Innovating While Drilling

Innovations in MWD/LWD and drill pipe technologies address key operator concerns and needs, put previously impossible wells into reach

By Linda Hsieh, assistant managing editor

Operators ask for a lot in their logging-while-drilling (LWD) and measurement-while-drilling (MWD) tools. And why shouldn’t they, considering the sizable chunks these services can chew off of a budget?

The growing number of directional, extended-reach and highly deviated wells means that MWD/LWD technologies are often indispensable – certainly if you want to have efficient wellbore placement. At the same time, drilling environments are increasingly harsher and putting extreme stresses on downhole tools – which means higher risks for failure.

For their part, the service sector has made important breakthroughs and set impressive records, and continue to work on trouble spots like reliability and the ever-elusive look-ahead capability. Drilling Contractor surveyed five major oil companies, then took their challenges and criticisms (anonymously) to two oilfield service providers. Below are some of the significant issues discussed.

BHA vibration

Downhole shock and vibration continue to be problematic, and the challenge is exacerbated by the increase in number of extended-reach and ultra-deepwater wells. One operator noted the need for accurate, high-frequency downhole vibration and bending monitoring tools in real time, integrated with all MWD tools. Another cited vibration as a cause in reducing his drilling penetration rates. It can also make the borehole twisted, causing “false” images to LWD tools, he said.

Jim Wilson, principal global champion for MWD/LWD for Halliburton’s Sperry Drilling Services, offered a couple of solutions they’re developing. First, his company is incorporating the DDS-R (Drillstring Dynamics Sensor) into their LWD tools, which “helps us understand the shocks and vibrations we’re experiencing.” When drillstring vibration exceeds pre-set thresholds, real-time alarm information will be transmitted to the surface, allowing for corrective action.
The IntelliServ Network’s ‘downhole broadband network’ concept has made ‘mind-blowing’ measurements in recent wells, offering a glimpse into what could be the future of downhole management. See Page 36 in this section.
Separately, the company plans to launch the WTB sensor later this year. This tool will help drillers see three critical downhole phenomena – weight on bit, torque on bit and bend on bit – in real time so that drilling parameters can be optimized.

Paul Radzinski, global marketing manager for Weatherford Drilling Services, offered this take instead: “Prevention is better than a cure. Pre-well planning is absolutely critical to efficiently preventing damaging BHA vibrations. “Through pre-well planning, we can model very accurately the BHA and proper stabilizers placement. We can tell an operator where the critical harmonics are and how to avoid BHA vibration and its damaging effects.”

“It’s so much better to prevent yourself from getting into the situation than trying to build something to survive the worst-case scenarios,” he said. “Rather than trying to build a car that won’t get damaged when it hits a tree, just try and avoid the tree.”

High pressures, high temperatures

Operators seem to agree that, for most wells, current MWD/LWD systems can handle the upper ranges of temperatures and pressures they see. However, they also say that cutting-edge HPHT developments have created a need for further improvement. One operator urged that temperature/pressure limits be upscaled to 200°C (400°F) and 35,000 psi.

“We have in our portfolio several prospects beyond 177°C,” another said.

Weatherford is preparing to commercialize the 165°C-capable Shock Wave LWD Sonic tool this year.

In one case, high-pressure conditions made it mandatory for the operator to take up development of “basic downhole tools” with partners and a major service company. “It is surprising that the (service companies) are not prone to developing such tools… despite the worldwide deeply buried reservoirs potential,” he added.

Service companies, however, say they are in fact putting in R&D dollars into designing and improving HPHT tools. Sperry is in the progress of working towards 35,000-psi tools, Mr Wilson said, and they plan to selectively upgrade LWD tools to 175°C and 30,000 psi, as dictated by market requirements.

Weatherford says it is proud of its achievements in HPHT wells around the world, noting that they hold the LWD world record for highest temperature (193°C, North Sea, 2005) and recently set a high-pressure record in the Gulf of Mexico last summer by going to 34,100 psi with a full LWD. “I have confidence that any well with a pressure approximating 30,000 psi, we will probably have an excellent chance of success,” Mr Radzinski said.

