Short-Radius Lateral Drilling System

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Summary. This paper describes the development and testing of a rotary-guided short-radius curve-drilling system. The curve-drilling assembly is composed of an antiwhirl polycrystalline-diamond-compact (PDC) bit, flexible joint, eccentric deflection sleeve, orientation indicator, and flexible drillstring. The system is used to drill drainholes from existing wells to enhance production in mature fields.

Introduction

Numerous mature oil fields worldwide are experiencing declining production. Unfortunately, even after the latest enhanced recovery methods are applied, vast oil resources will be left unproduced.

Lateral wellbores drilled from existing wells offer the potential to drain more oil than would be recovered otherwise. Laterals may be used to tap fresh oil by intersecting fractures, penetrating pay discontinuities, and draining updip traps. Lateral recompletions can correct such production problems as water coning, gas coning, and excessive water cuts from hydraulic fractures that extend below the oil/water contact. Synergistic benefits may result from coupling lateral recompletions with enhanced recovery techniques to solve conformance problems, to contact unswept oil by recompleting injection wells, and to redirect sweep by converting existing well patterns into linedrive configurations. Lateral recompletion strategies can take advantage of the current production infrastructure, capital resource of existing wellbores, known resources of oil in place, and secondary and tertiary recovery technology.

A major impediment to the widespread use of lateral re-entries is that drilling and completion of the laterals must be done relatively "cheaply." Workover economics in mature fields requires substantial cost reductions over the methods used most often for drilling new horizontal wells. The need for a reliable reduced-cost drilling system that uses the equipment and cost structures of workover and repair services provided the impetus for a development and field test program in west Texas where laterals were drilled in eight wells.

This paper discusses development of the curve-drilling portion of the re-entry system. Even though this is a small part of the overall effort to place a re-entry lateral in a well, it is a critical and costly element. Once the curve is drilled, the lateral is rotary drilled with a more conventional stabilized bottomhole assembly (BHA) and the same flexible drillstring used for curve drilling.

Curve-Drilling-Tool Background

For a re-entry drilling system to be technically successful, it must be capable of drilling a consistent radius of curvature and of drilling the curve in the desired direction. These requirements arise from the needs (1) to position the end of the curve within a precise depth interval so that the lateral can traverse the pay zone as desired; (2) to place the lateral in a direction dictated by well spacing, desired sweep pattern, or other geological considerations; and (3) to establish a smooth curve to facilitate drilling the lateral and completing the well.

Several types of short-radius curve-drilling systems are commercially available. The most common type uses a mud motor to rotate a drill bit that is tilted relative to the wellbore centerline. The tilted bit drills a curved path, and the rotational orientation of the motor housing in the borehole determines the direction of the curve. Either a steering tool or a measurement-while-drilling (MWD) tool is required to keep the motor housing oriented during drilling. The system may be used with conventional or workover rigs or with coiled-tubing units. This is the most popular method of drilling a curved borehole, but it is often too expensive to be economical for re-entries in mature fields.

Constrained-rotary systems are a second category of commercially available tools. They have a flexible drive shaft inside an articulated nonrotating housing. Since originated by Zublin[1] in 1952, this approach has been greatly refined. A resilient curve guide acts as a spring that applies a side force to the bit and forces the bit to drill a curved path. The curve guide initially is oriented in the desired direction and then relies on wellbore friction to maintain orientation as it advances along the curve. Because of the considerable hardware required and the associated operating procedures, use of constrained-rotary systems has declined in favor of the more reliable mud-motor systems.

Rotary-guided systems are a third category of short-radius curve-drilling tools. **Fig. 1** shows the downhole components of one such system. They include the curve assembly, flexible drill collars, and orientation equipment. The relatively short curve assembly incorporates a flexible joint that is pushed to one side of the hole to tilt the bit. The orientation equipment comprises a standard muleshoe sub for gyro orienting or a nonmagnetic collar and muleshoe sub for magnetic orienting. This basic tool concept has been around for decades, but problems with angle build and directional control have limited its commercial success. However, the appeal of drilling horizontal wells "cheaply" with such equipment remains. This paper discusses recent improvements to the rotary-guided curve-drilling system.

Fig. 2 highlights the evolution of rotary-guided curve-drilling tools before 1988. Early[2] described a tool in 1934 that used a flexible joint to allow the bit to be tilted to sidetrack a well. In 1944, Miller[3] patented a similar curve-drilling assembly (Fig. 2a) in which the bit tilt direction could be oriented to deflect the borehole in a particular direction. It was assumed that, after initial orientation, the assembly would continue to drill in a consistent direction. In 1954, Sanders[4] used a curve-drilling assembly (Fig. 2b) whose near-bit "reamer" caused the bit to be inclined. This system also incorporated a flexible joint to allow sufficient tilt to drill short-radius curves. The curve direction was determined by the orientation of a whipstock; again it was assumed that the assembly would continue to drill in a consistent direction.

In 1964 (Fig. 2c), Frisby[5] proposed an assembly that used an eccentric stabilizing sleeve to control the bit tilt to orient the tilt in a particular direction and to function as a stabilizer to minimize bit wobbling and oscillation. The eccentric sleeve could be positioned either above or below the flexible joint. It was attached rotationally to the drillstring with a pin that was released by fluid pressure when drilling mud was circulated through the tool. This sleeve is similar to one proposed by Giles[6] in 1955 for long-radius drilling, except that Giles' sleeve was oriented by rotating the drillstring counterclockwise to engage a lock to position the sleeve in the desired direction.

Development was renewed in the 1980's. Holbert[7] (Fig. 2d) and Schuh[8] worked on drilling an unpredictable radius of curvature caused by instability at the drill bit, especially when the bit drilled an oversize hole or became unstable as it crossed bedding planes. Burton[9] addressed the problem of poor orientation control by introducing a nonrotating eccentric sleeve (Fig. 2e) with spring-loaded blades to grip the wellbore and to maintain orientation as the drilling assembly is advanced. Burton advocated periodic repositioning of the sleeve so that a planar curve could be drilled.

