

SPE/IADC-204041-MS

Automatic Drilling Fluids Monitoring

Knut Taugbøl, Equinor ASA; Bengt Sola, Matthew Forshaw, and Arild Fjogstad, Baker Hughes

Copyright 2021, SPE/IADC International Drilling Conference and Exhibition

This paper was prepared for presentation at the SPE/IADC International Drilling Conference and Exhibition to be held virtually on 8 - 12 March 2021. The official proceedings were published online on 8 March 2021.

This paper was selected for presentation by an SPE/IADC program committee following review of information contained in an abstract submitted by the author(s). Contents of the paper have not been reviewed by the Society of Petroleum Engineers or the International Association of Drilling Contractors and are subject to correction by the author(s). The material does not necessarily reflect any position of the Society of Petroleum Engineers or the International Association of Drilling Contractors, its officers, or members. Electronic reproduction, distribution, or storage of any part of this paper without the written consent of the Society of Petroleum Engineers or the International Association of Drilling Contractors is prohibited. Permission to reproduce in print is restricted to an abstract of not more than 300 words; illustrations may not be copied. The abstract must contain conspicuous acknowledgment of SPE/IADC copyright.

Abstract

The drilling fluid is the primary barrier against well control incidents when drilling a well in conventional mode and the drilling fluid properties must be correct at all times to prevent well control incidents. Automatic drilling fluid monitoring through automated measuring techniques combined with real time data transfer into control center with 24/7 surveillance substantially improves this control compared to conventional methods relying on manual measurements with long sampling intervals.

New measurement devices have been introduced to the industry which measure the drilling fluid properties of all fluid going into the well as well as fluid coming out from the well. Properties measured are among others density and a full rheology profile. The data are transferred to users on the rig as well as directly to onshore operation centers. This highly improves the fluid engineering, enabling a more precise diagnostician and treatment in real time. This also improves efficiency when performing displacements from one fluid system to another.

This paper will present new units for automatic drilling fluids measurements and its use in offshore drilling. The surveillance of fluid properties and the use of data at an onshore operation center will be presented. The drilling fluid properties are also detrimental for drilling parameters such as ECD (equivalent circulating density), surge and swab pressures and hole cleaning properties and the added data will improve any estimation of such parameters. The paper will present experiences from use of these data into advanced real time hydraulic measurements and models for automatic drilling control and explain how this can improve safety in the drilling operations as well as improve the drilling efficiency.

Introduction

Digitalization and automation of the drilling process are among the highest prioritized projects in the oil industry. Improved drilling efficiency, consistency and improved quality in all operations are all depended on higher degree of automation. Operators as well as drilling contractors and service providers have this on their prioritized agenda. The drilling fluid is the primary well barrier in conventional drilling operations. Under static conditions the well pressure is a function of the density of the fluid column. During drilling, tripping, running of casing the viscous properties of the fluid will highly influence the total pressures in the well. High viscosity of the fluid will give high ECD during drilling and high surge and swab pressure effects

during tripping. In addition, the fluid viscosity affects hole cleaning and cuttings and particle suspension characteristics. Having control at all times of drilling fluids density and viscosity parameters are therefore of highest importance in order to operate with full well control. The drilling fluids parameters are also important input to software in use for drilling optimization for automatic optimization of the drilling parameters.

Traditionally, the fluid engineer has controlled the drilling fluid properties by conducting four manual mud checks a day. The time between measurements, typically 6 hours, the fluid properties as input to software calculations are unchanged. This can cause errors in real time hydraulic calculations since the drilling fluid properties can drift in this period without being noticed by the engineers performing calculations.

Based on the analysis performed in the mud laboratory, the fluid engineer will decide the proper addition of chemicals and materials to adjust the fluid properties to the desired specifications. This limited number of tests often results in reactive treatments to bring fluid properties back into specifications, often resulting in large dilutions and chemical consumptions. Drilling with water-based fluid in large diameter, long hole sections has proven to be especially challenging with respect to fluid optimization with this limited number of analyses. By introducing automatic fluid measurements with sampling frequencies down to minutes, where results are monitored by trained engineers in onshore centres, the fluid properties can be adjusted and controlled continuously during the drilling process. This can help ensure more consistent fluid properties and better quality throughout the drilling process, requiring fewer heavy dilutions and reduced chemical consumptions. It will also improve the accuracy of real time hydraulic calculations performed.

An operator has worked with different suppliers for several years to find and develop technology for automatic measurements of drilling fluid properties. Methods for measuring parameters like viscosity, fluid loss control, pH, electrical stability, particle size distribution, and cuttings morphology and mineralogy were all fitted into a flow loop in an onshore test center to demonstrate its potential. This work was presented in papers SPE-107547 (Omland et al. 2007) and SPE-112687 (Saasen et al. 2008). However, these tests were all performed with prototype equipment. Since then, work has been ongoing to optimize equipment for offshore installations, made for operating in harsh environments, and requiring limited maintenance to provide continuous and reliable data quality. The first field use and plans for field implementation of these type of technology has previously been presented in two papers (Taugbøl et al. 2019)

In this paper a service provider and an operator will present experiences from use of data from automatic drilling fluids measurements in the daily drilling operations. The data presented will demonstrate its use in the fluid surveillance, ensuring improved fluid quality, as well as the use of data into advanced hydraulic calculations, improving the input into autonomous drilling control.

Methods for measuring density and rheology of drilling fluids

The standard methods for drilling fluid analysis are presented in API 13B. The requirements are defining procedures for measuring density and rheology based on collecting a sample of the drilling fluid and manually analyse this drilling fluid sample in a drilling fluid laboratory on the rig. The two most important drilling fluid properties are density and rheology. Density is measured using a manually operated Mud Balance, and the rheology is measured using a Couette type viscometer. Both these instruments have been fairly unchanged the past 50 years, are time consuming to operate and allows for errors when manually reading and recording the measurement. These methods are still in use in most drilling operations around the world. On NCS an operator has introduced automatic measurements as a contract requirement with the aim of improving fluid quality, highly increase sampling intervals and thereby improve safety in operations (Taugbøl et al. 2019). The methods for measuring the fluid values has not been standardized, but the output shall be in accordance with API 13B, ensuring fast implementation of the data into existing drilling systems.

The fluid measuring technique presented in this paper is based on rheology measurement through pipe rheometer and density measurements through Coriolis meter. This technology was presented in SPE-196793

(Taugbøl et al. 2019). This rheometer measures at ambient temperature. The dual DP pipe rheometer is set up with high accuracy pressure transducers to measure the pressure loss inside the straight pipe section of the Pipe rheometer. By varying flow rate through pipe of different dimensions a rheology profile at varying shear rates can be calculated.

Field implementation

Installation of a unit starts with a rig survey together with the Drilling Contractor to find the best location and sampling point. Fluid is normally taken from the charge manifold for the mud pumps. This will ensure measurement of the fluid going in to the well to ensure correct data.

First installation in the North Sea of an AFM (Automatic Fluid Monitor) unit was in 2017, this unit is still up and running sending in data to our onshore support center. More details related to the technology qualification was given in SPE-196793 (Taugbøl et al. 2019). Fig.1 is a schematic description of the AFM unit. Fig. 2 is a picture from a unit installed offshore.

