The transition from vertical to horizontal drilling has been spurred by evolving technology that led the industry away from a dependency on conventional bottomhole assemblies and whipstocks and toward mud motors and rotary steerable systems. The latest innovation is a hybrid design that combines the performance capabilities of a rotary steerable system with the high build rates of a positive displacement motor. The shortest distance between two points is a straight line. However, it may not be the fastest, or most economical, when it comes to directional drilling. E&P companies increasingly turn to complex well trajectories to hit distant targets, intersect fractures, penetrate multiple fault blocks or reach deep into a reservoir. Although more difficult to drill than other profiles, these well paths often improve drainage efficiency by increasing wellbore exposure to the pay zone.
Complex horizontal and extended-reach trajectories are just the current apex in the evolution of directional drilling. The first nonvertical wells were not intentionally drilled that way, but by the late 1920s, drillers began to figure out how to point a wellbore in a particular direction. Since then, directional drilling technology has progressed beyond a reliance on basic bottomhole assemblies for influencing the course a bit might take, to using surface-controlled rotary steerable systems that precisely guide the bit to its ultimate destination. During the past decade, the development of new drilling technologies has continued to gain momentum.

This article describes advances that led to the development of rotary steerable systems and focuses on one of the latest steps in their evolution: the PowerDrive Archer rotary steerable system. This hybrid system produces the high build rate of a positive displacement motor with the rapid rate of penetration of a rotary steerable system.

A Brief History
The intentional deviation of wellbores came into practice during the late 1920s as operators sought to sidetrack around obstructions, drill relief wells and avoid surface cultural features; directional drilling techniques were even employed to keep vertical holes from turning crooked.

In part, the ability to drill deviated wells arose from the development of rotary drilling and roller cone bits. The design of these bits causes them to drift laterally, or walk, in response to various formation and drilling parameters such as formation dip and hardness, rotary speed, weight on bit and cone design. In some regions, experienced drillers recognized the natural tendency of a bit to walk in a somewhat predictable manner. They would frequently try to build a certain amount of lead angle to compensate for anticipated drift between the surface location and bottomhole target (below left).

Drillers also found that modifications to the rotary bottomhole assembly (BHA) could change a drillstring’s angle of inclination. By varying stabilizer placement, drillers could affect the balance of the BHA, prompting it to increase, maintain or decrease wellbore inclination from vertical, commonly referred to as building, holding or dropping angle, respectively. The rate at which a rotary BHA builds or drops angle is affected by variables such as distance between stabilizers, drill collar diameter and stiffness, formation dip, rotary speed, weight on bit, formation hardness and bit type. The ability to balance the BHA against these factors can be crucial for reaching a planned target.

A BHA configured with a near-bit stabilizer beneath several drill collars will tend to build angle when weight is applied to the bit (below). In this configuration, the collars above the stabilizer will bend, while the near-bit stabilizer acts as a fulcrum, pushing the bit toward the high side.

Using a BHA to change inclination. By strategic placement of drill collars and stabilizers in the BHA, directional drillers can increase or decrease flexibility, or bowing, of the BHA. They use this flexibility to their advantage as they seek to build, drop or hold angle. A fulcrum assembly (upper frame, top) uses a full gauge near-bit stabilizer and sometimes a string stabilizer. Bowing of the drill collars above the near-bit stabilizer tilts the bit upward to build angle (lower frame, left). A pendulum assembly (upper frame, middle) has one or more string stabilizers. The first string stabilizer acts as a pivot point that lets the BHA bow beneath it, thus dropping angle (lower frame, right). A packed assembly uses one or two near-bit stabilizers and string stabilizers to stiffen the BHA (upper frame, bottom). By reducing the tendency to bow, the packed assembly is used to hold angle.
of the borehole. Another type of BHA is used to drop angle. This variation uses one or more stabilizers; the collars below the lowest stabilizer in the BHA act as a pendulum, which allows gravity to pull the bit toward the low side of the borehole. Upon reaching the desired angle, the driller may use a different BHA to hold angle. The packed BHA utilizes multiple stabilizers, spaced along its length, to increase stiffness.

Drillers employ other mechanical means to help divert a well from its vertical path, most notably the whipstock. Simple in principle, this long steel ramp is concave on one side to hold and guide the drilling assembly. Used in either open or cased holes, the whipstock is positioned at the desired depth, oriented to the desired azimuth, then anchored in place to provide a guide to initiate, or kick off, a new well path (above).

While early techniques allowed some degree of control over wellbore inclination, they provided little azimuthal control. They were also inefficient, requiring multiple trips in and out of the hole to install a whipstock or to change BHA configurations.