Curve-Assembly Development

Fig. 3 shows a curve-drilling assembly (Burton's[9] design) similar to that used early in our development program. It included a standard PDC bit (sometimes a roller-cone bit was used), near-bit reamer, ball/pin flexible joint, and eccentric sleeve. The eccen-

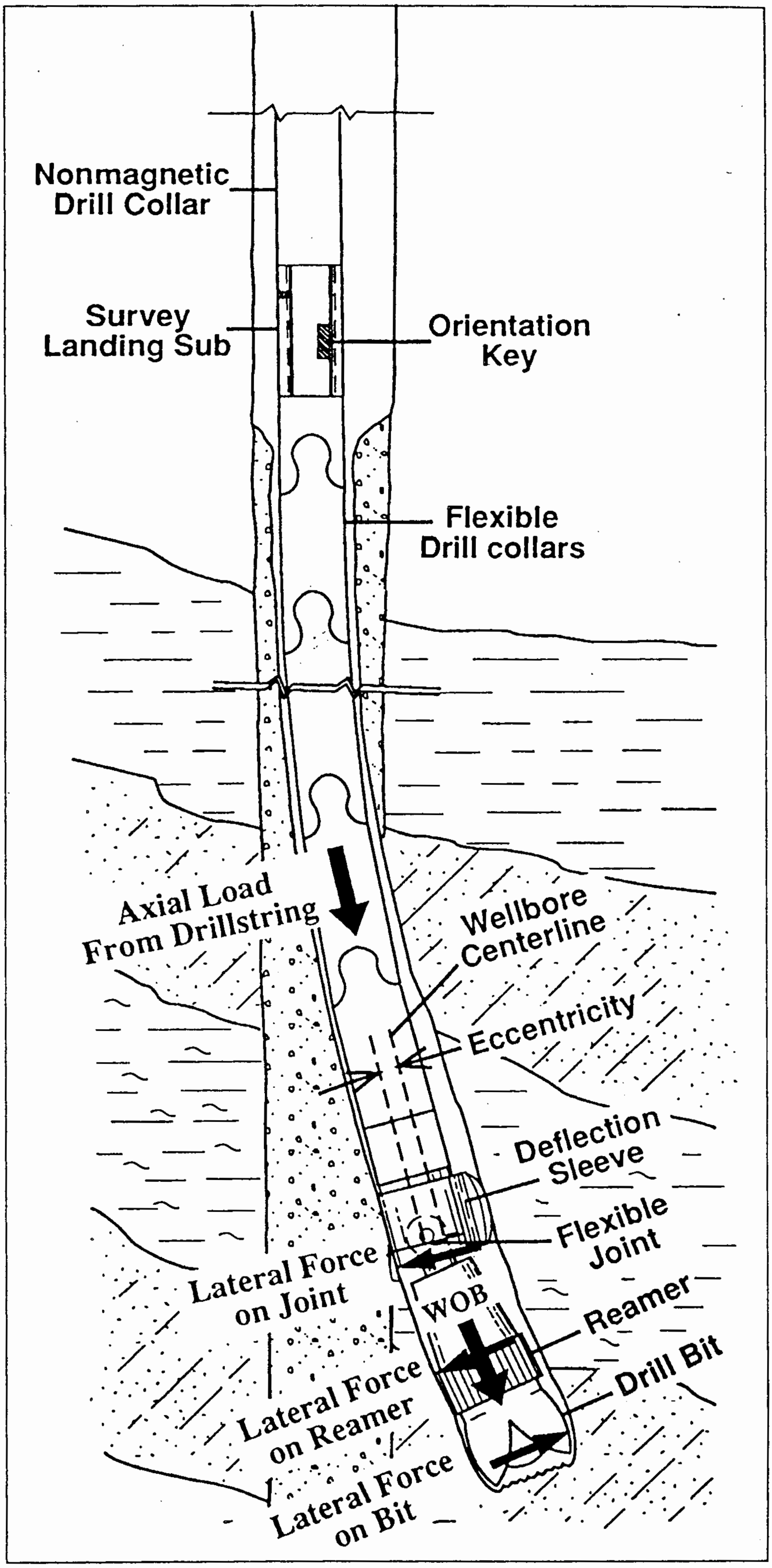

Fig. 1—Components of a rotary-guided short-radius curve assembly. Key forces are shown.

"Lateral wellbores drilled from existing wells offer the potential to drain more oil than would be recovered otherwise."

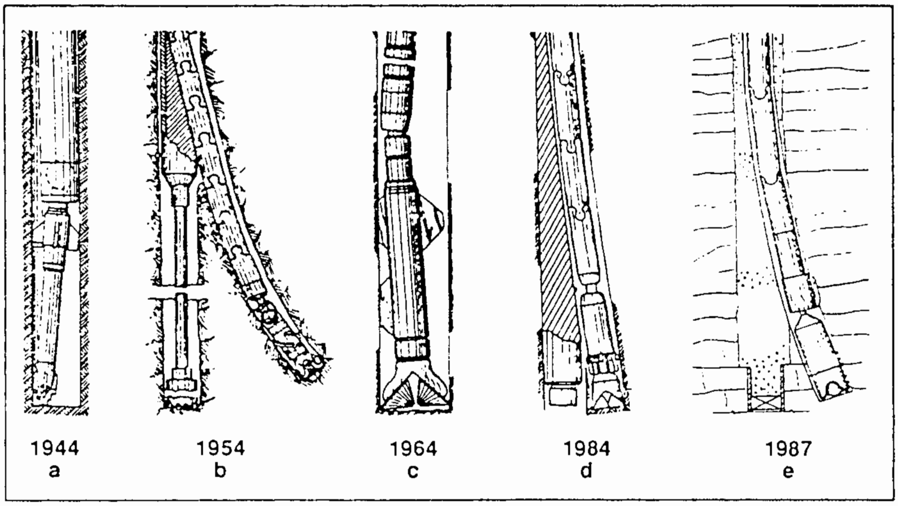

Fig. 2—Historical evolution of the rotary-guided short-radius curve-drilling tool.

tric sleeve could be oriented by rotating counterclockwise to latch the sleeve to the mandrel. This curve assembly had three fundamental problems: (1) the radius of curvature was inconsistent, (2) the ball/pin flexible joint was weak and could fail under normal operating conditions, and (3) determining and maintaining the desired orientation of the deflection sleeve was difficult.