On the temperature side, the company noted that it will commercialize its 165°C-capable Shock Wave LWD Sonic tool later this year. It also recently provided LWD equipment able to work at 180°C and 30,000 psi in an HPHT field in northern Italy, allowing the operator to drill a 5 ½-in. sidetrack well to access previously bypassed reserves. (See detailed case study, Page 22.)

Perhaps you might say that these advances are incremental changes rather than the major upgrades that operators seem to be requesting. Yet service companies point to the overall niche status of such high-temperature and high-pressure wells – which makes this kind of R&D a costly and potentially risky task.

“The overall extreme-HT market is small, yet the engineering cost to meet this challenge is huge. To just go another 20 degrees would be a very large effort,” Mr Radzinski said.

Fluid sampling

One capability that operators have wanted for years is a fluid sampling feature to complement pressure-while-drilling or testing-while-drilling tools. Now, Sperry says they may be ready to fill that gap with what could be a “game-changing” technology, according to Mr Wilson.

The InSite GeoTap IDS (identification/sampling) builds on the GeoTap formation pressure testing tool, available since 2002, to allow fluid identification and sampling as the well is being drilled, while obtaining pressure measurements at the same time. The new system will support real-time identification of reservoir fluid properties such as density, viscosity and conductivity, as well as enable timely downhole capture and surface recovery of multiple samples of uncontaminated formation fluids.

“Customers spend millions of dollars obtaining these data on wireline after the well has been drilled. With this tool, you’re able to do it in the drillstring BHA,” Mr Wilson said. Within hours, they could get a formation sample that’s 95% clean for further analysis.

The demand for this technology has been huge, and Mr Wilson recalls operators already asking ‘Can you take samples?’ on the day the original GeoTap was introduced a few years ago. “We have been working on the technologies, building on and leveraging off of the GeoTap formation pressure testing tool.”

The result is the GeoTap IDS – “probably the most complex tool that’s ever been built in the LWD arena,” said Mr Wilson. The tool is currently undergoing further tests and should go into the ground for continued on Page 26
Case study:

Hostile-environment LWD allows efficient oil recovery in HPHT field


IN THE DEEP, high-pressure, high-temperature wells in the Villafortuna/Trecate field in northern Italy, LWD was planned to enable continuous correlation for casing and coring points. Of two required targets for the well, the first was not assured because of possible faults. The second showed risks for depleted intervals, with very poor seismic control.

The field consists of two carbonate oil reservoirs with the presence of intense tectonic phenomena: the upper reservoir (Conchodon Dolomite and Dolomia Principale) and the lower reservoir (M.S. Giorgio Dolomite), overlayed by a thick carbonate and terrigenous sealing sequence. Analysis showed the possibility of draining an oil mineralization, cores were to be collected from the lower reservoir.

A sidetrack was planned from a previous well. Well profile included entering vertical at the top of the lower reservoir, but the sidetrack also had to verify the presence of mineralisation in the upper reservoir. The well plan called for a 8 ½-in. sidetrack from the 9 ¾-in. casing to the Medolo formation upper interval, followed by drilling a 5 ¾-in. hole to target.

Due to uncertainties about the formation type at target and the formation mineralization, cores were to be collected from the lower reservoir.

HPHT LWD

Because standard LWD equipment had experienced numerous failures at downhole circulating temperatures up to 180°C in the previous hole section, it was decided to use an HPHT LWD system to drill the 5 ¾-in. sidetrack. Weatherford provided a 4 ¾-in. suite of HPHT LWD tools, including directional MWD, pressure-while-drilling (bore and annular), multi-frequency resistivity and azimuthal gamma ray sensors.

To drill the sidetack, each collar was powered by a dual-battery module assembly consisting of two high-temperature intelligent batteries that enabled logging at temperatures up to 200°C.

These lithium batteries had two important operational considerations. One is the maximum safety factor before the cells become unstable and vent. Internal testing has shown that the cells will vent once the internal temperatures reaches 212°C.

