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Drillers' Notes

A New Direction in Drilling

Fred Florence

The oil and gas industry is separated into upstream and downstream operations demarcated at the wellhead. The upstream activities involve planning and drilling the well and producing the oil and gas from the reservoirs. The transportation, refining, and distribution of the products define the downstream efforts. The upstream oil and gas industry has historically been dominated by manual processes, but is moving to automated systems that require new technology and skill sets. Research and development budgets are being realigned to provide value by adapting work from others to the demanding environment of subsurface drilling. This is an ideal time for other industries and academic institutions to join with petroleum specialists to create new sensors, drilling models and control algorithms to increase the safety and efficiency of the drilling activities.

Some forward- looking members of the Society of Petroleum Engineers (SPE) in the Drilling Systems Automation Technical Section (DSATS) are leading the automation of downhole drilling processes through the use of surface and downhole sensors controlling the drilling machinery. This series of short columns is intended as a call to action to gather expertise from multiple sources to enable this new direction in drilling. It builds on "Providing Sustainable Energy" tutorials that were offered at the IEEE International Instrumentation and Measurement Technology Conference, I^2MTC 2012, in Graz, Austria.

The use of real-time or near real-time measurements is enabled by data telemetry systems between the surface and downhole devices that may be over 10 km (33,000 ft) away. Sophisticated sensors that measure the rock properties, down hole pressure and vibration, and provide navigational information and much more must perform for weeks at a time under extremely harsh environmental conditions. Temperatures are routinely 150 °C, and many users now desire up to 300 °C. Shock loads may exceed 100 g. Providers of electronic components and circuit boards suited to such conditions will be welcomed by the drillers.

The metallurgy of the equipment must allow for the corrosive brines and gases that are present in the drilled rock and for the wear encountered while rotating in abrasive sands. Since the process uses a specialized drilling fluid pumped at high pressure, the equipment must also survive the erosive effects both inside and outside of the tools. Research in coatings, nanotechnology, and metal sciences should be able to improve existing designs.

Today's downhole sensors infer wellbore geometry and rock properties by deploying measurement techniques using indirect physical sensors. In addition, they can be tuned for different depths of investigation to measure characteristics in near-field and far-field formations: e.g., seismic, acoustic, electrical, source and sourceless nuclear. Nuclear Magnetic Resonance (NMR) devices measure formation properties; porosity, permeability, fluid type and saturation, mineralogy, geomechanical rock properties, stress state, and so on. Bending moment and direction are used to navigate the well trajectory employing sensors such as accelerometers, magnetometers, and gyros. The physical parameters that are measured include drilling mechanics, tri-axial vibration, rotational speed, torque, and axial tension/compression. Fluid properties like pressure, temperature, flow rate, and more recently viscosity, are also monitored. Missing is formation sampling to determine *in-situ* pressures and fluid types in real time. New sensors to measure the chemical composition *in situ* of dissolved gases and other wellbore influxes are highly desirable.

Some downhole tools can be used to steer the drill bit by introducing small lateral forces near the bottom of the drilling assembly. These tools can be controlled in near real-time from the surface. Several companies are developing autonomous controls within their equipment that will steer to a prescribed target via a specific trajectory. Improved microprocessors capable of operating in downhole conditions will further enable development of these tools.

With some telemetry systems, i.e., wired pipe commercial systems, the downhole data can be transmitted at up to 56 Kbps. For some mud pulse and acoustic systems, data is transmitted at only 3 to 40 bps, and extreme data compression methods make good use of the limited available telemetry bandwidth. Interpreting the data in real time requires new dynamic models or enhancements to existing models. For the high speed data, the industry needs improved data display techniques suited for real time operations.

Depending on available technologies, market conditions and agreements for sharing or licensing of intellectual property, the upstream oil and gas industry may be a source of funding for research, new market space for existing products, or possibilities for new product development. Anyone interested in more information please refer to: http://connect.spe.org/DSATS/Home/.