Consistent Curvature

The axial load applied to the rigid mandrel of the curve assembly above the flexible joint creates a force component directed along the bit centerline [weight on bit (WOB)] and a lateral component at the joint (Fig. 1). The lateral force pushes the joint to the outside of the curve and transmits lateral loads in opposite directions on the bit and near-bit reamer. Some early developers envisioned the reamer as a "fulcrum" that caused the bit to cut sideways. Others viewed it more as a means of cutting the hole to the final size so that the bit could be pointed in the desired direction. In either case, the reamer is not supposed to cut laterally into the borehole wall; instead, it is to maintain the bit in the correct orientation. For this process to work properly, the borehole diameter, reamer diameter, and assembly length are critical. The reamer diameter either must be slightly smaller than the bit diameter (if the bit drills a gauge hole) to fit in the curvature or must enlarge the hole. A slight overgauging of the borehole by the bit can cause the reamer to lose contact with the borehole wall and totally eliminate its influence.

Lateral loads on the bit and reamer can cause the bit and reamer to walk counterclockwise (whirl) around the hole. There is no stabilizing influence from the drillstring stiffness because a flexible joint is directly uphole from the reamer. As a result, the bit moves around the hole, drills overgauge, and causes the average rate of curvature to be less than expected. Brett *et al.* [10] indicated that bit whirl is most likely during drilling of harder rocks at lower rates of penetration (ROP's), often is initiated during drilling from a soft to a harder layer, and causes the bit to drill an oversize borehole. These conclusions seem to be consistent with problems experienced by others.[5,7,8] They also are consistent with our experience with the early reamer assembly. It was very sensitive to slight changes in reamer design and dimensions and, in some cases, failed to drill a curve at all. The problems also seemed to be lithology-related. In one case when the assembly failed to drill a curve in San Andres dolomite at a depth of 5,000 ft, the hole drilled by the 3⅞-in. bit and reamer assembly was calipered to be 4⅛ in. in diameter.

An assembly that performs more consistently was developed by stabilizing the bit to point continually along a curved path and designing the bit so that it cuts only in the direction it is pointed. Bit stability is improved by use of the "low-friction gauge" technique.[11] The cutters are positioned so

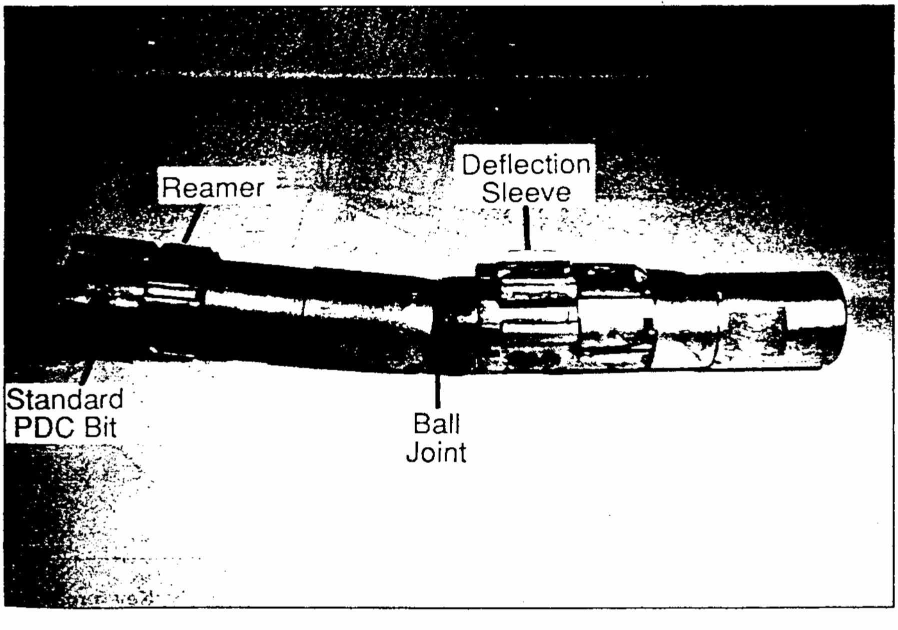

Fig. 3—Short-radius curve assembly (about 1988, at the start of the project).

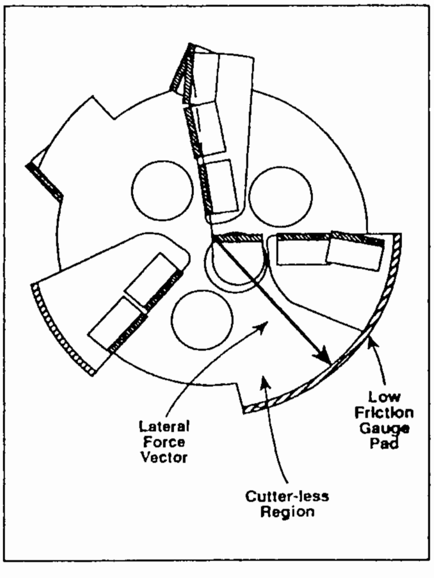

Fig. 4—Schematic of an antiwhirl bit developed for the curve assembly.

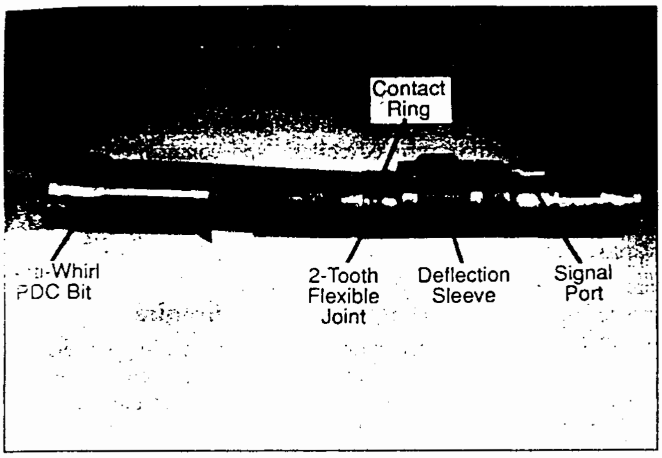

Fig. 5—Improved curve assembly (about 1992).

