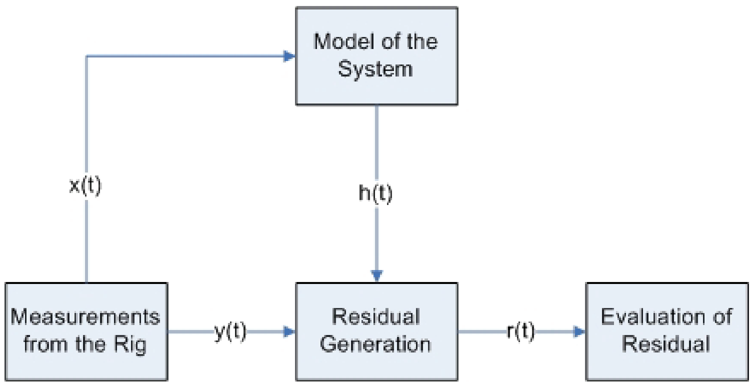

Figure 18: Graphical representation of a predictive system

In the presented system (B.W. Swanson, 1997) for detecting kicks in slim-hole applications two WITS channels are utilized in order to detect a kick: flow out of the well and standpipe pressure. A dynamic wellbore model based on the solution of conservation of momentum, mass and energy equations directly predicts flow out from an input flow rate coming from the flow in measurement. The model introduces delays caused by the flow path length, in addition to modelling changes in flow caused by pressure changes i.e., a change in drillpipe rotation (B.W. Swanson, 1997). This avoids false alarms generated by routine drilling operations. An explicit sensitiviy of the system is however not stated rather it is claimed that the system can detect an imminent kick situation within one to two minutes, which is not very meaningful since the rate of the detected influx is not mentioned. The most recent developments utilize neural networks to increase the accuracy of the model prediction (R. Nybø, 2009). In a first training step the neural network learns from the residual predicted by the physical model and the input data. In a second step the trained neural network is combined with the physical model to predict a more accurate residual $r_{new}(t)$. The prediction is improved if less of the data remains unexplained and $r(t) > r_{new}(t)$.

The output of deterministic systems is strongly affected by the accuracy and completeness of the underlying model which might be a big challenge to achieve (D. Hargreaves et al., 2001). Neural Network approaches might suffer form the lack of available training data and the strong class imbalance i.e. the number of drilling problems will be few compared to the number of normal events. The transformation from the training data set to another data set is another big challenge.

3.2.3.2 Statistical Approach

D. Hargreaves et al. (D. Hargreaves et al., 2001) utilizes a statistical model matching framework to detect drilling problems. Several models for different problem situations as well as different routine drilling operation are matched to the current real time data and the probability of the match is calculated using Bayes rule. The real-time applicability is achieved by allowing a data buffer which is essentially the size of the shortest (in terms of time) defined model. By introducing different models, for instance a kick is represented by a simple ramp up of flow out measurement whereas the increase in slope can be specified, several kick types are represented. The models for the kick detection have been designed with the aid of a kick simulator and by studying different kick situations from operational data. The advantage of the model based approach is that the models have a clear physical meaning and this means that the system and its behaviour is understood (D. Hargreaves, 2001), a circumstance all third generation alarm systems have in common. The author claims that the incorporated families of models cover all significant drilling event signatures; problem related signatures as well as signatures created from routine drilling operations. For instance reaming and washing operations are represented by a sudden drop in flow out as the pipe is moved up and a sudden increase in flow out as the pipe is moved down. Accounting for such harmless effects ultimately reduces the number of false alarms. The output of the proposed alarm system also deviates form the usual “binary” on/off alarm representation. A probability log allows the driller to evaluate a problem situation in the context of the history of the alarm, and the systems certainty that there is actually a kick and this can assist in decision making (D. Hargreaves, 2001).

The system has been initially tested on historical data and claims sensitivity in the range of 0.2 bbl (onshore) to 3 bbl (offshore) while the number of false alarms was mentioned to be around two per day. There have been no false alarms generated from connections. Real field tests however showed that inconsistent data processing and managing the complex algorithms required calculating the probabilities and normalizing and summing the results leaded to an excessively high false alarm rate (Walt Aldred et al., 2008).

3.2.3.3 Knowledge based Approach

Knowledge based drilling alarm systems utilize knowledge from operation and from experts which is presented in the form of cases that summarize the drilling experience. Each case contains data and associated information categorically describing individual situations (S.V. Shokouhi, 2009). By retrieving previous cases and adapting them to fit the current situation new problems are solved. In general the case based reasoning cycle consist of four components: Retrieve, reuse, revise and retain. For an introduction on case based reasoning we refer to (A. Aamodt and E. Plaza, 1994)

The outcome of a case based reasoning approach is highly dependant upon the database and definition of the individual cases. This implies that all of the important features, data and parameters of an individual case must be captured and described, which might be a difficult task. In addition, different problems might require a different type of description and thus a different case structure.

4 Hydraulics Monitoring during Pump Start-up

4.1 Purpose and Objective

Monitoring the response of the standpipe pressure during pump start-up operations represents one essential element of real-time drilling hydraulics monitoring.

Drilling fluids are designed to form a gelled structure once circulation is stopped and the well is under static condition e.g. during a slip to slip connection. This is necessary to keep cuttings and weighting materials in suspension. Once a gelled structure is formed, the energy required to break it will be higher and consequently a pressure peak is observed on the standpipe pressure log (K. S. Bjørkevoll et. al, 2003). The pressure peak can be much higher with increasing inclination of the well, resulting from cuttings sliding down towards the BHA. Especially in narrow operational windows this pressure peak may lead to fracturing of the formation, lost circulation, kicks or even collapse of the wellbore (K. S. Bjørkevoll et. al, 2003).

The example of a pump start-up sequence indicated by figure 19 shows that after the pumps have been brought up to full strokes the standpipe pressure exhibits a maximum of around 141 bars at 70 seconds (dashed line). At 120 seconds the standpipe pressure reaches a stabilized value of around 129 bars (solid line) hence, the magnitude of the pressure peak in this case is 12 bars.

Main objective of this chapter is to analyse the magnitude of the pressure peak in relation to individual pump start-up procedures, drilling fluid properties and the time the well has been under static conditions. This is essential in order to enhance understanding of the phenomena and to define the significant monitoring parameters.

The concept will be implemented by a pump start-up monitoring screen fed by the results of the analysis, which outlines the pressure peaks over depth in relation to the pump start-up procedure and other important parameters. This will enable the drilling personnel to act on the information generated.

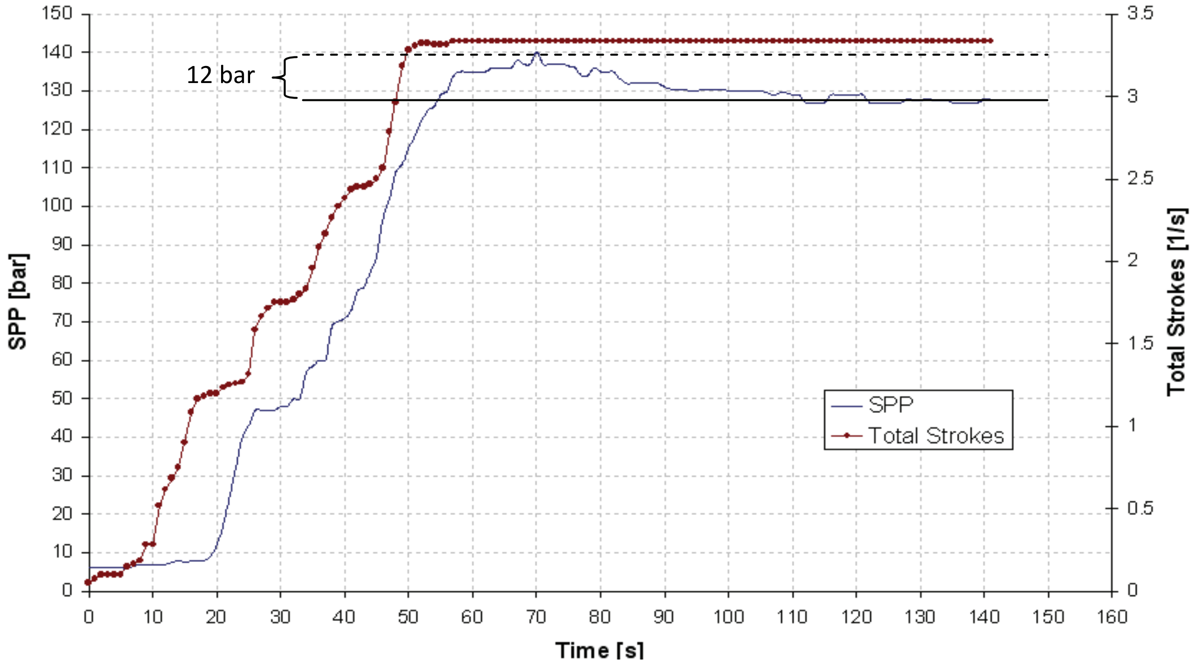

Figure 19: Pressure peak observed during pump start-up

4.2 Thixotropic Rheology of Drilling Fluids

In general drilling fluids are of thixotropic nature i.e. they exhibit a certain dependence on time- and shear rate- history.

The dependence can be related to the microstructure of the suspension resulting from interactions between electrically charged particles e.g. clay platelets (A. Tehrani, 2008). This microstructure and the resulting bulk rheological properties are responsible for the drilling fluids gelling characteristics under static conditions and its thinning behaviour when sheared. Figure 20, schematizes the general behaviour of drilling fluids when exposed to various shear rates. At zero shear rate the fluid exhibits an initial resistance to flow, reflected by the yield point which can be related to the initial microstructure. The yield point is important to keep cuttings in suspension once circulation is stopped. As the shear rate is increased the shear stress respectively the viscosity represented by the slope of the curve also changes i.e. the fluid becomes thinner. As the shear rate is decreased to zero again the microstructure is recovered to some extent, and a residual yield strength is formed. The resulting hysteresis loop (area between up and down curve) is an indication of the extend of the drilling fluids thixotropy.

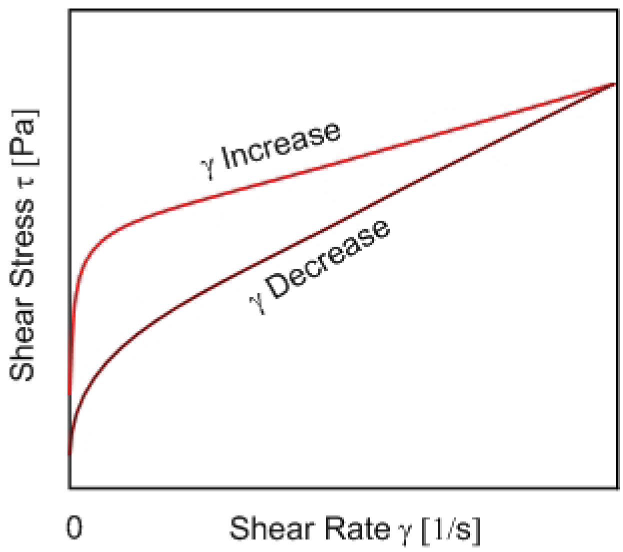

Figure 20: Schematic diagram of thixotropic hysteresis loop (adapted from A. Tehrani, 2008)

If the drilling fluid is now left under static conditions the microstructure will gradually reform. The strength of the gelled structure depends on the static time and the general gelling behaviour of the drilling fluid (K. S. Bjørkevoll et. al, 2003). In the field, 10 second and 10min gel strength values are obtained from Fann viscosimeter measurements to characterize the gelling behaviour of drilling fluids.

Figure 21 depicts the main gelling types of drilling fluids. Generally drilling fluids are designed to exhibit a non progressive gelling behaviour i.e. where the longer term gels are not significantly higher than the 10min gel values (A. Tehrani, 2008). High flat gels are also not desired because of the comparatively large pressure variations during pump start-up resulting form the very high gel strength.