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Modeling and Controlling Downhole Pressure during Drilling

Fionn Iversen

Drilling fluid is circulated in the well during drilling operations to transport the generated cuttings out of the well and to lubricate the drill bit while maintaining the required downhole pressure. When the pressure is too low in the well, the walls may collapse, or formation fluid may flow into the well, also known as a kick. On the other hand, if the pressure in the well becomes too high during drilling, then the formation being drilled will fracture, and drilling fluid will flow into the formation. The pressure region between the upper and lower pressure limits in the wellbore is known as the *geopressure* window. It is both a function of depth and time, as the temperature and the state of the wellbore wall change during the drilling process. Again, the wellbore wall is affected by previous fracturing, chemical reaction with the drilling fluid, and the particle layer deposited from the drilling fluid, known as the filtercake or mudcake.

In the planning process, the geopressure prognosis is estimated based on data from previously drilled nearby wells, known as offset wells. During drilling, the upper pressure limit may be measured by Leak Off Tests where the wellbore is pressurized until fluid flows into the formation. The *in situ* formation pressure may be diagnosed through inverse calculation when formation gas or fluid is registered in the drilling fluid, and the collapse pressure is derived from the observation of pressure cavings in the return flow or the evidence of hole enlargement when using a downhole caliper (a downhole measurement tool that measures the hole size). However, the leak off tests may damage the well and one uses them as little as possible and only with a very short open hole section to avoid massive loss of drilling fluids should formation fracturing occur. The determination of the formation pressure and collapse pressure is usually made unwillingly as a side effect of a downhole pressure being too low due to a mud weight being too light. Measuring these formation properties through non-invasive techniques is therefore a key area of research.

Further, if cuttings are not transported rapidly enough out of the well, then they may build up until the well packs off, potentially leading to the drill pipe getting stuck and also causing obstruction of flow. Pressure may build up, fracture the rocks, and fluid may flow into the formation. All of these described incidents may result in loss of control of the well and may ultimately lead to abandoning the well.

Let us now look more closely at the control of pressure through fluid circulation. The pressure in the wellbore is a function of the drilling fluid density, viscosity, the fluid flowrate in the wellbore generated by the mud pumps, and the axial and rotational movement of the drill-string controlled through the drawworks and top-drive. In the planning process, when the drilling fluid program is prepared, software tools applying computerized flow models are used to decide what properties the drilling fluid shall have and what the fluid flow rate should be during drilling in order to ensure good transport of cuttings out of the well while keeping the downhole pressure within the available downhole pressure window. Dynamic versions of the same models may also be used to plan the various procedures to be performed which will affect the pressure in the wellbore, such as pulling the drill string out of the well to change the bit, and starting and stopping the mud pumps to connect new strands of drill pipe as the drilling process proceeds. Historically, the driller's task is to apply the drilling flow rates and procedures prescribed in the drilling program while at the same time looking out for unexpected or unwanted behaviour. If such behaviour should indicate that the assumptions used in the planning process were incorrect, e.g. with regards to what the available pressure window is, then the drilling program would be updated and new drilling parameters and procedures would be prescribed to the driller.

Today, systems for drilling automation are available which use computerized drilling process models for both direct control, or automation if you will, and process stability diagnostics in real-time. The models take as input the real-time drilling data available from sensors and systems on the rig and downhole. They cover drill string mechanics and flow in the wellbore and also drilling mechanical energy, wellbore positioning, formation properties, etc. In automation systems, the control infrastructure used is typically layered, where parameter set points are calculated externally using computerized process models, and transferred either manually or through suitable data transfer protocols over a network to machine control Programmable Logic Controllers (PLCs) interfaces. These PLCs contain control algorithms which apply the externally calculated set points.

One challenge with regards to such an infrastructure is standardization of communication and storage. This is partly due to the complexity of the drilling industry, where multiple vendors and suppliers are involved in the operations on the drilling rig, so there are multiple independent systems and processes running on the rig, tied together more through verbal and written communication than actual data interfacing. As process digitalization and automation requires that these systems need to be connected, several standards are currently being developed and applied, such as the Well Site Information Transfer Standard Markup Language (WITSML) Standard developed through Energistics: http://www.energistics.org/ for data storage and OPC-DA or OPC-UA for communication in control. The Drilling Systems Automation Technical Section (DSATS) of SPE: http://communities.spe.org/TechSections/drlgauto/default.aspx. SPE DSATS also has a committee working on this issue through its COMMS Team.