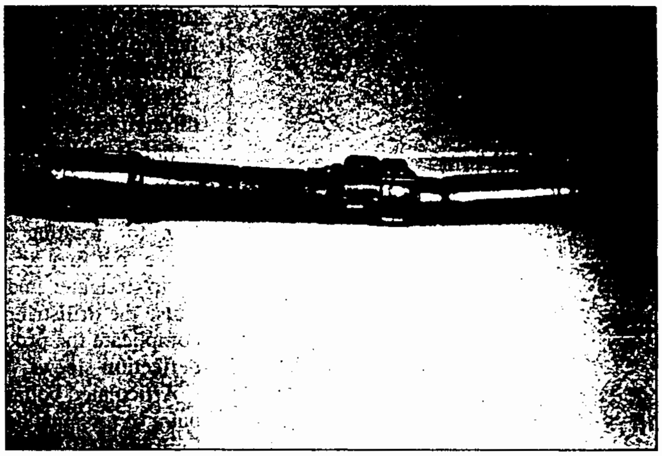

Fig. 6—Experimental assembly with flexible joint above eccentric sleeve.

that they direct a lateral force toward a smooth pad on the gauge of the bit. This pad contacts the borehole wall and transmits a restoring force to the bit. These forces rotate with the bit and continually push a side of the bit that does *not* have a gauge cutting structure against the borehole wall (**Fig. 4**). This minimizes side cutting and produces a much more consistent wellbore diameter.

Fig. 5 shows the improved assembly that drills a curved path by continually pointing the bit along a tangent to the curved path. It uses an antiwhirl PDC bit, eliminates the reamer, and incorporates a smooth contact ring at the flexible joint to fix the points of contact for controlling the bit tilt. The tool is designed so that the bit and assembly run smoothly, the hole is uniform in diameter, and the effects of varying lithology are negated. The curve assembly may also be constructed with the joint above the eccentric sleeve as **Fig. 6** shows. This configuration may be more stable than the assembly shown in Fig. 5 because it provides greater stability for the top end of the bit sub and provides more isolation from drillstring vibrations.

When the bit rotates about its center in a gauge hole, the off-center position of the flexible joint causes the bit axis to tilt with respect to the borehole centerline everywhere except at the bit face. At the bit face, the bit centerline is pointed at a tangent to the curve centerline. If the hole curvature is perturbed and becomes less than the designed curvature, the bit axis will point above the borehole inclination and thus will tend to increase the curvature. If the curvature becomes greater than the design, the opposite occurs. A stable equilibrium results when the bit-face centerline and hole inclination are aligned. Thus, as the bit drills ahead along a curved path, the inclination of the bit continually changes so that it always is inclined in a direction that keeps the borehole drilling along the curved path without requiring the bit to cut sideways.

When an assembly drills with these characteristics, hole curvature is determined by three parameters: the inclination of the bit centerline and two points of contact with the borehole wall. Using the information that the assembly contacts the borehole at the bit and joint and that the bit centerline is aligned with the hole centerline, we can show easily with geometry that the radius of curvature, r, is

$$r = L^2/(d_1 - d_2). \quad \text{(1)}$$

The bit and contact-ring diameters, d_1 and d_2, are measured easily. The characteristic length, L, is normally the distance from the contact ring to the cutter on the bit that cuts the borehole gauge.

Flexible Joint. The flexible joint allows the bit to tilt sufficiently to drill a short-radius curve. It must be capable of transmitting axial thrust for WOB, tensile force for pulling if the bit becomes stuck, and torque to rotate the bit. It also should rotate smoothly, buckle under compressive loading, not straighten under torsional loading, and conduct fluid with minimal leakage.

The curve assemblies in Refs. 3 through 9 use ball/pin joints similar to one described by James.[12] Because of the small tool size and increased torque capacity needed to drill with PDC bits, this type of joint was found to be torsionally weak. The joint was improved by transmitting compressive and tensile loads on the ball/pin and by transmitting torque by teeth cut in the outer shell. This provides more material to construct the torque transmitting features and simultaneously reduces the associated forces by increasing the effective moment arm.

The improved joint in **Fig. 7** provides two torque transmitting teeth that are engaged almost over the ball center. The joint uses a thrust bushing that can wobble slightly to keep both teeth engaged as the assembly rotates. The need for the thrust bushing to wobble can be minimized if the tooth loading is kept directly over the ball center. This joint has adequate strength and good operating characteristics for short-radius curve drilling. Other joint types were not as satisfactory because they tended to straighten under either compressive or torsional loads.

Deflection-Sleeve Orientation Indicator. The deflection-sleeve orientation must be established initially and maintained to drill a curve in the desired direction. The sleeve is oriented by turning the drillstring counterclockwise to engage a spring-loaded latch on the mandrel into a pocket on the sleeve. Further rotation of the drillstring moves the sleeve to the desired orientation. When the drillstring is rotated clockwise for normal

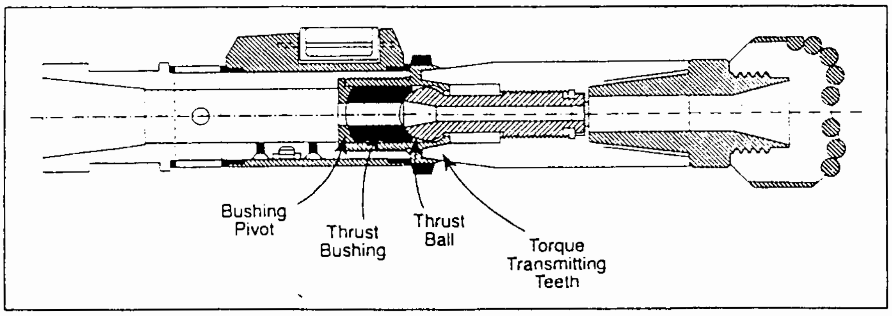

Fig. 7—The improved two-tooth flexible joint.

"The short-radius drilling system has proven potential for drilling low-cost reentry curves and laterals."

