Society of Petroleum Engineers

From Sensors to Solutions
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Foreword

First let us begin by stating the purpose of this workshop. As opposed to many other workshops the intent of this one was to demonstrate what is possible in terms of sensors that drive solutions that are available in the market place today.

Drilling automation has an extremely broad context and as such has multiple interpretations of not just where it will end up, but also where it is today. As such it is important that we set a stake in the ground that helps the community understand what is possible today, as much as what will be possible tomorrow.

The hopes of those involved in setting this workshop up was not only to provide detailed insight into the current state of the market and automated capabilities, but also to identify the current needs that will drive innovation in sensing and sanctioning technologies.
Memorable quotes

“No data, no automation.”

“In other industries, you either know the physics or you have enough experimental data. We have neither.”

“More information allows for better decisions yielding the best result.”

“We need to admit that we don’t know everything. We can drill the same well next door and it can be completely different.”

“Everyone is responsible for their own data. Service providers are responsible for the quality of the data that they generate. Operators are responsible for the quality of the data they receive.”

“The current culture is that if you’re wrong once, the trust does not come back again. Answers have to be consistently right.”

“We can no longer accept ‘the dogma ate my well.’”

“If you don’t understand the limitations of data, it will be inappropriately used.”

“Get the right data to the right person in the right format at the right time.”

“Saying that you will always need experts is basically saying that you don’t want to go the next step. It’s time to think about something actually different.”

“What is the value of detecting a quarter barrel kick and being required to stop operations to circulate when we could previously continue drilling ignorant of the same kick with no safety repercussions?”

“In my company, I don’t use the word ‘automation’, because we are not there yet.”

“We have a hard time selling the automation initiative to our management. We are all technical guys. We might require a new skill set to do this.”

“The young generation can crowd source their answers.”

“Massive training is required to instill the courage to break with tradition. Every activity and every job is a part of the process.”

“There is perhaps a negative value of measuring something we do not want to respond to.”
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About the Workshop

Description

Sensors are the primary data source for drilling process control and decision making. Optimization of the drilling process and drilling systems automation require consistent reliable quality data. Inadequacies in the data are becoming apparent as these applications become more prevalent. Drilling performance enhancements demand the development and deployment of automated systems that use data intensive techniques, such as, adaptive self-learning, physics-based, and data-driven modeling to compute solutions. The challenges are the aggregation, distribution, enrichment, management, and visualization of the resultant data.

Individual case studies within each session will be correlated to the International Standard ISA-95, from the International Society of Automation, to develop an automated interface between the enterprise and control systems. This workshop will bring together operators, drilling data solution experts, as well as service company and drilling contractor personnel to learn and discuss progress in resolving sensor to solution issues.

The general format of this workshop is oriented around presenting applications of automated solutions from sensors followed by questions and answers.

Who attended?

This workshop concerned all aspects of the well construction process and the drilling engineers, geoscientists, and operations managers who are engaged in real-time decisions during the drilling process. It was also of particular interest to managers and supervisors who must consider conflicting requirements from various disciplines and then seek the best compromise to minimize technical and business risk. Finally, systems engineers who streamline, interpret, and disseminate real-time information will benefit from their peers’ experience.

Feedback and Future Workshop Ideas

The SPE Sensors to Solutions Workshop was well received with over 100 participants actively participating. The workshop format, presentations followed by Q&A was preferred and encouraged productive discussions; however, participants would have liked to hold a break out session for small group discussions. By the end of the three day workshop, today’s burning issues in the drilling industry – data quality, data ownership, and getting business management to adopt technology – resonated
with the attendees as a key area that the industry must focus on.

How to get business adoption of automation?

This question lingered by the end of the workshop as a critical need to accelerate the advancement of drilling optimization. It was noted that “successful automation has no technical hurdles, [the roadblocks] are all about the business.” Nathan Zanero of Chesapeake has submitted an abstract around his work in this area for the next SPE/IADC Drilling Conference. However, the question of quality and excellence is an idea that must be taken beyond management to our engineering practices, sensors, well designs, business plans, and everyday lives. Quality is key to safety and success.

The Sensors to Solutions workshop focused on automation success stories inside of the drilling industry. Those success stories revolved around step change improvements of small components; yet there is a strong recognition that the entire rig system needs to be automated in concert to provide the most value. Cases studies of success whole rig systems automation would like to be reviewed. Furthermore, there is a strong interest in reviewing less successful and failed attempts at drilling automation and the lessons that can be applied to future implementations.

Finally, it was noted that drilling automation, in general, is not developing at the pace we would like to see. An important question is asked, “What are the DSATS initiatives which can make a timely and meaningful impact?”
Workshop Introduction

Opening Address

Speaker: Janeen Judah, SPE President elect

The downturn in the oil and gas industry due to low prices really allows companies to review and assess workflows. This is an opportunity to optimize the drilling process, improve engineering plans, improve data management, and exploit new technology.

SPE is greatly appreciative of volunteers because the technical strength of the organization is in volunteers, particularly event committees and event content. Currently, companies are reluctant to allow employees to participate in SPE events due to the downturn in the market. This is a bad business model because it limits the technical and professional growth of employees which will, in turn, limit the business.

Janeen provide an update of SPE today:

- To date, SPE has more than 100,000 professional members and 250,000 students internationally.
- The Offshore Technical Conference (OTC) is the biggest annual meeting followed by the Annual Technical Conference and Exhibition (ATCE) and Offshore Europe.
- OTC 2014 set the SPE event attendance record.

SPE’s technical focus lies in technical sections such as Drilling Systems Automation Technical Section, and Janeen expressed appreciation to DSATS because it has a very deep and narrow contingency, and a very committed core. The Sensors to Solution Workshop sold out more than three times while SPE has seen a general loss of attendees to other events during this downturn.

Go back and tell your company about learnings!

Speaker: Michael Behounek, Committee Chair, Apache

What is a workshop?

Technical workshops provide the platform for discussion, sharing ideas, and exposure to new things happening in the industry. Each technical session has been formatted by the session chairs to allow for the flow of ideas and concepts.

The purpose of this workshop is in response to what the industry is seeing as the fundamental basics needed to move to automation. Accurate measurements are critical for automation. This workshop will highlight successes of automation in the drilling industry and look at new sensors and measurement techniques where current sensors are lacking.
We hope to highlight and focus on the value of new technology rather than marvel on new technology itself.

What do you expect from the workshop?

- To find out more about existing technologies and solutions.
  
  What are the barriers to entry? Why aren’t operators ‘biting’?

- What technology and tools need to be, and can be, implemented?

- How accurate are sensors for predictive modeling?

- How are others experiencing, and solving, the problem of the lack of high fidelity and accurate data?

- What jobs and roles can academia fill in the development of automation?

- What are the best ways academia can educate new engineers about drilling automation?

Keynote: Next Generation Drilling Fluids Characterization – Multi-Parameter Sensing

Speaker: Richard Tweedie, Zaxxon Instruments

The current state of measurements for the drilling fluid circulation systems is rudimentary across the industry. Drilling fluids are non-Newtonian fluids that require multiple ingredients maintained in a specific blend of properties that vary throughout the well and between wells. Currently, advanced measurements are taken by analog tools by hand several times a day. Advanced hydraulic models required for applications like ECD, hole cleaning efficiency, early kick detection, loss circulation detection, etc. require detailed and accurate information on flow, rheology, gel strength, density, viscosity, particle size, conductivity, water/oil ratio, salinity, pH, etc. in and out of the well. However, more sensors and more information generally translate into more cost. A solution needs to be designed for the application rather than forcing existing sensors into applications they weren’t designed for.

Multi-parameter sensing from a single measurement is ideal in that it reduces the modality and reduces the cost. Ultrasound sensing of drilling fluids has great potential for development because ultrasound provides mechanical spectroscopy of the fluid. Ultrasound is information rich; typically, 90% of the information from ultrasound is thrown away. A well designed ultrasonic sensor is capable of measuring flow rate, density, rheology, viscosity, particle size and concentration, and more.

Richard Tweedie presented a novel approach to hydraulic measurements which measures multiple parameters from a single sensor.
Technical Sessions

Session 1: Industry Initiative in Support of Sensors to Solutions
Chairs: Moray Laing, SAS; Michael Behounek, Apache; John Macpherson, Baker Hughes

Participants will learn about three key initiatives supporting the concept of sensors to solutions.

- The Drilling Systems Automation Roadmap* (DSA-R) cross-industry initiative will present an overview of the roadmap to achieve drilling and completions automation.
- The Operators’ Group on Drilling Data Quality will present work done to build trust in sensor and measurement data.
- Members of the recently formed DSATS Data Quality Assurance subcommittee will present their work in support of higher quality in drilling systems data.

*DSA-R is affiliated with SPE Drilling Systems Automation Technical Section (DSATS), IADC Advance Rig Technology (ART) Committee, and Association for Unmanned Vehicle Systems International (AUVSI).

Presentation 1: Drilling Systems Automation Roadmap – Sensors Interdependency with Other Challenges

Speaker: John de Wardt, DE WARDT AND COMPANY

The Drilling Systems Automation Roadmap Industry Initiative (DSA-R) was launched mid 2013 and work began on forming the roadmap to provide the industry with a 10 year look ahead of the potential develops that combine to form drilling systems automation. DSA-R adopted the roadmap process from Sandia National Labs. The roadmap provides a foundation of systems architecture and seven distinct challenges. It provides a focus on each challenge uniquely along with integration across the challenges with a 10 year focus. Systems architecture is important for automation since it defines the higher and lower level control loops, leads to use cases, and defines the sensor data required for input. The ISA 95 and Purdue Model establish a framework for decision making and control, dividing the decision and control process into five levels. Level 0 is considered the actual well construction process. Level 1 captures the machine control such as the draw works and top drive which require high frequency and accurate sensing. Level 2, well construction execution management, focuses on the drilling process physics such as ROP optimization, directional steering, etc. Human supervisory monitoring falls into this category. Operations management which includes work flow activities, operation states, executing plans, etc. is Level 3. Level 4 is the enterprise level management which focuses on business related activities. Data, models, and simulation flow up and down the Levels of
It has been important to keep the human in the loop since human senses and interpret much more information than initially understood. Any control loop can be summed up to four steps – information acquisition, information analysis, decision and action selection, and action implementation.

It is important that automation be designed by taking into consideration the entire system and system goals rather than simply implementing new technology. The industry has historically introduced new technology in parts and to replace legacy systems rather than improving and revolutionizing the system as a whole.

Q&A

Q: How do you envision remote ‘operating’ and ‘excellence’ centers when making a decision?

A: Remote Operation Centers make the operational decisions; whereas, the Remote Excellence Centers make long term analysis and plans based on rig performance. This is the format that Rio Tinto successfully uses for its automated mining. This is a critical distinct particularly in the world of multiple wells, pad drilling, or well manufacturing vs. deep water exploration and wells with very high uncertainties.

Q: What is the benefit of separating remote excellence/operation centers?

A: These are two completely different roles. Real-Time Centers in the industry today have merged these roles too much. This is the difference between a control center and reviewing/implementing long term learnings. Excellence centers should provide lessons learned and make a valuable impact.

Q: For the human sensor analogy, what are the measurements that we really need if there is no human in the loop? Do we really need automation to monitor top drive sound for stick slip?

A: We need to define sensor measurements ahead of time. The human will always be in the loop, but the information has to be displayed in an understandable way; the human must be able to maintain situational awareness to take over control if needed. It may be possible for adaptive automation to balance work load on human in order to stay aware – more human in the loop when less aware to force attention.

Q: What key sensors are we still missing?

A: We have wrong names for sensors. For example, what we consider weight-on-bit, WOB, is measured at dead line anchor when true WOB is axial compression on the bit miles away. What we call WOB today is only slack-off.
Q: When will DSA-R be issued?
A: This has been twice as slow as expected. Everyone on the team are volunteers, and we don’t have the funding yet. Depending on funding, this could range up to 1-2 years. SPE papers have been published in the meantime; two papers were published at the 2014 SPE/IADC Drilling Conference in Fort Worth.

Q: How is the roadmap dealing with RT Measurements and memory only measurements when they are supposed to be merged later on since there are large challenges currently?
A: Ultimately, the industry will have to have one open system so everyone knows what it is. Real time and memory measurements are connected through a timestamp. The Data Quality Assurance subcommittee is investigating this and is opening a can of worms. First, we need to understand what we are actually measuring today then figure out which are good sensors (proximity, measurement type, accuracy, ..), what are poor sensors that can be upgraded / replaced and what are then missing sensors that ought to be sourced to improve the data spectrum.

Presentation 2: Operators’ Group on Drilling Data Quality

Speaker: Michael Behounek, Apache Corporation

The Operators’ Group of Drilling Data Quality (OGDDQ) was formed after the 2014 IADC/SPE Drilling Conference in Fort Worth, Texas because of a recognition within the Operators’ community that drilling data quality is a big problem that originates with Operators. The OGDDQ has 30+ Operators and intended to change the industry’s standards for data quality. Poor data quality impairs the ability to measure, analyze, and improve processes, share knowledge and best practices, can be detrimental to safety and negatively affect well deliverability and productivity, and be a barrier to automation. Operators share vendors, contractors, and OEMs and it is necessary to work together to drive a change across vendors.

Analyzing a failure mode and criticality analysis of the effects of inaccuracy of the basic sensors and their associated consequences is an important step in defining quality standards. Small errors may only cause sub-optimal drilling, analysis, and planning but large errors could be catastrophic. The OGDDQ surveyed many of their own rigs to observe many surface sensors are not very accurate which leads to unreliable analysis results (i.e. MSE).