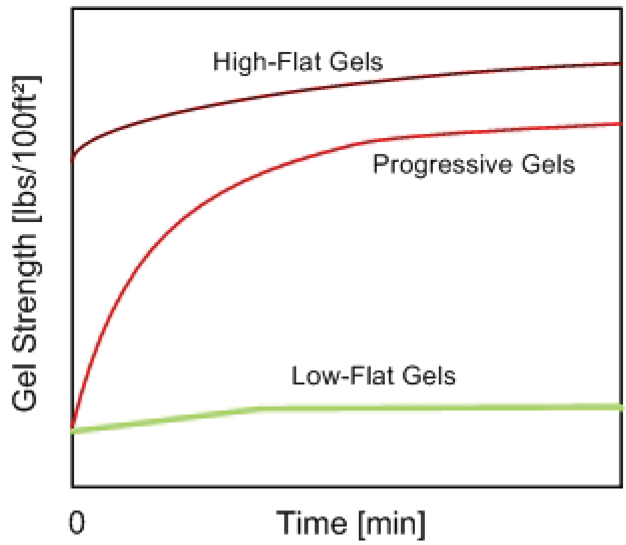

Figure 21: Schematic diagram of main gel types

The specific rheological properties and changes of the micro structure of different drilling fluids are however complex and subject to continuous changes along the flowpath of the drilling fluid (A. Tehrani, 2008). This includes changes caused by variations in shear rate, temperature, pressure, as well as chemical modification of the fluid as it contacts various formations on its way to the surface. Depending on the mud type, contaminants such as solids, salts, cement etc. will have a general impact on the drilling fluid additives. The contaminated mud returns may have high funnel viscosities, increased gel strength and damaged filtration properties leading to an increase of the frictional pressure loss along the flowpath. In addition, thermal degradation of drilling fluid additives for instance polymers can cause significant modifications of the fluid rheology. Generally, the gelling tendency is higher at lower temperatures as exhibited at the sea floor.

For an approximate calculation of differential pressure loss at pump start-up in a concentric annulus when the annular clearance is assumed to be small relative to the annular radii, the parallel plate approximation can be used (A. T. Bourgoyne et. al, 1986). Since the shear stress is greatest at the annular walls, this is where the initial fluid movement will occur. Equating the wall shear stress τ_w to the gel strength τ_g yields.

$$\frac{dpf}{dL} = \frac{2\tau_g}{\Delta R} \quad \text{Eq. 4}$$

As one can obtain from the equation, for a very narrow annular gap ΔR and high gel strength, the pressure peak will be largest. This also applies for small inner drillpipe or drill collar diameters.

4.3 Concept for Data Analysis

4.3.1 Data Extraction and Data Processing

Different measurements recorded at a frequency of 1 Hz during drilling operations conducted in Austria and Germany where available for the analysis. This high degree of operational detail is highly recommended as a significant portion of information during the pump start-up sequence might be lost at a lower acquisition frequency. Typically, the recorded drilling data time-series are quality controlled and are then available for further processing in a database.

As a first processing step, it was necessary to automatically extract individual pump start-up sequences as well as the corresponding pump off time from drilling data time-series. Further a stabilized pump pressure reading had to be obtained after the pumps have been brought up to full strokes in order to assess the magnitude of the pressure peak.

This has been achieved by using automated operations recognition (G. Thonhauser, 2004). The automated operations recognition system is based on different production rule sets which allow to transfer expert knowledge into logical statements, whereas every rule is defined by a condition part and a conclusion part (if *condition* then *conclusion*). The main intention of the system is to provide a tool to analyse the drilling performance and enhance standard reporting by utilizing certain mud logging measurements. Common drilling performance analysis is based on activity break downs captured in daily drilling reports. This implies some short comings for the accuracy of the analysis; (1) typically only operations between 15 and 30 min are captured and (2) the report will always reflect human observation and judgement. The sample by sample annotation of drilling data time-series generated by the operations recognition routine allows a better and more important precise calculation of different key performance indicators. Beside the availability of certain mud logging measurements, the accuracy also highly depends on the quality and sampling frequency of the data. A sampling frequency of 1 Hz with a lower limit of 0.2 Hz is highly recommended for the analysis of real-time data. A lower sampling frequency will significantly reduce the system's ability to detect certain operations for instance fast slip to slip connections.

As depicted in Figure 22, a weight to weight connection recognized by the system typically covers the required timeframe. By means of the resulting time stamp for the identified weight to weight connection it was possible to obtain the corresponding real-time measurements from the database. Other pump start-up sequences, for instance during running in hole are however not considered for further analysis. Measurements of the individual weight to weight data sets included: Timestamp, MDHole, MDBit, FlowIn, SPP, SPM1-3, RPM, ROP and MW. One benefit of extracting the whole weight to weight connection data rather than the specific pump start-up sequence was that already existing rules could be utilized.

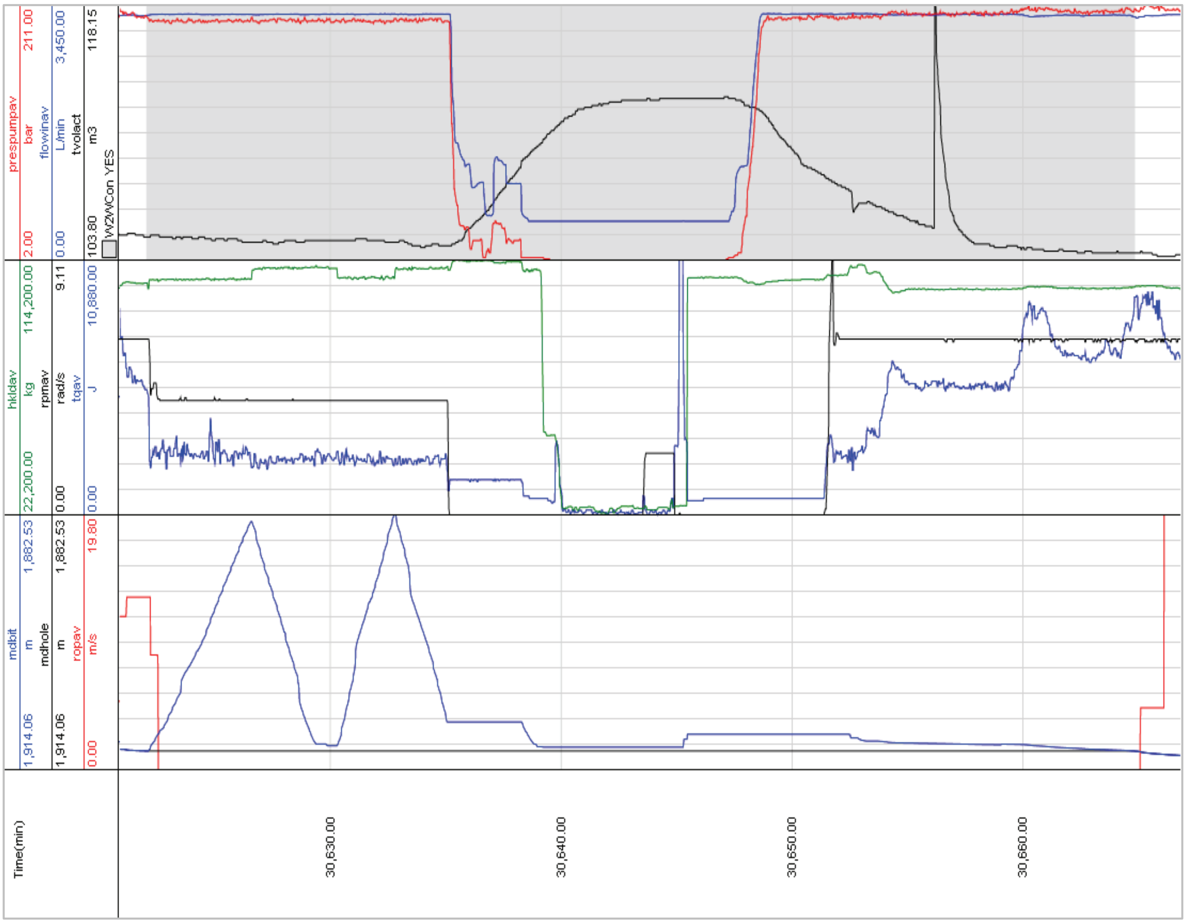

Figure 22: Extracted weight to weight connection

As a second processing step, the weight to weight data sets have been ordered by the measured depth of the wellbore and imported to MS Excel for further processing.

Figure 23 illustrates the significant parts of a general data sequence utilized in the analysis. The data sequence consists of a static period indicated in gold colour and the actual pump start up procedure indicated in turquoise colour. The static period is taken from zero strokes at pump shut in until pump start up. The actual pump start procedure is only taken until pipe rotations are initialized. This will ensure that pressure variations eventually resulting from pipe rotation are excluded. Also the bit is always off bottom as indicated by the difference between mdbit (lower blue line) and mdhole (lower black line). Insignificant portions of the data set e.g. the ream and wash operation prior to pump shut down have been manually removed from each sequence.

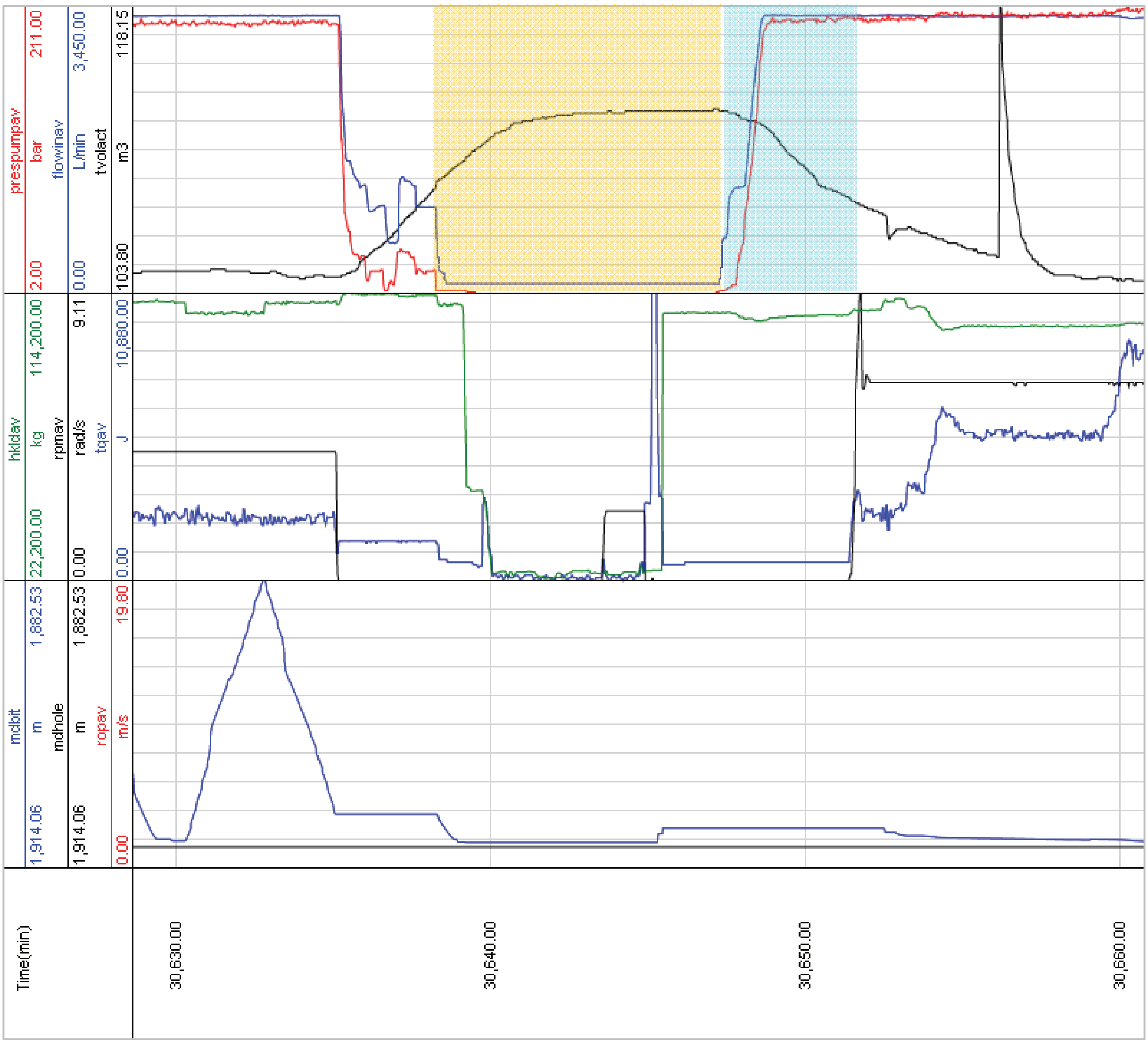

Figure 23: Pump Stat-up data sequence utilized for the analysis

4.3.2 Definition of Parameters characterizing Pump Start-up

As mentioned, several values had to be obtained to automatically characterize the extracted pump start-up sequences. In order to ensure consistent and automatic calculation respectively picking of significant values, a visual basic algorithm has been written in Excel. To cross-check and validate the individual values picked and calculated by the algorithm, a graphical data analysis of all data sequences has been performed. The analysis proofed the consistency of the algorithm.