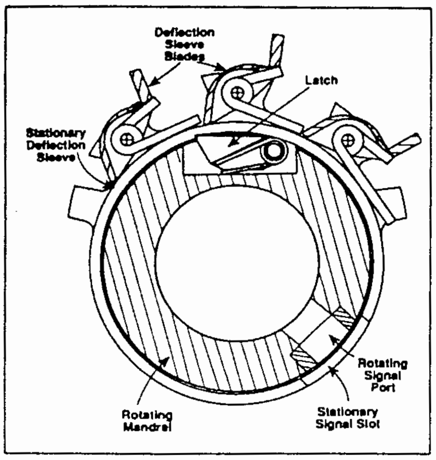

Fig. 8—Schematic of the deflection sleeve, latch mechanism, and signal valve. The valve opens when the latch engages the sleeve.

drilling, the latch disengages and the sleeve remains in its adjusted position.

A simple downhole valve provides a surface signal to assist in orienting the deflection sleeve.[13] When a reference point on the drillstring is aligned with the maximum eccentricity of the sleeve, the valve reduces the pump pressure by porting fluid above the bit. The valve comprises a slotted stationary ring attached to the deflection sleeve and a rotating port in the mandrel that passes through the sleeve. To simplify operation, the reference points are aligned and the latch engages at the same time. **Fig. 8** is a schematic of the sleeve, latch, and signal port.

Flexible Drill Collars. Because of the short radius of curvature that is drilled, special drillstring components are required to rotate through the curve to prevent pipe yield and fatigue failure. Articulated drill collars[14] normally are used. They are constructed by cutting a series of interlocking lobed patterns through the wall of steel drill collars. Each collar is fitted with a 2,000-psi hydraulic hose and seal assembly. Historically, these collars have been the only reasonable option for rotating through a short-radius curve, but they are not ideal because they try to straighten under compressive loading, cause the drillstring to rotate roughly, and complicate the procedure for orienting the deflection sleeve.

Articulated collars are a primary contributor to torsional drillstring oscillations that limit the ROP by limiting the WOB that can be applied. Also, twist discontinuities caused by the gaps between lobes create a major difficulty in determining the orientation of the deflection sleeve. A number of attempts have been made to improve articulated collar performance by changing the design and phasing of the lobes, but only recently has a design that rotates smoothly and minimizes the orientation problem been achieved. Changes in the pipe cutting and heat treating process also have reduced fatigue failures of the lobes.

Carbon/fiberglass composite drillpipe has been tested as an alternative to the articulated steel collars. Preliminary results indicate that composite pipe has adequate tensile and torsional strength and is flexible enough to drill a 30-ft-radius curve. The use of the composite pipe simplifies the process of monitoring the orientation of the deflection sleeve because the gaps between the lobes of the articulated collars are eliminated. Composite pipe rotates smoothly, appears to have adequate life, and provides a larger bore for running survey tools. More testing is under way to determine whether composite pipe is economical and sufficiently reliable for commercial use. **Fig. 9** compares the original articulated collars, recently improved collars, and composite pipe. (The field drilling discussed in the following sections was done with an asymmetric articulated collar design not shown in Fig. 9.)

Curve-Assembly Orientation Technique

The short-radius curve-drilling system depends on the eccentric deflection sleeve to deflect the lower portion of the drillstring and to tilt the bit to drill a curved wellbore. Sleeve orientation determines the curve azimuth; thus, the sleeve must be oriented initially in the target direction, and its orientation must be monitored as drilling progresses because the sleeve may slip and require repositioning.

Initial Orientation. The drillstring used for curve drilling is composed of the curve assembly, flexible collars, survey tool landing sub, nonmagnetic drill collar, steel drill collars, and drillpipe. When the BHA is made up at the surface, the deflection sleeve is rotated clockwise until the latch engages; then the adjustable survey landing key is aligned with the high side of the deflection sleeve.

Once the drillstring is tripped into the wellbore, it is reciprocated to remove any twist caused by torque in the string. Then a single-shot survey is taken to determine the orientation of the survey landing key (muleshoe). The drillstring is marked at the surface to indicate the orientation of the muleshoe key, which also is the orientation

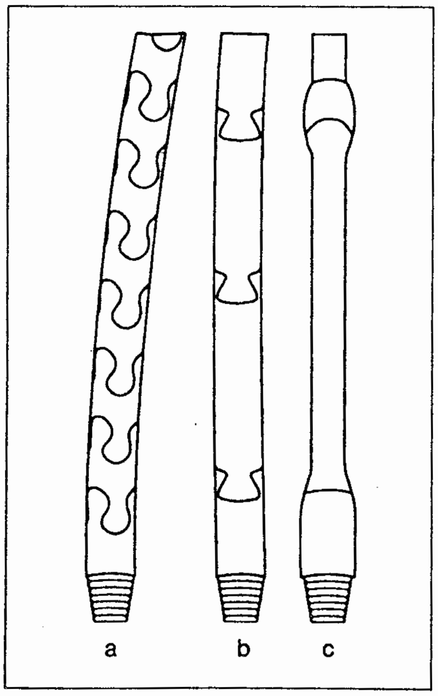

Fig. 9—Flexible collar designs: (a) original three-lobe symmetric; (b) improved two-lobe; (c) composite pipe.