The Operators’ Group sets out to collaboratively define the process capability requirements of operating companies, foster a set of productive approaches to quality, and share those with the industry. OGDDQ will develop process capability specifications for drilling tools, machines, and
instruments based on the desired outcomes of operating companies; these include: accuracy, precision, resolution, repeatability, reliability, safety, environmental, form factor, usability cost, and other process needs. They will develop high-level recommended practices for field-verification of drilling equipment.

To date, the Operators’ Group has completed work around sensors and equipment critically pertaining to safety. This includes top drive calibration, standpipe pressure measurements, block position, BOP testing expectations, make-up torque calibration and verification, and mud pump calibration and verification.

Q&A

Q: When will the OGDDQ share the documented standards and requirements with Service companies?
A: It is currently in draft form right now; we will release the first draft for comment in the next couple of months. We want to get it really spread out to all stakeholders.

Q: Current WOB measurements are derived from inaccurate hookload measurements. How does the OGDDQ envision improving weight-on-bit, WOB?
A: (Nathan Zenero) This is a multi-phased approach. We’ve set a priority for each measurement; derived measurements, such as WOB, are a whole different story. WOB is not in first round but will be in round 2 which will also include downhole measurements and other problems with downhole measurements.

Q: As an offshore operator, to address our data quality concerns, we employee a 3rd party to provide us quality data for our Real-Time Operating Center (RTOC) analysis and planning. Can we make this approach effective for 3rd parties?
A: Here is an analogy – rent a car and use a 3rd part speedometer. Do I know how fast I am driving, really? How can I trust it? – 3rd parties are used, but as an industry, those who provide the service have to be responsible for the quality of their data. If an incident happens, a 3rd party EDR system and the rig’s measurements conflict. As an example a rig’s poor hookload measurement reads 400,000 lbs pull which is less than 465,000 tensile strength of the pipe, but the pipe parts. Investigation shows the 3rd party system maxed out over 600,000 lbs, but Driller ignored this thinking his system was right. Data quality is important even on the most basic level.

Q: Reliable data that only comes from a single sensor is not feasible.
A: We have to have sensor redundancies if the sensor is critical and potentially different physics for the measurement may be required.

Q: Data quality is highly subjective. Are you looking for data quality requirements for difficult operations? How can we have data quality when metadata never gets stored? Are there any initiatives?
A: The OGDDQ recognizes this as a problem. We have yet to work on it.

Q: What is not achievable with existing sensors?
A: (Nathan) Current business needs and climate can be met right now with current sensors, but not necessarily for automation.

Q: In the OGDDQ’s current exercise, how do you find required solutions that do not yet exist in the market?
A: This is recognized, but our first efforts are focused on meeting current business needs. For requirements that don’t yet have solutions in the market, then the industry must create new tools and sensors driven by value to the Operator.

C: Downhole sensors, today, are good but the data is not well understood or utilized. The group plans to address these sensors as well.

Presentation 3: DSATS Data Quality Assurance Team
Speaker: Pradeep Ashok, University of Texas at Austin
The Data Quality Assurance (DQA) Team is an open subcommittee of DSATS with a similar charter as the Operators’ Group on Drilling Data Quality made up of operators, service companies, contractors, and academia. The team’s charter is to define an industry understanding of the required levels of drilling data quality for systems automation of monitoring, advice, and control. The DQA team will document minimum data quality required for reliable drilling systems automation and recommend methods for validating that the requirements are met.

The charter is sub-divided into four tasks – surface sensors, downhole sensors, contextual data, and derived data. The surface sensor task group intendeds to develop recommendations for the selection of surface sensors, specify required metadata, identify and document uses cases for which current instrumentation does not provide sufficient data quality. The downhole sensor task group will develop an open method for detailing the quality, transparency, and integration of data from downhole
memory and real-time measurements. The contextual data task group is focusing on contextual data recommendations for capture and possible ways to capture them. Contextual data includes: well state, drilling state, machine state, non-drilling state, intent, metadata, and security. The derived data task group will provide recommended and best practices for common derived information such as ROP and WOB; this includes: equations, time domains, and metadata for each Level of Automation.

**Q&A**

**Q:** Will DQA define how contextual data and natural language information from things like notes and IADC reports be processed in EDR?

**A:** The DQA team is not looking at this at the moment, and we hope the industry will pick this up.

**Q:** Pattern recognition approaches may present a challenge for the DQA requirements from the overall system for things like kick detection software. Requirements are dependent on the application and the process. How do you address the ambiguity between system requirements?

**A:** We realized that very early on that the requirements are dependent on use cases. We intended to define requirements for standards measurements and systems and provide a methodology for determining requirements.

**Q:** Sensing modality, methodology in current sensors/ new sensors might reduce some of the requirements.

**A:** We hope this is the case.

**Q:** What is the relationship between DQA and OGDDQ?

**A:** We formed the DQA group as an open group. The of Operator’s Group have a focused objective that is needed in order to make changes as soon as possible. However, many of the OGDDQ members are in the DQA group and working concurrently with Services companies and Academia.
Session 2: Trajectory Drilling—Quality Wellbore in the Right Place

Chairs: John Macpherson, Baker Hughes; John de Wardt, Consultant

The benefits of advanced sensing and control in three aspects of directional drilling will be examined in this session. These aspects are:

- Recent advances in surveying provide new insight into micro-tortuosity, leading to reduced nonproductive time and lower production cost.
- Automated control of sliding uses the aggregation of downhole and surface measurements coupled with advanced controls and user interfaces.
- Automated geosteering involves the interaction of measurements and actuators to steer the wellbore through geological targets using downhole and surface-supported control loops.

Presentation 1: High Frequency Survey Data – Understanding the True Shape of the Wellbore

Speaker: Steve Mullin, Gyrodata Inc.

Directional wells are traditionally drilled taking an MWD survey every stand (about 90+ft) and often less frequently than that. The calculation software assumes a constant curvature between these survey points and this is believed by many to give a clear picture of the shape of the wellbore. But often a directional driller or automated drilling assembly is making course corrections between these survey points in order to follow the plan. Drillers know when the next survey will be taken and sometimes make excessive corrections so that they are seen to “paint the line”. The subsequent tortuosity introduced will cause problems and costs for the life of the well. Examples from a new micro-guide log will show that this really does happen. And an example of how a novel rotary steerable technology, can be used to prevent high tortuosity being introduced, still ensuring accurate geometrical placement while drilling.

Q&A summarized for all presentations at the end of the session.
Presentation 2: Combining Downhole and Surface Sensor Data to Automate Steering While Slide Drilling

Speaker: Carlos Rolong, Canrig Drilling Technology

In recent years, surface oscillation systems have proven effective in improving slide drilling efficiency and quality. The next step in surface sliding control is to automate the steering process by aggregating downhole and surface measurements, coupled with advanced control systems and user interfaces that support the directional driller’s workflow. This presentation will discuss some of the challenges in achieving automated steering while slide drilling and the technology used to overcome them. The scope of the presentation includes: surface sensor resolution, signal conditioning and processing, TF resolution, accuracy, and data acquisition rate, control algorithms in the PLC, and user interface design along with human factors and driller workflows.

Q&A summarized for all presentations at the end of the session.

Presentation 3: Reservoir Navigation – Decision Processes for Optimized Geospatial Positioning

Speaker: Gavin Lindsay, Baker Hughes

Optimizing well placement with respect to the reservoir, in order to increase production, requires simultaneous update of geological, petrophysical and reservoir models. Moreover, this requires that updates are carried out in near real-time in order to positively impact well placement. These models are driven by multiple data sets, from seismic while drilling to deep azimuthal resistivity and near-well bore imaging. Interpretation of these data sets can no longer be carried out by simple inspection: typically advanced processing (e.g. inversion) is required, followed by some synthesis and visualization in 3D space to arrive at the best decision to meet reservoir objectives. This presentation illustrates this process as carried out in operations at the current time, and further considers automation of this process, and the continuing role of human expertise to the successful outcome.

Q&A summarized for all presentations at the end of the session.
Question and Answer Session

Q: (Carlos) Performance comparison, how long does it take for the human to make a change as opposed to the machine?
A: It would be unfair to compare that. The autodriller makes small incremental adjustments in milliseconds, while humans make large adjustments in seconds or minutes. You must evaluate the effectiveness of the slide and weight-on-bit transfer from an overall perspective.

Q: (Carlos) In your demo, why is there a change in the top drive but no change in the toolface?
A: The top drive is reacting to surface data that is calibrated using downhole data. The top drive makes decisions while the feedback from downhole may be received 15 seconds later.

Q: (Carlos) Are you reacting to diff pressure as a proxy for WOB? Are you using it or reacting to it?
A: We are making use of a combination of surface data and downhole data to adjust those and use the rest of the data to infer toolface.

Q: Where to put the well, trajectory of the well. What is the value of a feed forward model and how accurate does the model have to be? What about sensitivity? What is the next big input?
A: (Carlos) Models are valuable. Currently, other factors like hole cleaning and tortuosity are being evaluated. Auto sliding is enable by downhole info (continuous inclination, ECD, etc); the more accurate, the better.
A: (Steve) Data will change the way we look at drilling, BHA design, directional drilling, geosteering, etc.
A: (Gavin) Being able to reduce the time it takes to make decisions – terrain fracturing, continuous steering, and wellbore construction. More information allows for better decision making to yield the best result. The goal is better wellbore placement to improve the ultimate recovery.

Q: Next step is auto steering. Is it plug and play? Open to other systems?
A: (Carlos) The main component is patented. In general, our goal is to make this as available as possible.

Q: In the future we may see a combined system of all the new technology for automated steering (RT geosteering, placement optimization, etc). How do you manage potential system conflicts from the enterprise level? For example, two applications desire two opposing commands. What makes the final decision?
A: (Gavin): The automation framework needs to be built up from the priority of decision and
boundaries based on the ultimate goal – maximum production vs. maximum recovery. These ultimate goals must be decided up front.

A: (Carlos): The current challenge with the existing models in the industry today is at the contractual level. How do we deliver wellbore construction and well delivery? We will/should be a team, all in the same boat.

Q: (Steve): “Can’t miss the target, but can’t afford good survey measurements.” is a common dilemma. What is the real value for continuous survey data?
A: The value proposition. High resolution, accurate survey data is useful throughout the entire life of the well – well placement, production equipment placement, reservoir models, etc. Even for low cost targets, what if in five years the operator wants to drill close to target and avoid well collision?

Q: Is GWD available for wired drill pipe or other high frequency telemetry?
A: GWD is currently available for mud pulse or electromagnetic telemetry, wireline, or memory only.

Q: Does GWD actually reduce or eliminate time for common survey practices?
A: Continuous GWD eliminates survey time because surveys can be taken while the string is dynamically moving. There is no need to stop to take a survey.

Q: Is the continuous gyro data synced to surface in RT?
A: There are multiple applications and deployment methods – wireline, GWD (mud pulse), and drop gyro (memory multi-shots).

Q: The reason why operators take incomplete surveys is to save time. How does that apply to continuous surveys?
A: Conventional methods of making surveys require stopping. Continuous GWD does not require a stop to make a survey.

Q: What are the best applications for you three technologies? Success? Sweet spots? How can they be implemented on a larger scale?
A: (Mullin): Currently, optimizing placement of production equipment. But in the future, optimization directional control, and understanding/improving BHA design.
A: (Carlos): Enable truly effective directional drilling, remove the directional driller from location -> cost and performance is both improved. Our next steps are to improve models. Large scale remote directional drilling provides huge value savings.
A: (Gavin): Terrain tracking/geosteering to optimize long term production potential.

Q: Interconnected and interoperable systems may create an IP dilemma between companies. How might Operators resolve the IP dilemma in order to use different tools and systems from different companies?

A: (Mullin): GyroData equipment is already compatible with standard MWD providers.

A: (Carlos): Most of Canrig’s technology is already compatible, as well. However, to deliver interoperated services it will require a change in business model! We will simply develop partnerships.

C: We have no knowledge of the IP and no experience with the IP.
Session 3: Influx Prevention

Chairs: Andreas Sadlier, Halliburton; Fionn Iversen, Iris

It is critically important to recognize trouble zones and predict potential drilling hazards before they occur. Speakers will present solutions used today which combine planning phases of pre-well models with real-time information gathered while drilling to provide a continuous risk assessment and effectively reduce the probability of influx or kick events.

Presentation 1: Pressure Prediction and Process Assurance – Study, Assess, Monitor, Escalate, and Resolve

Speaker: Ian Says, Baker Hughes

Pressure Prediction and Process Assurance: Study, Assess, Monitor, Escalate and Resolve

The hostile nature of drilling environments coupled with financial and ecological impact of well control incidents has driven the need for enhanced risk identification, management and communication. In response, the industry has engaged in various process safety initiatives focused on flawless execution at the well site. What, though, is occurring at the operations support level? Are operations support groups enabled to mitigate process risks from their end?

The “BowTie” methodology is known and accepted in the oil and gas industry. “BowTies” made operational for real-time monitoring and management provide an opportunity to mitigate identified threats and potential incidents as well as remediate challenging conditions. The effectiveness of the processes to analyze or respond to threats noted in the “BowTies” is dependent on the experience and training of the operations support groups.

Many reports and studies have found the lack of process assurance, the inability to correctly execute procedures, is a root cause for well control incidents. Equipping the operations support personnel with a real-time process assurance system enables easy access to risk mitigation strategies, processes and procedures for identified threats and to respond with confidence in a timely manner, thus preventing potential catastrophic incidents or minimizing the impact.

This presentation will focus on pressure prediction modeling, risk identification, blind spots and real-time process assurance for pore pressure operations support. It incorporates a case study that presents all of the aforementioned points in action to respond quickly with positive results.