The following explains how significant values describing a pump start-up sequence are picked respectively calculated.

4.3.2.1 Pump Off Time

The pump off time or static period is calculated based on total pump strokes i.e. from zero strokes at pump shut down to “one” stroke at pump start-up as illustrated in figure 23 through the corresponding timestamps. The output is an automatic allocation of pump off time to the corresponding data sequence.

4.3.2.2 Maximum Pressure

The maximum pressure encountered during pump start-up as indicated in figure 19, is picked by Excels “maximum” operation and again automatically allocated.

4.3.2.3 Stabilized Pressure

As stated, a stabilized or constant pressure value had to be obtained for each data sequence in order to assess the magnitude of the pressure peak. The stabilized pressure value was taken as the average of the last 60 measurements at the end of each data sequences.

4.3.2.4 Pressure Peak

The pressure peak is the difference between the maximum and the stabilized pressure value.

4.3.2.5 Pump Start-up Procedures and Stroke Increments

The graphical analysis of stroke increments versus time during individual pump start-up sequences taken from several wells showed that essentially three different pump start-up procedures can be defined. Figure 24 is a representation of the three different procedures or types.

A type 1 pump start-up (red line) is reflected by a pretty sharp increase in total strokes.

A type 2 pump start-up (green line) is reflected by a stepwise increase in total strokes i.e. strokes are kept constant at an intermediate level for a certain time and are then increased to full strokes. This procedure can be considered as the most common way to start a pump. Typically strokes are increase to 80% of full strokes, then the survey is pumped and afterwards strokes are further increased.

A type 3 pump start-up (blue line) is reflected by a steady increase of total strokes. This is generally the most time consuming way to start a pump.

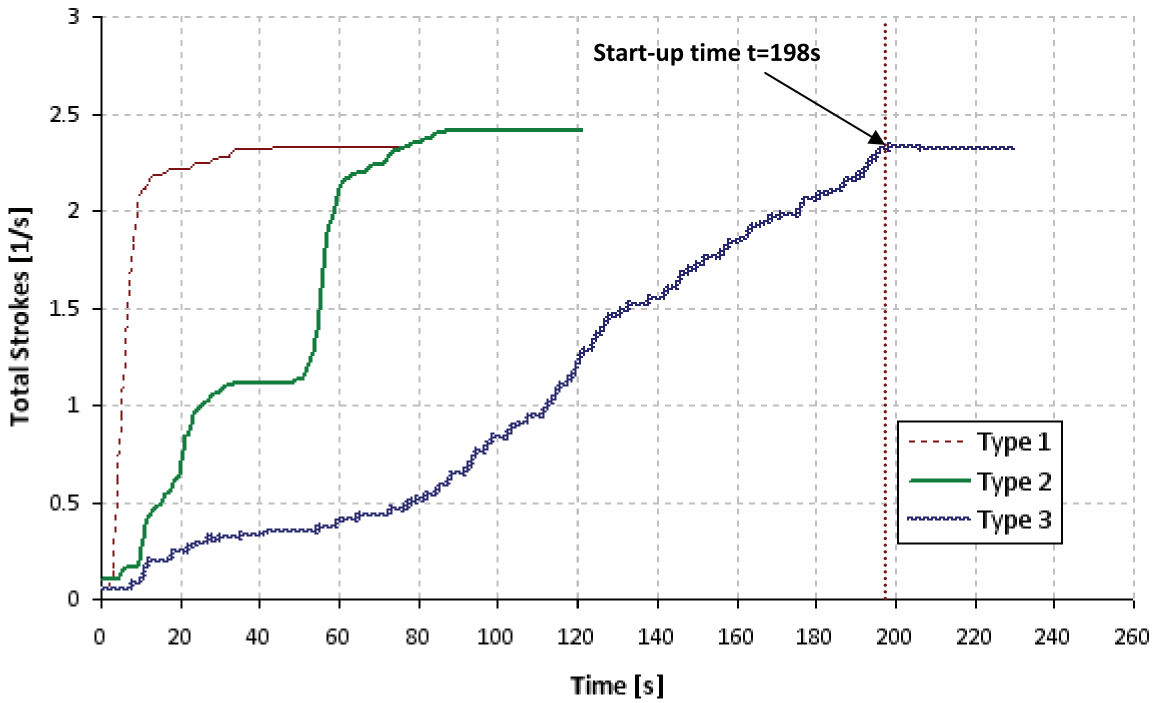

Figure 24: Main pump start-up procedures

To characterise the different pump start-up types by a single value, a new parameter has been introduced. This was necessary to allow an automatic classification of individual pump start-up sequence for the further analysis. In Equation 5, t denotes the pump start-up time i.e. the time required reaching full strokes and ΔTS denotes total stroke increments. Thus PA in Eq. 5 can be considered as a type of pump acceleration which is large in case of type 1, medium in case of type 2 and small in case of type 1.

$$PA = \frac{\int_t \Delta TS dt}{\int_t t dt} \quad \text{Eq. 5}$$

A suggestion of actual ranges for the three pump start-up types is summarized in table 1. These values have proofed to be the most appropriate ones for the data at hand. Accordingly, a type 1 pump start-up is characterized by a PA value above 0.05.

PA [1/s²]	**Type**
>0.05	1
0.02-0.05	2
<0.02	3

Table 1: Recommended values for PA parameter

4.3.3 Additional Information Requirements

As discussed, additional information concerning mud properties and wellbore geometry are necessary in order to allow a correct analysis of the data.

4.3.3.1 Geometry

Information about bit runs and corresponding wellbore geometry, drillstring geometry, casing setting depths etc. was obtained from morning reports. This was done manually.

Individual pump start-up sequences should be allocated to their according bit runs. Comparing only pump start-up sequences from the same bit run makes the result more meaningful since except from hole depth and eventually mud properties, parameters of the system e.g. annular clearance, BHA components, bit nozzle size etc. stay essentially the same. However, local variations in annular clearance, e.g. washouts are not considered.

4.3.3.2 Drilling Fluid Properties

Mud type, mud weight (MW), yield point (YP), plastic viscosity (PV) and 10s/10min gels have been extracted and manually from morning reports and prepared as table 2 indicates. Generally it is difficult to obtain these parameters automatically, since even within the same company the format of morning reports can be different. Additionally, information concerning the rheology is pretty coarse, since mud properties are only reflected by single measurements taken twice a day. Hence it is not possible to react to changes in real-time.

MD Hole [m]		MW [kg/l]	Plastic Viscosity [cp]	Yield Point [lb/100sqf]	10min Gels [lb/100sqf]
896	990	1.13	11	24	9
990	1205	1.12	11	24	6
1205	1316	1.12	11	24	5
1316	1518	1.11	11	25	8
1518	1691	1.14	15	27	7
1691	1779	1.16	16	24	8
1779	1961	1.15	15	24	7
1961	2076	1.14	14	23	7
2076	2198	1.14	16	25	6
2198	2283	1.15	17	23	6
2283	2418	1.15	16	22	6
2418	2552	1.15	15	21	5
2552	2687	1.15	14	20	5
2687	2759	1.15	17	21	6
2759	2828	1.18	19	24	6
2828	2955	1.22	20	25	7

Table 2: Drilling fluid properties extracted from morning reports

4.3.3.3 Temperature

Information about the mud temperature or thermal gradient of the formation could not be obtained from morning reports or real-time measurements.

4.4 Interpretation of Test Data

In order to evaluate the analysis concept, a data set of a vertical 4000m well was used. Consecutive screenshots showing real-time data all reefer to this well, called 'Well A' throughout the chapter. Data was missing from 1062 to 1287m MD and from 2024 to 2165m MD. A total of 117 pump start-up sequences and corresponding parameters have been extracted from well A. The extracted values have been summarized within the appendix section.

Figure 25 illustrates the frequency of pump start-up types and the corresponding pressure peak ranges. Generally, type 2 and 3 pump start-ups show the lowest pressure peak magnitudes. Whereas almost all of the type 1 pump start-ups are between 3 to 20 bars of magnitude.

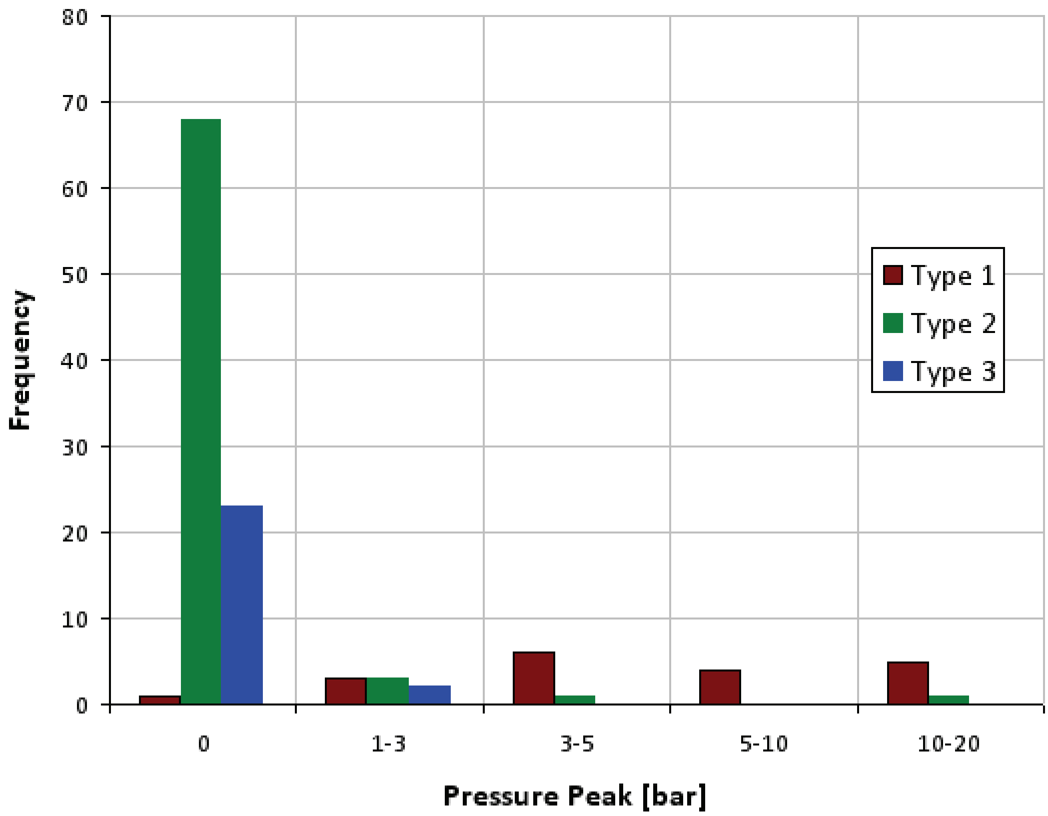

Figure 25: Frequency of pump start-up types

4.4.1 Drilling Fluid Properties

A KCO_2 polymer drilling fluid was utilized during the drilling process of Well A. Variations of mud weight, yield point and 10min gel strength over measured depth are illustrated by figure 26 and figure 27.

