

Slide Drilling—Farther and Faster

For decades, the mud motor and bent housing assembly have played a critical role in directional drilling; however, the technique used to drill a lateral section resulted in slow drilling rates. A surface-mounted torque control system is helping drillers reach farther while improving rates of penetration and toolface control.

Steven Duplantis
Houston, Texas, USA

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For help in preparation of this article, thanks to Edina Halilagic and Brandon Mills, Houston. Slider is a mark of Schlumberger.

1. Maidla E and Haci M: "Understanding Torque: The Key to Slide-Drilling Directional Wells," paper IADC/SPE 87162, presented at the IADC/SPE Drilling Conference, Dallas, March 2–4, 2004.

Directional wells have been a boon to oil and gas production, particularly in unconventional plays, where horizontal and extended-reach wells maximize wellbore exposure through productive zones. In many of these wells, steerable mud motors have been crucial to achieving the well trajectory necessary to hit operators' target zones. Directional drillers use a downhole mud motor when they kick off the well, build angle, drill tangent sections and maintain trajectory.

A bend in the motor bearing housing is key to steering the bit toward its target. The surface-adjustable bend can be set between 0° and 3°.

This slight bend is sufficient for pointing the bit in a given direction yet is small enough to permit rotation of the entire mud motor assembly during rotary drilling. This seemingly minor deflection determines the rate at which the motor builds angle to establish a new wellbore trajectory. By orienting that bend in a specific direction, called its toolface angle, the driller can change the inclination and azimuth of the well path.

To maintain the orientation of that bend and thus change wellbore trajectory, the drillstring must not be allowed to rotate, and this is where the mud motor comes into play. A mud motor is

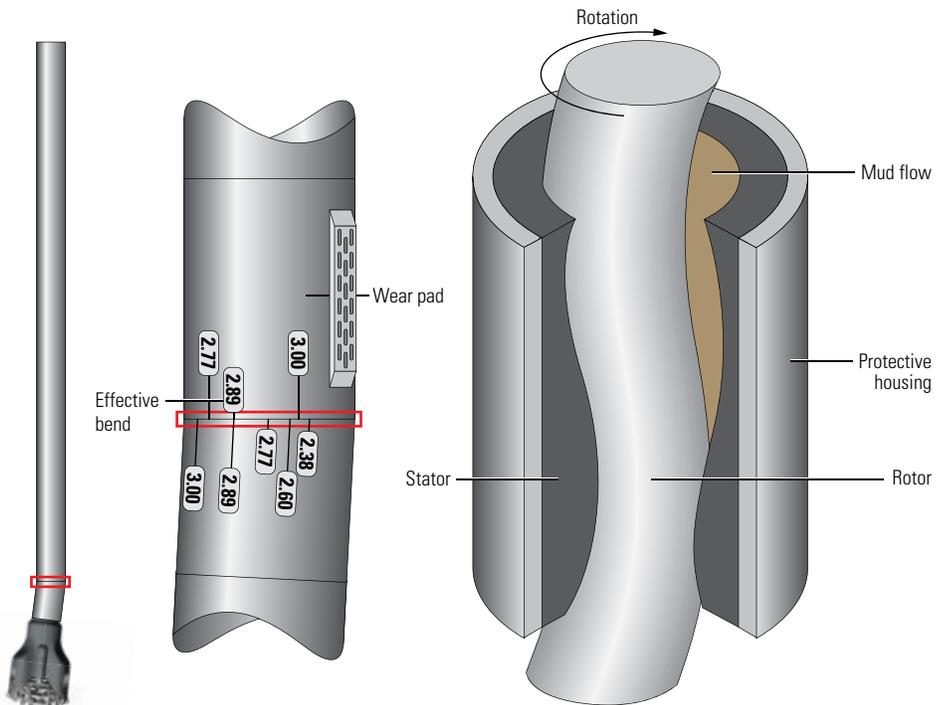


Figure 1. Typical mud motor. The bent housing of the mud motor (*left*) is the key to building wellbore deviation and controlling wellbore trajectory while the rotor turns the bit. The bend in the housing is dialed in at the drill floor when the drilling crew makes up the bottomhole assembly; here, the bend has been set at 2.89 degrees (*middle*). By selecting a larger bend, the driller is able to obtain curve having a smaller radius. The motor, installed immediately above the bit, consists of an eccentric rotor within an elastomer stator (*right*). As drilling mud flows through the stator, it displaces the helical rotor shaft, causing the shaft to rotate within the stator's protective housing, which turns the bit.

a type of positive displacement motor powered by drilling fluid. An eccentric helical rotor and stator assembly drive the mud motor (Figure 1). As it is pumped downhole, drilling fluid flows through the stator and turns the rotor. The mud motor converts hydraulic power to mechanical power to turn a drive shaft that causes the bit to rotate.