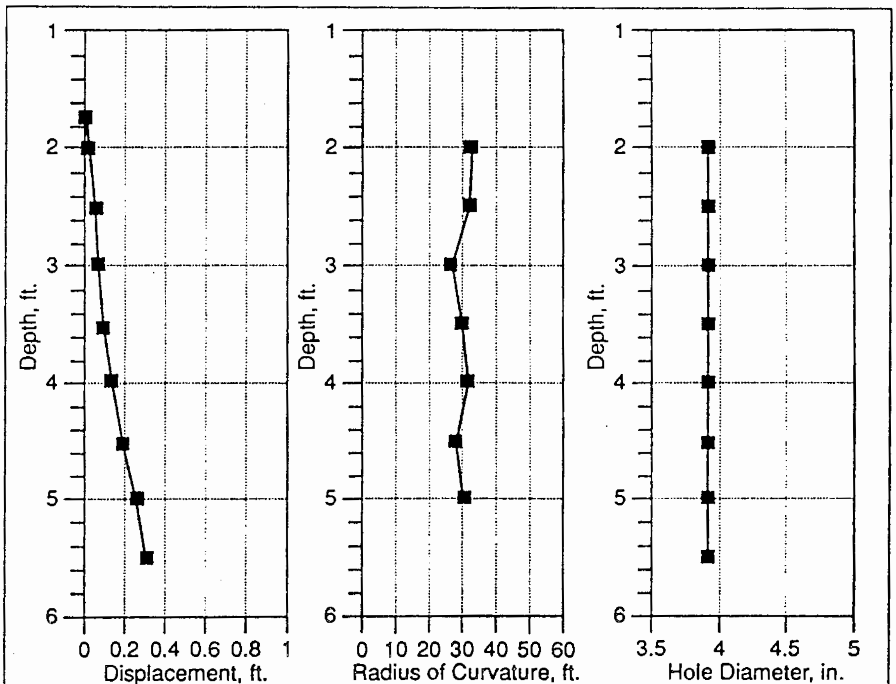

Fig. 10—Laboratory test data for the $3^{15}/_{16}$-in. assembly shows a gauge wellbore and uniform curvature.

of the deflection-sleeve high side when the latch is engaged and the signal port is open. The orientation of the deflection-sleeve high side then can be determined by rotating slowly clockwise, stopping when the pump pressure decreases, and noting the orientation of the mark on the drillstring.

The deflection sleeve is oriented by rotating counterclockwise until the pump pressure decreases, which indicates that the latch has engaged the sleeve. The drillstring then is rotated farther counterclockwise until the surface line is aligned with the desired well direction. Finally, the drillstring is reciprocated to work any torsion out of the string so that the downhole alignment of the deflection sleeve agrees with the surface mark.

Manual Orientation Monitoring. After the deflection sleeve is initially oriented and the curve is begun, sleeve orientation must be checked periodically to see if the sleeve has slipped and needs to be repositioned. This usually is done after every 1 or 2 ft of drilling by lifting the bit off-bottom and rotating slowly in small increments to locate the position of the surface reference mark when the pressure signal is detected. The procedure is straightforward in principle.

Signal interpretation can be challenging when articulated drill collars are used, and the process of gaining sufficient repeatability for confidence in the results can be time-consuming. The accumulated discontinuity effects from the cuts in the flexible collars introduce the risk of axial misalignment and significant error in sensing the true position of the deflection sleeve. Several methods have been used with some success to improve repeatability and to minimize error, but these methods are error-prone and time-consuming, particularly as the length of pipe deflected in the curve increases and when the curve trajectory is nonplanar.

Fortunately, manual orientation becomes quite simple when composite drillpipe instead of articulated drill collars is used. Dramatic improvements in signal sensing, drilling efficiency (reduction of off-bottom time), and target accuracy have been achieved with the use of composite pipe.

Dynamic Orientation Monitoring System. A dynamic orientation system was developed to monitor the orientation of the deflection sleeve while the drillstring is rotating.[15] This system is essentially a crude mud-pulse MWD device. A downhole mud pulse is generated each time the signal port opens (once per revolution). This mud pulse is detected and correlated with surface pulses generated by teeth of known orientations on a rotating sub directly below the power swivel to determine the compass heading of the deflection sleeve.

The teeth for the surface pulses are spaced about 30° apart, and the tooth used as a reference pulse is wider than the others. The position of the rotating downhole mud-pulse valve is known relative to the orientation of the surface reference mark (from the muleshoe survey); thus, the mud-pulse arrivals can be correlated with the surface pulses to determine the orientation of the eccentric deflection sleeve.

This correlation is done by a computer program in which rotary-pulse, pressure-pulse, and torque data are monitored continuously. The computer program detects the mud pulses, compensates for sonic travel time, compensates for drillstring twist, and calculates deflection-sleeve orientations. The computer program uses an FFT digital filter to separate signal pulses from pump noise. The signals have been readily detectable to depths of 6,000 ft, which is the deepest the system has been used thus far.

The mud pulse requires about 1 second to travel from 5,000 ft to the surface, so the orientation of the drillstring reference mark must be corrected for its movement between the time the downhole signal is generated and the time the signal arrives at the surface. At normal rotary speeds (60 to 100 rev/min), this correction is significant (400 to 700°) and depends heavily on how well the signal delay time is known.

The delay time can be measured at the wellsite by measuring the *apparent* change in position of the downhole deflection sleeve at various rotary speeds. The pulse position shifts linearly with rotary speed. The signal delay, in terms of degrees per revolution per minute, increases linearly with depth. The delay time is a function of depth, mud properties, and length of articulated collars but can be measured easily by observing the apparent orientation shift as the rotating speed is changed. Ref. 16 provides additional information on compensating for the effects of delay time and drillstring twist and an example of how the system works.

The dynamic orientation monitor is best applied as a tool to sense when the deflection sleeve has slipped rather than to determine absolute orientation. Work continues to refine it into an absolute orientation sensor.

Curve-Drilling System Performance

The curve-drilling assembly was tested by drilling into large blocks of Berea sandstone; drilling shallow (10- to 40-ft) holes into a limestone outcrop; and drilling somewhat deeper (250- to 1,200-ft) holes in Pennsylvanian sandstone, shale, and limestone. These tests were done to study the behavior of various curve assemblies, to determine their radii of curvature, to evaluate tool durability, and to develop orientation procedures to drill planar curves in the desired direction. The tools were field tested in west Texas where eight short-radius lateral wells ranging from 184 to 352 ft of total departure were drilled.