Challenges in organizational complexity and systems connectivity aside, let us get back to the issue of controlling the downhole pressure in real-time. We have available accurate enough process models and can build custom-made connectivity, thereby enabling automatic control using the models to determine the instantaneous downhole pressure and to predict dynamics for planed operations to optimize these. Now, we get to the issue of real-time drilling data availability and resolution:

- The models need measured boundary values as input, such as flowrate, temperature, and density for the drilling fluid being pumped into the drill string. Further,
- the flow model requires pressure measurements for calibration with respect to the flow frictional pressure loss in the well. This may be achieved by the application of surface and downhole measurements. However, the flow related measurements performed

downhole, normally pressure and temperature, are typically limited and delayed, and for many operations there are no such measurements.

In the cases where there are downhole measurements, data from these may today be transported to the surface through various types of telemetry, including:

- Mud-pulse, which communicates through pressure pulses in the drilling fluid, is slow (up to 40 b/s), and only works when there is flow. As limited additional equipment is required (a pressure pulse generator downhole and a pressure sensor at surface), this method is quite reliable.
- Acoustic telemetry is based on propagation of stress waves through the drill string. This provides a maximum band width compared to that of mud pulse telemetry, with the benefit that it also transmits data when the well is static, i.e., no flow rate. This requires amplifiers along the drill-string every 1000 meters or so, depending on the inclination of the wellbore. The increase in number of elements in the data transmission chain increases the risk of failure.
- Wired pipes, which use induction loops for signal transfer for each drill-pipe connection, have a large bandwidth (current commercial rate of 57.6 kbps) and may be the way of the future. However, this system requires that every single pipe used in the drill-string is wired and it also needs repeaters at regular intervals (typically every 500 m). The large number of elements constituting the data transmission chain makes this telemetry method very sensitive to component failure.

Today mud-pulse technology is generally applied, while acoustic telemetry and wired pipe are not in common use. Further research in telemetry technology may be valuable for the ongoing development towards automation.

To control the downhole pressure within the stable domain of the geopressure window, the downhole pressure may be estimated through the use of dynamic process models. The measured flowrate at the mud pumps is applied as a direct boundary value together with the measured fluid temperature, while the measured surface and downhole pressure may be applied to calibrate the model. There is normally a pressure sensor installed at the bottom of the stand-pipe (a high pressure rated pipe connecting the mud pump flow-line to the mud hose to the top-drive), while the temperature is measured in the drilling fluid pit from which the drilling fluid flows through the suction line to the mud pumps. Here, there are some issues, as the physical boundary of the flow model is the top of the drill-string, while the measurements are taken elsewhere (at the rig floor and in the pit).

For calibration, we wish to know what the pressure is in the entry of the drill string. However, the fluid is pumped from the mud pumps through the mud pump flowline, the standpipe, and the mud hose, and subsequently into the drill string through the swivel connected to the top-drive. Therefore, the pressure at the top of the drill-string is really a function of the pump pressure, the elevation of the top-drive and also the flow-frictional pressure loss in the lines pipes and hoses leading to the drill string. Further, the flow rate is normally derived from the stroke frequency of the pumps, where the pumped volume per stroke is given by the pump liner size corrected by a pump efficiency factor which shall account for the effects of valve design, closing speed and condition of the valve springs. The pump efficiency changes with pump rate and pump pressure, and is also influenced by the ageing of the mud pump. It is hard to calibrate and may be a source of significant error. Such discrepancy needs to be accounted for when wanting to apply the flow model directly in control, as opposed to when applying the models purely for planning purposes.

There are similar issues for the torque and load measurements applied to the top of the drillstring, used in the mechanical modeling of the drillstring dynamics. Clearly, in automating the process, positioning of instrumentation and correct processing of the measurements is an issue. Applications here of new types of measurement technology could be of significant benefit. And, we have yet to touch on the issue of measuring and controlling the ever changing properties of the drilling fluid here.

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The Drilling Environment

John Macpherson

During drilling, the deepest portion of the drillstring (the "downhole" end) is subjected to continuous and extreme vibration and high temperatures and pressures. This makes drilling one of the most challenging environments for instrumentation and measurement systems. The vibration seen by downhole electronics on an average drilling run is equivalent to in excess of 8,000 shuttle launches (based on a comparison of shuttle-launch and drilling rms vibration). The temperature environment for electronics ranges between -40 °C on surface to 150 °C downhole, while the pressure environment can be up to about 2,400 bars at 10,000 m depth. A drilling run can last for two weeks or longer and the electronics, sensors, and processing systems are expected to survive not only one drilling run, but multiple sequential drilling runs.

