Slimhole Advantage

MECHANICAL SYSTEM TRIMS DRILLING COSTS

BY DON LYLE

Slimhole horizontal drilling already lowers drilling costs in the right application, but a mechanical drilling system offers even lower costs.

OXY USA Inc. faced a special problem with a special solution in its Hugoton Field. It used a mechanical horizontal drilling system.

Greg Rowe, operations engineer in the company's Liberal, Kan., office, wanted to drill a well for Hugoton gas in the Krider zone of the Chase in the southeastern part of the field. He faced a problem that's not unusual in the oilpatch. If he drilled the vertical well and fractured it according to general practice, the model he built said he risked fracture growth into the Winfield zone. That zone produces a lot of water in the southeast part of the Chase.

He needed another solution, and he contacted Horizontal Ventures Inc. HVI in Tulsa to try and find it. HVI is a licensee of a mechanical, slimhole drilling technique that drills wells with a workover rig rather than a conventional drilling rig.

The company told Rowe it could make a turn to horizontal in a 45-foot radius. It also told him the bit would walk clockwise in the lateral section of the well.

"We got a 50-foot radius. That was all right," Rowe says. "They had been drilling with mud, and we wanted to drill the curve with foam. In all my experience with foam, the bit walks counterclockwise," he adds. The bit did walk counterclockwise in the hole.

In this case, drilling through the tight Krider, the direction didn't make much difference, and this was the first well HVI had drilled with foam.

"HVI said it could drill a 500-foot lateral. It showed up with 700 feet of pipe, so we used it all and ended up with a 700-foot lateral. That was good. We had no torque problems," Rowe says. It also was the longest lateral HVI had drilled to that point.

Technically, the well worked.

The Krider in that area was 34 feet thick, and Rowe wanted to run the horizontal leg parallel with the formation and 17 feet below the formation top.

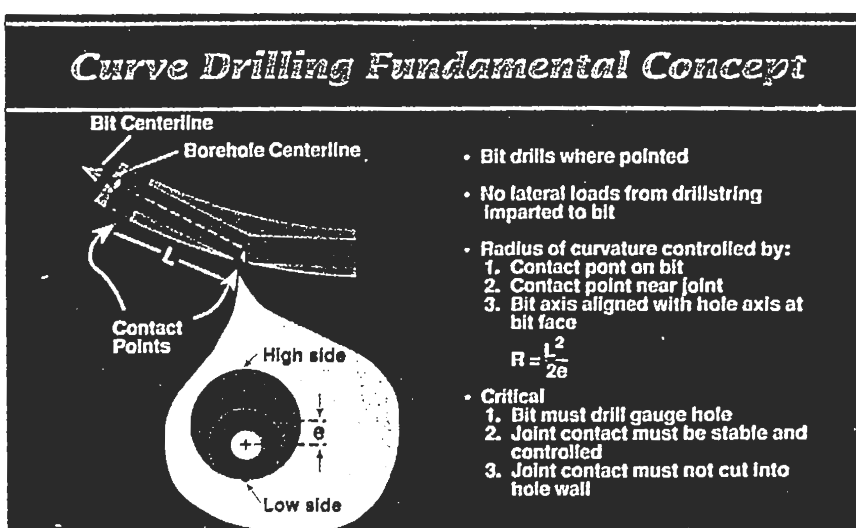
"We ended up a little below that—at about 30 feet [below the top]—but we never got out of the Krider. They put on a gentle riser [on the bottomhole assembly] and came back up to the 17-foot level," he adds. Most of the lateral was near the 17-foot level.

Would he use the mechanical system again. Yes, "If we found an applicable situation, we certainly would use it again," Rowe says.

The total well cost was $216,000. That includes the tubing but no rods or pumping unit. A standard vertical well in the Chase costs about $150,000 including rods and a pumping unit. But Rowe says that's an apples and oranges comparison, because a standard well with a frac job probably wouldn't work in this part of the field. A lot of the wells the company has drilled in this part of the field made so much water it had to abandon them.

When Amoco Corp. designed its mechanical slimhole drilling system, it had three major parameters. It wanted a system that a workover rig could operate—saving the cost of a full-size drilling rig—and it wanted a system that would allow it to recomplete old wells in new formations at as low a cost as possible. Finally, it wanted a system that would drill short-radius horizontal wells.

The development task went to Tommy Warren and the crew at Amoco's Tulsa Production Research Center. It's called the E&P Technology Center now.



ORIENTING SUB

The shaft within the stationary sleeve turns the drill bit. An eccentric housing helps orient the bit in the direction the operator wants it to travel. (Diagram courtesy of Horizontal Ventures Inc.)