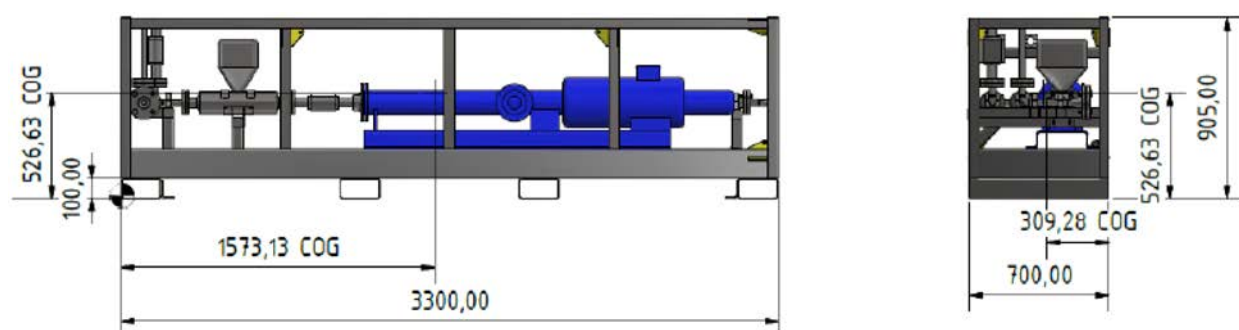


Figure 1—AFM Unit dimensions, weight is 750kg.

The AFM unit has only one movable part and that is the Mono-pump supplying drilling fluid through the unit. This makes this unit very robust and require low maintenance levels. Experience so far indicates that the only maintenance necessary is to change the pump on a yearly basis. Any support and updates to the software running the unit can be performed remote through the network connection.



Figure 2—AFM unit installed on an offshore platform in Norwegian sector

Once the Dual DP rheometer was factory acceptance tested in the yard, it was sent offshore to be commissioned and verified on a fixed installation in the North Sea. The data presented below was acquired in the field while drilling the 355m 8 ½ section with 1.35sg low ECD oil-based drilling fluid, drilling at around 4000mMD. The Mud Engineer on-board was requested to perform rheology checks on the Fann-35 at equal ambient temperature to the AFM so that the results could be compared since also the AFM measures rheology at ambient temperature.

The unit ran continuously for 399 hours during drilling, taking 2394 mud checks. When run through the AFM a total of eight data points must be collected to calculate an accurate rheology, which takes 10-11 minutes. With the AFM taking six mud checks every hour, as opposed to the usual 3-4 checks per 24 hours taken by our human Mud Engineer, there was a 3500% increase in mud checks.

All measured and calculated values can be monitored as numerical values via the visual display unit. The signal processing unit forwards data under specific mnemonics to be stored on the mud logging system. This data is then transmitted into a data aggregation server to provide online estimates of drilling fluid rheological values to all parties involved in the operation. These values include gel strength, plastic viscosity, effective viscosity and apparent viscosity, in addition to the shear stress at various velocities. Currently the readings from the pipe viscometer are converted to standard Fann-35 ‘RPM’ readings which are then used as input to hydraulic models.

The results presented in the following figures demonstrates the measurements made by the AFM unit compared to manual measurements performed by standard VG meter for rheology and mud balance for density.

The fluid density or mudweight as it often is referred to was taken at ambient temperature using the mud balance and compared to the Coriolis built in to the DualDP AFM, Fig. 3. The DualDP usually operates between 2-7bar but can function comfortably at 10bar before the high pressure shut down kicks in. Saasen et al. (2008) observed through in-line density measurements of the fluid using the Coriolis meter that gas/air entrainment was an issue. This has been remedied by using a pressurised flow loop to collapse bubbles. The results show that the DualDP tracked changing density of the fluid with good accuracy and that readings were consistent with the corresponding manual API measurements.

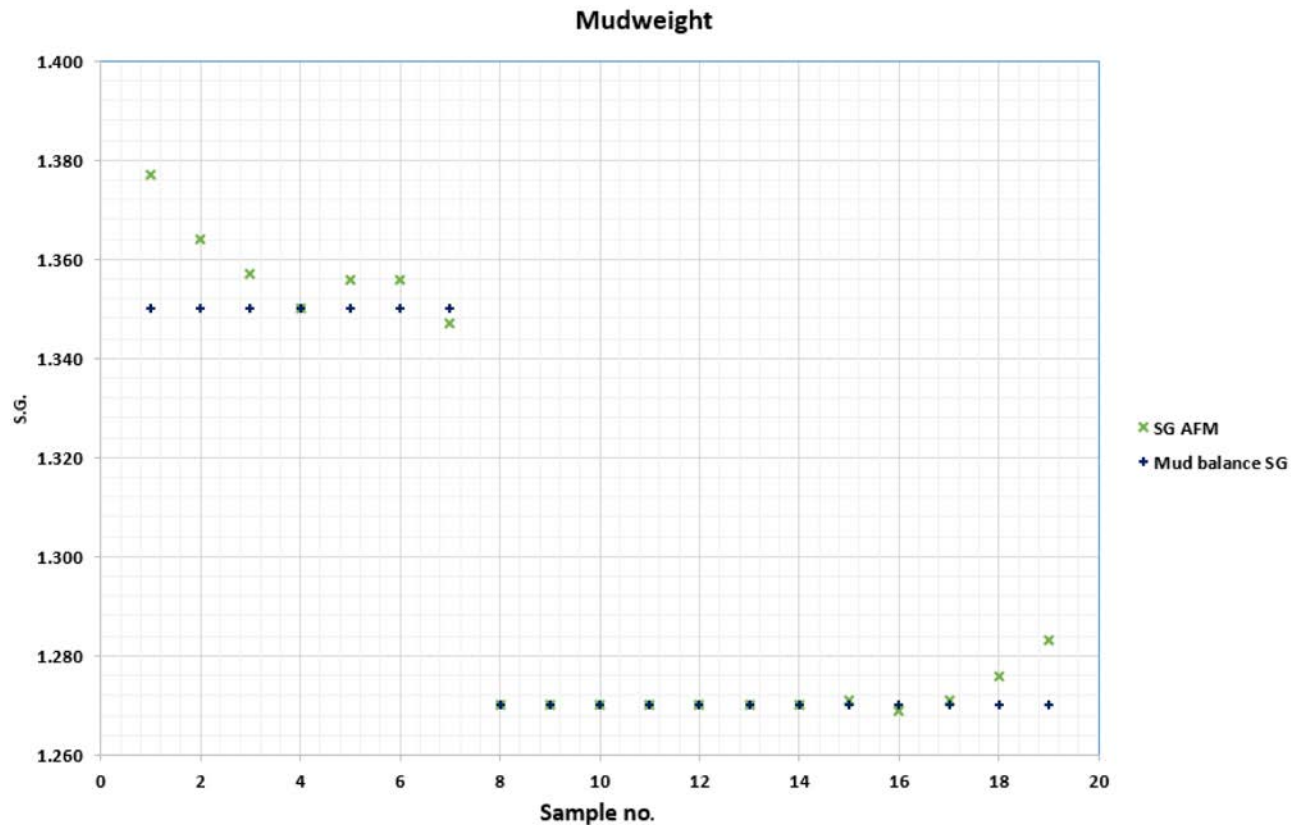


Figure 3—Drilling fluid density, (mudweight) measured using AFM and mud balance.

There is an interesting deviation from the manual mud checks at the beginning and end of the section, where the mud could have been conditioned while pumping in hole making a deviation in the samples due to point of sampling. Without these deviations the mudweight would have tracked with near perfection. The pressurised mud balance is susceptible to some element of human error, depending on the force applied and the amount of air left in the chamber of ± 0.005 . However, the continuous automatic reading shows no human bias. The movement of the mud through the screw pump compresses and energises the fluid to operational conditions and thus gives a more accurate density measurement than would otherwise be found with a human agent.