The early 1960s witnessed a significant change in directional drilling when a BHA with a fixed bend of approximately 0.5° was paired with a downhole motor to power the drill bit. Drilling mud supplied hydraulic power to a motor that turned the bit. The motor and bent sub offered much greater directional control than was possible with earlier BHAs, while significantly increasing the angle of curvature that a driller was able to build. Early assemblies had fixed tilt angles and required a trip out of the hole to adjust the angle of inclination.

These steerable motors operate on the tilt-angle principle. The bent sub provides the bit offset needed to initiate and maintain changes in course direction. Three geometric contact points—the bit, a near-bit stabilizer on the motor and a stabilizer above the motor—approximate an arc that the well path will follow.

Some motors use a downhole turbine; others use a helical rotor and stator combination to form a positive displacement motor (PDM). The basic PDM with bent sub has evolved, leading to the development of a steerable motor. Modern steerable motor assemblies still use PDMs, but include surface-adjustable bent housings (below right). A typical steerable motor has a power-generating section, through which drilling fluid is pumped to turn a rotor that turns a drive shaft and bit. The surface-adjustable bend can be set between 0° and 4° to point the bit at an angle that differs only slightly from the axis of the wellbore; this seemingly minor deflection is critical to the rate at which the driller can build angle. The amount of wellbore curvature imparted by the bent section depends, in part, on its angle, the OD and length of the motor, stabilizer placement and the size of drill collars relative to the diameter of the hole.

Steerable motors drill in either of two modes: rotary mode and oriented, or sliding, mode. In rotary mode, the drilling rig’s rotary table or its topdrive rotates the entire drillstring to transmit power to the bit. During sliding mode, the drillstring does not rotate; instead, mud flow is diverted to the downhole motor to power the bit. Only the bit rotates in sliding mode—the nonrotating portion of the drillstring simply follows along behind the steering assembly.

Different motors may be selected on the basis of their ability to build, hold or drop angle during rotary mode drilling. Conventional practice is to drill in rotary mode at a low number of revolutions per minute (RPM), rotating the drillstring from the surface and causing the bend to point equally in all directions, thereby drilling a straight path. Inclination and azimuth measurements can be obtained in real time by measurement-while-drilling (MWD) tools to alert the driller to any deviations from the intended course. To correct for those deviations, the driller must switch from rotary to sliding mode to change wellbore trajectory.

The sliding mode is initiated by halting rotation of the drillstring so the directional driller can orient the bend in the downhole motor to point in the direction, or toolface angle, of the desired trajectory. This is no small task, given the torsional forces that can cause the drillstring to behave like a coiled spring. After accounting for bit torque, drillstring windup and contact friction, the driller must rotate the drillstring in small increments from the surface while using MWD measurements as a reference for toolface direction. Because a drillstring can absorb torque over long intervals, this process may require several rotations at the surface to turn the tool just once downhole. When the proper toolface orientation is confirmed, the driller activates the downhole motor to commence drilling in the prescribed direction. This process may need to be repeated several times during the course of drilling because reactive torque that is generated as the bit cuts into the rock may force reorientation of the toolface.
Each mode brings distinct challenges. In rotating mode, the bend in the drilling assembly causes the bit to rotate off-center from the BHA axis, resulting in a slightly enlarged and spiral-shaped borehole. This gives the wellbore rough sides that increase torque and drag and may cause problems while running in the hole with completion equipment—especially through long lateral sections. Spiral boreholes may also affect logging tool response.

In sliding mode, the lack of rotation introduces other difficulties. Where the drillstring lies on the low side of the borehole, drilling fluid flows unevenly around the pipe and impairs the mud's capacity to remove cuttings. This, in turn, may result in the formation of a cuttings bed, or a buildup of cuttings on the low side of the hole, which increases the risk of stuck pipe. Sliding also decreases the horsepower available to turn the bit, which, combined with sliding friction, decreases the rate of penetration (ROP) and increases the likelihood of differential sticking.

In extended-reach trajectories, frictional forces may build until there is insufficient axial weight to overcome the drag imposed by drillpipe against the wellbore. This makes further drilling impossible and leaves some targets out of reach. Additionally, switching between sliding and rotating modes can create undulations or doglegs that increaseWellbore tortuosity, thus increasing friction while drilling and running casing or completion equipment.

