Putting a Damper on Drilling's Bad Vibrations

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Drillstring vibrations are increasingly acknowledged to be costing the industry dearly. Although most of the causes are understood and many remedies are already available, the vital step is to effectively implement this knowledge and technology to cut drilling costs.

Symptoms of drillstring vibrations vary. Sometimes, when the crew sees the drillstring bouncing or rotating irregularly, they are only too aware that something is wrong. In other cases, the first the driller may know is when downhole equipment fails because it has been shaken to pieces by vibrations that went undetected at surface.

Whether evident or invisible, these bad vibrations significantly increase the cost of drilling a well. Although the exact figure is still being assessed, large costs—an estimated 2% to 10% of well costs—can arise from vibration-related problems, such as lost time while pulling out of hole and fishing, reduced rate of penetration, poor quality wellbore and increased service cost because of the need for ruggedized equipment.

It is important to dispel the notion that potentially damaging vibrations may also benefit the drilling process. There is little evidence to support this. Although some types of vibrations may be useful—such as bit noise used as a signal for seismic while drilling—these are usually of a different frequency and amplitude from the destructive vibrations.

| The three modes of drillstring vibration. |

Shake, Rattle and Roll

Drillstring vibration can be divided into three types, or modes: axial, torsional and transverse (above). Axial vibrations cause bit bounce and rough drilling, behavior that destroys bits, damages bottomhole assemblies (BHA), increases total drilling time and may be detected at surface.

Torsional vibrations cause irregular downhole rotation that fatigues drill collar connections, damages the bit and slows drilling. The vibrations are recognized at the drillfloor by fluctuations in the power
needed to maintain a constant rate of surface rotation—this will be dealt with in more detail later.

The more destructive transverse vibrations may be unleashed with no sign at surface. Deep in the hole, the rotating BHA interacts with the borehole wall generating shocks from transverse vibrations as high as 250g. The collisions with the borehole wall produce out-of-gauge hole and the shocks can damage components of the BHA (left). Engineering to help equipment such as bits, measurement while drilling (MWD) tools and jars survive the tough downhole environment significantly increases the hardware costs.

Vibrations of all three types may occur during rotary drilling and are more violent in vertical or low-angle wells, where the drillstring may move more freely than in high-angle wells. Many studies of drillstring vibrations employ one-dimensional, linear harmonic analysis that largely ignores the dynamics of wall contact. This approach has proved relatively successful for axial and torsional vibration. For example, a major study of torsional vibration using 3500 hours of surface and downhole vibration data concludes that there are two types of torsional vibrations: transient and stationary.

Transient vibrations correlate with variations in drilling conditions—like heterogeneity in the rock. Stationary vibrations are caused by the natural resonance of the drillstring and are most likely to cause problems.

The most recognizable manifestation of stationary torsional vibration is stick-slip during rotary drilling, in which, because of friction between the bit or BHA and the wellbore and the spring-like nature of the drillstring, the bit actually stops rotating even though the drillpipe is still being turned at a constant rate on surface—the slip phase.

After a short period of stasis, sufficient torque is stored up in the system to overcome friction and the bit starts turning, speeding up to several times the speed of rotation being imparted by the rotary table or topdrive—the slip phase. This accelerated rotation may last for several seconds, depending on the length of the drillstring. Then downhole rotation begins to slow again for another stick phase.

Stick-slip motion results in harmonic, torsional oscillations along the entire length of the drillstring with a period governed largely by the length of the drillstring, and to a lesser extent, the rotational speed at the top. These vibrations exert high cyclic stresses on the drillpipe and slow drilling.

The high speeds achieved during the slip phase are also one of the causes of the third mode, transverse vibrations. However, analysis of transverse vibrations cannot rely on a harmonic model. This is important because in the past it was believed that by “fine-tuning” the drillstring—varying its rate of rotation (revolutions per minute or rpm) and weight on bit (WOB)—to avoid a resonant frequency, transverse vibrations that have been initiated downhole may be stopped. Studies by Anadrill reveal that once such vibrations start, fine-tuning does not always work.