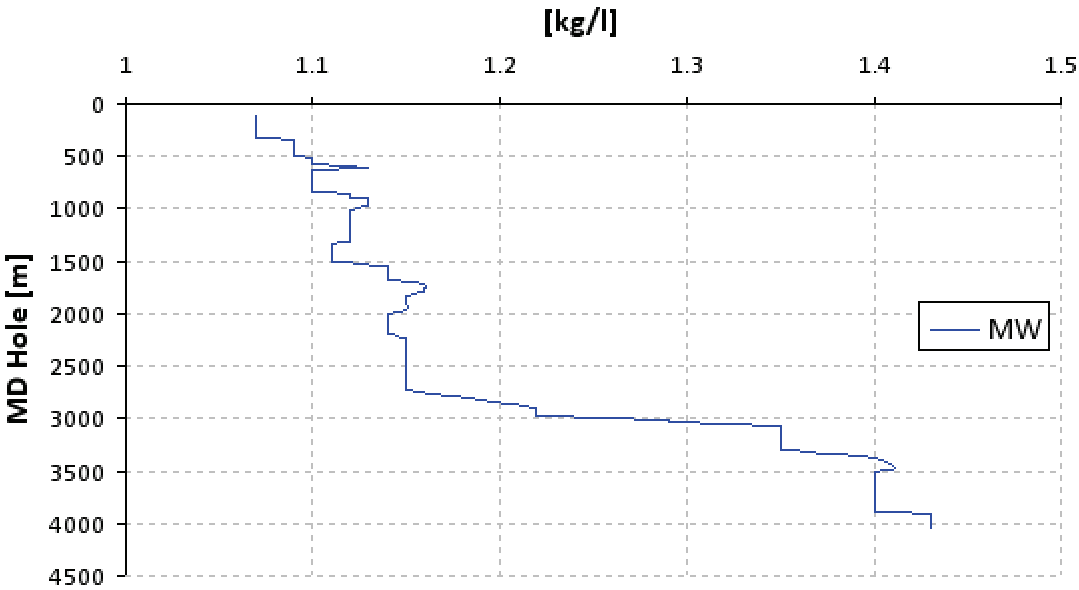

Figure 26: Mud weight versus MD Hole

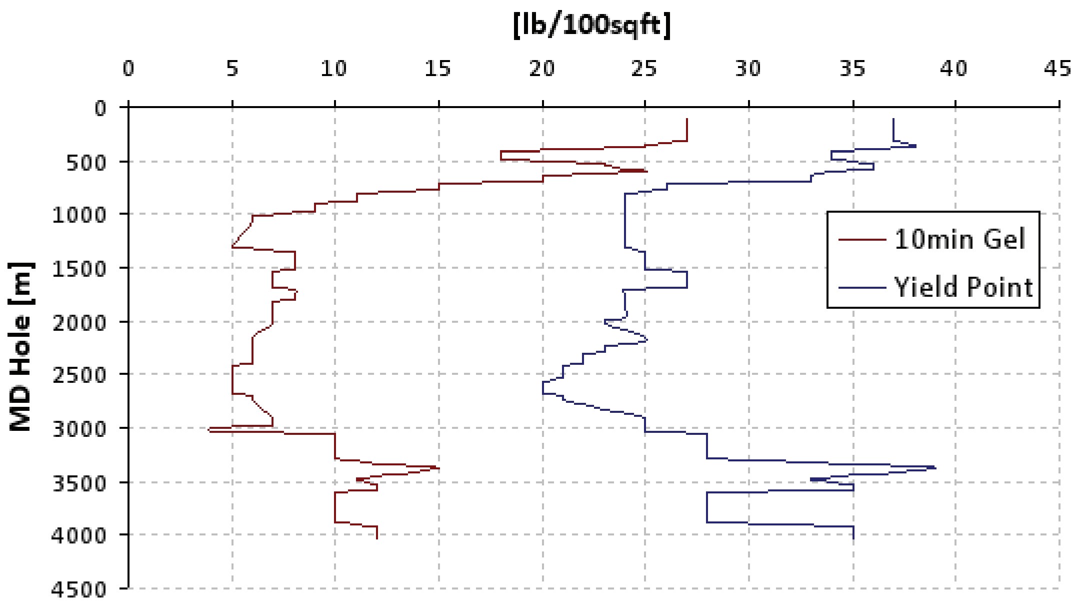

Figure 27: Gel Strength and Yield Point versus MD hole

4.4.2 Cross Plots

One step towards defining an automated analysis methodology is to use various cross plots of significant parameters in order to enhance understanding of the data set at hand.

4.4.2.1 Delta P versus Measured Depth

Figure 28 depicts the behaviour of the pressure peak over the measured depth (MD Hole). In the plot the three different pump start-up types are depicted by different colures and dot styles. Generally, dependence towards larger pressure peaks with increasing MD hole can be observed for a type 1 pump start-up. This may be related to the smaller annular clearance, increasing mud weight and gel strength (refer to Figure 26 and 27) as depth increases.

Type 3 pump start-up procedure exhibit no peak over the whole depth except of two cases, which couldn't be further specified.

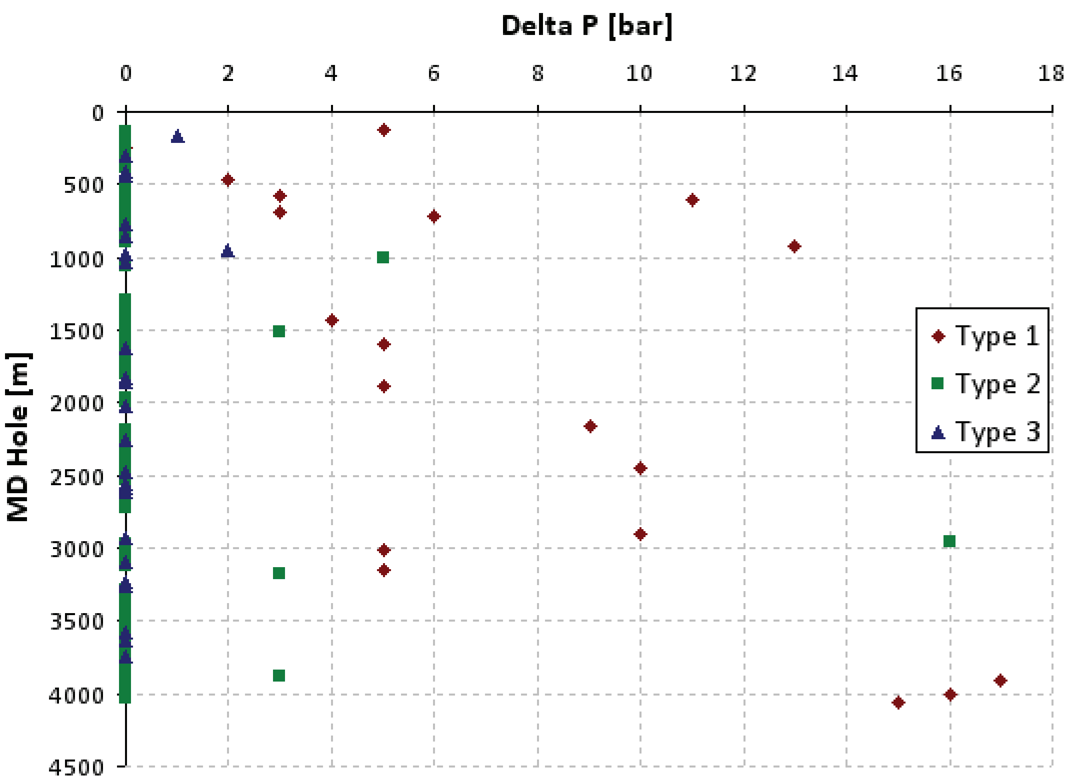

Figure 28: Delta P versus MD Hole

4.4.2.2 Delta P versus Pump Start-up Time

Generally, type one pump start-ups exhibit a decreasing pressure peak towards slower pump start-up. The five cases where a pressure peak was exhibited during a type 2 pump start-up may be related to the shorter pump start-up time i.e. time required to bring the pump to full strokes. Figure 29 plots delta p versus pump start-up time indicating a pump start-up time below 60 seconds for theses cases which is generally faster than the usual type 2 pump start-ups.

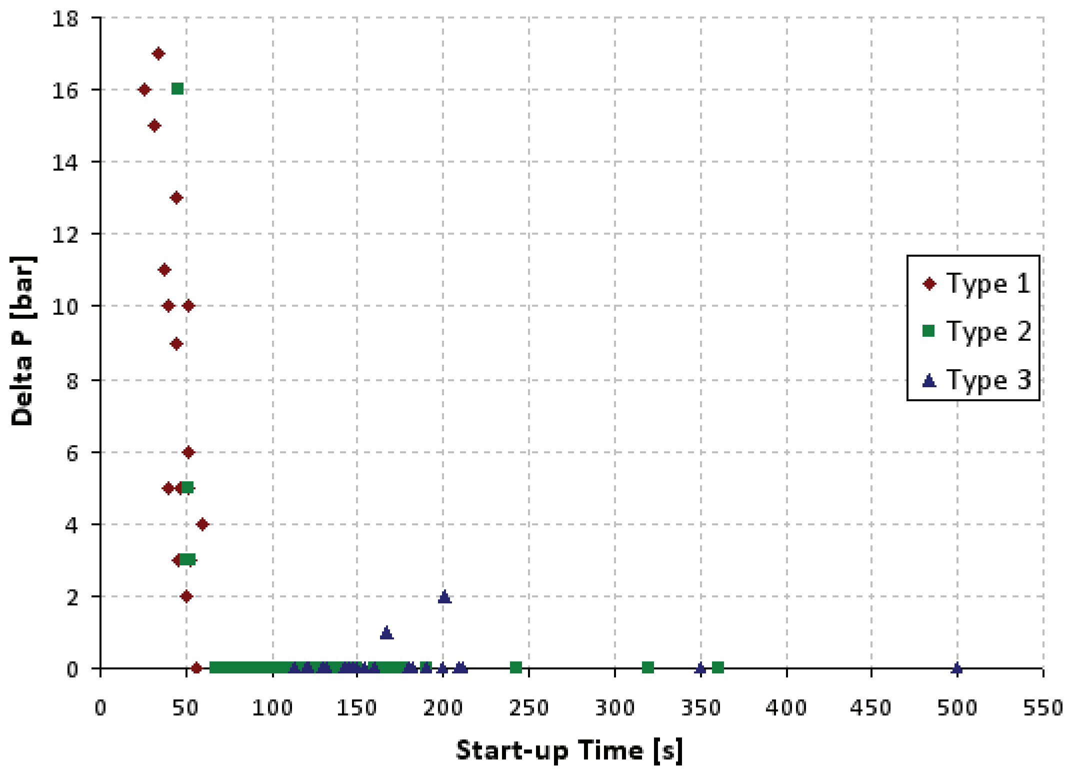

Figure 29: Delta P versus pump start-up time

Figure 30 presents one case where a type 2 pump start-up has been performed within 45 seconds. Additionally, the pump off time of 18min was pretty large. The resulting pressure peak has a magnitude of 16 bars. One interesting feature is the smaller pressure peak at around 30 seconds. A similar behaviour at intermediate strokes could be observed for almost all type 2 pump start-up sequences, which may be related to initial gel breaking.

Further a delay of around 20 seconds can be observed until the pressure responds to an increase in total strokes at the beginning of the pump start-up sequence. Similar delays, ranging from 8 to 20 second could be observed for other sequences.

Possible reasons for this delay may result form the drilling fluids compressibility and the distance between the stroke counter and standpipe pressure sensor. However this could not be verified.

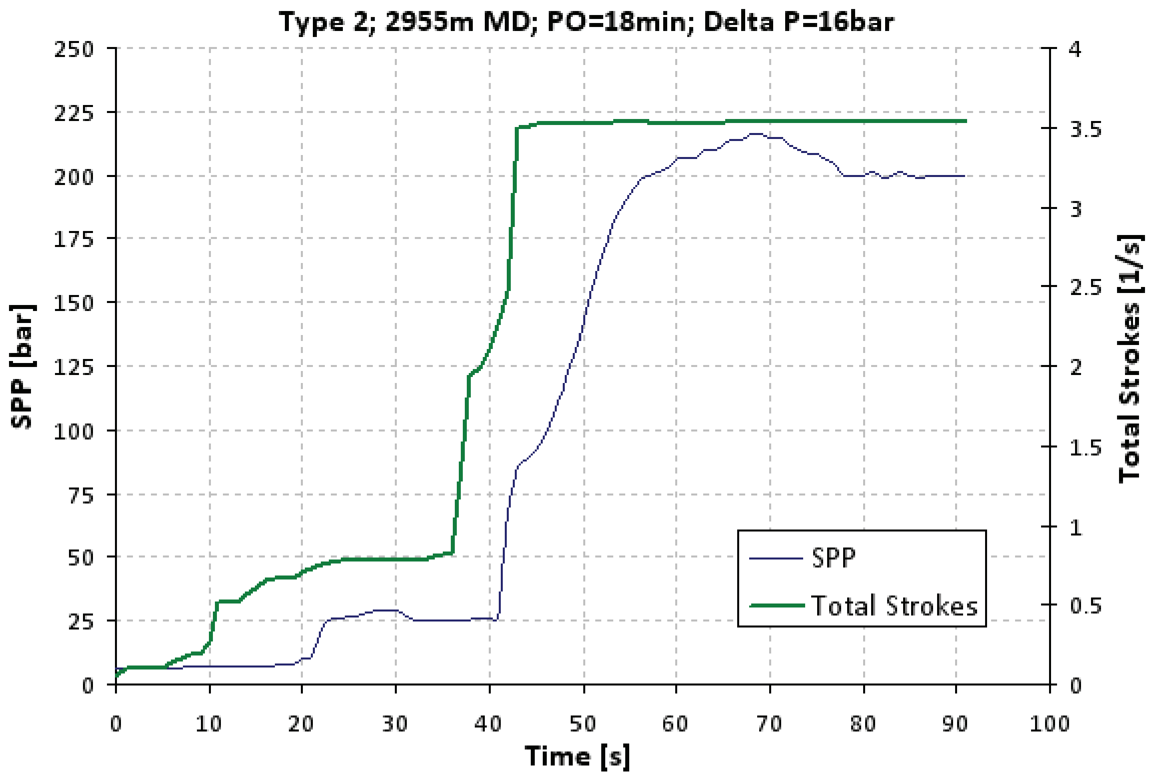

Figure 30: Example case for type 2 pump start-up

However a clear relationship cannot be obtained from the data. Additionally variations in gel strength resulting form longer static periods also need to be considered.