Using mud motors, directional drillers alternate between rotating and sliding modes of drilling. In rotating mode, the drilling rig's rotary table or topdrive rotates the entire drillstring to transmit power to the bit. This rotation enables the bend in the motor bearing housing to point equally in all directions and thus maintain a straight drilling path (Figure 2). In most operations today, measurement-while-drilling (MWD) tools provide real-time inclination and azimuth measurements that alert the driller to any devia-

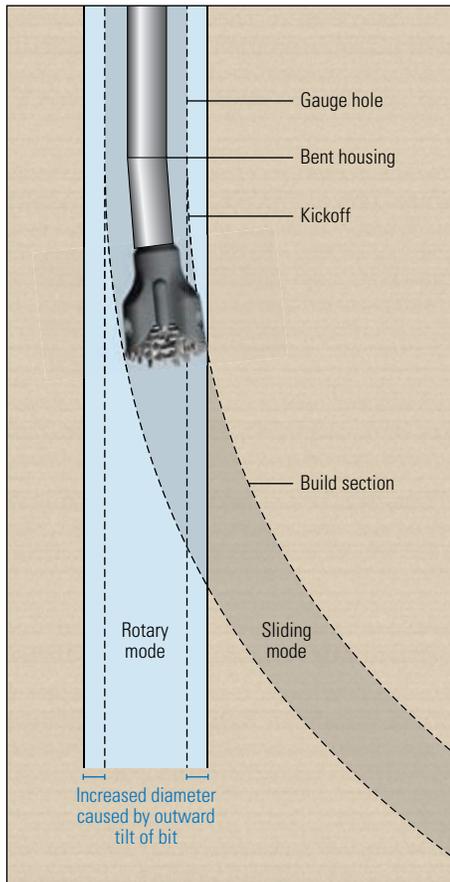


Figure 2. Drilling using a bent housing. In rotating mode, the bit carves a straight path parallel to the axis of the drillstring, which is also rotating. Because the bent housing forces the bit to tilt outward by a few degrees, the bit drills a hole that is slightly larger than the diameter of the bit. When the driller switches to sliding mode, only the bit rotates. The resulting hole is in gauge and follows the axis of the BHA below the bent housing.

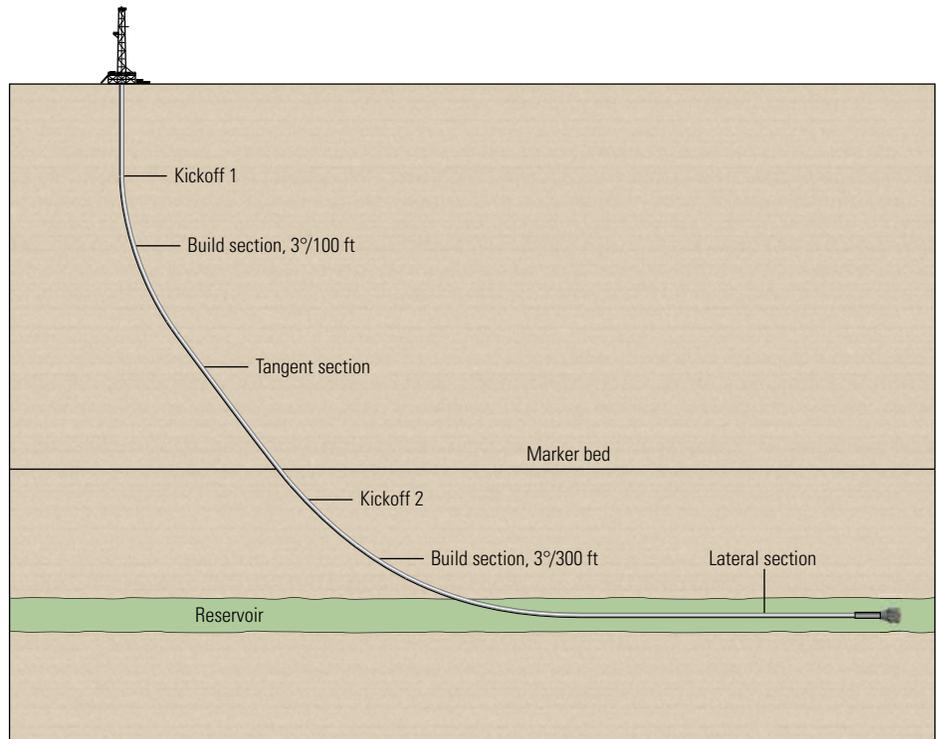


Figure 3. Directional drilling trajectory. After the well is drilled vertically to the specified kickoff point, the mud motor is used to build angle while slide drilling. When the target angle is achieved, a straight-line tangent section may be drilled in rotary mode. While the BHA maintains inclination and azimuth, the driller resorts to sliding mode only when the drilling direction deviates from the planned trajectory. In some fields, a stratigraphic marker bed above the reservoir can be detected by LWD tools, prompting the driller to initiate a second slide section to land the well horizontally within the reservoir.

tions from the intended course. To correct for those deviations or to alter the wellbore trajectory, the driller switches from rotating to sliding mode. In sliding mode, the drillstring does not rotate; instead, the downhole motor turns the bit and the hole is drilled in the direction the bit is pointing, which is controlled by toolface orientation. Upon correcting course and reestablishing the wellbore trajectory needed to hit the target, the driller may then switch back to rotating mode. (Figure 3).

Of the two modes, slide drilling is less efficient; lateral reach usually comes at the expense of penetration rate. The rate of penetration (ROP) achieved using conventional sliding methods typically averages 10% to 25% of that attained in rotating mode.¹ Conversely, by rotating the entire drillstring, drillers gain a substantial advantage in ROP. This article describes an automated system that helps drillers achieve significant gains in horizontal reach with noticeably faster rates of penetration. Field experience in Colorado, USA, illustrates how a torque-oscillation system can help operators exploit unconventional plays.