As the PV is the result of the difference between the 600 and 300 readings, it provides an excellent quick-look into how the pipe viscometer is performing relative to the Fann-35 measurements in the mud report. Fig. 4 shows the resulting PV from measuring with the AFM and the VG meter. The PV is regularly higher on the pipe viscometer. This may be due to the increased solids content of the sample taken from the AFM near the bottom of the pit, compared to the Mud Engineer measuring samples from the top of the pit. Questions were asked of the deviation of samples 6 to 10. This corresponds with the drilling out of cement and cutting back of the fluid. The Mud Engineer would have to ask if the rapid increase in solids were an

outlier that should be removed, or part of a trend that should be treated. With continuous trend-based fluid measurement, the increased PV could have been remedied instantly with no over or under treatment

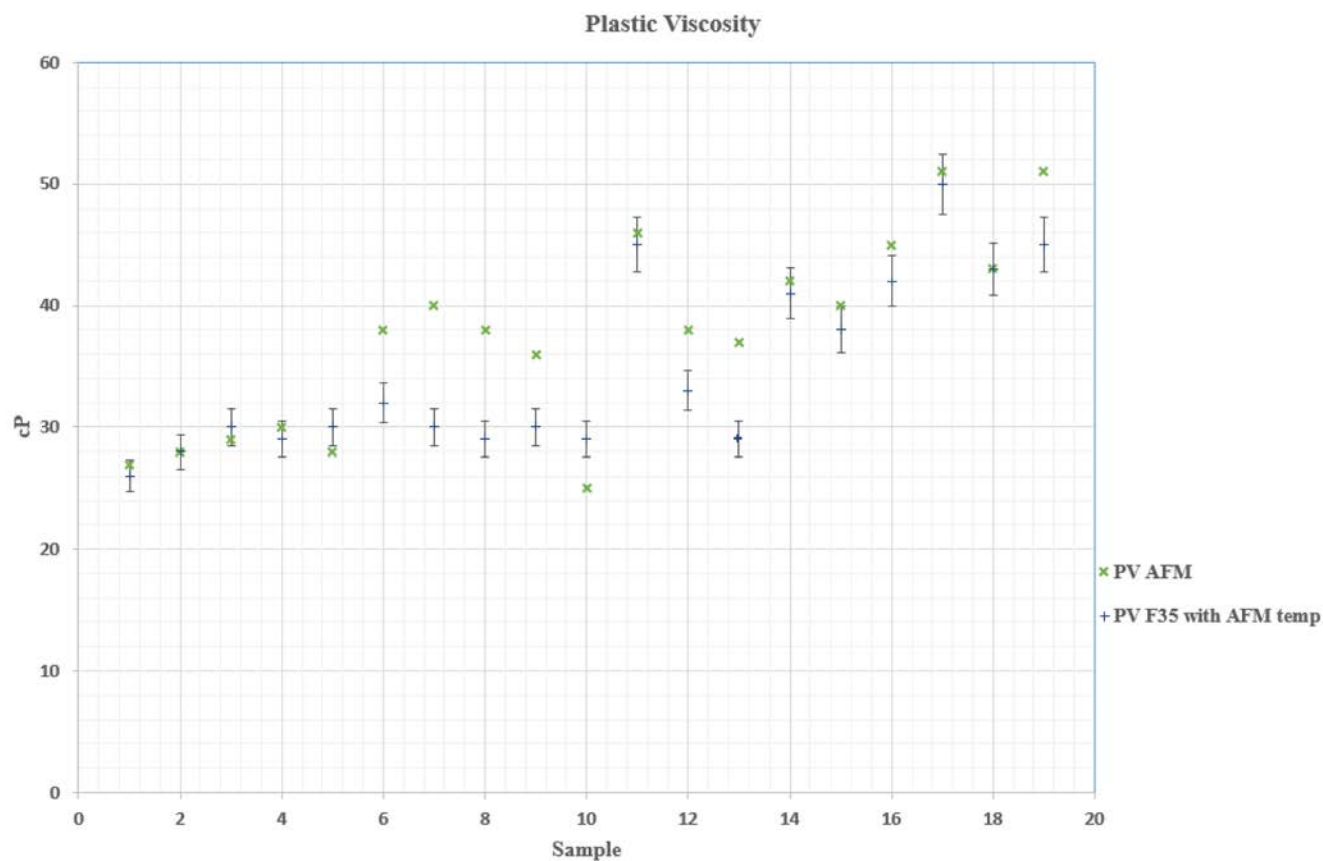


Figure 4—Plastic viscosity measured with AFM and manual VG meter.

In the following figures, Fig 5 and Fig. 6, the rheology readings representing the 300 rpm reading and the 6 rpm readings are plotted based on the AFM measurements and the measurements performed by manual VG meter. As shown by the figures the correspondance between the measurement methods are good throughout the series of measurements.