4.4.2.3 Delta P versus Pump Off Time

As discussed, another important parameter to consider is the time the well has been under static conditions prior to pump start-up. Especially, in vertical wells this parameter will have the most influence on the magnitude of the pressure peak.

Figure 31 illustrates the pressure peak versus pump off time for the data at hand. A relationship towards larger pressure peaks with increasing pump off time can be observed.

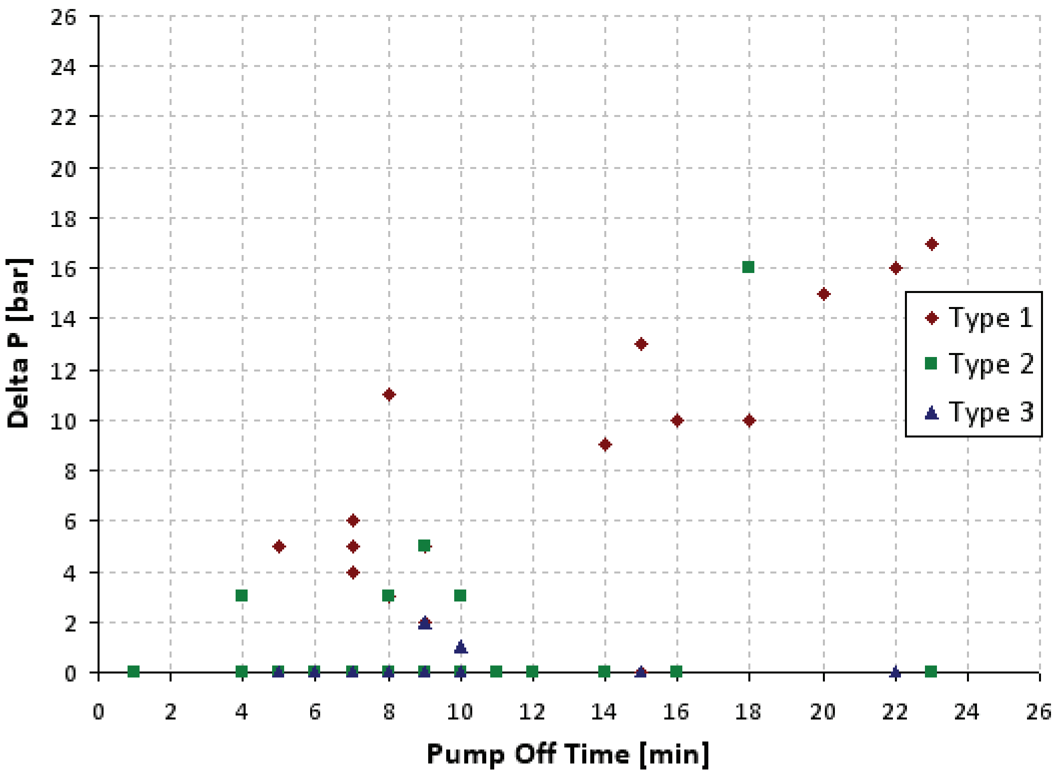

Figure 31: Delta P versus Pump Off Time

4.4.3 Concluding Remarks

For the data at hand, type 1 pump start-ups exhibit the highest pressure peak magnitude. Certain dependence towards larger pressure peaks with increasing pump off time can be observed. The largest pressure peaks resulted from the combination of a fast pump start-up, generally below 50 seconds and a pump off time larger than 18min. The analysis clearly proofed that type 1 pump start-ups should be avoided at all cost.

Type 2 pump start-ups above 60 seconds start-up time exhibited the lowest pressure peak. The additional time spend to start the pumps in case of a type 3 procedure don't lead to a benefit in terms of minimization of pressure peaks. It can be concluded that for the data at hand a type 2 pump start-up performed between 60 and 80 seconds is the optimal way to start a pump and results in the lowest possible pressure surge regardless of pump off time.

Apart from the smaller impact on the formation due to a reduced pressure surge an optimal pump start-up also has the potential to avoid hidden lost time. Figure 32 compares a type 2 pump start-up performed within 67 seconds and a type 3 pump start-up performed within 200 seconds. The difference in measured depth is only two stands and pump off times are also similar. Hence similar mud properties i.e. gel strength, mud weight etc. and geometry can be assumed.

For this case the difference in pump start-up time is roughly around 2 minutes. Considering the vast number of pump start-ups during the drilling process of a well there is a significant savings potential resulting form the optimization of pump start-up procedures.

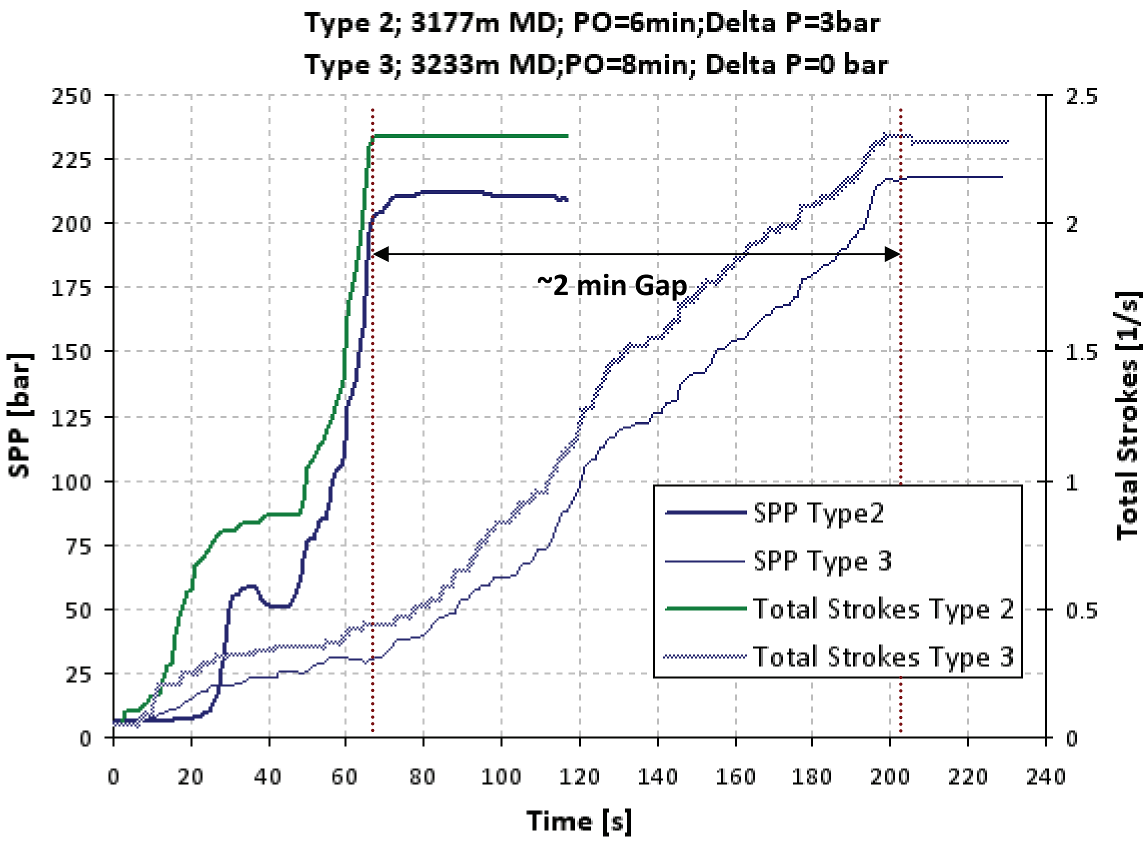

Figure 32: Comparison between type 2 and type 3 pump start-up

4.5 Concept for Data Visualization

As no common methods existed for visualizing the hydraulics during the pump start-up process, a novel concept had to be designed with the main objective to keep it as simple and user friendly as possible. This was essential since the driller is usually the one starting the pumps and required to work with it.

The graphical interface of the concept is presented by Figure 33. BHA run number two of well A is utilized for the presentation. The depicted plots have been manually prepared and are not available in real-time at this time of the concept development stage.

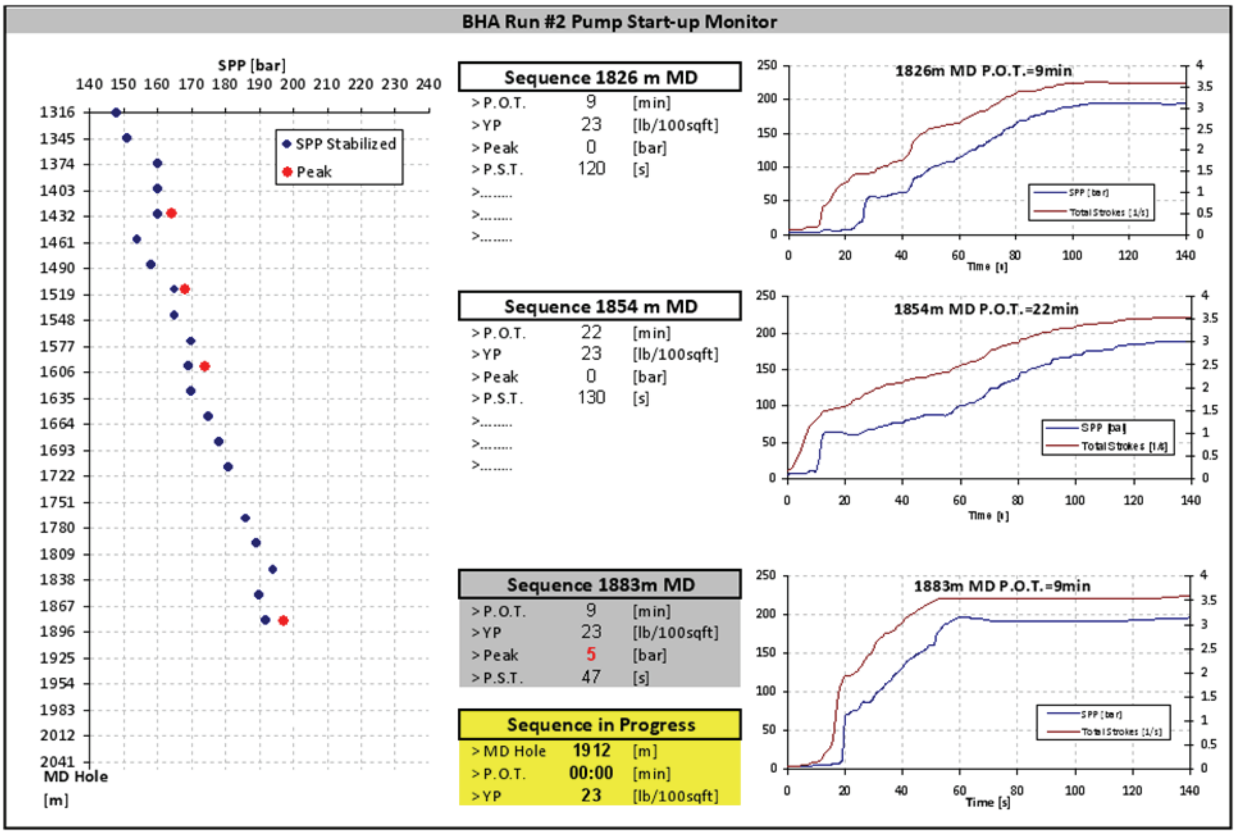

Figure 33: Pump start-up monitoring screen

A pressure versus depth plot on the left side of the screen summarizes the history of stabilized (blue dots) and maximum (red dots) pressures in order to provide the user with a general overview of the pressure development and the frequency of pressure peaks within one BHA run.