Slide Drilling Challenges

To initiate a slide, the driller must first orient the bit to drill in alignment with the trajectory proposed in the well plan. This requires the driller to stop drilling, pull the bit off-bottom and reciprocate the drillpipe to release any torque that has built up within the drillstring. The driller then orients the downhole mud motor using real-time MWD toolface measurements to ensure the specified wellbore deviation is obtained. Following this time-consuming orientation process, the driller sets the topdrive brake to prevent further rotation from the surface. The slide begins as the driller eases off the drawworks brake to control the hook load, which, in turn, affects the magnitude of weight imposed at the bit. Minor right and left torque adjustments are applied manually to steer the bit as needed to keep the trajectory on course.

As the depth or lateral reach increases, the drillstring is subjected to greater friction and drag. These forces, in turn, affect the driller's ability to transfer weight to the bit and control toolface orientation while sliding, making it difficult to attain

sufficient ROP and maintain trajectory to the target. Such problems frequently result in increased drilling time, which may adversely impact project economics and ultimately limit the length of a lateral section.

The capability to transfer weight to the bit affects several aspects of directional drilling. The driller transfers weight to the bit by easing, or slacking off, the brake; this transfers some of the hook load, or drillstring weight, to the bit.² The difference between the weight imposed at the bit and the amount of weight made available by easing the brake at the surface is primarily caused by drag. As the horizontal departure of a wellbore increases, so does the longitudinal drag of the drillpipe along the wellbore.

Controlling weight at the bit throughout the sliding mode is made even more difficult by drillstring elasticity, which permits the pipe to move nonproportionally. This elasticity can cause one segment of drillstring to move while other segments remain stationary or move at different velocities.³

Poor hole cleaning may also affect weight transfer. In sliding mode, hole cleaning is less efficient because there is no pipe rotation to facilitate turbulent flow; this condition reduces the drilling fluid's ability to carry solids. Instead, the solids

accumulate on the low side of the hole in cuttings beds that increase friction on the drillpipe, making it difficult to maintain constant weight on bit (WOB).

Differences in frictional forces between the drillpipe inside of casing versus that in open hole can cause weight to be released suddenly, as can hang-ups caused by key seats and ledges. A sudden transfer of weight to the bit that exceeds the downhole motor's capacity may cause bit rotation to abruptly halt and the motor to stall. Frequent stalling can damage the stator component of the motor, depending on the amount of the weight transferred. The driller must operate the motor within a narrow load range to maintain an acceptable ROP without stalling.⁴

At the driller's console, an impending stall might be indicated by an increase in WOB but with no corresponding upsurge in downhole pressure to signal that an increase in downhole WOB has actually occurred. At some point, the WOB indicator will show an abrupt decrease, indicating a sudden transfer of force from the drillstring to the bit.⁵

Increases in drag impede a driller's ability to remove torque downhole, making it more difficult to set and maintain toolface orientation.⁶ Toolface orientation is affected by torque and

WOB. When weight is applied to the bit, torque at the bit increases. Torque is transmitted downhole through the drillstring, which turns to the right, in a clockwise direction. As weight is applied to the bit, reactive torque, acting in the opposite direction, also develops. This left-hand torque is transferred upward from the bit to the lower part of the drillstring. Reactive torque builds as weight is increased, reaching its maximum value when the motor stalls. This reactive torque also affects the orientation of the motor.

Reactive torque must be taken into account as the driller tries to orient the drilling motor from the surface. In practice, the driller can make minor shifts in toolface orientation by changing downhole WOB, which alters the reactive torque. To produce larger changes, the driller can lift the bit off-bottom and reorient the toolface. Even after the specified toolface orientation is achieved, maintaining that orientation can be challenging. Longitudinal drag increases with lateral reach, and weight transfer to the bit becomes more erratic along the length of the horizontal section, thus allowing reactive torque to build and consequently change the toolface angle.⁷ The effort and time spent on orienting the toolface can adversely impact productive time on the rig.