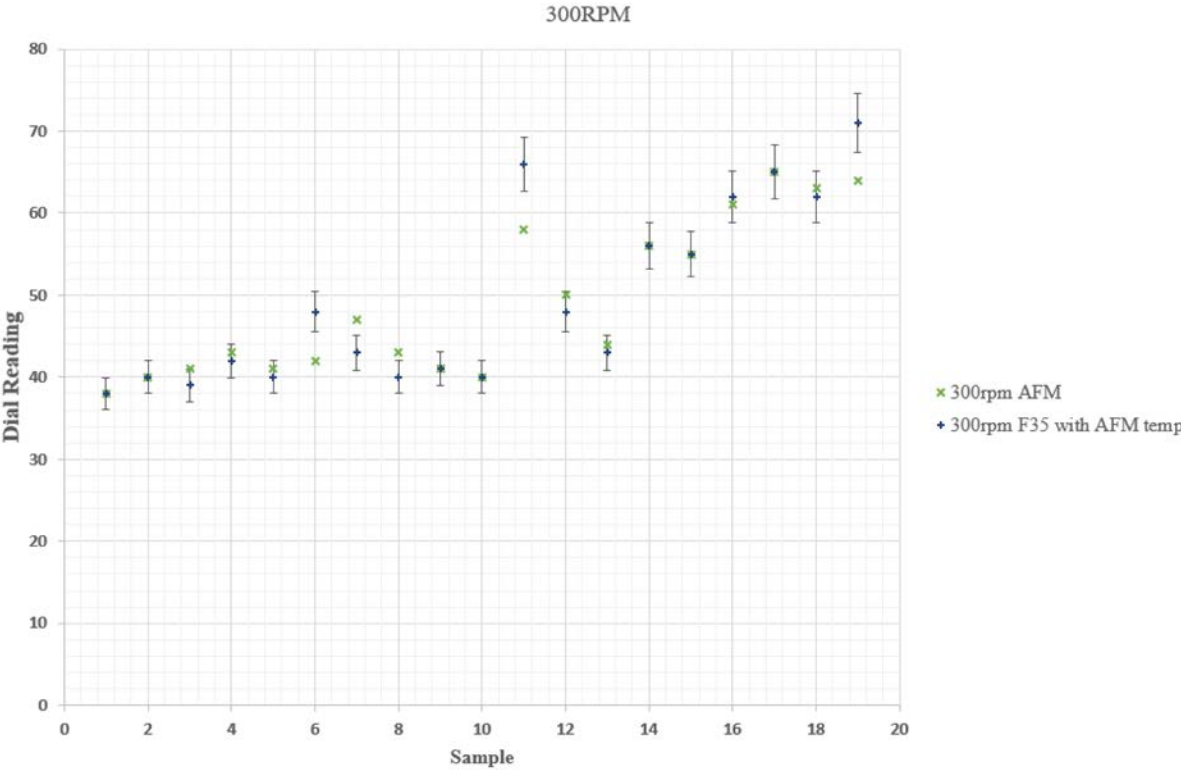


Figure 5—300 RPM Data from AFM compared with Fann35 data

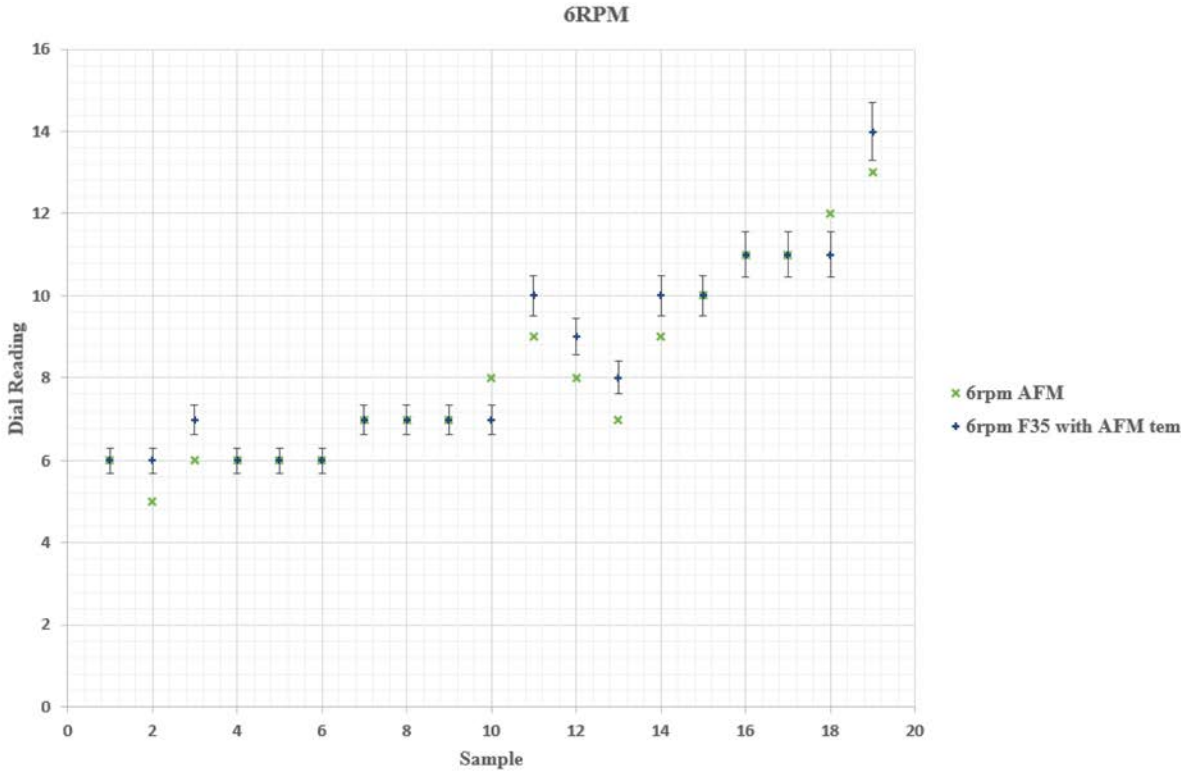


Figure 6—6 RPM Data from AFM compared with Fann35 data

Examples from field where AFM proves added value

Drilling fluid analysis is typically done 4-6 times pr 24 hours on a drilling operation. This will typically leave 4-6 hours of operations between each fluid test. By measuring drilling fluid properties in real time, costs can be reduced by mitigating problems, reduce overall dilution costs and reduce the amount of NPT experienced on every well.

The attached example below, taken from an operation in Norway shows that it was possible to detect a water influx into the active system based on the drop in viscosity and density measured by the AFM unit. Normal analysis could have resulted in a severe drop in fluid parameters and potentially drilling problems. Early detection and early engagement to stop the influx gave only minor effects on the fluid properties and no stop in drilling operations.

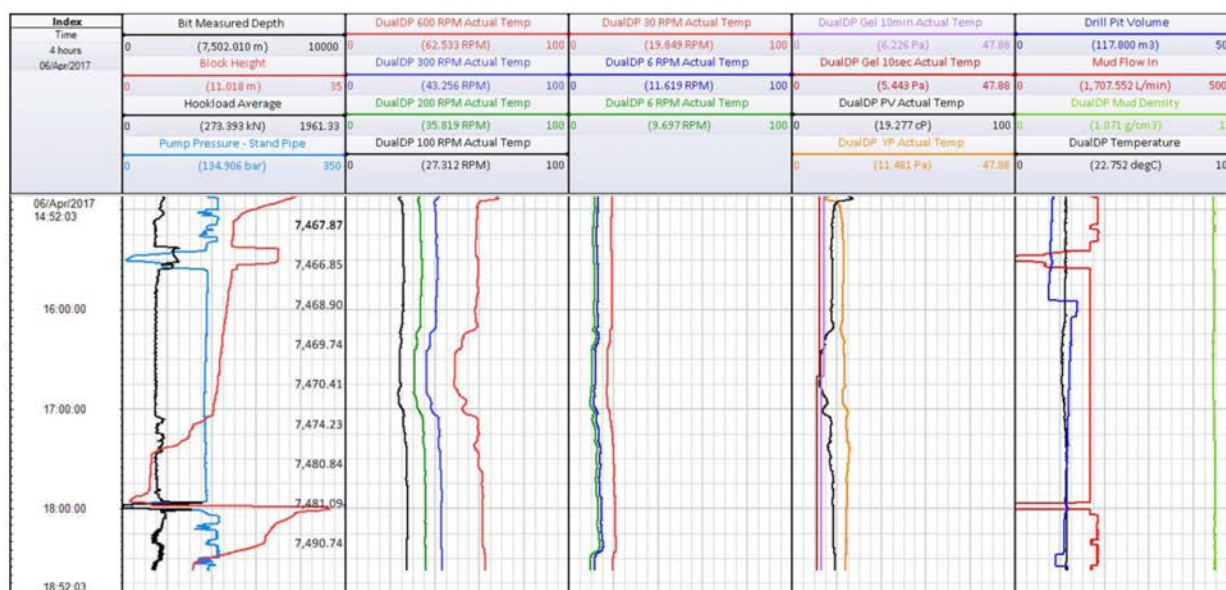


Figure 7—Time based data from AFM together with drilling data.
Detection of drop in rheology due to water influx from 16:15 to 17:00

Fig. 8 clearly demonstrates the improved fluid controlled obtained by automatic measurements. Over a period of 24 hours the drilling fluid was weighted up from 1.35 sg to 1.49 sg. This cause a distinct increase in rheological properties as demonstrated in the Fig. 8 This change in rheology could be followed continuously. A standard mud engineering with only four checks a day would leave the project with inaccurate data of the fluid properties over long periods. These are data which will be important for all type of hydraulic optimization while drilling.