On the right side the history of the last three pump start-up sequences is summarized, providing a reference for the start-up sequence being in progress depicted by the yellow box on the bottom. Corresponding parameters including pump off time (P.O.T.), yield point, the pressure peak and the pump start-up time (P.S.T) are displayed in the middle of the screen. Additional parameters might be further specified by the user.

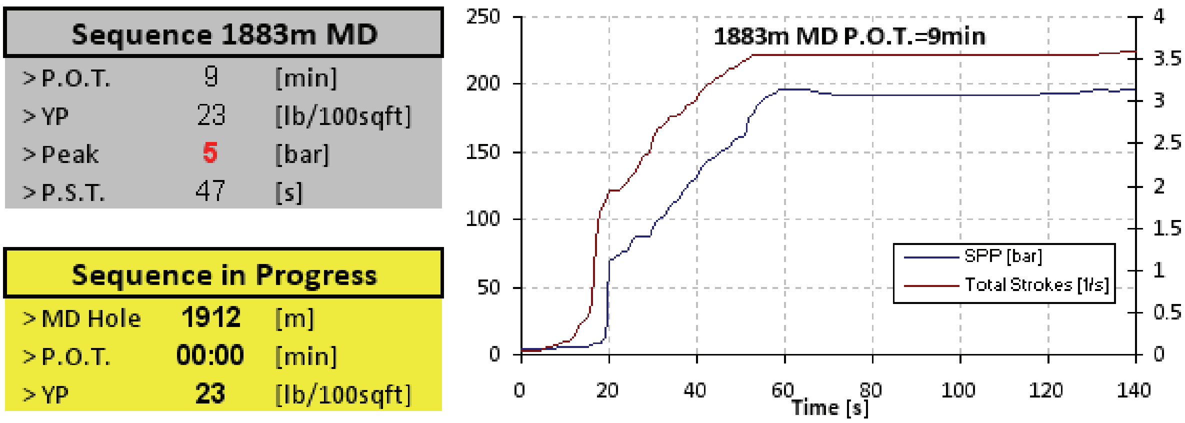

Figure 34: Detail of the pump start-up monitoring screen

The history will update itself as soon as the pump start-up sequence being in progress has actually been performed. As depicted by Figure 34, pump off time of the sequence being in progress is indicated by a clock starting at pump shut in. Additional information regarding the current MD hole, yield point etc. is also provided. The graphical representation of the previous pump start-up sequence allows to asses the pressure response in relation to a certain pump start up procedure. In this way, the driller is able to act on the information generated by comparing important parameters of the sequence currently in progress with previous pump start-ups. A general way, to start the pump is however not stipulated and will be left to the drillers experience and ability to interpret the data provided by the system.

5 Automated Kick Detection During Drilling

5.1 Purpose and Objective

The presented concept was developed to provide automatic detection and verification of an imminent kick during drilling with the objective to keep the number of false alarms low while maintaining the required sensitivity to allow an early detection. Reviewing different detection approaches within chapter 3 showed that monitoring changes of the return flowrate in relation to the flowrate into the well is generally the fastest way to detect an imminent kick situation. Hence the main intention was to utilize these channels rather than the active tank volume. Further, the system had to be able to work with data generated from paddle meters as they are the most common type of return flowrate sensors on the rig. Also transient flow effects resulting from axial pipe movement and pump start-up had to be taken into account to reduce the number of false alarms.

5.2 Concept for Kick Detection

As mentioned, during a kick situation a ramp of the return flowrate can be observed while the flowrate into the well remains fairly constant. Commonly, a kick is detected by comparing the difference in flow with an absolute threshold value. This however requires a calibrated measurement of the return flowrate and frequent adjustment of the absolute threshold value.

5.2.1 Flow Derivative

To overcome these short comings a new channel, essentially a normalized first derivative of both flow in and flow out measurements has been introduced. The detection approach based on a slope change rather than an absolute change of return flowrate implies that the physical behaviour of the circulation system during a kick situation is taken into account.

A two point slope is calculated by applying a sliding time window, which acts as a data buffer, on the time-ordered measurements of the WITS channels ‘Flow In Pump’ and ‘Flow Out’. A value of 10 seconds has been utilized for the sliding time window size as default. Generally, the size of the sliding window can be manually specified in an input sheet however data buffers larger than 10 seconds are not recommended as the detection will be further delayed.

5.2.1 Implemented Detection Routine

The detection routine is based on the automated operations recognition system described in the previous chapter and also utilizes certain rules defined by logical statements to detect a kick during drilling. Detection is still based on a single slope threshold value, however this value is now a better representation of a kick situation as it reflects the ramp up of return flowrate rather than a step change.

Generally, a kick will be detected if the slope change of the return flowrate is above a general slope threshold value ‘A’ specified in [lpm/s], while the slope of the flowrate into the well remains zero. To account for variations of the flowrate into the well resulting from the reciprocating pumping action a windowed threshold has been introduced i.e. a zero flow in slope is valid within a range of +/- 2 [lpm/s].

As mentioned in chapter 3, pipe movement during reaming operations prior to a connection and the lag between flow in and flow out during pump start-up can create a system response similar to a kick. Hence these effects had to be included in the detection routine to reduce the number of false alarms generated by the system.

To account for transient flow effects resulting from pipe movement the detection routine is automatically switched off as the on bottom state of the bit (Mdhole - Mdbit > 0.3m) is violated. The existing “on bottom” OPRec rule has been utilized for this purpose. However, this implies that a kick can only be detected during drilling.

To account for transient flow effects during pump start up, an absolute flow in threshold value was introduced. The detection routine is automatically switched off if the absolute value of the channel ‘Flow in Pump’ is below this threshold until the slope of 'Flow in Pump' is zero again and steady state drilling is re-established. Generally, the parameter can be manually specified, however a value of 10 [lpm] seemed to be most appropriate according to the data set used.

A decision tree is a good way to visualize the various logical statements. The one illustrated by figure 35 summarizes the general detection routine carried out by the system.

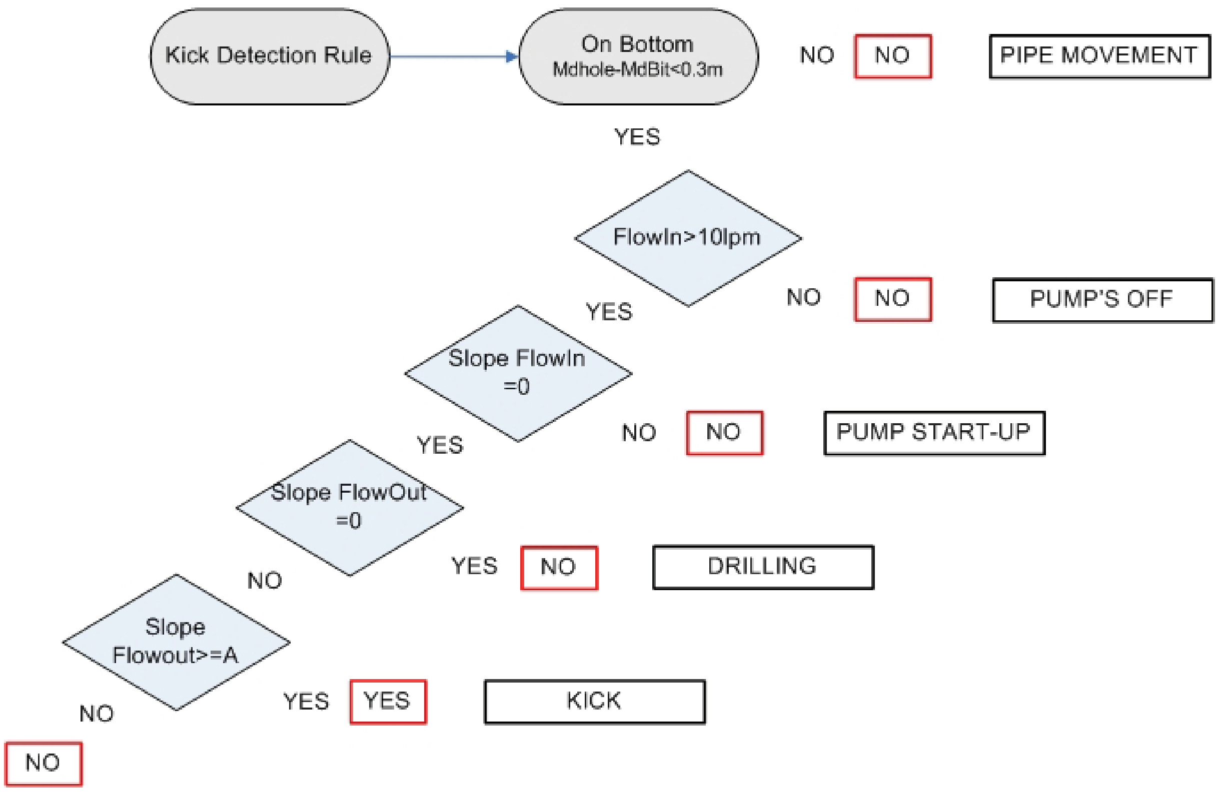

Figure 35: Decision tree for kick detection

5.3 Proof of Concept

In order to provide a proof of concept the system has been tested on historical real-time data acquired at frequency of 1 Hz of a vertical 1600m well. Consecutive screenshot showing real-time data all reefer to this well, called 'Well B' throughout the chapter. Out of the available real-time data this was the only well which included a flow out measurement and one reported kick situations at 1508m. The measurement of the return flowrate was available in liters per minute but hasn't been calibrated according to the flowrate into the well. The resolution i.e. the smallest recorded increment of the return flowrate measurement is 0.1 liters per minute.

5.3.1 System Output during a Kick

Figure 36 depicts the systems output during an initial test carried out a slope threshold value 'A' of 0.1 [lpm/s]. The kick detection state is switched on, indicated by the "CircProblemsDetection Kick" icon in the header of the right track.

As indicated by the horizontal red dotted line the flow out measurement (right green line) starts to deviate from a stabilized value at 10:02:30 while the flow in measurement (right blue line) stays constant at a value of around 2060 lpm. This time will be used as a reference time for further assessment of the sensitivity of the system through out the chapter as it represents the earliest possible time to detect the kick.

The system detected the kick at 10:02:22 outlined by the green bar on the right track, resulting in a reaction time of 52 seconds taken from the reference time.

In the morning report an influx of around 1m³ was stated. Active tank volume (right black line) started to increase at around 10:04:00, however in order to observe this a very small scale is required. The well was finally shut in at around 10:05:02 indicated by the horizontal dashed blue line, hence the crew required a reaction time of around 2:26 min to detect and shut in the imminent kick. From this time 15 seconds may be subtracted to account for the time required to close the preventers.

Hence, at a slope threshold value `A` of 0.1 lpm/s, the system was able to detect the kick 85 seconds before the crew.