Other field evidence has been assembled. Transverse vibration problems frequently occur in hard or abrasive formations. And shocks are often seen as the MWD or adjacent stabilizer passes from a soft to a hard formation, without changes in rpm.

These facts, together with laboratory observations, led Anadrill to conclude that the interaction between the drillstring and the borehole wall must be included in any

\[ \text{Creation of transverse vibrations. When a rotating drillstring collides with the borehole, its resultant motion is a response to rapid acceleration due to the inelastic collision, and tangential acceleration due to the frictional forces opposing its rotation.} \]

\[ \text{On wall contact, if the energy transferred from rotation to transverse motion is greater than that absorbed by the rock during the impact, drillstring transverse vibrations will increase. Consequently, subsequent interactions with the borehole will be increasingly energetic until the mean energy gained at each impact is balanced by the absorption of energy throughout the cycle.} \]
Effects of lithology

At the heart of the generation of transverse vibrations is a self-sustaining interaction between the rotating drillstring and the wellbore (previous page). Once initiated, this interaction is hard to stop. This coincides with field observations showing that once shocks are observed downhole, varying the rpm will often affect only the number and severity of the shocks. Shocks are not eliminated until the rpm is reduced to a much lower value than the rate at which they commenced. Thus, significant shocks may be sustained at all but the lowest rpm.

Variation in transverse vibration with lithology is due to changes in the rock's coefficients of friction and restitution. As friction between the drillstring and rock increases, more energy per impact is transformed from rotary to transverse motion. In some cases, "friction" may be exaggerated through the digging action of stabilizers clashing with the borehole.

The coefficient of restitution determines what proportion of the kinetic energy at impact is absorbed by the formation; low restitution results in significant energy absorption. Because limestones and sandstones have high coefficients of friction and restitution, they are more likely to generate high shocks than soft shales, which have lower coefficients of friction and restitution—again confirming field observations (right).

**Shock Treatment**

Once the general principles are understood, the next step is to find practical ways of reducing vibration-related drilling costs. To do this, the driller must be able to measure the downhole shocks caused by vibration and then apply appropriate remedies. The capability to fulfill both these objectives already exists. First comes measurement.

When there is a complex combination of events, as is the case with the creation and propagation of downhole vibrations, one approach is to try to construct a sophisticated model that may be employed to predict safe operating ranges for critical parameters. However, such a complex model must include parameters like rock hardness and hole gauge that are not available for real-time use during drilling.

So, at least in the case of transverse vibrations, modeling is not a field solution. A more pragmatic approach is to use a simple downhole sensor to answer the key question: Is the drillstring experiencing damaging vibrations? The answer may then be used without recourse to a model.

To supply this information, Anadrill uses a single downhole accelerometer mounted eccentrically—so that it measures both transverse and torsional vibrations—in the MWD electronics housing. It is programmed to count downhole shocks, sending the information in real time to surface. Such downhole shock measurements have been used to prevent drillstring damage and improve drilling efficiency.

2. 250g is approximately equivalent to the force felt by a driver when stopping a car travelling 150 miles/hr over a distance of 3 ft (or 240 km/hr over 1 m).


Using real-time information to manage downhole shocks. This example from the North Sea, with an 8 1/2-in. polycrystalline diamond compact (PDC) bit, shows why vibrations cannot be easily predicted using a model. More than 100 shocks per second were experienced in the first 15 m of drilling (2260 to 2275 m) with cyclical surface torque. This corresponded to the 1/2-in. BHA being unstabilized in the 12 1/4-in. rathole and precessing around the wellbore. Once the MWD fully entered the 8 1/2-in. hole, the measured shocks dropped significantly. At 2285-m bit depth, the stabilizer entered the 8 1/2-in. hole and downhole shocks were further reduced to an acceptable value. Coincidentally, the gamma ray log shows a formation change at 2285-m bit depth, the point at which the rate of penetration increases.