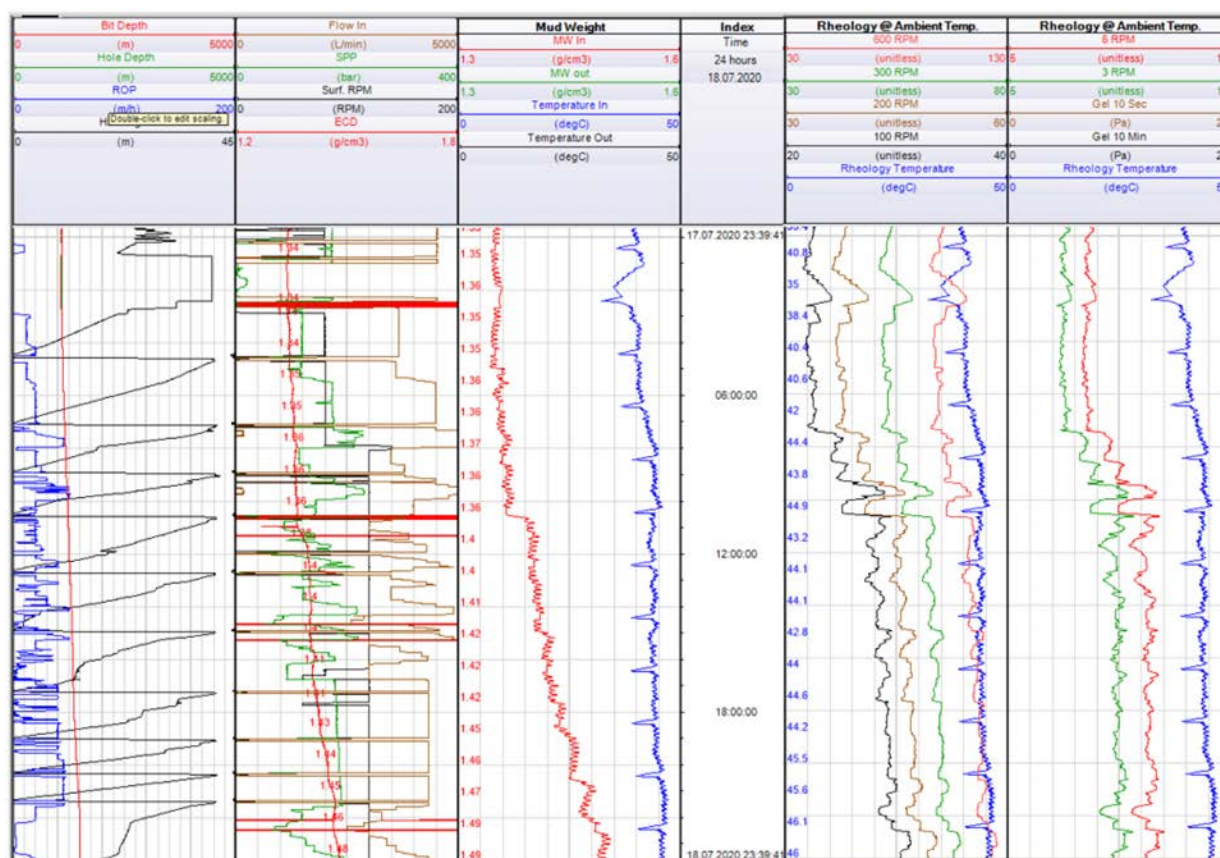


Figure 8—Time based drilling fluid data from AFM together with drilling data over a 24 hours period. Fluid weighted up from 1.35 to 1.49 sg in the period. Right column shows 6 RPM (red) and 3 RPM (green) rheology reading and fluid temperature (blue), next column shows 600 RPM (red), 300 RPM (green), 200 RPM (brown) and 100 RPM (black). Third column from left shows MW (red) and fluid temperature (blue). First and second column left show different drilling data as ROP (blue) block height (black) Flow (brown), ECD (red) and SPP (green)

Onshore surveillance

Data will be streamed from the AFM unit to the onshore support center (OSC) via ethernet and the data is available via the OPC-UA communication protocol. The data is displayed locally at the rigsite and transferred via a software to the OSC and can be accessed globally.

Setting alarm on selected parameters such as Density, YP and Low-end rheology will help in identifying changes into the fluids system and allow for monitoring multiple wells. Viscosity is very temperature dependent and alarms needs to be linked to changes in temperature. The example in Fig. 9 shows decrease in measured viscosity as temperature increases. In the same diagram the temperature corrected viscosity is also displayed which shows stable values over the same time interval.

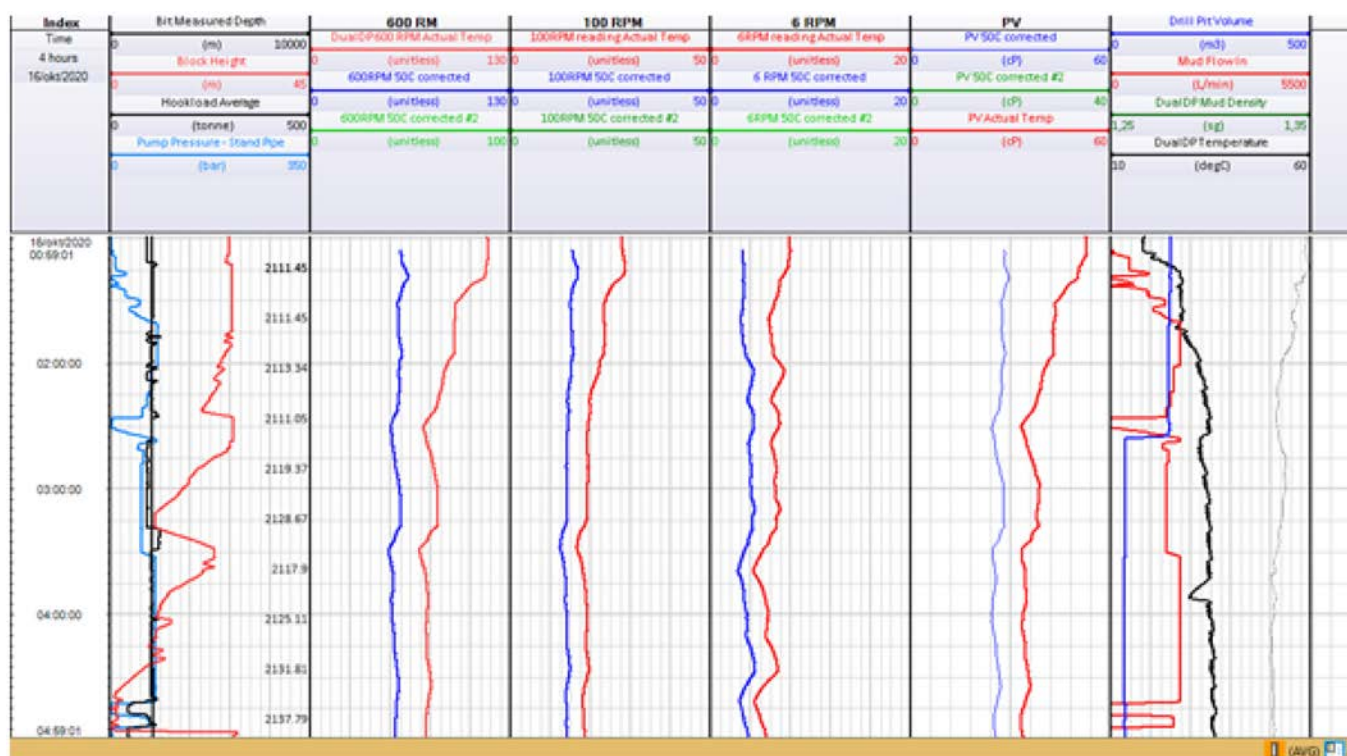


Figure 9—Time based data from AFM. Viscosity measurements at increasing temperature during start of flow. Red lines indicate measurements at ambient temperature. Blue lines are the temperature corrected values. Black line at the right shows the change in temperature.

Onshore support center will contact the rig mud responsible personnel if an alarm is triggered to discuss any fluid treatments and will monitor the effect of the treatment on an ongoing process. By utilizing such technology it can be possible to reduce the offshore manning with this equipment installed, the mud engineers' tasks where "hands on" activity is not needed will be moved to the onshore center.

Real-Time Modelling

In the current CAPEX-constrained environment E&Ps are placing increasingly higher priority on reducing the upstream well construction costs. Typically, 30-50% of total project expenditure is drilling investment. This cost can broadly be divided into two categories; productive and removeable time Fig. 10. The latter is further divided into non-productive time (NPT) and invisible lost time (ILT).