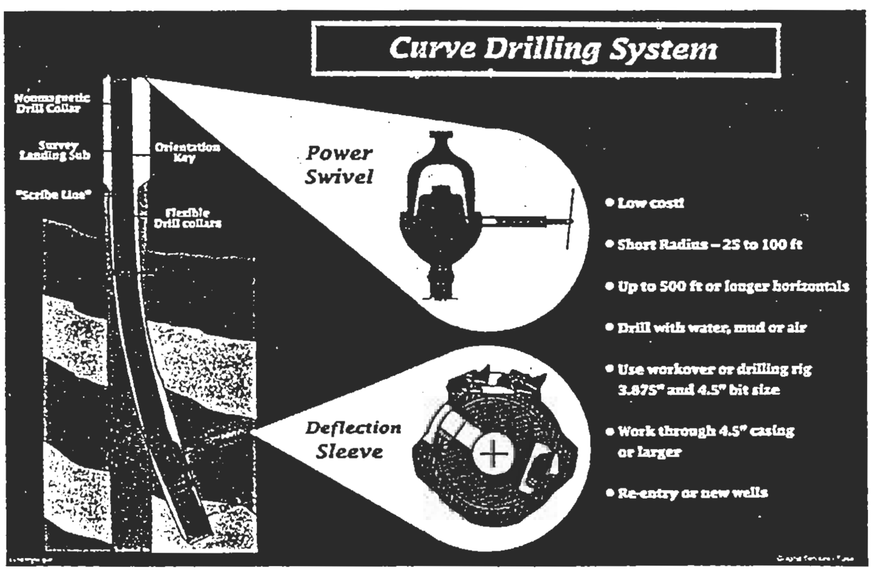
It came up with a purely mechanical system. No mud motors. No steering tools. No expensive rental fees. The cost of drilling a horizontal well from a re-entry into $4^1/_2$-inch or $5^1/_2$-inch casing compares favorably with a frac job, according to J. David LaPrade, vice president of HVI, one the few licensees for the technology. Wilson Downhole is another licensee. The other licensees drill wells for their own accounts.

Prime candidates for the technology are vertical wells with damage, wells with good pressure, wells with coning problems, wells with natural fractures and wells that missed the structures they were trying to reach.

The system can turn from vertical to horizontal with a curve radius between 30 feet and 90 feet, LaPrade says a 1,000-foot lateral was drilled from a 90-foot radius turn at Amoco's test facility. Lateral departures may be extended but depend on the radius of curvature (ROC). HVI's 700-foot departure on OXY's well was from a 50-foot ROC. Multiple laterals have been drilled in several instances. Kickoff points can be a minimum of eight feet apart on shorter radii with several additional feet needed for larger radii.

Under the direction of a trained operator and in a consolidated formation, directional control is usually within plus or minus 20 degrees of the target azimuth and plus or minus two to four feet from total vertical depth, depending on the target depth. When drilling a 500-foot lateral, missing the target direction by 20 degrees does not constitute a wide miss.

The system requires a workover rig with a top drive unit, generally a Bowen 2.5 or the equivalent power swivel, LaPrade says.



DRILLING OUT

The diagram explains how the mechanical drilling system drills out of the existing cemented hole and begins building a curve to horizontal. (Diagram courtesy of Horizontal Ventures Inc.)

For ROCs less than 50 feet, 2 3/8-inch composite pipe is used in the curve and lateral. For ROCs greater than 50 feet, $2^1/_{16}$-inch steel pipe is used. In either case, the pipe provides enough flex to allow continuous pipe rotation throughout the drilling process. This continuous rotation helps The rotating string also turns the bit. Only a sleeved section above the drill bit doesn't turn. It handles the technology that positions the bit to make the turn.

To visualize the bottomhole assembly, picture a mechanical pencil lying on a table balanced on the clip and the tip. That's the sleeved bottomhole assembly or mechanical orientation sub. At the pointed end of the mechanical pencil, picture a swivel, like the universal joint on a car. It's attached to the drill string and it turns the shaft within the stationary sleeve. The bit extends from the shaft at the stubby end of the pencil. That's the makeup of the orienting sub, but the sub has three fins instead of a clip, and the middle fin is the longest. The fins help maintain stability.

As long as the "pencil" remains standing on the clip, it forces the orienting sub and the bit to turn in the opposite direction of the clip. That's how the mechanical orientation sub that makes the turn. The distance between the back end of the sub and the front fin determines the angle of attack at the formation and the tightness of the turn to horizontal.

Obviously, with that kind of a bottomhole setup, it's imperative that the operator knows the direction the fin is pointing. In this case, when the fin on the bottomhole assembly lines up with a mule shoe keyway between 60 feet and 120 feet above the bit, the mud pressure drops sharply, sending a signal to the surface. That pressure drop tells the operator the direction of the turn.

Next, picture a ratchet system working on the shaft that goes through the pencil. As long as the drill string turns to the right, the shaft turns freely and the bit keeps moving away from the clip.

If the power swivel on the workover rig turns the drill string to the left, the ratchet kicks in. It locks the shaft to the the "clip" of the pencil in the hole and forces the bit to begin drilling in a new direction. When the assembly turns left, the three fins collapse to help make the reorientation procedure easier.

Once the unit finishes the curve to horizontal, the operator must trip out of the hole, remove the assembly and install a straight-hole assembly for the horizontal leg.

The requirement for the bottomhole assembly to rest on a stationary back end and on the raised flange at the front end places still another requirement on the system. To avoid jamming the bottomhole assembly, the wellbore must be nearly perfect.

To handle that task, Amoco came up with an anti-whirl, bi-center, low-friction, stabilizing bit.

That is, the bit cuts in the direction it's pointed, and it drills a nearly perfect hole.

Because this is a pure mechanical system, costs are lower, sometimes substantially lower than traditional horizontal drilling systems. For the operator, that means a lower well cost and a hole liability that is limited to less than $25,000, LaPrade says. A traditional horizontal well drilled with a 50-foot radius and a 700-foot lateral might cost between $85,000 and $125,000, he adds. The final cost depends on depth, location, lithology, solids control, drilling fluids and complexity of the drilling plan.

With a steadily growing track record and a cost advantage of other methods of drilling horizontal wells, the mechanical system is set to carve a substantial niche in the market for low-cost horizontal re-entries and even new wells in familiar formations. ■