Shocks between 2307 and 2311 m coincided with the topdrive stalling. At 2325 m the rotary speed was increased from 140 rpm to 175 rpm with no increase in downhole shocks. At 2344 m, the rotary speed was decreased and this resulted in shocks. The speed was then increased to avoid bit damage. A later reduction in rpm did not increase shocks.

been used successfully to monitor the vibration effects of the BHA (above).

Once significant shocks are detected, the next step is to reduce them. To do this, the driller has three options depending on circumstances: modify drilling parameters during drilling until shock measurement shows that harmful vibrations cease, pull the BHA out of hole and run one less likely to vibrate, or employ special systems, such as torque feedback to reduce stick-slip.

Monitor Shocks and Modify Drilling Parameters

Ideally, monitoring and modification may be employed without stopping drilling. Based on feedback from real-time shock measurement, drilling parameters—usually rpm and WOB—may be adjusted to minimize vibrations. However, in some severe cases it may be necessary to stop drilling altogether and let the vibrations dissipate. Then, when drilling restarts, the rpm and WOB may be modified to minimize high-energy wall contact.

In hard, abrasive formations, finding a rotary speed that completely eliminates shock is sometimes difficult, if not impossible. In this case, rpm may be reduced to its lowest acceptable level to reduce shocks as much as possible. The rate of drilling will clearly suffer and although WOB may be increased to limit the reduction in penetration, there is a trade-off. But if the number of trips is reduced or a fishing job eliminated by drilling more slowly, the trade-off will have been worth it.

Change the BHA

If drilling parameter control proves unsuccessful, the drilling engineer may opt to change the BHA, usually at the next scheduled trip. There are several different strategies to BHA design; pay extra attention to minimize the potential for wall contact; eliminate surface rotation almost completely by using downhole motors; or counteract vibration using special downhole equipment.

• Minimizing wall contact—An important design parameter for minimizing transverse vibrations is the span between two stabilizers. Long unstabilized spans—such as those found in pendulum assemblies used in vertical drilling—encourage bending and help induce transverse vibrations.

Another likely source of excitation is wellbore contact by undergauge stabilizers, which can make contact with the borehole wall following only a small displacement from the center of the hole axis (next page, top). Whenever possible, the number of undergauge stabilizers in the BHA should be minimized.

Care should be taken when drilling with the BHA in the casing, since the BHA is effectively unstabilized in the higher-diameter cased hole. Furthermore, vibrations in the casing tend to be more severe as the casing has a high coefficient of restitution and provides an ideal environment for vibrations to develop.

• Reducing vibrations by reducing surface rotation—Since drillstring rotation is a primary cause of torsional and transverse vibrations, significantly reducing rpm can be helpful. Downhole drilling motors may be used so that the rpm imparted at surface may be eliminated or greatly reduced, ensuring that most of the string has low rotational energy and substantially reducing the energy of interactions between the rotating BHA and wellbore.

• Counteracting vibrations using special downhole hardware—We will look at the two of the most popular classes of equipment used to limit drillstring vibrations: shock guards and antiwhirl bits.

Shock guards—Sometimes downhole subs are employed to absorb particularly bad axial vibrations. Most common are
Antiwhirl bit. All the forces on the cutters of an antiwhirl PDC bit force the smooth wear plate against the borehole wall preventing bit whirl.

Effect of an undergauge stabilizer. With little lateral movement, the undergauge stabilizer moves from the center of the borehole when at rest (top) to impact the borehole wall (bottom). With the rotating undergauge stabilizer hitting the formation, transverse vibrations will be established, sending shocks through the MWD collar.

Antiwhirl bits—Bit whirl is an integral part of the transverse vibration phenomenon. It is characterized by the bit's instantaneous center of rotation moving erratically around the work face during drilling—so that the center of the bit does not coincide with the center of the hole. It is particularly prevalent with polycrystalline diamond compact (PDC) bits and accelerates cutter damage and bit wear.