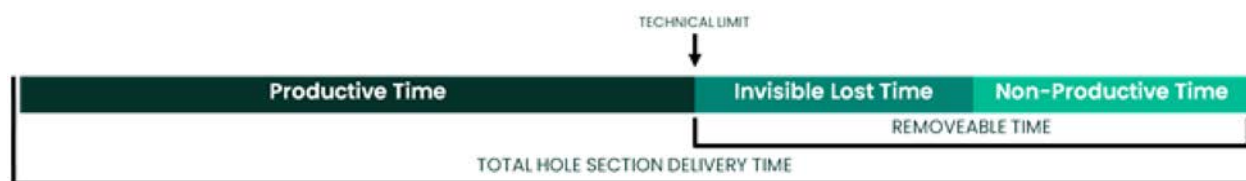


Figure 10—Upstream well construction time definitions

Perhaps one of the most high-value applications for data procured through automated fluid monitoring, specifically; density, temperature and rheology, is real-time physics-based modelling. Modelling the downhole environment during the well construction phase provides a reference point for which to judge direct measurements of various parameters. Deviations from this reference point, or expected, then can be used as early diagnostic signals for approaching NPT events, which can then be remediated.

A tangible example here would be modelling of cuttings bed accumulation and evolution in the wellbore while drilling (Forshaw et al, 2020), surveillance of these models in-conjunction with automated monitoring of other key diagnostic surface or downhole signals can allow earlier identification on inadequate hole cleaning and therefore remediation and prevention of either costly rig time for clean-up cycles or run, or worse, pack-offs and stuck-pipe events. (Zausa et al, 2018) cited that they believed this kind of proactive NPT anticipation could reduce CAPEX spend by 1% for E&Ps.

Additionally, pre-well defined operating parameters for certain operations can be refined during runtime when models are enriched with more accurate, or higher resolution data not available during well-planning. Planned running speeds for drilling or non-drilling assemblies are a good example of this. Specifically, tripping speeds are defined offline based on numerous variables, but perhaps most importantly human-measured drilling fluid rheology which are often outdated. Using automated measurements for these variables allow the model to be continuously updated, effectively moving closer to what could be considered a true digital twin of the downhole drilling environment. The output is an optimum tripping velocity array over depth. When deployed as part of an advisory system this allows the driller to visually follow and optimize the tripping process to a reasonable degree. However, this can further be optimized by having these real-time fluid data enabled models pass optimum parameters to a rig control system. This would either be done as a setpoint limit, or setpoint-target values. Similarly (Zausa et al, 2018) stated that this type of run-time optimization could contribute up to a huge 6% saving in well construction CAPEX through the reduction of ILT.

Fundamental Concepts & Drilling Automation with Automated Fluids Data

Real-time modelling is by no means a new concept. (Zamora et al, 2000) specifically cited use of adapted swab/surge models in real-time for monitoring and advisory purposes. The concept of overlaying variables that alter during the drilling execution phase on a model already containing static or semi-static objects, such as rig, assembly and formation data is shown below in Fig. 11. In legacy drilling optimization terminology, we would refer to the non-varying parameters as the fixed or semi-fixed environment. This data is known upfront and therefore can be populated in the pre-well phase. Simulations should be executed offline to determine viability prior to deployment in real-time. Once the drilling execution begins, providing correct system architecture is in-place, ‘real-time’ parameters can then be overlaid.

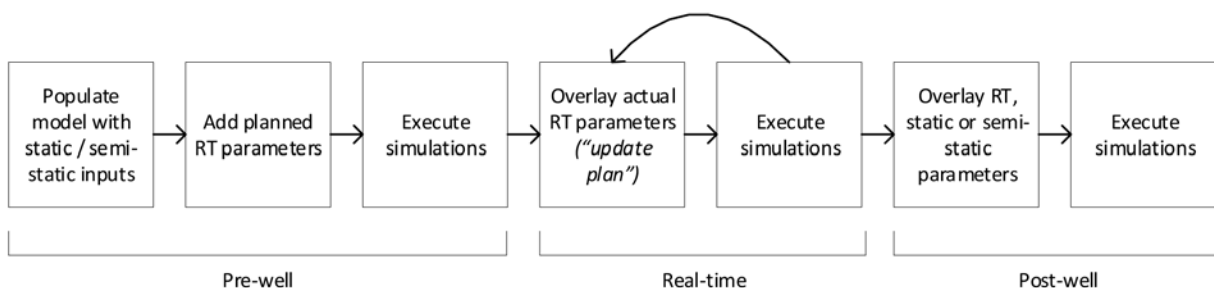


Figure 11—The concept of overlaying variables that alter during the drilling execution phase in real time modelling

Previously variables overlaid and updated in real-time were generally limited to surface parameters such as flow, RPM, ROP etc. Drilling fluid density and temperature sensors have also been common, but to a lesser degree. The step-change enabled by Automated Fluid Monitoring is that fluid rheology is now available as a digital object and input to these simulations. This is at comparatively high frequency, and high-accuracy when compared with legacy human sampled and manual entered values.

Fig. 12 shows an example of a high-level architecture of a drilling automation system comprised of two main groups. On the left are components or services typically supplied by oilfield service companies and on the right those by a drilling equipment provider. In the center the interfaces between both groups are

shown. This article will not cover the technical architectural details of Fig. 12 however, (Brackel et al 2018) describes the importance of an open approach to drilling systems automation, preferred communication protocols and implications of security, as well on touching on many other topics which have defined the detailed design of the system depicted here at a high-level.

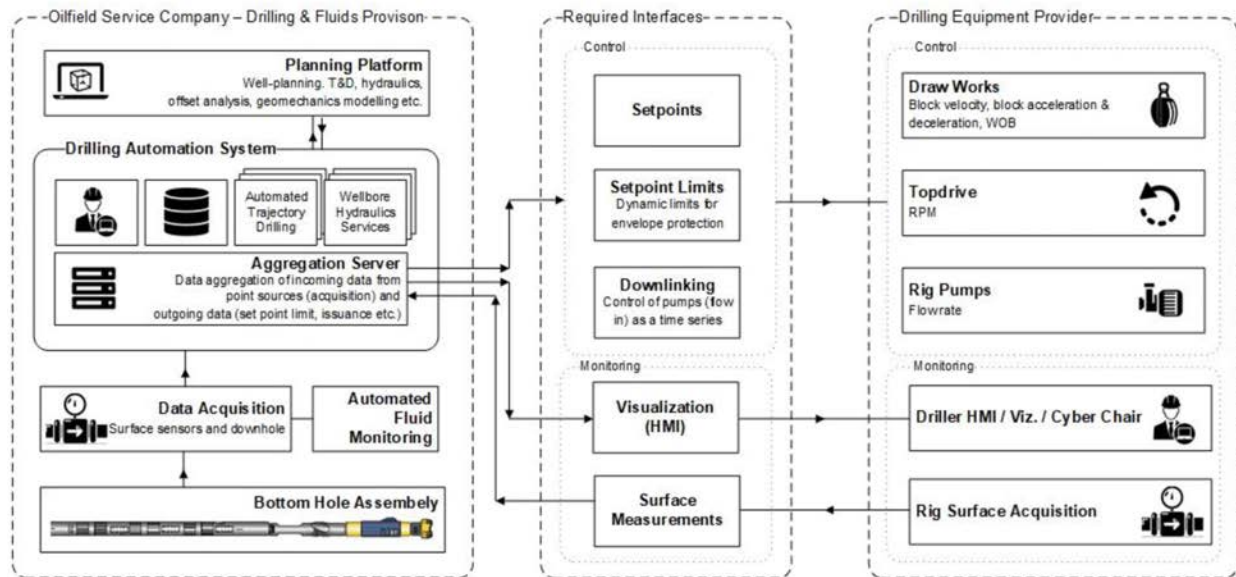


Figure 12—High-level topology of a drilling automation system with required system interfaces.