The second consideration concerns operation of the equipment at temperatures below 70°C, such as during deck tests and shallow hole tests. Extended use at low temperatures can cause high and erratic current usage, which can shorten the life of the batteries. The battery thermal protection function meant the pulser will not work until the temperature of 70°C is seen, allowing for extended life.

The MWD system was designed for hostile-environment logging. It provides real-time directional and logging data through a pressure-modulated telemetry system for HPHT drilling environments. It is able to operate at temperatures up to 190°C, survive at 200°C and withstand downhole pressures of 30,000 psi. An integrated directional sonde uses three orthogonal high-temperature accelerometers and magnetometers housed in a nonmagnetic titanium alloy chassis to provide directional and toolface measurements that track the drilling path and orient the PDM motor during sliding operation.

The suite was also equipped with a pressure-while-drilling sensor and programmed to store all pressure data in memory every five seconds and all temperatures every five minutes. The result was continuous, highly accurate downhole measurement while drilling, wiping or tripping in/out of the hole. Bore pressure, annular pressure and temperature, and ECD were transmitted and plotted real-time to help minimize mud losses and optimize the mud program.

The high-temperature multi-frequency resistivity sensor used three independent transmitter-receiver antenna spacings and two electromagnetic wave frequencies to provide highly accurate measurements in the extreme conditions, with 12 fully compensated phase and attenuation measurements recorded every 10 seconds.

The real-time-transmitted 2 MHz shallow, medium and deep-phase resistivity curves were useful in formation identification and continuous correlation for coring and casing points.

Gamma ray information was acquired using a high-temperature azimuthal gamma ray sensor consisting of five banks, each with two Geiger Muller tubes. The number, size and symmetric distribution of tubes were chosen to provide the optimal combination of statistical precision and azimuthal...
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sensitivity and to allow azimuthal measurements while rotating and/or sliding.

Triggered azimuthal gamma ray data in quadrant format was also transmitted in real time to maintain a good data density. The combination of total gamma ray, azimuthal and resistivity data while drilling made formation identification and continuous correlation for casing and coring points possible.

Gamma ray data in octant format (8-sector borehole), sampled and stored in memory every 10 seconds, was sent to the office at the end of each run to be analyzed and processed with specialized software.

Image logs and dips interpretation played an important role in improving the characterization of reservoirs by showing graphic details about texture and structural features, such as faults and fractures, and by identifying dips and defining the angle and direction of tilt in sedimentary layers.

LOG MEASUREMENTS

In addition to the temperature and pressure measurements recorded real time, 12 resistivity measurements and oriented azimuthal gamma ray measurements were acquired while drilling.

The azimuthal gamma ray sensor records eight values around the borehole in memory, and sends four values up hole in real time. These values are oriented using the directional package, then processed and mapped to a false colour palette to provide an image of the borehole. The resulting imaging log is depicted in a reversible dark/light scale that portrays high/low gamma values.

Two different images are typically generated: a static image, where the minimum and maximum values of the measurements for the entire data set are mapped to the colour palette; and a dynamic image, where a user-defined depth range determines the minimum and maximum values, which are then mapped to the colour palette. The static image is an absolute scaling of the measurements, whereas the dynamic image is a relative one, which also provides better contrast in areas where there are small changes in absolute values.

After a correctly oriented image is made, the bedding planes can be delineated. Planes in 3D space are represented in 2D using sinusoids. The geoscientist picks the sinusoids which represent the apparent dip angle and azimuth of the bedding plane. Using the directional information, true dip is calculated from the apparent dip and can be referenced to either magnetic north or true north by correcting for magnetic declination. The dips are then plotted using tadpoles.

LOG RESULTS

The main objective was to use the gamma ray and resistivity data to correlate the sidetrack well with the offset well, in real time while drilling, to set casing shoe between overpressure zone and depleted zone, to identify coring point and identify formational variations. This was achieved despite an in-situ static temperature of 180.5°C and a circulating temperature of 160°C.

