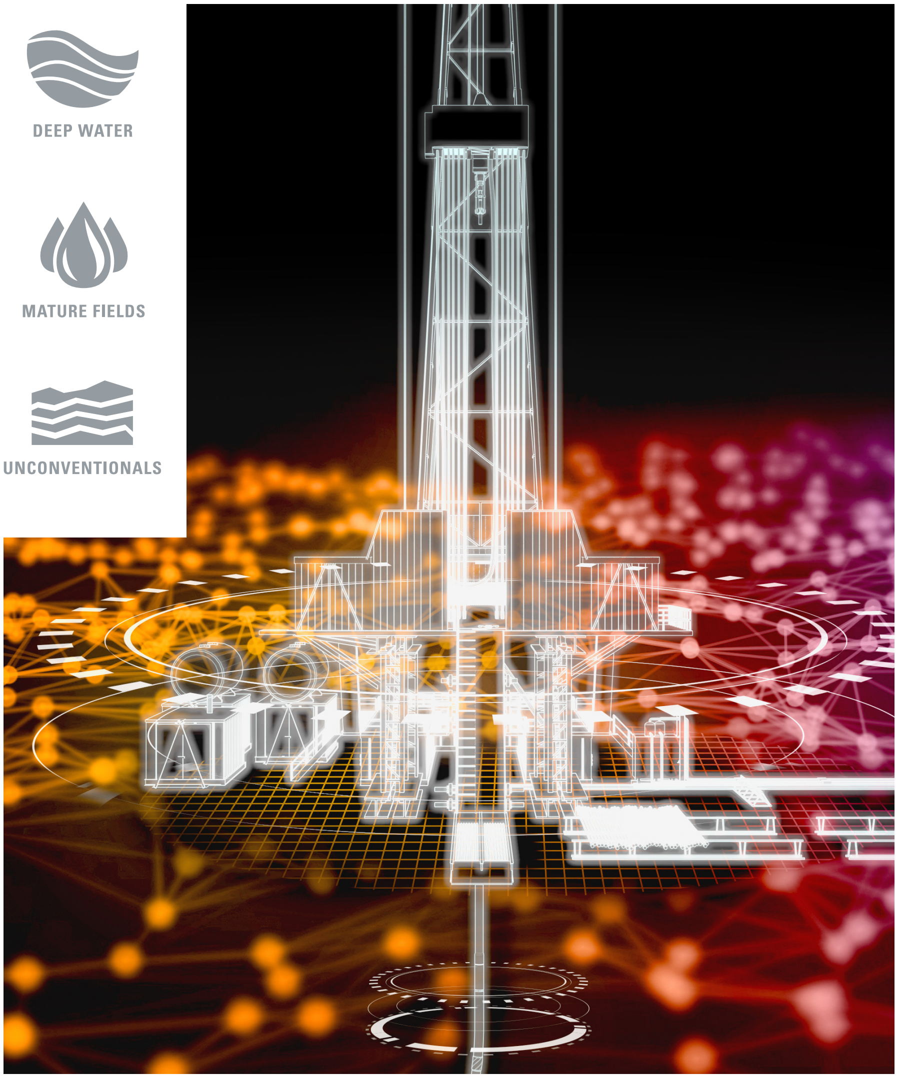
DEEP WATER

MATURE FIELDS

UNCONVENTIONALS



Sperry Drilling Vibration Monitoring and Mitigation Guidelines

HALLIBURTON | Sperry Drilling

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Sperry Drilling Vibration Monitoring and Mitigation Guidelines

Sperry Drilling delivers engineered drilling solutions and reservoir insight to maximize asset value.

Vibration monitoring and mitigation delivers value by reducing drilling trouble time, optimizing drilling practices, and improving overall drilling performance and well construction efficiency.

During the planning phase, all bottomhole assemblies (BHAs) and bits are designed to eliminate the occurrence of drilling vibration. During drilling, a suite of tools, monitoring software, and expert advisory services are available to identify and mitigate vibration induced by the drilling environment. This is achieved through the pre-well and real-time analysis of critical data from a variety of downhole and surface sensors and specialized software applications to model the BHA and monitor the drilling process.

The Drilling Engineering Solutions group provides BHA design experts during planning, along with Applied Drilling Technology (ADT®) optimization services during drilling, in order to optimization services during drilling to identify all modes and mechanisms of vibration, perform root cause analysis, and improve designs to eliminate problems.

All direction-drilling and logging-while-drilling (LWD) personnel are trained to recognize and react to the presence of vibration when drilling to mitigate the negative effects.

This brochure provides an overview of the services that are available, an explanation of all vibration modes and mechanisms, the factors affecting them, best practices and workflows, and the sensors and software utilized in the diagnosis and mitigation of vibration-related issues.

Significant improvements in overall drilling performance can be achieved by taking a proactive approach to the prevention or reduction of destructive downhole mechanical forces.

Drillstring vibration and high shock loads are a major contributing factor to poor drilling performance, creating both visible and invisible non-productive time.

The consequences of drilling vibration and high shock loads are:

- Inefficient drilling through wasted energy input, reducing rate of penetration (ROP) and increasing the time to drill a section
- Bit/reamer damage, reducing the ROP and increasing bit/reamer costs
- Motor/rotary steerable damage causing unplanned trips
- Measurement-while-drilling (MWD) and LWD damage leading to lost data and unplanned trips
- Accelerated fatigue of all drillstring components, leading to collar and drillpipe washout or twist off and the potential for fishing trips and/or unplanned sidetracks around stuck assemblies
- Loss of wellbore strength and increased caving through vibration damage to the borehole wall
- Interference with downhole tool telemetry, causing gaps in data
- Damage to rig equipment, causing increased downtime and cost

02

Drillstring Mechanics and Vibration Modes

Mechanically, the combined drillstring and BHA behaves as a pipe, a beam, a column, and a shaft.

It is a pipe to allow the flow of drilling fluid from surface to the bit and up the annulus. The movement of the drilling fluid and pressures generated creates deformation of the drillstring and associated stresses. The fluid system is used to provide power to downhole tools (such as mud motors or turbines), which imparts energy to the bit or the lower BHA.

The drillstring behaves as a beam to facilitate directional drilling, as the BHA consists of segments of different stiffness that are deformed by the presence of stabilizers, bent housings, or rotary steerable point or push mechanisms to deflect the bit in the direction required. The drillstring will also conform to the wellbore, either following the shape of the well exactly or straddling sections of high dogleg, hole enlargements, or ledges.

In a vertical or near-vertical well, the BHA and drillstring behave as a column that can become unstable and create buckling in either a sinusoidal or helical form. Stabilization is used to resist the buckling in the BHA. As the hole angle is increased, the drillstring and BHA will contact the wellbore and become more stable and require a higher compressive force to create buckling.

It behaves as a shaft, as rotational movement must be transmitted from the drive system to the bit, and torque must be transmitted to overcome the frictional resistance of the drillstring against the wellbore in high-angle wells and the cutting action of the bit, underreamers, or hole openers.

The drillstring and BHA have six degrees of freedom with three mutually orthogonal axes: X, Y, and Z. The convention is that X and Y are perpendicular to the drillstring, with Z oriented parallel to the long axis. X is oriented to measure lateral and radial accelerations, and Y is oriented to measure lateral and tangential accelerations. The Z axis is oriented to measure axial vibration.

The drillstring is free to move along each of these axes and to rotate around them. Rotation around the Z axis describes the rotational speed of the drillstring and responds to any twisting or torsional vibration. Any rotational movement around the X and Y axes is constrained by the presence of the wellbore limiting movement as a function of the difference in the wellbore diameter and the outside diameter of the drillstring component. This movement can be considered as flexing or buckling of the drillstring.

The three primary vibration modes used to identify the vibration mechanisms are lateral, axial, and torsional. Vibration mechanisms are classified according to which of these modes dominates the dynamic behavior when vibration occurs and the specific frequency range of the dominant vibration.

03

Types of Vibration

Free or Natural Vibrations

Free vibrations are excited by a non-repetitive force (impulse) applied to a system, and the system is then allowed to respond without further excitation. The vibration can occur at one or more of the system's natural frequencies (i.e., the period at which the material, due to its structure and shape, wants to vibrate in one of the modes). If no damage occurs because of the original impulse, the vibration will decay because of the dissipation of energy through system damping.

Forced Vibrations

Forced vibrations are caused by a periodic external excitation source, such as a mass imbalance of the BHA during rotation with the period of the excitation force in such an imbalanced system governed by the rotational speed.

When such a force acts on an elastic solid that has its own natural frequency, the interaction of the frequencies produces extremely large vibrations, when the forcing frequency and the natural frequencies are the same. This interaction is termed forced resonance or more commonly resonance.

If the forced vibration is at a different frequency to the natural frequency of the string, the resulting vibration amplitude may either increase or decrease, depending on the relationship of the interaction with input period causing either constructive or destructive interference.