A number of these problems were addressed in the late 1990s with the development of a rotary steerable system (RSS). The single most important aspect of the RSS is that it allows for continuous rotation of the drillstring, thereby eliminating the need to slide while drilling directionally. RSS tools provide a nearly instantaneous response to commands from the surface when the driller needs to change downdip trajectory. Early on, these systems were utilized primarily to drill extended-reach trajectories, in which the ability to slide steerable motors had been limited by hole drag. These jobs often resulted in improved ROPs and hole quality over previous systems. Today, the RSS is widely used for its performance drilling, hole cleaning and accurate geosteering capabilities.

**Revolutionary Steerable**

Rotary steerable systems have evolved considerably since their introduction. Early versions utilized mud-actuated pads or stabilizers to cause changes in toolface angle—a design concept that continues to enjoy success to this day. With a dependence on contact with the borehole wall for directional control, the performance of these tools can sometimes be affected by borehole washouts and rugosity. Later versions included designs that relied once again on a bend to produce changes in toolface angle, thereby reducing borehole environmental influences on tool performance.

Thus, two steering concepts were born: push-the-bit and point-the-bit.

The push-the-bit system pushes against the borehole wall to steer the drillstring in the desired direction. One version of this RSS uses a bias unit with three actuator pads placed near the bit to apply lateral force against the formation (below). To build angle, each mud-actuated pad pushes against the low side of the hole as it

2. Unlike conventional rotary drilling techniques, in which rotation of the entire drillstring is required to drive the bit, the drillstring does not rotate when a mud motor is employed. Instead, the mud motor relies on hydraulic power supplied through the circulation of drilling mud to turn a shaft that drives the bit.
5. A dogleg is an abrupt turn, bend or change of direction in a wellbore.
rotates into position; to drop angle, each pad pushes against the high side. Driller commands sent downhole by mud pulse telemetry direct the timing and magnitude of pad actuation. A control unit positioned above the bias unit drives a rotary valve that opens and closes the mud supply to the pads in concert with the drillstring rotation. The system synchronously modulates the extension and contact pressure of the actuator pads as each pad passes a certain orientation point. By applying hydraulic pressure each time a pad passes a specific point, the pad forces the drillstring away from that direction, thus moving it in the desired direction.

A point-the-bit system uses an internal bend to offset the alignment between tool axis and borehole axis to produce a directional response. In a point-the-bit system, the bend is contained within the collar of the tool, immediately above the bit. Point-the-bit systems change well trajectory by changing the toolface angle. The trajectory changes in the direction of the bend. This bend orientation is controlled by a servomotor that rotates at the same rate as the drillstring, but counter to the drillstring rotation. This allows the toolface orientation to remain geostationary, or nonrotating, while the collar rotates.

The latest development in the evolution of these rotary steerables—the PowerDrive Archer high-build-rate RSS—is a hybrid that combines performance features of both push-the-bit and point-the-bit systems.

The Hybrid RSS

Until recently, RSS assemblies were unable to deliver well profiles as complex as those drilled by steerable motor systems. However, the PowerDrive Archer rotary steerable system demonstrated its capability to attain high dogleg severities (DLSs) while achieving ROPs typical of rotary steerable systems. Just as important, it is a fully rotating system—all external tool components rotate with the drillstring, enabling better hole cleaning while reducing the risk of sticking. Unlike some rotary steerables, the PowerDrive Archer RSS does not rely on external moving pads to push against the formation. Instead, four actuator pistons within the drill collar push against the inside of an articulated cylindrical steering sleeve, which pivots on a universal joint to point the bit in the desired direction. In addition, four stabilizer blades on the outer sleeve above the universal joint provide side force to the drill bit when they contact the borehole wall, enabling this RSS to perform like a push-the-bit system. Because its moving components are internal—thus protected from interaction with harsh drilling environments—this RSS has a lower risk of tool malfunction or damage. This design also helps extend RSS run life.

An internal valve, held geostationary with respect to toolface, diverts a small percentage of mud to the pistons. The mud actuates the pistons that push against the steering sleeve. In neutral mode, the mud valve rotates continuously, so bit force is uniformly distributed along the borehole wall, enabling the RSS to hold its course.

Near-bit measurements, such as gamma ray, inclination and azimuth, allow the operator to closely monitor drilling progress. Current orientation and other operating parameters are relayed to the operator through a control unit, which sends this information uphole via continuous mud pulse telemetry. From the surface, the directional driller sends commands downhole to the control unit located above the steering unit. These commands are translated into fluctuations in mud flow rates. Each command has a unique pattern of fluctuations that relate to discrete points on a preset steering map, which has been programmed into the tool prior to drilling.