Q&A summarized for all presentations at the end of the session.
Presentation 2: Importance of Monitoring Real-Time Geopressure

Speaker: Zach Metz, Berger Geosciences

Real-time monitoring is a hot topic in the industry right now. Currently the government is exploring the possibility of making real-time monitoring mandatory for all the wells drilled in the Gulf of Mexico. This may have implications in regards to real-time geopressure monitoring. As such anyone monitoring real-time geopressure needs a good understanding of the effecting factors and limitations of the pre-drill models into the real-time monitoring plan. Secondly, a thorough communication plan must be put in place to successfully prevent and/or mitigate hazardous well events, accounting for uncertainties and limitations with real-time monitoring. This discussion outlines the pre-drill inputs into the real-time model, defines the methods used in real-time monitoring, emphasizes the importance of effective and timely communication for all parties involved, and highlights the benefits of real-time monitoring.

Q&A summarized for all presentations at the end of the session.

Presentation 3: Deepwater Geopressure Risk Mitigation – Planning Through Execution

Speaker: Nigel Yip-Choy, Halliburton

An ounce of prevention is worth a pound of cure. Nowhere is this more relevant than in deep water, frontier plays, where high overpressure, small drilling margins, depleted zones and proximity to salt bodies combine to form a complex, high risk environment. Geopressure related NPT events manifested in the form of loss of well control, lost circulation, stuck pipe and wellbore instability have cost the industry billions of dollars, and yet, are avoidable with the right technology and process. This presentation describes Halliburton’s approach to mitigating risk in deep water exploration plays through a comprehensive application of technology and process. This combination of advanced geomechanics pre drill modeling and rig site / real time model updates consistently delivers enhanced safety and drilling efficiency.

Q&A summarized for all presentations at the end of the session.
Question and Answer Session

Q: What can be done to take this to the next level, with respect to prevention of influx?
A (Zach): Technical expertise is the first step – physical education degree, subject matter experts in the field doing this work. Use experience gained from years of monitoring. There needs to be technical sophistication. Effectiveness of the monitors in real-time, field or remote is key.
A (Ian): Admitting that we don’t know everything. We can drill the same well next door and it can be completely different. We need to admit this as an industry
A (Nigel): Interpreting geomechanics and geopressure starts with a good model. We can reduce the uncertainties by updating the models with real-time data. While a model is a good start, we don’t know it all; things are very heterogeneous.

Q: One of the problems faced is that this falls within the discipline of isolated and siloed functional disciplines that the driller isn’t privy to or isn’t using. Geology, petrophysics, etc. is actively used by drilling in very few companies. How do you get the drillers to act on it, how do we bridge that gap?
A (Zach): Large organizations have this disconnect. Education is important. Forecast what will happen to the well beforehand then educate and inform your people on the rig pre-well. Group the different departments together. Perhaps third parties could guide that process.
A (Ian): Having proper communication protocol and escalation procedures is vital. This has to be agreed upon before the process. A Norwegian study showed that lack of process and communication is responsible for 80% of problems. Trust has to be developed early on.
The current culture is that if you’re wrong once, the trust does not come back again. Answers have to be consistently right.
A (Nigel): Root cause of many of the malfunctions is lack of communication. Geo-mechanics forming part of the basis for designing the well is critical. It needs to be represented in the drilling operations group. They need to understand the constraints on the operations. Drillers may or may not be as receptive to 3rd parties. Process and organization structures on the operator side are important.

C: Operators could have better, shared KPIs and goals on successful well deliveries. Right now they are often even contradictory. Unless the goals and KPIs get aligned, it will be hard to establish this connection between geology and geomechanics and drilling.

C: Data integration requires an understanding of the limitation of the data of all parties involved. Data might be good enough for a specific application, but it cannot just be taken for another purpose without understanding it properly. We move on in technology, so our data and models are not good enough anymore.
C: We need to admit that we are drilling different wells today than we did 20 years ago. The old adage “this is what we’ve always done” will no longer work. We need to apply the great technology now rather than forcing it into the way we did things yesterday. We can no longer accept, “dogma ate my well.”

Q: Pre-processing pre-drill models seems like a lot of work. Is the data quality good enough for this particular purpose right now?
A (Ian): Data quality control has to take place regardless. Often the question is whether data exists or not. This is more important than simply improve existing data quality; we need to get more coverage of data if possible. This allows us to make the whole field comparisons if the data exists for each well.
A (Nigel): Data quality is quite sufficient (MWD, LOT, etc.). We are trying to reduce the uncertainties by getting a better understanding; many different interpretations exist of the same data.

Q: What sort of advice would you give to sensor companies? Better sensors or better processing data?
A (Ian): Shear data in real-time and quicker turn-around of processing of shear data would be great to have.

Q: This workshop we don’t expect answers, we just get the discussion going. For me, in a workshop like this, what can we practically do to make it better? Get the right data to the right person in the right format at the right time. In this session, what can we do to help the driller in his job? We have a workflow issue. What does the driller know about this, how much of the pre-drill planning is the driller aware of? Drillers usually never see the well pre-drill plan. Can we display the data better to the driller, give alerts, etc. to make him do a better job, e.g. you might have just exceeded frac pressure, etc. What tools can we give to the driller?
A (Zach): Education on the rig is the key. Talk about potential problems and mitigation strategies before the operation starts.

Q: Build on previous question: One of the key things we don’t do, we don’t give the driller the speedometer. We don’t give the drillers the right downhole information to do their job right, as in showing downhole data or the limits of operations.
A (Ian): How can we make sure the driller understands the hazards before they happen? – Delineating the escalation chart, sharing a common view, understanding the basics that are particular to the area. We might be able to implement some form of traffic light system.
Q: Automation is supposed to help the communication issues. Does it actually help?
A (Zach): Automation certainly could help. I still believe that we still need subject matter experts to interpret and understand the science behind the data.
C: Saying that you will always need experts is basically saying that you don’t want to go the next step. It’s time to think about something actually different.
A (Ian): Properly, triggering and enabling the experts is the actual key. The question is just what these triggers should be.
A (Nigel): Our session is predictive. The next session is about prevention once it actually occurred. Pressures at the rig floor, many of these issues are not the driller’s decision because he wants to save time. This goes back to the common KPI discussion from earlier.

Q: Breaking down the silo effect; we use Monte Carlo and other well established analytical methods for geological evaluation. First question – Are these methods passé? Second question – Are integrated operations cross correlation of information across disciplines effective?
A (Nigel): Geo-mechanics really bridges all these different disciplines.
A (Ian): We have to look at new technologies and changes in the way we do things, but at the same time, if we are talking about doing more automation, we have to be cognitive of the fact that engineers/personnel will be accustomed to using these new technologies and don’t actually know what they are doing.

Q: Under the assumption that your models work. Are there any sensors ahead of the bit that could make a difference? What are the things that make your predictions more accurate?
A (Ian): If you have one or multiple imaging tools in the hole and can look at it in real time, using that information (e.g. check if a thief zone can be detected) and have a proper workflow established and being able to take the time for that would help. Mud laboratories downhole would be great to have. E.g. salt water influx into the wellbore, change of the drilling fluids downhole, etc.

Q: How do you determine, operationally, what the pressure in the borehole is without a sensor down at the bit? This is all based on mud weight, which is measured 1-2 times a day.
A (Nigel): PWD is our downhole sensor for pressure. We use LOTs FIT to infer the pressure but it’s difficult to really know the actual pressure in real-time.
A (Zach): We use real-time data to understand if our models and predictions were accurate. We use a combination of multiple sources of information to understand the downhole pressure.
A (Ian): Fast, reliable uplinks of downhole data is key to have.
Session 4: Influx (Kick) Detection

Chairs: Mark Anderson, Shell; Moray Laing, SAS

This session will focus on new solutions in three key areas of influx or kick event detection. The areas are:

- Providing accurate and timely measurement of the influx.
- Integrating the measurements and the alarms with the well control systems.
- Automating the identification and notification of any influx or kick event to the driller through displays that are both clear and actionable.

Presentation 1: Improved Sensors and Smart Alarms Pave the Way for Automated Kick Detection

Speaker: Brian Tarr, Shell

Presentation will summarize the journey from initial analysis of existing rig-based kick detection systems to field testing of a new style automated kick detection system jointly developed by Shell, Noble and NOV.

The initial analysis indicated the high value of improved sensor data (both accuracy and reliability) and of improved kick detection software (both in terms of coverage and how the driller is alerted to respond to a confirmed kick condition). The Gulf of Mexico field trial demonstrated the enhanced functionality of this first generation automated kick detection system and highlighted areas for further improvement.

Q&A summarized for all presentations at the end of the session.


Speaker: Chris Russell, Emerson

Coriolis meters are a revolutionary step change in accurate flow and density measurements of complex drilling fluids. With very high accuracy and precision of measurement for mass flow rate and density, Coriolis meters prove invaluable for early kick detection. This presentation describes how Coriolis meters work and the advantage of using Coriolis meters while drilling.
Q&A summarized for all presentations at the end of the session.

Presentation 3: Multi-Sensor Information Fusion for Improved Influx Detection and Reduced False Alarm Rates

Speaker: Peter Torrione, CoVar Applied Technologies and Sean Unrau, Pason

Multiple sensors combined with an effective algorithm are so much more effective than individual sensors which are alarmed. For example connections are difficult situations for simple sensors including Coriolis meters and most alarm systems are turned off or mostly causing distraction during connections. Another points include potential to reduced driller workload and human error by eliminating Driller input.

Q&A summarized for all presentations at the end of the session.

Question and Answer Session

Q (Peter): How many parameters (streams of data) can you handle to monitor in your system before it becomes hugely complicated?

A: The actual implementation details are complicated – we may have multiple mud tanks and sensors. This is not processor intense, and the actual outputs and display are not that complicated.

Q (Sean): Who is the end user of this system?

A: The system is designed to be distributed to all the people involved, multiple users. Drillers are the first and primary end user, but also engineers in the office can use it.

Q (Sean): What frequency of the data do you need for the machine learning input.

A: We are using 1 Hz surface data for our models. Also lower frequency data works for your system surprisingly well.

Q (Sean): As Pason, are you ready to be that kind of data integrator for the Coriolis meter (11 data streams)?

A (Sean): Yes, we can integrate that data. Pason accepts Modbus inputs.

Q: You mentioned a specific downhole drilling time for your data training set. What kind of variability
did you account for in that data set? Did you come up with different algorithms?

A (Sean): We analyze our data in an anonymous way. Our algorithms don’t really work by training. The algorithms aren’t trained from historical data but rather from recent data from the same well. It, for example, learns from the last five connections from the exact same well. The models are physics based models rather than completely statistical. Coupled together, this gets rid of the training bias.

A (Peter): All of the data set is from North American Land drilling. We’ve gotten new data since, and it worked for new data sets.

Q: What was the number of kick or influx incidents did you see in your data sets?

A (Sean): We have a lot of data, about 30 influxes and about 30 losses in the whole data set. It is hard to find these incidents in the huge data sets. We don’t use algorithms like support vector machines, etc. We use actual physics based modeling for our algorithms. 1 or 2 were well control events while many other events were very small, like 0.5 bbls.

Q: In the introduction you said you had a data driven approach, but now you’re saying it is a physical approach?

A (Peter): You have to have a sound physics model underlying. Its physics based and statistics based, but on a very simplified level.

C: Perhaps the industry can/should adopt you Probability of Detection vs. False Alarm Rate and Event to Detection Time as a metric for event detection algorithms.

C: Data transmission has to be part of the solution when you think about this whole system. With WITSML data comes in batches every minute or every 30 seconds. Parts of the data were “late” and came with the other batch. The batches did not come in in order, so this posed challenges on our rig state detection system.

C: Rig States play a real role in occurrences of taking a kick; for example, a kick is more likely while tripping and making connections than while drilling. Current EDR systems rely on the driller to manual change a rig state flag in the EDR. Turning off the pumps to make a connection typically causes false alarms for early kick detection algorithms because the EDR is still in the “drilling” state. Accurate real-time rig state detection algorithms are required for the success of early kick detection algorithms.

Q (Brian): Is there any correlation between operational consistency and the false alarm rate?
A: This project is from one rig.

Q: You mentioned very small losses can be detected with your system. Does this include filtration losses?
A (Chris): I am not sure what they do to account for this.
A (Brian): When we have a MPD system, we can push fluid through the Coriolis meter. We don’t see significant filtration and seepage losses.

Q: High sensitivity Coriolis meter, is it mass produced?
A (Chris): Yes, they are mass produced. The same meter can be used for other industrial applications.

C: What is the value of detecting a quarter barrel kick and being required to stop operations to circulate when we could previously continue drilling ignorant of the same kick with no safety repercussions?

Q: There is great value in historical data for coming up with and training new analytical algorithms that are critical for automation. Is there a way or a forum for open source data sharing that has proprietary information removed? Can the data be donated to academia?
A: At every event like this, everyone says it would be great to share that data. But there are no rules around that, and we are happy to share it if there were.
C: Ultimately, operators’ own the data and there is monetary value in it.
C: Perhaps the Operator’s Group for Drilling Data Quality or something similar should evaluate an approach to open source data.
C (Major Operator): We will not openly share our data.
Session 5: Influx Management

Chairs: Fred Florence, Rig Operations; Nathan Zenero, Chesapeake

The human factors, safety, and economic concerns that drive automation will be discussed. Presentations will focus on how an automation system achieves influx management both safely and reliably using adaptive control techniques posed by the following question. After detecting a kick, how do we shut in the well and circulate out the influx using sound automation techniques?