Self-Excited Vibrations

Self-excited vibrations are caused by a constant energy source, which may be either external or internal to the system. It is defined as the conversion of a non-oscillatory energy into vibration. There are similarities to forced resonance, in that the system will vibrate at a natural frequency. However, the important difference is that the source of excitation is constant in this case, not periodic. Therefore, although the energy source has a bearing on the amplitude of the vibration, it has no bearing on the frequency at which the system vibrates.

Motion is initiated in an elastic solid by an external non-linearity, such as friction, causing displacement from its equilibrium. The constant energy source continues to input energy into the system, and the material in the system stores the energy until the disturbing force is overcome and the system moves back toward equilibrium. However, as the system oscillates back toward equilibrium, the elastic properties of the system cause an over-displacement, due to the natural tendency to oscillate, and this creates a situation where the non-linearity (friction) requires more storage of energy to overcome it during the next oscillation – hence, the system is displaced further. This feedback due to the oscillation continues, effectively increasing the amplitude of the vibration.

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Vibration Mechanisms

Mechanism	Mode of Vibration	Expected Frequency Range
Stick-Slip / Low-Frequency Torsional Oscillation (LFTO)	Torsional	0.1–5 Hz
Torsional Resonance / High-Frequency Torsional Oscillation (HFTO)	Torsional	10–800 Hz
Bit Bounce	Axial	1–10 Hz
Bit Forward Whirl	Lateral- Torsional	0.5–5 Hz
Bit Backward Whirl	Lateral- Torsional	10–50 Hz
BHA Forward Whirl	Lateral- Torsional	0.5–5 Hz
BHA Backward Whirl	Latera- Torsional	5–20 Hz
Lateral Shocks	Lateral	Irregular Impacts
Parametric Resonance	Axial- Lateral	0.1–10 Hz
BHA Harmonic Resonance	Lateral	0.5–5 Hz
Bit Chatter	Lateral- Torsional	20–250 Hz
Stabilizer Contact Chatter	Lateral	10–50 Hz
Modal Coupling	Lateral- Torsional and Axial	0.1–20 Hz

Stick-Slip / Low-Frequency Torsional Oscillation (LFTO)

Description: A feedback mechanism between the drillstring and the rotary drive system causes a non-uniform drillstring rotation and repeated full-stall events. The torque required by the bit and drillstring to rotate exceeds the torque being supplied by the rotary system, and the bit stalls. The drillstring begins to twist, and the speed of the drillstring at surface drops. This causes the rotary drive to apply more torque to maintain the set rotary speed – thus increasing trapped torque, twist, and the stored potential energy in the drillstring. When the applied torque is greater than the resistance, the bit and drillstring break free and are accelerated by the trapped torque, causing the RPM to accelerate higher than the rotary system set point. Under extreme conditions, a reverse twist can be created in the drillstring, as the BHA accelerates faster than the surface string RPM, creating a reverse twist and then a counter-rotation as the twist is released. After the increase in surface RPM, the rotary drive then reduces the applied torque to slow the drillstring down, and the torque drops below the required threshold to maintain smooth rotation, and then the stick-and-slip cycle repeats. The frequency response is a function of the length and stiffness of the drillstring, the mass of the BHA, and the rate at which the resistance to rotation is overcome (Kyllingstad and Halsey, 1987). An instantaneous downhole RPM variation has been measured between 2x to 15x the average surface RPM. The onset of this vibration mechanism, where the bit does not fully stall, can be described as low-frequency torsional oscillation (LFTO). The frequency of the vibration is controlled by the mass of the BHA, and the length and stiffness of the drillstring. Weight-on-bit (WOB) fluctuations can also be created by rig heave when offshore, with the period of heave being close to or at the the stick-slip frequency.

Typical Environments: Affected environments can include high-angle or extended-reach wells, hard formations, or salt sections where salt creep is occurring, use of aggressive PDC bits with high WOB, high-tortuosity wellbores, wellbores with high friction factors caused by poor hole quality or poor hole cleaning, and stiff BHA designs being run into high-dogleg sections.

Consequences: Potential consequences can include large surface torque fluctuations, causing damage to the rotary system; trapped torque, causing connection over-torque and connection damage leading to drillstring twist-off; slip-phase reverse BHA rotation, causing connection back- off; impact damage to PDC bits during the stick phase, with the potential for reverse rotation of PDC bits and damage to PDC cutter diamond tables; damage to the bit and stabilizer gauges, which can occur with the repeated rotational acceleration; and the stick-and-slip cycle can interfere with mud pulse telemetry by creating pressure pulses at the bit if the stall frequency overlaps the telemetry frequency.

Torsional Resonance / High-Frequency Torsional Oscillation (HFTO)

Description: This includes the excitation of a natural or harmonic torsional frequency of the drill collar (Warren and Oster, 1998), and torsional resonance (or HFTO, as it has been more recently termed) occurs at natural frequencies of the BHA, typically greater than 50 Hz. The vibration attenuates rapidly with distance from the bit and tends to be isolated only to the BHA – in many instances, below a motor where the elastomer serves to dampen HFTO propagation above the motor. HFTO matches exactly with the higher torsional natural frequencies of the drillstring (Jain et al., 2014).

Typical Environment: These environments include hard rock, where PDC bits with high WOB and low RPM create a deep depth of cut.

Consequences: The high-frequency torsional cycling can damage the elastomer in motor power sections, reducing their expected life. Additional consequences can include damage to electronics, broken connectors and cables, and cracks appearing in tools and connections caused by cycling stresses.

Bit Bounce

Description: Bit bounce can be described as axial or longitudinal motion of the drillstring generated by the bit interaction with the formation, creating resonance in the axial mode (Lubinski, 1950, and Dykstra et al.,1994).

Typical Environments: These environments can include tricone bits with an unstable bottomhole pattern, creating axial resonance of the BHA; and vertical wells where there is no frictional damping between the drillstring and wellbore, especially in the absence of a shock absorber.

Consequences: The impact loading will damage the drill bit cutting structure, bearings, and seals. The drillstring can sustain damage from the axial shocks and lateral shocks induced by the string flexing. Hoisting equipment may be damaged in shallow wells. Additionally, downhole electronics may be damaged from repeated shock.

Bit Forward Whirl

Description: Bit forward whirl occurs when the bit has cut itself a hole larger than its own diameter (Brett et al., 1989). This allows the bit to precess around in the wellbore, instead of rotating around its natural center. The hole enlargement can be relatively small for this to occur – 1/32 inch to 1/16 inch or 0.8 mm to 1.6 mm is sufficient. The frequency is 1x the RPM.

Typical Environment: Bit forward whirl can be caused by excessive side cutting on the bits or insufficient bit gauge pad support, or by softer or washed-out formations.

Consequences: The primary consequence of bit forward whirl is the damage caused to PDC bit cutting structure. During the forward precession of the bit rotating in the hole, increased loading in directions different to the expected vectors on the PDC cutters occurs – accelerating the bit wear, and reducing ROP and the length of the run. Whirling creates an over-gauge hole, thus reinforcing the tendency for the bit to whirl. Interbedded lithology of different compressive strengths and friability can lead to the creation of ledges, as the weaker rock will be enlarged to a greater diameter than the stronger rock, which may remain in gauge. This can lead to problems cleaning the hole and tripping the BHA.

Bit Backward Whirl

Description: Bit backward whirl occurs when the bit has cut itself a hole larger than its own diameter that is sufficient in size to allow the bit to pivot in the hole from a point of contact on the bit blade for PDC bits of the cone gauge on roller cone bits (Brett et al.,1989). This causes the bit to precess around in the wellbore, instead of rotating around its natural center. As the bit is constantly rotating forward, the pivoting motion from the blade or cone contact causes the cutting structures to slide across the face of the hole in a backward direction. The frequency is the number of blades multiplied by the RPM, where "n" is a function of the hole enlargement and the bit outside diameter (OD).

Typical Environment: Bit backward whirl can be caused by excessive side cutting on the bits or insufficient bit gauge pad support, or by softer or washed-out formations.

Consequences: The primary consequence of bit backward whirl is the damage caused to the PDC bit's cutting structure. During the backward precession of the bit rotating in the hole, increased loading in directions different to the expected vectors on the PDC cutters occurs – accelerating the bit wear, and reducing ROP and the length of the run. Whirling creates an over-gauge hole, thus reinforcing the tendency for the bit to whirl and possibly increasing the hole size sufficiently to initiate BHA whirl. Interbedded lithology of different compressive strengths and friability can lead to the creation of ledges, as the weaker rock will be enlarged to a greater diameter than the stronger rock, which may remain in gauge. This can lead to problems cleaning the hole and tripping the BHA.