Laboratory Testing of Curve Assembly. **Fig. 10** shows data measured from a $3\frac{15}{16}$-in.-diameter curve drilled in Berea sandstone with the improved assembly. The first 18 in. was drilled vertically with a rigid drilling assembly. The curve assembly then was run into this pilot hole and drilled an additional 4 ft. The hole was calipered, and inclination was measured every 6 in. with

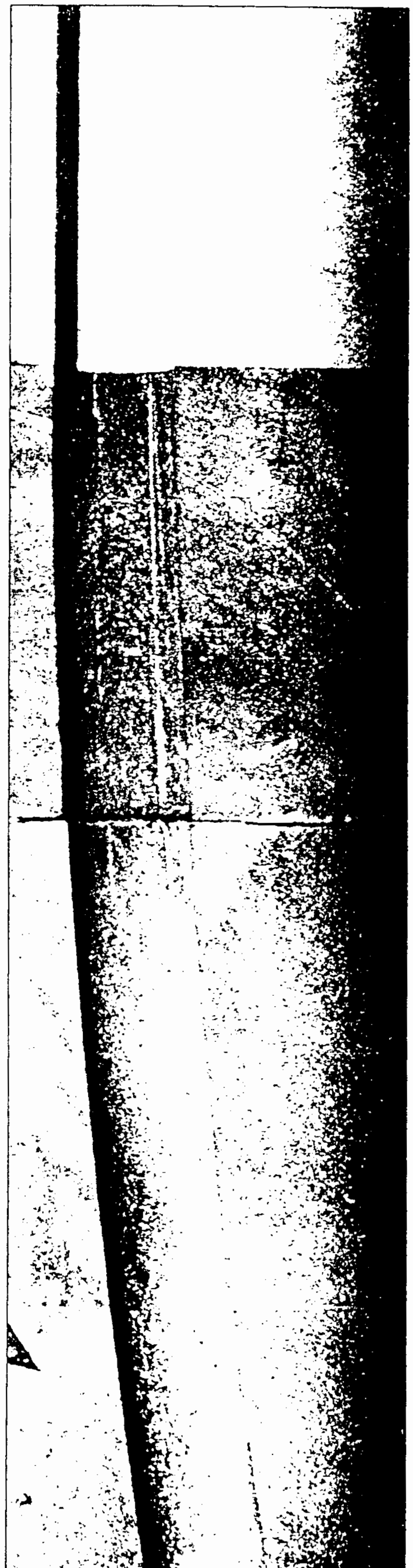

Fig. 11—Cross section of a 30-ft-radius curve drilled in sandstone with the $3\frac{15}{16}$-in. assembly.

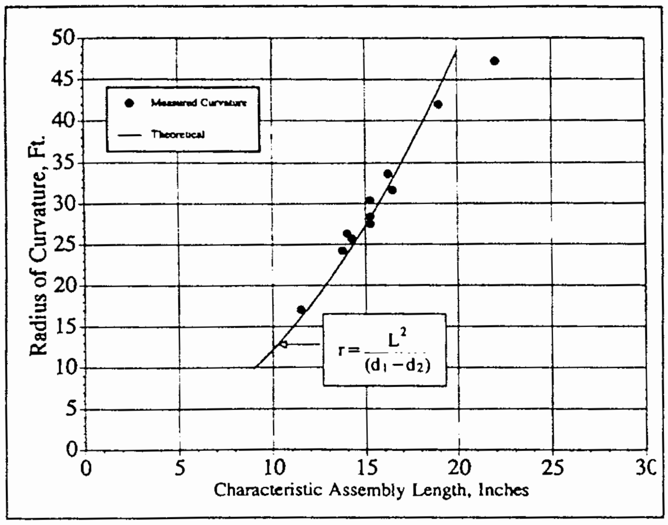

Fig. 12—Radius of curvature varies with length between two points of contact on the curve assembly, as described by Eq. 1.

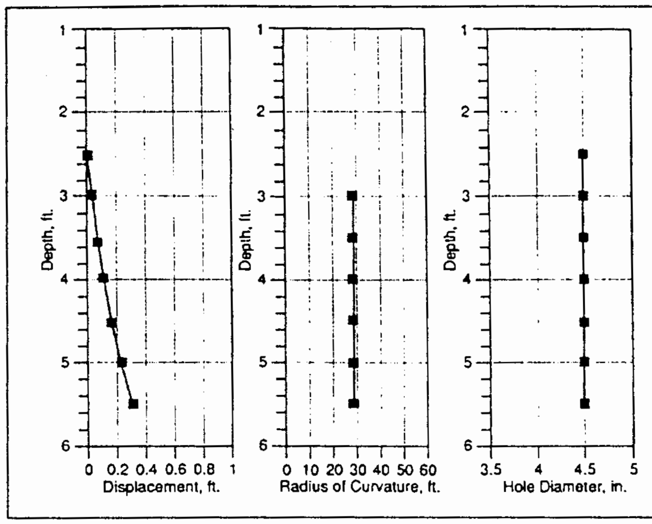

Fig. 13—Laboratory data for the 4½-in. tool with the flexible joint above the deflection sleeve show a gauge wellbore and a smooth curve.

a special procedure developed for these tests. Radius of curvature was calculated from the inclination measurements. These data show that the borehole was gauge, the curve kicked off right away, and the curvature was uniform over the total distance drilled. **Fig. 11** shows a cross section of a 30-ft-radius curve drilled with the improved assembly. The rock was composed of three different layers glued together to provide a hardness contrast. The curve is very smooth, and there are no ledges in the wall.

Fig. 12 shows the curvature measured from similar tests of several assemblies where the distance from the joint to the bit face was varied. Eq. 1 predicts the curvature quite well.

Fig. 13 shows the curvature drilled by a 4½-in. assembly with the flexible joint located *above* the eccentric sleeve. The curvature was uniform, and the borehole was gauge and smooth. This assembly appears to run more smoothly than the assembly with the joint below the eccentric sleeve.

Shallow Testing of the Complete System. Curves and laterals were drilled in a variety of lithologies with a Chicago Pneumatic RT-2000 rig. Many of these tests were directed at improving curve-assembly consistency and developing a reliable orientation method. About 44 curves and 11 laterals with up to 444-ft departure were drilled.

Fig. 14 shows examples of these tests. About 24 curves and 8 laterals at depths between 250 and 1,200 ft were drilled from a single vertical wellbore. The curves were spaced vertically as close as 8 ft apart, which is the minimum distance needed to bypass one curve and establish the pilot hole for the next curve. **Fig. 15** shows detailed survey data from a curve drilled with composite pipe.