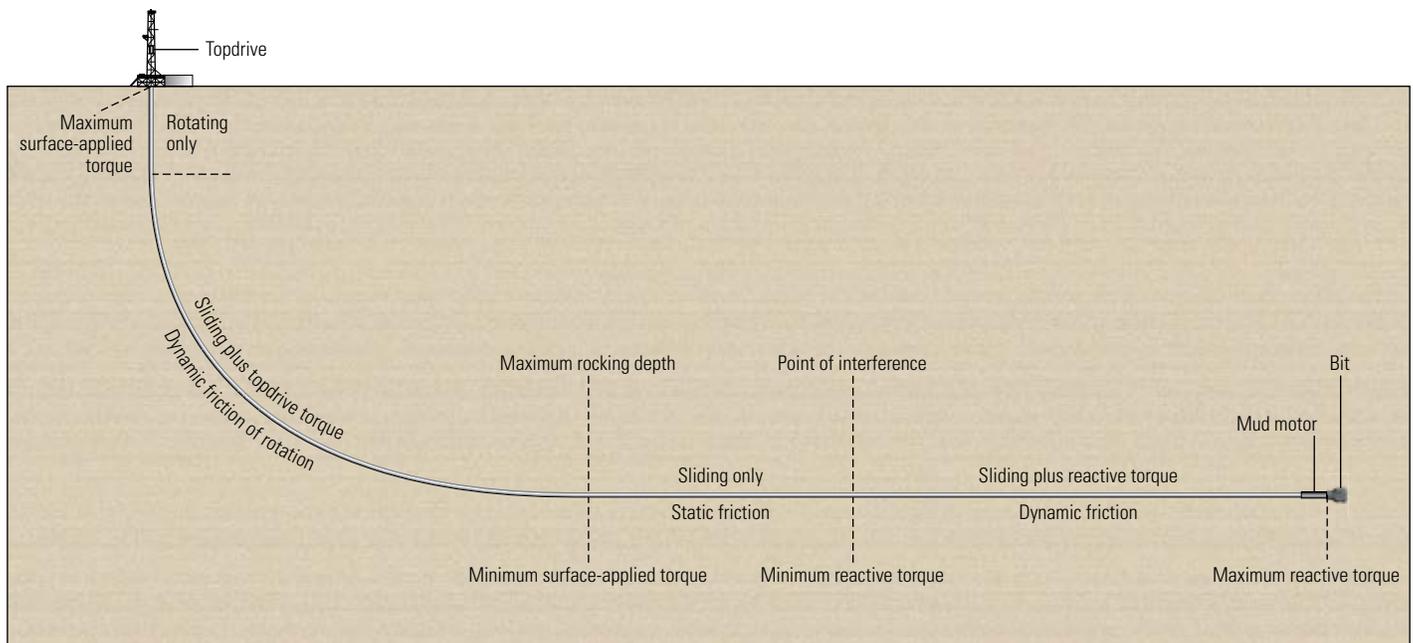


Figure 4. Torque versus friction. Longitudinal drag along the drillstring can be reduced from the surface down to a maximum rocking depth, at which friction and imposed torque are in balance. By manipulating the surface torque oscillations, this point can be moved deep enough to produce a significant reduction in drag. Similarly, reactive torque from the bit creates vibrations that propagate back uphole, breaking friction

and longitudinal drag across the bottom section of the drillstring up to a point of interference, where the torque is balanced by static friction. An intermediate zone remains unaffected by surface rocking torque or by reactive torque. By continuously monitoring torque, WOB and ROP while sliding, the Slider system helps minimize the length of this intermediate zone and thus reduces longitudinal drag.

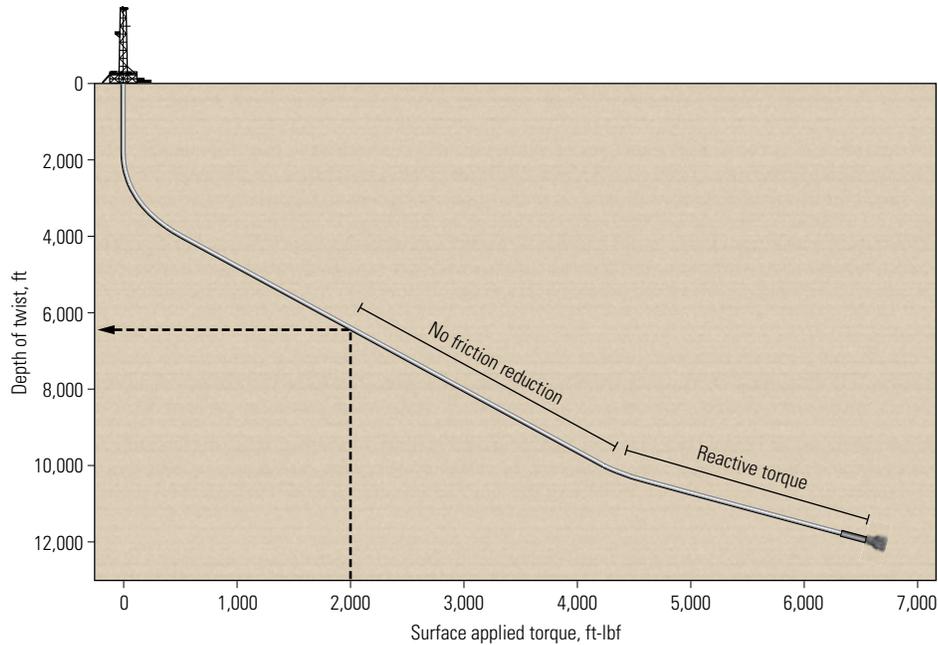


Figure 5. Torque versus depth plot. Surface-applied torque will tend to twist the drillstring to a certain depth depending on the drag encountered over the length of the pipe and on pipe thickness and weight. In this model, 2,000 ft-lbf of torque applied at the surface will cause the pipe to twist to a depth of 6,400 ft. (Adapted from Maidla et al, reference 5.)

The Slider System

Manually correcting and maintaining toolface orientation can be a difficult process. Drilling efficiency is largely dependent on the driller's ability to:

- transfer weight to the bit without stalling the mud motor
- reduce longitudinal drag sufficiently to achieve and maintain a desired toolface angle
- attain acceptable ROP.

The Slider automated surface rotation control system was developed to help operators regain some of the drilling performance of a conventionally rotating drillstring. The Slider interface interacts with the topdrive control system to rotate the drillstring back and forth. This torque rocking technique reduces longitudinal drag along part of the drillstring while slide drilling. Rocking back and forth subjects the upper drillstring to near-constant tangential motion, producing a dynamic friction coefficient, which is lower than a static friction coefficient created by

nonrotating pipe. Rocking can also help reduce axial friction along the drillstring. However, this motion is not necessarily transmitted all the way to the bit—other processes are at work.