Presentation 1: Automating Influx Control and Decision Making Processes Before Handover

Speaker: Ferhat Gümüş, Weatherford

The presenter gave an overview of automated influx detection and the influx control system. The system provides visual feedback on the location and size of the kick that helps to understand the process and requirements. The automatic control procedures as described go through multiple stages (modes) if necessary to control the well by principally using an adapted form of the driller’s method. These automatic controls include details on both the well control aspects as well as equipment aspects. The influx detection mode is followed by the reaching circulation pressure and circulating influx out mode. The software confirms if the influx is out and continues with kill mud selection mode. The position of the influx as well as the kill mud within the wellbore is visualized by the software. Once the situation is under control, we can make use of ‘just in time simulation’ capabilities. The system now allows to change the boundary conditions and assumptions used for the simulation that were insufficient to prevent the influx before, either manually or automatically. Also discussed were workflows the engineers use regularly to determine dynamic vs conventional well control, i.e. when to dynamically kill the well vs passing control over to standard well control techniques.

Conclusions:

- Utilize latest flow and pressure measurement technology; coriolis, not pit level.
- Detect, control and circulate the influx out
  - Real-time simulation; compare sensor with predicted value
  - Closed system, so influx volume measurable
  - Calculation based on rheology
- Calculate/predict maximum pressures and flow rates at critical depths in the well and at surface real time
- Prevent making wrong decisions which may cost valuable rig time or safety compromises
Presentation 2: Barriers and Options for Automatic Well Control in Subsea Drilling

Speaker: Børre Fossli and Zhizhuang Qiang, Enhanced Drilling

Automation in well pressure management during over balanced drilling and MPD operations is gaining acceptance in our industry, but there is still considerable resistance to automate well control. Reliable and correctly placed instrumentation downhole, subsea and topside feeding a reliable control system are essential. This presentation touches on experience with sensors and control systems gained from operating the well pressure management system in deepwater GOM and on the NCS. Further it will outline the options and potential for automatic well control that exists and barriers that have to be overcome.

Summary and recommendations:

- In order to go automatic, the sensor both on flow and pressure need to improve. We do automatic pressure management, but there are some liabilities and structures that prevent us from flow control. We need to practice in order to move to the next level, just like no one wants to fly on an airplane with an inexperienced pilot.
- I consider wired pipe as a prerequisite for automated pressure control.
- Automatic well control in subsea drilling is not impossible to do, we have challenges to overcome that are mostly organizational or human based, not technical. It cannot done by small companies alone, since regulators and operators need to be involved in this. The real challenge is to get approval and budgets by our management to pursue this.
- BOP pressure measurement is better; subsea flowmeter would improve performance
- Better if linked to the controls of the rig pumps

Q&A summarized for all presentations at the end of the session.

Presentation 3: Gas in Deepwater Risers: Problem or Hidden Opportunity?

Speaker: Paul Sonnemann, Chair of IADC Gas-In-Riser Workgroup, Safekick

The presentation showcases recent work by the IADC Gas-In-Riser Workgroup to assess and improve our ability to understand, quantify, and potentially control deepwater riser systems containing large
volumes of gas has led to several unexpected and surprising results.

Ways are explored in which the resulting improved understanding of underlying relationships suggest ways in which well control outcomes might be improved, rather than compromised, by permitting even large unexpected gas influxes to enter deepwater risers, where they may be managed efficiently without compromising personnel and environmental safety, or well control objectives.

Conclusions:

- The phenomenon of ‘explosive unloading’ cannot yet be really well explained with conventional models, since it behaves differently than traditional well control. So there are a lot of uncertainties around this phenomenon. Our group developed a logical explanation for the phenomenon of ‘explosive unloading’, which helps to understand and counteract it better.

- There is an opportunity in the future, to not only accept the presence of gas in the riser, but use it as an opportunity. We quickly move these unknown conditions into the riser, and keep the gas there to manage it properly. Willingness to do this has to be there. We limit ourselves thinking we have to close the BOP for even a small influx, this limits the technological advancement. Considering the separation of riser and well below BOP gives us a lot of flexibility.

- The challenge is to find reliable modelling tools, so the behavior of the gas is much more predictable. There is a value of real time measurement of gas, but decision making is based on understanding of the behavior.

Q&A summarized for all presentations at the end of the session.

Question and Answer Session

Q: Børre, you said there is nothing more powerful than early detection, but I would say there is something more powerful: Prediction! What do you think?
A (Børre): Up until now, the inherent use of MPD is always in difficult wells, where prediction of pore pressure is so unreliable that predictions don’t work. It would be nice to know beforehand, but we often don’t know, we don’t live in a perfect world. So I still believe that early kick detection and the correct procedures must happen. Prediction is part of the point I was trying to make, once you have detected a kick and know what it is, it is going to take 1-2 hours until you see it at the rig.

Q: Gas is coming in in multiphase, it is slugging, coming in in batches, but not bubbles like they teach in well control classes. How do we deal with that ambiguity?
A (Ferhat): We are using the bubble assumption right now, because more complicated fluid models
would exceed the calculation time and processing powers we currently have. In the future, with progress in technology, we might be able to account for that.

A (Paul): Many are very interested in accurately predicting what is going to happen, but it does not really influence the actions we take, which is the ultimately all that counts. One of our challenges in well control is that we go so slowly that we cannot use some of the existing measurement tools. If we are really interested in downhole pressure, we can use PWD, but we are limited by flow rates needed to operate the tool’s telemetry system. Use of high rate and real time data is fantastically valuable, more than exactly predicting what will happen.

Q: Børre, did you have any research or study on the cost effectiveness and what are the steps to include this?

A (Børre): The main idea of MPD influx control is not to shut the well in, but just circulate it out during drilling. The cost benefits are beyond $5 Mio, to circulate out any influx. The real cost is that in reality the well control event takes a lot longer, and the casing may have to be set higher.

Q: Paul, the volume of gas downhole and in the riser will be different. What are the volumes the RGH system could handle?

A (Paul): The system could handle at least 100 bbls of dry gas at the bottom. Mechanics and physics of the system can be easily calculated and modeled.

A (Børre): State of the art is OLGA, a dynamic multiphase flow simulator, we used for our simulations. We calculated, that we could circulate out the Macondo influx, and would have no issues and excess pressures at the surface

Q: It’s been 9 years since the first system like this has been run, but in fact there was no progress. Most companies predict the BHP, no one actually measures it.

A (Paul): You identify the fact that there are working solutions out there, but they are not being used on a regular basis. We need to analyze the barriers to change. One of my observation is that there is a lot of presumed expertise in this world, where people do not really understand what they are talking about and cannot back it up with numbers. Engineers often use assumptions when they move into unknown territory. It is remarkable how rarely some people can answer why they follow common practices.

A (Ferhat): Service companies in general adapt technology quicker than operators, so they have more of an open mind than operators.

Q: As operators we see a lot of redundancies of equipment and sensors on the rig. What can we do
A (Ferhat): I don’t think redundancies are a big problem, because all our sensors are critical and we would not place them if they weren’t essential. We are willing to share our data with anyone else.

C: As an operator that has used MPD extensively, I can confidently say that there are operators out there that use MPD to enhance efficiencies and drill more wells safer. The industry is still kind of struggling, there are technological problems (examples: risers are not part of the well control system right now, leading to issues with H2S ratings, testing of equipment). There are some hurdles and concerns (technical) that need to be addressed. We are trying to steer a path to get this to a safe and satisfactory employment of this, but there are barriers that we have to overcome on a holistic level. We have to together work through the barriers and cannot just throw rocks at each other. I hope to continue the dialog and make the technology sound and safe.

A (Børre): Yes, I totally agree. Of course there are challenges with this technology (e.g. H2S), but it is more a complexity cost issue. The solution to this is to carefully analyze all these addressed factors.

A (Ferhat): In the field I started observing 3 different manifolds (choke control, MPD and riser control manifold). If we continue like this we will end up with 10 manifolds. I believe that we ultimately can combine all of them into one manifold. We are moving towards giving the well control operation/MPD towards the rig contractor, it will become a standard operation as opposed to a service.

Q: Onshore influx management is still a significant issue, I’d like to know more about influx management onshore and what are the next steps?

A (Nathan Zenero): We are currently working on this and I will talk about this tomorrow.

A (Paul): We have learned enough of our MPD experience to apply this effectively to land operations. We have a couple of examples of existing applications already, with operators using RCDs, flow meters, and better sensors, hence better measurement of existing operations. We can take advantage of the technology that is already available off the shelf. But we are doing a much better job than 5 years ago.

C (Fred Florence): For us to be able to speed that process up, we could have two different ways to handle influx. If it is small, we use system 1, if it is large, we use system 2. Things like that, involve a quick mindset change but have huge opportunities.

A (Farhat): I think it is a cost issue. Technology-wise, whatever you can apply offshore can be applied onshore as well. But on the land, MPD currently is more expensive. We have to automate the system enough, such can achieve a lower price, e.g. by reducing the manpower required. Then the adaptation will be much better.
Q: If you had the means of detecting the influx downhole, what would be the value of having this downhole?

A (Paul): There is perhaps a negative value of measuring something we do not want to respond to. Imagine there is an advanced system in place that allows the detection of a very small influx (e.g. 1 bbl or less). But now we need to shut in the well, because we need to be responsible. Without instruments we would have ignored it and it would have been totally fine. Do we really need sensible downhole measurements that detects a quarter bbl kick downhole, or should we rather make absolutely sure that a 5 or 10 bbl kick never ever becomes a problem?

Q: At Shell, we drill most of our shale wells underbalanced and manage our kicks and influxes using rotary heads and we didn’t have problems with kicks. Why isn’t the industry using wired pipe, we haven’t yet seen the advantage of the severe costs of wired pipe. The marginal gain from an automated well control system over a manual system is not all that great.

A (Børre): I have no idea about wired pipe in onshore operations. On floaters there are a lot of issues: during the last 2 years, every small well control incident cost 2-10 days of rig time, and also possibly setting casing higher. If you know what the pressure is and have the ability to manage the pressure in real time, there is a real benefit and synergy in this.

Q: In the remote operation centers, how well is geology and pore pressure integrated today?

A (Mark Anderson, Shell): G&G and drilling are different units in many companies, but in our company we just adapted the setup such that the pore pressure prediction folks are in the same room as our drilling engineers, also the engineers managing BOPs are in the same room. They are physically all together in our re-design remote operating center.

Q: How sensitive are hydraulic models to the diameter of the wellbore, how critical is it to exactly know that?

A: Hydraulics models are extremely sensitive to flow rate, which is a function of the area perpendicular to the flow. So the diameter is really important.
Session 6: Borehole Stability

Chairs: Riaz Israel, BP; Mikhail Gurevich, Schlumberger

Many drilling failures are caused by unstable boreholes. Instability can be caused by mechanical failures, erosion, poor hole cleaning, or chemical reactions between fluids and formation. Failure to manage these can cause major issues during drilling and in delivery of robust zonal isolation. This session will explore the range of technological advances in delivering high quality wellbores, from predicting and monitoring borehole stability issues to the novel drilling techniques and effective zonal isolation methods in use today.

Presentation 1: Automatic Hole Cleaning Conditions Detection

Speaker: Julien Converset, Schlumberger

The presented hole cleaning and wellbore risk reduction solution monitors hole cleaning effectiveness and wellbore instability. The volume of cuttings reaching the surface is continuously measured and compared with theoretical volumes to detect poor hole cleaning condition. In drilling environment, the removal of drill cuttings from the wellbore is one of the key factors in avoiding various problems such as a bit balling, cuttings bed accumulation, pack off and pipe sticking, which could lead to formation damage, loss of circulation or NPT.

This system makes use of the installation of a mechanical trap at the lid of the shaker. This allows to weight the cuttings using strain gages, the mass is then converted in volume, using density estimates. When the trap is full, the trap turns around and unloads the cutting at once. This is installed at each shale shaker, onshore and offshore. On today’s rigs there is only a qualitative assessment of the amount of cutting coming over the shakers. We can use this to quantitatively assess factors like a sweep efficiency.

In addition, cutting/caving characteristics monitoring and rock flow rate monitoring can highlight a borehole instability issue. The solution helps to maintain good wellbore condition and provides recommendations for the mud and drilling parameters for effective removing and bringing cuttings to the surface in order to mitigate stuck pipe and pack off conditions. Two application case studies were shown.

Q: For the calculation of bottoms up time, how do you make that determination, in order to correctly allocate ROP vs cuttings?

A: We are using a simple hydraulic model for our calculations.
**Q:** Are you looking at the cutting size, to determine terminal velocity, how do you differentiate between small and large sizes.

**A:** We use a really simple model, so we can use this as an input for the calibration of complicated hydraulic simulations.

**Q:** The cuttings that are not removed by the shale shakers, e.g. fines or sands. Do you account for those?

**A:** We get an estimation and use correction factors for these.

**Q:** Hole cleaning in deviated holes is one of the most difficult things to model. I am assuming that you use a simple model for this. Your decisions are based on a comparison of actual vs. modeled results. Do you think your simple model is still valid for highly deviated hole and special cases?

**A:** We apply this on simple situations. We are focusing on the measurement, which gives us a lot of information that allows us to change the model input. The models need to be calibrated anyways.

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**Presentation 2:** Casing Running Advisory System

**Speaker:** Colin Mason, BP Exploration

Detailed analysis of real-time data from casing running operations affords unique insights into the residual health of the as-drilled wellbore. Monitoring the casing running operation is usually carried out by matching real-time hookload data with modelled drag curves. At the same time a health check on the efficacy of rig hookload sensors can be inferred.

By focusing attention only on hookload and block velocity parameters, i.e. rotary and pumping operations are not used, a case of whether automation is a good candidate for casing running operations can be posed. Aspects to be considered are casing running anomalies that can occur in both cased and open hole sections, accuracy of torque and drag models, reliability of sensors, and appropriate operational rig site responses.

BP has developed a well advisory system that has been used to monitor over 350 casing, liner and completion running operations from 30 offshore installations. Experience from these operations is provided in the context of opportunities for automation.