Field Test Examples. Fig. 16 shows a vertical section and plan view of a short-radius lateral recompletion of a CO_2 injector. The west Texas well was drilled in the San Andres dolomite at 5,000 ft. A standard pulling unit equipped for drilling with a power swivel, mud pump, and $2\frac{7}{8}$-in. drillpipe was used on the well. Eight short-radius lateral wells were drilled in west Texas during the mechanical field test stage of the R&D program described in this paper. Total expenditures during the drilling phase of the lateral recompletions averaged about $65,000/well (excluding plugback and stimulation costs) for an average lateral departure of 260 ft. This is somewhat greater than the goal for the system, but it is expected that the cost will decrease significantly as more wells are drilled and the system performs more consistently and routinely.

Conclusions

The short-radius drilling system has proven potential for drilling low-cost re-entry curves and laterals. The tools have been used to drill several production and injection wells laterally in west Texas. Two major problems were experienced during curve drilling of these wells. The first, inconsistent curvature, has been eliminated and was not a problem in later wells. The second problem, inaccurate directional control, was

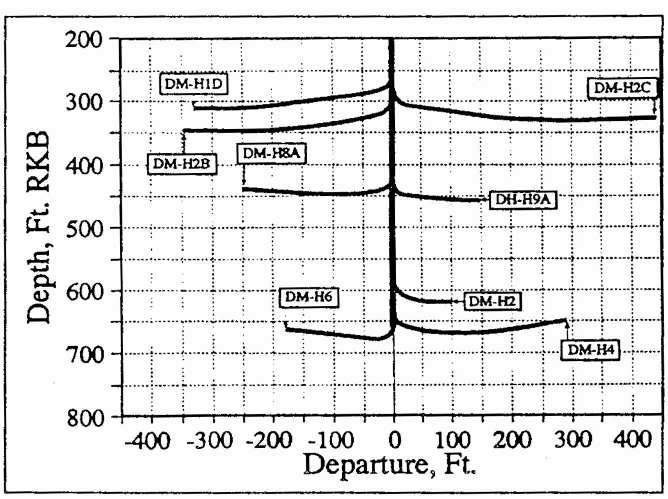

Fig. 14—Multiple curves and laterals were drilled in shallow tests of the short-radius tools. Minimum vertical spacing between curves is 8 ft.

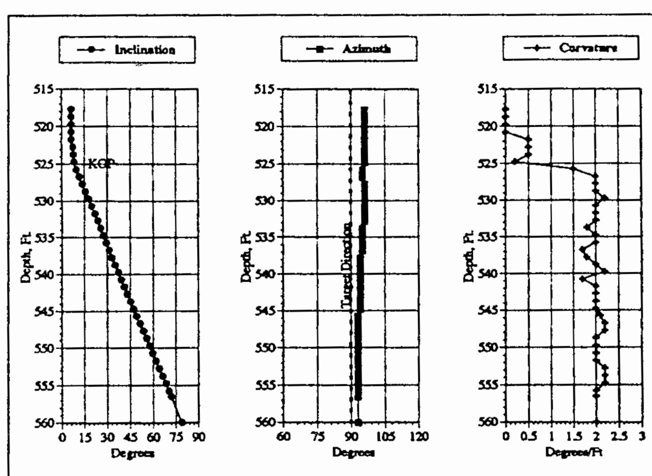

Fig. 15—Data from a curve drilled with composite pipe show consistent near-planar curvature and good target accuracy.

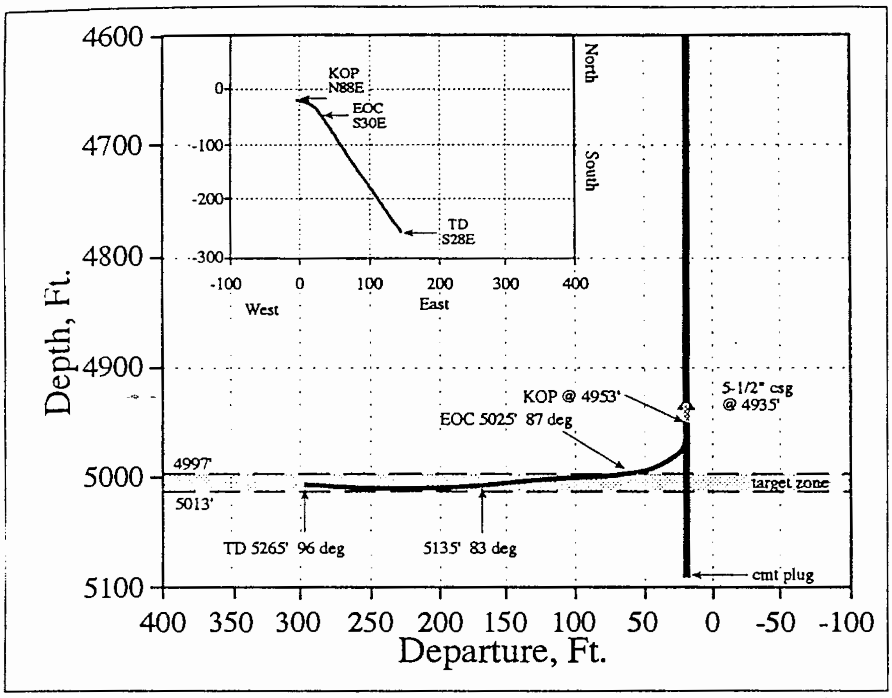

Fig. 16—Vertical section and plan view of laterally recompleted CO_2 injector in west Texas. Two lateral assemblies were used to drop and build angle.

caused by behavior of the articulated drill collars and has been eliminated in shallow field tests by the use composite drillpipe and the modified articulated collars. Neither the composite pipe nor modified articulated collars have been used yet in a production well. Laboratory tests and field results indicate that the rotary curve- and lateral-drilling system is sufficiently reliable and inexpensive to meet the objectives for lateral recompletions of wells in mature fields.

Nomenclature

d_1 = bit diameter, ft
d_2 = contact-ring diameter, ft
L = characteristic length, ft
r = radius of curvature, ft

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SI Metric Conversion Factors

ft	× 3.048*	E−01	= m
in.	× 2.54*	E+00	= cm
psi	× 6.894 757	E+00	= kPa

*Conversion factor is exact.

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