Torque from the topdrive rotates the drillstring from the surface down to a *maximum rocking depth*, where friction against the side of the hole prevents the pipe from turning. At the same time, as the mud motor turns the bit, it generates a reactive torque in the opposite direction. This torque is transmitted a short distance up the drillstring until it is overcome by friction at some point between the bottom of the wellbore and the BHA, referred to as the *point of interference* (Figure 4). Throughout the interval between the bit and the point of interference, the velocity component of reactive torque imposes a reduction in longitudinal drag along the lower part of the drillstring and possibly a change in toolface orientation. Between the depth where surface torque is overcome by friction and the point where reactive torque is overcome by friction, the pipe does

not rotate. This section of drillstring, which has no tangential motion, moves by sliding only and is subject to static friction, which is greater than the dynamic friction of pipe in motion.

The location of the point of interference varies with changes in the amount of reactive torque. To efficiently minimize the sliding interval between the depth of rocking and the point of interference while keeping the maximum rocking depth relatively constant, an automated control system must be used.

The amount of surface torque supplied by the topdrive dictates in large part how far downhole the rocking motion will be transmitted. This relationship between torque and rocking depth can be modeled using conventional torque and drag programs (Figure 5). However, these programs are not needed when using the Slider system. Using inputs from surface hook load and standpipe pressure as well as downhole MWD toolface angle, the Slider system automatically determines the amount of surface torque needed to

2. The hook load includes more than simply the weight of the drillstring in air; it is the total force pulling down on the hook as it hangs beneath the derrick traveling block. This total force includes the weight of the drillstring, drill collars and ancillary equipment reduced by any forces that tend to decrease the weight. These forces might include friction along the wellbore wall and buoyant forces on the drillstring caused by its immersion in drilling fluid.

3. Maidla and Haci, reference 1.

4. Tello Kragjcek RH, Al-Dossary A, Kotb W and Al Gamal A: "Automated Technology Improved the Efficiency of Directional Drilling in Extended Reach Wells in Saudi Arabia," paper SPE 149108, presented at the SPE/DGS Saudi Arabia Section Technical Symposium and Exhibition, Al-Khobar, Saudi Arabia, May 15–18, 2011.

5. Maidla E, Haci M, Jones S, Cluchey M, Alexander M and Warren T: "Field Proof of the New Sliding Technology for Directional Drilling," paper SPE/IADC 92558, presented at the SPE/IADC Drilling Conference, Amsterdam, February 23–25, 2005.