BHA Forward Whirl

Description: BHA forward whirl is the eccentric rotation of the BHA about a point other than its geometric center, and is associated with the BHA rolling around the wellbore as it rotates. The eccentric rotation of whirling can be caused by a hole that has been enlarged, or by undergauge BHA stabilizers or slick BHAs. The motion of the BHA in forward whirl has the center of rotation following a circular track around the wellbore. This can be initiated by a mass imbalance of the BHA or by friction between the BHA and the wellbore, causing the assembly to roll up the side of the hole and drop down. This creates lateral shocks within the BHA, and, if the frequency of the lateral shocks matches a natural frequency of the BHA, then forced resonance will occur, significantly increasing the magnitude of the lateral vibration and most likely transitioning to BHA backward whirl (Besaisow and Payne, 1988; Vandiver et al.,1990; and Dareing, 1984). The frequency is 1x the RPM.

Typical Environments: BHA forward whirl can occur in all hole sections with higher friction factors; zones with hole enlargements; vertical holes with poorly stabilized or slick BHAs; and BHAs operated with high RPMs and low WOB.

Consequences: BHA forward whirl causes downhole tool failure by generating high shock impacts and sustained vibration in the BHA. The repeated flexing of the drill collars at frequencies significantly higher than the rotational speed will increase the stress levels and significantly increase the number of cycles at higher stress, thus accelerating the fatigue rates of components. The potential high bending stresses can damage drill collar connections, and the associated lateral shocks can cause downhole electronic failure. The surface torque level can also increase, as more energy will be required to turn the vibrating BHA. The bit will exhibit wear on one side of the bit or gauge pad. The BHA and drillstring may show wear on one side of the stabilizers and collars, and this can also be evident in the drillpipe and tool joints.

BHA Backward Whirl

Description: BHA backward whirl is the eccentric movement of the BHA about a point other than its geometric center. The movement is created from high energy shock impacts and is associated with the BHA bouncing off the wellbore in a direction different to the rotational direction with each impact. It is common that the high energy shock impacts are created by forced resonance, but this is not always the case, as it can also be a product of excessively high RPM. BHA backward whirl can be initiated by straight-bladed stabilizers gearing off the wellbore in the same manner as with bit backward whirl (Besaisow and Payne, 1988; Vandiver et al., 1990; and Dareing, 1984). The frequency is "n" multiplied by RPM, where "n" is a function of the hole enlargement and the collar or stabilizer OD.

Typical Environments: This condition can be initiated by the mass imbalance of the BHA or by the BHA resonating at a critical rotary speed. BHA backward whirl can occur in all hole sections with higher friction factors, and in zones with hole enlargements. There can also be an increased tendency for this to happen in vertical or overgauge hole sections, or where the BHA is operating with high RPM and low WOB.

Consequences: BHA backward whirl causes downhole tool failure by generating high shock impacts and sustained vibration in the BHA. The repeated flexing of the drill collars at frequencies significantly higher than the rotational speed will increase the stress levels and significantly increase the number of cycles at higher stress, thus accelerating the fatigue rates of components. The potential high bending stresses can damage drill collar connections, potentially leading to washouts or twist-offs, and the associated lateral shocks can cause downhole electronic failure. The surface torque level can also increase, as more energy will be required to turn the vibrating BHA. In weaker formations, damage from these shocks could result in hole enlargements.

Lateral Shocks

Description: Chaotic behavior of the BHA and drillstring can cause the release of energy built up in the drillstring through large lateral shock effects. Unlike BHA whirl, in which the motion settles to a steady state, the BHA moves sideways and can briefly whirl forward or backward randomly; this is a mechanical response to wellbore condition, as opposed to resonance of the assembly or steady-state forward whirl (Mitchell and Allen, 1987).

Typical Environments: Lateral shocks of the BHA can be induced from too much energy in the drillstring and from excessively high RPM. These shocks can also be triggered by bit whirl or by rotating an unbalanced drillstring. They can also occur with lateral movements caused if the drillstring flexes during bit bounce. These shocks can occur in zones with hole enlargements, and there can be an increased tendency for them to happen in vertical or overgauge hole sections.

Consequences: Lateral shocks can cause downhole tool failure by generating high shock impacts. The potential high bending stresses can damage drill collar connections, potentially leading to washouts or twist-offs, and the associated lateral shocks can cause downhole electronic failure. The surface torque level can also increase, as more energy will be required to turn the vibrating BHA. In weaker formations, damage from these shocks could result in hole enlargements.

Parametric Resonance

Description: In parametric resonance, severe lateral vibrations can be induced because of axial excitations caused by bit/formation interaction. The dynamic component of axial load is primarily caused by bit/formation interaction, which results in WOB fluctuations. Axial fluctuations at a specific frequency will cause lateral deflection of the drillstring through the small lateral displacements that are already occurring – i.e., the small bends that already exist will be magnified due to the wave traveling through them (Dunayevsky et al.,1993).

Typical Environment: Parametric resonance can occur in interbedded formations and undergauge holes.

Consequences: Severe lateral vibration can induce accelerated failure in the drillstring, and can also create the opportunity for borehole enlargement, which may lead to poor directional control and also to whirl and other mechanisms of vibration. In weaker formations, damage from vibrational shocks could result in hole enlargements.

BHA Harmonic Resonance

Description: Lateral vibration waves may occur in a BHA that are related to the stabilizer contact spacing and the rotary speed. For any given spacing of contacts (nodal points), certain rotary speeds (frequencies) may correspond to waves with large amplitude response. This may be considered as a system response excited at a forced excitation frequency at or near the rotary speed, resulting from, for example, mass eccentricity and/or a bent assembly (intentional or not). In this vibration mode, the waves may be sustained by stabilizer contact spacing that creates a system that is prone to vibration through a constructive interference pattern, also known as harmonic resonance (Bailey et al., 2020).

Typical Environments: This can occur in any drilling application, but more serious vibrations are typically observed in harder formations where shock and vibration damage to drilling tools may occur.

Consequences: This type of vibration can damage BHA components and slow ROP.

Bit Chatter

Description: The high-frequency resonance of the bit and BHA is thought to be caused by effects of each blade or, in some cases, each individual cutter corresponding to the relative movement between the formation and the drill bit. The vibrations result in waves on the face of the borehole that perturb the movement of the bit away from its geometric center (Warren and Sinor, 1986).

Typical Environment: PDC bits drilling in high-compressive-strength rocks will create this vibration, where the PDC has lost its shearing cutting action and each cutter is impacted on the formation.

Consequences: This high-frequency vibration can cause electronic equipment to fail due to the vibration of electronic components and solder joints. It can also cause damage to bit cutters, and bit dysfunction can lead to bit whirl.

Stabilizer Contact Chatter

Description: When blades that contact the borehole are closely spaced, there is the potential for a form of contact chatter between the two blades as they alternately make contact with high force at high frequency. This dysfunction can create a form of dynamic contact drag that is similar to static contact forces. In many cases, this causes low ROP and higher wear rates and damage to drilling tools (Bailey et al., 2016).

Typical Environments: This can occur in any drilling application, but more serious vibrations are typically observed in harder formations where shock and vibration damage to drilling tools may occur.

Consequences: This type of vibration can damage BHA components and slow ROP.

Modal Coupling

Description: Modal coupling describes vibration occurring in axial, torsional, and lateral directions simultaneously. It creates axial and torsional oscillations, and high lateral shocks, along the BHA. This is the most extreme form of vibration, and usually results from a failure to control one of the vibration mechanisms – allowing it to become severe enough to initiate one or more other mechanisms simultaneously.

Typical Environment: Modal coupling can occur wherever stick-slip, whirl, or bounce can be initiated.

Consequences: This type of vibration can cause MWD component failures, localized tool joint and/or stabilizer wear, washout or twist-offs due to connection fatigue cracks, and increased torque.

05

Factors Affecting Vibration

Hole Angle

The hole angle affects the stability of the drillstring and BHA, and controls the normal force created by any contact of the drillstring and BHA against the wellbore wall.

In vertical In vertical wells < 5°, the string is an unstable column and is more likely to buckle sinusoidally or helically. This increases the likelihood of lateral shocks occurring as the string is rotated, and larger cyclic bending loads as the drillstring is rotated.

As the hole angle begins to increase, the string and BHA contact the wellbore and the contact force increases as the hole angle increases. This reduces the chances of lateral shocks occurring caused by rotation, but increases the torque demand for the BHA and the likelihood of torsional vibration being generated.

Increasing friction on the drillstring with higher hole angle can force the pipe to ride up the wall and fall to the low side of the hole, generating severe shock impacts.

In high-angle and extended-reach wells, the string becomes more prone to buckling again and it may sinusoidally buckle along the low side of the wellbore and therefore generate lateral vibrations as the string is rotated. Torsional vibration (stick-slip) is much more likely to occur in deviated holes in high-angle holes. The higher frictional torque along the length of the wellbore reduces the amount of energy reaching the bit, thus increasing the tendency for the bit, BHA, and drillstring to vibrate torsionally.