Several benefits were identified to logging high-temperature gamma ray and resistivity data in real time:

1. The real-time continuous gamma ray curve and resistivity curve permitted the operator to correlate while drilling the sequence crossed in the sidetrack well with the similar sequence crossed in offset wells.

2. The real-time correlation made it possible to identify the presence of a main direct fault and to estimate its reject. The upper reservoir was identified 136 m higher than the prognosis estimation.

3. The continuous real-time gamma ray and resistivity curves allowed the operator to better define the stratigraphic setting. This definition was critical because the use of a PDC bit often destroyed the lithological characteristic of the drill cuttings.

4. The continuous real-time gamma ray and resistivity curves allowed the operator to identify a carbonate sequence in the lower section, which prompted the decision to cut a core at bottom. The core results, which showed the rock to be very tight, and log correlation resulted in the decision to plug and abandon the lower section and to produce the upper reservoir with very good results. New wells in the project are planned as a result of this well.

5. Real-time annular borehole temperature gave the operator an idea of the temperatures present in the sequence.
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commercial field testing in Q2 or Q3 of 2009, depending on the success of initial tests, he said. (See Page 28 for more information about two other new InSite tools coming out in 2009 – a litho density neutron tool and a multi-well geosteering service.)

Reliability

“The biggest value impact from LWD/MWD/DD is to get it right the first time,” one operator noted. Yet tool reliability issues continue to eat away at this value – whether because of component failures, QA/QC problems or human error.

Service companies appear to agree on this point and emphasize that they understand the importance of reliability.

“The No.1 buying criteria is absolutely reliability. You can have everything working great, but if you have one part fail twice as often as your competition, you won’t get the contract. Coming out of the hole is very expensive – it could be a significant portion of the entire rig cost,” Mr Radzinski said.

Service companies say they continuously take on all sorts of destructive testing, vibration testing, pressure testing, etc, to ruggedize and improve their tools.

“We’re reducing connections, reducing the number of electronic boards in there, including redundancy where possible and taking advantage of the advances in the computer/electronics industry to have smaller LWD tools that are less impacted by the huge shocks and vibrations they experience downhole,” Mr Wilson said.

Another way they’re tackling reliability is through competent training, added Mr Radzinski, who attributes one-third of all tool failures to human error.”30% is a big segment of total failures, so training and hiring good, competent people is something we’ve been focusing on.”

The lack of an industry standard for measuring reliability also makes it difficult to talk about the issues, he continued. “For airlines, there’s a government standard for on-time arrival, so you can see who’s the best. But in our industry, there is no common standard for reliability.”

For now, looks like operators may just have to remember that, sometimes, the value of the MWD/LWD service is simply being able to obtain these downhole data in real time.

Looking ahead of the bit

The capability to see ahead of the drill bit – especially in vertical, exploration wells – has been a long-sought-after yet elusive goal for the drilling industry. After decades of research, there are still few seismic-while-drilling (SWD) systems on the market, and acceptance among operators remains low.

One operator noted that SWD systems have not been accepted at his company “maybe because the first tests conducted did not work out satisfactorily.”

Another elaborated more, saying that “90% of current (SWD and vertical seismic profile/VSP) techniques are just used for a time-depth calibration. The reason is simple: The look-ahead is still difficult and just obtained today in some VSP for vertical wells. ... We have today no solution fitting all our expectations. The gap is rig time impact, deviation of the well, continuous and real-time survey acquisition and processing, real time with look-ahead feature, HPHT.”

Mr Radzinski acknowledged these concerns, noting that SWD technologies “just seem to have difficulty gaining traction.” “The perfect tool would be right at the bit or in front of the bit to directly measure the pore pressure, and that sensor does not yet exist,” he continued.

Michael Bittar, director of formation evaluation technology for Halliburton’s drilling and evaluation division, agreed that look-ahead capabilities need more work. “We’re hoping to have the break-through. It is an extremely difficult problem to focus the sonic or electromagnetic signal ahead of the bit. ... We all understand the importance of look-ahead, and I think it’s something the whole industry will work on, but we have to understand the difficulties.”