The electrical systems developed for downhole drilling are constrained not only by the environment, but also by the physical packaging requirements dictated by the slender drilling tubulars. These tubulars have a central bore for circulation of fluid, which leaves only a narrow annular space within the body of the tubular for instrumentation and measurement systems. So system layout and packaging are key concerns; electrical and mechanical engineers and scientists need to work closely together when creating these systems.

Extremely sensitive instruments, such as packages of accelerometers and magnetometers for directional steering, antennas and receivers for measuring and imaging formation resistivity, and nuclear magnetic resonance measurements of formation properties, among others, are run regularly within this environment. Mechanically and electrically complex semi-autonomous systems for steering the drilling operation through involved trajectories are standardly deployed. Engineers working on the instrumentation and measurement systems needed for this environment are constantly being challenged to push the envelope: one of the latest challenges — extend the temperature limit up to 300 °C for geothermal drilling.

Geothermal Drilling

A few years ago, the US Department of Energy launched a series of awards focused on Enhanced Geothermal Systems. These awards to research institutes, national laboratories, and both small and large for-profit business, focused on kick-starting research and development aimed at tapping the huge geothermal reserves located at deep-depths within the earth's crust. Other governments, for example in Germany and Australia, have started similar programs. The objective is to drill deep wells, say between 7,500 and 10,000 m depth, in some of the hardest rocks and most challenging drilling environments. The objective is to pump cold surface water through the hot downhole formation, to generate steam that turns turbines and produces electricity on surface. The program has generated electrical components that can survive this high temperature environment. However, putting these components together in a drilling system—one that cannot only drill directional holes in this environment but also measure environmental, directional, and formation properties, and communicate that information to surface in real-time—is still a subject for the R&D laboratories.

While geothermal drilling attempts to push the outer limits of what is possible, oilfield drilling is likewise pushing temperatures higher than the conventional 150 °C downhole environment. The reason is that several economic reservoirs, such as those encountered in gas rich shale deposits, are at elevated temperatures. The desire is to improve electronics and packaging so that a new generation of downhole instrumentation and measurement systems can deliver reliability similar to current electronics operating at 150 °C. Currently, some complex systems are available that operate at up to 175 °C, while simpler systems; e.g., the gamma ray formation sensor, directional accelerometers and magnetometers, have demonstrated performance in excess of 200 °C. To survive for extended periods at these temperatures, the vibration environment has to be monitored and controlled, since electronic life depends on both temperature and vibration history.

Drilling Systems Automation

A 10,000 m long drillstring is quite compliant. There are heavier tubulars on the lower end (used to deliver weight to the drill bit to destroy rock and advance the borehole), and slimmer drill pipe above this running to the surface. The entire drillstring acts like a large torsional spring when rotated from the surface, and motions at the lower end can be quite difficult to predict due to intermittent wellbore contact, formation related friction along the drillstring, and the complex geometries involved. The endeavor to repeatedly drill quality boreholes at an economic price, and to keep the workforce safe, has resulted in a surge in automation systems development in the drilling industry. This development spans mechanized systems on surface used to handle the drill pipe and other components, to semi-autonomous downhole systems that can drill through complex lithologies while optimizing the direction of the borehole. The inclusion of these automated components in an overreaching control system termed *Drilling Systems Automation* is now underway and offers opportunities in instrumentation, measurement, signal processing, control systems, and real-time data processing, among others.

Drilling Systems Automation is challenging. It brings together many diverse facets of the drilling industry: operators, drilling rig contractor, equipment suppliers, and service companies, to develop the standards and infrastructure for automation. This opens up opportunities for developing "automation quality" surface instrumentation as well as the development of new data handling and signal processing systems as the industry attempts to move *big data* analysis into real-time for the purposes of safely automating drilling in challenging environments, such as deep water offshore operations.

In summary, drilling modern wells in the sub-surface is complex and challenging. Downhole instrumentation and measurement packages must survive high temperature, vibration, and pressure. On surface, systems automation is driving the adoption of standards and a need for accurate and reliable instrumentation, and the requirement for real-time data processing in simulators and models.

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