Operators have been quick to capitalize on the capabilities of the PowerDrive Archer steer-
Marcellus Shale contains an estimated 363 trillion m\(^3\) of recoverable gas. Ultra Petroleum recognized the potential for such problems in a recent project and selected the PowerDrive Archer RSS to meet these challenges, drill the wells quickly and place them in the productive zones of the formation. In 2010, Ultra began an aggressive drilling campaign, having identified numerous targets within this play. The company drilled the first Marcellus well using a steerable PDM to establish a benchmark. The next 10 wells were drilled using the PowerDrive Archer RSS. Some of these wells were kicked off from vertical with a long turn in azimuth of 90° or more to line up with the target while simultaneously building angle at rates up to 8°/100 ft [8°/30 m]. Geologic uncertainties near the landing point sometimes called for corrective action, often requiring higher build rates (above).

9. A dogleg is typically quantified in terms of dogleg severity, which is measured in degrees per unit of distance.
With one exception, the wells drilled subsequent to the benchmark PDM well realized significant savings in rig time. In addition, all completion strings were run without incident. The hybrid RSS was also able to reach farther into the target section, resulting in more than a twofold increase in production rates.

A different resource play has been receiving attention in central Oklahoma, USA, where Cimarex Energy Company has been drilling the Woodford Shale. Cimarex selected PathFinder, a Schlumberger company, to utilize the PowerDrive Archer RSS in drilling the curve section of the company’s Kappus 1-22H well. Using this RSS to drill the 8¾-in. hole with an 8°/100 ft build rate, the operator achieved an 80% increase in ROP over that of previous wells drilled with PDMs. Having attained a smooth wellbore through the curve, the operator was able to switch to a PowerDrive X5 RSS, which drilled a 4,845-ft [1,485-m] lateral section to TD in just one run. A fast ROP through the curve, combined with high build rate and smooth drilling operations in the lateral section resulted in a savings of 10 drilling days (left).

The high-build-rate capability of this hybrid RSS makes for a shorter curved section, enabling operators to design trajectories with deeper KOPs. A deep KOP lets the operator expand the length of the vertical section, which typically drills faster than the curved section. An operator in the Middle East used the PowerDrive Archer RSS to drill an 8¾-in. curve section for 846 ft [258 m] at a build rate of 7.6°/100 ft [7.6°/30 m]. After meeting the objectives for this well, the operator selected the same system to drill a second well.

The second well required a more aggressive build rate, but in carrying out this plan, the operator was able to boost overall ROP by drilling through a longer vertical section before kicking off, which enabled a rapid ROP through the vertical section. After drilling the 12¾-in. section, the operator set casing and kicked off the 8¾-in. section. The hybrid RSS consistently maintained an 11°/100-ft [11°/30-m] DLS and drilled the 742-ft [226-m] interval in a single run of 15 hours (left). The well was landed within 1 ft [0.3 m] vertically and 3.8 ft [1.2 m] laterally of its intended target. Because the 8¾-in. section was shortened, the operator also saved nearly 700 ft [210 m] of liner. Pushing the kickoff point deeper sharpened the curve, which reduced the amount of drilled footage needed to reach the reservoir and allowed drilling engineers to consider downsizing the casing strings to achieve further savings.12

In northwest Arkansas, USA, SEECO, a wholly owned subsidiary of Southwestern Energy Company, tested the performance of the PowerDrive Archer system as it drilled the vertical, curved and lateral sections of an Atoka Formation well. The vertical section was drilled...

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then the well was kicked off along the planned azimuth. The driller built angle at 10°/100 ft [10°/30 m] DLS before making a soft landing at the desired target point with an 88.2° inclination. Using an automated inclination hold feature, the RSS drilled ahead, with inclination maintained within 0.5° of the planned trajectory. After drilling for about 1,000 ft [305 m], the directional driller nudged the well path upward to follow the general dip of the reservoir, with the RSS building inclination up to 92° before an unexpected fault created an abrupt lateral termination of the reservoir (right).

**Planning for Success**

The success of PowerDrive Archer steering technology can be attributed largely to extensive planning, modeling and testing. BHA design and modeling of bit and BHA response go into each PowerDrive Archer job.

As a first step, Schlumberger drilling engineers obtain offset well information from the operator and focus on drilling issues and bit performance data. Engineers use DOX Drilling Office integrated software to design a trajectory to land within the designated target zone while optimizing drilling efficiency. This software package integrates trajectory design with drillstring specifications and BHA design, hydraulics, torque and drag. The DOX software lets drilling engineers quickly run multiple scenarios to optimize the well path. A well plan and equipment plan are then formulated to reach the given target, taking into account known drilling issues. Anticollision modeling ensures that the proposed trajectory will avoid nearby wells.