Cost vs benefits

The issue of cost always seems to be a rather difficult one to achieve consensus and agreement on between operator and service company. One side believes that costs for LWD/MWD have risen to “prohibitive” levels. In combination with smaller volumes per well in mature basins, the reliability issues mentioned earlier, and companies’ risk aversion tendencies, “there are projects/wells where the ‘value for money’ balance tips to the side of no LWD/MWD at all,” one operator said.

On the other side, service companies point to the tremendous costs they must undertake in order to build these highly sophisticated and complex tools.

Moreover, LWD/MWD costs must be considered in terms of the total rig cost, Mr Radzinski said. “If the rig cost is $8,000/day, there’s no economic reason to run LWD. An operator can’t afford it. If you’re running a $700,000/day rig, you wouldn’t even think about it – you run it. And if it’s a $70,000/day rig, you have to look at the cost vs benefits. Still, a lot of wells need a basic LWD service to properly place the wellbore through geosteering. Sometimes you just can’t drill the objective properly without it.”
New litho neutron density tool features shorter length, wireless capability

Aside from the GeoTap IDS (discussed on Page 20), two new tools have been added to the InSite suite of technologies from Halliburton’s Sperry Drilling Services.

First, the LDN (litho density neutron) is a compensated density and compensated neutron tool in one collar. It incorporates an integral acoustic caliper, and all measurements are azimuthally binned so an image can be created from the density, neutron (density) and the acoustic caliper sensors.

It also boasts a shorter length – at 16 ft compared with the traditional density neutron’s 34 ft or longer. Operators won’t have to drill additional ratholes to take these measurements, said Jim Wilson, Sperry’s principal global champion for MWD/LWD.

The other key feature is that the tool can be read wirelessly. “Rather than having to electronically plug in the tool as done in the past, we’ll be able to read the tool as soon as the antennae clears the surface of the drill floor. The data acquisition time will be faster probably by a factor of 10 to 100 times,” Mr Wilson said.

He expects the tool to undergo field test on US land within the next couple of months.

Also coming into the InSite toolbox is StrataSteer 3D multi-well geosteering service, to be launched later this year. Michael Bittar, director of formation evaluation technology for Halliburton’s drilling and evaluation division, explains that StrataSteer 3D is a workflow in the digital asset. The digital asset is a real-time collaborative environment to model, measure and optimize the oil and gas asset.

“It will allow us to continuously update the Earth model as we are drilling and geosteering the well. We’ll use the InSite ADR and other InSite tools to precisely place the well in the sweet spot of the reservoir,” he said.

The ADR (azimuthal deep resistivity) is a deep-reading device that can measure in 32 sectors around the borehole. It can distinguish whether a change in resistivity is happening above, below or to the side. It also has 14 depths of investigation up to 18 ft so you know how far away the formation change is.

Recently, the ADR was used successfully on a well in the North Sea’s Oseberg area to precisely place a long, horizontal section through the reservoir while avoiding an overlying, unstable formation, according to one presentation at the 2008 SPE Annual Technical Conference & Exhibition, held 21-24 September in Denver, Colo.

In that well, seven resistivity curves were pulsed in real time to the surface: three average resistivity measurements at deep, medium and shallow depths of investigation; four azimuthal resistivity measurements with one deep reading and one shallow reading, each from the up and down octants.

The deepest resistivity measurements had an estimated depth of investigation of 2 m to 2.5 m – which the authors said was ideal because a deeper depth of investigation would not help to geosteer the well through the formation with interbedded sands and silts of 2-3 m thickness. The achieved depth of investigation allowed the sensor to see the upper/lower boundaries of the sands, therefore able to steer between the boundaries.

The StrataSteer 3D was also used in this project to correlate the azimuthal resistivity data against offset well data. This allowed for continuous updates of the geological model based on seismic data, offset data and real-time well data.


The LDN tool is only 16 ft long and can be read wirelessly once its antennae clears the surface.