Theoretically, the best way to prevent the onset of bit whirl is to perfectly centralize the BHA at all times. However, in many cases the hole becomes enlarged or there are undergauge stabilizers and, once the bit is slightly unconstrained, it can begin to whirl. When this starts, the hole becomes even more out of gauge and the process becomes self-perpetuating.6

PDC bits usually have aggressive side cutters that dig into the borehole, accentuating transverse vibration and bit whirl. Antiwhirl PDC bits have been developed with all the cutter faces placed to create a radial force that is focused in one direction, driving one side of the bit against the borehole (above, right). However, on this side of the bit, the cutters are replaced by a noncutting wear plate that has much lower frictional contact with the borehole than the cutters. Because friction in the direction of the bit's deliberate imbalance is low, the bit slides at the borehole wall and does not whirl.

shock guards that contain an arrangement of springs and act like car shock absorbers to limit bit bounce. Typically, these modify the resonant axial response of the drill-string to avoid excitation of axial vibration in the range of rpm being used.

Employ a Torque Feedback System

The third major option is the elimination of stick-slip. When people catch a hard ball, they draw their hands back as the ball enters. If they don’t absorb energy in this way, the ball may bounce out. Torque feedback—or soft torque as it is sometimes called—uses a similar approach to eliminate torsional vibrations.

Conventionally, rotary speed is maintained at a constant rate, independent of torque load. The ideal rpm is usually specified by the drilling engineer depending on the formation and the bit type. The driller then attempts to maintain the prescribed rpm without fluctuation.

When a torsional vibration wave travels up the drillstring, it increases strain in the drillpipe at surface. To oppose this strain and maintain constant rpm, the rotary table or topdrive has to work harder. In modern rigs, this is usually achieved by an automatic increase in the current driving the electric motors that turn the drillstring. In these circumstances the torque waves are effectively reflected back, amplifying stick-slip downhole. Left alone, these vibrations are essentially self-sustaining and torsional vibrations build to a maximum amplitude limited by interactions along the drillstring.

Like successful catchers, a torque feedback system finds a way of absorbing this torsional energy. By sensing the increase in torsional strain in the drillpipe at surface, the system reduces input rotation to create a sort of “antitorsional wave” that dampens rather than amplifies the vibration, effectively eradicating the self-sustaining torsional vibrations.

Perhaps the most direct way of achieving this is through direct measurement of drillstring torque using surface strain gauges. But in practice, delicate instruments required for this are unlikely to withstand the harsh drillfloor environment. Sedco Forex has devised a system that produces results similar to those using strain gauges but employs drive motor current and acceleration measurements that may be equated to surface torque (top).8

The aim is to dampen the torsional wave at surface to a minimum across a wide range of vibration frequencies. A control system continuously monitors the current and acceleration of the motor turning the drillstring. Part of the control system consists of a feedback loop set up so that the system automatically adjusts the instantaneous rpm to dampen torsional waves (above). The system is now fitted in a dozen or so rigs and may be employed whenever stick-slip is expected to be problematic.

The Future for Drilling Vibrations

Some sectors of the industry have recognized the potential for reducing drillstring vibrations and know that much of the required technology is already available. The challenge is to build effective teams of drilling engineers, drillers and service company personnel dedicated to raising awareness and using the available tools and know-how. These teams can then effectively plan vibration-reducing strategies and operational guidelines based on reliable monitoring and application of suitable hardware.

If these efforts are successful, rates of penetration will be increased, numbers of fishing jobs reduced, hole quality improved and downhole equipment will be spared damaging and expensive shocks. At a time when almost all eyes are focused on costs, the elimination of drilling’s bad vibrations represents a significant potential for savings without the need for massive technology development programs.

—CF


Dufeyte and Henneuse, reference 3.