BP’s motivation for developing a casing running advisory system was that we experienced 2-4 stuck casing situations per year and this can be very costly offshore. Most service companies are more concerned about drilling, they don’t care as much about casing running. Capturing data on stuck casing events allowed us to do root cause analysis and find real solutions. For sensor requirements,
we used 1 Hz data. Hookload sensors tend to be the most inaccurate, facing sensor drift and outliers, requiring recalibration. Block position sensors were working quite well, bit depth is inferred from block position, which is not very reliable, low performance with low hook loads. I would like to see better and more reliable sensors. Torque/drag and swab/surge predictions were used for this system. Often, these models do not account for hydraulics, the assumptions of the models do not necessarily apply to our cases. Models should be more fit-for-purpose, can we integrate models with the rig control system. There is a good chance for the industry to develop systems that recognize and automatically respond. But how can we visualize our data in a better way? Could we develop automated responses to the anomalies that we probably understand?

Q&A

Q: 10 years ago, you were having 2-4 stuck casing incidents per year? How did this change?
A: We haven’t had any incidents where we deployed this system. But this system alone is only one part of what we’ve done to mitigate stuck casing.

Q: I am glad BP has an initiative to improve casing running, everyone else usually focusses on the actual drilling operation. What is your proposed solution instead of using hookload for WOB? Would you use instrumented bails?
A: Even though hookload is not always very accurate we are still able to use these values. In fact, the change in trends are more valuable and telling than the actual values.

Q: Colin, you said this has been deployed on 32 rigs. Do you run the models on the rigs or in some RTOC?
A: This depends on the region, some are run on the rig, others in RTOCs.

Q: Do you use offset data?
A: The engineers look at previous runs and use friction factors and other calibrations from these offset wells.

Q: You mentioned that you plan to train the operators to recognize sticking events. What is a typical period of oscillation when you observe these sticking event?
A: The casing acts like a string, so the hookload signature is a response to the load changes within the entire string.
Q: You mentioned that even though we think the wellbore is in good condition, we can still fail during the casing run. So you weren’t sure if the last trip out of the well bore was a good indicator of casing stuck risk, can you elaborate on this?
A: Yes, we saw troubles when tripping out, but no problems running casing and vice versa. That might happen 10% of the time, but maybe 90% of the time the conditions we face during the last trip and casing run correlate.

Q: Did you compare your results running casing with well trajectories, and identify effects of wellbore tortuosity?
A: Not recently, but I have done it in the past. There isn’t a strong correlation.

Q: Besides improved hookload measurements, are there any other hydraulics measurements you need?
A: We have a system looking at the mass flow into the wellbore.

Q: Are there limits on the sticking trends that are acceptable, do you have limits when you decide to come out and do a cleaning run?
A: I don’t think there is a threshold as such, I think it’s just about raising the awareness, having a discussion and evaluating the risk, but no hard threshold.

Presentation 3: Logging While Drilling Acoustic Measurements for Borehole Stability – From Measurement to a Solution

Speaker: Matthew Blyth, Schlumberger

The field of logging-while-drilling acoustics measurements has expanded greatly over the last ten years, with the advent of a number of new technologies, measurement hardware and a more thorough understanding of the physics at play. This has enabled a number of unique applications that can be applied to increasing drilling safety and reducing drilling costs. These include being able to monitor wellbore stability in real-time, assessing well integrity and drilling optimization. This presentation follows the flow of the measurement process from sensor acquisition through processing and interpretation to the final answer product and will show case studies of applications of these measurements and how they can contribute to improving drilling performance.

Q&A
Q: What is the accuracy of the USC measurement, when you use an acoustics tool?
A: I don’t know the accuracy on top of my head. The accuracy of velocity measurements is within 2 percent and USC and its accuracy is derived from there.

Q: Do you see anything of what is going on in the fluid system, the annulus, is there some latent information on this?
A: We spent a long time developing the tools to ignore the mud as well as possible, because we like to see past the annulus. Some things about the mud can be picked up, but how to translate this into information is another question. We would like to measure the mud speed, because it has a lot of implications.
Session 7: Making Hole

Chairs: Riaz Israel, BP; Mikhail Gurevich, Schlumberger

This session will focus on improving the rate of penetration (ROP) and enhancing drilling performance. In pursuit of this goal, the speakers will demonstrate examples of novel techniques that use both high frequency and conventional surface and downhole drilling data. They will describe processes that are being used to transform this data into operational intelligence, and discuss how this transformation has improved drilling performance and efficiency.

- Reduction in the drilling risks
- Unplanned events
- Reduced variance between planned and actual sensor data

Presentation 1: Use of High Frequency Dynamics Data for Lithology Identification and Bit Condition

Speaker: John Macpherson, Baker Hughes

Dynamic signatures from the drill bit during rock destruction occur within an expected range of frequencies. This frequency range is dependent on the bit type, number of cutters, and the rotational speed of the drill bit. The energy measured within these frequency ranges is indicative of rock properties such as rock strength and hardness. These rock-destruction related dynamic signatures from the drill bit will be affected and possibly masked by drilling dysfunctions such as stick-slip, bit bounce and whirl, and with changes to the condition of the drill bit as it wears.

The presentations features examples from a downhole dynamics and mechanics tool with downhole processing that measure the signal within the expected frequency range of the bit-formation interaction. This information is valuable in helping identify zones of interest, without having to penetrate deeply into the zone of interest. This measurement also helps define bit condition over the course of a bit run.

Q&A summarized for all presentations at the end of the session.

Presentation 2: Directional Drilling Guidance System for Performance Improvement and Cost Reduction

Speaker: Bill Chmela, Hunt Advanced Drilling Technologies
The complex geology of unconventional plays makes it difficult for directional drillers to accurately follow a well path defined by geologists, geophysicists, and reservoir engineers. This difficulty results in high tortuosity and reduced ROP. Drillers must make continual corrections, compensating for a vast number of changing downhole variables. In fact, there are too many variables and concerns for even the absolute best directional drillers to consider in real-time. We will present a field-proven directional drilling guidance platform that uses advanced computations in real-time. The platform guides the driller and significantly reduces drilling time and cost, while also reducing risk and enhancing future production as a result of improved accuracy. Case study results will show consistently greater than 15% improvement in ROP when using the platform.

Q&A summarized for all presentations at the end of the session.

Presentation 3: Drilling Optimization Benefits of Direct Drill String Surface Measurements

Speaker: Robert Wylie, NOV

Correct information is crucial to drilling effectiveness and well construction success, with the greatest data accuracy achieved by measurement instruments applied as close as possible to the target load. Until recently, most drilling parameters were derived from sensors designed for the use of surface equipment. These measurements were taken remotely on supporting structures or equipment related to the drill string—but not actually a part of the string itself.

Data from traditional sensors include variable friction and other effects from the surface equipment, leading to well documented errors and uncertainties in values that are being used every day for drilling decisions. Integrating instrumentation into the standard top drive IBOP allows direct measurements to be made of an extended range of drilling parameters, removing these errors and reducing the uncertainties.

This presentation discusses specifically how better string tension and torque data translates into applications such as improved weight on bit, better knowledge of torque and drag conditions, and more consistent MSE values. All of these lead directly to improved drilling efficiencies and better well construction, reducing lost-time incidents and overall well construction costs.
Question and Answer Session

Q: Robert, Referring to slide 10 of you presentation, is the data from the IIBOP going back into your rig control system?
A (Robert): The data is processed and the control system can take the processed data and use it for rig control

Q: John, is the downhole WOB data analyzed in real time?
A (John): No. Ok, let me back up on this: We do transmit some (processed) values to surface in real time, but the examples I showed were all from memory logs.

Q: John, you measure the frequency at the bit, how do you differentiate the lithological change from a change in bit vibration?
A (John): If the bit started whirling backwards, we could detect a frequency of that range, and we could misinterpret it. To do a complete analysis we look at different signals, like lateral, and try to analyze it holistically. It is a complex environment that has to be understood.

Q: Bill, is your system able to learn from the past event, e.g. sliding for 10 ft, but for some reason you don’t achieve that target, are you going to readjust the next path, or do you just go back to the plan?
A: Bill, the plan is continuously readjusted. Every time a survey station ends, it readjusts the entire plan moving forward. The system is focused on the steering, we do not adjust the ROP and MSE curves, etc. but mainly focus on the trajectories and tool face.

Q: John, there is a high correlation of lithology and vibration, can you figure out today what kind of lithology it is, or in the future, can we use this one day?
A (John): We’ve published on this topic, and we can identify gross lithology. I expect that with time we will be able to refine this.

Q: Bill, when you examine all these paths, one of the goals is to maximize ROP? Do you have a master ROP equation, is it based on historical data, or how do you do that?
A: We actually look at decreasing the overall drilling time by taking the historical times of this same well, how long did it historically take to set tool face, what ROPs did we see sliding or rotating, etc.?

Q: Robert, along the lines of data quality, I realized that the word ‘health’ was in your presentation, can you elaborate on this?
A (Robert): In addition to the measurements, there are additional things like ‘heartbeat’ of the system,
etc. Health shows if the system is working properly.

Q: Robert, in one of the slides, the traditional WOB differed from the WOB measured by the IIBOB, also the MSE was lower. Can you elaborate on the discrepancies?

A (Robert): You will see less WOB calculated from the IIBOP than from the traditional system. There might be losses through the system that show up in the measurements. Anywhere between 0 to 20-25%, how much are the costs for this lack of applied WOB the course of a well? MSE is typically 15-25% less, this means that there are significant energy losses in the surface system. All we want to know for MSE are the energy losses in the downhole system only, we want to exclude surface losses. So the best way to drill a well would be to use real time downhole WOB.

Q: John, I assume that the hole gauge between bit and borehole wall have an influence on vibrations. Do we have sensor that helps identify that gauge around the bit?

A (John): When it comes to tool face, we have magnetometers and gyros in there at the MWD level. We don’t have direct hole gauge measurements.

Q: There are several of the gaps I see using the downhole tools, one is redundancies the other one is on site inbound and outbound calibration. Also, how do you deal with time synchronization?

A (John): on the DH side there is a fair bit of redundancies when it comes to MWD. For dynamic measurements, these things are expensive, who would pay for the increase in redundancy. For automation, you can switch to surface measurements, e.g. if you lose the downhole WOB measurement. Weight is typically shock calibrated, different measurements have different calibrations.

A (Robert): On surface, when we are doing calibration, we don’t think our sensor change much over time. We have a field calibration process in the labs. For redundancies, we have got some backup things in place and you can go back to traditional sensors.
Session 8: Remote Control and Advisory Operations

Chairs: Pradeep Annaiyappa, CanRig; Jim Rogers, Chevron

There are various questions about remote control and advisory operations. What are the current and perceived future challenges in supporting various remote drilling operations? Has technology improved on the volume, validity, velocity, and variety of real-time data to support remote efforts? Speakers in this session will discuss the current technology used in the field, and review the gaps and opportunities which exist in this space from the perspective of remote control and advisory operations.

Presentation 1: Bridging the Gap – Sensors Equals Real-Time Data Equals Process Safety

Speaker: Jeff Beasley, Chevron

Real Time Data in the RT Center give us the ability to assist and collaborate with daily Process Safety in drilling environments. Quality Controlled RT data allows the user to validate and adjust models that are developed for optimal performance. Along with Quality Control, Quality Assured data gives us the ability to develop future processes that can further improve our optimal performance. Data Stores allows us the ability to mine data to locate gaps for improvement through optimize queries. Pre-planned, tested, and agreed upon procedures on calibration, validation, transmission, frequency, and storage of RT data will give us possible solutions for quality data. Our main challenges are: Raw data access, data transfer protocol, ownership of data, ability to aggregate from data source, compatibility between software, mnemonics, time synchronization.

Q&A summarized for all presentations at the end of the session.

Presentation 2: Real-Time Coring Process Measurements and Downhole Diagnostics

Speaker: Gaurav Goyal, Schlumberger

The objective of the coring process is to get the core out of the hole in one piece, while achieving a high ROP. The 4 main problems during the coring process are:

- Jamming, by fluctuations in torque
- High differential pressure risking the collapse of the inner barrel
- Low ROP while coring - We can perform ROP optimization by using a linear correlation between downhole torque and downhole WOB
How can we confirm downhole parameters based on surface parameters?

Downhole sensors give us an opportunity to confirm surface measurements and give us an early indication of anomalies. We can then mitigate issues and get the coring job done properly. Monitoring helps to stay within the downhole limits for differential pressure and reduce safety margins.

How can downhole sensors add value? Real-time diagnosis and early warning of issues increases coring efficiency and core recovery.

Q&A summarized for all presentations at the end of the session.

Presentation 3: Real-Time Performance Engineering – Making the Most of Well Construction, Twenty Four/Seven

Speaker: Jeff Hamer, Devon Energy

The Industry has had tremendous success at driving down well construction costs and improving recovered reserves over the years. However, there is still untapped value in finding ways of economically leveraging the acquisition, analysis and related decisions from the mountains of Real Time data available. With the lower commodity pricing we have today the successful extraction of this value is key to efficient capital deployment.

Devon has taken an approach focused on Performance Engineering, utilizing 24/7 real-time data flows to drive decisions & collaboration across the entire well construction process (Drilling, Geosteering, Fracturing and Flowback). We took an Earn and Learn approach - Start small, prove your value and grow, creating an analytics center that evolves into a decision center. Getting the right information to the right people at the right time.

Q&A summarized for all presentations at the end of the session.

Question and Answer Session

Q: Gaurav, where is the diagnosis happening?
A (Gaurav): Downhole data collection, we look at the data from downhole, just like at surface data. Tool records data every two seconds, real-time mode, sending data with the MWD pulsing.

Q: Jeff B., you showed the tool that the IT department put together for you, you can drill down to the individual sensor, can you expand on what you do if the sensor is bad?
A (Jeff B.): I prefer to have all aggregation at the rig, we can remote into the aggregation system at
Q: **Gaurav, where are your load sensors placed within the BHA?**

A (Gaurav): For coring BHAs, they are located above the core barrel – maybe 90 ft from the bit.