Wellbore tortuosity is also important in the generation of frictional torque, as smoother well profiles generate lower torque – therefore, large dogleg severity and sharp changes in hole angle should be avoided, as this will increase the likelihood of torsional vibration.

Bit Type

Having a suitable bit for the formation to be drilled is one of the key factors in drilling optimization and will help prevent bit-induced vibration from occurring. It is important to operate the bit within its recommended range of parameters to avoid dynamic instability at the bit, which can cause vibrations. Vibrations can often be increased with the use of aggressive bit features, larger cutter sizes, fewer blades or cutters, and low back rake angles. Bit features should also be chosen that reduce the tendency for bit whirl or excessive tortuosity.

Lithology

Particle size and mineral composition determine the abrasiveness of rocks. The cementation material (i.e., the mineral holding it together) will determine its hardness or strength. Torsional vibrations induced by PDC bits are created where the rock strength and resistance from the depth of cut are greater than the power being applied to shear the rock. Differential hardness ((such as interbedded sands and clays or limestone stringers) are often a source of vibration. The angle of attack to the layers has an important influence on the occurrence of vibration, as it controls how much of the bit face is against one layer and how much is against another layer, and how rapidly that proportion changes as the hole is drilled. This vibration is created as an uneven torque demand and depth of cut on the bit face. Also, localized differential mineral hardness with a formation (i.e. chert nodules, pyrite and boulders/pebbles) often will lead to bit vibration as an uneven torque demand and depth of cut on the bit face is created. Torsional vibrations generally increase with formation strength. Vibrations are particularly associated with interbedded formations that have zones with high-compressive strength and low-compressive strength. Depleted formations can also be a source of vibration, as the compressive strength is reduced and secondary fracturing may occur.

Bit-Lithology Interaction

Each bit will create its own cutting pattern on the bottom of the hole, and this pattern continues to propagate as it turns at the rock face. For PDC bits, any disruption to this pattern will cause the cutting elements to jump over the ridges created, and the cutters will experience differential loading, as some cutters bite and others are free – potentially leading to bit chatter or parametric resonance. In the case of rock bits, a conical structure is created, which, if disrupted, may create bit bounce.

Borehole Size / BHA Size

The borehole size determines the amount of deflection that the tools undergo when vibration occurs. Overgauged and undergauged parts of the well will influence the string motion, thus increasing or decreasing the confinement of the BHA. Undergauged sections produce an increase in torque, leading to stick-slip. Overgauged sections reduce stabilization, which leads to whirling or lateral shocks. Drilling out of casing and into large ratholes can lead to high vibration through lack of stabilization of the BHA, especially at higher angles where the bit and BHA will sag to the low side of the hole.

BHA Stabilization

Lack of stabilization in slick and pendulum assemblies can lead to vibration through whirling, as the BHA has a larger amount of freedom for movement. Undergauged stabilizers may lead to vibration through whirling again, as there is a larger amount of freedom of movement. Straight-bladed stabilizers can act as an excitation source for resonant vibration of the BHA.

Drilling Fluid Type

The fluid weight, type, and viscosity will influence the motion of the string. It will provide viscous damping to any vibrations set up in the system. Drilling fluid is also the medium through which pressure is transmitted. Therefore, any pulsation of pressure in the system will be transmitted through the fluid and from the fluid to the steel of the drillstring.

Rig Electrical System

Fluctuations in or limitations of the electrical system itself may be the source of vibration. For example, with electrical top drives the available power is not sufficient to maintain constant speed of rotation and stick slip is initiated.

Rig Torque Limiters

Rotary drive systems have torque limit settings to prevent overloading connections in the case of a drillstring stall trapping the drilling torque. In conditions where the drillstring torque demand during drilling triggers the torque limiter, the power is immediately reduced, creating a behavior like stick-slip where the rotary speed fluctuates.

Auto-Drillers

The configuration of the auto-driller can create vibration through poor control of WOB and RPM. ROP control can be quite stable so long as the other parameters do not limit ROP, as the drill line is simply fed at a constant rate and there is no feedback mechanism. With motors, when ROP and differential pressure settings are set to higher rates than can be achieved, this can lead to the system selecting WOB and RPM settings that can trigger stick-slip or whirling vibrations.

Rig Heave

On floating vessels, heave can occur that creates a cyclic fluctuation in bit weight, despite the use of a compensator (active or passive). This can be an input energy source disturbing the system and creating variations in bit weight, which will lead to variations in torque as the depth of cut is increased. These fluctuations may create a forced resonance in the system.

Backreaming with Excessively High RPM

Backreaming with excessively high RPM will always cause vibrations in the drillstring, as the bit is no longer acting as a point of stabilization for the base of the drillstring column and the whole BHA is in tension. The higher the RPM, the greater the dynamic instability and severity of vibration. In high-angle wells, high rotary speed may be selected to enhance hole cleaning. This may be acceptable, so long as lateral vibrations are not excessive. The rotary speed should be no higher than required for hole cleaning. Surface torque and drag measurements, annular pressure, and cuttings monitoring can help establish the hole cleaning status.

06

Drillstring Integrity Best Practices

PRE-WELL PLANNING

Design Out Vibration

The BHA will be designed to give the required directional performance for build, drop, and turn, while managing stress levels to prevent equipment mechanical yield and the development of fatigue.

Analysis will be performed at every change in well trajectory to determine the severity of the stresses and the expected duration at the stress level. Modeling will also be performed with a sensitivity around the planned trajectory to ensure that problems do not develop if the well path does not follow the plan exactly.

Wellbore size and shape, tortuosity, and friction factors will be obtained where possible from offset wells and the worst-case scenarios considered when modeling. Torque and drag will be modeled to determine if the rig has the required power to rotate the drillstring at the total depth (TD) of each hole section to avoid torsional vibration.

Guidelines for the required stabilizer shape and morphology will be followed to reduce the friction factor and decrease the probability of BHA whirl being initiated. Side force at every stabilizer will be modeled and the BHA design created to ensure that excessive side force is not created compared to the rock strength of the formations being drilled. Consideration will always be given to keeping the required number of stabilizers to a minimum while meeting the requirements for LWD log quality for tool centralization.

Bit selection will be made based on design features incorporated to prevent bit whirl, and modeling will be done to determine an acceptable torque profile and depth of cut for the formations being drilled to avoid the creation of torsional vibration.

It is also vital to run critical-speeds analysis to determine the fundamental and harmonic frequencies of the BHA and the amplitude of vibration created by forcing frequencies acting on the drillstring. Sensitivity analysis based on trajectory changes will be performed to establish the variation of the BHA fundamental and harmonic frequencies caused by changes in the distance to the tangency point of the BHA.

Stabilizer placement should be adjusted so as to provide a BHA design that has inherently lower vibration tendencies than alternative designs.

Offset analysis will be performed and any high-risk operations identified to ensure that the correct vibration reduction procedures are in place – and that drillers, directional drillers, and LWD engineers are made aware of correct practices for backreaming, hole opening, pilot hole drilling, reaming, hole opening while drilling, underreaming while drilling, and drilling out of casings or liners.

DURING DRILLING

Measure and React to Vibration

Run vibration sensors that can identify lateral, axial, and torsional vibration and instantaneous rotary speeds in the BHA. On surface, sample and store drilling parameters at a sufficient frequency to diagnose the correct vibration-generation mechanism.

» Calculate BHA fundamental and harmonic frequencies while drilling, and compare to actual drilling parameters to avoid inducing resonance.

» Use real-time vibration measurements to determine the mode and mechanism of vibration, and follow the recommended corrective actions.

» Make vibration-reduction procedures for each type of vibration available on the rig floor.

» Lost detection may be an indication of severe vibration. If detection is lost, pick up off bottom and determine if detection can be reestablished.

» Where installed, use torque feedback and soft-torque systems, and verify if the system is damping the correct frequency with the DrilSaver™ III vibration monitoring system.

» If required, increase mud lubricity to reduce friction and thereby torsional vibration.

» Keep an offset log of formations, if available, and track bit and stabilizer positions against lithology in order to anticipate and avoid vibration risks.

POST-DRILLING

Analyze Memory Data and Capture Lessons Learned

» Analyze vibration tool memory data to establish the vibration mechanisms active during the run and to identify any correlations to hole angle, formation type, bit or underreamer selection, hole enlargement, hole instability, hole cleaning efficiency, and cuttings bed buildup, and the relationship to the operating parameters of WOB and rotary speed.