6. Maidla and Haci, reference 1.

7. Maidla and Haci, reference 1.

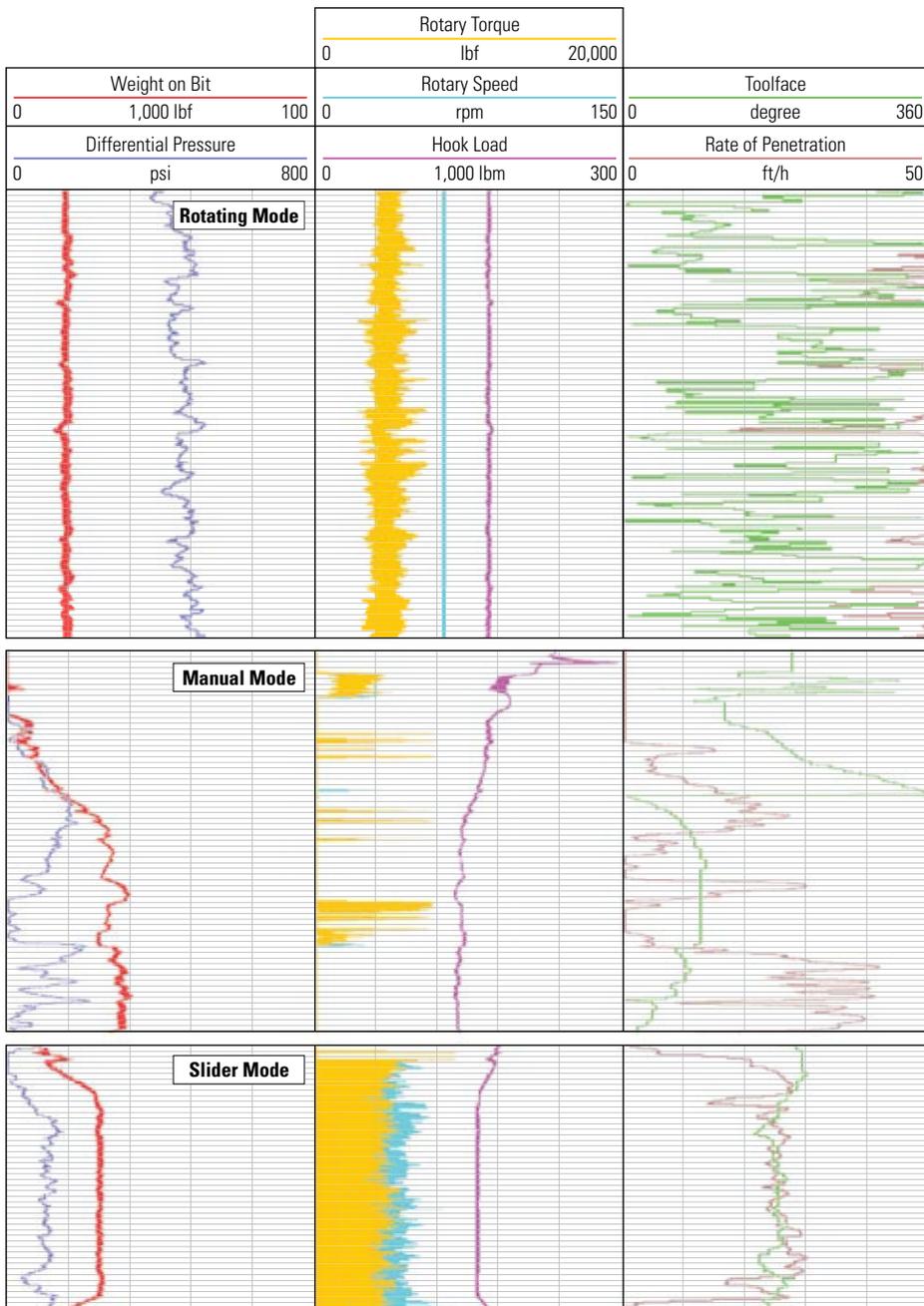


Figure 6. Comparison of rotating and sliding drilling parameters. Rate of penetration (ROP) and toolface control depend largely on the driller's ability to transfer weight to the bit and counter the effects of torque and drag between rotating and sliding modes. The best ROP is achieved while rotating (*top*); however, toolface varies drastically, as there is no attempt to control it (Track 3). Hook load (Track 2) and weight on bit (WOB) remain fairly constant while differential pressure (Track 1) shows a slight increase as depth increases. To begin manual sliding (*middle*), the driller pulls off-bottom to release trapped torque; during this time, WOB (Track 1) decreases while hook load (Track 2) increases. As drilling proceeds, inconsistencies in differential pressure—the difference between pressures when the bit is on-bottom versus off-bottom—indicate poor transfer of weight to the bit (Track 1). Spikes of rotary torque indicate the directional driller's efforts to orient and maintain toolface orientation (Track 2). Toolface control is poor because of trouble transferring weight to bit, which is also reflected by poor ROP (Track 3). Using the automated Slider system (*bottom*), the directional driller quickly gained toolface orientation. When the WOB increased, differential pressure was consistent, demonstrating good weight transfer (Track 1). Weight on bit during a Slider operation is lower than during a manual sliding operation. Left-right oscillation of the drillpipe is constant through the slide (Track 2). Average ROP is substantially higher than that attained during the manual slide, and toolface orientation is more consistent (Track 3).

transfer weight downhole to the bit, thus eliminating the need to come off-bottom to make toolface corrections (Figure 6). This results in an efficient drilling operation and reduced wear on downhole equipment.

System Hardware

Slider system hardware consists of a compact package that houses the circuitry and sensors needed to interact with the rig's topdrive control system. An interface plug is installed on the control panel for the topdrive, and the system is mounted at the driller's console. Installation typically takes less than two hours with no interruption to the drilling process. The Slider system's connections require no alterations to the drilling contractor's topdrive mechanism or modifications to the drilling rig. The system is entirely surface mounted and has no downhole equipment that might become lost in the hole. To ensure operational safety, the system is designed to allow manual intervention at any time.

The directional driller's interface consists of a ruggedized notebook computer with a display configured to enable the driller to command the Slider system while monitoring surface and downhole parameters (Figure 7). The Slider system takes input such as MWD toolface angle, surface torque and standpipe pressure from measurements already available at the rig. The MWD toolface measurement is used to determine the amount of correction needed to restore the toolface to the angle needed to drill the prescribed trajectory. Surface standpipe pressure provides an indicator of reactive torque. The Slider software processes these inputs to determine whether additional torque should be applied to the drillstring to maintain the toolface angle and ROP.

To begin slide drilling, the driller can activate the Slider system and initiate the automatic rocking action, which alternately applies torque to the right and the left. The transfer of weight is controlled by varying surface torque to compensate for changes in reactive torque. Corrections in toolface angle are achieved through additional torque pulses during the rocking cycles.⁸ For every torque cycle to the left or right, a corresponding differential pressure peak occurs, indicating that the weight is being transferred to the bit. To adjust the toolface orientation, the driller can control the magnitude and frequency of torque pulses during a rocking cycle.