Q: **Gaurav, differential pressure, is that between the inner and outer barrel?**

A: Yes, diff pressure is between inside and outside.

Q: **Jeff H., do you have algorithms looking at data quality as it comes in?**

A (Jeff H.): We don’t have algorithms to look at data quality, that’s part of the engineer’s job to check these. We don’t have a data management system on top of this.

Q: **Jeff B., are you willing to share the protocols that you are using, do you have recommendation of sensor placement, etc. do you get down to that level?**

A: We have some of these specifications in our contracts.

Q: **Jeff H, in the world of Formula 1, they have a strategist who never sees the raw data, who makes the final decisions based on the analysis provided to him. What are your thoughts of having such a structure in place?**

A (Jeff H.): We need to get there, but I don’t know how to get there. It starts with simple KPIs, and production data, the drilling group has to know the implication of quality measurements, such as doglegs that affect production.

Q: **Jeff H., you showed us automated torque and drag plots, to minimize the work for drilling engineers, are you automating other things as well?**

A (Jeff H.): This was a low hanging fruit. Granular data is messy and takes a lot of time, the real good drilling engineers had their own spreadsheets using raw continuous data. Our business is managed by exception, look for good and bad outliers.

Q: **Jeff H., how similar are the wells you are monitoring?**

A (Jeff H.): We talk about land operations here at Devon Energy, we are at 20 rigs today at 3 different basins. Some basins show a lot of well variance. In other basins we drill 400 wells per year, all showing a similar structure. Our group in Canada was Drilling SAGD wells, where the wells are completely different.

A (Jeff B.): We have operations all over the globe, we try to give everyone one area, and balance out
experiences of the crew. We have a complexity ranking system for our wells, which is based on multiple parameters. Not only a deep, water well can be complex, but also a very deep onshore well.

Q: Jeff H., You’re quoting Deming on your last slide: “Massive training is required to instill the courage to break with tradition. Every activity and every job is a part of the process.” Do you feel in your operation that lean concepts and lean thinking is where you want to take your business?
A (Jeff H.): Yes, I believe in lean management.

Q: Question to all the operators. How do you want to impact the process, do you want to directly talk to the drillers? What is the process to make RT change the way we do things?
A (Jeff B.): We outlined an engagement process. We decided on a communication protocol upfront. Also, we have a heat map tracking the alarms. Our next stage is to be able to project the data directly on the rig floor. I think phone calls distract the drillers.
A (Jeff H.): We have a communication protocol that is worked out ahead of time. Our ultimate goal is to have answer/solution products that are not all that complicated. Products that give simple recommendations whenever needed.

Q: With the “Crew Change” being accelerated by this downturn - many engineers are now retiring, what is your advice for young engineers especially in the area of adopting automation?
A (Jeff B.): Chevron has a program where our young engineers have to come to the center twice. The learning curve in a real-time center should be much greater than in the old days.
A (Gourav): You see experience leaving this industry, and it is going to be a problem to retain that experience.
A (Jeff H.) When I started working in our industry, the information available was anecdotal, it could be very wrong; there was no data to back it up. Today, engineers can watch hundreds of wells a year, and with the data you can watch cause and effect relationships and the access to data is changing how things are linked at today.
A (reference to Eric van Oort’s talk): The younger generation is the social media driven generation, now it is very different. You can be mentored across, not only by people above you. The young generation can crowd source their answers.
Session 9: Equipment Condition-Based Monitoring

Chairs: Jeff Mayhew, TH Hill; Pradeep Annaiyappa, CanRig; John Macpherson, Baker Hughes

Imagine the operational impact of predicting maintenance cycles and time-to-failure for critical parts and machines, both on surface and downhole during drilling operations. This session delves into the role of sensors, instrumentation, data aggregation, failure analysis, and data mining in developing real-time methods for condition-based monitoring of downhole and surface drilling equipment.

Presentation 1: Condition Monitoring and Life Prediction for Drilling Tools Based on Drilling Data

Speaker: Hanno Reckmann, Baker Hughes

Technological advances such as higher build rates, longer directional wells, high pressure and temperature conditions, using PDC bits in hard formation and faster drilling overall pose challenges to our drilling systems.

Environment and measurements: Description of vibration excitation and response source. Measurement at multiple points along the BHA and the drillstring. Data processing and modeling includes data collection, factor identification and model generation. With increasing vibration and increasing bit hours you have to expect less tool life expectations.

Model application and methods include real time application and repair and maintenance application.

Q&A summarized for all presentations at the end of the session.

Presentation 2: Improve Drilling Equipment Reliability Using Sensor Data for Condition Monitoring and Condition-Based Maintenance

Speaker: Jose Sanchez, Canrig Drilling Technology

Condition based monitoring of the drilling machinery is becoming the low hanging fruit to improve reliability and savings on a drilling rig. Currently, proactive maintenance is performed: after a certain period of time, a maintenance is scheduled, even if the machine does not need it. Current practice is also to run to failure. The basis of condition monitoring make informed decisions.

Looking at a reliability curve for machinery, the proactive domain is before the first point of failure happens. After the first failure point we can start to predict that a failure will happen. The methodology of fault detection depends on where we are on the chart. Before the actual fault we can use methods, such as ultrasound, vibration, oil analysis or infrared. In the fault domain, there is an
audible noise, smoke or the machine gets hot even. When an equipment left manufacturing, it often gets installed without proper pre-use work (e.g. forget to put in oil and other lubes, misalignments, etc.) so the machine pre-maturely fails only hours of installation.

Methods of condition monitoring:

- **Vibration analysis:** Machine condition changes can be detected with vibration analysis. Knowledge of a baseline for a healthy machine is required, as soon as we deviate from the healthy baseline, we can see that a failure starts to happen. Well known application on the market.
- **Oil analysis:** Portable systems for oil analysis, online oil analysis of oil properties are common practice. Parameters get compared with healthy baseline and the oil properties tell about failures.
- **Acoustic emission:** For war and tear on rotating machinery parts
- **Infrared Thermography:** Mainly used on electrical equipment
- **Other sensors technology includes pressure or temperature sensors**

Online CM sensor data architecture: Form the sensor, we go to a data acquisition system, where raw data is gathered and analytics is done. From there information is visualized and analyzed. Information is displayed either at the driller’s cabin, or on a phone or any device and the data sent to computerized maintenance management systems.

**Visualization:** The idea is to display the processed data, create a human machine interface, and only show impact of data, not non-informative data itself. The decision maker does not have to be an expert to understand the displayed data.

Data analysis includes diagnostics and prediction. Diagnostics means to know if there is a problem, and what is the severity of the problem. If the severity is too high, action will be required. Based on the diagnostics we go from safe, to warning, to severely defective. Prognosis is essential after the detection of a problem. How much time is left until the catastrophic failure? The operator can make an informed decision on when the best time is to replace/repair equipment.

*Q&A summarized for all presentations at the end of the session.*

**Presentation 3:** Critical Equipment Condition Monitoring – Where’s the Business Case for It?

**Speaker:** John Kozicz, Transocean
Looking at the history of condition monitoring (CM), the first step was oil monitoring in the 1960ies. CM has not much has improved since then. We are still detecting the failure after it has happened.

For the application of CM, we recommend to differentiate critical machinery (top drive, draw works), essential machinery (e.g. mud pumps) and general purpose machinery (e.g. engines). There are a variety of methods we are using today, depending on the progression of the failure curve. CM is applied to BOPs and rotating machinery. Other than condition monitoring, the options are to completely change the design of the machine or part or to implement better work practices that prevent and/or delay failure. For example, through sealing of the bearings of our top drives we could achieve greatly reduced down times. Other examples:

- Contamination of the oil: If the oil is kept clean, the life expectancy is increased by multiple times.
- Misalignment leads to failure through vibration: Better design practices means that if you never overload something, it won’t break. Examples are tension rings, proper fit and tolerances,…

Top drive manufacturers often do not know the details of the usage of their equipment (e.g. the vibrations they are exposed to during normal drilling operations). The economic value of CM can be assessed through a cost per unit working age calculation. CM is valuable when combining machine age and condition data to optimize maintenance decisions.

Q&A summarized for all presentations at the end of the session.

Question and Answer Session

Q: John, you’ve talked about condition monitoring for the machine, do you also do CM for the fleet? What happens to one vessel compared to another vessel. You could do more predictions, when comparing things on a larger scale?

A (John): We do analysis based on fleets, rigs and manufacturers. Bits have gotten really good…

Q: We saw that we can monitor BHA equipment at the surface, what about monitoring the drill pipe (DP)? Who would be responsible for that?

A (John): I am not aware of a DP fatigue sensors. We maintain running hours, but we do not do a good job in correlating running hours to failures. We don’t know how much remaining fatigue life there is left in a DP. I don’t think there is a direct sensor for DP failure. We used RFID technology, we had troubles with the antennas, and the RFID chips would pop out every once in a while. Nobody really knew what to do with the data.

A (Jose): I have see RFID tags, we can monitor the history of the torque applied to the DP and infer
degradation from there, but drill pipe fatigue is not monitored directly.

A (Hanno): we have sensors that can tell us about life of DP, so we can use our very good models, and use our standard tools to reduce the risk of DP failure.

**Q: I saw many condition monitoring techniques, about 20. These things take a lot of time to prove value?**

A (John): As rig managers, we are only successful with new implantations of technology if we can show that we reduce someone’s workload. We (Transocean) prefer to install things permanently, to not add extra work to workforce. So we reduced the sensors to really only critical equipment.

A (Jose): In our case, it’s been hard to put the technology out there. It is hard to change the mindset of people. For us, the visualization is the key. If we show the customer something simple, just a color sign, this is what they are looking for. They shouldn’t be subject matter experts, just tell them what to do and offer easy solutions.

**Q: There was the argument that we just need to improve the equipment and we’ll be fine. For automation, we will always need to know the state and condition of the machinery.**

A (John): 60 % or 70 % of the signals you’d want to use for CM is probably already there. You can use these sensors in a better and more efficient way.

**Q: I’ve been working with data acquisition and data models [rig information model]. We left space in the model for monitoring data, but our model is built as column with many numbers. Monitoring data, can it be standardized? Is the data in a structured form, can we standardize this for a data base?**

A (Jose): You don’t need big data to do CM, we for instance use 4 data streams to do oil analysis. The way we do analysis, we just extract key performance indicators from huge loads of data and store both, the raw data and the key factors.

A (John): I haven’t given it much thought about the historian of data, which is part of the problem.

**Q: Hanno, on slide 13 of the presentation you showed these 2 fuel tanks for illustration purposes, can I ask you what the difference is between those is?**

A (Hanno): One shows the lifetime (how full is your tank), the other one shows the consumption (what is the rate of life time decline).

**Q: The different components would fail at different points in time; some have higher life times than others. Are you showing the weakest components, or what are you doing?**

A (Hanno): We are showing the overall tool life.
Q: Hanno, you didn’t mention temperature as a factor for the tool life. In our experience, this is a big factor, how do you account for this?
A (Hanno): When we did the overall tool analysis, the temperature wasn’t a big factor for us, but maybe there is a bias in the dataset.

Q: There are 2 factors in our space/industry: One is downhole drilling optimization, the other one is surface pipe handling. For pipe handling, are we adequately equipped with sensors to move to mechanizing pipe handling?
A (John): No, we do not have enough sensors to safely mechanize pipe handling. We cannot design a system that excludes people from the workspace. The solution to this is to use cameras instead of millions more sensors.
A (Jose): One of the challenges is the harsh environment the systems are exposed to and we are not quite there yet.

Q: John, I noticed the MTBF calculation, did you use some other normalization factors like torque and stresses from the drilling operation?
A (John): One of the analysis technique is the proportional hazards method, where you have age related damage (history) and add on to that the statistically relevant covariance. If torque was one, e.g. exceeding a threshold, we do not currently do that.

Q: There are so many different variables in this area. John, you talked about the failure rate, which is always associated with a particular failure time. There are different definitions of reliability, one could be, does the equipment perform as it should be doing until we finish our job? Mission success, rather than MTBF. You should add the required time of the mission and compare this with the life time of the tool?!
A (John): What you are looking at is running statistics in real time.

Q: I have a challenge: I heard the comment that we can’t automate. I would agree and say that with the current design and equipment we can’t. Other industries have shown that mechanization works. If the current rig design is made for people to be on the rig floor, we have a problem. What is it going to take for future designs, to change that?
A (John) I fully agree, we try to do stuff differently, in order to really revolutionize e.g. pipe handlers on the rig, we have to change how the pipe looks like. You have to accommodate these changes in the machines, so they can handle both things in transition phase. Still, one has to change the equipment
as well, it’s a chicken and egg problem – where do we start? But people still have to go and fix things. At Transocean we had 6 fertilities, all related to mechanization. In one incident the iron roughneck was going back to its starting position when a guy was behind the roughneck. We are working on using cameras to have surveillance at the rig floor, these systems are available right now off the shelf.
Session 10: Lots of Data, Low Trust, Unreliable Solutions (We Can Do Better)

Chairs: Michael Behounek, Apache; Nathan Zenero, Chesapeake Energy

To move toward more value from sensors and data, we have the following questions.

- What needs to change?
- How can we make it less painful to effortlessly get good data and use data to improve drilling?
- What does it take to use real-time models and data analytics that deliver solutions you can trust?

This session will evaluate what foundation is needed from a system’s view to deliver excellent advice to the driller and eventually repeatable, reliable, and dependable automation.