An example of optimization of the tripping process empowered by automated fluid monitoring data:

1. Automated fluid monitoring sensors make fluid rheology, density and temperature available by publishing data to a native OPC UA server.
2. Other required surface data is acquired at source and published too it's respective server.
3. All data is aggregated in a common aggregation server running on industrial grade PC on-premise.
4. A controller looks for trigger events, this this case either connections or change in flowrate and on detection samples the required array of input variables from the aggregation server.
5. The hydraulics simulation, in this case a swab surge simulation, is called. The engine call is already populated with static or semi-static variable such as wellbore geometry and assembly components so only real-time parameters must be overlaid.
6. Simulation results are returned to the aggregation server.
7. Monitoring applications can monitor tripping velocities to either advise on the optimum tripping speed through an intuitive visualization Fig. 13 or in a active-control setup directly pass the optimum trip speed as either a setpoint or setpoint-limit directly to a rig control system.



Figure 13—Intuitive visualization showing swab/surge limits which adapts dynamically to operational state (pumps on / pumps off tripping)

Case study: potential time-savings from AFM empowered advisory or automated tripping systems

Fig. 14 shows a time-based plot which demonstrates potential inefficiencies in running speeds, firstly during a POOH to surface, and then with the subsequent RIH back to bottom to resume drilling. Bit velocities are shown in light green for the POOH, and dark green for the RIH as a scatter plot. The linear series (grey, maroon and dashed-yellow) represent swab and surge limits valid for that bit depth, at that point in time. These are continuously re-calculated based on time, or event-based triggers. For tripping four limits based on formation pressure boundary conditions are produced simultaneously. A swab and surge velocity limit for no-circulation, and a simulation which considers a pumps-on mode of operation. This simulation has an additional trigger, as the flowrate input variable is not binary, if the system sees a change in circulation rate it will then re-simulate for pumps-on swab/surge to ensure that the active limits are representative of the current operational conditions at all time.

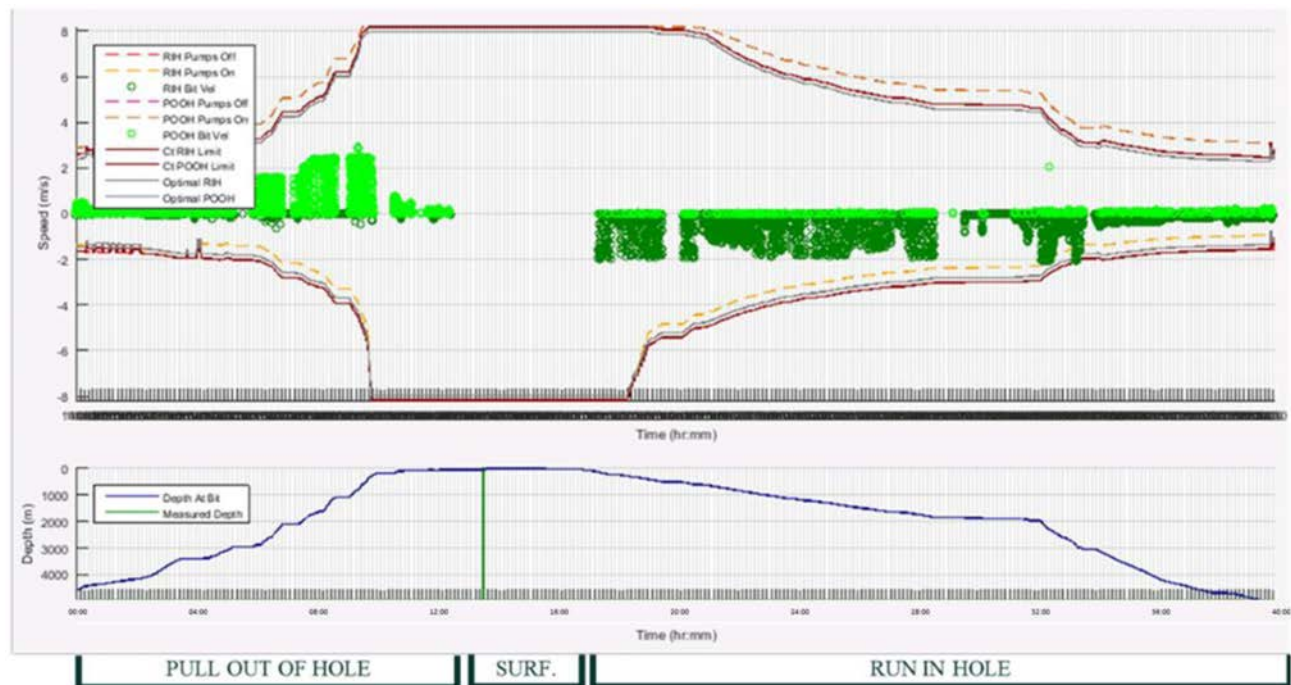


Figure 14—Time-based plot showing swab/surge limits and corresponding bit velocities during a bit trip.

The legacy workflow for defining swab/surge velocity limit for a trip would use a fixed fluid density, temperature and rheology for the simulation, effectively done offline before start tripping. Hypothetically, if a stop was made midway up the open-hole section and circulation and rotation for a period of time to work through a tight spot a set of limits that represent this new operational state have not been set, and changes in the fluid properties that have evolved since the original mud-check taken at some point before starting tripping have not been implemented.

Fig. 15 now takes the POOH section of the original time-based plots and transposes it into a more classical depth-based visualization. The mechanical hoisting limit of the rig is superimposed here. This is then aggregated with the formation and operationally depending velocity limits to give an optimum trip that that specific bit-depth and operational state. When viewed over time, integration can be made below both this optimum speed and below the actual bit velocities. The resultant value when subtracting between these integrations in time represents the removeable time, or invisible lost time (ILT) that could be removed from bucket of tripping time pertaining to specifically running assemblies – excluding what is typically referred to as slips-to-slips time.

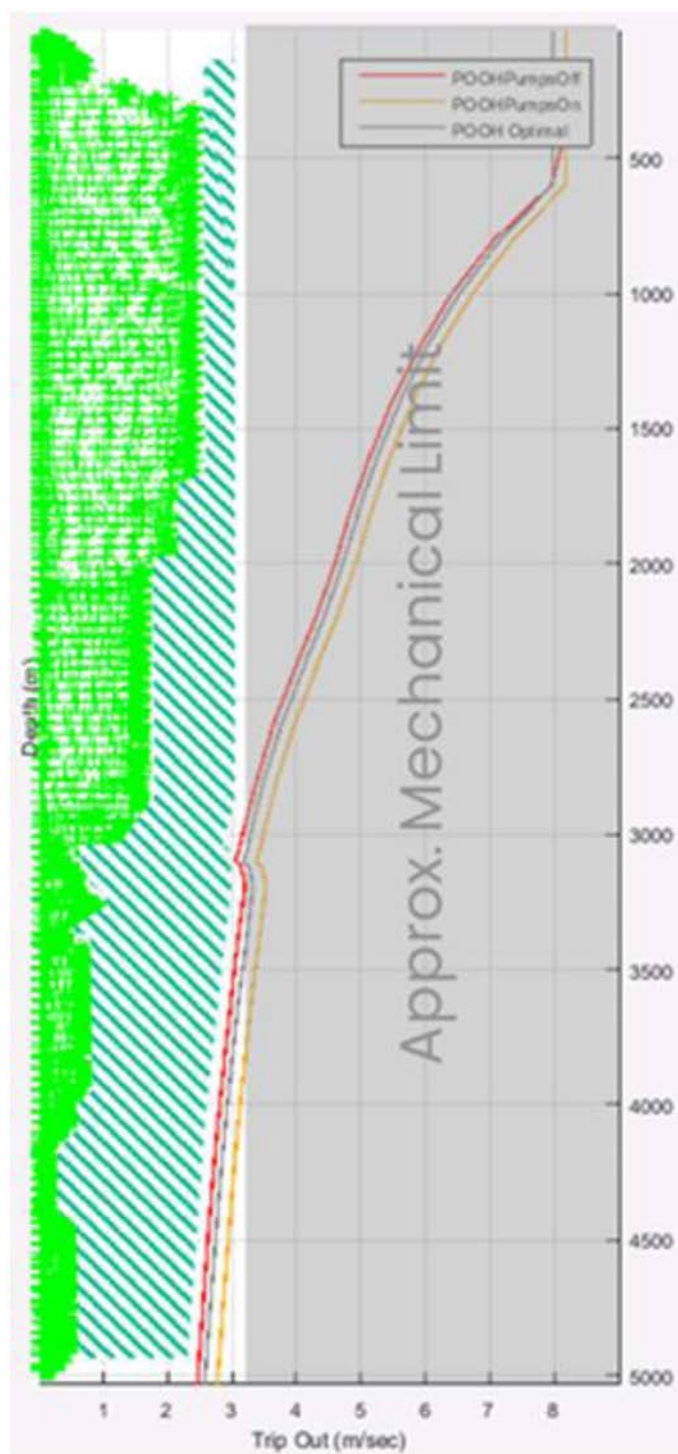


Figure 15—Depth-based swab plot showing ILT (dark green shading)