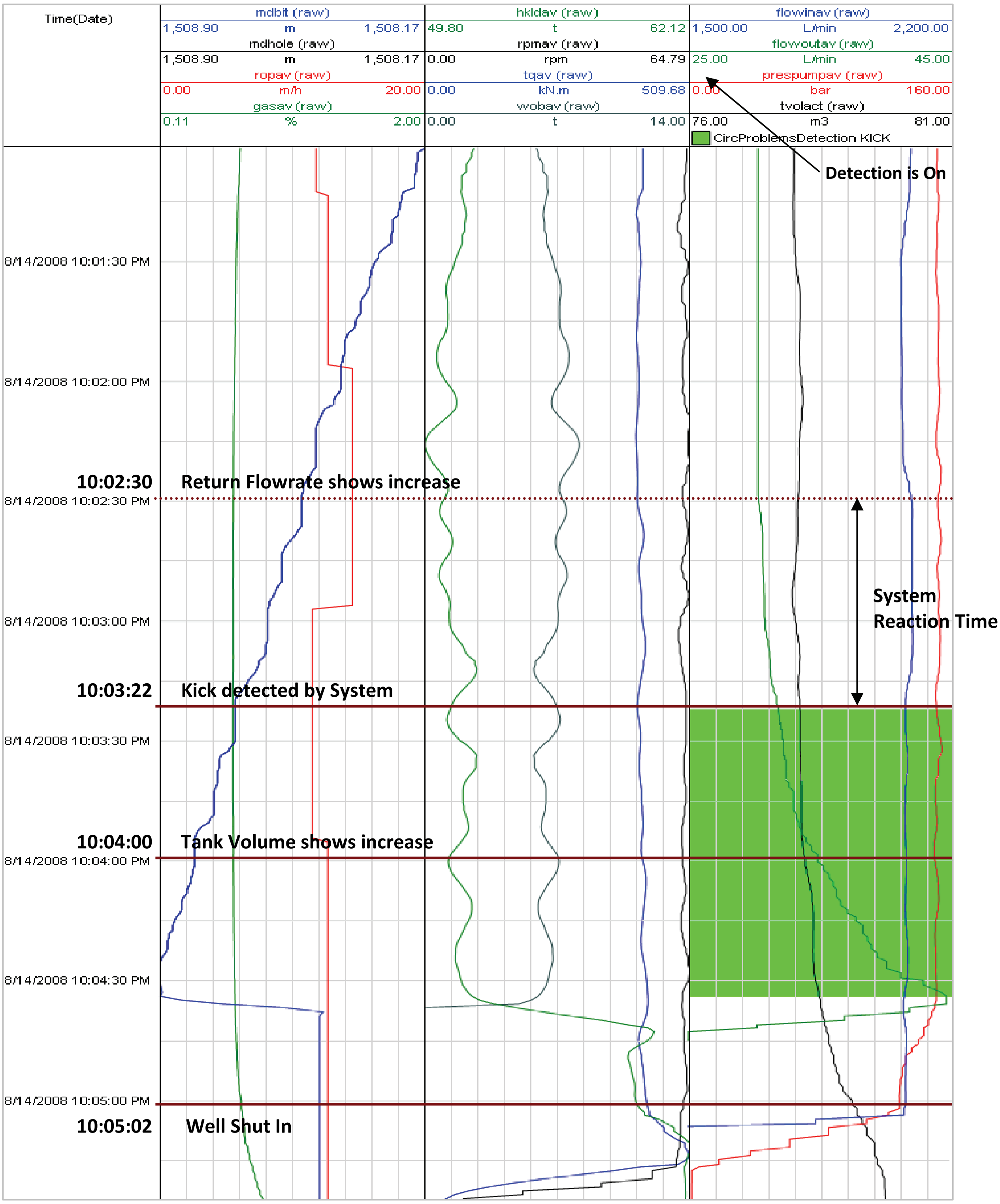

Figure 36: Kick detected at a slope threshold value of 0.1 lpm/s

5.3.2 Monitoring through Connections

Figure 37 depicts the system output during axial pipe movement followed by a connection and consecutive pump start-up. The green icon again shows that the kick detection system is switched on. As indicated by the vertical dotted red lines, the flow out measurement (upper green line) exhibits a decrease as the drillstring is moved up and a corresponding increase when the pipe is moved down again while the flowrate (upper blue line) remained constant. The system successfully monitors through this transient flow period without raising an alarm. As the pumps are turned on again another transient flow period is exhibited as indicated by the two vertical blue dashed lines. Again, no alarm is raised by the system.

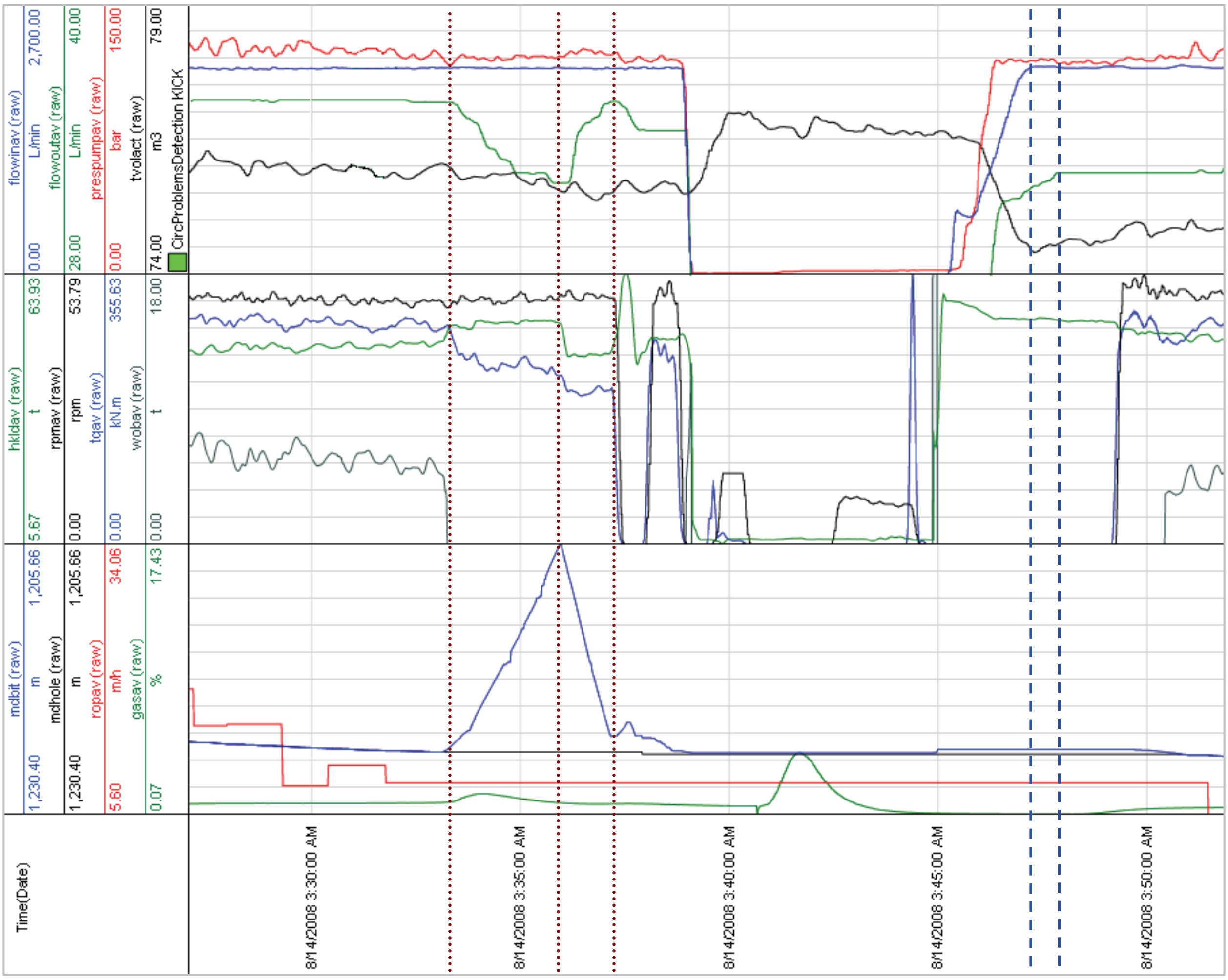

Figure 37: Monitoring through connections

5.4 Sensitivity Analysis

5.4.1 False Alarm Rate

Generally, it is possible to develop an arbitrarily sensitive detection system, but it may generate several hundred false alarms per day. Therefore, to evaluate the systems sensitivity in context of false alarms, several tests have been performed at different slope threshold values over a depth interval of roughly 600 meters drilled within around two days. The reaction time of the system during the particular test has been utilized as a measure of sensitivity. False alarms for each test have been plotted versus the given depth interval of the hole to obtain the total number of false alarms. As indicated by the vertical green lines in figure 38, a total of 23 false alarms false have been generated by deploying a threshold value of 0.1 lpm/s resulting in a reaction time of 52 seconds.

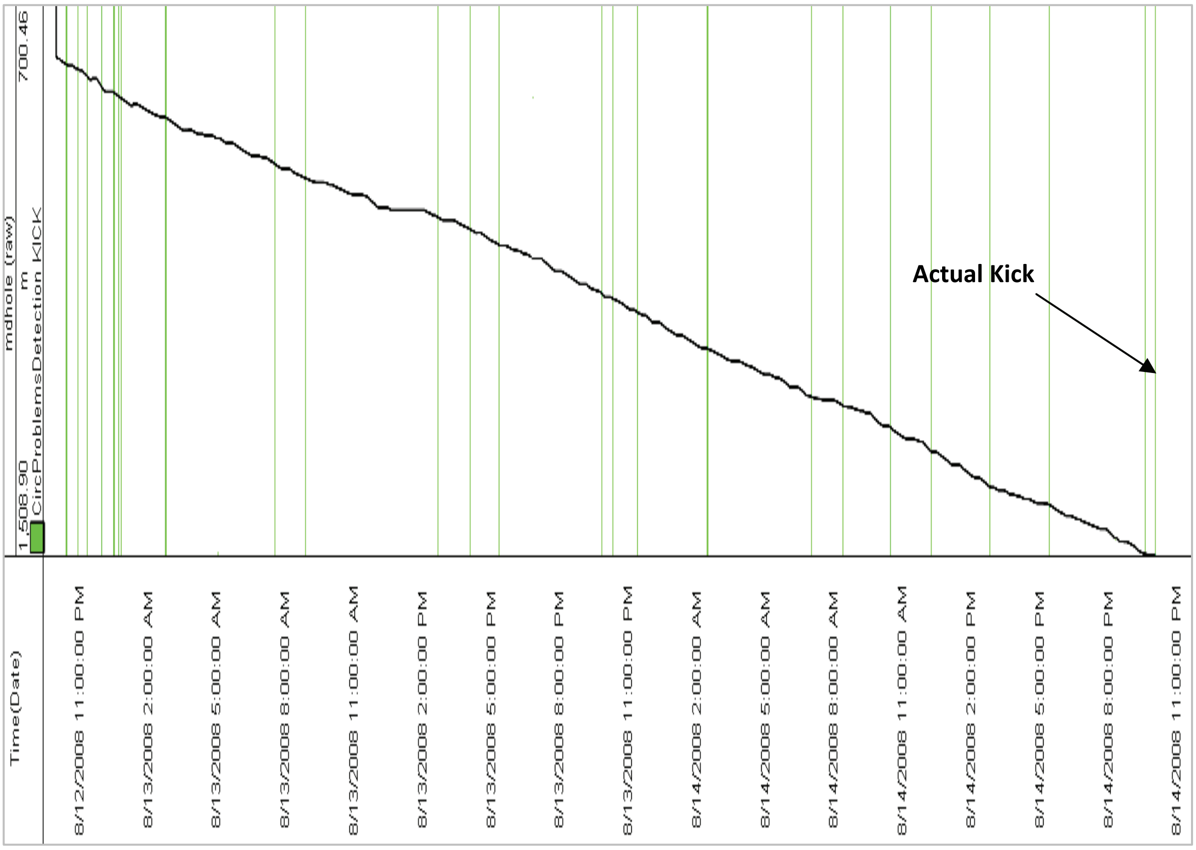

Figure 38: False alarms versus measured depth

The result of the analysis has been summarized by table 3. As indicated by the table threshold values larger than 0.6 [lpm/s] did not lead to a detection of the kick at all. This can be explained by the small incremental changes of the return flowrate resulting from the generally small and slow influx. Threshold values in the range of 0.3 to 0.4 [lpm/s] seem to be the most appropriate ones for the data at hand, resulting in a false alarm rate of 5 alarms per day.

Slope Threshold 'A' [lpm/s]	Reaction Time [s]	# False Alarms [-]	Difference to Crew [s]	False Alarm Rate [Alarms/d]
0.1	52	23	85	11.5
0.2	81	18	56	9
0.3	83	18	54	9
0.4	88	10	49	5
0.5	110	6	27	3
0.6	115	4	30	2
0.7	n.a.	0	n.a.	0
0.8	n.a.	0	n.a.	0
0.9	n.a.	0	n.a.	0
1.0	n.a.	0	n.a.	0

Table 3: Results of kick detection sensitivity analysis

Detail analysis of the individual alarms showed that a majority of the false alarms resulted from real rises in return flow rate.