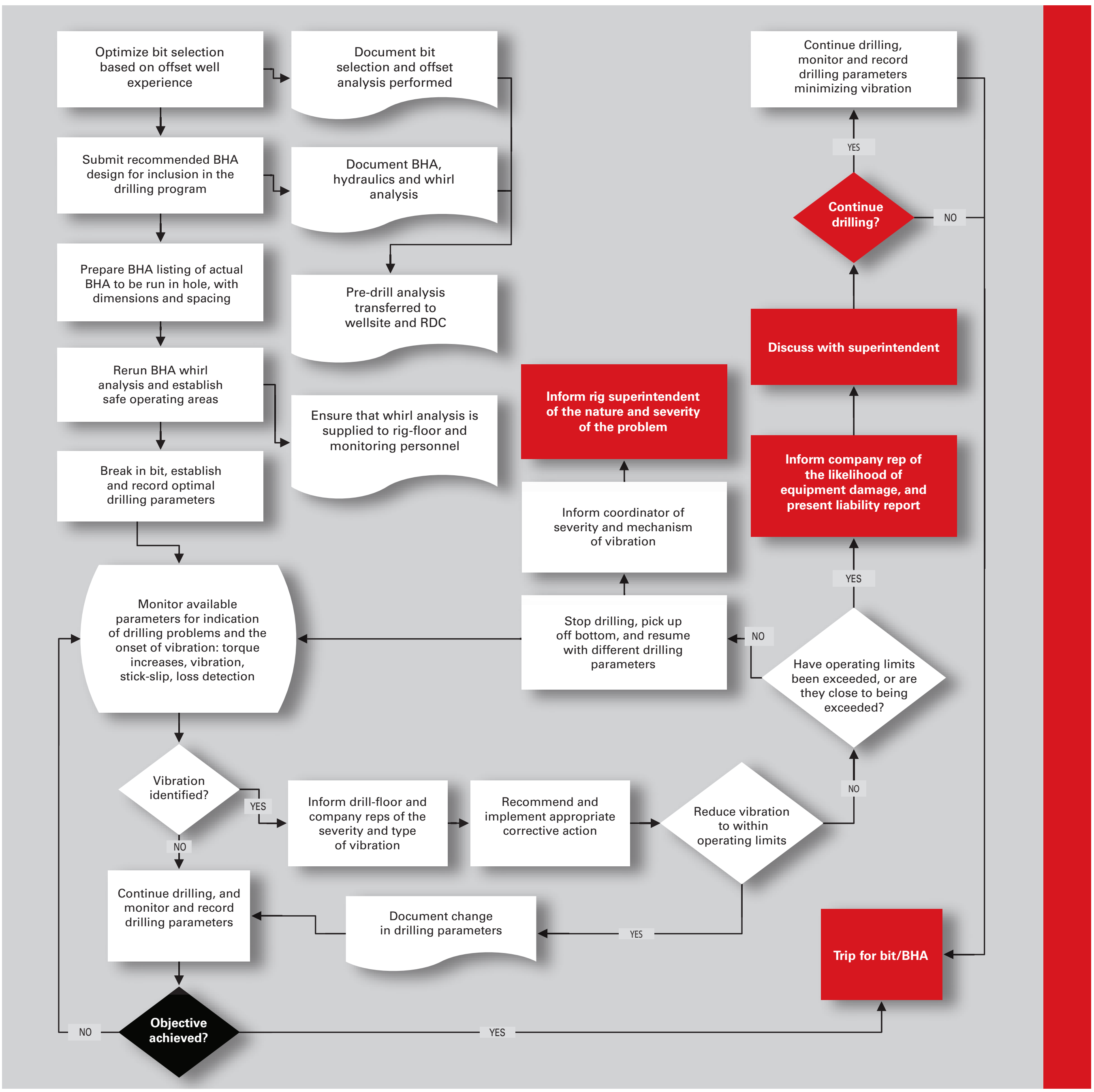
» Establish any correlation between the settings of the auto-driller or of system and the presence and severity of vibrations.

» Using high-frequency downhole data to perform a frequency analysis to identify the dominant frequency and amplitude of vibration on all three axes (X, Y, and Z) in order to confirm the active vibration mechanism.

» Ensure that experience is captured and transferred to the next well, with clear guidance for the teams on how to prevent the onset of vibration and to mitigate any vibration that does occur.

07

Vibration Alert Flowchart



08

Real-Time Detection

Mechanism	Vibration Measurement System
Stick-Slip / Low-Frequency Torsional Oscillation (LFTO)	DrilSaver™ III / Geo-Pilot® TEM / DDSr™ / BaseStar™ Vibration / Cerebro®
Torsional Resonance / High-Frequency Torsional Oscillation (HFTO)	iCruise at bit Gyro / DDSr / BaseStar Vibration / HDBS Cerebro
Bit Bounce	DDSr / BaseStar Vibration / HDBS Cerebro
Bit Forward Whirl	DDSr / BaseStar Vibration / HDBS Cerebro
Bit Backward Whirl	DDSr / BaseStar Vibration / HDBS Cerebro
BHA Forward Whirl	DDSr / BaseStar Vibration
BHA Backward Whirl	DDSr / BaseStar Vibration
Lateral Shocks	DDSr / BaseStar Vibration
Torsional Resonance	DDSr / BaseStar Vibration / HDBS Cerebro
Parametric Resonance	DDSr / BaseStar Vibration / HDBS Cerebro
Bit Chatter	DrilSaver III / Geo-Pilot TEM / DDSr / BaseStar™ Vibration
Modal Coupling	DrilSaver III / Geo-Pilot TEM / DDSr / BaseStar Vibration / HDBS Cerebro

Mechanism	Real-Time Surface Indications	Real-Time Downhole Indications	Real-Time Actions
Stick-Slip / Low-Frequency Torsional Oscillation (LFTO)	Primary • Cyclic torque and RPM at surface • Increase in DrilSaver™ KT magnitude • Rotary drive stalls • Loss of tool face, poor directional control with motors • Reduced or erratic ROP Secondary • Interference with mud pulse telemetry and signal loss	Primary • Cyclic RPM and torque downhole • Stalling of the bit and BHA • Increase in DDSr™ / BaseStar™ vibration stick-slip indicators • Decrease in Geo-Pilot® TEM torsional efficiency	• Decrease WOB and increase RPM • WOB increments are dependent on the size of the bit (10% of the maximum WOB value is recommended) • RPM increments are recommended in 10 RPM steps • Ensure that real-time depth of cut (DOC) calculators are running, and maintain optimum DOC as per roadmap
Torsional Resonance / High-Frequency Torsional Oscillation (HFTO)	Primary • No surface indicators	Primary • iCruise HFTO Secondary • Increases in tangential (Y axis) • vibration with little or no increase in radial (X axis) vibration • Y axis peak values greater than X axis peak values • Y axis average values greater than X axis peak values	• Increase the rotary speed to obtain a stable system • Control the WOB to limit the bit depth of cut

Mechanism	Real-Time Surface Indications	Real-Time Downhole Indications	Real-Time Actions
Bit Bounce	Primary • Shaking of surface equipment at shallow depths Secondary • Large WOB fluctuations • Possible SPP fluctuations • Loss of tool face, poor directional controlSecondary • Interference with mud pulse telemetry and signal loss	Primary • Medium to high average, and peak Z vibration, DDSr/BaseStar vibration Secondary • Possible associated torsional vibration, increase in DrilSaver KT magnitude • Decrease in Geo-Pilot (TEM) Torsional efficiency	• Increase WOB and decrease RPM • Amount is dependent on assembly size (guideline is +/- 10% of specified maximums for the bit) • Correlate stabilizer positions to formation changes.
Bit Forward Whirl **Bit Backward Whirl** **BHA Forward Whirl** **BHA Backward Whirl**	Primary • Increase in mean torque • Loss of tool face, poor directional control • Reduced or erratic ROP Secondary • Increase in calculated MSE values without a formation hardness change	Primary • Medium to high average, and peak X and Y vibrations from DDSr/BaseStar vibration • Rotary speed matches predicted critical frequency for BHA whirl Secondary • Increasing bending moment values from the DrillDOC® tool	• Increase WOB and decrease RPM • WOB increments are dependent on the size of the bit (10% of the maximum WOB value is recommended) • RPM increments are recommended in 10 RPM steps • If on a critical rotary speed, select a new rotary speed +/- 5 rpm from critical RPM and give the system time to dissipate the vibrational energy
Lateral Shocks	Primary • No primary indicators Secondary • Possible increase in mean torque • Possible associated torsional vibration cyclic RPM and TRQ	Primary • Medium to high peak X and Y accel-erations, but low average X and Y accelerations from DDSr/BaseStar vibration	• Decrease RPM to reduce energy input • RPM increments are recommended in 10 RPM steps
Parametric Resonance	Primary • No primary indicators Secondary • Possible increase in mean torque	Primary • High peak and average X and Y accelerations (DDSr/BaseStar vibration) Secondary • There may be a coupled Z axis acceleration (DDSr/BaseStar vibration); however, these will be much lower amplitude or may not be present telemetry and signal loss	• Increase WOB and decrease RPM • WOB increments are dependent on the size of the bit (10% of the maximum WOB value is recommended) • RPM increments are recommended in 10 RPM steps
Bit Chatter	Primary • No primary indicators	Primary • High peak and average X and Y accelerations (DDSr/BaseStar vibration)	• Adjust RPM up or down to a region away from the RPM being used (it may also be necessary to adjust the WOB to remove the condition) • Pick up off bottom and break in the bit with low RPM and WOB to reestablish a cutting pattern
Modal Coupling	Primary • Increase in mean torque • Loss of tool face, poor directional control • Reduced or erratic ROP Secondary • Interference with mud pulse telemetry — signal loss	Primary • High peak X, Y, and Z accelerations, with low average X and Y accelerations (average X may be greater than average Y, with low Z accelerations) • Increase in DDSr/BaseStar vibration (stick-slip indicators) • Decrease in Geo-Pilot (TEM) torsional efficiency	• Try a lower RPM first (RPM increments are recommended in 10 RPM steps). • Stop rotating and pick up off bottom, and then resume drilling with modified WOB and RPM

