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Meticulous Engineering And Rugged Equipment Deliver Ever-Longer Laterals

By Danny Boyd

Time flies. Ten years ago, what was then Eclipse Resources began flowing natural gas and condensates from its Utica Purple Hayes No. 1H. With a lateral span of 18,544 feet drilled in 17.6 days using a BHA that was robust enough to complete the entire job in one run, the feat might have made the 10 o'clock news. It certainly turned industry heads.

Fast forward to today, and modern drilling techniques have made three- and four-milers run of the mill. In fact, the decision on whether to drill several two-milers or opt for ones that extend beyond four miles often comes down to whether the lease can accommodate the longer length.

With U-laterals gaining popularity, even lease boundaries may no longer be enough to restrain the industry's penchant for drilling record-setting laterals. Whether they stay straight or curve back on themselves, these engineering feats have strong economic drivers. Exposing more source rock in the production zone boosts both initial production rates and estimated ultimate recoveries from each well, and achieving that goal with a single well costs less per lateral foot than drilling several shorter laterals.

But drilling or completing particularly long laterals is rarely easy, cautions Andy Biem, vice president of technical services at Altitude Energy Partners. "Drillers must contend with increased tortuosity, stick-slip tendencies and a host of other downhole challenges that can inhibit performance and lead to costly tool failures that force extra trips," Biem says. "The key is to assess the risks and plan accordingly, optimizing wellbore placement, drilling system selection, and drill string design."

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The Perfect Wellbore

While the theoretically perfect wellbore minimizes doglegs and overall tortuosity, the reality is that even in ideal drilling conditions, BHAs shift vertically and azimuthally, Biem notes. This movement adds up to accumulated tortuosity that directional drillers have to combat when making steering decisions.

An engineered BHA design improves stability, allowing for introduction of intentional doglegs during sliding, while minimizing the tendency of that BHA to build or turn while rotating. The goal is to have a relatively neutral and balanced BHA during rotation but still allow drillers to adequately steer the assembly to make trajectory changes.

Optimizing stabilizer size and placement provides the balance needed to reduce vibrations and helps control the drilling angle and trajectory in longer wells. In many cases, stabilizers should be employed near the bit as well as placed farther back throughout the BHA.

Selecting the right drilling system is critical, Biem reports. Rotary steerable systems are more common in Appalachia, where lateral wellbores tend to be larger, with some up to 8.75-inches in diameter. However, operators might prefer conventional BHAs and slide drilling for applications in the Williston and Haynesville that involve laterals with six inch hole sizes, Biem says.

In slide drilling on long wells, transferring sufficient weight is especially demanding when making steering changes farther down the borehole.

Vibratory Tools

More effective vibratory tools are helping the string transfer weight to the bit in complicated slide drilling environments. In general, vibratory tools reduce the natural friction from drill pipe laying on the bottom of the hole, Biem explains.

Multiple vibratory tools are often deployed on long wells. For example, one tool may be 1,000 feet from the BHA, a second a few thousand feet farther up, and if required, a third 7,000-8,000 feet from the assembly.

Some of the latest vibratory tools can be selectively activated as drilling proceeds into the deepest sections of the lateral instead of vibrating throughout drilling. Constantly operating vibratory tools from the start increases the risk of degrading MWD tools' ability to transmit information to the surface, Biem says.

Now, vibratory tools can be selectively activated by dropping a ball down the drill string. When the ball seats, the flow of drilling mud is redirected and creates a change in hydraulic pressure that activates the tool. In addition to protecting MWD and other sensitive tools, the delay can postpone the need for extra hydraulic pressure required to operate the tool throughout drilling. Additional tools of any kind can come with trade-offs that affect pressure.

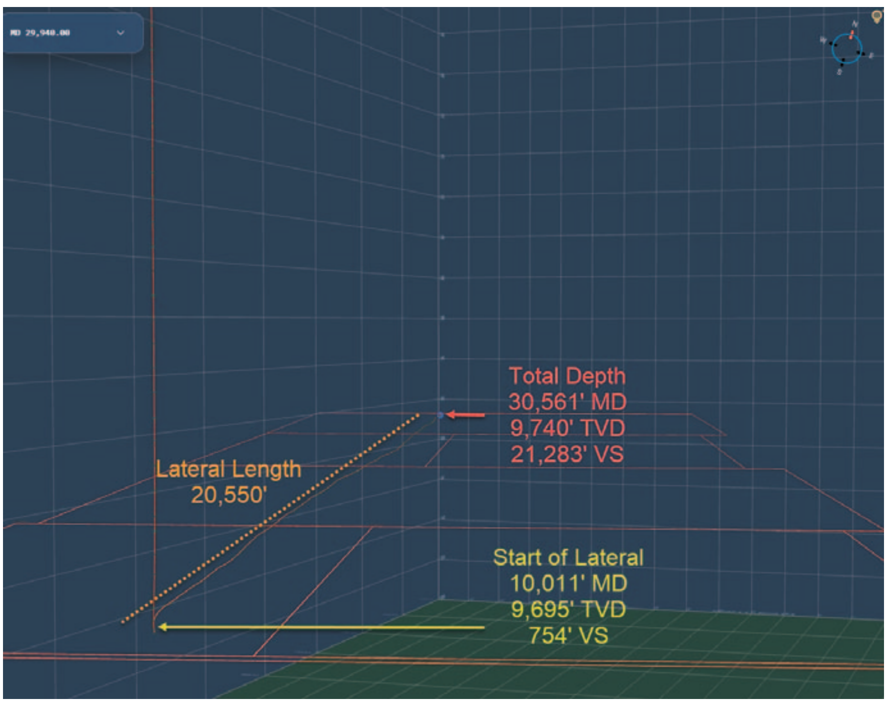
"Extra tools can have this compounding effect with extra pressure drops and frequencies that drilling engineers have to take into consideration," Biem says.

Other techniques to reduce friction and torque include oscillating the drill string in alternating clockwise and counterclockwise rotation. Top drive control systems can be programmed to dictate rotation frequency, speed and direction. This creates a rocking motion in the drill string that breaks friction to enhance sliding performance.

Improvements to mud motors also contribute to success in long laterals. Biem says Altitude works with OEM partners to create mud motor power section technology that can deliver higher horsepower under higher flow rate conditions for longer periods of time.

These mud motors benefit from mud pumps that focus on durability and capacity, sending more fluid at higher pressures through the motor and drill string as well lengths increase, Biem says. To improve their longevity and reliability, the pumps may be made from alternative materials. For example, nonmagnetic alloys can be used in place of conventional steel in some cases.

Coupling the BHA and drill string together is also a critical piece of the puzzle. More durable threaded connections between the power section and the bottom end of the mud motor are helping to extend motor life, as are modern elastomers and rotor coatings. Collectively, these advances have helped drillers double mud motor horsepower from 300 to 600 over the past 15 years. ❐



This survey shows a West Texas well with a total depth of 30,561 feet, including a lateral that is almost four miles long. According to Altitude Energy Partners, such long laterals have become increasingly common as operators look for ways to access more productive rock at lower cost. It helps that improvements to drilling equipment and techniques have greatly reduced the risks associated with the extra length.