Figure 39 shows a false alarm resulting from disturbed flow after a connection conducted at around 10:05:00. An alarm is raised at around 10:18:00 indicated by an increase in the return flowrate. The rather large gas peak which can be observed on the total gas reading (bottom green) indicates a large volume of connection gas coming out of the wellbore which can be an indication of a developing kick situation. Also an increase in active tank volume (upper black line) can be noticed.

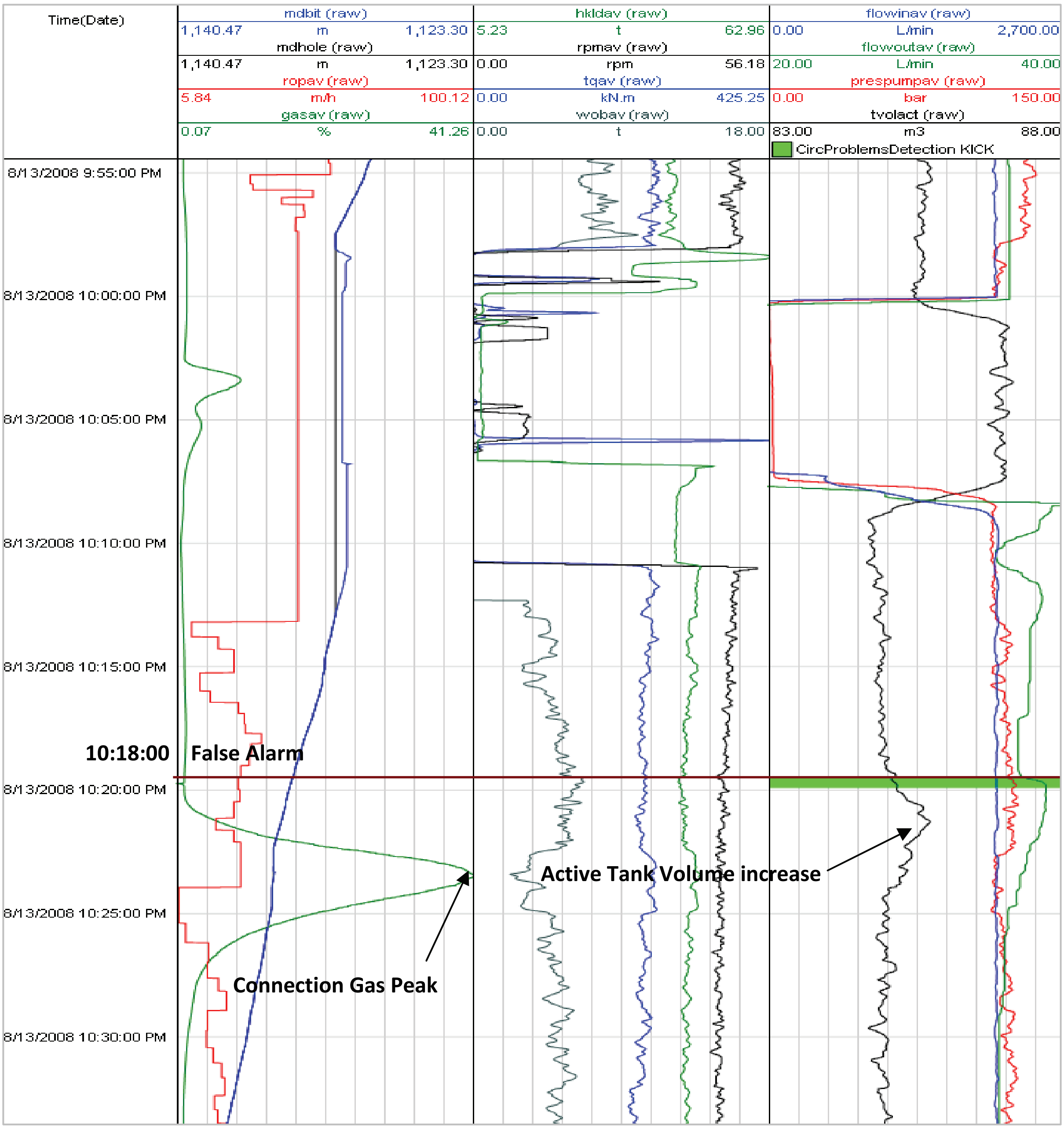

Figure 39: False alarm resulting from disturbed flow after a connection

Another example of a similar event which occurred around 25 min prior to the actual kick is presented by figure 40. A flow disturbance indicated by a sharp rise in the return flow rate (right green line) can be observed at 9:36:00. The actual kick was encountered at around 10:02. Prior to this event an increased rate of penetration (left red line) as outlined by the dotted black circle eventually indicates a drilling break which might explain the consecutive false alarm. An increased total gas reading after the false alarm is however not observed.

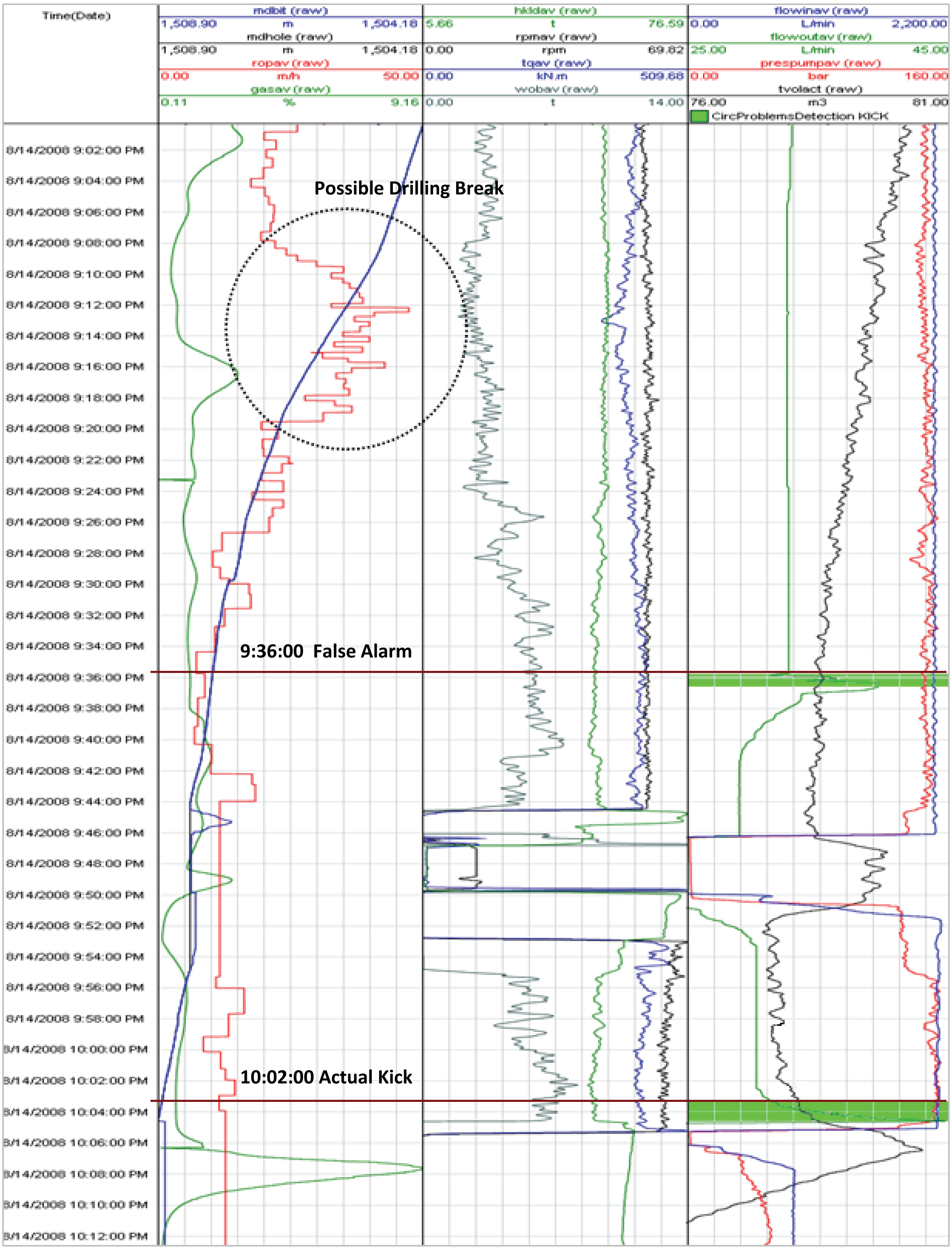

Figure 40: False alarm after drilling break

6 Concluding Remarks

6.1 Conclusions

A number of operational problems encountered during the drilling process impact the pressure and flow of the circulation system, two parameters essentially linked to real – time hydraulics monitoring. The initial analysis of hydraulics related problems clearly showed that similar variations of these parameters can be observed for different problems. Additionally, the lack of an accurate measurement of flow on most rigs, both into and out of the well, doesn't allow effective problem anticipation. Further, variations resulting from rheological modifications of the drilling fluid properties cannot be quantified in real-time as the measurement technology is not yet ready to be used in the field. All these circumstances make the real-time detection and verification of the actual problem a difficult challenge. One step towards defining an early problem recognition methodology by taking all available data into account has been made by the developed detection and verification trees. The summarized knowledge can be utilized in further automated problem detection applications.

Monitoring drilling hydraulics during pump start-up operations can be seen as one essential building block of real-time drilling hydraulics monitoring. Pressure surges obtained from the standpipe pressure measurement reflect a global impact on the whole circulation system, whereas the actual pressure exerted on to the formation during the start-up process remains unknown. However, minimizing the global pressure surge should also lead to smaller formation damage.

The outlined concept to display previous pump start-up sequences and corresponding parameters to provide a reference for the driller should result in a minimization of start-up time and pressure surge of the current sequence in the sense of an ongoing optimization process within one BHA Run. In this way lost and hidden lost time can be avoided. However this needs to be verified by field tests. Currently, the presented plots have been prepared manually and need to be transferred to a fully automated monitoring screen.

The developed automated kick detection concept has the potential to detect imminent kick situations during drilling faster than the drilling crew. No calibrated measurement is required for the implemented detection routine based on a slope change of the return flow rate which is an advantage compared to other systems. The visual warning generated by the system should be combined with an acoustical signal in order to improve the field applicability. Generally, a larger slope threshold value resulted in a decrease of the number of false alarms but at the same time the systems reaction time and hence the sensitivity was also reduced. The majority of false alarms could be related to real rises in the return flow rate. Not alarming such events by lowering the sensitivity is not practicable and would delay the detection of real events. However, false alarms resulting form data inconsistencies generated by the crude measurement still remain a problem. Generally, the rule based approach could be transferred to detect other problems based on the expert knowledge summarized in the developed detection and verification trees.

6.2 Further Work

To provide a full real-time hydraulics monitoring tool other building blocks need to be considered apart from the pump start-up block, they should include:

- Transient Hydraulics

As soon as the pumps have been brought up to full strokes and drilling is continued, the transient hydraulics block should provide a comparison between actual and simulated values of pump pressure and ECD versus the measured depth of the well. Important parameters, such as the fracture gradient of the formation and minimum cuttings lift velocity, should outline the optimal operating window for the current drilling situation.

- Surge and Swab

During tripping, control of the pipe moving speed in relation to drilling fluid properties and annular clearance is essential in order to avoid formation damage or kicks resulting from surge and swab effects. A comparison between the actual and the maximal allowable pipe moving speed for a given geometry and yield point in relation to the current position of the bit should be included in the surge and swab block.

- Automated Trip Sheet

During tripping, the volume of steel removed from the well must be replaced by an corresponding volume of drilling fluid in order to maintain a constant bottom hole pressure. However, the volume comparison is still done manually which often leads to kicks because of wrong calculations, omitted hole fill etc. The automated trip sheet should indicate the volume of steel based on string geometry and MD bit and visually or acoustically advice the driller when the wellbore actually needs to be filled again.

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Nomenclature

APWD	Annular Pressure While Drilling
BHA	Bottom Hole Assembly
DHM	Downhole Motor
DVT	Detection and Verification Tree
ECD	Equivalent Circulation Density
HPHT	High Pressure High Temperature
LWD	Logging while Drilling
MWD	Measurement while Drilling
MW	Mud Weight
P.O.T.	Pump off time
POOH-	Pulling out of Hole
PV	Plastic Viscosity
RIH	Running in Hole
ROP	Rate of Penetration
WOB	Weight on Bit
YP	Yield Point