09

Real-Time Displays

LOGIX™ Vibration Director

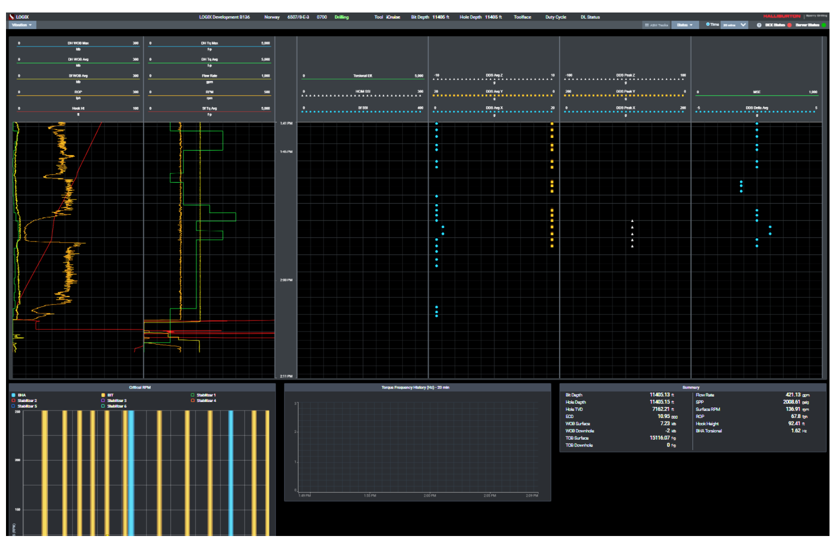
The LOGIX™ automated drilling solution's vibration director minimizes tool failure and improves drilling efficiency by identifying the type of surface or downhole vibration and then providing mitigation recommendations. Three real-time models for vibration mitigation and mechanical fatigue monitoring – drilling dynamics advisor, real-time whirl, and top-drive stick-slip controller – use a combination of downhole sensor data, surface measurements, natural frequency calculations, and the Fast Fourier Transform (FFT) algorithm to identify vibration type and define parameters to mitigate vibration. The corrective action can be automatically applied to improve drilling performance by avoiding downhole tool failures, hole damage, and unplanned rig repairs.

Drilling Dynamics Advisor (DDA)

The Drilling Dynamics Advisor (DDA)monitors data transmission from the DrilSaver™ III, Geo-Pilot® TEM, DDSr™, and BaseStar™ vibration sensors to automatically identify the mechanism of vibration and provide recommendations for mitigating the vibration. Alerts are passed to the InSite® alarm system to notify users on the InSite network of the alarm condition.

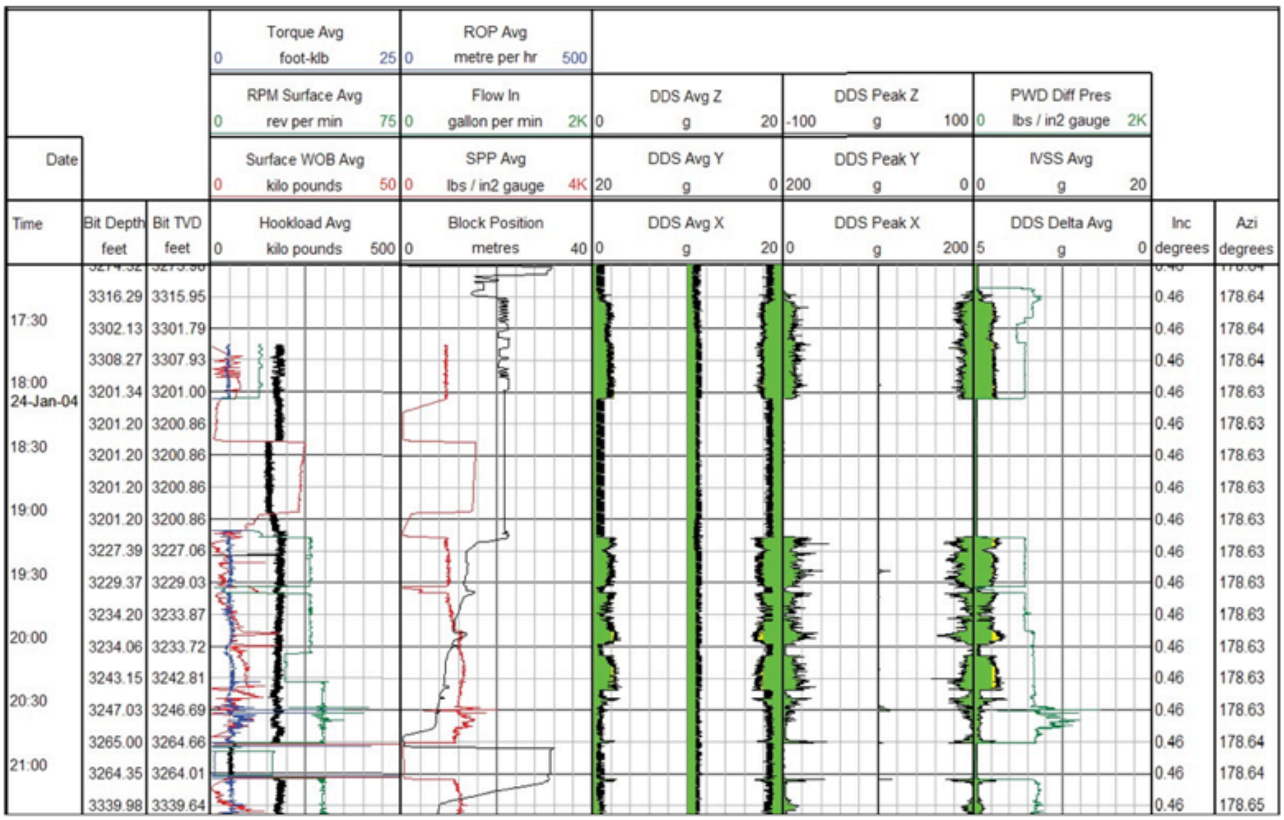
Real-Time Whirl™ Software

Real-Time Whirl™ software provides automatic while-drilling recalculation of the natural and harmonic resonant frequencies of the BHA based on changes in WOB, hole angle, dogleg severity, hole size, and mud weight – reflecting the actual drilling conditions encountered. All of the critical RPM values are displayed in in the InSite alarm system so that rig-floor personnel can avoid the creation of resonant BHA vibration and whirl.



InSite® Displays

InSite software allows the numeric and graphic display of surface and downhole drilling and vibration data to be customized for the specific application in question. This system enables any workstation at the wellsite to display the most up-to-date drilling and vibration data. Using this web-based access allows anyone with an Internet connection to view the information.