Presentation 1: The State of Sensors and the Value They Can Bring

Speaker: Nathan Zenero, Chesapeake Energy

This talk is about quality, not just data quality. Typical US Land Drilling measurements do not meet necessary and sufficient conditions for the following:

- Current Desired Outcomes of Drilling (e.g. not enough good data to run casing to bottom, do torque and drag modeling, etc.)
- Optimization
- Advisory Systems (a lot of time spent on making sense out of data)
- Automation

Bad data affects all steps on the roadmap of a closed loop automation system.

Example #1 – torque error – many people say they do not need absolute values, they only follow trends, but I don’t agree with this. The hook load measurements are sensitive to e.g. temperature variations throughout the day, adjustments on the rig, etc. The error is not constant and the distributions of the errors are not constant, since they show they show multiple different distributions. We need to stop calculating torque and start measuring torque! Hence put different sensors as close to the pipe as possible and measure it directly.

Example #2: Hook load is the biggest offender in the world. Error in the hook load measurement is often as big as the hook load itself. Again, the error is very variable. The driller knows about this, he
will intuitively accept an overpull, which is the right thing to do in most cases. But this one time, he’ll exceed the limit, and part the pipe because the measurements are just not reliable.

Example #3: annular BOP test. Radial chart recorders for BOP tests are used in 90% of the time. What errors can occur with these sensors? We collected digital data in conjunction of radial chart recorders, which shows that the tests would actually fail if tested with different sensors.

There are technology solutions out there and we know about them. Part of the problem we have right now was that operators have been complacent, they did not attack the root cause of the issues. Operators and drilling engineers haven’t built the expertise to address the challenges, since they are not experts in data.

Also, operators haven’t specified the needs sufficiently. Suppliers would be willing to produce whatever specification we give them, we have to better specify the process capabilities and requirements. Other industries have shown that this could be done very well, decades ago. We have an imperative now, which is $40 oil. Supply chain management was the key to many other industries to achieve their goals. The problem that we have today is not technology; the problem we are facing today is rooted in culture. We all have very technical mindsets, but maybe it’s time to realize that our job is much less technical.

Q&A

C: Your Nummi example of GM was really good. They had to get the worst union on board. When you say change the culture, they changed an entire culture, not just the management.

Q: Do you have any thoughts of safety specifications?
A: If we approach our business by a concept of minimizing waste, we’ll have a system that is much leaner. Human injury is waste, since it is costly. Sensors should support these concerns as well. A properly specified sensor should satisfy the process capability (which has performance, reliability and safety). However which one of these capabilities dominates, will drive the sensor specification. If it is safety, then this will influence the sensor specification in the way. Good example is BOP testing, 100 psi could cause an injury, so we specified BOP tests to a minimum of 10 psi.

Q: Do you see a difference in the culture with our younger generation?
A: Yes, and no. People want to be in the analytics and the big data, but when it comes to the machinery and equipment, drilling engineers are mostly not that interested.

Q: The key to actually getting an organization to move towards better data quality, is getting the top
level management to understanding the importance of data. So I think case studies on how much can be saved having better data quality would be the key, but I don’t see many case studies like this out there.

A: The title of this presentation was quality, not just data quality, because there really is no distinction. As Chesapeake, we don’t take quality very seriously. If there is not an API spec there, we don’t try to fill that void. If you have part of the organization involved in defining these specifications [e.g. if you have a separate procurement department], I would say start there.

Q: I think people know that the data quality is bad, and they want it to be better, but companies right now don’t have too much money to spend. What is the priority right now, to focus our resources on key projects that can be solved medium or short term. What priorities should that be?

A: Yes, that’s a great point. If we look at other industries, it is not completely comparable. We are local monopolies for our resources; there is no global competition. The operator’s group right now is working on this; we prioritized our next steps. Safety is number one; hook load and pressure are most safety critical. The next priority would be things that affect the bottom line, such as non-productive-time (NPT). It’s a slow progress, but we think that we’ll see an exponential adoption rate.

Q: People that need to see your presentation are the senior management in a company, but giving this presentation to them is really hard. Because it shows their own errors and shows that they are not as good as they thought. What does it take to give this presentation and get traction and momentum to sell it to management? We are not very good at that right now?

A: As the operators group, we brought in a change management consultant who taught us how to bring this back to our own managements. One way would be to find champions for single issues, who has a real stake in the subject. The ways to do this will vary by departments and organizations. We are all technical guys, it may require developing new skill sets.

Q: In your organization, are your efforts seen as a drilling automation?

A: In Chesapeake, I don’t use the word automation, because we are not there yet. I don’t view this as necessary attached to automation, but I see this as a necessary step toward automation. [Michael from Apache agreed, that this topic has been resonating very well in his organization].

Presentation 2: Moving Data Effortlessly – It Takes a New Architecture

Speaker: Terry Weaver, Apache Corporation

Correct and timely information is crucial to drilling effectiveness and it allows to respond quickly to
developing situations. The first step to enhancing performance is the accurate and timely measurement of data allowing you to proactively manage your drilling process before problems occur. Currently there seems to be a variety of methods to collect and move data on drilling rigs. Most of these methods involve service companies and or rig contractors to collect and move the data. The method most commonly used is either WITS0 or WITSML into a server at the service provider or corporate real time center. While these methods work and provide a great deal of information they do pose problems when we try and capture real-time data at greater frequencies up to 100 samples per second versus the traditional one and five seconds. In addition they do not give tools to assist data quality at the well site and not all data sources use WITS therefore making data aggregation difficult. This presentation will discuss a new architecture that will provide a very flexible and efficient way to collect and move the data from the rig to real-time centers and corporate data storage sites. It will discuss the different methods for collection and validation of data at higher frequencies and the additional benefits of going to this new architecture. Benefits include new visualization, connection to well site databases, and an open platform for running real-time models, algorithms at the well site. By eliminating the existing barriers posed today, different data streams can now flow easily, improve data quality, lead to the better analytics to reduce drilling costs and reduce current data aggregation, use costs.

Q&A

Q: You showed us the benefits of OPC UA, I think 90% of the industry is using WITSML servers, how to we manage this change?
A: One of the things that WITSML is not good for is high frequency data collection, because it is text data collection. OPC-UA allows to stream data from everywhere. WTIISML is good for lots of things, but is not suited for real time data, higher than a certain frequency.

Q: As far as taking data from your rig historian to your company historian, did you have any issues with security and countries that do not allow that?
A: We currently do it in the US, we didn’t have problems here.

Q: Why do we not take data directly from the rig? The reason for that is security, we don’t want to interfere with system critical systems. How do you handle your downhole data? The timestamps you’ll have from GPS won’t work for downhole recordings.
A: Currently, we do not handle our downhole memory data. As far as tying into rig PLCs, yes, there are security issues, but we can deal with this. I think there are lots of ways to mitigate security issues, but we can put in place safety measures.
Q: Opening up the RT [Real Time] data transmission to the office, have you studied bandwidth requirements for these new data streams?
A: We played around with lots of wireless stuff, yes, it has its good and bad quarks to it. We didn’t have so much luck with it when it was on the rig floor, the pipes seem to interfere with the wireless data. Our antennas probably weren’t placed properly. On transmitting the data form historian on the rig to the historian in the company, yes, it can be done. Most historians have back up capabilities, and can transfer data very well from one to the other.

Q: I have a question when it comes to security, how do you mitigate [unwanted] inference with the rig control system? There are potential security threats if the rig can be manipulated from everywhere across the globe.
A: UPC-UA has several different mechanism for security. So there are many issues built into that system, we don’t see so much of a problem with this. That’s why you have to work with the rig manufactures, to make sure that there is a buffer in place e.g. only allow reading and not writing access.

C: Downhole data can be dealt with very well with OPC UA.

Presentation 3: Automatic Drilling on Statfjord C, First Use Experiences

Speaker: Jim Krupa, Sekal

In 2014 Statoil installed drilling automation software and successfully drilled the first well on the permanent drilling platform Statfjord C. Now in 2015 the automation software is part of normal drilling operations on Statfjord C. This discussion will focus on the application of the software and the demonstrated value it brought to Statoil on the first well and the value this software is expected to deliver going forward.

The installed automation software is integrated into the rigs infrastructure and sends limits for safe operational procedures and set-points for automated functions to the drilling control system. On the Statfjord C, the drilling control system is NOV’s Cyberbase. The integration allowed for the Driller to view the operational limits i.e. Torque, Standpipe pressure and Axial Velocity and acceleration set by the software within the Cyberbase console as well as have access to the automated functions i.e. Pump startup and automated friction tests via the Cyberbase keypad.

The business value delivered from a system like this includes:
• Improved consistency with friction tests. Typically friction tests are considered stressful for the Driller as they must be very precise with their movements. Having this function automated makes for a lower stress experience and consistent results which deliver more confidence in the results.
• Reduced strain on the well and equipment which leads to delivering a faster well with less opportunity for a sidetrack.
• More efficient use of the existing Cyberbase system. The business case is strengthened by positive feedback from the rig crew. (Drillers, Assistant Drillers and Tool Pushers)
• The Crew trusts / likes to use the system
• The Crew thinks that the system is well integrated with operation

Areas of improvement include: The Response indicates that the training could have been better – Initial training was good and thorough, more follow-up training was needed. This is now being implemented with weekly refresher courses being offered.

The first well drilled using this software delivered an estimated 10% savings in performance measured in time. While this is only one well and there was significant investments made for the installation and deployment and there is certainly room for improvement, this software proved that automating limits for safe operational procedures and set-points for automated functions can deliver significant value.

Q&A

Q: Is any effort spent on automating the core drilling process, to increase the ROP during that coring process?
A: We do not focus on ROP optimization right now, we are taking small steps towards that. Once the system is proven we can expand towards these areas, but at this point in time it’s not the focus.

Q: At the end you mentioned that you had remote operation monitoring, how critical was this to the overall success?
A: Very critical, whenever conditions changed, we had to update the system with new values, e.g. mud properties, etc. We weren’t taking the risk of not having it, especially in the testing phase.

Q: How easy is it to use your system if you need to adapt it to land based wells, does it add business values there?
A: That’s tough to say, a lot of the functionalities are concerned with offshore in particular. There is probably a case that can be made to improve onshore drilling, but we’ll have to see how this works
out with the given tight cost margins, and rig modifications. The ease of use is there, but the installations would take some time and costs.

Q: I have a question on the hydraulic model. The human interaction that is needed doing that model, how much effort is that?
A: It’s a software based model, so we have real time data fed into the model, as well as static parameters, such as wellbore architecture. There is built in calibration to the system, but we require manual inputs, such as mud weight changes, and similar parameters, changes in BHA, etc. but there is very little interaction with the model during operations.

Q: What about the implementation of your system. You showed a slide with a couple of hardware system, are these off the shelf solution? Software as well?
A: Hardware is all off the shelf, as far as servers, gateways, etc. go. Nothing on the hardware side is proprietary. The hardware is located in a separate location (in a special room about 10 meters behind the driller’s cabin) on the rig, but we never had concerns with hardware requirements. We had to add additional sensors, which was more of a sensor. On the software side, it’s all tailored.

Q: How do you avoid outliers of data points affecting your model?
A: The calculation is based on the deviation of the trend from the past. So short term spikes are usually ignored, we don’t really do specific data filtering before we put it into the model.
An automatic real-time data quality indicator for drilling operations

Pradeepkumar Ashok, University of Texas at Austin

Abstract:
Problem statement: Recent field studies show a large percentage of rig sensors delivering bad data values creating the biggest challenge in going from sensors to solutions. Data analytics both in a real-time setting and of historical data sets have the potential to reduce Invisible Lost Time (ILT) and Non Productive Time (NPT), and thereby reduce drilling costs. Automated software solutions for ILT and NPT avoidance exists today. However the results produced by these software are skewed due to the fact that the input data is bad. This leads to bad predictions, and ultimately distrust in these very relevant technologies. Often data has to be cleaned manually before such analysis and this is a big waste of human resources. More importantly as the industry seeks to move towards automation, the lack of a real-time data quality analyzer, is delaying progress on that front. Today’s drilling automation engineers are forced to work around this problem either through physical sensor redundancy, or through less optimal algorithms.

Solution: Based on technology developed at The University of Texas at Austin, originally for the Department of Defense (DOD), a software product has been built to automatically detect faulty drilling data in real-time. On a scale of 0 to 1, it provides a trustworthiness measure for the sensor readings. This trustworthiness index can then be used by downstream data monitoring and control algorithms for a more reliable operation. In addition, when a sensed data is identified to be faulty, a model derived value with probabilistic bounds can be supplied to downstream software, enabling their continued operation, or operation until safe system shut down. Such derived values can also be used to clean and re-populate historical data sets thereby making them more useful and complete for data mining exercises.

Technological Innovation: The technology that powers this software is a physics based Bayesian network model of the system. All data collected from a drilling rig are networked (connected to each other) through this model. This in turn enables all readings to be cross-checked against one another. The Bayesian network approach maximizes the number of redundant relationships usable to validate data. Bayesian networks inherently also have the capability to accommodate uncertain in the relations and sensor characteristics, and this feature is leveraged by the software solution.
Drilling Data as a Service (DDaaS)

Hans-Uwe Brackel, Baker Hughes

Abstract:
Data is increasingly becoming the most critical asset in the process of wellbore construction. Many participants in the drilling process, such as customers, rig contractors, service companies, and regulatory authorities are acquiring and exchanging information in real-time to perform their work and monitor and safeguard activities. It is of utmost importance for a safe and efficient operation that all parties have a common, consistent view at the same data. The importance is further amplified by the advent of automation in the drilling process, where decisions made by automation software based on ambiguous or uncertain information can lead to dramatic consequences.

A common rigsite data hub, or data aggregator, based on open and industry-standard protocols can make real-time and context data accessible to all parties in a secure and consistent way. Data originating from a variety of protocols, such as Profibus, ModbusTCP, WITS, etc. can be integrated seamlessly through gateways and be exposed through a well-defined OPC UA interface (IEC 62541 – OPC Unified Architecture, Part 1-13), the designated Standard for rigsite data exchange by the SPE DSATS group.