For this specific example the ILT calculated for the POOH was 2.92 hours. The equivalent cost saving to the operator for this North Sea shelf jack-up asset would have been ~\$120k USD. Advisory systems with intuitive user interfaces as shown in Fig. 13 are enabling operators to enable a component part of this value however in order to completely remove this component of ILT for tripping operations direction connection between real-time modelling system and actuator control systems, as shown in Fig. 12 must be enabled.

Possible enablers from the use of Automatic Drilling Fluid Monitoring

The examples given above from both the offshore field measurements as well from the use of these data into real time automatic drilling services clearly demonstrates some of the immediate benefits both related to the improved fluid quality control as well as improvements of the input data necessary for accurate real time hydraulic calculations which further is necessary input to optimization of the drilling process.

As part of an ongoing re-structuring of the drilling process for an operator where key specialist functions are moved from the offshore rig location to onshore operation centers, the use of more automatic functions on the rig will be required. Reduction of manning of drilling fluid engineers offshore are among the changes implemented. When this service is not covered 24/7 at the rig, but reduced to having one engineer onboard, the fluid engineering needs to be followed up by the engineers in the onshore center. Automatic measurements of basic parameters as fluid density and fluid rheology are then key enablers for this transition of manning.

The next step in the utilization of data can be to develop automatic fluid processing at the rig. It is fair to say that within this area the drilling industry is far behind other industries where process control of liquid suspensions is controlled automatically through automatic diagnostics, analysis and automated processing and mixing. [Boubsi et al. \(2017\)](#) discussed the development of a closed loop mud control system. [Brevik et al \(2011\)](#) filed a patent application describing a fully automated drilling fluid process for a drilling process. Developing additional sensors will be a requirement for further automization. Papers SPE-107547 ([Omland et al. 2007](#)) and SPE-112687 ([Saasen et al. 2008](#)) presented several prototype fluid analysis tests done on real drilling fluids in an onshore test center. More automation in the drilling fluid mixing systems of the drilling rigs must also be installed and new algorithm for process control must be developed. Having this in place a consistent and high quality drilling fluid system can be achieved at all time. The control of the fluid system can as a result be moved from the mud engineers present on the rig to operators located in onshore control centers.

Conclusions

- Automatic drilling fluid measurements have been installed and run on several offshore drilling rigs giving high quality real time data of fluid density and rheology.
- The fluid data are transferred to onshore operation center for continuous surveillance of fluid properties during drilling operations.
- Real time measurements highly reduce the sampling time intervals enabling improved fluid control and improved fluid quality.
- Real time fluid data are used as necessary input into real time hydraulic modelling highly improving the accuracy of such calculations.
- It is proved that margins related to tripping can be increased by improved accuracy of hydraulic modelling. This will give reduced operational time by removing ILT.

Abbreviations

AFM	Automated fluid monitoring
ECD	Equivalent circulating density
PV	Plastic viscosity
YP	Yield point
LSYP	Low shear rate yield point
OPC UA	Open platform communication unified architecture
OBM	Oil based mud (oil based drilling fluid)
WBM	Water based mud (water based drilling fluid)

POOH Pull out of hole
 RIH Run in hole
 NPT Non-productive time
 ILT Invisible lost time

References

- API "Recommended Practise for Field testing Water-based Drilling Fluids"; *API RECOMMENDED PRACTISE 13B-1*; Fourth Ed. March 2016.
- API "Recommended Practise for Field testing Oil-based Drilling Fluids"; *API RECOMMENDED PRACTISE 13B-2*; Fourth Ed. March 2018.
- Boubsi, R. E., Andresen, J. A., Van OG, G., Bjørkevoll, K. S., Nybo, R., Brevik, J. O., Nygaard, G., Smith, G. G., "DEMO2000 – Drilling Mud Proces Control." SPE-185929, SPE Bergen, Norway, 5 April 2017.
- Brackel, H.-U., Macpherson, J., Mieting, R., & Wassermann, I. (2018, October 19). An Open Approach to Drilling Systems Automation. *Society of Petroleum Engineers*. doi:[10.2118/191939-MS](https://doi.org/10.2118/191939-MS)
- Brevik, J.O., Omland, T.H., Taugbøl, K., "Method of conducting well operation" *Patent application WO 2011/095600 A2*. International Publication date 11 August 2011
- Forshaw, M., Becker, G., Jena, S., Linke, C., & Hummes, O. "Automated Hole Cleaning Monitoring: A Modern Holistic Approach for NPT Reduction". IPTC-19639, International Petroleum Technology Conference, Dhahran, Kingdom of Saudi Arabia 13-15 January 2020.
- Omland, T.H., Saasen, A., Taugbøl, K., Dahl, B., Jørgensen, T., Reinholdt, F., Scholz, N., Ekrene, S., Villard, E., Amundsen, P.A., Amundsen, H.E.F., Fries, M., Steele, A. "Improved Drilling Process Control Through Continuous Particle and Cuttings Monitoring" SPE107547, SPE Digital Energy Conference and Exhib., Texas, US, 2007.
- Saasen, A., Omland, T.H., Ekrene, S., Breviere, J., Villard, E., Kaageson-Loe, N., Tehrani, A., Cameron, J., Freeman, M., Growcook, F., Patrick, A., Stock, T., Jørgensen, T., Reinholdt, F., Scholz, N., Amundsen, H.E.F., Steele, A., Meeten, G., "Automatic Measurement of Drilling Fluid and Drill Cuttings Properties" SPE112687, IADC/SPE Drilling Conference, Orlando, USA 2008.
- Taugbøl, K., Lien, M., Clinch, D., Stock, T., Oven S., Hernandez, J. "Automation of Drilling Fluid Measurments". IADC World Drilling Conference & Exhibition held in Milan, Italy, 19-20 June 2019
- Taugbøl, K., Brevik, J.O., Rudshaug, B. "Automatic Drilling Fluid Measurements". SPE-196793, SPE Russian Petroleum Technology Conference, Moscow, Russia 22-24 Oct 2019.
- Zamora, M., Roy, S. "The Top 10 Reasons to Rethink Hydraulics and Rheology". IADC/SPE 62731, IADC/SPE Asia Pacific Drilling Technology, Malaysia 2000.
- Zamora, M., Roy, S., Caicedo, H.Y., Froitland, T.S. & Ting, S.T. "Major Advancements in True Real-Time Hydraulics". SPE 62960, Annual Technical Conference and Exhibition, Dallas, Texas, 1–4 October 2000.
- Zausa, F., Pellicciotta, L., Spelta, A., Bruni, V., Baio, F., Medea, A., & Rossi, N. "Multi Source Data Analysis To Improve Drilling Efficiency, Reduce Costs and Enhance Performance Monitoring". SPE-192624-MS Abu Dhabi International Petroleum Exhibition & Conference, Abu Dhabi, UAE, 12 November 2018