10

Vibration Modeling Software

DrillingXpert™ – MaxBHA™ Whirl Module (Geo-Pilot®, Motors and Rotary Assemblies)

- Based on the DYNAMICS program created by Boeing and developed by Dykstra at Tulsa University to analyze the BHA in 2D
- Performs critical-speed analysis of the BHA to identify the fundamental lateral resonant frequency and its harmonics
- Models sensitivity of resonant frequencies to variable drilling parameters
- Performs mode-shape analysis to determine the displacement and bending of BHA components during vibration events
- Models assemblies with dual cutting structures to identify resonant frequencies below and above reamers

DrillingXpert – MaxBHA Whirl Module (iCruise® Rotary Steerable System)

- Based on the Sperry Drilling Semi-Contained Modal Analysis (SCMA) program to analyze the BHA in 3D
- Performs critical-speed analysis of the BHA to identify the fundamental lateral resonant frequency and its harmonics
- Models sensitivity of resonant frequencies to variable drilling parameters
- Performs mode-shape analysis to determine the displacement and bending of BHA components during vibration events
- Models assemblies with dual cutting structures to identify resonant frequencies below and above reamers

DrillingXpert™ – WellPlan® BHA Dynamics – Vibration Analysis

- Based on a general-purpose finite element program to analyze the BHA in 3D
- The BHA Dynamics module facilitates 3D analysis of the static BHA, configured according to various wellbore geometries at different inclinations and directions
- The BHA Dynamics module can be used to identify critical rotary speeds and areas of high stress concentration in the drillstring
- Results obtained can be used to avoid critical rotary speeds that accelerate pipe fatigue, resulting in catastrophic drillstring failure; the stresses calculated are relative (not absolute) and should only be used for locating critical frequencies
- Outputs include a stress component plot, a displacement plot, a resultant stress plot, a shear force plot, a moments plot, an axial force plot, an axial displacement plot, a torque plot, and a torsional displacement plot

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Vibration Sensors

Drillstring Dynamics Sensor (DDSr™)

The Drillstring Dynamics Sensor (DDSr™) sensor, with rotation, can be mounted on various sensors and tools, including on the Halliburton dual gamma ray (DGR™) sensor, the Geo-Pilot DrillDOC® tool, the GeoTap® IDS sensor, the InSite® IXO interface tool, and the gamma/at-bit inclination (GABI™) sensor. This versatility allows for the gathering of vibration measurements on multiple sensors at multiple locations within the same BHA.

The sensors mounted on the board are:

» Triaxially mounted accelerometers

» Magnetometers

» Gyroscope

The measurements available from the tool are:

» Recorded and real-time X, Y, and Z peak vibration

» Recorded and real-time X, Y, and Z average vibration

» Recorded and real-time minimum, maximum, and average RPM

» Recorded and real-time calculated SSI indicator to show how close conditions are to stalling, or how severe an ongoing stall is in the drillstring [a value of 0% stick-slip index (SSI) indicates no RPM variation, and a value of 200% indicates a full stall condition]

» Recorded high sample rate burst data for frequency analysis

Geo-Pilot® Torsional Efficiency Monitor (TEM)

The torsional efficiency monitor (TEM) is derived from a measurement obtained from within the Geo-Pilot® rotary steerable system (RSS). A sensor located on its outer housing measures the rotational speed of the drive shaft. Where the speed of the shaft is constant, then torsional efficiency is high, 100%. As the rotational speed varies, then torsional efficiency reduces, with 0% indicating that the string is achieving a stalled condition. The measurement is available from each of the Geo-Pilot 9600, 7600, and 5200 series systems.

The measurements available from this RSS are:

» Recorded and real-time mean RPM

» Recorded and real-time RPM variation, minimum RPM and maximum RPM

» Torsional efficiency

DrilSaver™ III Vibration Monitoring System

DrilSaver™ III software is a surface data acquisition system that measures at a high sample rate (100 hz) for torque RPM, hook load, and standpipe pressure. The system can be run with its own sensors or tied into the rig's sensors.

The measurements available from the tool are:

» Performs Fast Fourier Transform (FFT) analysis on the torque, RPM, hook load, and standpipe pressures to calculate, in real time, the dominant and secondary frequency and amplitude.

» Recorded and real-time Kt magnitude (amplitude of torsional vibration at the dominant frequency)

» Records high-frequency burst data for use with PlayBack application for post well analysis and recalculation of the FFT analysis

Cerebro® and Cerebro Force™ Sensors

The Cerebro® tool is mounted within the shank of the bit – either as a sonde or mounted into a recess in the body. This tool's sensors measure vibration and orientation at the bit with the force version adding strain gauges.

The sensors mounted in the Cerebro Tool are:

» Triaxially mounted accelerometers

» Magnetometers

» Gyroscope

» Cerebro Force™ strain gauges

The measurements available from the Cerebro tool are:

» Recorded X, Y, and Z vibration

» Recorded X, Y, and Z shock

» Recorded RPM minimum, maximum, and average

» Recorded pitch (clockwise around the Y axis), Y axis (clockwise around the X axis), and roll (clockwise around the Z axis)

» Recorded weight on bit (Cerebro Force)

» Recorded torque on bit (Cerebro Force)

» Recorded bending at bit (Cerebro Force)

» Recorded continual high-frequency data storage (1,000 Hz) and post-run frequency analysis

BaseStar™ / LithoStar™ / ResiStar™ Vibration

A vibration sensor is mounted in all BaseStar™, LithoStar™, and ResiStar™ collars.

The sensors mounted in the board are:

» Triaxially mounted accelerometers

» Magnetometers

» Gyroscope

The measurements available from these sensors are:

» Recorded and real-time X, Y, and Z peak vibration

» Recorded and real-time X, Y, and Z average vibration

» Recorded and real-time minimum, maximum, and average RPM

» Recorded and real-time calculated SSI indicator to show how close conditions are to stalling, or how severe an ongoing stall is in the drillstring (a value of 0% SSI indicates no RPM variation, and a value of 200% indicates a full stall condition)

» Recorded high sample rate burst data for frequency analysis

iCruise at bit Gyroscope (HFTO)

The iCruise tool has an at-bit gyroscope mounted in the steering collar. A Fast Fourier Transform (FFT) of the Gyroscope output is used to determine the acceleration and frequency content of the measurement to identify High Frequency Torsional Oscillation.

The measurement available from the tool are:

» Recorded and real-time HFTO magnitude

» Recorded and real-time HFTO Magnitude for primary, secondary, and tertiary FFT amplitudes

» Recoded and real-time HFTO primary, secondary, and tertiary FFT frequencies

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Vibration Operating Limits

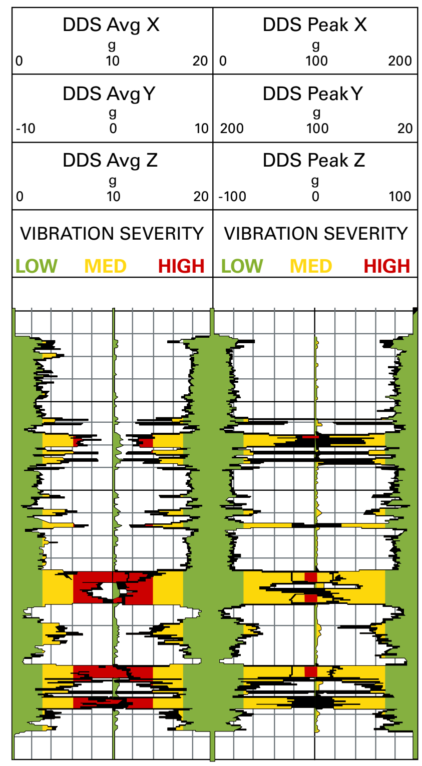
iCRUISE® / iCRUISE X™ / iSTAR™ M/LWD TOOL VIBRATION OPERATING LIMITS (iCRUISE DDSr™, iSTAR™ DRILLING DYNAMICS)

Vibration operating limits are referenced in real-time to the primary vibration tool assigned during download.

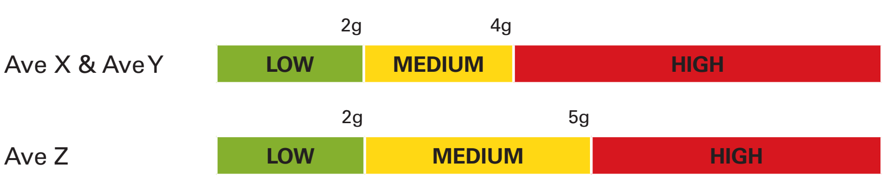
» When present, the iCruise DDSr™ is the primary vibration tool.
» When the iCruise® is not present, the ResiStar® is the primary vibration tool.
» When the iCruise and ResiStar® are not present, the BaseStar® is the primary vibration tool. The 4-3/4″ BaseStar® has different operating limit thresholds.

The vibration histograms from the tool memory are the definitive record for operating limits exposure.

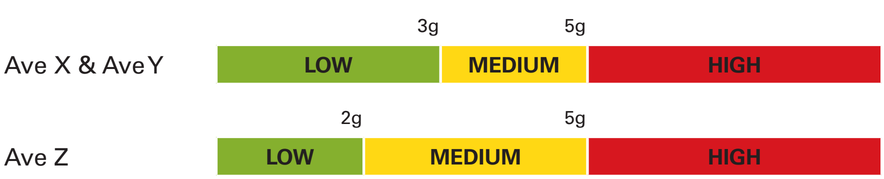
X axis accelerometers are mounted radially. Y axis accelerometers are mounted tangentially. Z axis accelerometers are mounted axially. SSI and HFTO are derived from rotational measurements.