One of the most important prerequisites for sharing data is the unambiguous identification and annotation of data with context information (metadata), describing the properties and quality attributes of a data item, such as engineering unit, accuracy, sample rate, data types, just to name a few. The DSATS group is currently working on a proposal for a “Rig Information Model” that will offer an ontology proposal for drilling rig data using an OPC UA information model. As systems and data models are continuously evolving, the data aggregation server needs to provide a simple and efficient way to quickly accommodate any upcoming ontology updates.

However, data aggregation and sharing can go well beyond drilling rig sensor values and control set-points. Real-time or memory data from downhole tools, mud property measurements, drillstring information and derived information, such as drilling state, rig state, calculated depth, should be integrated to provide a single, most comprehensive, complete and, most importantly, consistent view on the drilling operation. By extending the out-of-the-box OPC UA security mechanisms it is possible to control the visibility and accessibility of proprietary or confidential items to authorized parties only, thereby recognizing respective requirements from legal authorities or service companies without sacrificing the availability of information through the common data hub.
By complementing the OPC UA aggregation server with an OPC UA historian, this new data hub can be the solution to most of today’s and up-coming data aggregation, distribution and consistency challenges. All those benefits can be implemented on top of the existing rig instrumentation infrastructure, offering an excellent migration path for the adoption of standard protocols without demanding infrastructure changes for legacy installations. Taking this idea one step further, the data aggregation, management, and enrichment can be defined and offered as a dedicated service, including responsibilities for availability, quality, backup and security concerns.

With the introduction of an OPC UA-based data aggregation hub, the technology now is available to realize a single point of access for all real-time drilling data at the rigsite. Drilling data as a service (DDaaS) may become the up-coming solution to enable and empower drilling automation.

Kick Detection: From Sensors to Solution and Back to Sensors

Eric Cayeux, IRIS/Sekal

Abstract:

"Early kick detection is of critical importance during drilling operations. The prime indicator for formation fluid influxes is abnormal variations of pit volume. However the interpretation of the change in pit volume can be difficult during non-steady state conditions, like when the flow-rate is changed or when the drill-string is axially moved. This is due to naturally occurring physical phenomenon that takes place between the intakes of the mud pumps and the return flow to the pit, as for example the effects of mud compressibility and momentum inside the drill-string and borehole, or the retention of mud into the transport and treatment equipment at the top-side (e.g. return flow line, shale shakers). Efforts have been spent in modelling the downhole transient hydraulic behavior as well as the transient flow of fluid in the return equipment from the well outlet to the pit. Experience as shown that the predictions made by both models (downhole and top-side) are well aligned with real measurements even in demanding drilling conditions, therefore opening for the possibility to automate kick detection also in transient conditions. However, this approach gets quickly limited when the drilling team is not cautious to avoid spill of mud before its return to the pit or if liquids, solids or chemical are directly added to the pit as part of the mud maintenance process.

To avoid unnecessary false gain/loss detections induced by untidy work at the rig site, it would be better to measure the return flow-rate as close as possible to the outlet of the well. It is quite common that a flow paddle is mounted at the entrance of the return channel, but such a sensor gives only indicative values, since many factors influence the readings made with a flow-paddle like the fluid
density, viscosity, temperature and the amount of cuttings that tends to accumulate at the bottom of the channel. A better alternative is to install a Coriolis flowmeter but because of the pressure loss through the instrument, it is necessary to install a diverter which is not always possible. Furthermore, Coriolis flowmeters tends to get clogged by cuttings therefore necessitating maintenance work at regular interval.

There is therefore a need for a flowmeter that is quantitatively precise, can be installed close to the well outlet, can work under atmospheric pressure and is little prone to be clogged by cuttings. Such a flowmeter combined with a precise estimation of the expected flow-rate out of the well, including transient periods, are the corner stones of a reliable automatic gain/loss detection.

GeoMation: How to automate steering within the sweet spot

**Bronwyn Djefel**, Sperry Drilling

**Abstract:**
Integrating automation within geosteering is an exciting opportunity to bring together the drilling and G&G departments in an optimised system to increase reservoir exposure, maximise efficiencies, reduce cost and ultimately make more money for everyone. The challenges are diverse, some similar to other areas that are being automated, others are unique - how do you impart a love of rocks and their origins to an algorithm? We will explore the challenges, what is being done in the industry today and what possibilities there are in the future. Recommended viewing: Armageddon and The Core.

Continuous, fluid flow independent, downhole pressure and tension measurements transmitted through a closed BOP from a through bore tool.

**Duncan Groves**, XACT

**Abstract:**
Influx detection and management, today, largely depend on measuring and interpreting the responses of various surface sensors. Downhole measurements are currently available only at the bit, and only when circulating at high flow rates. These can be used to enhance the detection of possible influxes, but due to the mud pulse telemetry limitations, are not available when actively managing an influx.

An acoustic telemetry network enables measurements to be taken from down hole, not only at the bit, but also along the drill string. As the telemetry method is fluid flow independent, data can be acquired at all times, with and without circulation, and as will be shown in a real example, can be transmitted when the annular and pipe rams are closed. Multiple annular and bore pressure measurements can be
used to monitor an influx progression, provide measurements below the BOP, across the shoe or other weak zones and provide real downhole data if bullheading or circulating out the kick.

In addition, downhole measurements from a full through bore tool can also be used to monitor downhole liner running loads to increase the probability of getting the liner to bottom. Real time downhole pressure measurements, at the liner running tool, during cement jobs can also enable better displacement decisions to improve cementing assurance.

The presentation / poster will give an overview of the technology and a real well example of transmission through closed BOPs and monitoring fluids along the drill string annulus and during liner running and cement displacement.

**A New Method for Measuring Return Flow and Mud Density**

**Bruce Henderson**, MezurX

**Abstract:**

The Background

Traditional method for measuring return flow has been paddle meters. They suffer from a range of substantial issues, not least of which is the absence of a quantifiable flow signal. In recent years, Coriolis meters have been used to provide return flow and density measurements, however they also have issues including cost and reliability.

The Challenge

Develop a cost-effective system for measuring return flow and mud density that offers accuracy, reliability, and simplicity, and is applicable to open flow lines and MPD operations.

Our Solution

The X-Omega meter, developed by MezurX, provides measurements of flow and density determined from pressure sensors located in a branch of the flowline. It combines the principles of a conventional wedge meter and hydrostatic pressures. The arrangement used provides accuracy, reliability and ruggedness in a cost-effective package. Data will be presented comparing the X-Omega with existing flow and density meters, including assessments of its accuracy.

**Computer Vision Applications for On-Rig Sensing**

**Kenneth Morton**, CoVar Applied Technologies

**Abstract:**
Thousands of sensors monitor a wide array of parameters on modern rigs. When used properly, these sensors provide situational awareness to the driller that improves efficiency and safety. However, many on-rig sensing problems are notoriously difficult to instrument with classical sensors. For example, constant monitoring of the mud-front on a shaker requires equipment to work in a dirty, high-impact environment. Similarly, large-scale personnel localization and rig state estimation requires a big-picture view of the rig processes that may be difficult to identify from numerous small-scale sensing devices. Recent advances in computer vision technologies enable automatic and robust extraction of information from video streams, which make the combination of cameras with advanced computer vision algorithms a potentially powerful sensing modality. This work describes several recent advances in leveraging computer vision technologies to solve rig-site problems. Specifically we will show proof-of-concept studies focusing on mud-front tracking on shakers, personnel localization on the rig floor, and large-scale state estimation from standard camera feeds.

Non-intrusive flow rate and rheology sensor

Richard Tweedie, Zaxxon Instruments

Abstract:

Saving time, money and ensuring safety should be major goals of any drilling operation. To this end, future drilling operations will require improved monitoring of drilling fluids.

On-Site’s objective is to develop a Real Time In-situ Drilling Fluids Monitoring System which will identify all drilling fluids, solids control and geology & waste management properties automatically in real time or near real time. Key to this is the integration of sensing technologies to the drilling operation. However, having tested and evaluated more than 50 existing measurement modalities, none were found to be suitable. Hence we have taken the step of developing our own sensing technologies. This work details development of a novel technology to measure the structural and mechanical properties of the fluid.

Drilling fluids are a complex Non-Newton multiphase particulate systems operating at high solids concentration. The functional performance fluid has specific mechanical requirements which can be characterised using the rheology, particle size distribution and solids loading. Combining these with information on the flow and density will enhance drilling management. Existing methods for characterising the rheological and particle size properties are either manual or offline or are highly intrusive and invasive involving moving parts, sample extraction and/or substantial intrusion into the sample. In-situ sensors for drilling applications must be robust, able to handle aggressive materials, harsh environments and rough handling. Creating Intrusive installations interferes with operations, increases costs and hence the need is for externally mounted, clamp-on application.
We have developed a unique new method of monitoring drilling mud using ultrasound and introducing a new method of ultrasound measurement. Ultrasound has already been proven to provide a wide range of single parameter measurements; however conventional ultrasound has limited dynamic range. Using digital ultrasound extends dynamic range to provide larger pipe diameters and higher concentration capability and enhances measurement accuracy. The goal of the project is to maximize the information returned by a single sensor. The method ultimately will provide enhanced information on the rheological and structural characteristics of the material, rheology; yield point and Plastic Viscosity, particle size, concentration, and density in both full and partially full pipes using a clamp on sensor.

Near Real-time Monitoring System for Deep-Water Drilling Risers

Shaopeng Liu, GE Global Research

Abstract:
Subsea drilling operations are moving into harsher, deeper and less familiar offshore environments. The uncertainties associated with these environmental conditions such as high pressure reservoirs, as well as new drilling riser system operating specifications, and assumptions in modeling and numerical simulation for vibration and fatigue estimates, and increasingly stringent regulatory requirements warrant near real-time monitoring systems of the riser and wellhead in order to avoid disruptive events. Apart from minimizing impact on operations due to such events, real-time monitoring systems could also support data-driven, performance-based riser inspection and maintenance programs, and validate predictive models.

A Riser Lifecycle Management System (RLMS) has been developed for near real-time condition monitoring and fatigue estimation of drilling risers. The RLMS is an integrated system of hardware and software tools, including: 1) subsea sensing modules with acoustic telemetry enabling wireless communication between the subsea sensing modules and the drilling vessel, and 2) software algorithms for data processing, riser fatigue analysis, and visualization and alerts for enhanced operational decision-making for contractors and operators. Unlike conventional techniques such as strain gauges for direct strain/stress measurement, the RLMS places accelerometers and angular rate sensors at select riser joints for minimal impact on running operations, and provides robust fatigue estimation from the motion data.

Specifically, a modular approach was used for designing the subsea platform. The platform consists of an acoustic modem and transducer, rechargeable batteries, tri-axial accelerometers and gyroscopes, and a micro-processor for data acquisition and edge processing. Based on data from real-time sensor measurements, a semi-analytical approach is used to estimate fatigue damage. The system displays critical alerts and key parameters to the rig operator showing how fatigue damage is actually
accumulating during a drilling campaign relative to what is expected based on design specifications and known average ocean currents in the drilling region. In addition to this enhanced visibility into the drilling operations, the system will make recommendations to the rig operator on how to optimize the riser configuration when fatigue damage estimates in some riser components reach high levels or after extreme events. When deployed, the RLMS will provide continuous updates on key parameters related to the ‘health’ of the riser string. Benefits include reduce potential safety concerns, enhanced riser system reliability and operational performance with critical event alerts for unforeseen problems, reduced service costs and optimized engineering design of future ultradeep water risers.

Preliminary laboratory and sub-scale rig testing have been conducted to test key subsystems and validate the system functionality and sensor signal fidelity under simulated environments. The next phase of the research will include 1) an at-sea trail to test the long range deep water communication and integrated system functionality and 2) a field trial of the developed system on a drilling riser as a production tool for riser life assessment.

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Intelligent Pipeline

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Abstract:

Current global transportation pipeline infrastructure stretches across more than three million kilometers. Pipeline companies invest up to $40 billion per year to expand networks and maintain their assets, but they are increasingly challenged by aging infrastructure, IT systems complexity and capabilities to leverage growing amounts of data. It is estimated that less than 25 percent of the data generated for any given pipeline is used to formulate data-driven decisions.

This paper looks at the challenges facing the industry and explores how new technologies connecting assets, data and people can help address specific pipeline issues, such as:

- Asset safety and reliability
- Limited and siloed data
- Processes highly dependent on people and an aging workforce
- Increased regulation & public scrutiny

In this paper we will draw on research and development conducted by GE and Accenture in collaboration with one of the largest pipeline operators in the United States, providing examples that demonstrate the benefits new digital technologies and data analytics can bring to pipeline management. We will identify new technology and analytics applications that now help pipeline
companies take advantage of the massive amounts of data generated through business operations, including secure data integration and modern visualization technologies, risk management capabilities, and decision support tools. Finally, we will discuss innovations in inspection, sensing and remote monitoring capabilities that can be leveraged by the Intelligent Pipeline Solution to deliver enhanced outcomes to operators.

With the adoption of the Intelligent Pipeline Solution, operators can unlock quantitative benefits in asset maintenance, productivity and throughput optimization, as well as qualitative benefits in risk management, safety and knowledge transfer. As a result, they will be able to better identify and mitigate risk while optimizing their operations and efficiently allocating valuable resources when and where needed.
Final thoughts

If we as an industry are to harness the value of automation it is clear that we must not just look to the future. We must also understand the present and our current limitations. As we shown clearly by several of the speakers, notable Dr. Tweedie in his keynote, many of the technologies we could benefit from are available today, what is lacking is a robust and integrated implementation to crosses boundaries of the operation – and the leadership and will to do it.