Hole quality is a critical issue in high DLS or extended-reach wells; poor hole quality may impact the success of a well by hampering efforts to deploy drilling and completion equipment through tight curves and may limit the footage that can be drilled through the lateral section. Extensive testing has played an important role in developing capabilities to deliver high-quality boreholes. One such test involved a series of blocks, each with a different compressive strength. These test blocks were arranged side by side to form a rectangle nearly 45 m [150 ft] long. The PowerDrive Archer RSS drilled through the blocks using various combinations of bits and power settings to simulate downhole drilling conditions. Once the holes were drilled, a laser caliper measured the borehole gauge in each block and consistently found no borehole rugosity (right).

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^ Two-dimensional curve and lateral section. SEECO developed two drilling scenarios to accommodate uncertainties in Atoka Formation dip. The actual well path (red) differs from the two planned trajectories. Geosteering LWD sensors proved the dip to lie between those assumed in the two plans. Faulting terminated the reservoir and shortened the lateral section considerably. (Adapted from Bryan et al, reference 7.)

^ Smooth drilling through test blocks. Laser calipers revealed no borehole rugosity in the borehole drilled by the PowerDrive Archer RSS (bottom). (Photographs courtesy of Edward Parkin, Stonehouse, England.)
Schlumberger performed finite element analysis and bending moment modeling and analysis on components of the PowerDrive Archer BHA (left). Field testing validated BHA Archer BHA integrity. Hydraulics modeling was also conducted across various mud weight and flow ranges.

Drillbit technology is another factor that is vital to the success of any well. The bit affects drilling efficiency, or the ability to achieve and maintain a high average ROP. Bit design also impacts steerability, or the ability to place the well in the right part of the reservoir. Push-the-bit systems generally require an aggressive side-cutting bit for delivering doglegs, while point-the-bit systems tend to rely on stabilization from a less aggressive bit with a longer side gauge. With a hybrid system, using the right bit is especially critical. For this RSS, engineers conducted extensive testing to characterize interactions between the bit, tools and formation to best match the bit profile to the tools and maximize performance.

Bits for the PowerDrive Archer system can be tailored to enhance steerability and deliver improved ROP for a particular field. The IDEAS software is an integrated drillbit design platform that lets drilling engineers optimize bit selection based on modeling the drilling system overall. The IDEAS software accounts for a wide range of variables in its bit design and BHA optimization packages:
- rock type and formation characteristics
- interaction between bit cutter surface and rock face
- contact between drillstring and wellbore
- detailed bottomhole assembly design
- casing program
- well trajectory
- drilling parameters.

Modeling data were also used as input to a fatigue management system that predicts fatigue life for each component of the BHA. When subjected to rotation through high doglegs, BHAs will experience large bending moments. Fatigue life decreases exponentially with increasing build rate and can reduce the life of standard BHA components to a matter of hours. Fatigue modeling and tracking is helping drillers avoid twist offs and other catastrophic failures.

Schlumberger tracks fatigue life automatically to ensure integrity of BHA components. With the aid of PERFORM Toolkit data optimization and analysis software, the wellsite engineer can record RPM, ROP, DLS and other contributors to fatigue, providing real-time fatigue management information and predictions of fatigue life. Monitoring fatigue life is not a trivial task: The position of each component along the well path must be tracked and the bending moment caused by DLS—along with RPM and time—needs to be quantified. Tracking fatigue in real time, including time off-bottom rotating, can significantly improve the accuracy of the fatigue life estimates. These fatigue data may be monitored remotely at operations support centers, where the data can be reviewed by drilling experts who can advise operators when critical components need to be replaced.

Advances in directional drilling technology are helping operators access hydrocarbons that could not otherwise be produced. The latest generation of rotary steerable is achieving well trajectories and step-outs that were previously unimaginable, while delivering lower cost and lower risk wells and improving production. These increasingly complex well trajectories are spurring the industry to reach further in the search for new reserves.

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Although modeling of BHA and bit response has been notoriously difficult, recent advances make it possible to analyze dynamic downhole drilling conditions and compute drillstring stresses. The forces generated by the bit and their effects on BHA steering performance can also be predicted. This is followed by laboratory testing and, finally, field testing to deliver optimized BHA and bit designs.

13. The IDEAS program was developed in the 1990s by Smith Bits, which was later acquired by Schlumberger. For more on bit design using the IDEAS system: Centala P, Challa V, Durairajan B, Meehan R, Paez L, Partin U, Segal S, Wu S, Garrett I, Teggart B and Tetley N—“Bit Design—Top to Bottom.” Oilfield Review 23, no. 2 (Summer 2011): 4–17.