9-1/2″ Tools: Ave Acceleration



8″ Tools: Ave Acceleration



High-Speed Communications Port

Mud Resistivity and Temperature

EWR™-M5

Dynamic Motion Sensor

Azumuthal Gamma Ray

Pressure While Drilling

6-3/4" and Smaller Tool Sizes: Ave Acceleration

		3g		6g	
Ave X & Ave Y	LOW		MEDIUM		HIGH

		2g		5g	
Ave Z	LOW		MEDIUM		HIGH

All Tool Sizes: Peak Accelerations

		30g		90g	
Peak X & Y	LOW		MEDIUM		HIGH

		15g		40g	
Peak Z	LOW		MEDIUM		HIGH

4-3/4" BaseStar®: Ave Acceleration

		2g		4g	
Ave X & Ave Y	LOW		MEDIUM		HIGH

		2g		3g	
Ave Z	LOW		MEDIUM		HIGH

4-3/4" BaseStar®: Peak Accelerations

		20g		50g	
Peak X & Y	LOW		MEDIUM		HIGH

		10g		25g	
Peak Z	LOW		MEDIUM		HIGH

All Tool Sizes: Stick-Slip

	0g		100%		200%	
SSI		LOW		MEDIUM		HIGH

All Tool Sizes: High Frequency Torsional Oscillation

		5g		10g	
HFTO	LOW		MEDIUM		HIGH

	10g		30g	
PEAK HFTO		HIGH		EXTREME

Average X, Y in the high zone for 40 minutes or greater and tools have exceeded specified limits.

Average Z in the high zone for 20 minutes or greater and tools have exceeded specified limits.

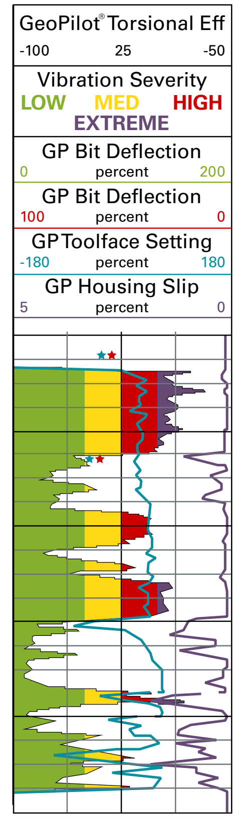
HFTO in the high zone for 60 minutes or greater and tools have exceeded specified limits.

Peak HFTO in the Extreme Zone for 10 minutes or greater and tools have exceeded specified limits.

Peak X or Y in the high zone for 300 events or greater and tools have exceeded specified limits.

Peak Z in the high zone for 200 events or greater and tools have exceeded specified limits.

SSI between 100 percent and 200 percent for greater than 12 hours and tool is outside limits. SSI greater than200 percent for greater than 60 minutes and tool is outside limits.



ADDITIONAL M/LWD AND GEO-PILOT® RSS TOOLS VIBRATION OPERATING LIMITS (DDSr™, DDS2-M5™, GEO-PILOT® TEM™)

Vibration operating limits are referenced in real time to the primary vibration tool assigned during download.

» When present, the Geo-Pilot® DDSr™ is the primary vibration tool.
» When the Geo-Pilot® is not present, the DDSr-DGR™ is the primary vibration tool.
» When the Geo-Pilot® DDSr™ and DDSr-DGR™ are not present the DDSr-HCIM™ is the primary vibration tool.
» When no insert-based DDSr™ tools are present, the DDS-Sonde™ is the primary vibration tool. The 4-3/4" DDSr-Sonde™ has different operating limit thresholds.
» When no DDSr™ tools are present, the SVSS is the primary vibration tool.
» When the M5™ tool is being run and no DDSr™ tools are in the string, the M5-DDS2™ is the primary vibration tool.

The vibration histograms from the tool memory are the difinitive record for operating limits exposure.

X axis accelerometers are mounted radially. Y axis accelerometers are mounted tangentially. Z axis accelerometers are mounted axially.

9-1/2" Tools / Geo-Pilot® 9600 / Geo-Pilot® Duro™ 9600: Ave Acceleration

		2g	4g
Ave X & Ave Y	LOW	MEDIUM	HIGH

		2g	4g
Ave Z	LOW	MEDIUM	HIGH

	-2g	-1g	0g
Ave X-Ave Y	HIGH	MEDIUM	LOW

8" Tools / Geo-Pilot® 7600 / Geo-Pilot® Duro™ 7600: Ave Acceleration

Ave X & Ave Y	LOW	3g	MEDIUM	5g	HIGH	
Ave Z	LOW	2g	MEDIUM	4g	HIGH	
Ave X-Ave Y	HIGH	-2g	MEDIUM	-1g	LOW	0g

6-3/4" and Smaller Tool Sizes / Geo-Pilot 5200® / Geo-Pilot® Duro™ 5200: Ave Acceleration

Ave X & Ave Y	LOW	3g	MEDIUM	6g	HIGH	
Ave Z	LOW	2g	MEDIUM	4g	HIGH	
Ave X-Ave Y	HIGH	-2g	MEDIUM	-1g	LOW	0g

All Tool Sizes: Peak Accelerations

Peak X & Y	LOW	30g	MEDIUM	90g	HIGH
Peak Z	LOW	15g	MEDIUM	40g	HIGH

4-3/4" DDSr-Sonde™: Ave Acceleration

Ave X & Ave Y	LOW	2g	MEDIUM	4g	HIGH
Ave Z	LOW	2g	MEDIUM	4g	HIGH

4-3/4" DDSr-Sonde™: Peak Accelerations

Peak X & Y	LOW	15g	MEDIUM	45g	HIGH
Peak Z	LOW	15g	MEDIUM	40g	HIGH

All Tool Sizes: M5-DDS2™ Shock (Short Average) Acceleration

Peak X & Y	LOW	15g	MEDIUM	30g	HIGH
Peak Z	LOW	10g	MEDIUM	20g	HIGH

Average X, Y in the high zone for 18 minutes or greater and tools have exceeded specified limits. For certain Geo-Pilot Duro BHAs the limit is 30 minutes.

Average Z in the high zone for 8 minutes or greater and tools have exceeded specified limits. For certain Geo-Pilot Duro BHAs the limit is 15 minutes.

Average X-Average Y in the high zone for 18 minutes or greater and tools have exceeded specified limits.

Peak X or Y in the high zone for 150 events or greater and tools have exceeded specified limits. For certain Geo-Pilot® Duro™ BHAs the limit is 250 events.

Peak Z in the high zone for 100 events or greater and tools have exceeded specified limits. For certain Geo-Pilot® Duro™ BHAs the limit is 150 events.

For details of Geo-Pilot® Duro™ BHAs contact your Sperry representative.

DDSr™ STICK-SLIP INDICATOR (SSI)

All Tool Sizes: Torsional Efficiency %

	0% – 100%	100% – 150%	150% – 200%
SSI	LOW	MEDIUM	HIGH

SSI between 100 percent and 150 percent for greater than 12 hours and tool is outside limits. SSI greater than150 percent for greater than 30 minutes and tool is outside limits. For certain Geo-Pilot Duro BHAs the high threshold is 200% and the duration is 60 minutes.

Note: Contact your Sperry Drilling representative for details of the Geo-Pilot® Duro™ BHAs that can be run with the higher operating limits.

GEO-PILOT® SYSTEM TORSIONAL EFFICIENCY MONITOR

All Tool Sizes: Torsional Efficiency %

	100%	50%	25%	0%	-VE%
TEM	LOW		MEDIUM	HIGH	

TEM between 50 percent and 25 percent for greater than 12 hours and tool is outside limits. TEM less than 25 percent for greater than 30 minutes and tool is outside limits. For certain Geo-Pilot® Duro™ BHAs the high threshold is 0% and the duration is 60 minutes.

SONDE VIBRATION SEVERITY SENSOR (SVSS)

9-1/2-In. Tools: Average Acceleration

	LOW	MEDIUM	HIGH
Ave X	< 2g	2g – 4g	> 4g
Ave Z	< 2g	2g – 4g	> 4g

8-In. Tools: Average Acceleration

	LOW	MEDIUM	HIGH
Ave X	< 3g	3g – 5g	> 5g
Ave Z	< 2g	2g – 4g	> 4g

6-3/4-In. and Smaller Tool Sizes: Average Acceleration

	LOW	MEDIUM	HIGH
Ave X	< 3g	3g – 6g	> 6g
Ave Z	< 2g	2g – 4g	> 4g

All Tool Sizes: Peak (Short Average) Acceleration

	LOW	MEDIUM	HIGH
Ave X	< 15g	15g – 30g	> 30g
Ave Z	< 10g	10g – 20g	> 20g

Average X in the high zone for 18 minutes or greater and tools have exceeded specified limits.

Average Z in the high zone for 8 minutes or greater and tools have exceeded specified limits.

Peak X in the high zone for 10 minutes or greater and tools have exceeded specified limits.

Peak Z in the high zone for 6.67 minutes or greater and tools have exceeded specified limits.

Sales of Halliburton products and services will be in accord solely with the terms and conditions contained in the contract between Halliburton and the customer that is applicable to the sale.

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