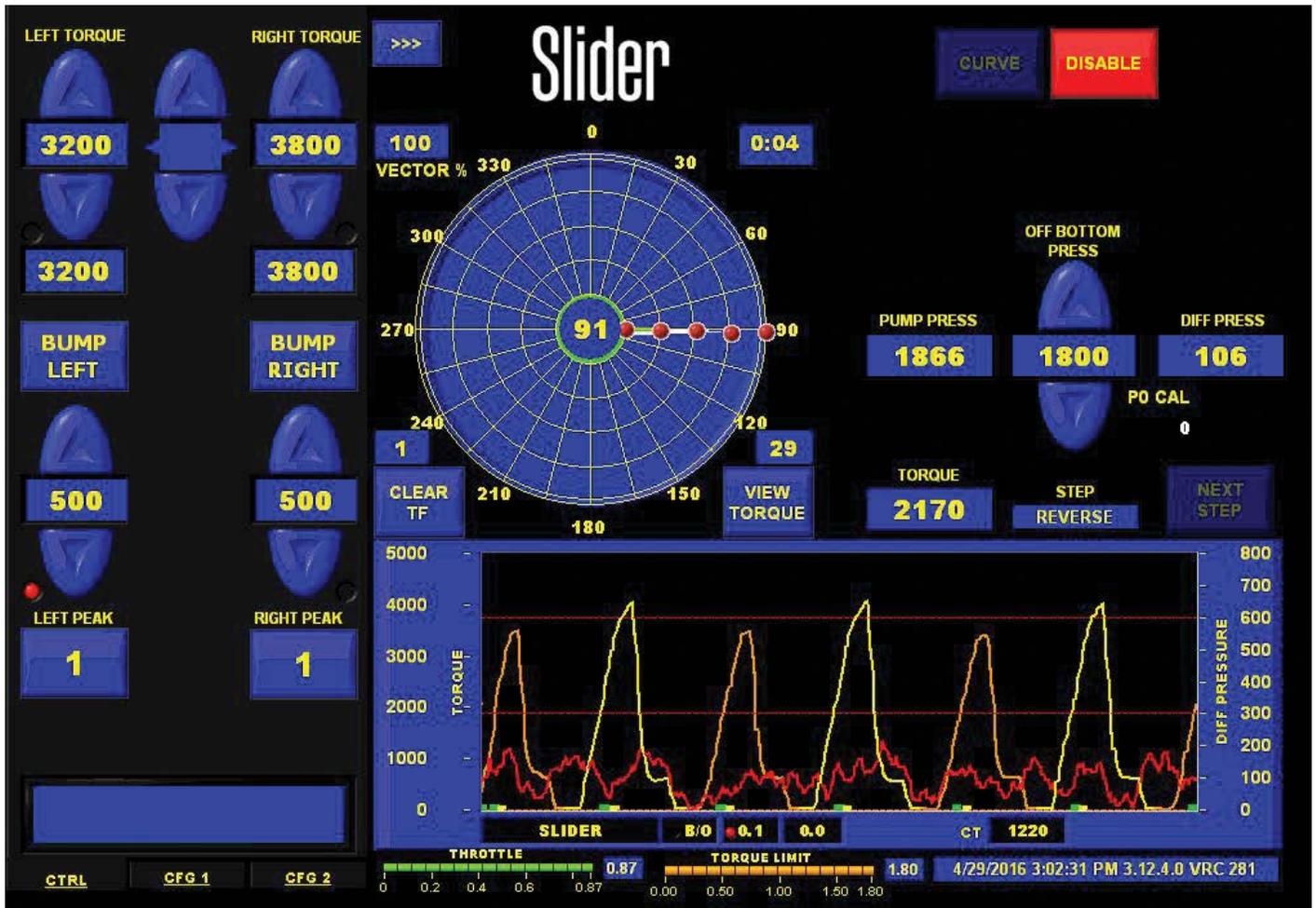


Figure 7. The Slider system graphical display. Downhole performance parameters are monitored and controlled via a notebook computer interface between the topdrive and Slider system. The directional driller can configure this display to show various key parameters such as toolface (dial, center) and torque and differential pressure (chart, bottom right). Torque curves show higher values for right-hand torque (yellow) than for

left-hand torque (orange). Up-and-down keys allow the driller to set values for left and right torque (upper left). Brief torque increases above set values can be added for one oscillation cycle by bumping left or right (middle left). The driller can immediately override the system by hitting the disable button (upper right).

Field Experience

Slider technology has been instrumental in developing unconventional plays throughout North America. Wattenberg field, one of the more prolific fields in the Denver-Julesburg basin, is located in Weld County, Colorado. There, a leading operator in the area used the Slider system to drill horizontal wells in the Cretaceous Niobrara gas play (Figure 8).

One of those wells, spudded in February 2016, was drilled vertically to its kickoff point, then drilled in a westerly direction to its land-

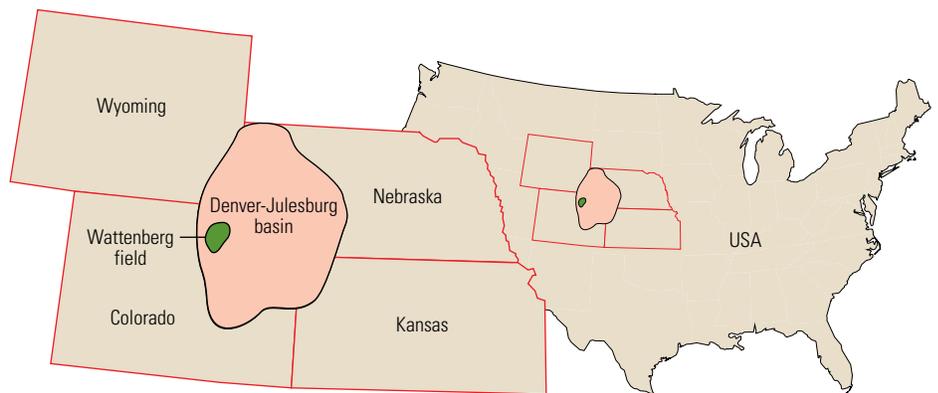


Figure 8. Wattenberg field. The prolific Wattenberg field lies in north-central Colorado, USA, within the Denver-Julesburg basin.

8. "Slider: New Level of Efficiency to Directional Drilling," *Drilling Contractor* 11, no. 4 (July–August 2004): 28–31.

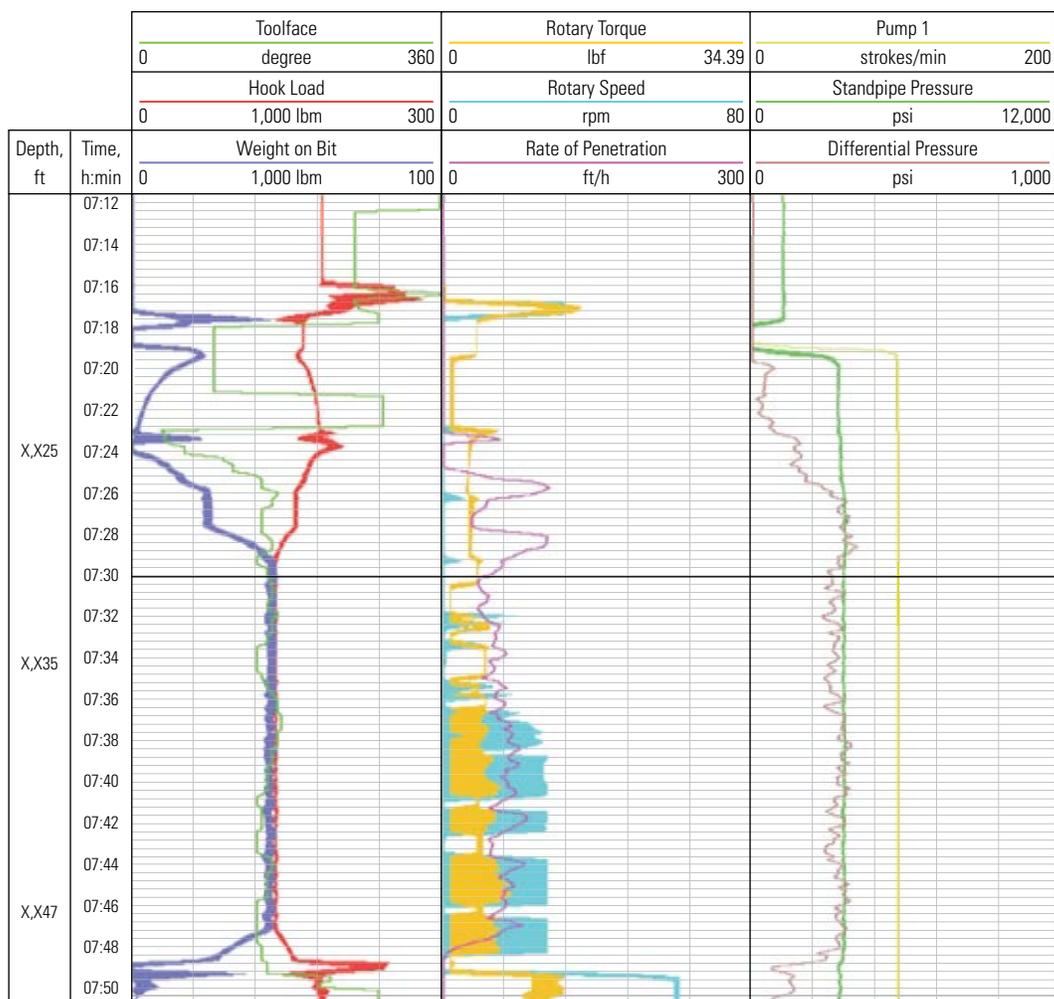


Figure 9. ROP improvement. A drilling parameter display indicates that from X,X25 ft to X,X35 ft, the directional driller was manually controlling the slide drilling operations. After taking 16 min to drill that interval (averaging 38 ft/h ROP), the driller activated the Slider automated system. Drilling from X,X35 to X,X47 ft in 14 min (averaging 51 ft/h ROP), the driller achieved a 34% improvement in ROP.

ing point in the Niobrara pay zone. Beginning at X,X25 ft, the directional driller manually controlled the slide drilling while averaging 38 ft/h [11.6 m/h] ROP. Upon engaging the Slider automated system, the driller reported an average ROP of 51 ft/h [15.5 m/h], for an improvement of 34% in ROP compared with that of manually controlled sliding (Figure 9). The Slider system was engaged several times during the course of drilling this well. Each time the trajectory began to drift beyond specified tolerances, the directional driller switched from rotating to sliding modes to bring the wellbore back on course. Comparisons between manually controlled sliding and automated sliding with the Slider system consistently showed significant gains in ROP over the manual approach.

Faster and Farther

By sensing the amount of surface torque required to transfer weight to the bit and by eliminating the need to pull off-bottom to make toolface corrections, the Slider automated surface rotation control system enables substantial increases in ROP and lateral reach for directional wells. Rocking, or oscillating, the drillstring back and forth helps the driller overcome friction and thus reduce drag on the drillstring. Along with reducing drag, operators can decrease the amount of mud additives normally used for lubrication. The Slider automated system typically applies less WOB to maintain toolface control and has markedly fewer motor stalls than are experienced while manually slide drilling. By achieving consistent toolface control, this automated torque

rocking system facilitates a longer horizontal section, which has less tortuosity, ultimately leading to increased production. —MV

Contributor

Steven Duplantis is an Operations Manager for Schlumberger in Houston, where he oversees day-to-day operations, sales and development for the Slider automated surface rotation control system. Steven began his oilfield career in 1994 and has held positions with MD Totco, Noble Engineering and Epoch/Optidrill. Since 2006, he has been focused on the Slider system, working as a field coordinator and engineer involved with Slider system testing and field trials along with implementation and ongoing development of advanced features for the Slider product line.